

ASSET MANAGEMENT PLAN



2026

WAIPĀ
NETWORKS 



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FOREWORD FROM THE CHIEF EXECUTIVE

Over the past year, Waipā Networks has taken substantial steps to strengthen our asset management approach, ensuring it is future-ready and responsive to the evolving needs of our customers and communities.

Central to this progress is the enhancement of our customer engagement process, where we are embedding customer and community insights earlier and more consistently into network planning. Our approach is to engage with customers and assess non-traditional options such as demand response, distributed generation, and storage alongside conventional network reinforcement.

Alongside these improvements, we are committed to maximising the efficiency and effectiveness of our assets and operations. Our approach centres on maintaining affordability by driving cost efficiencies and productivity, enabling customer and business electrification, fostering collaboration and shared services when they provide clear customer benefits, and standardising customer-facing processes to ensure best practices and positive experiences.

A key milestone in this AMP is the completion of the first stage of the Te Awamutu architecture review. This review has informed the inclusion of our hybrid network architecture, which blends traditional and non-traditional solutions to help unlock existing capacity. The hybrid approach leverages technologies such as fast transfer systems and battery energy storage systems. Through

these advancements, we are better positioned to meet future demand and deliver reliable service, especially in rapidly growing areas like Te Awamutu.

Our commitment to progress is demonstrated by the significant increase in our ten-year forecast capital expenditure (capex) compared to the previous AMP. This substantial investment is driven by regional and distribution capacity projects in Te Awamutu, supply upgrades for our major customers, and asset relocations associated with the SH1 Cambridge to Piarere project.

As we move forward, Waipā Networks remains committed to delivering safe, reliable, and cost-effective electricity distribution. Our renewed focus on engagement, efficiency, and innovative network design will underpin our ability to serve our stakeholders and communities for years to come.

I invite you to read our 2026 AMP to understand how we are preparing our electricity network to support our Region's future.

Ngā mihi,

Thomas Bromfield
Acting Chief Executive



1. EXECUTIVE SUMMARY

1.1 Progress on our asset management journey

We began our asset management improvement journey in our 2023 AMP by updating our Asset Management Strategy to ensure we deliver electricity to our customers in line with New Zealand's electricity future. We continued this work in our 2024 AMP, which included assessing the scope of energy transformation and defining comprehensive fleet plans for all our material assets. These AMPs significantly updated the previous plans and described our evolution toward an electrified, low-emissions future. In 2025, we elected to publish an AMP update as there are relatively few material changes to our development and lifecycle plans.

The 2026 AMP continues our asset management journey. It details a significant change to our customer engagement process, embedding an ongoing partnership with customers and communities into asset management decision-making. It also presents the outcome of the first stage of our Te Awamutu architecture review, including our specific plans to increase capacity in the Te Awamutu area and the broad scope of the investment required in the distribution network. Our plans to improve capacity include the use of non-network solutions to lower costs and adapt to demand growth. We will also look to unlock capacity that is inherent in our and neighbouring networks via fast transfer systems, additional connections and the use of non-network solutions. We expect distribution investments to also include non-network solutions, and this is our focus as we move into the next phase of the Te Awamutu architecture review.

1.2 Introduction

This executive summary highlights the key factors driving investment and performance, the strategies adopted to ensure the network responds to those factors, and the key programmes and projects supporting the strategy.

The 10-year forecast capital expenditure (capex) of \$309.5m, which is a \$98.9m (52%) increase compared to the 2025 AMP. This increase is primarily due to the expansion of the Waikeria

Prison, which requires a major supply upgrade, regional and distribution capacity projects in Te Awamutu (now included due to greater planning certainty), asset relocation linked to the SH1 Cambridge to Piarere project, and offset by a decrease in asset replacement capex. The AMP outlines the reasons for these changes.

1.3 Purpose and structure of this AMP

This AMP communicates Waipā Networks' approach to facilitating the safe, reliable, and cost-effective distribution of electricity to customers in our region. We are committed to the long-term stewardship of an electricity network that meets the needs of our stakeholders and supports the livelihoods of the people and businesses throughout the areas we serve.

We aim to communicate the alignment between our Asset Management Strategy and our stakeholders' needs. To aid this approach, this executive summary and the AMP have been organised into three parts:

- **Part 1:** The key issues facing the network
- **Part 2:** Strategies to address the key issues
- **Part 3:** Implementation plans to deliver the strategy and the required performance.

This AMP continues to provide all the information to assure our stakeholders that:

- Our assets are being managed for the long term
- The required level of performance is being delivered (and where there are gaps, improvement plans are being implemented)
- Our business is efficient (so the distribution prices are no higher than need be).

A reconciliation of the Information Disclosure requirements is included in the appendices.

Summary of part 1: The key issues facing the network

1.4 Our customers and customer engagement strategy

Our customer base is diverse, spanning urban, rural, higher and lower-income communities, as well as businesses. This diversity means that affordability, reliability, resilience, sustainability, and power quality are valued differently across the network. As a result, our asset management approach must balance cost impacts carefully while ensuring that service levels and investment decisions reflect what customers in different locations and circumstances value most.

Demand for electricity across the region continues to grow, driven by population growth, urbanisation, decarbonisation and ongoing agricultural activity. At the same time, the profile of our customers is changing. A network that historically served predominantly rural communities is now supplying a larger and growing urban population. This shift has already influenced major investment decisions, including the reconfiguration of the Cambridge network and a review of network architecture in the Te Awamutu area, and will continue to shape future development priorities.

The energy system is also changing. Decarbonisation, electrification, and the emergence of distributed energy resources such as rooftop solar, batteries, and demand response are altering how customers use electricity and how they can participate in meeting network needs. These changes introduce new trade-offs between affordability, reliability, resilience, sustainability, and power quality, and reinforce the importance of understanding customer preferences before committing to long-lived investments.

Customer research indicates that perceived satisfaction with network reliability is high (81% satisfied with a further 17% neutral), but perceptions vary by customer group. Rural and commercial customers have a slightly lower satisfaction with the reliability of supply. These differences underline the need

for more targeted, place-based approaches to planning and investment. Overall, 41% of customers prioritise reliability and are more willing to pay for improvements.

Uptake of emerging technologies such as electric vehicles and distributed generation remains at an early stage, and stated intentions to invest vary significantly by location and demographic. This uncertainty supports a staged and flexible investment approach, where projects can be accelerated, deferred, or reshaped as customer preferences, technology uptake, and system conditions become clearer.

To respond to these challenges, this AMP introduces a strengthened customer engagement strategy. We are embedding customer and community insight earlier and more consistently into network planning so that investment decisions are informed by a clear understanding of what customers value and the trade-offs they are prepared to make. This includes testing non-traditional options such as demand response, distributed generation, and storage alongside conventional network reinforcement.

Our new engagement approach is grounded in inclusive, material, and responsive engagement, with clear accountability. Customers and communities will be involved earlier in defining problems, shaping options, and co-designing solutions, particularly where investment choices have significant implications for price, reliability, or resilience. This approach is expected to influence investment timing and scope, while Waipā Networks remains accountable for the final decisions. We are in the early stages of this engagement, and it will be iterative, developing as our learnings and knowledge grow. Further details on our customers, stakeholder engagement, and place-based engagement approach are set out in Section 3.



1.5 The network

Our network supplies customers across the Waipā district and surrounding areas, including parts of the Waikato and King Country regions of the North Island. This is primarily within the Waipā and Ōtorohanga districts, with smaller sections extending into the Waikato district south of Hamilton and the Waitomo district south of Kāwhia. Our distribution network covers approximately 1,865 square kilometres.

Overall, our network infrastructure is relatively young, with a weighted average age of 14 years, which is approximately 30% of the average expected lifespan. However, we have an increasing population of older assets that will require replacement over the coming decade.

We have two networks: one servicing the Cambridge area, supplied from Transpower's Cambridge and Hautapu GXPs at 11kV and 33kV, and another serving the Te Awamutu area, supplied from Transpower's Te Awamutu GXP at 11kV. These networks were established to serve the modestly populated townships of Cambridge and Te Awamutu, as well as the large surrounding rural areas.

Our region has seen significant population growth over the past twenty years. The increased demand has prompted changes in network configuration, particularly in the Cambridge area, with a similar transformation now planned for the Te Awamutu area. These developments are driven by the shift from a predominantly rural network to one that increasingly serves urban and semi-urban communities.

The Cambridge and Te Awamutu networks have distinct characteristics requiring tailored asset management approaches. The Cambridge network now exhibits features typical of semi-urban areas, while the Te Awamutu network remains largely rural, with lower customer density and a higher proportion of overhead lines and lengthy feeders. This differentiation means that each network faces unique operational and maintenance challenges and requires different strategies to ensure reliable service.

Recent infrastructure upgrades have addressed security constraints in the Cambridge area, notably the commissioning of the Hautapu GXP, Forrest Road substation, and four new feeders. These improvements have enhanced regional security and support continued growth.

However, we are facing constraints in the Te Awamutu area, which will worsen with the upcoming decommissioning of Fonterra's embedded cogeneration plant and ongoing population growth. The Te Awamutu network is experiencing consistent increases in customer numbers and demand, pushing the existing 11kV feeders closer to capacity limits and restricting backfeeding options, which impacts network security.

Refer to Section 4 for full details on our network.

1.6 Review of performance

Section 5 includes the full suite of performance metrics, all of which are important. At a strategic level, reliability and delivery performance are key inputs in developing the asset management strategy. We comment on these performance measures below.

FY25 performance highlights

Our safety outcomes in FY25 were strong, with all key safety measures meeting or exceeding their targets. This positive result is attributed to the continued effectiveness of our safety strategy.

In terms of reliability, unplanned reliability (for both SAIDI and SAIFI) remained favourable throughout FY25, supported in part by favourable and stable weather conditions, and proactive measures taken.

Reliability performance

We achieved our unplanned reliability targets in both FY21 and FY25 (see figure 1). However, the period faced challenges. Unfavourable environmental conditions in FY22 and FY23 led to more outages, underscoring how external factors can affect our operations. Additionally, FY24 experienced a significant increase in third-party damage incidents, which impacted our reliability.

Planned reliability performance has remained within target over the past five years. Although earlier AMPs assessed performance annually, the target applies across the full five-year period to FY25 and has been achieved. While we remained under for the 5 year period, in FY25, planned SAIDI and SAIFI were significantly higher than the notional annualised target. This was driven by major planned projects and an increasing volume of renewal work. We plan to review the drivers behind this change, identify improvements, and consider how we will manage the increased workload over the coming years. We may also consider revising our targets if the improvement options are uneconomic and once we understand in more detail the constructability and the delivery methodologies.

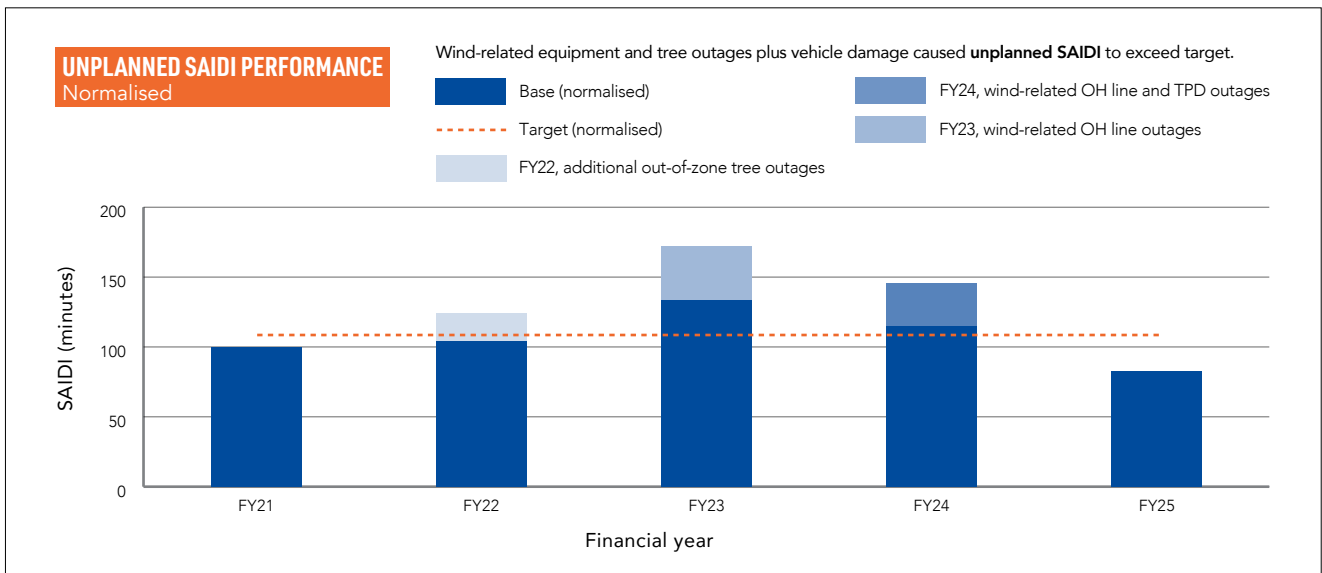


Figure 1: Unplanned SAIDI performance (normalised)

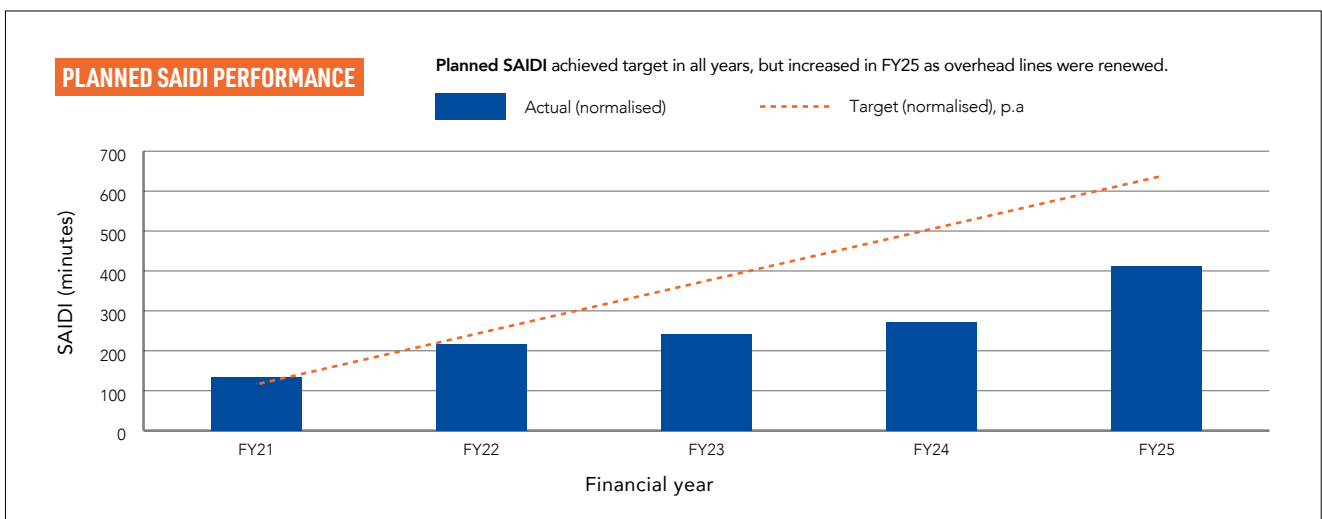


Figure 2: Planned SAIDI performance

A deeper dive into the causes of unplanned reliability performance indicates that:

- The network is exposed to adverse weather (e.g. Cyclones Dovi and Gabrielle), and resilience to wind events needs to be a key focus on our rural and urban feeders.
- Defective equipment outages continue to perform favourably against our semi-rural peer group; however, this is a major contributor to SAIDI, and there are further areas for improvement identified.
- Third-party damage (primarily from vehicles) is an ongoing issue and remains difficult to address due to the spread of incidents across the network.
- Vegetation-related outages are broadly consistent with our peer group. Except for the Kāwhia and Pencarrow feeders, performance issues have been addressed.

We have seen a concentration of the above-mentioned issues on a few feeders. Our four worst-performing feeders account for 39% of SAIDI. We have a specific project examining a solution for the Kāwhia feeder (see Section 11.12.2) and programmes in place to address security improvements on other feeders (see Section 11.8.2 and 11.12.2).

Regarding defective equipment, failures of conductors, insulators/binders, crossarms, and overhead switchgear on our overhead network are the primary causes, accounting for 60% of defective equipment outages. These primarily impact rural feeders and correlate strongly with wind events. Our fleet plans target asset renewals in areas where we have both performance and health issues.

Delivery of the work programme

Our capex delivery performance has improved, with a network capex variance of 5% over the past two years (refer to figure 3). For FY25, capex delivery was good and within target.

We are also making good progress on completing our asset condition assessments, which are important inputs into our health assessments. Since the start of FY22, our focus has been on our wooden pole, pillar and RMU fleets and inspections are ahead of plan in these areas. We are at or ahead of plan for most other assets, with the feeder inspection program slightly behind plan.

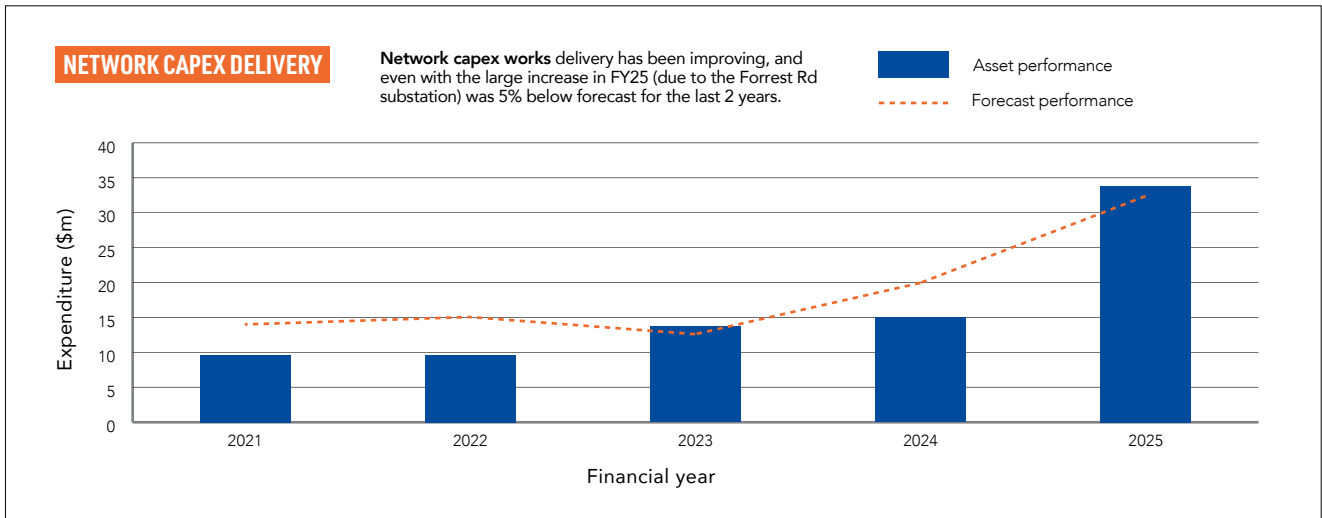


Figure 3: Network capex delivery

1.7 The key factors that are driving investment and performance

Ensuring we understand and address the key issues affecting the network is important. We continue to monitor a wide range of issues and have highlighted the key factors that are driving investment and performance in Section 6. These are the most important issues that shape our asset management strategy. The key issues are:

- The high regional population and industrial growth
- The need to manage future demand growth due to electrification
- The ageing of our network assets
- The increasing incidents and impact of adverse weather events
- The need for greater maturity in asset management to effectively manage the issues above.



The high regional population and industrial growth

The Waipā district is highly attractive for both residential living and business activity. Since 2013, our network has recorded the third-highest ICP growth rate among New Zealand's electricity distribution businesses, with residential customers expanding at a notable 2.2% compound annual growth rate.

Looking ahead, strong growth in residential connections is expected to continue, with the Waipā District Council projecting the population to exceed 74,000 by 2034. This anticipated increase will require connecting approximately 12,000 new homes to the network by 2050. To accommodate this expansion, the Council has designated significant land for residential development, including 201 hectares in Te Awamutu and Kihikihi, to accommodate about 3,000 homes. It plans to allocate approximately 18 hectares annually in the Cambridge area.

The commercial and industrial sectors have also seen solid growth, with large customer connections increasing by 9% each year since 2023. This segment has contributed more than half of the region's recent consumption growth, partly due to Waipā's strategic position near the "golden triangle" of Hamilton, Tauranga, and Auckland. The region is also preparing for further industrial expansion, with ongoing efforts to rezone land and deliver essential services to new industries in Hautapu. The installation of the Hautapu GXP provides an ideal location to connect in large electricity intensive loads.

By 2050, the number of network customers, along with their consumption and demand, will significantly impact the network. Our demand forecasts suggest that growth from new customers (excluding electrification growth driven by decarbonisation) will account for 55% of the total demand growth by FY50.

The need to manage future demand growth due to electrification

Electricity will play a central role in meeting New Zealand's 2050 emissions reduction goal by enabling the widespread electrification of transport and industry, which requires a significant increase in renewable generation. This transition involves replacing fossil fuels with electricity.

As electricity replaces less sustainable energy sources, demand for our network will rise, requiring investment in capacity, reliability, resilience, and new technologies to support flexible, bi-directional usage. Uncertainty about the scale and timing of these changes complicates planning.

As electrification grows, the connection between electricity and GDP will strengthen. Electrification will also reduce energy diversity, for example, by shifting reliance on transport fuels to electricity, which could increase dependence on electricity. It will therefore be critical that electricity security and resilience are managed to meet customer needs.

Demand growth due to electrification has been modest to date. Given the factors mentioned above, electrification growth by 2050 could significantly impact the network. Our demand forecasts indicate that electrification growth could account for 45% of the total increase in demand by FY50. Significantly higher growth from electrification could occur if we are unable to secure flexibility services from customers (or their agents) to shift EV charging to low-demand periods, access battery support, or control water heating loads. Hence, there is uncertainty as to the future shape and flexibility of the load, which requires an adaptable approach to our development plans.

The ageing of our network assets

We expect to see end-of-life drivers emerge in some of our assets over the coming decade. This is a normal part of the asset ageing process, but one that we need to be ready for. Our current data suggests an increasing risk that end-of-life drivers will emerge. Our pole fleet is in good condition, as recent inspections have confirmed. However, wooden crossarms have a life expectancy of around half that of concrete poles and this is an area where we are focusing on data improvements and understanding.

Overall, our ageing asset fleet is not currently a significant issue for our business. However, we must understand and manage asset health through our inspection, maintenance, and renewal programmes.

The increasing incidents and impact of adverse weather events

Our 11kV network is mostly overhead (88%), making it especially vulnerable to adverse weather, as seen with Cyclones Dovi and Gabrielle in FY22 and FY23. Climate change is expected to increase the frequency and intensity of major storms, so these risks must inform our approach to network resilience, design standards, and asset renewals. High winds have been the primary cause of weather-related outages, affecting reliability due to extended restoration times. As dependence on electricity grows, building a resilient network against severe weather is increasingly essential to meet customer needs.

The need for greater maturity in asset management to effectively manage the issues above

Each year, we assess our asset management maturity using the AMMAT tool.¹ Our assessment indicates that some components of our asset management system are fully developed, whereas others are still being implemented. With a score of 2.6 (up from 2024 AMP), we are below the industry average, with most gaps stemming from process issues and a need for better information and systems.

Our historical asset management maturity has been satisfactory during a period when our assets supported growth, showed limited signs of ageing, and customers' energy transformation was in its early stages. However, improvement is now necessary to ensure we have the systems, information, and capabilities to handle the strong demand growth, the complexity of the energy transformation, the rising threats from climate change, and our ageing asset fleet. We need to enhance information quality, engage more effectively with customers, consider a broader range of solutions, and undertake more complex modelling and analysis. These improvements are required to operate effectively in an increasingly interconnected electricity sector. The focus areas for our asset management improvement plan are outlined in Section 9.

¹ As measured using the Asset Management Maturity Assessment Tool (AMMAT), in Schedule 13.



Summary of part 2: Strategies to address the key issues

1.8 Asset management strategy

Our asset management strategy addresses customer and network needs, improves performance, and responds to investment drivers. It connects our corporate goals with planning for development, renewal, and improvements.

In this 2026 AMP, we have added an extra strategy related to customer engagement, as it has become more important to clearly understand customers' needs and future plans, to co-develop solutions and build meaningful, lasting relationships.

Our asset management strategy comprises seven initiatives:

Initiative	In response to...
1. Enhance our customer and stakeholder engagement	Customers' energy needs are shifting, creating opportunities for co-designed solutions that offer clear benefits over traditional network approaches.
2. Improve regional supply capacity and security	Historical and forecast demand growth that is reaching the limits of an 11kV-only network
3. Develop and implement a network transformation roadmap to further prepare for decarbonisation	Meeting New Zealand's 2050 emissions reduction goal and supporting customers' future usage of the network, including enabling customers' adoption of new technology and ensuring that our network supports them, maximising the benefits from that investment
4. Improve the reliability and resilience of our network	Our current reliability challenge and the greater reliance on electricity as a single source of energy for our customers
5. Maintain comprehensive fleet plans and renewal forecasts	Ageing of our asset fleet, the emergence of end-of-life drivers, and the increasing requirement for asset renewals
6. Improve asset management maturity	A need to make quality decisions based on quality data in an environment that is increasingly complex
7. Reduce the impact of vegetation on the network	Continued material impact of vegetation interference on reliability

Table 1: Our asset management strategy

Pursuing these strategies will require investment in network assets, information, systems, and people. We have outlined many of these investments in this AMP, but some of them have yet to be fully considered (and will be defined in future AMPs).

1.9 Performance targets

Customer service (reliability) targets

Figure 4 shows our forecast of average performance over the next 10 years, assuming the same instances of external events and implementing the planned reliability and security improvements. This provides a view of the ongoing risk to reliability while we implement the planned improvements. We are forecasting an improvement in our average performance, consistent with our asset management strategy (in particular, initiatives 2, 4, and 7), resulting in a 50% probability of achieving the target by FY31 and a 75% probability of achieving the target by FY36

probability by FY36 (see figure 5). This is the first year we have disclosed a forward view of improvements. We will refine our targets and estimates over the next year based on our customer engagement.

Our planned reliability targets increased in FY2021 and remain unchanged. Our planned work is increasing, which will put pressure on our planned work targets. However, we are focused on ensuring that our planned outages are coordinated to minimise the impact of increased work volume.

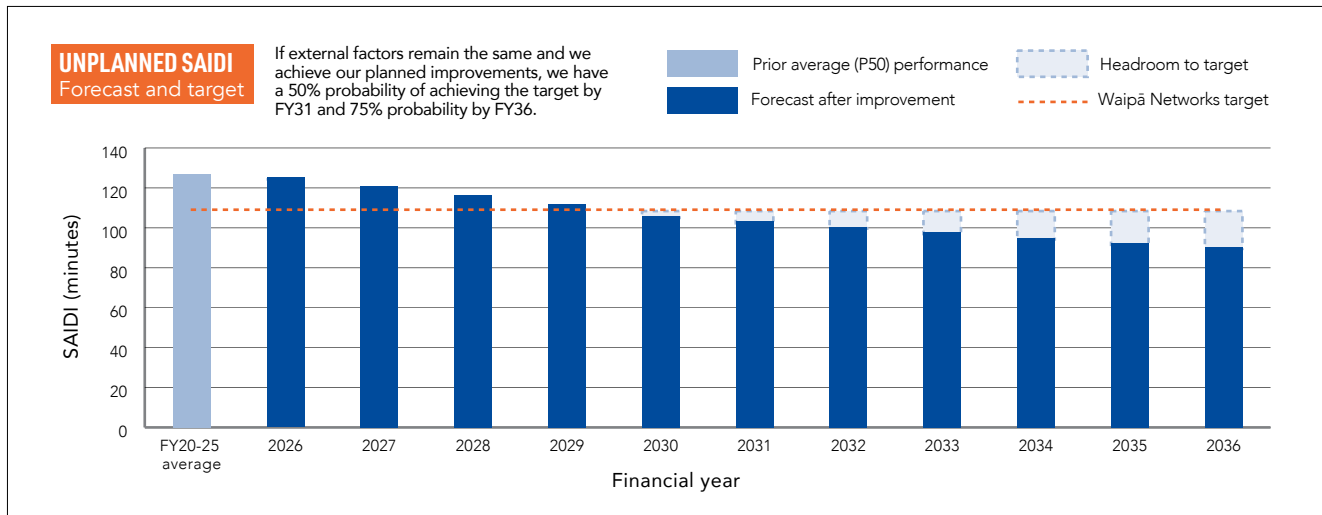


Figure 4: Unplanned SAIDI forecast and target

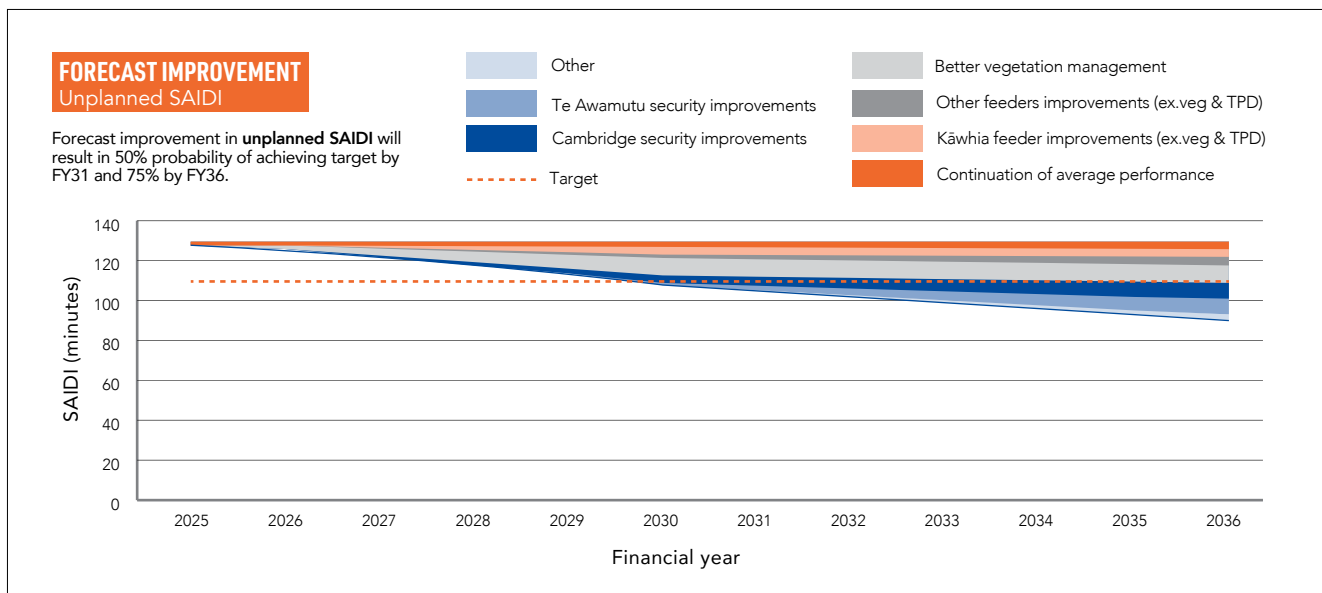


Figure 5: Forecast improvement in unplanned SAIDI

Delivery target

We aim to keep maintenance and fault response spending (excluding major weather events) within 5% of targets, and reduce planned maintenance and vegetation variances to 10% this year. For capital works, we target a 15% variance over the next two years due to consenting process impacts on project timelines.

1.10 Our role towards a sustainable future

We play an important part in supporting our region's shift to sustainable electrification. Our priorities include aligning with New Zealand's drive for decarbonisation, ensuring secure and resilient services, and supporting an equitable energy transition. Achieving these goals calls for customer engagement, innovation, and sound decisions.

Framework

The Energy Trilemma² is a well-recognised and useful framework (see figure 6) when considering the energy transition. It is guiding the development of New Zealand's Energy Strategy.

In the energy context, the three limbs refer to:

- Sustainability means supporting New Zealand's energy transformation, minimising emissions, and adapting to climate change.
- Security means the ability to reliably meet current and future energy demands, as needed by our customers, including being resilient to external events.
- Affordability means the cost of, and access to, energy (of which electricity is an increasingly important component).

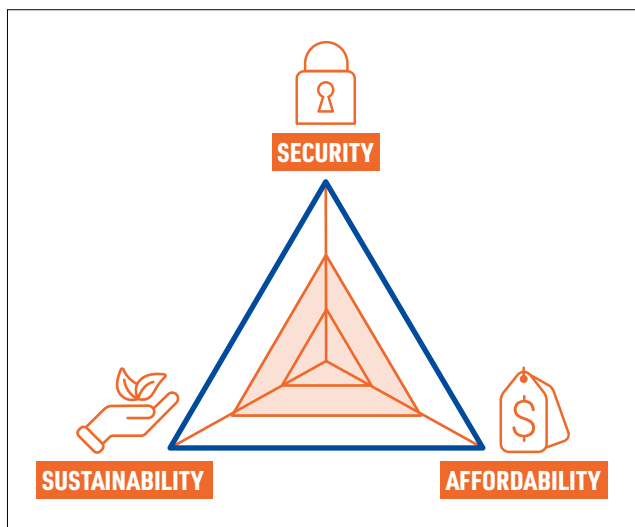


Figure 6: Energy trilemma framework

How we are considering the factors

Figure 7 illustrates our assessment against the three limbs of the energy trilemma framework. This assessment indicates our current view on the direction of travel over the 10-year horizon of this AMP, which is:

- Sustainability is forecast to improve as New Zealand moves toward a sustainable, electrified future³
- Security and reliability are expected to improve. As dependence on electricity grows, our customers will require a more secure and reliable supply. We will engage with our community to better understand and define our customers' service level expectations now and in the future
- Electricity distribution costs will likely increase, but overall energy affordability should improve.

Improving sustainability and security will require significant network and non-network investments, which are expected to increase electricity supply costs. However, electrification should enhance overall energy affordability. In the future, customers are expected to benefit from lower total energy costs, despite higher electricity expenses, and enjoy a more secure, resilient network.

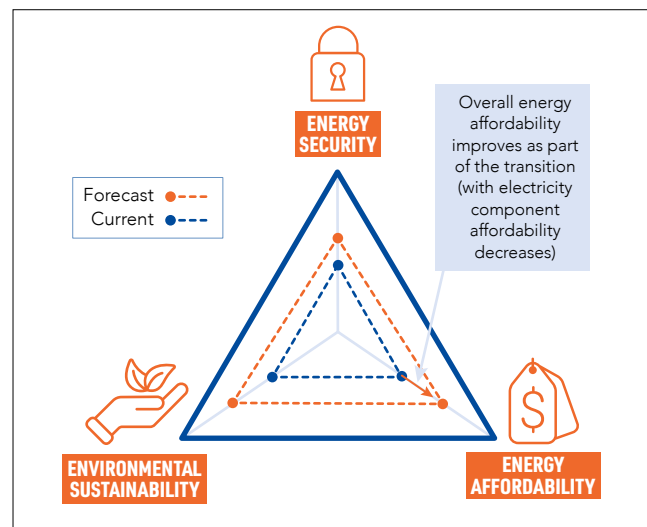


Figure 7: Assessment against the energy trilemma framework

² Source: World Energy Council.

³ Report by Boston Consulting Group "Climate Change in New Zealand: The Future is Electric" <https://www.bcg.com/publications/2022/climate-change-in-new-zealand>

Summary of part 3: Implementation plans to deliver the strategy and the required performance

1.11 Improvement to asset management processes, systems, and data

Recent information technology improvements

Between FY23 and FY25, we made significant progress in our information technology by deploying several key systems. These upgrades included implementing the MagicQ Cloud system for core finance, inventory, and project accounting, alongside the ARC system, which streamlined billing, ICP management, service management, and outage reporting by replacing multiple legacy systems. Additionally, a new GIS platform was introduced to consolidate asset information and improve field data access and collection, while DigSILENT was adopted for advanced network modelling. The Assura health and safety system was also launched, supporting field staff with vital information and enhancing safety management and reporting.

Asset management improvement plan

Our current asset management maturity⁴ has improved over the past two years, but further progress is needed as our assets age, and we prepare for a more complex future. We will continue to focus on improving our asset management maturity over the next two years to ensure our business has the capabilities to deliver on our asset management strategies (asset management strategy #6).

We have prepared an Asset Management Improvement Plan (AMIP), a strategic roadmap to strengthen our asset management capability and deliver better business and customer outcomes through more reliable, efficient, and evidence-based investment in network assets and operations. The plan addresses key business weaknesses identified using the self-assessment framework and provides a structured pathway to align with good industry practice. The AMIP targets:

- Having elements of the asset management system in place and integrated by the end of FY28 (AMMAT score of 3.0)
- Improving asset data accuracy, aiming for a score of 4 (error rate <1%) for critical assets
- Ensuring all important asset data is available and integrated in GIS (The AMIP only considers the GIS and related systems).

Data quality and planned improvements

We have improved asset data through surveys over the past six years, particularly for poles. While pole and name-plated asset data is reliable, condition information on crossarms, switchgear, and transformers is still being captured. It requires completing a full inspection cycle to cover all assets.

Challenges remain in accurately determining the age and condition of conductors and cables, particularly for LV overhead assets where installation records were not consistently maintained. Visual inspection is the primary method for assessing aerial conductor condition, while underground cable assessments require complex and costly testing. In situations where condition data is lacking, age and fault performance data are used to guide asset renewal forecasts. Additionally, some underground cable locations are less precisely plotted than current standards require, with risks mitigated through the beforeUdig process and cable locates service.

Efforts to improve asset management information focus on closing identified data gaps through targeted enhancements. This involves refining asset attribute data, increasing the accuracy of age and condition details for better health predictions, and capturing connectivity information for the low-voltage (LV) network. Our next phase of improvements focuses on enhancing data reliability for conductor and cable attributes by utilising additional resources for data validation. After this, we aim to build a comprehensive model of LV network connectivity, with its approach and budget still needing to be fully defined.

For some assets, where capturing age data is problematic, we will rely on condition data (which will be progressively improved as condition inspection standards evolve and inspections are completed). However, for some assets where condition assessments are challenging, we need to improve age data to enable more accurate health forecasting.

Planned information technology and operational technology improvements

Our focus has shifted towards greater integration and strategic planning. Efforts included initiating and approving the Advanced Distribution Management System (ADMS). Work is underway to build our Information Systems Strategic Plan (ISSP). This is focused on ensuring we have the correct foundational architectural components: integration architecture, data architecture, and process framework. This will enable Waipā Networks to make evidence-based decisions about what broader capabilities and/or systems require investment and in what sequence.

⁴ As measured using the Asset Management Maturity Assessment Tool (AMMAT), in Schedule 13.

1.12 Network transformation

New Zealand is transitioning in terms of how it produces and uses energy. Reducing emissions through electrification and increasing renewable generation is critical to New Zealand achieving its 2050 emissions reduction goal. At the same time, technological advances are also making alternative energy choices economically accessible to customers. Developing and implementing a network transformation roadmap (the "roadmap") is a key asset management strategy for Waipā Networks (asset management strategy #3).

Several factors drive the shift toward new energy sources, including government policies and regulations, technological advances, lower costs, and consumer decisions. Yet it is customer behaviour that ultimately drives the adoption of new technologies and changes how the electricity system operates.

The impact of the energy transition on Waipā Networks is uncertain, particularly regarding how quickly customers will decarbonise and adopt new technologies. These factors influence operational complexity and investment needs in both capacity and organisational capabilities. Clarifying these issues will require time.

We face challenges in predicting network demand, managing complexity, and making future-proof investments.

Therefore, we are prioritising adaptability and making "low regret" investments and capability building, and those are likely to remain valuable across scenarios. The Te Awamutu architecture review is considering these issues; hence, this work will influence our network transformation roadmap.

We also continue to watch market changes closely to improve our understanding, adjust our approach, and build our positions in areas we haven't yet explored thoroughly. This uncertainty calls for adaptable investment strategies to prevent stranded assets and ensure the network can respond to shifting demands.

We have updated our demand forecast scenarios (see figure 8), indicating that network demand in FY50 could range from 148 MW to 244 MW, a difference of 96 MW. The forecasts consider a range of possible outcomes, from rapid growth driven by widespread electrification and technology uptake, to more moderate increases if adoption is slower or flexibility is limited. This range highlights significant uncertainty regarding future network demand.

We have applied the predicted scenario for planning purposes. Our planning approach includes testing the impact of low and high-scenario outcomes for major projects.

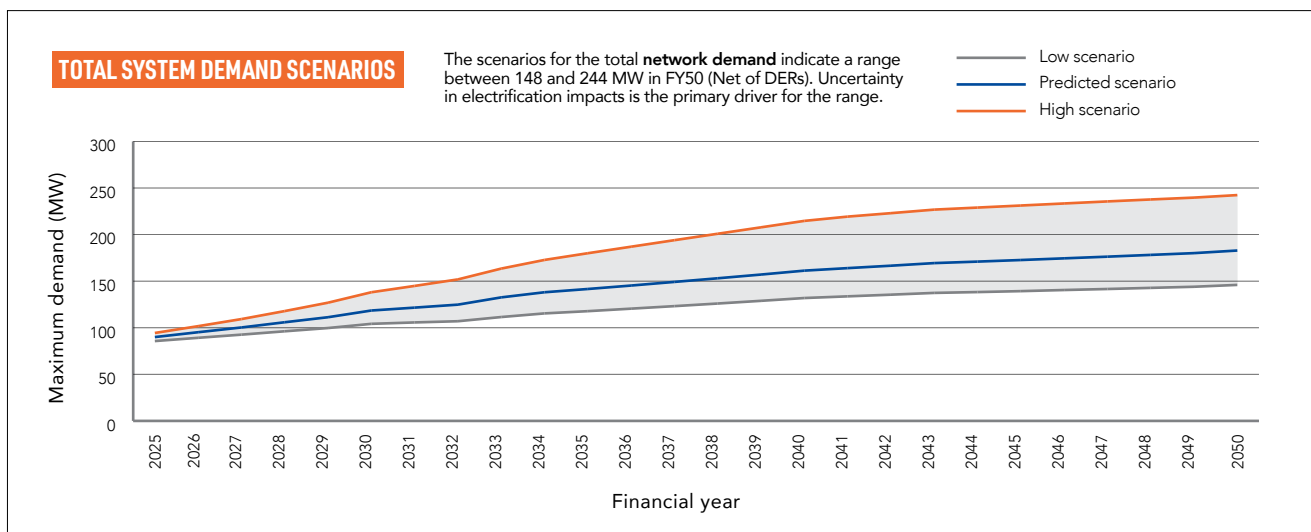


Figure 8: Total system demand scenarios

Over the next 12 months, we will focus on developing our network transformation roadmap, with ongoing tracking of market trends and refinement of our strategic stance. The roadmap's development focuses on supporting New Zealand's energy transformation and decarbonisation goals while keeping long-term costs for customers as low as possible. Community engagement will play a key role in shaping service offerings and pricing structures, ensuring the roadmap aligns with customer expectations and supports a secure, reliable, and flexible electricity network.

1.13 Material network development programmes and projects

Overview of our development plans

Our network development plans respond to changes in demand, service levels, and current and future network constraints. The focus areas include:

- Increasing capacity: such as integrating the new Forrest Road substation into the Cambridge network
- Developing a network architecture roadmap for Te Awamutu.

Looking ahead, the strategy emphasises investment efficiency for system capacity. This will improve the distribution network capacity to support regional growth and incorporate non-traditional solutions. Efforts during FY26 and FY27 will concentrate on establishing a long-term subtransmission and distribution network architecture capable of meeting projected demand scenarios. In Te Awamutu, where future capacity constraints already exist, a balanced approach is required to manage customer needs, service levels, and costs while considering the region's broader vision. The financial implications of the proposed network upgrades, including subtransmission, zone substations, and distribution, have been carefully evaluated and incorporated into current expenditure forecasts.

We have just begun improving customer engagement, so all listed projects are pre-engagement. Ongoing or necessary projects for serving new customers will proceed as planned. For new initiatives, we will work with customers and communities to identify issues and priorities, ensuring project benefits match expectations. This process may lead to updates in future development plans.

Material network developments in the Cambridge area

For the predicted scenario (used for planning purposes), Cambridge's demand is forecast to grow from 52 MW to 87 MW by FY36 and to 110 MW by FY50, with an FY50 low/high range of 88 MW to 140 MW. The demand forecast accounts for the significant subdivision developments and industrial customer growth.

Major development initiatives in the Cambridge area focus on enhancing supply capacity, reliability, and network security. Key projects include a building second-zone substation in Bardowie and installing two 33kV cables (initially operated at 11kV) to support a third-zone substation in Leamington towards the end of the planning period. Additionally, the number of feeders in the region will increase with load transfers from existing feeders to the new Forrest Road substation, directly addressing growing demand and improving network security.

To further strengthen the Cambridge network, targeted security improvements are planned, such as a dedicated project for Cambridge East and further expansion of the feeder network. These efforts are supported by the ongoing installation of 11kV reclosers and continued implementation of switch automation programmes, which collectively enhance the system's resilience and operational flexibility.

The total subtransmission, zone substation and development capex for the Cambridge area is forecast at \$51.2m. Table 2 summarises the material network development projects in the Cambridge area.

Driver	Project	Timing	Cost
Capacity	Bardowie zone substation and associated land purchase and subtransmission connection	FY28-31	\$16.6m
Capacity	Leamington zone substation and associated land purchase and subtransmission connection	FY27-36	\$16.7m ⁵
Capacity	Ongoing capacity upgrades on the distribution network	FY27-36	\$10.4m
Security reliability	Ongoing security and reliability projects and programmes on the distribution network	FY27-36	\$2.9m
Voltage	Ongoing voltage improvement projects and programmes on the distribution network	FY27-36	\$2.2m
Other	Other minor projects in response to capacity, security, voltage and resilience drivers	FY27-36	\$2.4m
Total			\$51.2m

Table 2: Material network development projects

The Te Awamutu architecture review

Our work on the Te Awamutu architecture review began in earnest during FY25 and continued in FY26. This review responds to growing demand and evolving technology in the Te Awamutu area, focusing on ensuring the network remains secure, reliable, and adaptable to customer needs.

Waipā has experienced rapid and sustained demand growth in the Te Awamutu area, driven by population increase. This ongoing growth has resulted in capacity constraints, voltage constraints and reliability concerns on existing feeders.

The region faces a complex array of issues, including constraints on the regional transmission system, security limitations at the GXP, and challenges within the local distribution network. These factors have led to low reliability and limited capacity to backfeed during outages, causing prolonged disruptions for many customers. The network configuration, with a high number of feeders sharing infrastructure, further reduces resilience and increases the risk of widespread outages during maintenance or faults.

⁵ Total project cost is \$22m. Some expenditure will occur beyond the planning period of this AMP.

Technological advancements now allow customers to both generate and store their own electricity, altering how they interact with the network. Waipā Networks' challenge is to support all types of customers, from those who rely solely on the network for supply to those capable of responding to price signals and providing demand response or selling their own generated power.

Recent upgrades by Transpower and improvements to feeder cables have provided us with a window to carefully evaluate and plan future network architecture. The Te Awamutu architecture review is taking a customer and stakeholder-focused approach, incorporating both traditional network solutions and innovative non-network alternatives. This ensures that the network's development aligns with changing usage patterns and customer expectations.

The ultimate objectives of the review are to identify solutions that enhance customer service, network resilience, and capacity for growth, while managing risk and remaining affordable for customers.

Material network developments in the Te Awamutu area

For the predicted scenario (used for planning purposes), Te Awamutu area demand is expected to increase from 42 MW to 60 MW by FY36, and then to 75 MW by 2050 (with a low/high range between 60 MW and 104 MW). The strong growth is partly driven by the increase in industrial demand from the Waikeria Prison and the decommissioning of the cogeneration plant at Fonterra.

Our development plan to enhance supply capacity and security in the Te Awamutu area involves implementing a hybrid network and non-network solution (an outcome of the Te Awamutu review). It is estimated that this is a \$25m saving over a traditional network design approach, as detailed in section 11.11.1. This work includes constructing subtransmission circuits from Hautapu GXP to a zone substation near Waikeria Prison, with a new zone substation near Pirongia anticipated later. These network solutions are complemented with battery energy storage systems and generation support. Additionally, specific distribution projects have been defined to address immediate capacity needs, alongside broader programmes targeting long-term improvements.

The distribution development plan includes broad programmes based on the Te Awamutu architecture review. These programmes currently assume traditional network solutions, as alternatives are still to be assessed. We anticipate a reduction in capex for these programmes and increased spending on non-network (potentially opex) solutions such as merchant flexibility services or customer-led solutions.

Many of the capacity-related projects will also resolve security and reliability issues. We are also continuing with the ongoing installation of 11kV reclosers and advancing the switch automation programme.

Table 3 summarises the material network development projects in the region.

Driver	Project	Timing	Cost
Capacity	Waikeria zone substation and associated land purchase and subtransmission connection	See customer works	
Capacity	Battery energy storage solutions	FY31-34	\$2.7m
Capacity	Pirongia zone substation and associated land purchase and subtransmission connection	FY33-35	\$22.7m
Capacity	Feeder front-end cable capacity upgrades	FY27-29	\$4.2m
Capacity	Programme to upgrade the capacity of the network, which may result in non-network solutions	FY27-36	\$25.9m
Security reliability	Ongoing security and reliability projects and programmes on the distribution network	FY27-36	\$2.3m
Voltage	Ongoing voltage improvement projects and programmes on the distribution network	FY27-36	\$1.9m
Other	Other minor projects in response to capacity, security, voltage, resilience drivers	FY27-36	\$2.0m
Total			\$61.7m

Table 3: Material network development projects

Other development work

There is a range of other development programmes to address capacity, security and voltage issues for distribution transformers, the LV network and the communication network. These amount to \$7.6 over the planning period.

We describe the justification for the project and how we are dealing with the demand forecast uncertainty for each development plan. The full development plan is described in Section 11.

1.14 Customer works

Customer-initiated work includes new connections, upgrading existing connections, and relocating distribution assets. We are forecasting \$101m of customer-initiated work. This is a significant increase over prior AMPs due to the work for the Waikeria Prison and NZTA SH1 Cambridge to Piarere project.

In 2025, we signed an MoU with the Department of Corrections for stage two of the Waikeria Prison expansion. The expansion project includes significant infrastructure upgrades, with the prison projecting future load growth to nearly 10 MVA by around FY30. This anticipated demand represents a 25% increase over the existing load in the Te Awamutu area and will directly influence the regional network architecture review.

To meet these requirements, the proposed solution is to construct a new zone substation near the prison, fed by a 33kV circuit from Hautapu GXP and reinforced by an 11kV network for N-1 support. Additionally, a battery energy storage solution will be deployed once load growth surpasses 9 MVA. The total cost for these upgrades, including the substation, lines, and battery, is estimated at \$34.8m.

The SH1 Cambridge to Piarere project will create a 16 km four-lane expressway from Cambridge to Piarere. Stage one involves about 8 km of new or widened road near Cambridge. To support this stage, approximately 6 km of overhead lines will be relocated or placed underground, enhancing network reliability by rationalising the location of an overhead HV switch and using larger conductors to improve voltage. These relocation works are forecast to cost around \$8m.

The Electricity Authority's recent reforms are driving significant changes in customer connection processes. The new requirements standardise how distributors calculate and present capital contributions, with implementation scheduled for April 2026 and capacity-based costing to follow in April 2027. While process updates and system changes are being developed to meet these milestones, the specific details of capital contributions are still being finalised and have not yet been reflected in this AMP (so existing assumptions remain unchanged until the work is completed).

1.15 Material asset lifecycle programmes and projects

Fleet plans and health forecasting approach

We have developed comprehensive asset fleet plans for our material asset classes (which are aligned to asset management strategies #5 and #6). As mentioned in Section 1.7, we expect to observe more end-of-life drivers over the coming decade. Ensuring we have accurate asset condition, health, and risk information will be essential to enable optimal network renewal.

We are shifting from health-based renewal forecasting (using asset age and inspection data) to a more robust approach based on asset health, criticality, and risk. Each year, we're integrating improved health forecasting into our AMP. Full implementation will take several years as we collect more detailed field condition data. Currently, asset renewal forecasts prioritise health and criticality at the project level. Over the next year, we plan to adopt a comprehensive risk-based methodology, which may further refine our renewal and expenditure forecasts in future AMPs.

Fleet health and renewal forecasts

Figure 9 and figure 10 show the evolution of our asset health assessment and renewal forecasts for our material asset classes in this AMP. H1 or H2 refer to assets with low health, meaning end-of-life drivers are present, and there is a risk of asset failure. This indicates that asset replacement is required.

The material changes in our five-year forecast asset health since the 2025 AMP (Figure 9) include:

- Crossarm forecast of low health assets has increased. This forecast was based on an extrapolation from assets with a reliable health assessment (22% of the fleet). This assessment likely overstates the extent of low health crossarms as we have undertaken a programme of crossarm replacement over the past three years (since the defect survey in FY2022). This data will improve as we complete our inspection programme over the next few years
- Pole-mounted transformer forecast of low health assets has increased. This is based on condition data, but relates to H2 assets
- All voltage regulators have been inspected, and five sites (15 voltage regulator cans) have been identified as due for refurbishment over the next five years
- RMU forecast of low health assets has increased. Most of the assets have been inspected, and the condition issues relate to the tank and partial discharge.

Our zone substation and subtransmission assets are new or near-new; therefore, health issues have not yet emerged.

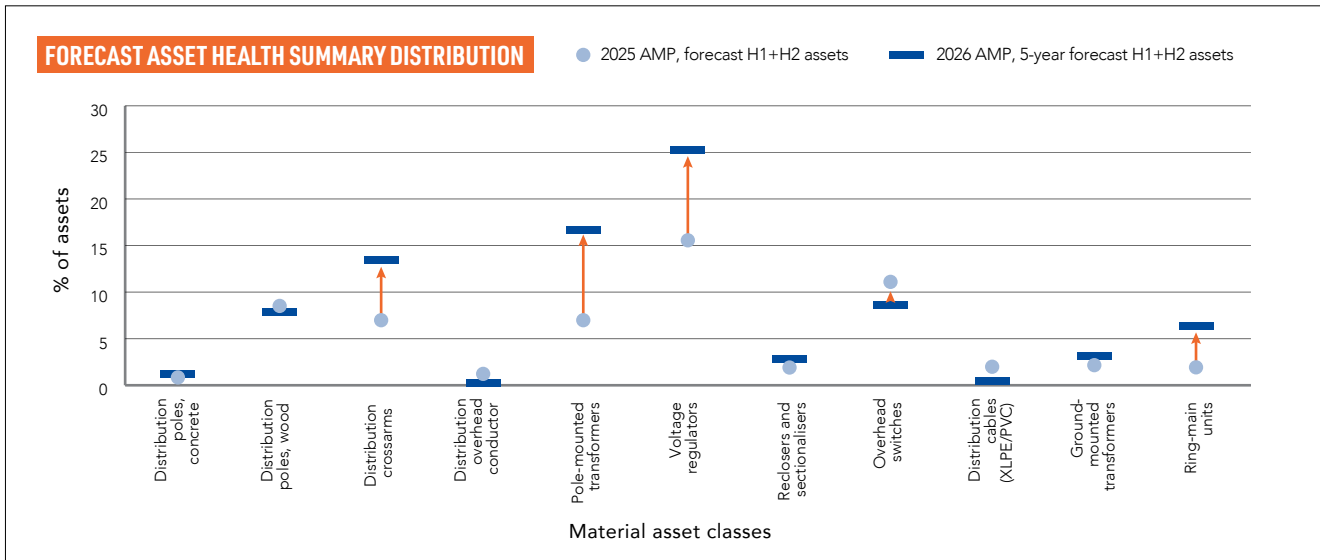


Figure 9: Forecast asset health summary, distribution assets

Our five-year renewals are forecast to address low health assets, with a few exceptions (Figure 10):

- The crossarm fleet forecast renewals reflect the continuation of our current programme (c. 500 p.a.). As noted above, we are awaiting more reliable health data before adjusting our renewal programme, as low-health assets identified in our prior inspections have been addressed, and we are not seeing an increasing trend in crossarm-related failures
- For pole-mounted transformers, our planned renewals are forecast to replace all H1 assets over the next five years. This is consistent with a failure – and defect-driven replacement strategy, given the relatively low consequence of failure for these assets
- The forecast RMU renewals address all tank issues and immediate partial discharge issues. We are taking a little more time to fully consider the partial discharge results, as these may not necessarily indicate the need for replacement (i.e. it could be a cable termination issue that needs cleaning or replacement).

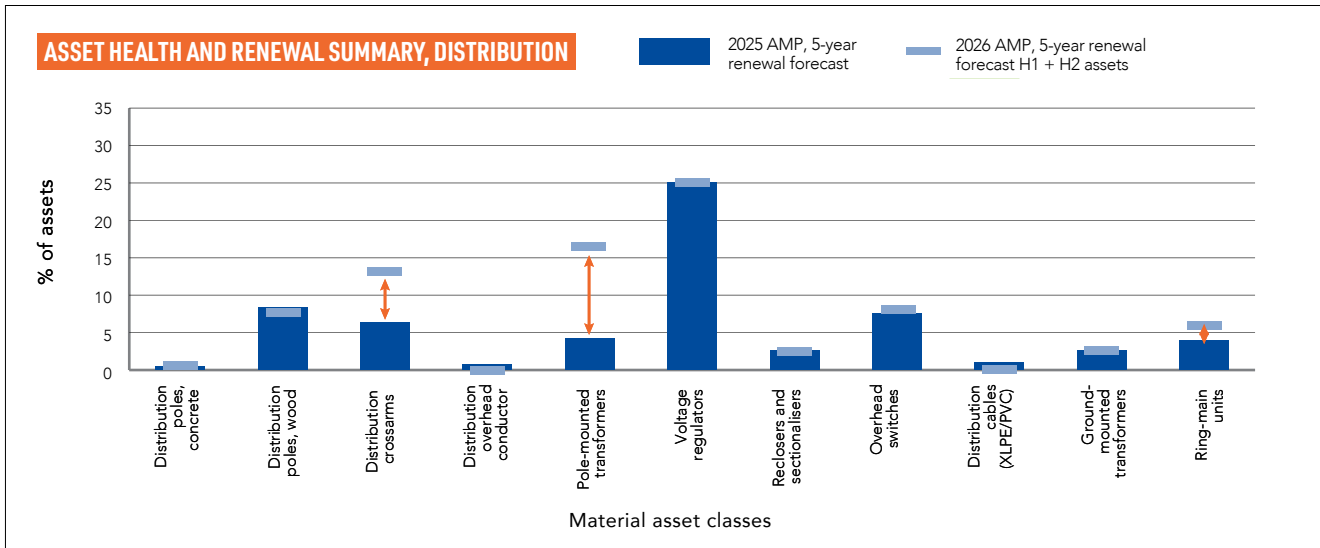


Figure 10: Forecast asset renewal summary, distribution assets

Material fleet renewal programmes

Compared to the 2025 AMP, asset replacement capex has reduced by \$6.4m. This primarily relates to voltage regulator refurbishment (rather than replacement) and the transfer of the ADMS to non-network capex.

Table 4 summarises the material renewal programmes. Our most significant renewal programme is for crossarms, driven by the fleet size (our largest by quantity) and our current view of health. Crossarm renewals are forecast below our current

health assessment, reflecting current data issues that will be resolved as new inspection data is incorporated. The next largest renewal programme is overhead switches, most of which relate to the replacement of air-break switches. These are reaching end-of-life or have operational issues. Some of these are being replaced with higher-cost enclosed switches that improve durability and allow automation.

Full details of each fleet's health and renewals are included in the fleet plans (see Section 13).

Fleet	Programme	Timing	Cost
OH structures	Planned and reactive crossarm replacements	FY27-36	\$20.7m
OH switches	Planned and reactive overhead switch replacements	FY27-36	\$11.0m
PM transformers	Defect and reactive replacement of pole-mounted transformers	FY27-36	\$8.8m
OH structures	Planned and reactive pole replacements	FY27-36	\$5.2m
GM transformers	Ground-mounted transformer replacements	FY27-36	\$3.0m
Service connections	Pillar box replacements	FY27-36	\$2.8m
OH structures	Wood pole replacements	FY27-36	\$1.8m
All others	Renewal programmes for all other assets	FY27-36	\$8.0m
Total	Asset replacement and renewal capex		\$61.4m

Table 4: Material asset renewal programmes

Fault response, maintenance and inspection

Our fault response, maintenance, and inspection programmes⁶ continue as outlined in our fleet plans, but are 11% lower than in the 2025 AMP. The reduction reflects a lower expectation of fault costs, given recent performance and the forecast improvement in reliability, as well as adjustments to major and period maintenance.

Vegetation management

Mitigating vegetation-related outages is a key strategy for our business (asset management strategy #7). This strategy was initiated because vegetation outages remain a major cause of network outages.

Starting in FY25, the vegetation management approach for feeders will separate inspection from cut/trim activities, emphasising the need for up-to-date intelligence before planning any actions. This shift enables more targeted, risk-based management of the network, ensuring decisions are informed by the latest data and resources are directed to where they are most needed.

Inspections are now scheduled based on the risk and importance of each network segment. Lines near the GXP or zone substation undergo annual checks due to their potential significant impact on network reliability, while most of the network is also inspected each year. The rest, particularly the rural feeder ends, follow a three-year rotation, with ongoing assessments to determine whether this interval should be shortened. Worst-performing feeders and those in difficult terrain receive more frequent or reactive inspections as necessary.

Cut/trim work is planned based on inspection results, with priority given to cases that pose the greatest risk to safety and network reliability. The team aims to maximise tree-removal rates by maintaining a high tree removal success rate through effective stakeholder engagement. Efforts are also made to exceed legislative clearance requirements whenever possible, reducing long-term risks and the need for repeated interventions. A dedicated Scoping and Liaison officer supports these activities, fostering cooperation with landowners to ensure safer, more reliable network operations.

Vegetation management costs are 4% lower than those included in the 2025 AMP due to changes in the overhead allocation. The allocation now reflects the vegetation management operating as if it were a standalone business.

⁶ These include System Interruption and Emergency, Reactive and Corrective Maintenance and Inspection, and Asset Replacement and Renewal opex categories.

1.16 Delivery

The electricity distribution sector faces increasing operational complexity and workload growth. For Waipā Networks, this includes enhanced community and customer engagement and network strategy and planning functions to support the new hybrid network architecture and complement a more customer-focused network solutions model. We have established the Network Intelligence function to expedite the identification, discovery and adoption of specialised digital systems for the network function and deliver asset management improvements.

Our resourcing strategy for delivering these functions is under review, as traditional resourcing models risk adding complexity and reducing efficiency. We plan to participate in a structured evaluation of shared services to increase efficiency and enhance customer experience while maintaining local decision-making and accountability.

The Delivery team is adjusting its resource mix to meet the needs of a semi-urban network with increasing underground and ground-mounted assets. Historically focused on overhead lines, the team now requires more technical expertise as protection systems and digital networks become more complex. The current model of multiskilled field staff is no longer sufficient. To address this, Delivery is forming a dedicated group of cable jointers, electrical fitters, and substation technicians. This transition and ongoing upskilling will support the growth in substations, underground assets, and operational technology (OT) devices.

Our 10-year resource forecast indicates that in-house field resources are sufficient for core network work. However, from FY27 to FY31, we expect a shortfall of ~18,000 hours each year (including major customer work), which equates to around \$27m (of which some major material procurement will be retained). This in-house resource shortfall is suitable for engaging an external service provider under a service-level agreement.

The intent is to establish a long-term relationship with a field delivery partner, comprising an ongoing base work commitment and the ability to tender for major project work. This arrangement will provide scalable resourcing for our core network and customer work (excluding Waikeria Prison and SH1 Cambridge to Piarere, major customer projects). We began a trial in FY26 with two field delivery partners to enable a robust performance assessment, from which a delivery partner will be selected.

We believe the local contractor market can support both our regular and major projects, with capacity across key disciplines. Outsourcing has delivery risk, which we will mitigate by sharing forward plans, staging tenders to avoid peak periods, and maintaining contingency options, including dual-sourcing and clear escalation processes.

1.17 Risk management

We use a systematic risk management approach based on ISO 31000:2019 and NZS 7901:2014 standards. Our Risk Management Policy and Framework were updated in FY2024.

Our risk management process encompasses all aspects of our business, including the electricity network, and addresses a range of risk categories such as:

- Health and safety (including public safety)
- Environmental
- Stakeholder and community confidence and reputation
- Cultural considerations
- Financial impacts
- Operational risks that affect the network's ability to meet demand and maintain a reliable electricity supply
- Compliance with relevant regulations.



1.18 Network expenditure forecasts

Capital expenditure

Table 5 summarises the 2026 AMP total capex compared to 2025 AMP (in comparable, 2026 AMP constant prices).

Total capex in the 2026 AMP is \$309.5m, which is a \$98.9m (52%) increase compared to the 2025 AMP⁷. The material reasons for the change are:

- \$34.8m increase in customer connection capex in relation to the significant supply upgrade to the Waikeria Prison
- \$57.4m increase in system growth capex, mainly in relation to regional and distribution capacity-related projects in Te Awamutu. This work was anticipated in prior AMPs, but not included due to the level of uncertainty. Our Te Awamutu architecture review has progressed during FY26, and plans are now sufficient to include in this AMP

- \$8.3m increase in asset relocation due to the widening of SH1
- \$1.8m increase in network security and reliability improvements
- \$2.1m increase in non-network assets due to additional spend in FY27 on vehicles and office equipment
- \$6.4m reduction in asset replacement capex, mainly in relation to voltage regulator refurbishment (rather than replacements) and the transfer of the ADMS to non-network opex.

The reasons for the movements are discussed in more detail in Section 15.

Year	FY27	FY28	FY29	FY30	FY31	FY32	FY33	FY34	FY35	FY36
2026 AMP capex	29,611	41,521	49,155	28,355	29,787	23,259	23,645	30,087	29,453	24,637
2025 AMP capex ⁸	26,798	23,293	18,771	21,232	23,067	18,807	17,809	18,523	17,651	–
Change	2,812	18,228	30,384	7,124	6,720	4,452	5,836	11,564	11,802	–

Table 5: Capex forecast (before capital contributions), real 2026 \$000

Operational expenditure

Table 6 summarises the 2026 AMP total opex compared to 2025 AMP (in comparable, 2026 AMP constant prices). Total opex in the 2026 AMP is \$196.3m, which is a \$5.8m (3%) increase over the \$189.5m included in the 2025 AMP⁷. The material reasons for the change are:

- \$4.0m reduction in network opex driven primarily by changes in routine and corrective maintenance and inspections, and reduction in allocations for vegetation management and the opex for asset replacement and renewal

- \$9.8m increase in non-network opex, predominantly due to the ADMS project being transferred from capex to opex and an increase in associated maintenance and support costs, LV visibility project costs, and a refinement in the allocation of overhead costs across the business.

Year	FY27	FY28	FY29	FY30	FY31	FY32	FY33	FY34	FY35	FY36
2026 AMP opex	20,708	19,223	19,059	19,391	19,502	19,645	19,866	19,429	19,462	19,978
2025 AMP opex ⁸	18,929	18,996	18,908	19,039	18,842	19,013	18,889	18,988	18,883	
Change	1,779	227	151	351	660	633	977	441	579	

Table 6: Opex forecast, real 2026 \$000

⁷ The 2026 AMP period is FY27 to FY36 and the 2025 AMP period is FY26 to FY35. Hence, the periods are not directly comparable, but provide an indicator the scale of the change. The variances refer to the comparable FY27 to FY35 period, therefore the total of variances for the comparable range does not equal the total variances for the 10-year forecast. Both values for 2026 AMP and 2025 AMP in 2026 real\$.

⁸ In 2026 real\$.

1.19 Concluding comments

This AMP communicates our key issues, asset management strategy, and programmes and projects impacting our network. It includes significant revisions to our customer engagement process and network development for Te Awamutu.

It also highlights the need for substantial investment in the network. These investments will influence affordability, sustainability, resilience, and power quality, and there is now a broader range of credible solutions, including customer and community-based options. Consequently, we are shifting from a solely provider-led planning approach to one in which customers and communities help identify problems, options, and trade-offs from the outset. This engagement process will influence the scope of investments in future AMPs.

The Te Awamutu architecture review addresses the significant challenges caused by ongoing demand growth in the region. We have taken a comprehensive approach that considers both network and non-network solutions, ensuring the network supports all customer types and adapts to changing usage patterns. The review process emphasises

stakeholder and customer engagement to ensure future developments mirror the needs and expectations of those served, aiming to deliver solutions that balance performance improvements, cost-effectiveness, and innovation.

We continue to face reliability challenges, and addressing these issues requires targeted investment programmes. We have included an initial improvement pathway that incorporates enhancements to the Kāwhia feeder (currently in the concept stage), improvements to other underperforming feeders, increased security (enabled by the new Forrest Road substation), and a targeted reduction in vegetation risk. Other benefits will stem from the Te Awamutu architecture review and its subsequent projects.

Finally, this 2026 AMP indicates a substantial rise in capital expenditure for the Te Awamutu network. This results from our work on the Te Awamutu architecture review. Our focus in the coming years is to engage with customers and refine the solutions to ensure they are the most cost-effective and best aligned with customer needs.



2. BACKGROUND, OBJECTIVES AND RESPONSIBILITIES

2.1 About Waipā Networks

Our network originally began as the Te Awamutu Power Board and the Cambridge Borough Council electricity department, which were established over 100 years ago. In 1993, the two entities merged to form Waipā Power, which was later renamed Waipā Networks Limited in 1998. The Waipā Networks Trust holds the shares in the company. The beneficiaries of the Trust are the customers connected to our network.

We distribute electricity throughout the Waipā district and surrounding areas to more than 29,000 customers (ICPs). Our position is to operate the distribution function in the electricity supply industry, shown in figure 11.

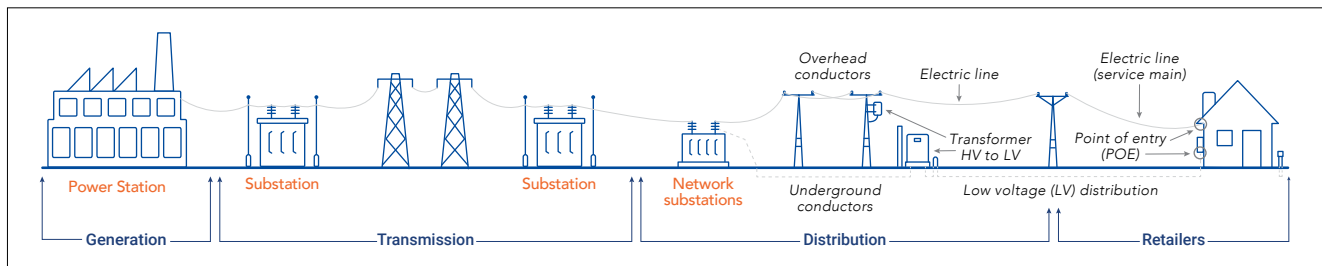


Figure 11: Illustration of the New Zealand electrical supply industry

2.2 Purpose of this AMP

This AMP details our plan for managing our assets over the next decade and beyond. It discusses the current state of our network, our understanding of our customers' future expectations, how we maintain our assets, our current resources and the new capabilities we need to develop to implement our plan.

We are transitioning from a period of strong incremental growth to one of significant regional growth and change, driven by decarbonisation. This growth is driving a change in our network configuration, which has already started in the Cambridge area. This change is continuing with the architecture review for the Te Awamutu area. In addition, some of our network assets are ageing and are due for replacement and renewal, providing an opportunity to replace them with equipment with improved features that enable future operations. This AMP outlines our approach to ensure that we deliver a network that meets customers' immediate needs and lays a foundation for one that will serve their evolving needs in a future that will be increasingly electrified.

The AMP informs stakeholders about:

- Our key asset management policies and planning standards
- How we set service level targets for the network that reflect safety, customer, community, and regulatory requirements
- Our understanding of network capacity, reliability, power quality, and supply security that is required now and in the future
- Our process for managing all phases of our network lifecycle from concept to disposal
- Our systematic process to manage risk
- The provision for funding and resourcing for all phases of our network lifecycle
- Our plans for enhancing our understanding of assets, asset management systems, and processes
- The network developments and asset replacements required, along with the associated capital and maintenance expenditures expected over the next 10 years.

2.3 Objectives

The objectives outlined in this section provide the key linkage between this AMP, our corporate strategy and our Statement of Corporate Intent (SCI). They represent our highest-level objectives, which we aim to achieve, and the intention is that these endure over the long term. We have expanded the objectives to include sustainability and updated them to ensure they remain consistent with our corporate strategy.

These objectives complement and are supported by the asset management policy (in Section 7.2) and asset management strategies (in Section 7.3).

2.3.1 Statement of corporate intent

Our 2025 SCI can be found on our website⁹. This document is agreed upon between the company and our Trust owners. It sets out our focus areas and performance targets. The focus areas are illustrated in figure 12 and relevant performance targets are outlined in Section 7.6 to 7.12.



Figure 12: 2025 SCI focus areas



⁹ <https://waipanetworks.co.nz/wp-content/uploads/2025/06/Waipā-Networks---SCI-2025-FINAL.pdf>

2.3.2 Corporate strategy

Sitting below the SCI is our corporate strategy. We have undertaken a significant refresh of our strategy during the past 12 months. Our strategy responds to the significant challenges ahead and aims to transform Waipā Networks

from a traditional network operator into an insight-led, flexible, and customer-centric energy partner – one that leads through disruption, shapes its operating environment, and ensures affordable, equitable access to electricity that enables regional prosperity.

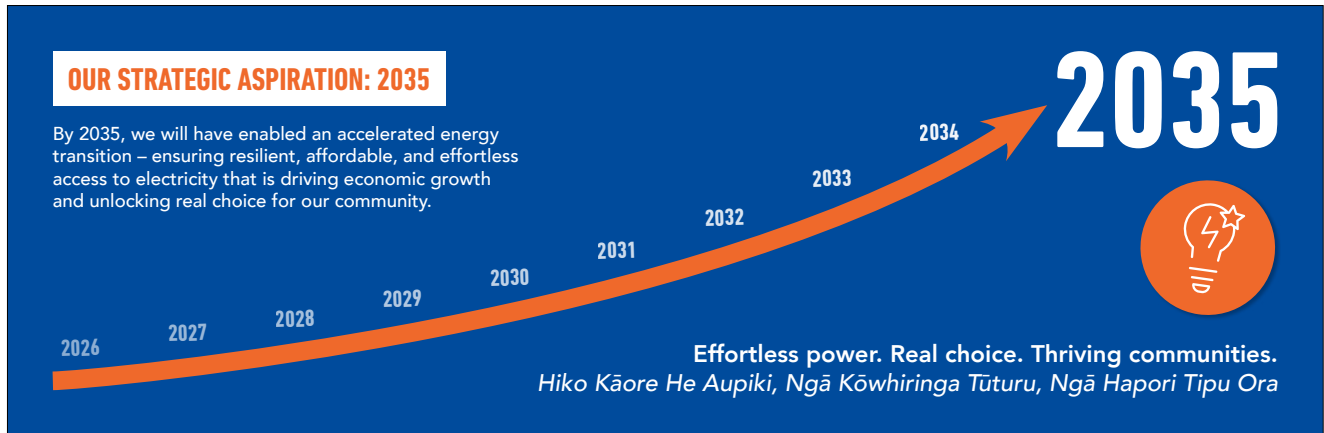


Figure 13: Our corporate strategy – strategic aspiration

Our goal is for Waipā Networks to be a reliable energy provider and a trusted partner that deeply understands and responds to customer needs. This means moving beyond transactional relationships to a truly customer-first approach. Where customers feel heard, understood, and empowered with real choices.

We will deliver and achieve our strategic aspiration through three horizons. We have developed various actions to implement Horizon one in FY27-FY28, and the development for the future horizons will be iterative in the future years. Regarding this AMP, the strategic influences on future iterations of this plan include:

- Building real customer insights and creating a process for ongoing engagement
- Developing and refining the future network blueprint (i.e. building on the Te Awamutu network architecture review)
- Defining the capability we need for our future across people, processes and systems
- We continue to improve our core performance in safety and asset management.

2.3.3 Asset management objectives

Our asset management objectives ensure the safe and reliable distribution of electricity, consider energy transformation drivers, and balance affordability, reliability, and sustainability. These objectives ensure that this AMP supports the achievement of our Statement of Corporate Intent and Strategic Plan.

The objectives driving our AMP are:

- **Safety:** Provide a safe environment for the public and staff by embedding safety considerations in network design, equipment choice, and operations
- **Customers and stakeholders:** Actively engage with customers and communities to understand their needs and enable participation in shaping solutions
- **Assets:** Minimise asset life cycle costs by maximising asset utility and network performance that meets service level targets
- **Capability:** Continuously improve our asset knowledge and asset management processes and systems to deliver performance and efficiency improvements.
- **Sustainability:** Being socially responsible, acting ethically, respecting mana whenua and protecting the environment and communities we serve and live in.

These AMP objectives are aligned with our SCI and corporate strategy. The safety and capability objectives support the performance goal in the SCI and the capability element of our corporate strategy. The customer objective supports the community goal in the SCI and the customer insight element of our corporate strategy. The asset objective supports the performance goal in the SCI and core performance elements of our corporate strategy. The sustainability objective supports our SCI's sustainability goal.

2.4 Basis of AMP

The AMP document details our asset management policy, strategies, and processes that enable us to achieve our objectives and target service levels. It encompasses investment and operational plans that guide our annual budgets.

The AMP describes assets and their condition and risk, as well as how our network needs to adapt to change, including any required network development. It also outlines our fleet lifecycle management and the resulting forecast expenditure needed to meet our asset management objectives and service levels.

We are subject to regulatory oversight by the Commerce Commission through information disclosure regulation, including monitoring levels of return on investment. However, as a Trust-owned business, we're exempt from the Commerce Commission's default price/quality path requirements.

We prepare and disclose our AMP each year to comply with the requirements of Section 2.6 and attachment A of the Commerce Commission's Electricity Distribution Information Disclosure (ID) Determination 2012. We have included a reconciliation of the Information Disclosure requirements in the appendices.

This AMP provides all the information to assure stakeholders that:

- Our assets are being managed for the long term
- Our required level of performance is being delivered (and where there are gaps, improvement plans are being implemented)
- Our business is efficient (so the distribution prices are no higher than they should be).

2.5 Period covered

This AMP covers 10-year planning from 1 April 2026 to 31 March 2036. Consistent with Information Disclosure requirements, greater detail is provided for the first part of this period.

Directors approved the AMP on 27 March 2026. A statutory declaration has been made to the Commerce Commission on behalf of our Network's Directorate for this full AMP.

2.6 Structure of this AMP

In this 2026 AMP we have organised it into three parts:

- **Part 1:** The key factors driving our asset management strategy.
- **Part 2:** Strategies to address the key issues.
- **Part 3:** Implementation plans to deliver the strategy and the required level of performance.

This structure makes it easier to understand our business context, the factors we are considering in setting our strategy, our asset management strategy, and how we are executing plans to deliver on the strategy.

Our considerations include stakeholder interests, customer perspectives, the current state of the network, and our recent performance (which are covered in Sections 3 to 6). Our asset management strategy is included in Section 7, and our implementation plans are included from Section 8.



2.7 Responsibilities for asset management

Figure 14 shows our organisational chart and the significant responsibilities in relation to this AMP. The responsibilities are discussed further below.

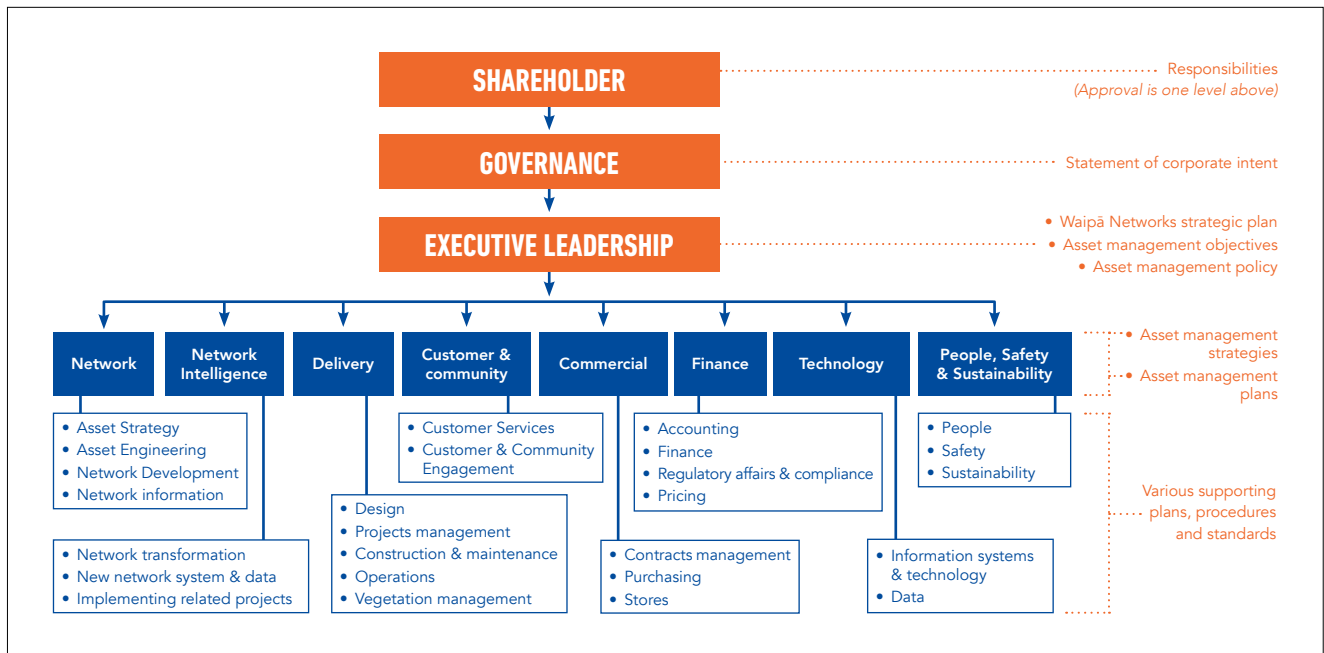


Figure 14: Organisational structure and key responsibilities

When it comes to asset management:

- At the highest level, the Waipā Network Trust approves the annual Statement of Corporate Intent (SCI). The Trust also reviews progress biannually against the targets and plans agreed upon in the SCI
- The Board of Directors reviews and approves the Asset Management Policy and the AMP to ensure it reflects the strategic direction, the current SCI, and meets the required forecast performance for the business and customers
- The CE and executive management team oversee the preparation of the AMP, asset management objectives, asset management strategies and the various supporting plans, procedures and standards
- The Network team has overall responsibility for preparing the AMP and overseeing its delivery. The team sets the planning, design and construction standards for the network. The team determines the asset management improvement plan, network development plans, and asset lifecycle programmes, and assesses and approves new connection applications, as well as any associated network upgrades. There are specialists within the team who provide engineering support, conduct outage assessment, and manage the network assets data and records (including assessing data quality and improvement)
- The Network Intelligence team was created in the past year to provide greater focus on preparing for the future. This team has responsibility for developing new network systems, data foundations, and processes that enable a future-ready network that's flexible, intelligent, and customer-centric
- The Customer and Community team plays a vital role in understanding customer needs and ensuring we have strategies in place to meet the needs of our customers and community over the next decade and beyond
- The Delivery team has primary responsibility for delivering the AMP. It is responsible for the design, project management, works scheduling and delivery of the development plans, asset lifecycle plans and new connections. The operational personnel within the team undertake the construction, maintenance, inspection and fault response. We use internal resources to complete most of our planned and unplanned work and vegetation management. External service providers are contracted when internal resources are insufficient and for civil and traffic management services. This is discussed further in Section 14
- The Finance and Commercial teams support the AMP in relation to forecasting, budgeting, financial reports, purchasing and stores
- The Technology team is responsible for corporate business systems, IT functions and cybersecurity. This team has primary responsibility for delivering the Information Systems Strategic Plan, which supports the asset management system. This is an area of constant evolution and importance as technology changes
- Lastly, the People, Safety & Sustainability team is responsible for people services, recruitment, training, liaison with WorkSafe NZ, industry compliance, and accreditation of our Public Safety Management System and Workplace Safety Management Practices.

2.8 Delivering the AMP

As noted above, the delivery of the AMP is the primary responsibility of the Delivery Team and the Network Team. The Network Intelligence Team and the Data and Information Team also support the delivery of specific network, operational technology, and information technology projects. Table 7 summarises the key stakeholders involved in delivering the AMP.

Elements of the asset management	Stakeholders involved in delivery	Communication
Asset management policy	<ul style="list-style-type: none"> • Network team • Network Intelligence team • Delivery team 	<ul style="list-style-type: none"> • Communicated via the AMP, and available in Waipā's document management system.
Asset management strategies	<ul style="list-style-type: none"> • As above 	<ul style="list-style-type: none"> • Communicated via the AMP
Performance targets	<ul style="list-style-type: none"> • As above 	<ul style="list-style-type: none"> • Communicated via the AMP
Development and lifecycle plans	<ul style="list-style-type: none"> • As above 	<ul style="list-style-type: none"> • Communicated via the AMP • The development plan and lifecycle plans are communicated to the Delivery team in advance of the forthcoming year (to allow designs to be prepared and resources scheduled)
Asset management improvement plan	<ul style="list-style-type: none"> • Network team • Network Intelligence team • Data and information team 	<ul style="list-style-type: none"> • Communicated by the Asset Management Improvement Plan (a summary of which is included in this AMP)
Project proposals	<ul style="list-style-type: none"> • Senior management (GMs, CE and/or Board, depending on project value) 	<ul style="list-style-type: none"> • Project proposals (Project Definition Document) are prepared and approved, consistent with this AMP and our delegated authority limits.
Annual works plan	<ul style="list-style-type: none"> • Network and Delivery teams • External contractors and consultants (when used) 	<ul style="list-style-type: none"> • A detailed Annual Works Plan is prepared and issued. This provides additional detail on projects and programmes.
Standards, policies and procedures ¹⁰	<ul style="list-style-type: none"> • As above 	<ul style="list-style-type: none"> • All policies and procedures are available in the Waipā document management system.
Project design (or work packs)	<ul style="list-style-type: none"> • As above 	<ul style="list-style-type: none"> • The required design standards are communicated to the Design team or external consultants when design work commences.
Monthly reporting on delivery performance	<ul style="list-style-type: none"> • Senior management (GM, CE and Board) 	<ul style="list-style-type: none"> • The General Manager Network provides monthly reports to the Board on progress against our performance targets and progress against our development and lifecycle plans.

Table 7: Summary of asset management communication and participation in the delivery of the AMP

¹⁰ This includes the Design Manual, Construction Manual, Maintenance and Network Inspection Standards (discussed in Section 9), and Public Safety Management System (discussed in Section 8).

2.9 Link to other documents

The AMP is aligned to Waipā Networks' strategic plan and its SCI, and other corporate documents. A description of other important documents is as follows:

- The Statement of Corporate Intent (SCI) is published annually and is available on our website. This document sets our key strategic objectives each year, including network reliability targets, customer engagement objectives, business development goals, customer discounts, and rate of return to shareholders. Asset-related objectives in the SCI are included within this AMP. The SCI is a requirement under Section 39 of the Energy Companies Act 1992. It serves as the primary accountability mechanism between our Board and our shareholders.
- The Strategic Plan outlines the strategic initiatives we're pursuing to achieve the SCI over the long term. It defines the business plan initiatives for the forthcoming year. The Asset Management Objectives (which are discussed in Section 2.3) provide the key linkage to the Strategic Plan and SCI.
- The Information System Strategic Plan (ISSP) outlines Waipā's technology and information development pathway and plans. This document is being updated and aligned to our IT Strategy and Capability Pathway, which is also under review. The Asset Management Improvement Plan (outlined in Section 9.6) is the key linkage to the ISSP.
- The AMP informs the Annual Budget and provides the necessary financial resources to achieve the improvement plan, development plan and lifecycle plans outlined in this AMP. Directors approve the Annual Budget before the commencement of the forthcoming year.
- The Annual Works Plan covers the delivery plan for the first year of this development plan and the lifecycle plans outlined in this AMP. It is updated annually.
- Standards, policies, and procedures ensure that works are undertaken safely, to appropriate quality standards, and in consideration of our stakeholders' interests.

2.10 Compliance

A key driver of our Asset Management Policy is compliance with legislative and regulatory requirements. The following are some of the key statutory Acts (including subsequent amendments) and Regulations that direct our asset management activities¹¹:

- Health and Safety at Work Act 2015
- Electricity Act 1992
- Electricity Industry Participation Code
- Commerce Act 1986
- Utilities Access Act 2010
- Energy Companies Act 1992
- Companies Act 1993
- Electricity (Safety) Regulations 2010
- Electricity (Hazards from Trees) Regulations 2003
- Various Electrical Codes of Practice (tied to the Electricity (Safety) Regulations)
- Resource Management Act 1991.

Our procedures and policies are written to comply with these requirements.

We regularly review our legislative compliance via a company-wide assessment using ComplyWith. Reports are provided to the Board of Directors on a six-monthly basis. Legislative breaches are reported to our Board as they occur, and are remediated promptly.

¹¹ Other legislation and regulations about our activities (for example, the Employment Relations Act 2000) exist. They are not included here for the sake of brevity.



PART 1:

FACTORS DRIVING OUR ASSET MANAGEMENT STRATEGY



3. OUR CUSTOMERS AND STAKEHOLDERS

3.1 Introduction

This section describes how we are embedding an ongoing partnership with customers and communities into network planning and asset management, and how this shapes the investment decisions set out in this AMP.

How we use the terms customer and stakeholder in this AMP		
Term (as used in this AMP)	Definition (asset management lens)	How it is used in the AMP
Customers (service recipient lens)	Electricity consumers connected to the Waipā Networks distribution network, including residential, rural, commercial and industrial consumers. This also includes customers seeking new or upgraded connections and, where relevant, customers with distributed generation (prosumers) who rely on the network connection.	Used when describing service outcomes and performance measures such as safety, reliability, resilience, power quality, connection experience, and outage communications.
Owner / governance (accountability lens)	Waipā Networks is consumer-owned via the Waipā Networks Trust . In this AMP, the Trust is described as our owner representative and governance accountability channel (including SCI expectations), rather than as a stakeholder group.	Used when describing governance expectations, accountability, trade-offs, and how customer interests are represented through ownership and reporting.
Treaty partners and mana whenua (relationship lens)	Iwi/hapū and mana whenua have place-based relationships and interests that are not well described by a generic "stakeholder" label. In this AMP, we recognise and describe iwi/hapū as Treaty partners and mana whenua, including how engagement will inform planning and delivery (for example, cultural, environmental, and resilience considerations).	Used when describing relationship expectations, engagement approaches, and how relevant place-based outcomes are considered in programme development and delivery.
Other stakeholders (influence/obligation lens)	Parties who influence, regulate, govern, partner with, or are materially impacted by our asset management decisions. This includes (for example) regulators, retailers, councils and consent authorities, Transpower and other network/interface parties, emergency management, other corridor utilities, suppliers and contractors, landowners, and dispute resolution schemes.	Used when describing statutory and regulatory obligations, approvals and corridor access, system interfaces, delivery dependencies, emergency coordination, and other requirements that shape asset decisions.

Dual roles: An individual or organisation can sit across more than one category (for example, a council may be both a customer at some sites and a planning authority; an iwi organisation may also be a network customer). In this AMP we describe and engage parties using the primary lens most relevant to the decision being made.

Customer relationship context: While retailers manage billing and many account interactions, Waipā Networks' asset management decisions directly affect end consumers through service outcomes (for example, reliability, power quality, connections and outage communications). For the purposes of this AMP, 'customer' refers primarily to connected end consumers and connection applicants, regardless of retailer.

Customer types: Customers include anyone connected to the network (residential, commercial and industrial), connection applicants (new and upgraded connections) and customers with distributed generation (prosumers) who export electricity.

Throughout this AMP, we signal the need for significant investment in the network. These investments will affect affordability, sustainability, resilience, and power quality, and there is now a wider set of credible, customer and community-controlled solutions. As a result, we are moving away from a purely provider-led planning model toward one in which customers and communities help shape problems, options, and trade-offs from the outset. Historically, the network set acceptable service levels using conservative planning criteria that suited stable demand and conventional solutions. Today, demand is changing rapidly due to decarbonisation, electrification, and regional growth, requiring us to regularly test assumptions with customers.

At the same time, non-traditional options such as energy storage, distributed solar generation, and demand response are becoming more capable and more economic. These technologies can defer or reduce the need for network investment, improve resilience, and give customers more

choice in how they use and supply electricity. Selecting between these options involves trade-offs that cannot be resolved through technical analysis alone. Understanding customer and community needs, constraints and preferences by place and group is therefore a prerequisite to sound planning.

Customer and community engagement is not one-off or transactional. We will keep engagement long-term and regular to inform how we define service levels, evaluate options, sequence investment, and explain decisions. Over successive planning cycles, we will build a clearer picture of customer requirements and use it to shape trade-offs between affordability, reliability, resilience, sustainability, and power quality.

This section also describes who our customers and stakeholders are, what they tell us about our current performance, and how their input has influenced the choices and priorities reflected in this AMP. We reference recent survey and engagement insights, the impacts of growth and change on our network, and the priorities this creates for investment and service.

We expect these enhanced approaches to surface a wider and richer range of customer and community perspectives on how energy needs can be met. Over time, this will better position us to develop solutions that meet customer expectations and make trade-offs more transparent. It may also highlight themes we have not previously understood or prioritised. As a result, we may need to refine elements of this AMP over the coming years as insights evolve and circumstances change.

3.2 Summary

Based on recent engagement and regional economic and demographic indicators, what we're seeing is:

- **A diverse community:** Our footprint spans higher and lower-income areas, so affordability matters and must be balanced fairly across all customers.
- **Strong regional growth:** Population and agriculture continue to drive demand. Growth trajectories could shift, so our plan needs flexibility to advance or defer investment as needed.
- **An evolution in our customer mix:** Rapid population growth has shifted the network from predominantly rural supply toward a much larger urban customer base. This has driven a reconfiguration of the Cambridge network and is also shaping our network architecture review of the Te Awamutu area (discussed further in Section 4).
- **Ongoing energy transformation:** Decarbonisation, electrification and distributed generation will change how customers use the network, increasing the importance of managing trade-offs over this AMP period.
- **Customer preferences on price and service:** Survey results indicate many customers are cautious about paying more for improved service unless the value case is clear. Willingness to pay more is higher among rural and commercial customers, reflecting the greater impact of outages on these groups.

- **Adoption of decarbonisation options is still in its early stages:** Self-reported intent to adopt new technologies remains low (for example, EV purchase intent is ~2% overall). This reinforces the need to stage investment and avoid committing too early where uncertainty remains high.
- **Customer satisfaction and priorities:** Overall satisfaction increased in the latest survey, with improvements in value for money and communication, while perceptions of core services and image and reputation reduced and remain below target. We are responding by strengthening engagement and improving outage communications, with the goal of lifting confidence in service delivery and decision-making.

These insights are important. They are used to frame planning questions, test options, and explain decisions, including where trade-offs are required between price, reliability, resilience and sustainability. They also underpin our decision to strengthen engagement so that customer and stakeholder perspectives remain visible throughout planning and delivery.

For a deeper discussion of the energy transformation and its implications for demand, resilience and investment timing, see Section 10.

3.3 Our customer strategy

We are strengthening our customer and stakeholder relationships so that customer insight informs network planning from the start and is carried through as options are developed and delivered. We will use co-design to help define the problem, test options and trade-offs, and shape delivery staging and impact mitigations. In this AMP, co-design means involving customers and communities early enough for their input to influence option assessment, priorities, implementation approach and identify customer and community owned solutions. Waipā Networks remains accountable for final decisions, including meeting statutory obligations and managing safety, reliability, affordability, and system performance.

This approach helps us understand what different customer and community groups value, test planning assumptions, and develop solutions that fit local needs and constraints. It reflects the scale and type of investment signalled in this AMP and the impacts those investments can have on affordability, sustainability, resilience, and power quality. It also recognises that credible alternatives to traditional reinforcement now exist, including customer and community-controlled solutions. This will be a new approach for Waipā Networks, and we are still in the early stages of this engagement programme. We expect that we will need to adapt and adjust our programme as we gain experience. In this chapter, we discuss our initial thinking; however, as discussed, we fully expect this to change over time.

Our customer strategy is to:

- **Embed ongoing customer and community involvement into planning** to develop a clear and current understanding of future customer requirements and expectations. We will co-shape solutions to network constraints, ensuring the trade-offs between affordability, reliability, resilience, sustainability and power quality are right-sized for the community's needs.
- **Be transparent and informative:** share the evidence behind constraints and options so communities can understand the issues, the trade-offs, the role they can choose to play, and what informed input looks like.
- **Set and achieve reliability targets that reflect customer priorities** and regularly test whether those targets remain appropriate as needs change.
- **Set and achieve customer experience and satisfaction targets that reflect customer priorities,** and report progress openly.
- **Communicate promptly and proactively,** especially during outages, with information that customers can act on.
- **Lift engagement quality** by considering the needs and engagement preferences of the differing communities.

3.4 Enhancing how we engage with customers

3.4.1 Our new approach

We are strengthening how we listen, involve and respond so that our customers and communities shape our planning, solution development, operations and the outage experience on an ongoing basis. This AMP signals significant investment ahead. To make the right choices and manage price-quality trade-offs effectively, we need a clearer understanding of what customers value and what non-traditional options they are prepared to consider.

Our approach is grounded in inclusive, material, and responsive engagement, with a clear accountability loop. Customer insight will be used to shape service definitions, develop and test options, and co-design solutions. This will help ensure investment is aligned with customer requirements and help us identify where non-traditional options can improve outcomes or defer conventional reinforcement.

This means we will:

- Engage early on what matters most to customers, before preferred solutions are selected.
- Actively involve customers and communities in the co-design of solutions.
- Set targets that are meaningful to customers (service and satisfaction), focus our activities on meeting these, and publish progress.

- Communicate early and often, particularly during outages, with clear explanations of cause, expected timeframes, and restoration priorities.
- We will draw on the structure and benefits of established engagement frameworks (for example AA1000, IAP2, ISO 26000, and other recognised public participation approaches) and apply the most relevant elements to suit our context, the decision at hand, and different community needs. This enables a flexible approach that draws on proven methods while remaining proportionate and responsive to the communities we are engaging with.

We are enhancing our engagement framework to make customer perspectives visible at key decision points in investment planning and asset management, and to ensure they inform those decisions. A priority is to improve how we develop future investment decisions and their price impacts, and to test alternatives such as storage, distributed generation, and demand response alongside conventional network options.

Over the coming planning cycles, we will build a clearer picture of customer requirements by group and locality, use that insight to guide investment priorities, and work with communities to identify and sequence solutions together.

Place-based engagement pilot: Kāwhia (FY26-27)

As the first step under this enhanced engagement approach, we are piloting a place-based programme in Kāwhia and neighbouring areas. The purpose is to work with the community to better understand reliability, resilience and price-quality choices, and to make the resulting trade-offs more explicit in our investment decisions and timing. This is a new approach for Waipā Networks and we expect it will be iterative. The methods, timing and outputs will be refined as we learn what works locally and what provides the most useful input for decision-making.

Kāwhia and the surrounding areas are supplied by our worst-performing feeder, with configurations that are difficult to improve through conventional means alone. There are a number of potential solutions and we believe that a mixture of these will be required. This may include targeted network investment (security, automation, vegetation risk reduction) and non-traditional options (distributed generation and battery technology). Community input will help test assumptions and inform how options are assessed, including which options are progressed, which are not, and why. Rather than a simple 'you said / we did' approach, we will maintain a transparent decision record showing what we heard, what changed, what did not, and the reasons for those outcomes. We will also ensure engagement continues beyond the initial investment period and develops into an enduring relationship built on mutual respect and trust.

Why Kāwhia first

Kāwhia's selection reflects its isolated location, high deprivation (index 10), limited road access, and high outage harm. Feedback to date highlights priorities such as faster storm restoration, more timely updates, and stronger support for critical local facilities. These circumstances make Kāwhia an appropriate starting point for developing and testing a scalable, place-based engagement and relationship development model, while recognising that whatever we land on needs to be seen as fair and defensible by our wider customer base.

What we're doing

To ensure our engagement in the Kāwhia area is meaningful and inclusive, we are targeting a range of activities that enable community members to share their perspectives, priorities, concerns and opportunities. The following provides examples of the key engagement methods we intend to use and adapt as part of the Kāwhia place-based pilot:

- We will develop engagement plans that address the different needs and engagement preferences of each section of the community
- Co-hosted whānau hui with marae, Community Board, and community groups
- Critical-site interviews (Health Centre, School, Fire Station, Waipapa Marae/CDEM, petrol station/shops)
- Pop-ups and intercepts at Kāwhia Kai Festival, petrol station, and school gates
- Use of short SMS/paper survey (≤10 questions) in plain language
- Accessibility supports: transport stipends, childcare, kai, evening/weekend sessions, paper/SMS options, te reo Māori where appropriate.

Phase one does not have a defined timeframe, as we recognise it will take time to ensure the approach is meaningful and successful. Where practicable, we expect early insights from phase one will be able to inform option assessment and timing decisions in early FY27, while recognising that the value of this pilot will build over more than one planning cycle.

What we'll measure and publish

We intend to publicly share findings to support transparency and learning as the pilot progresses. The specific measures and frequency will be refined over time. Indicatively, this may include:

- **Community priorities:** what matters most to the community and how this influenced options.
- **The community's opportunities:** where customers can participate in or lead solutions.
- **Equity outcomes:** results by township/settlement and priority groups (including medically dependent customers), and how the approach remains fair and transparent for customers across our wider network.
- **Service experience:** raw and normalised SAIDI/SAIFI, and total connected kVA-hours interrupted.
- **Engagement quality:** participation breadth and diversity, participant satisfaction, and how feedback themes were considered in decisions.
- **Other information and insights that the community feels are useful and relevant.**

We will report the decision principles used in Kāwhia so customers elsewhere can see how choices are made consistently across the network, even where local circumstances differ.

Governance and risk management

This work will be led by the GM Customer & Community, in collaboration with the GM Network, and delivered through a cross-functional team drawing on engagement, engineering, and communications capabilities (including specialist support as required), and will be reported regularly to the Board. Key risks include low turnout, misinformation and weather disruptions. We will manage these through local partners, plain-English explainers, and adapting engagement methods and timing to support participation.

What comes next

Kāwhia will provide a learning opportunity and a visible commitment to place-based engagement. We will use the learnings to inform how we engage in other locations, recognising that each community will require a tailored approach and that Kāwhia will not be a one-size-fits-all template.



3.5 Customer and stakeholder interests

From an asset management perspective, this section summarises the key requirements and constraints we must consider when making asset decisions. These requirements come from customers (service outcomes), governance (owner and accountability expectations), Treaty partners and mana whenua (place-based interests), and other stakeholders (statutory, regulatory, interface, access, delivery, and public safety requirements).

These requirements are reflected in the performance measures and targets used in this AMP. Reliability and restoration measures align to expectations for continuity of supply and timely recovery from outages. Power quality measures and monitoring respond to the need for stable voltage and fewer quality-related issues. Customer satisfaction, complaints, and communication measures reflect expectations for clear, timely information and for issues to be resolved effectively. Connection performance measures reflect expectations for predictable timeframes, transparent requirements, and reduced customer effort.

3.5.1 Our customers and stakeholders

As defined in Section 3.1, the term “stakeholders” refers to parties who influence, regulate, partner with, or are materially impacted by our asset management decisions (for example, regulators, retailers, councils, emergency management, Transpower, corridor partners, suppliers, contractors, landowners, and dispute resolution schemes). These relationships shape requirements, constraints, risks, and delivery sequencing for our investment programme.

Customers are the direct recipients of network service outcomes, so we describe customer needs and service outcomes separately from stakeholder requirements. Owner accountability (via the Waipā Networks Trust) and relationship expectations with iwi/hapū are described using the lenses set out in Section 3.1.

A summary of requirements by group is shown in table 9 to table 11.

3.5.2 The engagement that informed this AMP

Customer and stakeholder engagement is a vital part of our business. It ensures we identify and consider the interests of all stakeholders when setting our objectives, strategies, and performance targets. In preparing this AMP (and prior AMPs), we have engaged through a mix of formal and informal channels to inform our asset management objectives, including:

- An annual customer survey, project-specific consultations, and input on medium – to long-term plans
- Day-to-day contact when customers connect or upgrade, manage vegetation, apply for distributed generation, or report outages
- Ongoing dialogue with councils, businesses, iwi/hapū, community groups, and emergency services.

From 2026, we expect our more focused engagement approach to provide deeper insight into customer and stakeholder priorities and drivers. As these more in-depth insights emerge, we expect that customer drivers and feedback may evolve, and we will refine our asset management approach and future AMPs to reflect this.

Table 8 outlines our current engagement approaches, which informed stakeholder interest in this AMP.

Purpose	Category <i>(As defined in Section 3.1)</i>	Method of engagement	Information and usage
Understanding and improving customer satisfaction	Customers	Annual customer survey as part of wider industry benchmarking and additional shorter surveys to gather intel and feedback on performance and initiatives.	Regularly measure customer experiences with us to support understanding of customer needs and enable continuous improvement in customer experience and future network requirements.
		Proactive engagement of customer groups to gain clarity on where there are energy hardship issues, more frequent supply disruptions, and in areas where future network development projects are planned.	Provides a deeper understanding of our customers and their needs.
		Community engagement initiatives to increase customer interaction and feedback.	Supports continual improvement in customer service.
Understanding customer views on our price-quality trade-off and future needs from the network	Customers	Proactive engagement of customer groups, to gain clarity where there are energy hardship issues, more frequent supply disruption, and in areas where future network development projects are planned.	Supports understanding of customers' views on price vs quality; assists our review of customer service targets; supports understanding of future needs and how the network can respond.
Improving the customer connection process	Customers	Customers engage with our team throughout the new connection process; a network perception survey is sent after each engagement to measure experience continuously.	Customer experience measures inform internal processes and provide insights for network development and customer communications.
Improving vegetation management	Customers; Other stakeholders (landowners/ general public/ public safety)	Digital and print advertising campaigns across the region, targeting proactive vegetation management, three times per year.	Communication is currently one-way, consistent with the public safety management system and tree regulations.
Improving network fault restoration	Customers	Customer faults number, call centre and field service engagement.	We capture feedback through our survey process.
Resolving complaints promptly and effectively	Customers; Other stakeholders	When a complaint is raised, these are proactively managed by the Customer & Engagement team to resolve issues quickly. We use our customer disputes resolution process when appropriate.	Analysis and insights from complaints are used to understand needs, identify trends, and proactively address recurring issues.
Understanding major customer needs for future planning	Customers (large users)	Individual meetings and correspondence as required to develop a deeper understanding of current and future needs, informing network development.	Insights from direct engagement support customer group profiles and inform development planning.
Incorporating needs in major work delivery	Customers; Treaty partners and mana whenua; Other stakeholders (community)	Public meetings, individual meetings and/or correspondence as required.	Ensures customer, community and place-based considerations are incorporated into option assessment, staging, and mitigations.
Understanding regulatory and consenting requirements	Other stakeholders (councils/regulators)	Meetings with council officers as required for specific projects; meetings with the Commerce Commission (as required).	Regulatory and consenting requirements inform option selection and delivery planning. We coordinate to understand council initiatives and to support consistent customer communications where responsibilities are shared.
Receiving feedback on pricing structures and retailer implementation	Other stakeholders (retailers)	Engagement guided by the formal consultation process in our use-of-system agreement.	Feedback is used to ensure our pricing structure is implementable and understood, and to improve coordination on customer-facing impacts where relevant.

Table 8: Current customer engagement activities

3.5.3 Stakeholder interests

Table 9 to table 11 summarise the main requirements by group and how they are addressed through our planning, service targets, engagement, and delivery approach. These views are based on our surveys and engagements over many years. As discussed in Section 3.4, we are enhancing our engagement process, which may lead to an evolution of these interests in future AMPs.

Customer group <i>(Service recipient lens)</i>	Primary interests / needs	How the AMP responds
Residential (urban and semi-rural)	Safe, reliable supply; affordable network outcomes; timely, useful outage information; straightforward fault reporting and restoration; good power quality for modern appliances.	Service targets and performance reporting; investment programmes focused on safety, reliability and resilience; improved outage communications and restoration updates; customer satisfaction measures and complaint insights used to refine service delivery.
Rural and remote residential	Reliability and resilience during storms; longer restoration times managed well; vegetation and access issues addressed; clear expectations and communications.	Resilience and reliability programmes targeted to rural feeders; vegetation management and fault response improvements; tailored communications for longer outages and access constraints.
Commercial and small-to-medium business	Predictable reliability; fast restoration; power quality (equipment sensitivity); advance notice of planned outages; clear connection and upgrade pathways.	Planned works coordination and notice; power quality monitoring and response processes; service targets and reliability investment; improved connection process measures and communications
Industrial / large users	High reliability, power quality, capacity planning visibility, coordination for planned work, and options analysis for capacity and resilience.	Early engagement for major loads; transparent option assessment and trade-offs; targeted investment and operational planning; connection/upgrade planning and delivery sequencing.
Critical services customers (e.g., water/wastewater sites, health facilities, communications hubs, emergency services sites)	Continuity of supply; fast restoration priority; clear escalation. Pathways; coordination for planned outages; resilience planning.	Critical customer identification and restoration priorities; joint planning where relevant (e.g., planned works windows); resilience initiatives. (Including targeted asset replacement, automation, and redundancy where justified); clear communications and escalation processes.
Medically dependent customers	High consequence of outages; early warning and frequent updates; clear support pathways.	Processes aligned with medically dependent customer requirements (registration, prioritised communications, restoration information); outage communications designed to be timely and actionable; coordination with retailers and relevant agencies where required.
Customers facing hardship / higher vulnerability	Affordability impacts, clear and accessible information, practical support, and reduced customer effort.	Plain-language, accessible communications; targeted engagement where affordability impacts are likely; input used to inform trade-offs and sequencing (while meeting safety and statutory obligations).
New connections and developers (including subdivision and growth-related connections)	Clear requirements; predictable timeframes; transparent cost contributions; coordination with councils and other infrastructure.	Defined connection standards and processes; improved forecasting of capacity needs; clearer communications on requirements and timeframes; coordination with growth partners and consenting processes.
Distributed generation/prosumers (e.g., solar PV, batteries)	Safe connection and export management; clarity on technical requirements; transparent constraints and solutions.	Connection guidance and technical standards; network planning considers non-network solutions where appropriate; engagement to test options and constraints for local solutions.

Table 9: Customer groups, interests and how the AMP responds

Owner / governance <i>(Accountability lens)</i>	Primary interests / expectations	How the AMP responds
Waipā Networks Trust (owner representative)	Stewardship on behalf of consumers; confidence in long-term investment decisions; transparency of trade-offs; appropriate risk management; delivery on SCI expectations.	AMP sets out service outcomes, investment rationale, and trade-offs; performance and delivery reporting; structured engagement to inform key decisions; governance assurance processes and reporting lines.
Board/governance oversight	Clear line of sight between customer outcomes, statutory obligations, and investment choices; disciplined prioritisation; evidence-backed decisions.	Defined decision-making approach, option assessment, and prioritisation criteria; regular reporting on performance, risk, and delivery; clear definitions and categorisation (Section 3.1) to avoid ambiguity.
Statement of Corporate Intent (SCI) accountability	Alignment to agreed objectives and reporting expectations; customer benefit focus; transparency of performance.	AMP links planned work and performance measures to SCI objectives; monitoring and reporting approach set out (including customer satisfaction and service delivery measures).

Table 10: Owner and governance, interests and how the AMP responds



Treaty partners / other stakeholders <i>(Relationship or influence/obligation lens)</i>	Primary interests / requirements	How the AMP responds
Iwi/hapū and mana whenua (Treaty partners/ mana whenua lens)	Place-based interests; cultural values and sites; environmental outcomes; resilience for communities; meaningful engagement early enough to influence options and delivery approach.	Engagement approach that supports early input to option assessment, staging, and mitigations; relationship-building and information sharing; consideration of relevant place-based outcomes in planning and delivery (with a clear link back to Section 3.1 definitions).
Regulatory bodies (relevant sector regulators and oversight agencies)	Compliance with statutory obligations; delivery of required service levels; prudent investment; transparent reporting.	AMP demonstrates planning approach, justification and trade-offs; compliance obligations reflected in planning and delivery; reporting against required measures and targets.
Retailers	Coordinated customer communications; outage and planned works information; smooth customer experience across interfaces.	Clear outage and planned works communications flows; coordination protocols; consistent customer messaging where responsibilities sit across parties.
Local and regional councils / consent authorities	Growth planning coordination; corridor management; consenting and land use impacts; resilience and emergency planning alignment.	Early engagement on growth and infrastructure programmes; coordination on planned works; alignment with consenting and corridor requirements; shared understanding of constraints and sequencing.
Emergency management and response agencies (e.g., CDEM groups and responders)	Rapid situational awareness during events; restoration coordination; critical sites prioritisation; public safety.	Event communications protocols; restoration priorities for critical sites; coordination processes and information sharing during incidents; post-event review to improve resilience and response.
Transpower and other network/interface parties	Secure interface coordination, planned outage coordination, system performance, and risk management.	Planned works coordination; interface and operational requirements reflected in planning; joint risk management where relevant.
Other corridor utilities and infrastructure operators (e.g., telecommunications, water, transport)	Safe coordination in shared corridors; efficient scheduling; minimised community disruption.	Coordinated planning for works and traffic management; joint scheduling where practical; consistent community communications for disruptions. Resilient supply to critical infrastructure and clear identification of risk.
Suppliers and contractors	Clear scopes and standards; safe delivery; predictable pipeline; performance expectations.	Contracting and safety management frameworks; delivery planning and sequencing; supplier performance management aligned to service outcomes.
Landowners	Safe access and respectful engagement; clarity on easements/rights; minimised disruption; fair process for vegetation and access.	Clear access and easement processes; planned works notice where practicable; vegetation management communications; site-specific engagement for higher-impact work.
General public and public safety	Safety around assets and worksites; safe road crossings and corridors; fast hazard response; clear information during incidents.	Public safety focus in planning and delivery; hazard response processes; worksite safety controls; clear public communications during incidents and disruptions.
Dispute resolution scheme(s) (e.g., utilities disputes)	Fair, accessible resolution processes; timely responses; learning from issues.	Complaint and dispute processes set out; trend monitoring used to improve service and communications; reporting on key themes where relevant.

Table 11: Treaty partners and mana whenua, and other stakeholders, interests and how the AMP responds

3.5.4 Managing conflicts of interest

When there are conflicts in stakeholder interests, we prioritise safety. We then seek to resolve any conflicts in a manner that best aligns with the AMP objectives as outlined in Section 2.3.



3.6 Our customers

Customers refer primarily to connected end users and connection applicants.

3.6.1 Customer spread and growth

Our network serves approximately 29,000 customer connections, with a total regional population of just under 62,000. The Waipā district is a desirable place to live and is well-situated for business. Since 2013, residential customer growth has averaged 2.1% p.a., and we expect strong residential connection growth to continue (refer to figure 15).

As shown in figure 16 around 65% of the population (and customer connections) is concentrated in the Cambridge, Te Awamutu, and Tamahere townships and their surrounding areas¹².

Our customers range from residential to large industrial. Around 19% of our customers are from the business sector, of which 46% are involved in the dairy and agricultural industries. The remaining customers include urban residential, lifestyle properties, and rural homes.

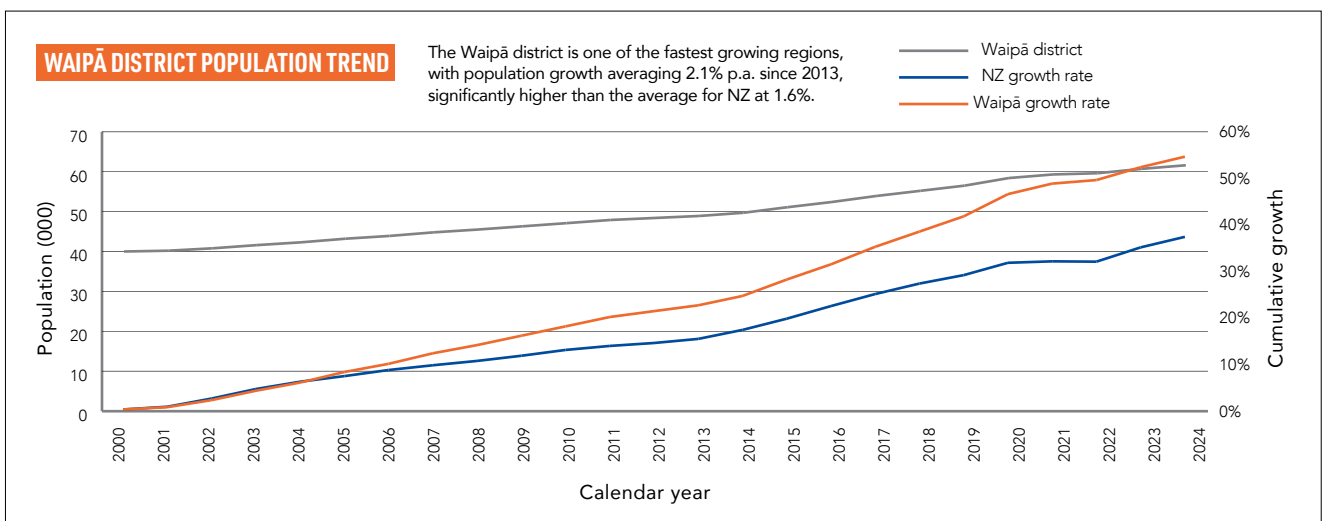


Figure 15: Recent population growth¹²

¹² Source: Infometrics Regional Economic Profile, Waipā district, to CY24.

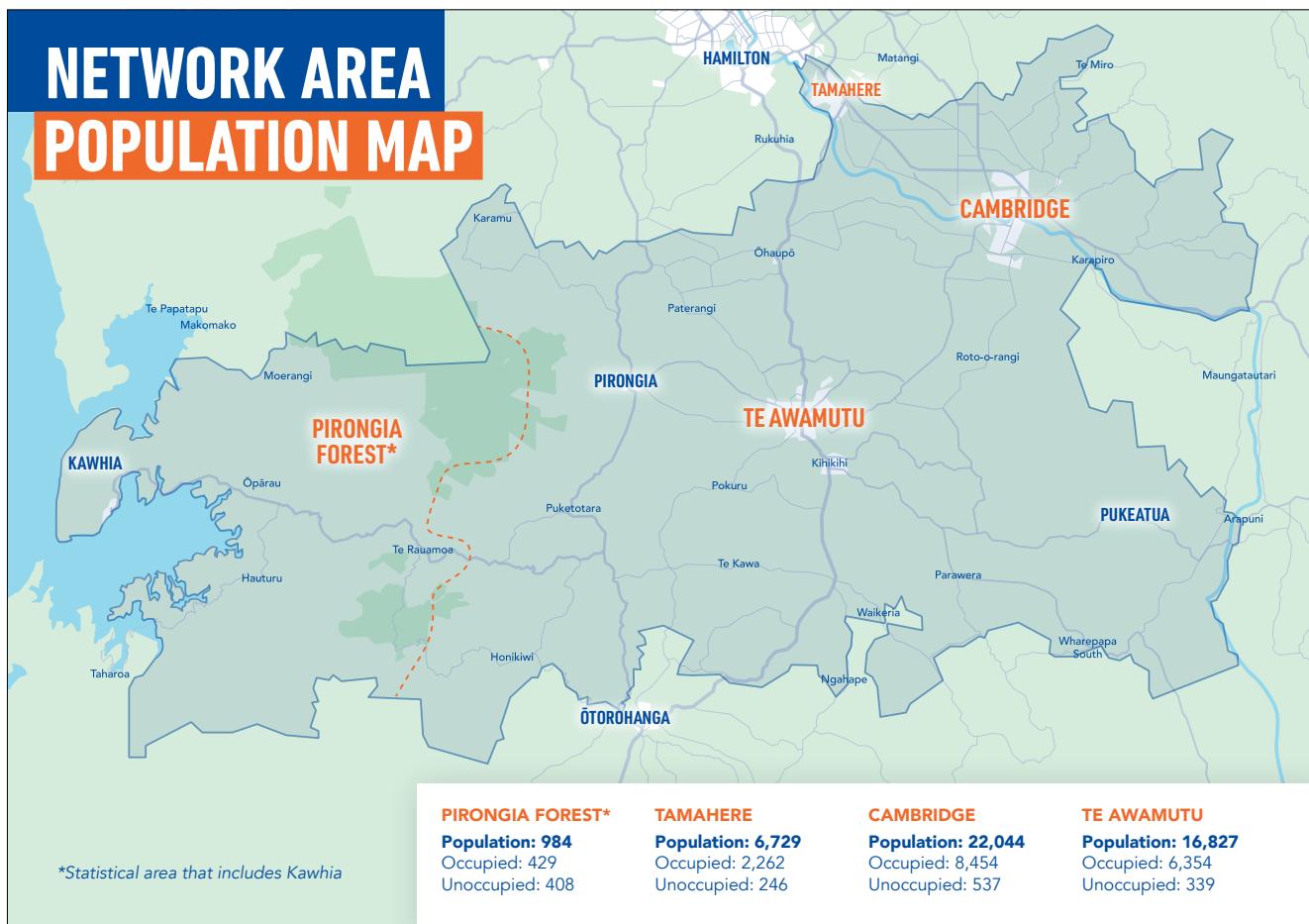


Figure 16: Population distribution in the network supply area¹³

3.6.2 Residential/domestic customer profile

Our network supports a diverse range of customers, spanning areas where customers typically have high incomes and low levels of deprivation, as well as areas where customers have low incomes and high levels of deprivation.

The average household income in the Waipā district was just under \$126,000 in 2025, which was slightly lower than the New Zealand average of \$135,000. However, household income in rural areas is significantly lower at around \$105,000, which highlights the income diversity we have across our network.¹⁴

As shown in figure 17, we have significant variation in economic hardship across the region (measured by the NZ index of deprivation). Areas of Cambridge and Tamahere have generally low deprivation. By comparison, areas such as Te Awamutu and Kāwhia have much higher levels of economic hardship.¹⁵

We are planning work to broaden our customer profile analysis to include age profile, ethnicity and additional vulnerability indicators (alongside deprivation). We will discuss this in future AMPs. This analysis will help us better target customer and community engagement and understand the potential equity impacts of investment and service-level trade-offs. We will use this segmentation to tailor communications and engagement approaches, particularly in areas where affordability pressures and outage impacts are likely to be higher.

¹³ Source: Stats NZ, to 2023.

¹⁴ <https://www.infometrics.co.nz/product/regional-economic-profile>

¹⁵ Cambridge is 1 and 5 (mostly 1-3), Tamahere is 1. Te Awamutu has large areas at 7 to 9. Kāwhia is 10. The NZ index of deprivation is: 1-2 is the least deprived, and 9-10 is the most deprived. A rating of 10 indicates the area is within the 10% most deprived areas by population.

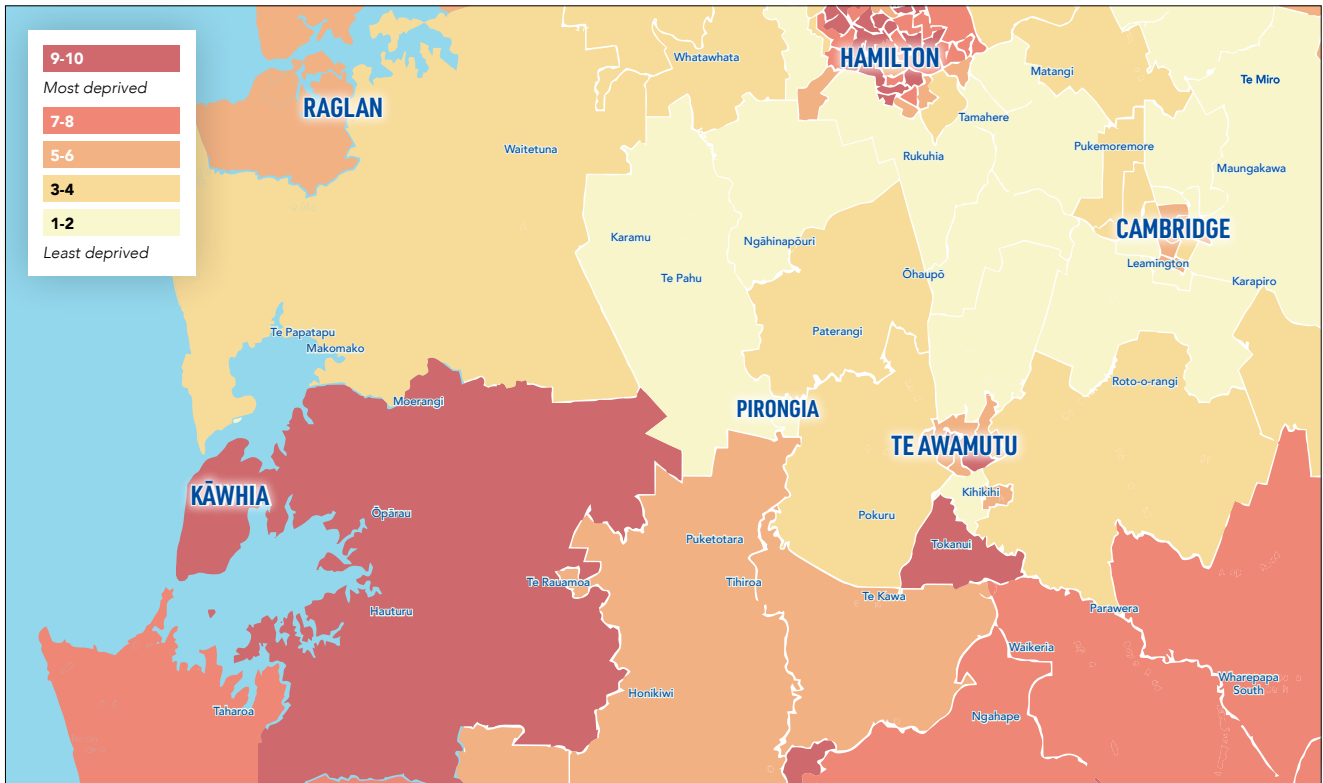


Figure 17: Deprivation Index for our region¹⁶

3.6.3 Regional economic drivers and commercial/industrial customer profile

Figure 18 shows the contribution to our region's economic activity. Agriculture is the largest single contributor to the regional economy, followed by manufacturing, construction and a range of professional services, retail and healthcare.

This composition is reflected in our largest customers, which include:

- Two large Fonterra dairy factories, which are located at Hautapu and Te Awamutu. Hautapu's maximum demand is contracted at 12 MW, and Te Awamutu at 4.5MW, net of their embedded generation
- Architectural Profiles Limited (APL), which is a glass and aluminium joinery factory at Hautapu, has a demand of 2.7 MW. Subsequent stages could add another 10-12 MW by 2028
- Department of Corrections operates the Waikeria Prison, with planned works estimating an increase in power demand from the current 1.75 MW to 10 MW in the next five years.

Large customers significantly influence our system's peak demand at Cambridge and Te Awamutu GXPs.

Figure 19 shows the historical trend in GDP for the Waipā region. Our region's economic growth has been stronger than NZ's, driven primarily by Cambridge.

Construction made the largest contribution to overall growth in the Waipā district since 2013, which was primarily occurring in and around Cambridge. Professional services, manufacturing, healthcare and agriculture also contributed to the growth.

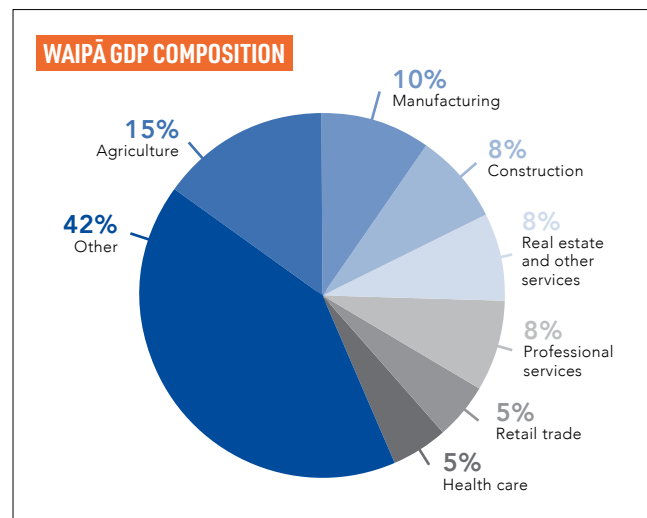


Figure 18: Waipā district composition of economic activity¹⁷

¹⁶ <https://www.ehinz.ac.nz/indicators/population-vulnerability/socioeconomic-deprivation-profile/#nzdep-for-2023-nzdep2023>

¹⁷ Source: Infometrics Regional Economic Profile, Waipā district, to CY24.

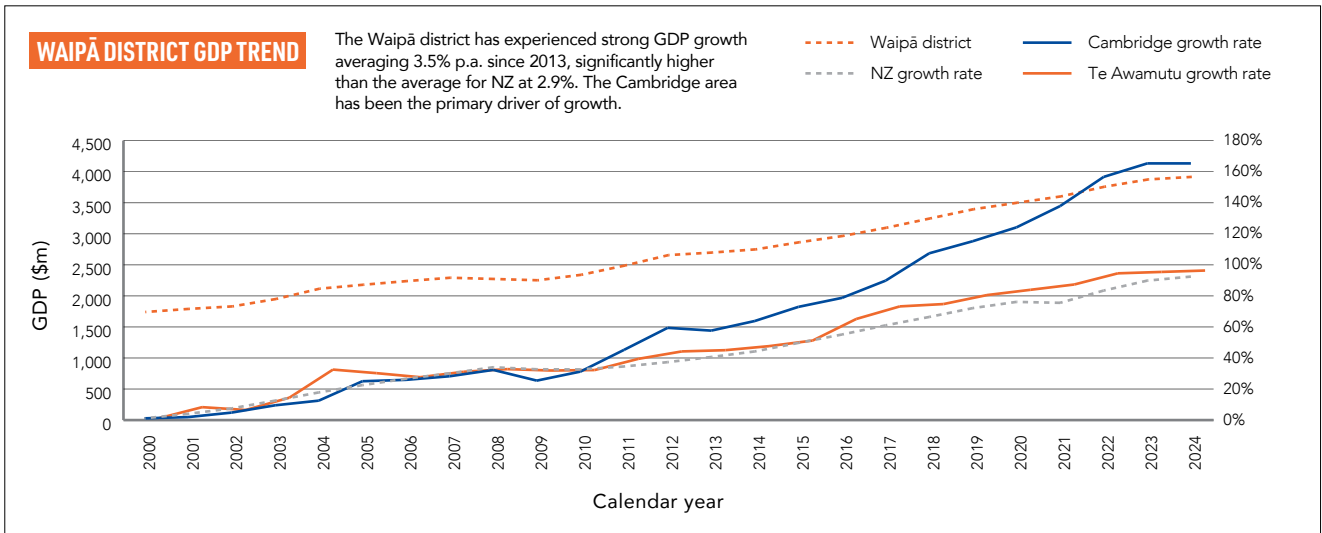


Figure 19: Waipā district gross domestic product¹⁸

The forecast increase in population will result in an influx of new commercial and industrial businesses. The Waipā District Council is working to rezone more industrial land and provide services in Hautapu to accommodate new industries.

3.7 Customer load characteristics

3.7.1 Seasonal profile

Our current seasonal load profile is primarily driven by winter residential and commercial loads, as well as the ramp-up of dairy loads in August and September. Dairy milking loads typically peak in summer. This is reflected in figure 20, which shows the demand peaks in winter-peaking and sustained load growth from 2017 to 2024.

In FY25, the network delivered 456GWh. The maximum coincident (instantaneous) system demand was 89MW, with a load factor of 59%, which is in line with the industry median and our peer group. Load factor describes how evenly demand is spread across time and is not a proxy for overall network performance. We use it here to describe demand shape and the potential value of demand flexibility, distributed generation, and targeted investment

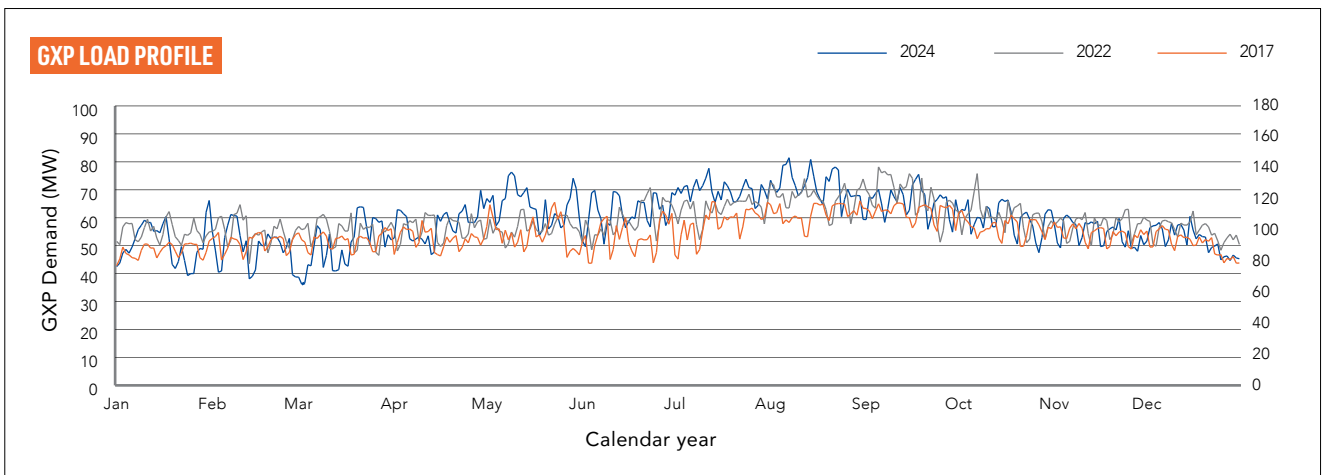


Figure 20: Our seasonal load profile (MVA)

¹⁸ Source: Stats NZ, to 2023.

3.7.2 Daily load profile

Our daily load profile, especially in winter, consists of twin peaks: one in the morning and another at night. Our daily profile has peaks driven by dairy milking times, with dairy processing influencing the baseload. These profiles are net of load management (using ripple control).

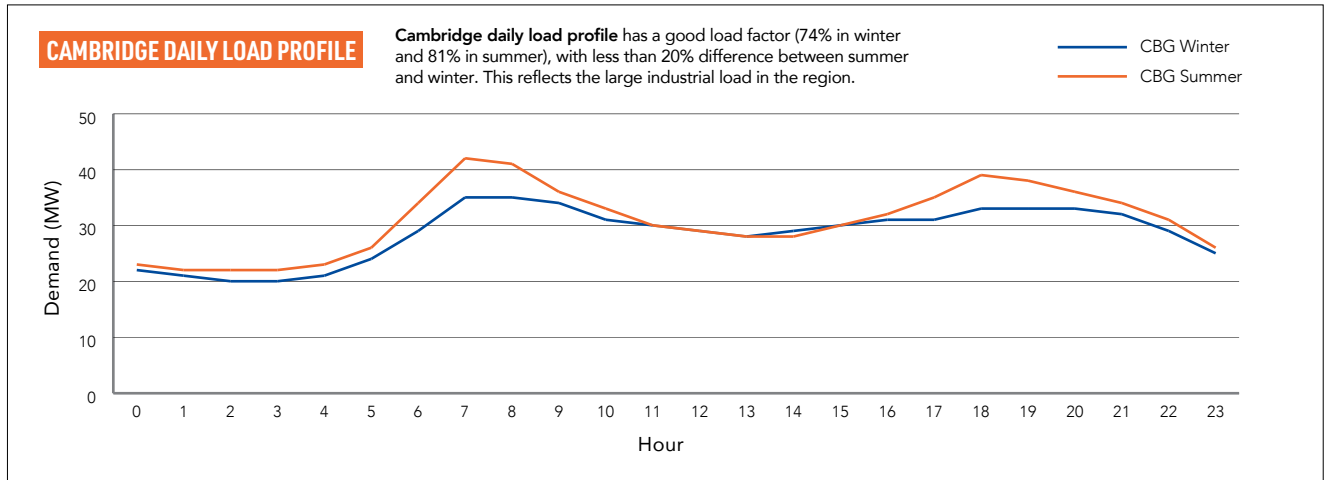


Figure 21: Cambridge GXP daily load profile (summer/winter)

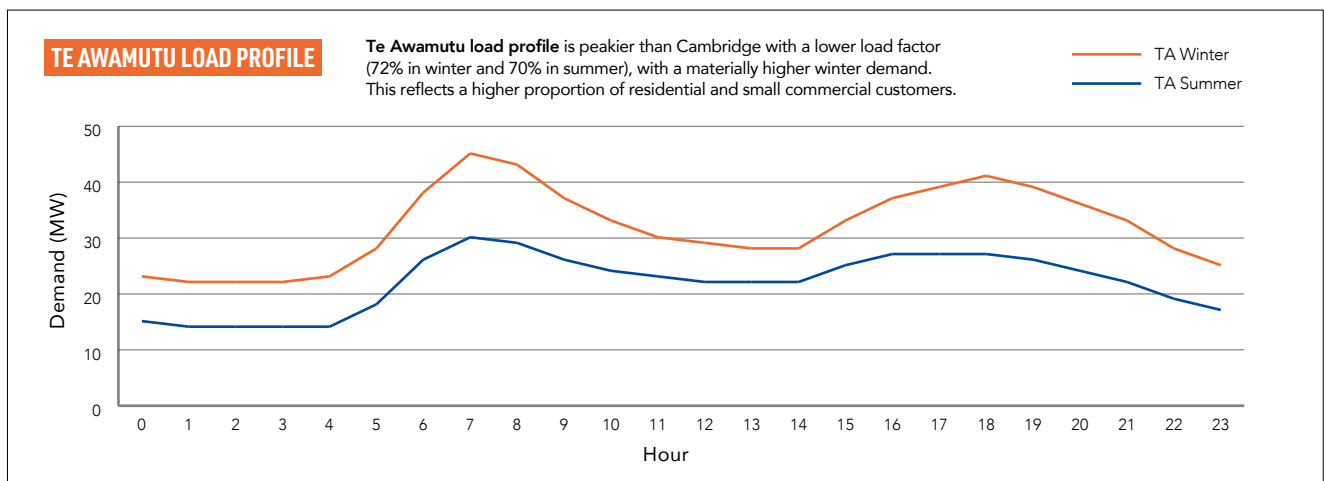


Figure 22: Te Awamutu GXP daily load profile (summer/winter)

3.7.3 Small distributed generation (DG)

As shown in figure 23 and figure 24, customers are increasing their use of distributed generation (mainly solar PV) and batteries. Presently, around 6.5% of our customers utilise this technology, with around 25% of these customers including batteries. This past financial year, around 48% of distributed generation included battery storage.

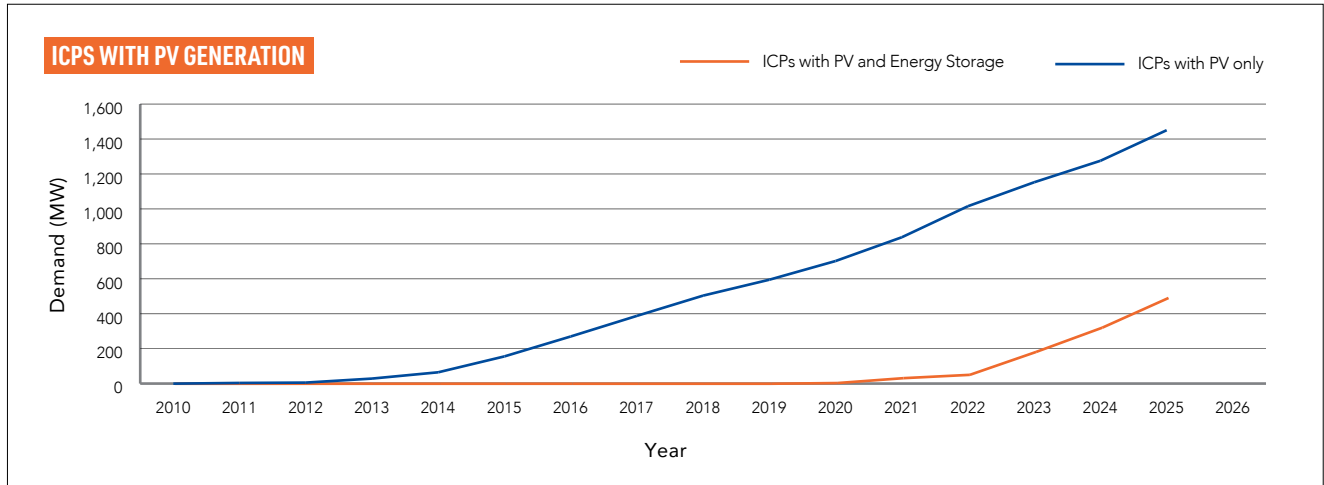


Figure 23: Customers with DG and batteries

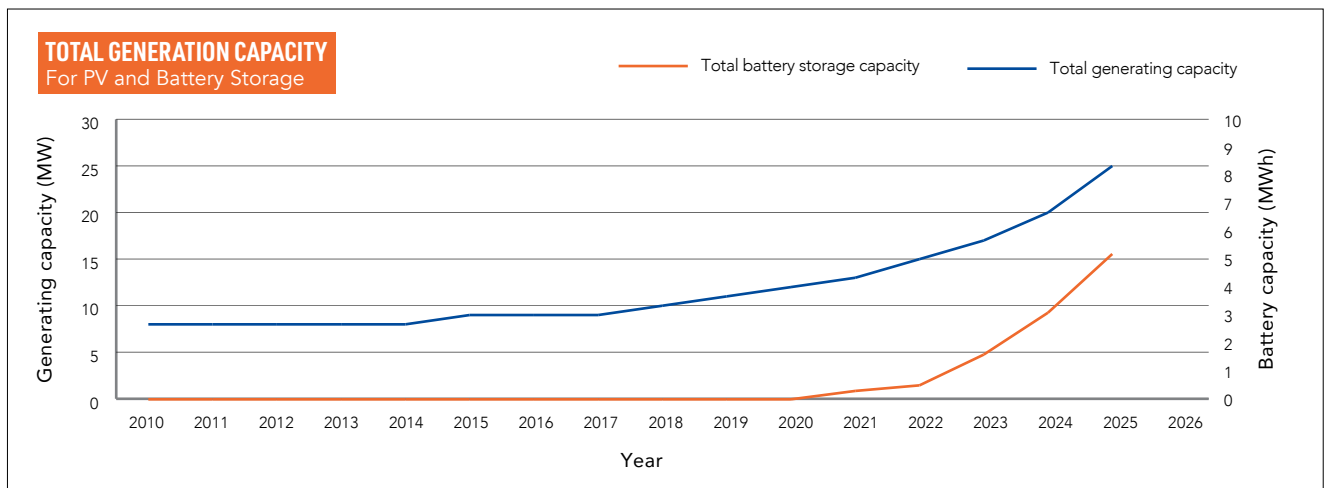


Figure 24: DG and battery capacity

Recent growth in DG connections has been linear. However, new subdivisions (where DG installation is simpler) and where developers require the connection of solar DG at every house are likely to accelerate DG uptake.

In November 2025, we updated our default export limits, increasing the single-phase export allowance from 5kW to 10kW. In addition, inverters must now use the "Australia A" 4777.2 settings, which ensure compatibility with an expanded voltage range of 230V ±10%. Volt-Watt and Volt-VAr response modes must be enabled at all times. These changes are expected to positively influence the amount of distributed generation installed on our network.

3.7.4 Large distributed generation (DG)

We have one large DG site connected to the network, which is an embedded cogeneration plant at the Fonterra dairy factory in Te Awamutu. This site usually consumes all the generated electricity, but occasionally it exports at 11kV.

Customers with large or sensitive loads also have standby generation available for backup and/or demand management. These are typically diesel generators ranging from 10kW up to 1MW. Notable examples include communications sites, District Council water infrastructure and the Waikeria Prison.

3.8 Factors that could impact our customers

There are a range of factors that could impact our customer and their demand on the network. Table 12 outlines what we currently see as the major factors and the impact that these could have on customers' demand profile and our network. We have assessed these factors in our more detailed review

of the energy transformation and in our demand forecasts (presented in Section 10). Where these factors could have a material impact on the business, they are also considered in our risk management process (Section 8).

Factor	Impact on customers	Impact on the network
Shifts in the international market demand for milk	Changes in demand or price for milk could result in an increase or decrease in dairy production (on farm) by increasing or decreasing the use of supplementary feed and/or the conversion of land to dairy. These changes will influence the operation of the dairy factories in our region.	An increase in demand for milk would increase on-farm energy usage, increasing the demand on our rural feeders. An increase in demand for milk would also increase dairy factory energy demand, increasing the demand on the dedicated feeders supplying these sites. A fall would have the opposite effect.
Climate change increases the frequency of droughts	In the short term, this would lead to a drop in farm production. In the long-term, this could lead to increased irrigation demand.	As above, a reduction in production reduces farm demand and processing demand. However, the long-term implications of irrigation are significant and could lead to a significant increase in demand on our rural feeders.
Lack of generation and/or electricity supply nationally	Based on prior energy crises, customers will reduce their energy usage, with some of these changes being permanent Enforced curtailment of supply is very unlikely.	A large temporary reduction in demand, with a smaller enduring reduction in demand.
An increase or decrease in population growth	–	Higher population growth will lead to greater customer connection, which will increase demand on our urban feeders. Lower population growth will lower connections and reduce demand growth on our urban feeders.
An increase or decrease in economic activity	–	Higher GDP will typically lead to increased commercial and industrial activity, increasing demand A decline in GDP leads to a decline in commercial and industrial activity, reducing demand.
The closure of a significant industry in our region	This could have a material impact on the regional economy, reducing economic growth and causing a population shift.	See the population and economic factors above.
Improvement in the economies of DG and batteries (either through lower cost, subscription models, or higher grid-supplied energy costs)	An increase in the uptake of DG and batteries. This is discussed in Section 10.	This could affect power flow patterns and power quality, and is discussed in Section 10.
An increase in electrification (process heat, general heating, EVs and reduction in gas usage)	An increase in electricity consumption and the potential to shift demand. This is discussed in Section 10.	This could significantly increase demand, and also increase the options for flexibility and is discussed in Section 10.

Table 12: Economic influences and impacts on our network

3.9 Customer satisfaction targets

Table 13 presents our current customer satisfaction targets. The targets are based on the higher average benchmark score (from other EDBs from the same survey) and our current performance. We are seeking a progressive performance improvement, which was set to achieve the top end of the EDBs in our survey group.

As we progress with our new stakeholder engagement, we will review these targets to ensure that they align with the areas that matter most to our customers. This may lead to new measures or an increase or decrease in target performance.

Performance targets	Target FY27	Target FY28	Target FY29
Overall Satisfaction	65%	>65%	>65%

Table 13: Customer satisfaction targets

3.10 Customers' views on our performance

Our annual customer survey has historically been our key method for engaging with customers. Since FY21, we have used the same survey as several other EDBs, which enables benchmarking¹⁹. At the time the survey was developed, it was aligned to stakeholder requirements. The survey enables us to:

- Understand our customers' perception of us and satisfaction and experience when engaging with us
- Identify opportunities to enhance customer satisfaction and experience
- Provide feedback on our price-quality trade-off.

These measures will be updated in future AMPs, following the changes to our engagement processes outlined at the start of this section.

3.10.1 Customer satisfaction

Our annual customer survey (November 2025, n=2,640) shows overall satisfaction increased to 64%, which is in line with the 2024/25 EDB benchmarking average. Waipā Networks is above the benchmark average for value for money (59%), enquiry handling (75%), communication (54%), and image and reputation (58%). Perceptions of core services reduced to 73%, which is also in line with the benchmark average, but below our target. This reinforces the need to lift confidence in core service delivery and strengthen how we explain investment choices and service outcomes.

Measures	Waipā results FY26	Average benchmark FY26	Waipā Results FY25	Trend since last survey
Overall satisfaction	64%	64%	59%	Improving
Reliability / core service	73%	73%	78%	Declining ²⁰
Value for money	59%	51%	52%	Improving
Image and reputation	58%	57%	62%	Declining
Communication	54%	53%	49%	Improving
Enquiry handling	75%	73%	65%	Improving

Table 14: Annual customer survey results (November 2025)

¹⁹ *Average benchmark is the Key Research EDB Benchmarking 2024/25 average (based on 8 EDBs). Survey results are from the Waipā Networks Annual Customer Service Survey 2025 (fieldwork November 2025, n=2,640).

²⁰ Within one percentage point.

3.10.2 Customers' views on our price vs. quality (reliability) trade-off

As shown in figure 25, customer willingness to pay more for improved reliability has increased. In the November 2025 survey, around four in 10 customers are willing or somewhat willing to pay more for improved reliability (up from 2024), while 50% were not willing to pay more. This indicates growing openness to reliability improvements where the value case is clear.

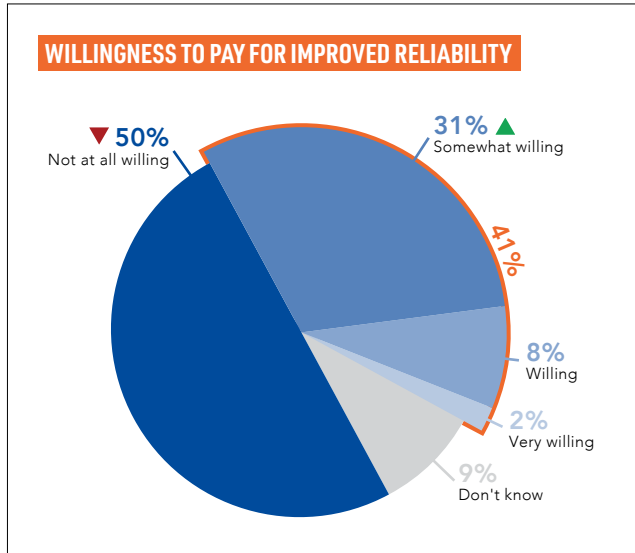


Figure 25: Customers' view of willingness to pay (n=2640)



Customer views on reliability investment are consistent with the core services results in table 14. While overall satisfaction has improved, the decline in perceptions of core services indicates a continued need to prioritise reliability-focused improvements and to clearly explain trade-offs.

CUSTOMERS' VIEW OF CORE SERVICES				TOTAL '24 (%8-10)	Mean	RESIDENTIAL (%8-10)				COMMERCIAL (%8-10)			
Good (%8-10)	Neutral (%5-7)	Poor (%1-4)	Urban			Rural	Te Awamutu	Cambridge	Urban	Rural	Te Awamutu	Cambridge	
*Overall core services (n=2,347)	73%	23%	3%	78%	8.2	77%	71%	77%	72%	65%	66%	70%	57%
Delivering a safe power supply (n=2,223)	81%	17%	2%	80%	8.6	82%	80%	84%	79%	81%	81%	83%	76%
Providing a reliable power supply (n=2,387)	81%	17%	3%	76%	8.5	83%	77%	83%	79%	78%	75%	79%	70%
Minimising the number of outages (n=2,144)	74%	22%	3%	73%	8.3	78%	70%	77%	73%	79%	65%	73%	63%
Being quick to respond to issues (n=2,085)	73%	23%	4%	70%	8.2	74%	72%	76%	69%	67%	73%	75%	63%
Focusing on line maintenance (n=1,884)	71%	25%	3%	71%	8.2	74%	70%	75%	70%	68%	62%	64%	64%
Embracing technology to improve their service (n=1,543)	67%	28%	5%	61%	7.9	70%	63%	70%	64%	63%	60%	68%	46%
Focusing on continued investment growth (n=1,485)	64%	32%	4%	59%	7.9	68%	62%	70%	60%	58%	58%	65%	41%

Figure 26: Customers' view of core services (n=2,347)

As shown in figure 27, among customers who reported a power supply issue, the most common problems were long unplanned outages (50%) and multiple short interruptions (46%). Lower voltage was also reported (21%). These results highlight the customer impact of outage duration and repeat interruptions, and reinforce the importance of restoration performance and timely, practical outage communications.

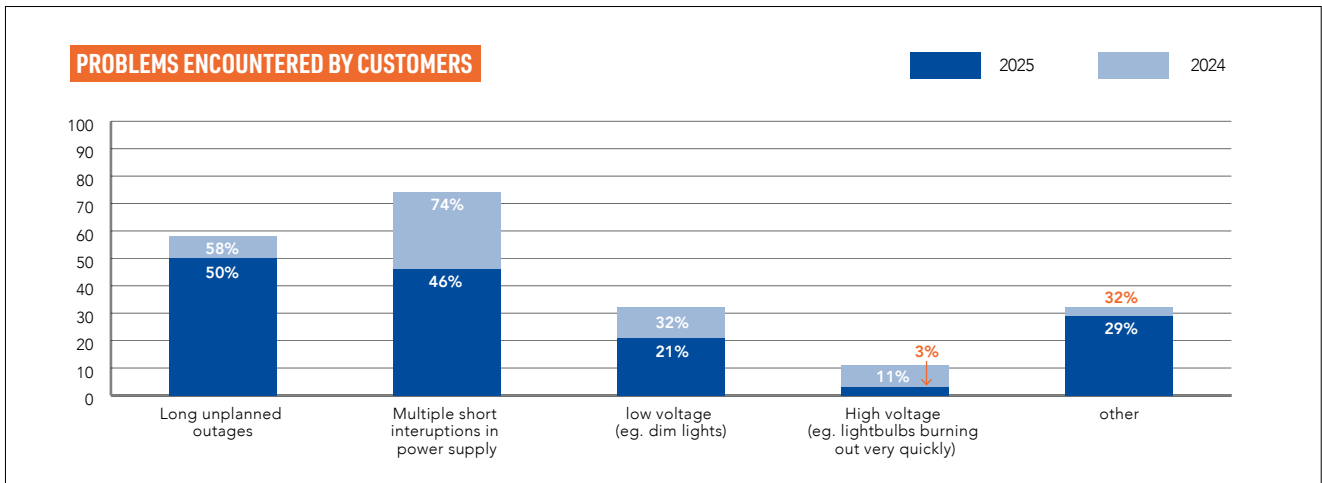


Figure 27: Problems encountered by customers who experienced an outage (n=61)

3.10.3 Customers' views on their adoption of new technology

As shown in figure 28, the likelihood of adopting new technologies remains low for customers who have not already adopted them. LED lighting remains the most likely future adoption (20% likely), followed by solar PV (9%), battery storage (5%), and electric vehicles (2%). This reinforces the need to plan for change, while recognising that uptake rates will vary and are unlikely to be uniform across customer groups.

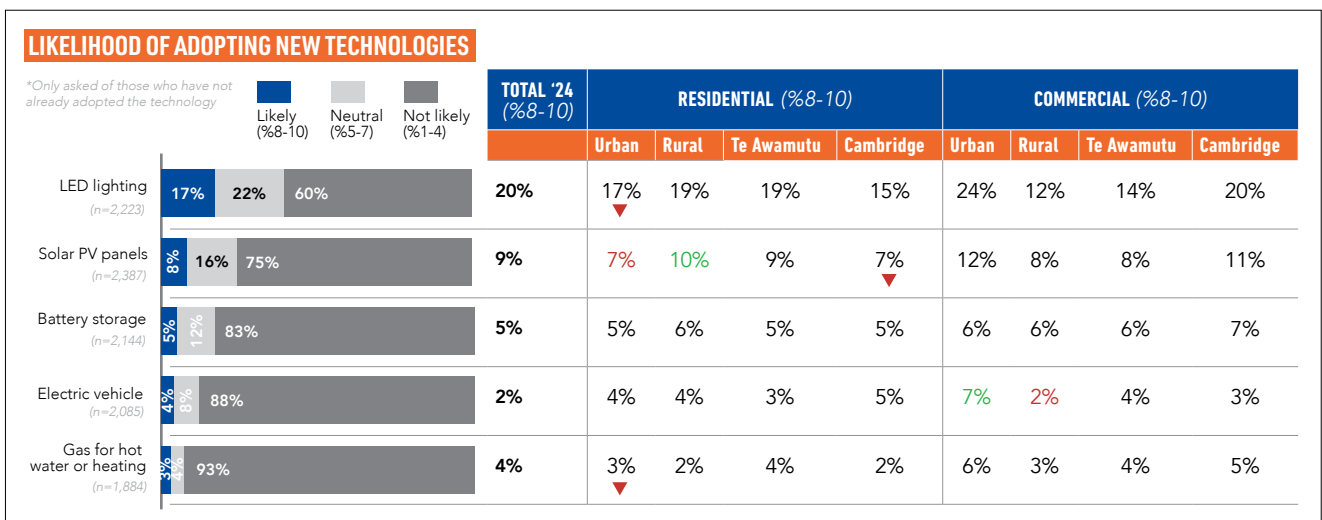


Figure 28: Likelihood of adopting new technology (asked only of customers who have not already adopted each technology; base varies by technology; total survey n=2,640)

3.11 Planned improvements to address gaps in customer satisfaction

The November 2025 survey shows overall satisfaction has improved, while perceptions of core services and image and reputation remain below target. Customer feedback continues to highlight the importance of clear, timely communication and a straightforward service experience.

Our planned improvements therefore focus on (1) enhancing external communications and (2) transforming customer-related processes and systems to reduce customer effort and lift confidence in service delivery.

Programme	Influence on measure	Details
Enhancing external communication	<ul style="list-style-type: none"> Value for money Communication Image and reputation 	<p>Focus our external communications programme on being transparent and informative about our highlighted investment choices, reliability, safety, community outcomes, and what customers receive for their line charges. This will lift understanding of value for money, improve the usefulness of our communications, and rebuild confidence in our image and reputation.</p> <p>Our focus is:</p> <ul style="list-style-type: none"> Applying a single value narrative across all communication channels (website, email, SMS, and outage/planned-works updates) Ensuring message clarity using plain English and visual explainers for where funds go and what customers receive Providing a concise discount explainer linked to customer ownership Prominent placement on website and timed communication around key customer touchpoints Micro-pulse checks on comprehension and usefulness.
Transforming customer-related processes and systems	<ul style="list-style-type: none"> Overall satisfaction Enquiry handling Communication Image and reputation 	<p>A focused programme to reduce customer effort and improve the service experience by streamlining enquiry handling and strengthening consistent communications across channels, alongside the supporting regulatory processes.</p> <p>Key focus areas:</p> <ul style="list-style-type: none"> Enquiry handling: Standard response times, first-touch resolution checklist, queue transparency and callback options, improved channel routing, and short post-contact surveys Communication: Consistent outage and planned-works updates, plain-language templates, integration across SMS, email, web, and app channels, and follow-up messaging.

Table 15: Planned improvements



3.12 Overview of important customer processes

3.12.1 Our customer complaint process

We operate a formal customer complaint process. To submit a customer complaint, customers can use the online form, email talk2us@waipanetworks.co.nz, or call 0800 800 769. We keep customers informed of progress throughout the resolution process and aim to resolve complaints within 20 working days. If we need to exceed this timeframe, we will inform the customer of the reason and work to resolve the complaint as soon as possible.

3.12.2 How we respond to customer voltage complaints

Refer to Section 13.23.2.

3.12.3 How we communicate on planned and unplanned outages

For planned interruptions, consumers are currently notified of planned interruptions using the following methods:

- An email to impacted customer's retailers providing a minimum of 10 working days' notice, who then notify customers directly.
- Website notification before planned interruptions aligned with notifications to retailers of 10 working days. An additional notification on the day of the outage as the outage reaches 'active' statuses via the Waipā Networks website.
- A letterbox card is also distributed to customers where a planned interruption is required within the 10 working days requirement for a retailer notification.

For unplanned interruptions, customers are notified of unplanned interruptions using the following methods:

- An email of the impacted area is sent to all retailers, the Waipā Networks customers and call centres (including after hours). This email is sent via the outage notification communication system and is manually generated. Retailers are then able to notify customers of the unplanned outage.
- Website notification at the time of the unplanned interruption on the Waipā Networks website.

We have adopted a new platform to manage several services, including notification of planned and unplanned interruptions to retailers. Notifications are automatically system-generated for planned interruptions rather than manually and aligned with a minimum 10-working-day timeframe. Unplanned disruptions will also be generated on the new platform for retailers once an interruption is logged.

3.12.4 Our customer connection process

Our network serves a high-growth region in New Zealand, so we need to operate an efficient process for developers to connect new subdivisions and for customers to connect to the network. Our connection process will change as new connection rules take effect on 1 April 2026. We present our current connection process and discuss how it will change in Section 12.



4. NETWORK OVERVIEW

4.1 Introduction and summary

This section provides an overview of our network. It provides important context for understanding our current position and some of the factors that will shape our future investment and performance. In this regard, the key conclusions from this section include:

- As noted in Section 3.2, our region has experienced significant population growth over the past two decades. This growth is increasing demand on what was once a largely rural network.

We've already started reconfiguring our network in the Cambridge area to respond to this change. We now need to update the network architecture in the Te Awamutu area to ensure it can meet the future demand.

- Our Cambridge and Te Awamutu networks are different. The Cambridge network exhibits attributes of a semi-urban network. The Te Awamutu network represents a more rural network, characterised by lower customer density and a greater proportion of overhead lines and long feeders. This requires different asset management strategies and plans.

- Commissioning of the Hautapu GXP, Forrest Road substation and the four new feeders has resolved the recent security constraints at our Cambridge GXP. This strengthens security across the region and supports future growth.
- Regional supply constraints at the Te Awamutu GXP are likely to emerge due to the forecast decommissioning of Fonterra's embedded cogeneration plant and continued population growth.
- Customer numbers and loads have been steadily increasing on Te Awamutu's 11kV network, and this growth is now reaching its limits. The feeders have high customer counts and are generally heavily loaded, which limits backfeeding (i.e., security).
- Our network load factor is 59%. That's in line with our peers, but below the best-performing EDBs. This means there's an opportunity for customers to shift some demand to off-peak periods, which would help reduce peak demand across the network.

4.2 Network supply area

We supply electricity to homes and businesses across the Waipā district and surrounding parts of the Waikato and King Country. Most of our network is in the Waipā and Ōtorohanga districts. We also cover smaller areas in the Waikato district south of Hamilton and the Waitomo district south of Kāwhia.

In total, our distribution system spans 1,865 square kilometres, connecting communities across the region.

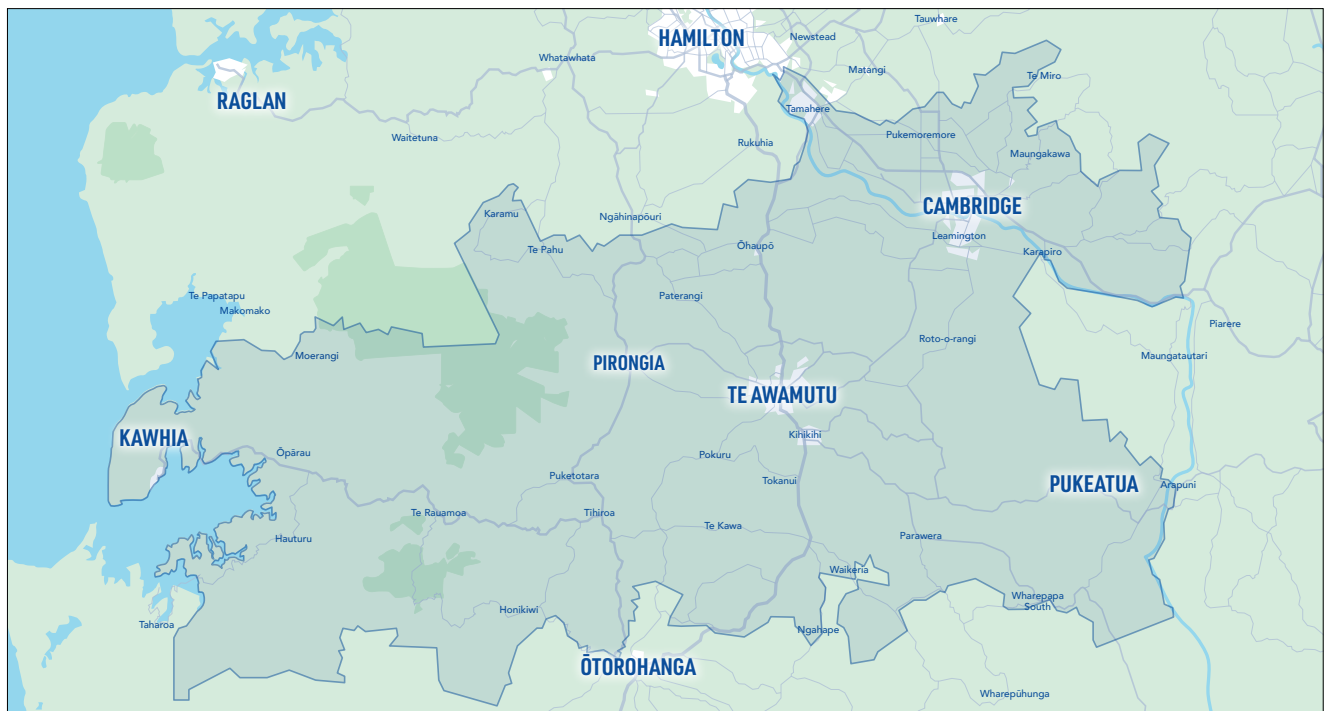


Figure 29: Network supply area overview

4.3 Overview of our assets

Table 16 presents a summary of our major asset groups. Overall, our network is relatively young, with a weighted average age of 14 years, which is approximately 30% of the average expected lifespan. However, these averages

mask the age profile of the assets (which we discuss further in Section 5.3). We have an increasing population of older assets that will require replacement over the coming decade, which is addressed in our fleet plans (refer to Section 13).

Asset category	Quantity	Average age (years)	Value (\$m)
110kV transmission lines	33 km	7	22
Distribution and LV lines	1,417 km	28	40
Distribution and LV cables	903 km	14	31
Distribution transformers	3,765 units	11	40
Distribution switchgear	4,788 units	10	25
Other network assets	–	9	9
Non-network assets	–	2	18
Total	–	14	184

Table 16: Our major asset classes

4.4 Network configuration

We have two network areas: one servicing the Cambridge area, supplied from Transpower's Cambridge and Hautapu GXPs at 11kV and 33kV, and another servicing the Te Awamutu area, supplied from Transpower's Te Awamutu GXP at 11kV. These networks were established to serve the modestly populated townships of Cambridge and Te Awamutu, as well as the large surrounding rural areas.

Currently, there is limited interconnections between the two networks. An 11kV interconnection point (normally open) to WEL Networks in the Te Pahu area was initially established to assist WEL with conductor renewal.

As mentioned in Section 3.2, we have experienced significant population growth, which has materially increased demand.

The distribution network has been progressively enhanced by adding additional feeders and voltage regulators to cater to growth, as well as automated line reclosers to improve reliability. This incremental approach has mostly kept pace with this growth.

However, the increasing network demand and forecast growth have reached a point where an alternative network architecture is required. The Cambridge subtransmission network and the new Forrest Road zone substation were commissioned in FY26. We envisage a similar shift for the Te Awamutu area, and are progressing with the Te Awamutu network architecture study, quantifying the costs of the possible future architecture.

4.5 Transmission connections

4.5.1 Cambridge 110/11kV GXP

The majority of Cambridge's load is supplied at 11kV from Transpower's Cambridge GXP. The GXP is supplied via a double-circuit 110kV line from Karapiro to Hamilton and has an N-1 capacity of 47 MVA (winter)²¹. There are various constraints on Transpower's 110kV system, which limit the ability to upgrade the supply at this GXP²².

Before we commissioned the Hautapu GXP and Forrest Road substation, peak load at Cambridge GXP was around 46 MVA (net). To maintain regional supply headroom, we operated a 3 MW diesel generation plant connected to the 11kV network to help manage the GXP peak demand.

Since commissioning Hautapu GXP and Forrest Road substation in June 2025, we've reduced load at Cambridge GXP by around 10 MVA by transferring demand to Forrest Road. As a result, the 3 MW diesel plant is no longer needed and has been disconnected from the network.

²¹ This relies on the short-duration overload capabilities of the Transformers during winter months.

²² Refer to Transpower's Transmission Planning Report 2023, Section 9.5.2.

4.5.2 Hautapu 220/33kV GXP

In 2025, Transpower commissioned a new GXP at Hautapu, which is connected to two separate 220kV circuits and has an N-1 capacity of 96 MVA at 33kV. This project was initiated to resolve the 110kV constraints at the Cambridge GXP. This GXP can provide capacity to support regional growth for several decades. The Hautapu GXP supplies our new Forrest Road zone substation at 33kV.

Approximately 10 MVA of load was transferred from the Cambridge GXP to the Hautapu GXP and Forrest Road Substation.

4.5.3 Te Awamutu 110/11kV GXP

All of Te Awamutu's load is supplied at 11kV from Transpower's Te Awamutu GXP. Te Awamutu GXP is supplied through a single-circuit Transpower 110kV transmission line from Karapiro and a Waipā Networks-owned single-circuit 110kV transmission line from Hangatiki. We commissioned the Hangatiki to Te Awamutu 110kV line in 2016 to enhance security for our customers in Te Awamutu.

The Te Awamutu GXP has an N-1 capacity of 52 MVA (summer) and 54 MVA (winter). The current peak load at Te Awamutu is 43 MVA, which is net of around 5 MVA of embedded generation²³ at the Fonterra dairy factory site connected to the Te Awamutu GXP via 11kV cables. This generation is expected to reach the end of life over the next decade, resulting in demand approaching capacity in the years to come. We are engaging with Fonterra regarding their decommissioning plan and future capacity requirements.

4.6 Subtransmission and zone substation

In June 2025, we commissioned a new Forrest Road zone substation adjacent to Transpower's new Hautapu GXP. Two 33kV cables from the GXP supply the substation, which comprises two 16/24 MVA 33/11 transformers, and indoor 33kV and 11kV switchboards. The substation was initially configured with four 11kV feeders, which will be expanded as the load increases.

The Forrest Road substation has a firm capacity of 24 MVA at 11kV, sufficient to supply approximately 10,000 homes. Each transformer has a continuous emergency rating of 30 MVA.

4.7 11kV distribution network assets²⁴

The 11kV distribution network is configured radially and supplies distribution transformers in urban and rural areas. There are interconnections between feeders in urban and higher-density rural areas. There are fewer interconnections between feeders in rural areas.

The 11kV feeders are primarily overhead pole lines (approximately 87%), which are susceptible to vegetation contacts and adverse weather conditions. In urban areas, underground reticulation is increasing as the network expands to serve new subdivisions, most notably in Cambridge.

Figure 30 shows the geographic view of the 11kV feeders supplied by the Cambridge and Te Awamutu 11kV GXPs and the new Forrest Road Zone Substation in Cambridge.



²³ This has a capacity of 7.5 MVA, but typically operates at 5 MVA.

²⁴ All statistics are from the FY25 Information Disclosure schedules.

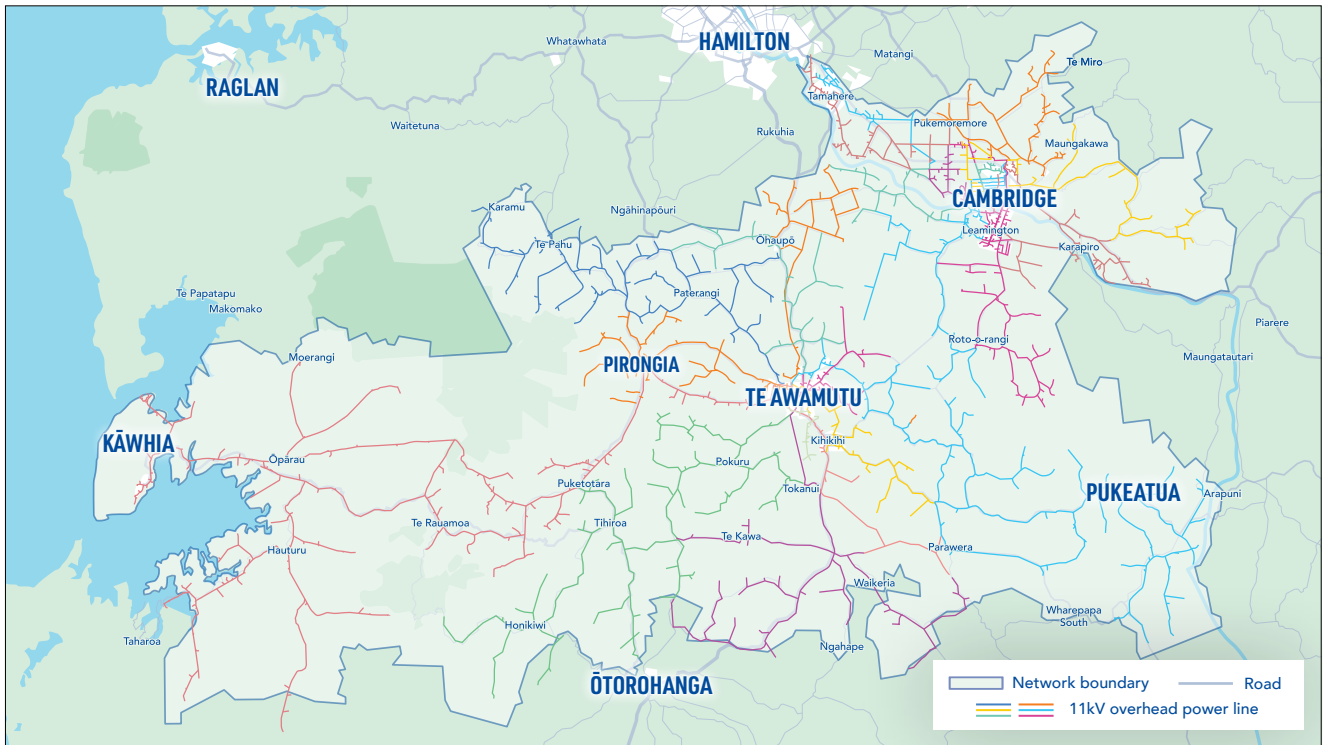


Figure 30: Extent of our network

There are differences between our two networks, as shown in table 17 below. The Cambridge network has the features of a semi-urban network, with high customer density and a lower proportion of overhead lines. This reflects Cambridge's dense urban centre, alongside lower-density rural areas served mainly by overhead lines. We discuss these features in more detail in the sections following.

Attribute	Cambridge network	Te Awamutu network
Customer density ²⁵	30 ICP/km	16 ICP/km
Zone substations	One 110k/11kV GXP One 33/11kV substation	One 110k/11kV GXP
Feeders	18 ²⁶	15
Average feeder length	33 km	67 km
Average customers per feeder	917 ²⁷	1,280 ²⁸
% of rural feeder (by length)	72%	93%
11kV network length	463 km	957 km
Voltage regulators (per 100km)	0.96	1.64
11kV % overhead	72%	95%

Table 17: 11kV network attributes

²⁵ ICPs per km of 11kV network.

²⁶ Four of these were commissioned in FY26.

²⁷ Including the four new feeders commissioned in FY26, excluding the dedicated feeders. This was 1,250 prior to the new feeders.

²⁸ Excluding the dedicated feeders.

4.7.1 Cambridge area 11kV network

After the Forrest Road zone substation was commissioned in June 2025, the Cambridge area network includes four 11kV feeders from Forrest Road 33/11kV zone substation and fourteen 11kV feeders from the Cambridge 110/11kV GXP. The 11kV network supplies Cambridge, its suburbs, and rural areas near the Waikato River, stretching from Lake Karapiro to Tamahere on the outskirts of Hamilton.

From Cambridge 110/11kV GXP, two feeders form a dedicated supply to the Fonterra dairy factory at Hautapu, and one feeder supplies the APL glass factory.

4.7.2 Te Awamutu area 11kV network

The Te Awamutu network is more rural in nature, with lower customer density and a higher proportion of overhead lines. The network's feeders are significantly longer, averaging 67km, with four feeders between 100 and 200km in length.

Customer numbers and loads on the 11kV network have been steadily increasing, and this growth is now approaching the limits of an 11kV-only network. This strong growth has resulted in a higher number of customers on rural feeders than our peers²⁹. The feeders are generally highly loaded, which limits backfeeding due to thermal and voltage constraints.

On our long rural feeders, we use voltage regulators to ensure the voltage delivered to customers is maintained within regulatory limits. These are used extensively on the Te Awamutu network (at around 1.6 regulators per 100km, compared to 1.3 on the Cambridge network and around 1.0 for our semi-rural peer group).

There are 15 11kV feeders supplied from the Te Awamutu GXP. The 11kV network serves Te Awamutu's urban, suburban, and rural areas, extending from Te Awamutu north to Mystery Creek, south-east to Arapuni, south towards Ōtorohanga, and west to Paterangi, Pirongia, Pökuru, and Kāwhia.

In Te Awamutu, two dedicated underground feeders supply the Fonterra dairy factory in Te Awamutu, and one feeder supplies the Department of Corrections' Waikeria Prison.

The high number of feeders leaving a single site has led to many feeders, mainly rural, sharing the same pole structure. Sharing structures reduces the network's mechanical security. There is electrical security through feeder capacity; however, there is no mechanical security, as failure of a shared structure can interrupt multiple feeders. The loss of a single structure will impact multiple feeders and make maintenance and renewal work complex.

4.8 Distribution transformers and low-voltage assets³⁰

Distribution substations step down the voltage from 11kV to 400V/230V in locations that serve customers' needs. In rural areas, the distance between customers typically limits the utilisation of low-voltage lines; hence, many rural customers are supplied from a small distribution transformer.

Our distribution substations are predominantly pole-mounted transformers (up to 100kVA on single pole structures) as permitted by District Council Plan requirements. In urban areas and industrial applications, pad-mount substations (typically ranging from 50 kVA to 1,500 kVA) are used.

We operate a 400V/230V low voltage (LV) reticulation asset. These are configured radially. In rural areas, there is no interconnection between LV circuits. In urban areas, there is limited interconnection. However, there is more interconnection in urban business district areas.

Most customers are connected to the LV network, except for a few very large customers who take supply at 11kV. Usually, LV supply to residential customers is single-phase or two-phase. Commercial and industrial customers with higher load requirements, as well as many rural properties, connect to a three-phase supply.

As shown in table 18, there is more underground LV reticulation in the Cambridge area, reflecting the larger urban customer base. There is higher overhead LV reticulation in Te Awamutu, which reflects the extent of overhead reticulation in Te Awamutu township and the surrounding rural area.

Attribute	Cambridge network	Te Awamutu network
400V network length	369 km	525 km
400V % overhead	39%	67%

Table 18: Low-voltage network attributes

²⁹ Te Awamutu rural feeders average just over 1,000 customer per feeder, which is just under 50% more than our semi-urban peers (at just under 700 customers per feeder).

³⁰ All statistics are from the 2025 Information Disclosure schedules.

4.9 Network protection and reliability management

Isolation and protection are achieved through feeder circuit breakers at Transpower's GXP, Forrest Road zone substation, ring main units, line auto-reclosers, sectionalisers, disconnectors and dropout fuses. There is 400V fusing at each distribution transformer and at the customer's point of connection.

We use line auto-reclosers extensively on rural networks to minimise the impact of outages. These devices can isolate faulted areas of the line while maintaining supply to upstream customers. Our dedicated SCADA radio communication system has been expanded and will be developed to enable remote control of switching devices within our network.

Lightning protection is generally installed at all underground-to-overhead transitions and in other areas prone to lightning strikes.

4.10 Other network assets

Our SCADA system covers all the distribution feeders. This system enables remote monitoring and control of the network. We also utilise the SCADA system to initiate ripple signal injection into the network, controlling load, street lighting, and metering tariffs.

SCADA communication uses dedicated radio equipment and leased fibre and cellular networks. We also use voice radio for communication between control and field crews.

We use the ripple control system to manage loads, such as water heating and streetlights. We also use ripple control to manage GXP peak demand and load within the 11kV network to avoid network constraints during peak periods. The Cambridge GXP and Hautapu GXP ripple injection plants are in our building at the GXP, and the Te Awamutu ripple injection plant is in a separate room within Transpower's Te Awamutu GXP switch room.



4.11 Location of, and access to, our assets

Our assets extend to the customer point of supply, which (in most cases) is the property boundary line crossed by a customer's service line. This means that most of our customer service line are owned by the property owner, not us.

Our distribution assets are generally located within the road reserve in the urban and suburban areas of Cambridge, Leamington, Te Awamutu, Hairini, Kihikihi, Ōhaupō, Pirongia and Kāwhia. Access to these assets is generally straightforward, and other areas are subject to prevailing ground conditions.

In the rural areas around Cambridge, including Tamahere, French Pass, Roto-o-Rangi, and Kaipaki, and around Te Awamutu, including Paterangi, Pirongia, Pōkuru, Kio kio, Waikeria, Pukeatua, and Mystery Creek, there are more locations where assets pass through private property as the most cost-effective way to reticulate power in the region.

In more remote areas with low population density, such as Kāwhia and Hauturu, our assets frequently intersect private land.

The Electricity Act provides for access to assets on private property, however, where possible, we work with landowners to agree practical access arrangements.

Some of our existing lines were built in the 1960s and 1970s on private or government-owned land. Access is protected through wayleaves and the "existing works" provisions of the Electricity Act.

We have the right to replace these assets, but there are limits on the scope of the upgrades we can carry out. If an upgrade goes beyond those limits, we need to secure a new easement. That process can be complex, costly and time-consuming.

New assets (since the early 1990s) on private property are protected by easement.



5. PERFORMANCE REVIEW

5.1 Introduction

In this section, we review prior performance, identify the main drivers, and reference where issues are addressed later in the AMP. The performance targets were defined in previous AMPs. Further explanation of the measures are given in Section 7.

We have a range of performance measures aligned to our business strategy, Statement of Corporate Intent (SCI), and asset management strategies. Details on how we set these targets are described in Section 7.5 to 7.12. Our performance targets cover all relevant aspects of asset management and include:

- **Safety performance** – how we are performing against our key safety metrics.
- **Network customer service** – the network reliability that customers experience.
- **Customer satisfaction** – which are included in Section 3
- **Network reliability and quality** – detailed analysis of the performance of the network.
- **Work delivery** – how we are delivering our planned work on the network.
- **Asset utilisation and efficiency** – how the utilisation of our assets is changing as we grow and invest in the network.
- **Environmental performance** – how we are performing against our key environmental metrics.

The assessment of our asset management maturity is included in our asset management improvement plan presented in Section 9.

5.2 Conclusions from the performance review

Having reviewed the performance in FY25 and across the FY21 to FY25 period, the key conclusions are shown in Table 19. Part Two of this AMP outlines strategic responses to the issues raised, while Part Three outlines tactical and project responses to address them.

Conclusion	Reference to remediation plans
FY25 safety performance was positive, with all measures being ahead of, or very close to, the target.	Our safety strategy and plans are presented in Section 8.3.1.
Unplanned reliability performance in FY25 was favourable, which was consistent with the relatively settled weather during the year. Looking at the past five years, we achieved our unplanned reliability targets in FY21 and FY25. Our performance was impacted by environmental conditions that caused an increase in outages in FY22 and FY23. In FY24, we had a spike in third-party damage incidents.	Reliability improvements are supported by our security and reliability improvement plan presented in Sections 7.8, 11.8.2 and 11.12.2. See specific reliability issues below and our actions on the worst-performing feeders in table 23.
The network is exposed to adverse weather (e.g. Cyclones Dovi and Gabrielle), and resilience to wind events needs to be a key focus on our rural and urban feeders.	Refer to our resilience strategy presented in Section 8.4 and our resilience standard in Section 11.4.5.
Defective equipment outages continue to perform favourably against our semi-rural peer group ³¹ ; however, this is a major contributor to SAIDI, and there are further areas for improvement identified.	This is being addressed through specific improvements to our fleet plans for ABSs, RMUs, and overhead conductors. Refer to Sections 13.18, 13.21 and 13.14.
Third-party damage (mainly vehicles) is an ongoing issue and remains hard to address due to the spread of events across the network.	We prioritise addressing multi-circuit lines, and we are repeating analysis that examines crash data to identify high-risk locations. These will then be prioritised. Refer to Sections 11.12.2 and 11.12.3.
Vegetation outages are consistent with our peer group, and, except for the Kāwhia and Pencarrow feeders, performance issues have been addressed.	Further remediation works for Kāwhia were completed in FY26. Also, at the time of drafting the Pencarrow feeder was 40% patrolled and is scheduled to be completed in FY26/27. Refer to table 23.
Our four worst-performing feeders account for 39% of SAIDI. We have a range of security improvement projects planned, which will help mitigate the impact of all outages (regardless of cause). These projects are specifically targeting our worst-performing feeders.	Refer to table 23.
The Kāwhia feeder is our worst-performing feeder. This is not a failure rate issue, but rather due to its configuration; namely, its near 200km length. Hence, addressing security on the Kāwhia feeder is a focus for the 2026 AMP.	Understanding and resolving the Kāwhia feeder issue is a subject of our place-based engagement pilot (refer to Section 3.4). We have included a view of the Kāwhia reliability improvement in our reliability plans (refer to Section 7.8 and 11.12.2), but this may change following engagement.
Planned outages on the network have increased, largely due to higher work volumes.	We are working to ensure our planned outages are coordinated and managed efficiently to achieve our targets.
Our work delivery has improved in recent years and remains a key focus for the business. Our inspection work has been focused on overhead assets, and these inspections are generally ahead of plan. We have experienced some delays on other inspection work as we roll out new inspection regimes. We experienced some delays on major project work. There were a range of contributing factors, including planning and design constraints.	The outstanding inspections will be completed within the next 12-24 months. The planned resource improvements are presented in Sections 14.4.2 and 14.4.3.

Table 19: Key conclusions and reference to remediation plans

The remainder of this section provides the details to support these conclusions.

³¹ The semi-rural peer group comprises EDBs with customer density of ~10 to 15 ICPs/km and ~30% to 40% of lines in urban areas. Waipā has a customer density of 12.7 ICPs/km and the percentage of overhead lines of 32% of lines in urban areas. The companies included Counties Energy, Network Tasman, Northpower, Powerco, and Waipā Networks.

5.3 Safety performance

We are committed to ensuring the health and safety of anyone who works on, interacts with, or is near our assets. Our health and safety policy ensures our continual focus on hazard control, staff competency, incident investigation, contractor management and our public safety management system.

We monitor our safety performance using a mix of leading and lagging indicators. Safety performance improved in FY25, with all measures being ahead of, or very close to target as shown in table 20.

Key performance indicator	Type	Actual FY24	Actual FY25	Target FY25	Comment
Number of safety observations	Leading	110	270	290	We were close to the target in FY25, as some safety observations did not occur in part due to managers completing more full-site audits rather than safety observations.
Public safety compliance	Leading	Compliant	Compliant	Compliant	Our public safety management system is audited to NZS 7901 and remains fully compliant.
Number of notifiable injuries ³²	Lagging	Nil	Nil	Nil	We had no notifiable injuries.
Total reportable Injury Frequency Rate (TRIFR)	Lagging	12	7	<10	We met the target in FY25. All actions from these events have been completed.

Table 20: Health and safety measures



³² Notifiable injury is defined in the Health and Safety at Work Act guidelines published by WorkSafe NZ.

5.4 Network customer service

Our primary customer service measure is network reliability as measured using the internationally accepted performance measures of SAIDI and SAIFI:

- **SAIDI:** System Average Interruption Duration Index, which is the average duration (in minutes) customers are interrupted over a year.
- **SAIFI:** System Average Interruption Frequency Index, which is the average number of interruptions per customer per year.

Within these two measures, we assess unplanned and planned outages separately. Unplanned outages are especially significant because they cause inconvenience to customers due to their unforeseen nature. Planned outages are communicated in advance, and customers can usually accommodate them.

Since FY21, we have adopted a normalised methodology for calculating SAIDI and SAIFI, which is consistent with other regulated EDBs' measures of reliability.³³

5.4.1 Unplanned reliability performance

As shown in figure 31 and table 21, unplanned reliability achieved its target in FY21 and FY25, but missed the target in FY22 to FY24. The performance issues were predominantly related to SAIDI. Note: this is based on our normalised target and normalised actual performance.

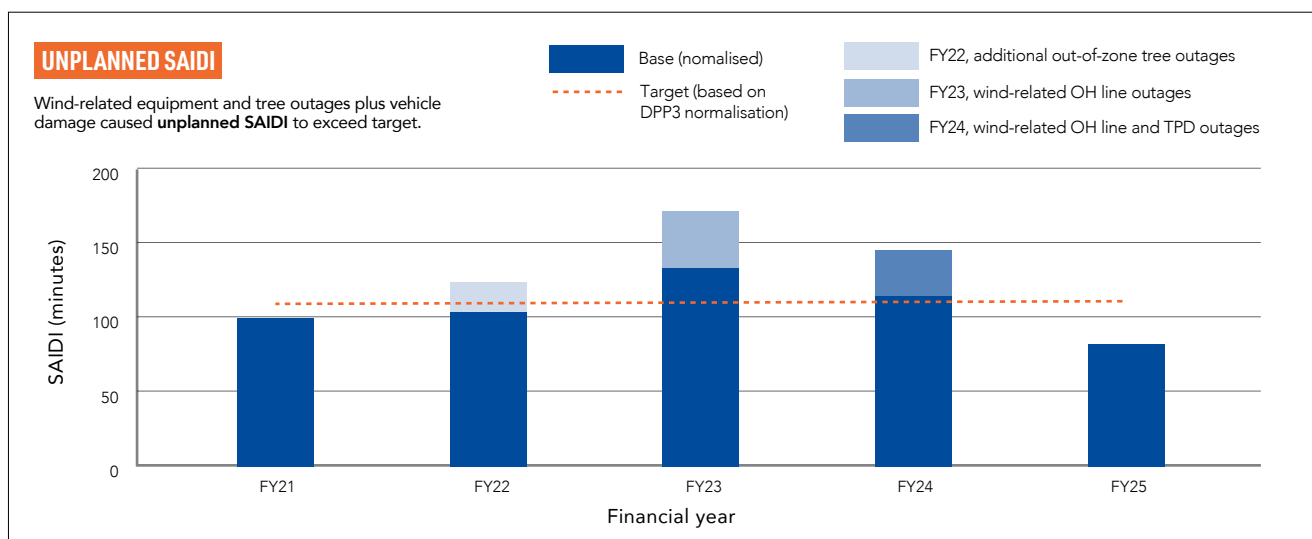


Figure 31: Unplanned SAIDI performance (normalised)

Unplanned SADI	FY21	FY22	FY23	FY24	FY25
Target normalised	109.3	109.3	109.3	109.3	109.3
Actual normalised	99.8	117.1	168.6	146.3	82.8
Compliance	Achieved	Not achieved	Not achieved	Not achieved	Achieved

Unplanned SAIFI	FY21	FY22	FY23	FY24	FY25
Target normalised	1.73	1.73	1.73	1.73	1.73
Actual normalised	1.19	1.48	1.87	1.58	0.98
Compliance	Achieved	Achieved	Not achieved	Achieved	Achieved

Table 21: Unplanned network reliability performance

³³ This is based on the DPP3 methodology.

Figure 31 shows the key drivers of the reliability in FY22 to FY24, when the target was not achieved:

- In FY22, we saw a significant (260%) increase in the number of out-of-zone tree incidents. This increase was driven by near-gale winds^{34, 35}.
- FY23 was a particularly windy year, with the number of strong wind days³⁶ being 200% higher than the recent average. The increase in wind-related events caused additional adverse weather outages, vegetation and unknown outages.
- In FY24, there was a significant (200%) increase in third-party vehicle incidents on the network. We also experienced additional outages involving overhead conductors and switchgear. The increase in conductor outages was wind-related, and the switchgear outages look (at this stage) to be a one-off event.

Excluding these events has resulted in compliance issues with our FY22 target and a minor exceedance in FY24. As mentioned above, FY23 was particularly windy, and this likely contributed to additional defective equipment outages that caused the breach of the target.

Recent performance has been challenging, and the statistics indicate a 28% probability of achieving the unplanned SAIDI target (assuming the same external influences and normalisation). This is 84% for unplanned SAIFI. We have a range of initiatives underway to improve both reliability and resilience (refer to table 19 and table 23).

5.4.2 Planned reliability performance

As shown in figure 32 and table 22, our planned reliability performance has been within target over the past five years. In previous AMPs, we assessed the planned reliability performance annually; however, the target covers the entire five-year period up to FY25 (631 SAIDI and 2.42 SAIFI). We have therefore met the requirements set out. In FY25, we experienced planned SAIDI and SAIFI significantly higher than the notional annualised target due to major planned projects and an increasing volume of renewal work.

We plan to review the drivers behind this change, determine what improvements can be made, and consider how we might manage the increased workload required over the coming years.

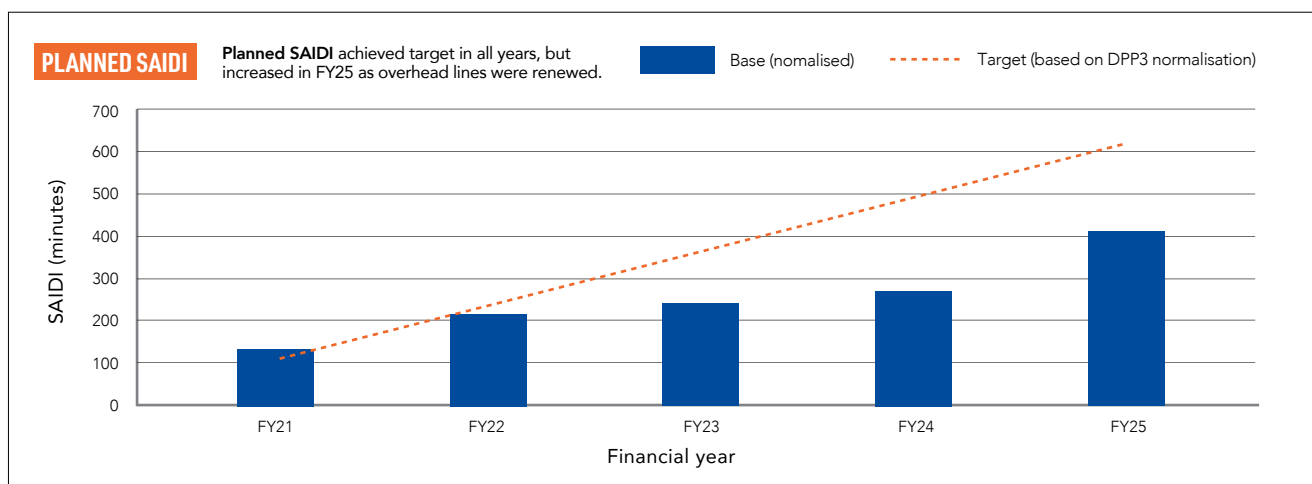


Figure 32: Planned SAIDI performance

Planned SADI	FY21	FY22	FY23	FY24	FY25
Target normalised	126.2	252.4	378.6	504.8	631.0
Actual	134.6	216.9	242.2	271.3	411.7
Compliance	Achieved	Achieved	Achieved	Achieved	Achieved

Planned SAIFI	FY21	FY22	FY23	FY24	FY25
Target normalised	0.48	0.97	1.45	1.93	2.42
Actual	0.43	0.83	1.15	1.32	2.20
Compliance	Achieved	Achieved	Achieved	Achieved	Achieved

Table 22: Planned network reliability performance (cumulative)

³⁴ Greater than 51 km/h. Which is near gale on the Beaufort wind scale.

³⁵ That were not excluded through the major event process.

³⁶ A strong wind day is characterised by sustained winds that can significantly impact the environment and daily activities. Typically, a windy day is defined as having wind speeds of 20-30 mph (approximately 32-48 km/h), which can cause leaf and branch movement, noise, and potential damage to plants and structures.

5.5 Network reliability and quality

5.5.1 Introduction

In this section, we examine the key factors influencing our reliability performance. The insights gained here guide our asset management strategy, shape our priorities for security³⁷ and reliability initiatives, help prioritise renewal activities, and provide a focus for addressing issues on our worst-performing feeders.

We use raw reliability data for analysis in this section – that means we don't normalise for major events.

Customers experience every outage, so it's important we understand how all outages affect performance.

5.5.2 High-level benchmarking

At a high level, our total unplanned SAIDI is comparable to that of our semi-rural peers, but it lags the industry average (see figure 33). Figure 34 shows that our distribution line fault rate is favourable compared to our peers and the wider industry. This tells us there are no underlying fault rate issues. Instead, unplanned SAIDI is being driven by the number of customers affected and how long the unplanned outages last.

Underground cable fault rates are also in line with our peers³⁸. This points to network architecture issues as a key factor in our SAIDI performance. As part of our review of the Te Awamutu network architecture, we're also looking at how distributed energy resources (DER) could improve our customers' experience.

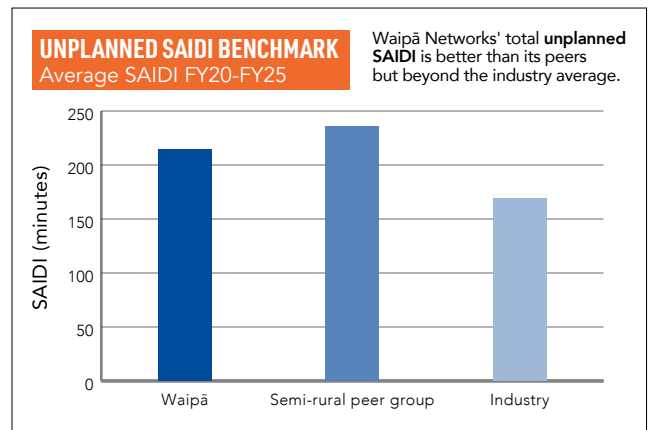


Figure 33: Unplanned SAIDI benchmark

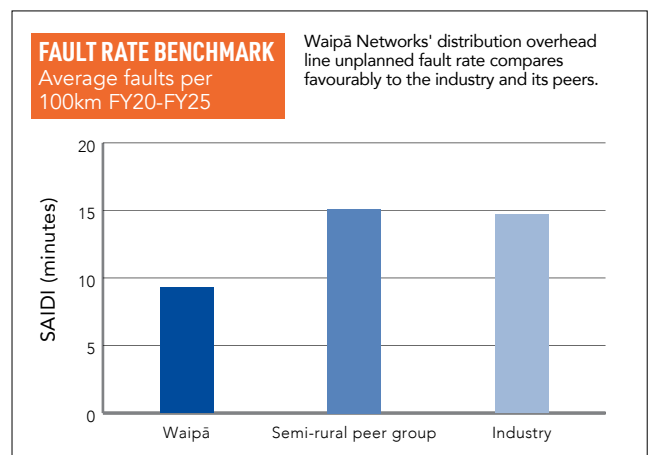


Figure 34: Fault rate benchmark



³⁷ In this section security refers to network configuration, including the number of customers between control devices and the ability to back feed.

³⁸ The periods weren't directly comparable. For Waipā, the average included FY20, FY21, FY24, FY25. FY22 and FY23 were excluded as they were unusually low due to the classification of most faults as other distribution. The peer group and the industry was FY21 to FY24.

5.5.3 The overarching drivers of reliability performance

As shown in figure 35, there were four material drivers of unplanned SAIDI. These included vegetation outages, defective equipment, third-party damage, and adverse

weather. These were also the drivers of SAIFI performance. These four causes resulted in 90% of unplanned SAIDI and 80% of unplanned SAIFI over the past five years. Given that the issues are common between SAIDI and SAIFI, our analysis in this section focuses on SAIDI to avoid repetition.

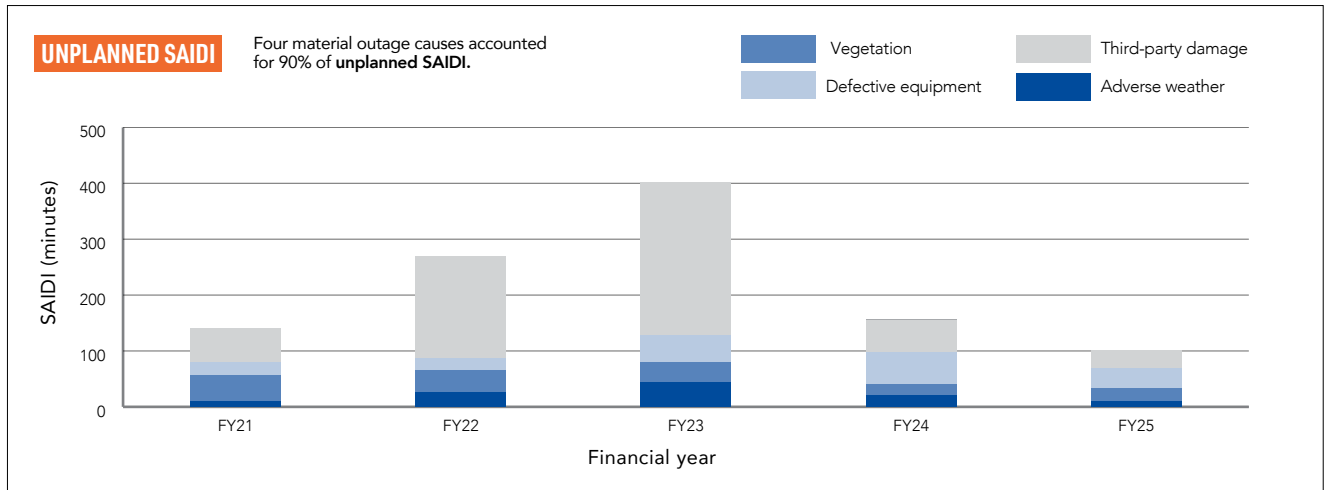


Figure 35: Material causes of unplanned SAIDI

We review each of these drivers in the following sections to determine the root cause and areas for improvement.

5.5.4 Adverse weather outages

As shown in figure 36, our network has been significantly impacted by adverse weather in recent years. Much of this was related to cyclone's Dovi and Gabrielle in FY22 and FY23. Those events affected many networks in the upper North Island. As shown in figure 38, Gale and Near Gale winds³⁹ have been the main drivers of outages during adverse weather events.

Due to the location of the weather events, they materially impacted urban Cambridge feeders and the Kāwhia feeder (refer to figure 39). These feeders incurred 64% of adverse weather SAIDI incidents over the past five years. Typically, rural feeders are the worst affected by adverse weather due to their long lengths (refer to figure 40). However, during Cyclone Gabrielle, the Cambridge area was hard-hit, resulting in very long outage times (refer to figure 41).

The recent events indicate that resilience to wind events needs to be a key focus, and that this is not just a rural network issue; our resilience strategy also needs to consider urban feeders. We have identified several avenues to increase our resilience in response to adverse weather events, detailed in Section 10.4.

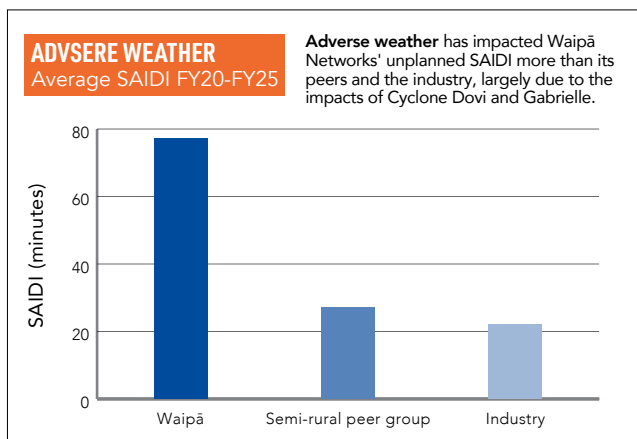


Figure 36: Adverse weather SAIDI vs. peers

³⁹ Refer to Beaumont wind scale.

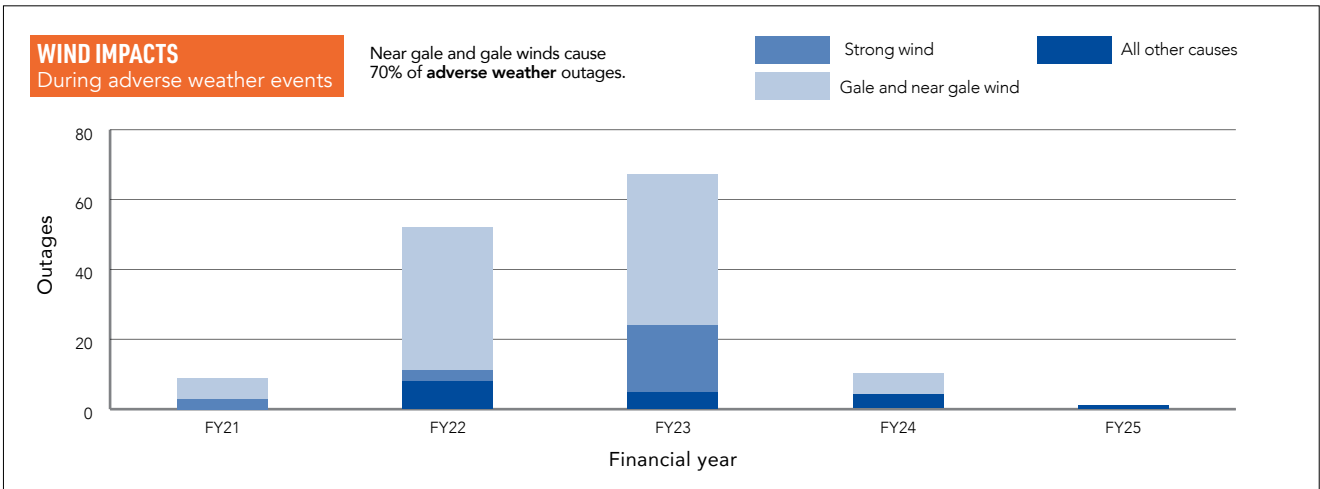


Figure 37: Wind impacts during adverse weather events

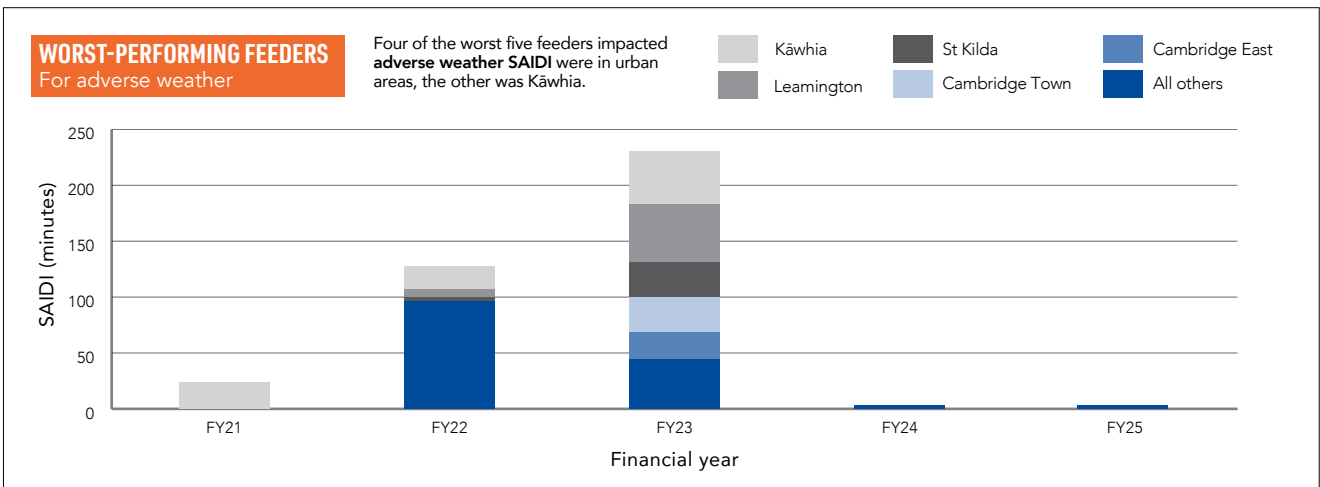


Figure 38: Worst-performing feeders for adverse weather

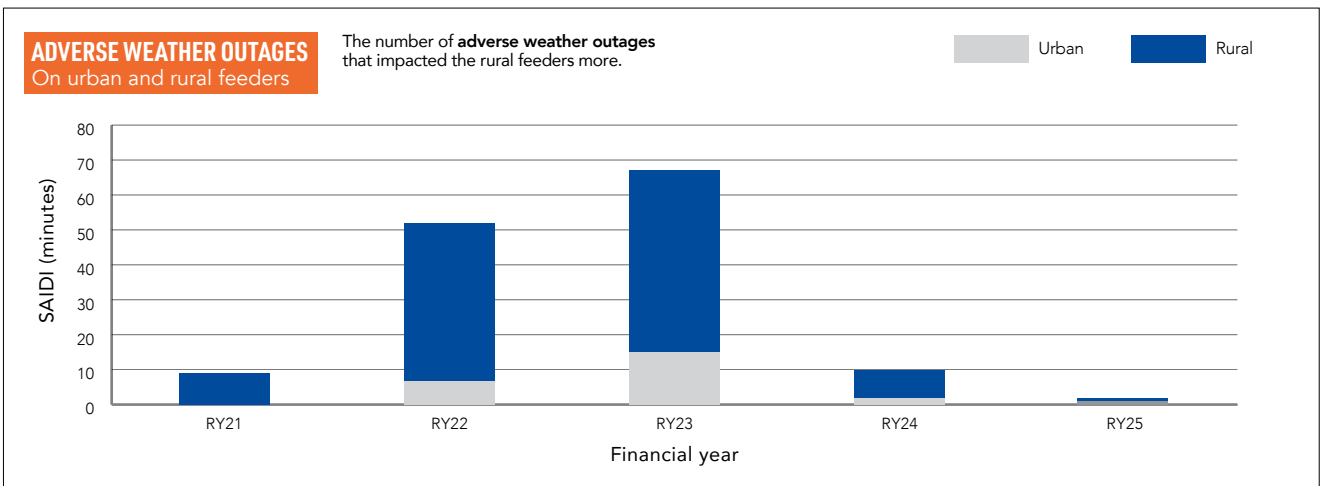


Figure 39: Adverse weather outages on urban and rural feeders

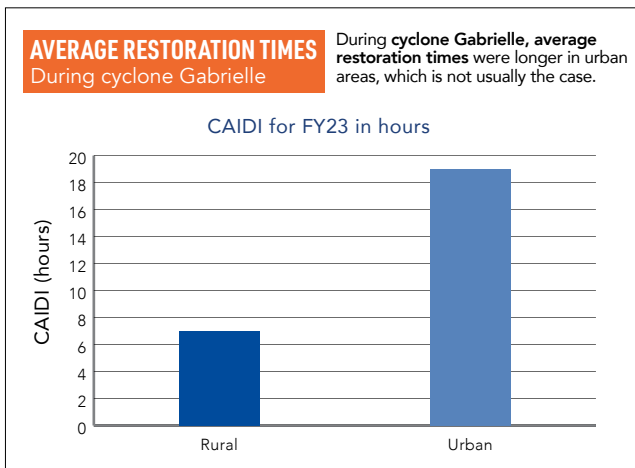


Figure 40: Average restoration times during Cyclone Gabrielle

5.5.5 Defective equipment outages

Defective equipment is a material cause of outages on many electricity networks. On our network, performance in this area is better than our semi-rural peers and in line with the wider industry (see figure 41). Defective equipment fault rate on our network is lower than that of a comparable industry sample, providing confidence that our renewal programme is keeping abreast of issues.

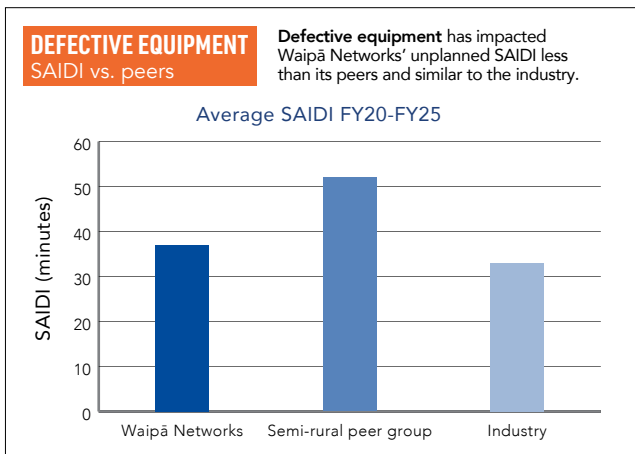


Figure 41: Defective equipment SAIDI vs. peers

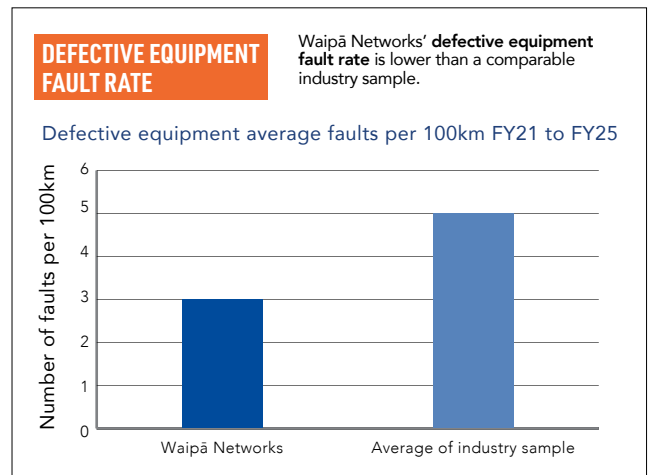


Figure 42: Defective equipment fault rate vs. industry⁴⁰

Conductor, insulators/binders, crossarm, and overhead switchgear failures on our overhead network are the primary causes, accounting for 60% of defective equipment outages (as shown in figure 42) and 80% of defective equipment SAIDI.

Conductor, pole-top⁴¹, and overhead switchgear outages primarily impact rural feeders (in terms of SAIDI), with the worst-performing rural feeders accounting for 38% of outages (refer to figure 43), with nearly half of these on the Kāwhia feeder. These outages correlated strongly with wind events (refer to figure 43).⁴²



⁴⁰ Not all EDBs disclose fault rate data in their AMP. The comparison included Firstlight, Electra, EA Network, Powerco, Northpower, Counties Energy.

⁴¹ Pole-top comprises insulators, binders, crossarm and crossarm braces.

⁴² Strong, near gale, and gale winds on the Beaumont scale.

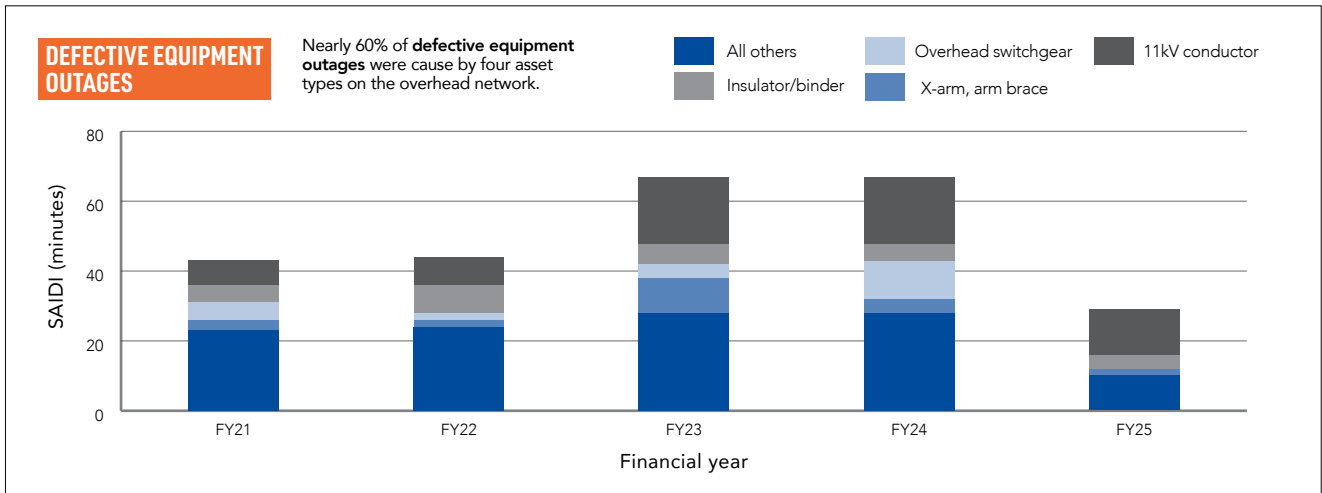


Figure 43: Conductor, pole-top and switchgear outages

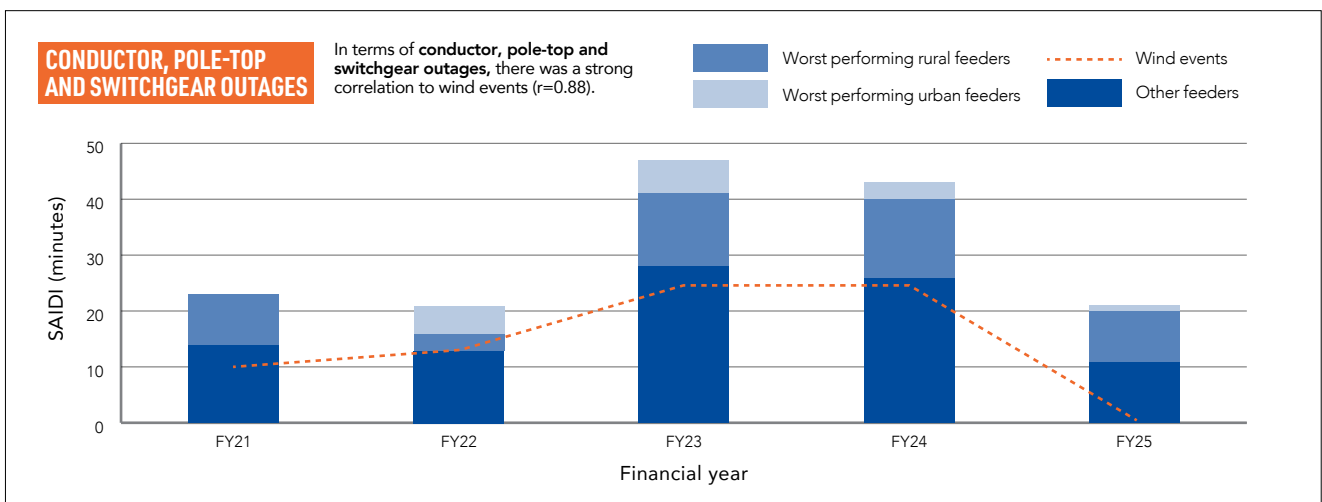


Figure 44: Conductor, pole-top and switchgear outages

The worst-performing feeders account for 33% of defective equipment SAIDI (refer to figure 45)⁴³. A closer examination of the data reveals two main drivers. For rural feeders, it is the number of outages that primarily influences SAIDI (refer to figure 46). However, for the worst-performing urban feeders, it is the high number of customers that drives SAIDI (refer to figure 47).

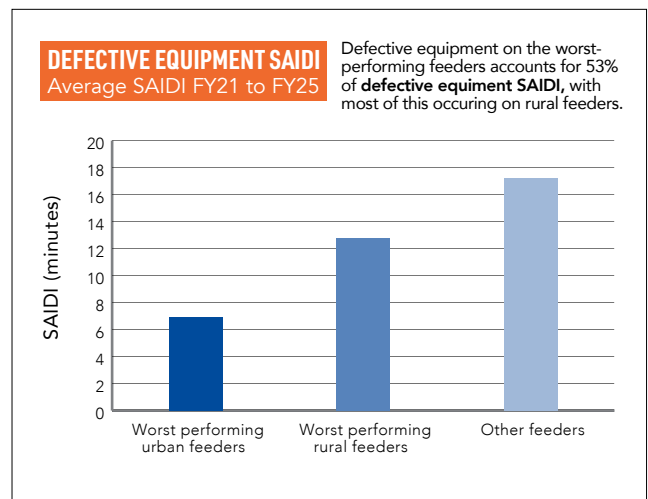


Figure 45: Defective equipment SAIDI

⁴³ The worst-performing urban feeders are Cambridge East, Cambridge North and Cambridge Town. The worst-performing rural feeders are Kāwhia, Pukeatua and Rotorangi.

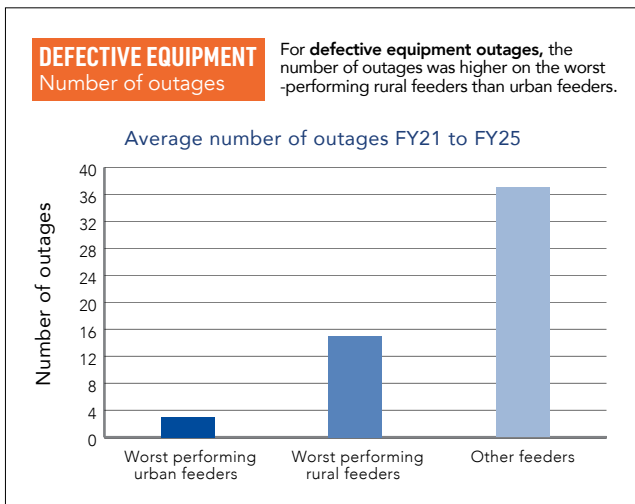


Figure 46: Defective equipment, number of outages

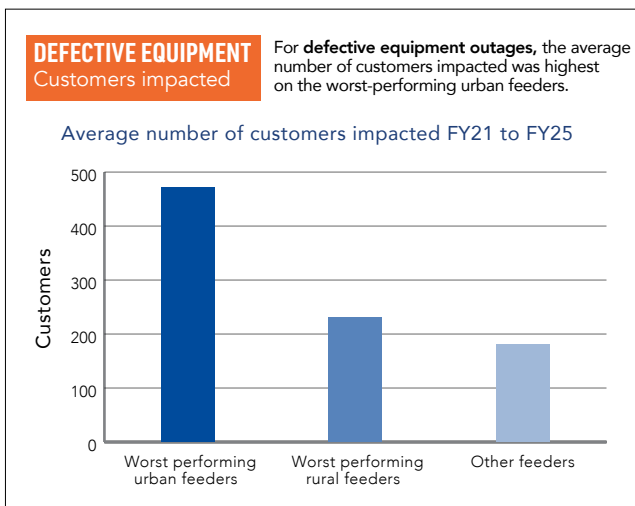


Figure 47: Defective equipment, customers impacted

We assessed how often a feeder exceeded 2.5 SAIDI minutes due to defective equipment over the past five years⁴⁴. Only the Kāwhia feeder recorded defective equipment SAIDI greater than 2.5 minutes three or more times. For most feeders (82%), a SAIDI greater than 2.5 minutes occurred once or not at all. This is an indicator that, other than Kāwhia, we are not seeing a persistent concentration of poor performance on feeders. The Kāwhia feeder has a high number of customers at the end of the feeder, so most outages can result in a high SAIDI.

While defective equipment fault rates are generally better than the industry average and don't indicate an underlying issue, there are still opportunities to improve. These include:

- For the worst-performing rural feeders, targeting inspection programmes and prioritising renewal on pole-tops and crossarms and considering automation and segregation opportunities. The failure mode for conductors requires further investigation to determine whether faults indicate emerging asset health issues.



- For the worst-performing urban feeders, the issue is not a failure rate problem but rather security issues that lead to a high number of impacted customers. Hence, the worst-performing urban feeders will be targeted for security improvements.
- Operational insights and inspection results from FY25 and FY26 show an emerging trend in ABS and RMU issues that warrant proactive intervention. This includes reviewing renewal rates for low health grade ABSs and reducing the RMU partial discharge survey interval from three years to two years.
- The Kāwhia feeder is our worst-performing feeder by some margin and requires a specific solution to overcome its particular configuration challenges, which we are doing as part of the Te Awamutu architecture review.

⁴⁴ This is appropriately 5% of our annual target.



5.5.6 Third-party damage

Our network is significantly affected by third-party damage, and this is materially higher than our semi-rural peers and the industry (refer to figure 48). 90% of third-party SAIDI impacts are due to vehicle damage. The high SAIDI is partly due to the average outage duration seen on the network (refer to figure 49).

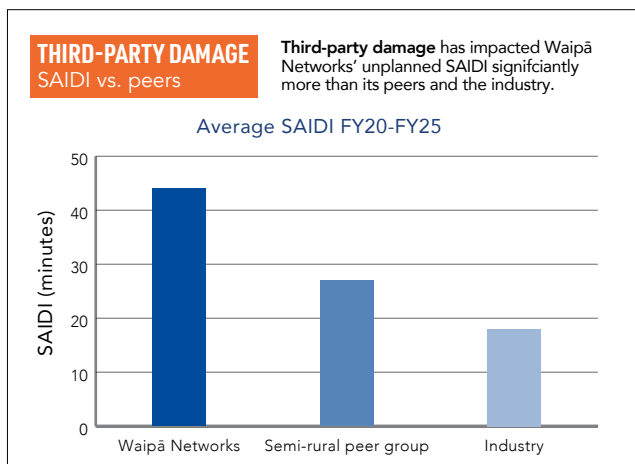


Figure 48: Third-party damage SAIDI vs. peers

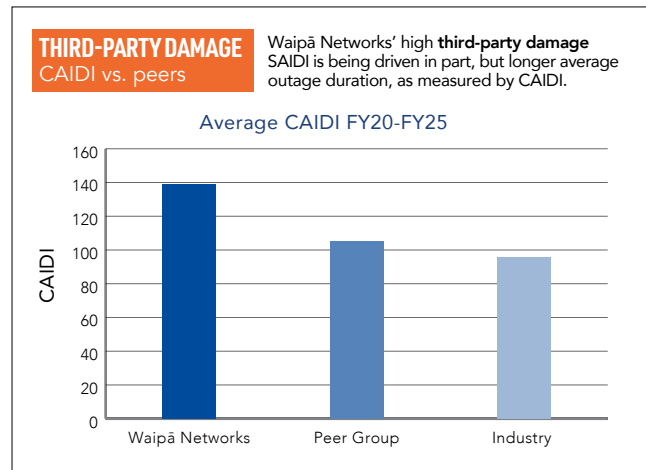


Figure 49: Third-party damage CAIDI vs. peers⁴⁵

In FY23, we mapped the locations of vehicle vs. pole incidents using transport data and our database, highlighting the hotspots in Cambridge and Te Awamutu. The visualisation shows various hot spots across key routes and townships. The hot spots are not concentrated on a small number of sites that can be easily targeted or addressed cost-effectively. One site has been identified (and was included in the 2025 AMP), but the locations are too diverse to warrant a systematic programme. Refer to figure 50 and figure 51 which shows vehicle damage incidents⁴⁶. To gain better insight, we are repeating this analysis using an alternative methodology, looking at accidents within an envelope around the pole. It is hoped that this will provide additional insight into some high-risk locations.

Third-party damage risk mitigation will begin with resolving multi-circuit lines in the Te Awamutu area, which are being resolved for other reasons (see section 11.12).

⁴⁵ CAIDI means Customer Average Interruption Duration Index, which is a measure of the average time it takes to restore power to customers who have experienced an outage.

⁴⁶ The colour scale is from blue (low) to yellow (high) incidents.

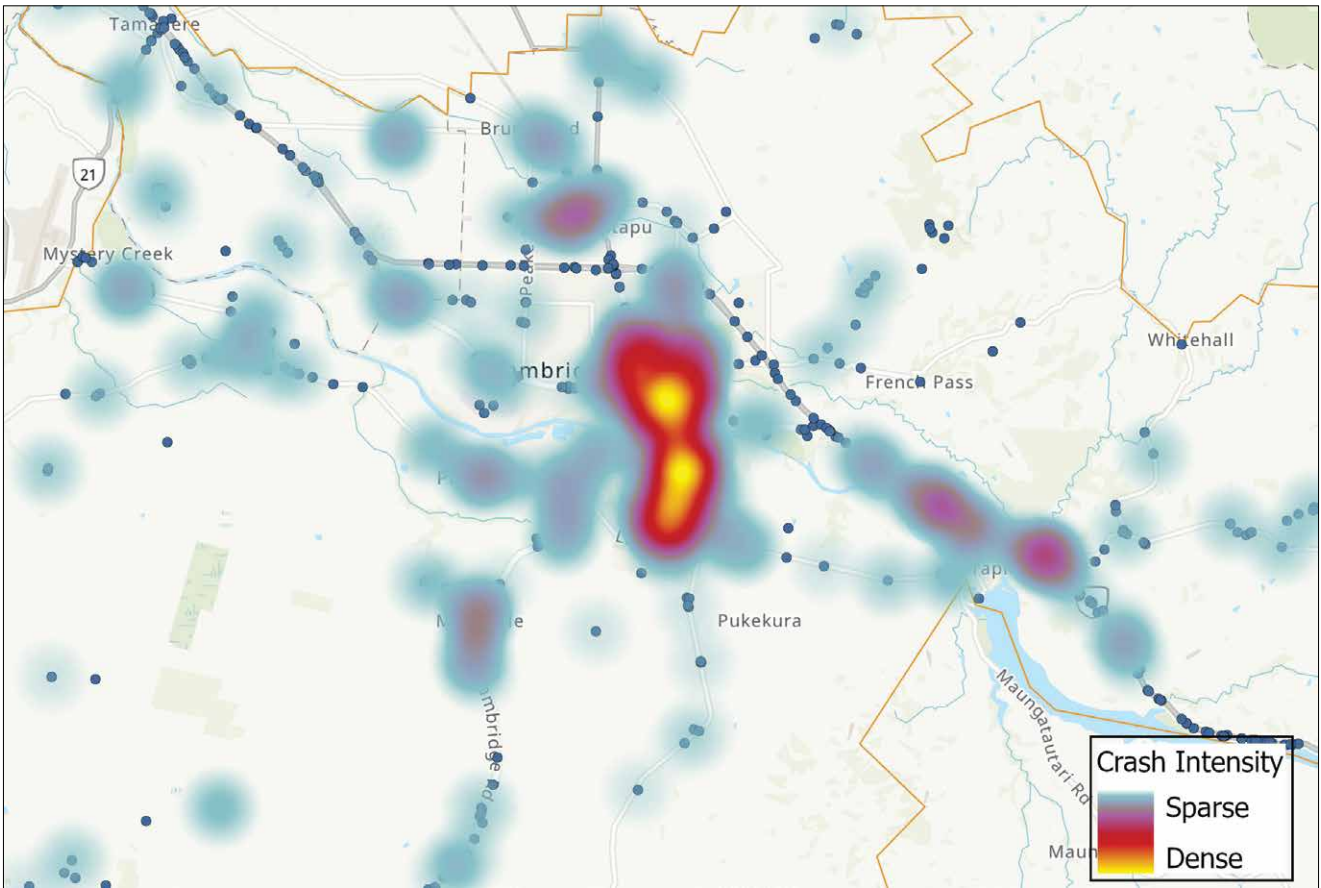


Figure 50: Vehicle damage sites, Cambridge area

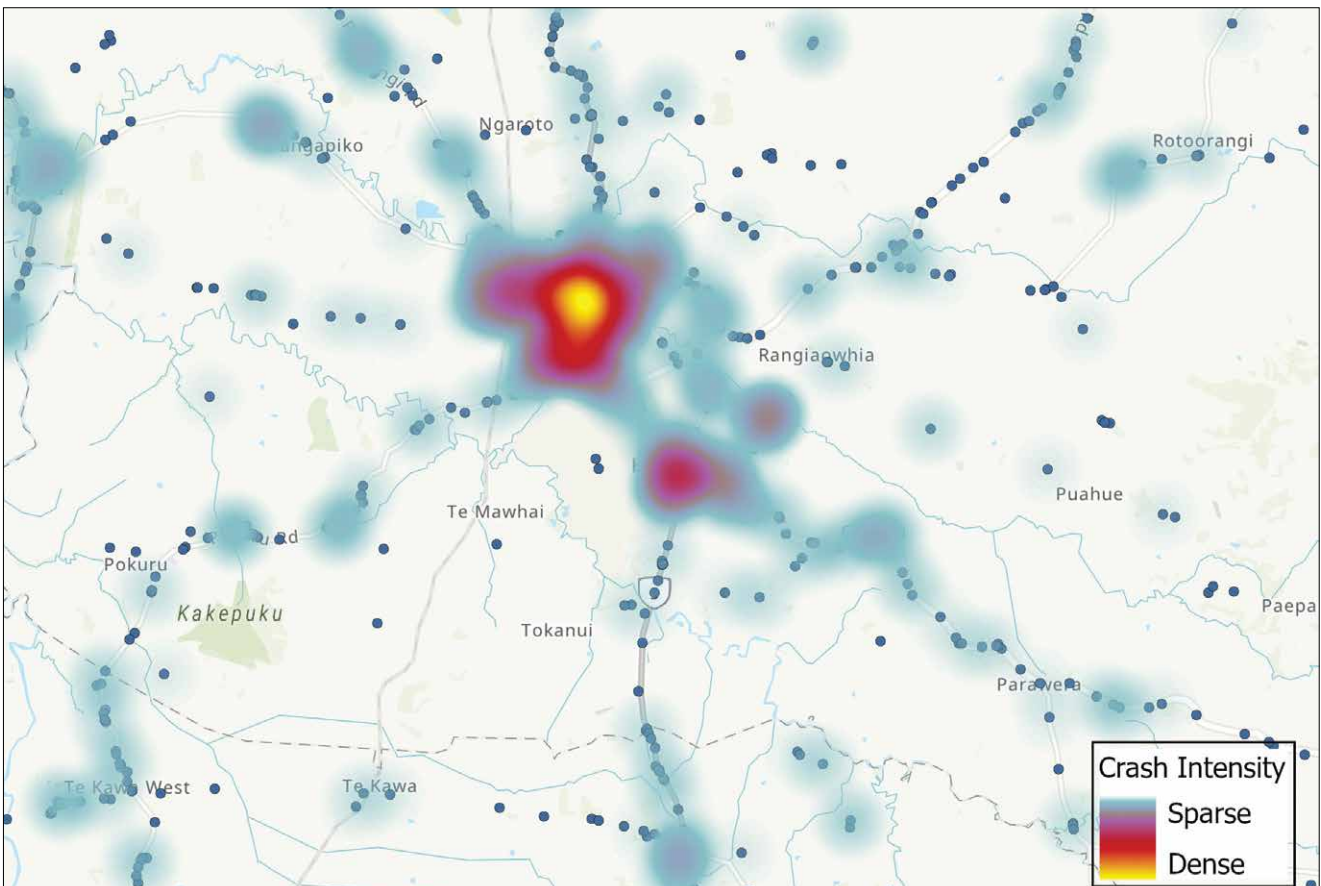


Figure 51: Vehicle damage sites, Te Awamutu area

5.5.7 Vegetation

We implemented a new vegetation strategy in FY24, and this (and more settled weather in FY25) saw us achieve the target in FY24 and FY25. Our vegetation target was to achieve a 36% reduction in SAIDI between FY24 and FY30. For FY25, actual vegetation SAIDI was 22.6 vs. a target of 36.2. Hence, we are on track to achieve our targeted improvement.

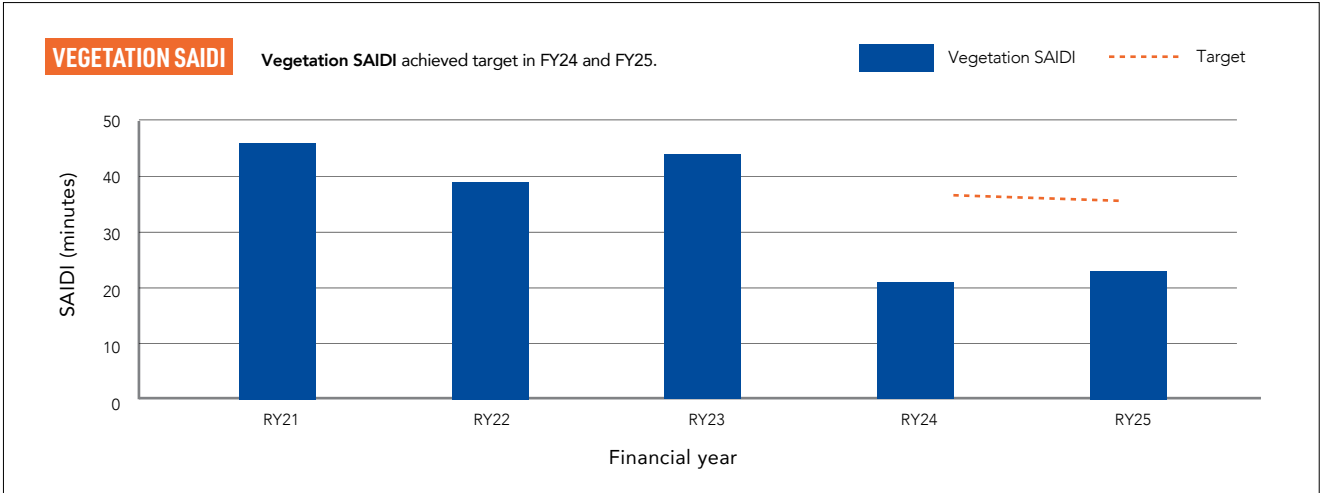


Figure 52: Vegetation SAIDI vs. target



Damage from vegetation is a material contributor to unplanned SAIDI. Our vegetation-related SAIDI is similar to our semi-rural peers, but above the industry average (refer to figure 53). 60% of the vegetation SAIDI (and outages) was because of vegetation outside of the notice zone (refer to figure 54). As expected, vegetation contact outside the notice zone occurs due to wind (correlation, $r=0.77$), creating significant volatility in SAIDI.

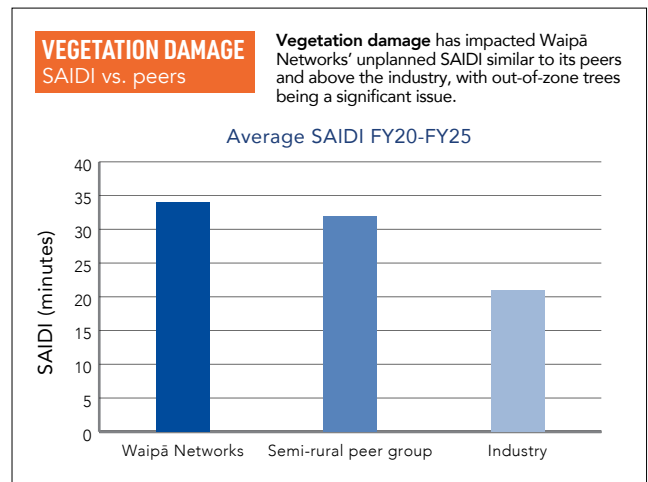


Figure 53: Vegetation SAIDI vs. peers

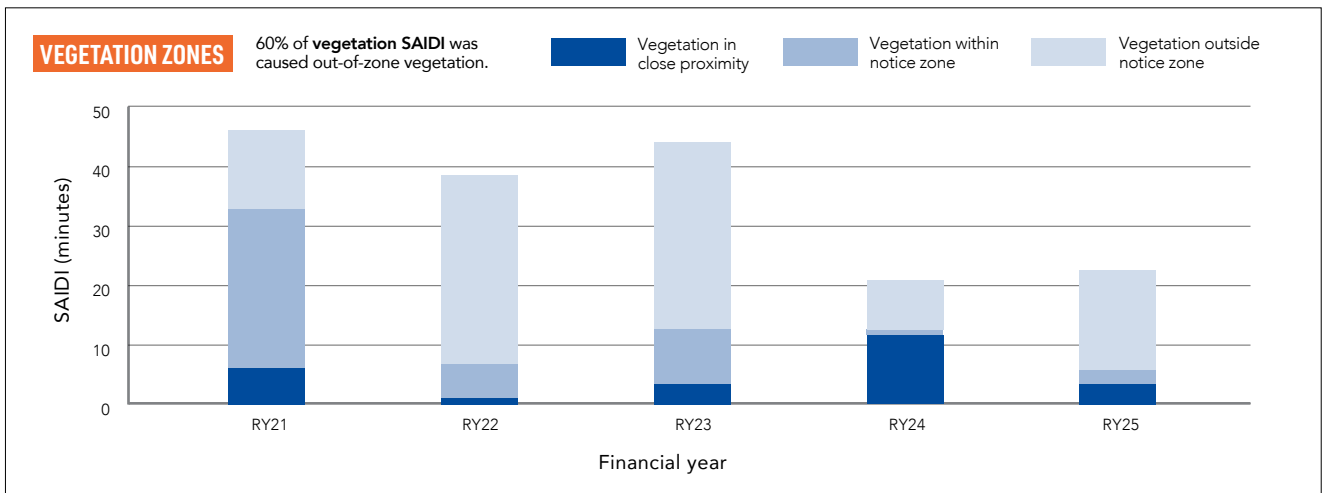


Figure 54: Vegetation zones

Management of vegetation outside the notice zone is complex and lacks regulatory support. Although the Electricity (Hazards from Trees) Regulations were amended in 2024 to extend the notice zone by one metre, these have not addressed the risk of fall in trees. Changes have also been proposed that would improve the management of trees outside of the growth zone, however this has not yet come into force.⁴⁷

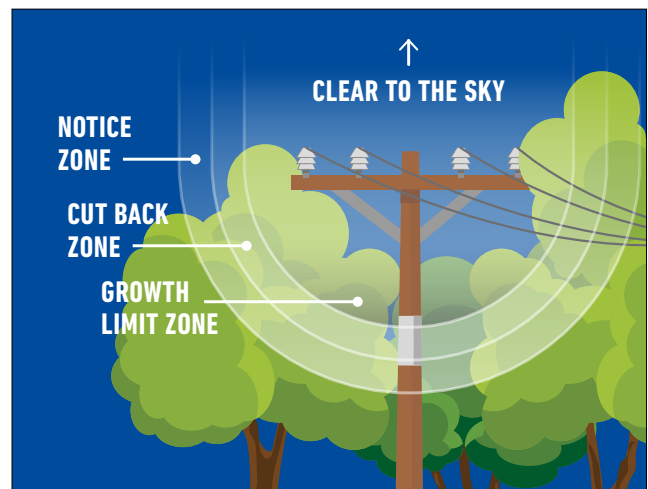


Figure 55: Vegetation zones

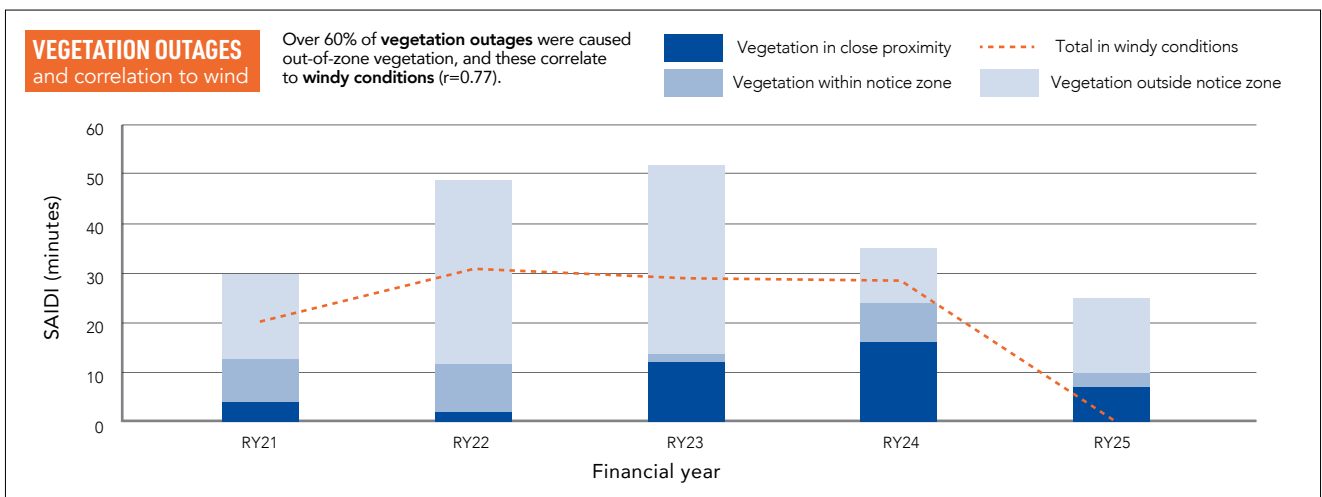


Figure 56: Vegetation outages and correlation to wind

⁴⁷ The Electricity (Hazards from Trees) Regulations 2003 specifies minimum distances from overhead power lines that vegetation must be clear from, with distances varying depending on voltage and conductor span length (the GLZ). These were updated in November 2024, extending the notice zone by one metre and making the zones clear to the sky. For 11kV lines, the GLZ is 1.6m, the cut-back zone is 2.6m and the notice zone at 3.6m from the line. While these zones provide clearance from interference from branches (although greater clearance would be useful), they are inadequate to manage tree fall risk and interference during storm events, where greater separation is needed.

As expected, vegetation contact outside the GLZ affects reliability due to wind. The correlation with wind creates significant volatility in the number of outages, and hence SAIDI (refer to figure 57). There are further regulations planned to increase our rights to address out-of-zone trees, but these have not been enacted at the time of writing.

We assessed how often a feeder exceeded 2.5 SAIDI minutes due to vegetation over the past five years⁴⁸. Only three feeders recorded vegetation SAIDI greater than 2.5 minutes three or more times⁴⁹. For most feeders (82%), a SAIDI greater than 2.5 occurred once or not at all. Hence, other than three feeders, our vegetation management program has been effective in controlling vegetation issues.

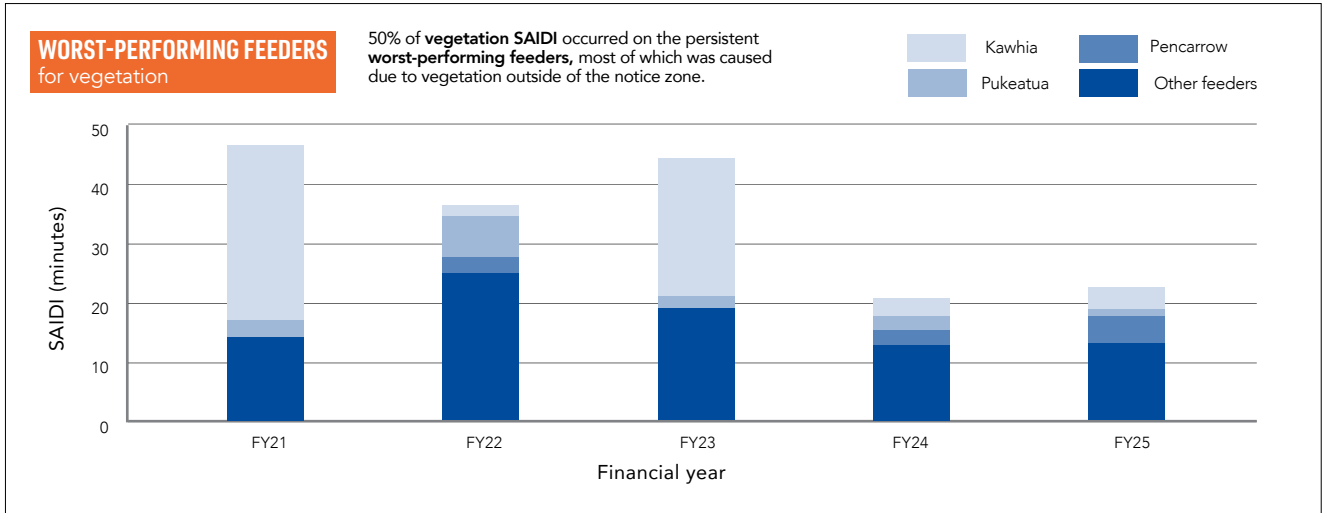


Figure 57: Worst-performing feeders for vegetation

Vegetation outage management is an ongoing issue worsened by climate change, the difficulty of obtaining access and approval to trim vegetation, and the narrow GLZ, which reduces the effectiveness of trimming work (and, in particular, the potential impact of trees beyond the notice zone). We have an extensive management programme in place to manage vegetation on all feeders. At the time of drafting this AMP, progress on the three worst performing vegetation feeders is:

- 100% of Kāwhia has been patrolled, and 95% of the trees identified have been addressed, including all high-risk sites
- 100% of the Pukeatua feeder has been patrolled, and 95% of the trees identified have been addressed, including all high-risk sites
- 50% of the Pencarrow feeder has been patrolled, with no trees addressed. It is planned to complete the inspection and address all high-risk sites.

Our operational plans have been prioritised to ensure the three worst-performing feeders are addressed (refer to Section 13.21.5).

5.5.8 Extended duration outages

Most unplanned outages are restored within three hours, which is consistent with our semi-rural peer group and the industry (refer to figure 58). The percentage of outages restored within three hours has improved over the past five years, which is a positive result (refer to figure 59).

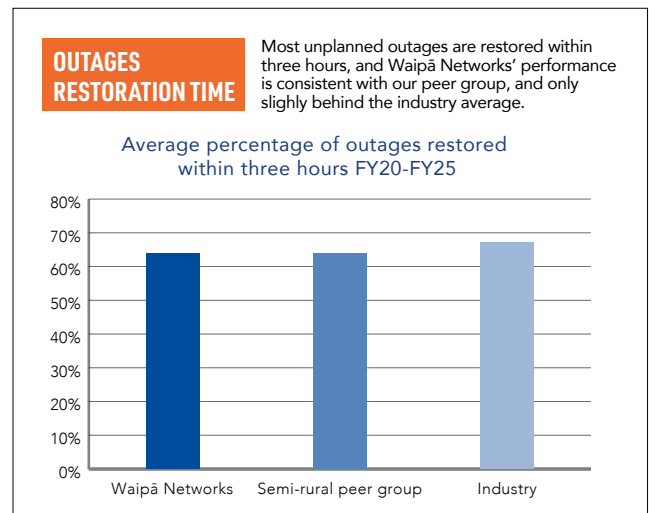


Figure 58: Outage restoration times vs. peers

⁴⁸ This is appropriately 5% of our annual target.

⁴⁹ Kāwhia, Pukeatua and Pencarrow.

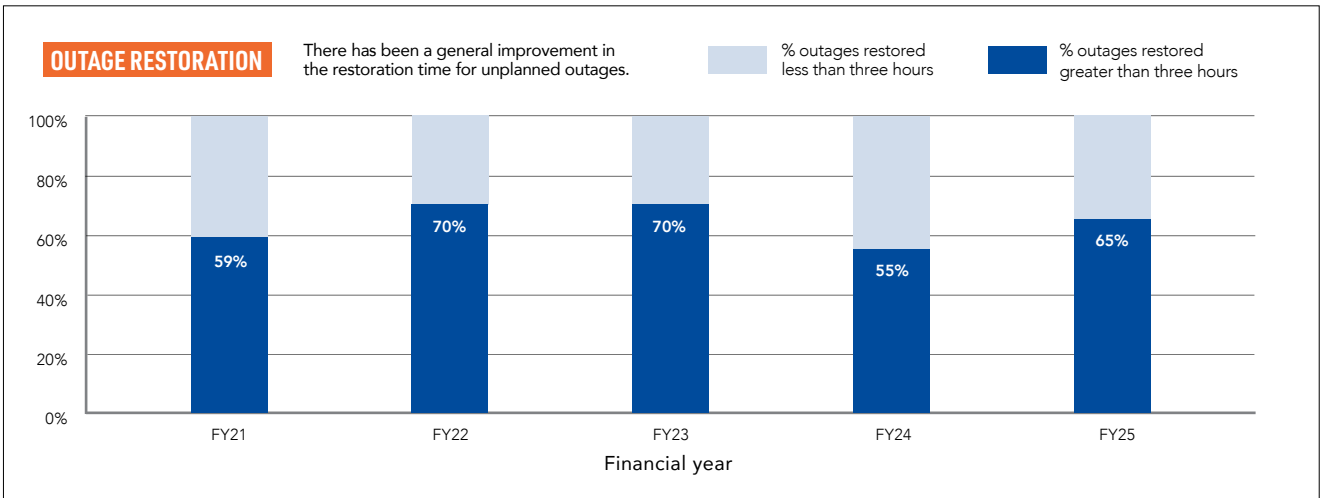
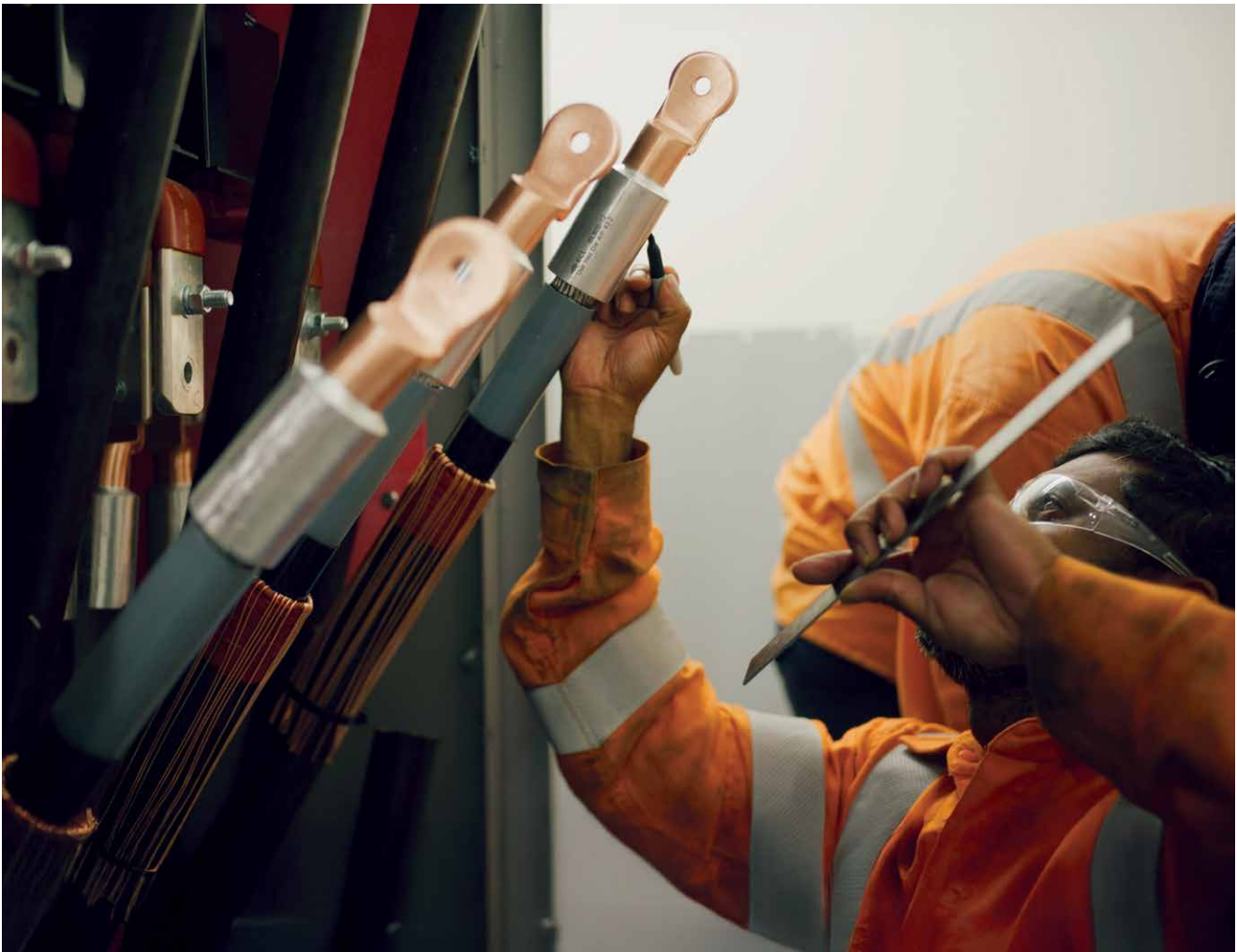


Figure 59: Trend in outage restoration

5.5.9 Worst-performing feeders

We are focusing on improving currently underperforming feeders. How we do this is evolving, and we will engage with customers to understand their needs (see Section 3.4). It is expected that this will change how we define worst-performing and is likely to shift our focus in the future. Table 23 summarises the feeders with high SAIDI

contribution over the past five years and references specific solutions to address the performance issues. They are predominantly rural feeders, and in some cases, historical issues have been addressed (or were a result of one-off specific problems, e.g., third-party damage). Addressing security on the Kāwhia feeder is a difficult issue, but one that will deliver significant improvement.



Feeder	% Total SAIDI FY21-25 ⁵⁰	Fault rate/100km FY21-25 ⁴⁴	Causes of outage (in order)	Reference to remediation plans
Kāwhia	21% ⁵¹	13.9	<ul style="list-style-type: none"> • Vegetation • Defective equipment • Third-party damage 	Kāwhia's poor performance is not a fault rate issue, but rather due to its configuration. Understanding and resolving the Kāwhia feeder issue is a subject of our place-based engagement pilot (refer to Section 3.4). We have included a view of the Kāwhia reliability improvement in our reliability plans (refer to Section 7.8 and 11.12.2), but this may change following engagement.
Pukeatua	8%	16.0	<ul style="list-style-type: none"> • Third-party damage • Vegetation • Defective equipment 	Most of the poor performance relates to historical issues in FY22 and FY23. Current performance would see the feeder fall outside of the poor-performing group. However, there are some constraints that impact backfeeding that are being resolved (refer to Section 11.12.1 and 11.12.2).
Ex-Pencarrow (now split into new Victoria and new Pencarrow post June 2025)	5%	18.7	<ul style="list-style-type: none"> • Third-party damage • Vegetation 	Vegetation work planned. Refer to Section 13.24. Note: this is the ex-Pencarrow feeder and the recent reconfiguration of the feeder will have improved reliability by reducing the customer numbers.
Roto-o-Rangi	5%	21.4	<ul style="list-style-type: none"> • Vegetation • Defective equipment 	Vegetation work planned. Refer to Section 13.24. As part of the update to the fleet plans, we will be reviewing the inspection and renewal programmes to ensure this feeder is prioritised.
Paterangi	5%	14.7	<ul style="list-style-type: none"> • Third-party damage 	Most of the poor performance relates to FY22 and FY23. Recent performance would see the feeder fall outside of the poor-performing group. There are no specific improvements planned for this feeder.
Pokuru	4%	13.9	<ul style="list-style-type: none"> • Third-party damage 	As above.
Kiokio	4%	17.4	<ul style="list-style-type: none"> • Third-party damage 	As above. Issues were FY23 and FY24.
French Pass	4%	25.7	<ul style="list-style-type: none"> • Vegetation 	Most of the vegetation relates to FY21 and FY23, which have been resolved. Unrelated outages in FY24 and FY25 have seen the feeder remain in the poor-performing group. There are no specific improvements planned for this feeder.
Cambridge North	3%	12.5	<ul style="list-style-type: none"> • Defective equipment 	There was a single cable fault in FY25 that impacted 1,880 customers.

Table 23: Worst-performing feeders

Other than Cambridge North, all the feeders are rural. However, we have observed a small number of high-impact outages on our urban feeders. These are rare but can have significant SAIDI impacts. The security improvement projects (in the development section of the AMP) address security issues across several of these feeders.

5.5.10 Power quality

Power quality relates to voltage and harmonics. We investigate and resolve power quality issues as soon as these are identified through our SCADA, network monitoring or customer complaints. We are working to establish performance metrics for this area, and they will be included in future AMPs.

⁵⁰ Excluding adverse weather and adverse environment outages. We excluded these outages to assess the underlying performance of the feeder.

⁵¹ This is 15% after normalisation.

5.6 Efficiency and asset utilisation

5.6.1 Efficiency

As stated in Section 7.10, we are developing new efficiency measures. The goal of developing these measures will be to have indicators that are actionable and drive meaningful change, and can be clearly communicated to our customers. We will report these in the next AMP.

5.6.2 Asset utilisation

Figure 60 shows our asset utilisation for distribution transformers. This shows that capacity utilisation has been flat since 2023. The utilisation appears low because it uses the total system demand and accounts for demand diversity. Zone substation and feeder diversity will be added in the 2027 AMP.

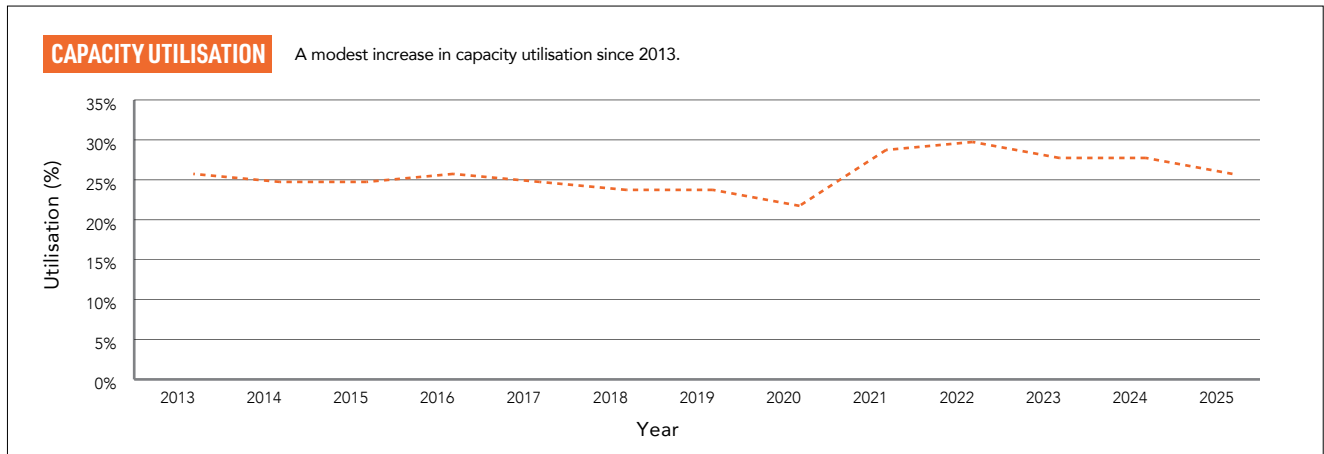


Figure 60: Asset utilisation

5.6.3 Load factor

The load factor for an electricity network measures how efficiently customers utilise the network. Since 2013, our load ratio has reduced from 63% to 59%. This reflects customer demand becoming more concentrated during peak periods. As mentioned in Section 4.1, there could be opportunities to shift demand to off-peak periods.

5.6.4 Loss ratio

The loss ratio measures the ratio of kWh lost on the distribution network to kWh injected into our network from the GXP's per year. Since 2013, our loss ratio has reduced from 6% to 5%. The reduction reflects a combination of factors, including capacity increases and the rollout of smart meters, which reduce measurement losses and theft.



5.7 Work delivery

We measure our work delivery in terms of overall expenditure, major project delivery, and inspections. Our condition assessment programme is the foundation of our lifecycle fleet plan; hence, we have enhanced our disclosure in this area.

5.7.1 Expenditure

Our capex delivery performance has improved, with a network capex variance of 5% over the past two years (refer to figure 61). For FY25, capex delivery was good and within target (refer to table 24). Our opex delivery variance was large for FY23 and FY25, primarily due to the significant adverse weather conditions in FY23 and the settled weather conditions in FY25. For FY25, vegetation management work was within target, but system emergency work and network maintenance were below budget due to the settled weather (fewer faults), inspection delays due to resource constraints, capitalisation of distribution transformer and RMU fitouts, and reactive resource labour optimisation.

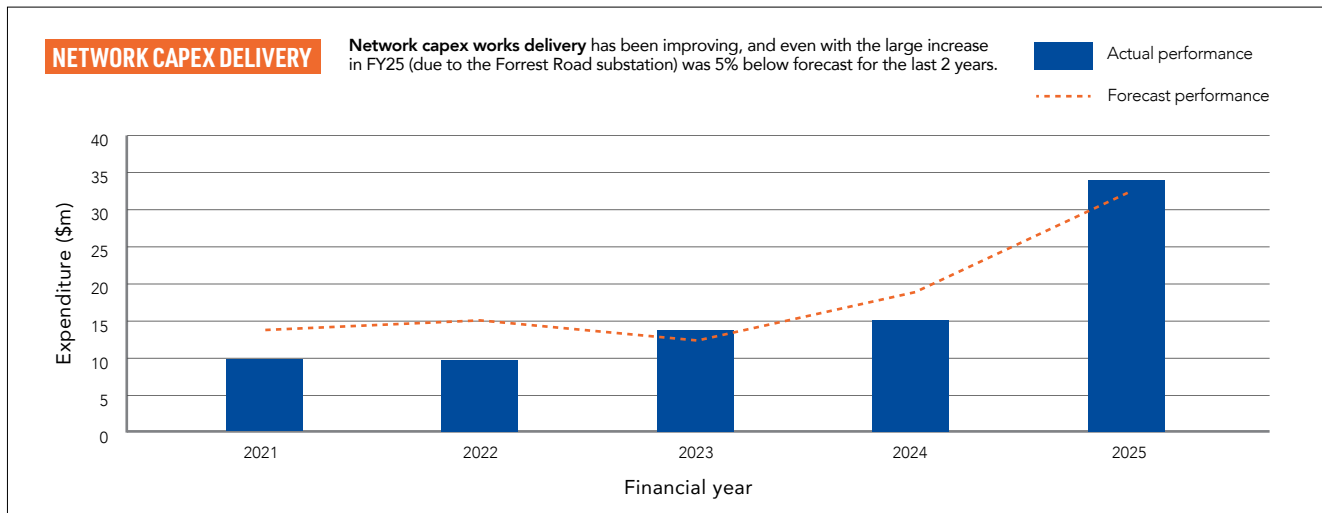


Figure 61: Network capex delivery

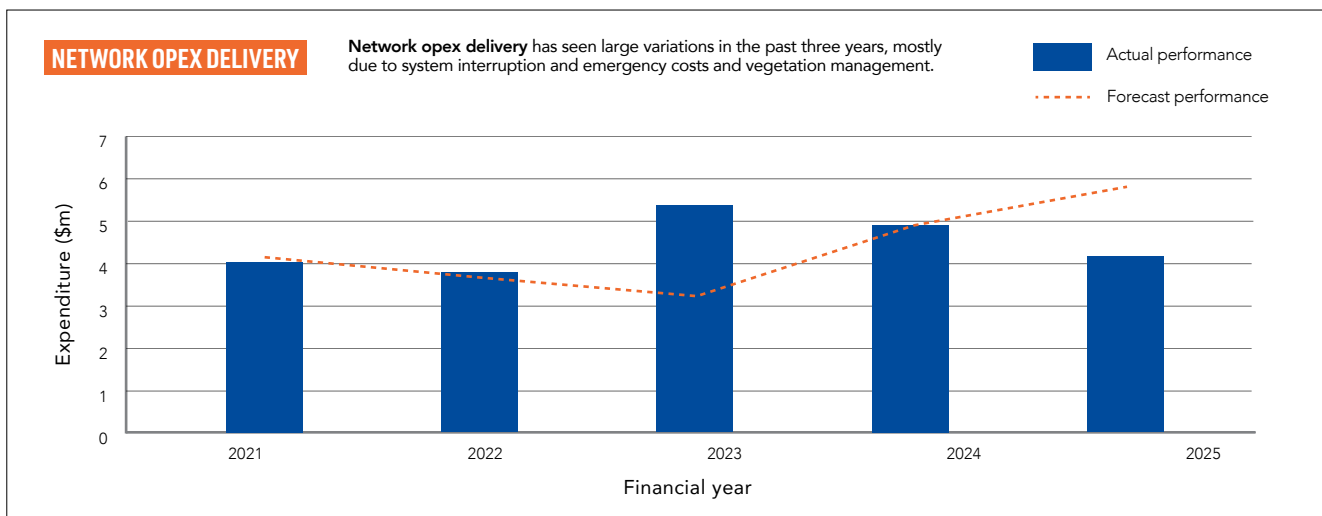


Figure 62: Network opex delivery

Expenditure category	Variance target	Variance in FY25 ⁵²	Commentary
Network capex, excluding customer connections	<15%	(10%)	The variance was within target and due to the catch-up on a large 11kV cable project, which was delayed from FY24.
System interruption and emergency ⁵³	<5%	37%	This is regarded as a positive variance – we had settled weather in FY25, which led to a reduction in fault-related work and costs.
Network maintenance and inspections ⁵⁴	<5%	54%	Some inspection work was delayed, and capitalisation of distribution transformer and RMU fitouts. We caught up on many of these inspections in Q1 and Q2 of FY26.
Vegetation management	<10%	(2%)	The minor overspend was within target.

Table 24: Specific works delivery measures

5.7.2 Major projects/programme

Table 25 shows progress on our major projects and programmes (excluding customer-related connections and extensions). We experienced a range of variances due to

delays in land access, constraints in planning and design efficiency, and scope changes. We are addressing these constraints through recent resource reviews (refer to Section 14.4.2 and Section 14.4.3).

Project/programme	FY25 Budget (\$000)	FY25 Spend (\$000)	Variance % ⁵⁵	Commentary
Forrest Road substation	\$9,000	\$10,015	(11%)	GXP and zone substation were successfully commissioned in Q1 FY26. This is a multi-year project.
Forrest 11kV Feeder Integration	\$2,350	\$1,850	21%	A budget variation was approved due to increased equipment and installation costs.
Forrest Road substation feeder augmentation (Includes the four new Forrest substation feeders)	\$2,600	\$2,879	(11%)	
Total of Forrest	\$13,950	\$14,744	(6%)	
Te Awamutu feeder cable upgrade	\$3,600	\$3,267	9%	Multi-year project, commissioned in FY25.
Mutu St – Te Rahu Road underground project	\$780	\$69	91%	Deferred to alignment with Kihikihi/Harini Project. Efficiency in delivering both together.
Communication network upgrade project	\$700	\$347	50%	Project components deferred to FY26 due to land access delays for establishing a new repeater site.
Asset Replacement and Renewal	\$5,342	\$7,524	(41%)	Replacements of cross-arms, poles, and air-break switches were major contributors to the higher expenditure. Increased inspection efforts have led to more urgent, defect-driven reactive replacement.

Table 25: Major projects and programmes expenditure in FY25 >\$500k

⁵² Positive is under-budget. Negative is over-budget.

⁵³ Excluding major events.

⁵⁴ Reactive and corrective maintenance and inspection, and asset replacement and renewal opex.

⁵⁵ Positive is under-budget. Negative is over-budget.

5.7.3 Condition assessment programmes

Table 26 shows our progress against our condition assessment regime. These are important inputs into our health assessments. Our focus since the start of FY22 has been on our pole fleet, and inspections are ahead of plan (although not all of these are used for health forecasting).

We have been rolling out new digital inspection forms (using Field Maps, a field mobility solution), and for some assets, the progress only reflects inspections using that system (and excludes inspections using other prior systems). Hence, some of the variances are due to system changes and delays in inspections as the new system was rolled out. This will correct itself in subsequent AMPs.

Asset Class	Inspection cycle	% of assets inspected using updated inspection criteria at Q2 FY26 ⁵⁶	Commentary
Subtransmission line	First inspection at year 10	0%	Not yet due.
11kV and LV Poles	5 yearly	37% Concrete 100% Wood	This relates to new inspection regime that aligns to our health forecasting model. 70% of the concrete fleet have been inspected and any defects resolved, but some of the data was not in a form suitable for health forecasting.
11kV and LV Crossarms	5 yearly	22%	This relates to the new inspection regime that aligns with our health forecasting model. As with poles, over 70% of crossarms have been inspected and any defects resolved (but this related to the old regime and is not reported here).
Reclosers and sectionalisers	3 yearly	95%	The fleet has been recently inspected.
Ring main units	2 yearly	65%	These assets were previously inspected as part of our 5-year feeder inspection. Progress now relates to the new two-yearly targeted inspection regime.
OH transformers	5 yearly	80%	This relates to the inspections that began at the start of FY22. All data is used for health forecasting.
GM transformers	5 yearly	76%	These assets were previously inspected as part of our 5-year feeder inspection. Progress now relates to the new inspection regime using Field Maps.
Voltage regulators	3 yearly	95%	100% were inspected at the start of FY26.
OH switches and fuses	5 yearly	5%	These are inspected as part of planned line inspections but are currently reported as defects.
Pillar boxes	5 yearly	32%	This is the new inspection regime that commenced at the start of FY26.

Table 26: Progress against our condition assessments

There is no dedicated inspection regime in relation to 11kV and LV conductors. However, Cable terminations are inspected as part of the equipment inspections. Binders and terminations are inspected in conjunction with pole inspections. There is no standalone inspection regime for overhead switchgear; inspections are undertaken in conjunction with pole inspections.

⁵⁶ As used in the health forecasting in this AMP.

5.8 Environmental performance

Table 27 shows our current environmental performance. We are developing a framework to monitor our environmental performance, and additional measures will be implemented in the future. Additional environmental performance measures are included in our SCI.⁵⁷

Key performance indicator	Type	Actual FY24	Actual FY25	Target FY25	Comment
Number of environmental incidents	Lagging	Nil	Nil	Nil	We have not had any environmental incidents in the past two years.

Table 27: Environmental measures

⁵⁷ <https://waipanetworks.co.nz/wp-content/uploads/2025/06/Waipā-Networks---SCI-2025-FINAL.pdf>



6. THE KEY FACTORS THAT ARE DRIVING INVESTMENT AND PERFORMANCE

6.1 Introduction

This section considers the key issues that are driving investment and performance. It builds on the preceding three sections. These are the most important issues that shape our asset management strategy:

- The high regional population and industrial growth
- The need to manage future demand growth due to electrification

- The ageing of our network assets
- The increasing incidents and impact of adverse weather events
- The need for greater maturity in asset management to effectively manage the issues above.

We discuss each of these issues in the following sections.

6.2 The high regional population and industrial growth

Residential growth

The Waipā district is a desirable place to live and is well-situated for business. Since 2013, our network has consistently experienced growth, with the third-highest ICP growth rate among EDBs in New Zealand (a 1.9% compound annual growth).⁵⁸ This has been driven by residential customers, which grew at a compound annual growth rate of 2.2% p.a. over the same period. Residential customer growth has been driven by regional population

growth of Waipā district, which has averaged 2.1% per annum since 2013. This rate is 33% higher than the national average (refer to figure 11).

We expect strong residential connection growth to continue (refer to figure 63). Waipā District Council expects the population to grow to more than 74,000 by 2034 (an annual growth rate of 1.7%).⁵⁹ Based on similar occupancy rates and continued population growth, we expect to connect around 12,000 new homes by 2050.⁶⁰

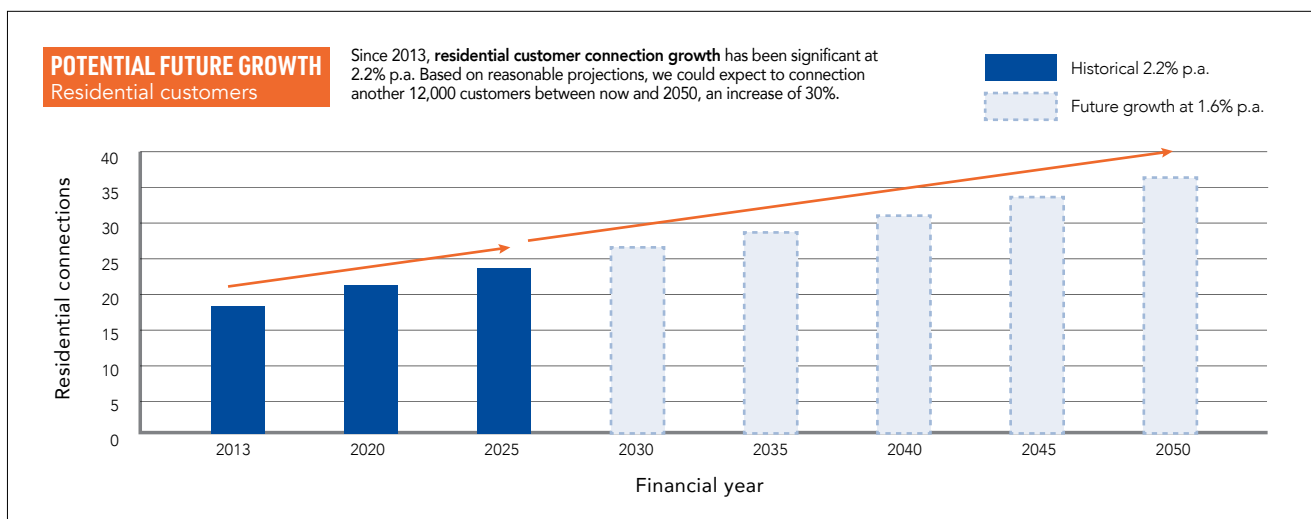


Figure 63: Potential future residential customer growth

The Waipā District Council has prepared a growth strategy for the district and has allocated 201ha of residential and large-lot residential land in Te Awamutu and Kihikihi, which would fit approximately 3,000 homes. To accommodate the expected population growth in the Cambridge area,

around 18 hectares of land will be required every year. The Council is also working to rezone additional industrial land and provide services in Hautapu to accommodate new industries.

⁵⁸ Compounding annual growth rate between FY13 and FY25. Source: Information disclosure data.

⁵⁹ Waipā District Council, 2025-34 Long Term Plan, page 308. <https://www.waipadc.govt.nz/repository/libraries/id:26zgz4o7s1cxbyk7hfo7/hierarchy/our-council/Strategies%20and%20plans/10-year-plan/documents/2025-34%20Long%20Term%20Plan.pdf>

⁶⁰ Our connection growth rates reflects the number of new homes and is consistent with the Council's growth cell housing projects (at 1.64% p.a.).

Large commercial and industrial growth

We have seen significant growth in large commercial and industrial customers.⁶¹ Combined, connection growth has been 9% p.a. since 2023. This accounted for over 50% of our consumption growth during that period. Our network is well placed geographically for this growth to continue (i.e. close to the golden triangle of Hamilton, Tauranga and Auckland).⁶²

Even if growth slows, large commercial and industrial customers are expected to account for over 40% of consumption by 2050, up from 32% in 2025, excluding step-change growth from decarbonisation (refer to Figure 64). These customers will significantly impact our future consumption and demand. We are already seeing strong inquiry, including a request for an additional 6 MW increase in demand on the Waikeria Prison feeder by 2030.

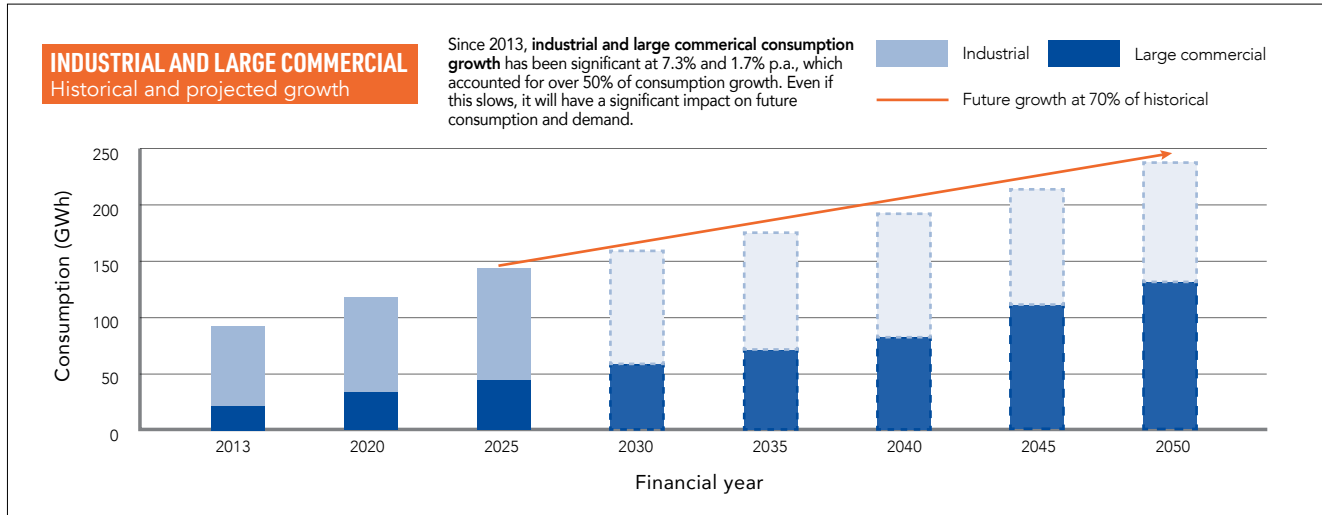


Figure 64: Historical and projected industrial and large commercial growth

Impact on the network

The growth in our residential, large commercial, and industrial customers has resulted in demand increasing by approximately 31% to 89 MW since 2013 (a compounding average growth rate of 2.3%). This growth drove the commissioning of a new GXP and a 33/11kV zone substation in Cambridge this year.

By 2050, the number of network customers, along with their consumption and demand, will significantly impact the network. As shown in figure 65, our demand forecasts suggest that growth from new customers (excluding electrification growth driven by decarbonisation) could account for 59% of the total demand growth to FY50, amounting to 75 MW (refer to Sections 10.6, 11.5.2, 11.6 and 11.10 for our demand forecasts).

The customer and demand growth have led to an increase in 11kV feeder customer numbers and loading. The limits of an 11kV-only network were reached in Cambridge, and new feeders from the new Forrest Road substation were commissioned this year. We are approaching the limits of the 11kV-only network in the Te Awamutu area. Resolving these issues is a focus of this and future AMPs (refer to Section 11.8 11.9 and 11.12).



⁶¹ This is 400V and 11kV customer connections.

⁶² The "Golden Triangle" refers to the economic powerhouse region in New Zealand's North Island bounded by the cities of Auckland, Tauranga, and Hamilton. This area is crucial to the country's economy, accounting for over half of the GDP and home to more than half of the population, driven by strong growth rates, advanced logistics, and transport infrastructure.

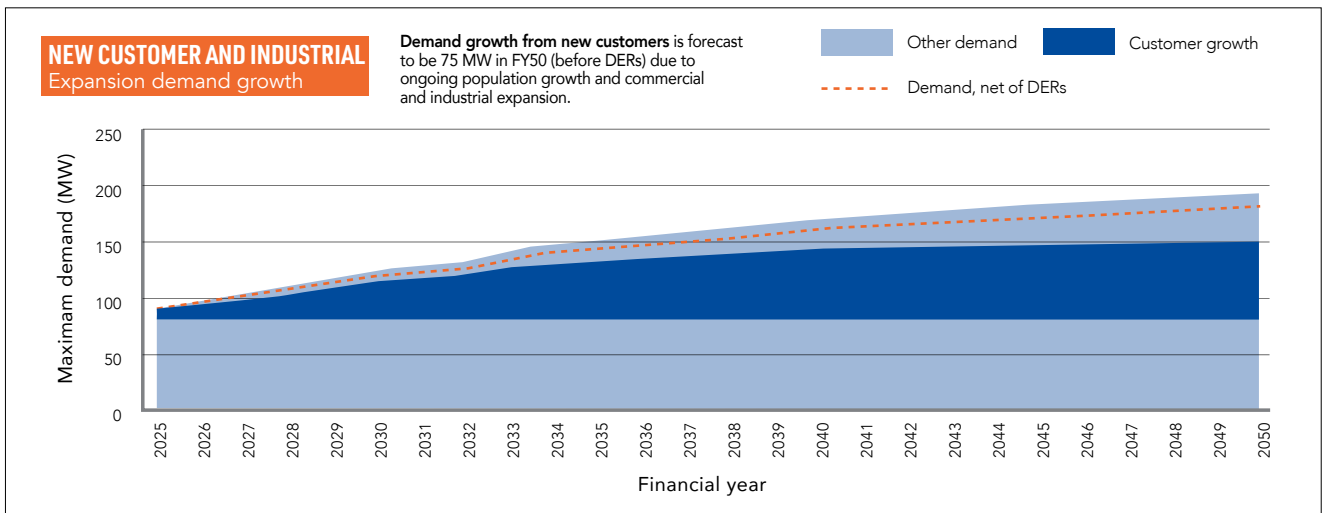


Figure 65: New customer and industrial expansion demand growth

6.3 The need to manage future demand growth due to electrification

The role of EDBs in supporting the decarbonisation of New Zealand using electricity

Electricity will play a central role in meeting New Zealand's 2050 emissions reduction goal by enabling the widespread electrification of transport and industry, which requires a significant increase in renewable generation. This transition involves replacing fossil fuels with electricity.

We have a key role to play as electricity offsets other, less environmentally friendly forms of energy, leading to expected:

- Significant demand growth that will require investment in additional network capacity
- Greater reliance on the electricity network, requiring investment to ensure reliability and resilience and to meet customers' needs
- Connection of new types of devices that allow new ways of using our network (including bi-directional power flows and flexibility services) that will require investment in technology to operate with a new network architecture.

However, the scale and timing of these changes remain uncertain, making transition planning challenging. As we face this issue, we recognise the importance of providing clear signals to customers, communities, and other stakeholders about the likely medium to long-term impacts of this shift. We discuss these issues in more detail in Section 10.

Decarbonisation impacts review

We undertook a review into the impact of decarbonisation in our network area. This study indicated that we could expect:

- Access to new technology will increase due to the falling cost and increasing efficiency of solar panels and energy storage. This will drive broader adoption of distributed energy resources (DERs), primarily rooftop solar and battery storage. Small-scale solar PV is expected to reduce demand by an additional 25 MW between FY25 and FY50 (high scenario). This will shift demand from the evening peak to the day as customers take advantage of on-site generation or utilise batteries to reduce peak period demand
- Automation and digitalisation may influence the agricultural sector, improving productivity and sustainability, which could increase electricity demand from this sector. The pace of technology adoption determines the timeframe and impact
- We have experienced a slowdown in EV adoption since our 2024 AMP and have therefore adjusted our forecast to reflect a slower uptake. However, we are still forecasting an increase of 20 MW due to both light and heavy EV adoption between FY25 and FY50 (predicted scenario). Light EVs will increase a household's electricity demand by 20-25% with charging predominantly at home using "smart charging" options that will respond to price signals to defer charging to low-demand, low-price periods
- Not all the energy needs of our large industrial customers will be electrified. It is expected that biofuels will be used in some energy-intensive processes
- Residential and commercial gas-to-electricity conversion will occur. However, this is not expected to be a significant factor for our region, as household energy from natural gas is a small component of the total energy demand
- We are receiving enquiries regarding large-scale solar and battery installations (>5MW). Historically, accommodating large solar or battery installations has been challenging. However, the introduction of Forrest Road Substation and 33kV subtransmission circuit will enable greater opportunity.



Changing regulatory rules

The Electricity Authority (EA) is promoting the flexibility market and the connection of distributed energy sources (DERs), through rule changes, market initiatives, and innovation support. This involves making time-of-use pricing compulsory for large retailers, consulting on new models for distribution system operators (DSOs) to manage DERs and launching the Power Innovation Pathway to accelerate new ideas. Other steps include supporting industry trials and developing new flexibility products for the wholesale market.

These changes could create opportunities to secure firm flexibility as alternatives to capacity development, but they also increase compliance requirements and complexity, which must be managed effectively. However, it remains unclear whether these regulatory changes will enable a retail flexibility market, and when it will develop to a sufficient depth to be effective.

Energy security and resilience

As electrification increases, the link between electricity and GDP will strengthen. Electrification will also reduce energy diversity, for example by shifting reliance on fossil fuels for transport to electricity, which could increase dependence on electricity. This is acceptable, provided electricity security and resilience are maintained at the necessary level to minimise the impact of low-probability, high-consequence events that could disrupt supply for days or weeks.

Impact on the network

Demand growth due to electrification has been modest to date. Given the factors mentioned above, electrification growth by 2050 could significantly impact the network. As shown in figure 66, our demand forecasts suggest that electrification growth could account for 41% of the total demand increase by FY50, amounting to 46 MW (refer to Sections 10.6, 11.5.2, 11.6 and 11.10 for our demand forecasts).

Significantly higher growth from electrification could occur if we are unable to secure flexibility services from customers (or their agents) to shift EV charging to low-demand periods, access battery support, or control water heating loads.

Electrification could result in different load profiles and two-way power flows that could impact the network. These are likely to require more complex monitoring and management, with technology and resourcing implications for the business. We discuss these matters further in Section 10.

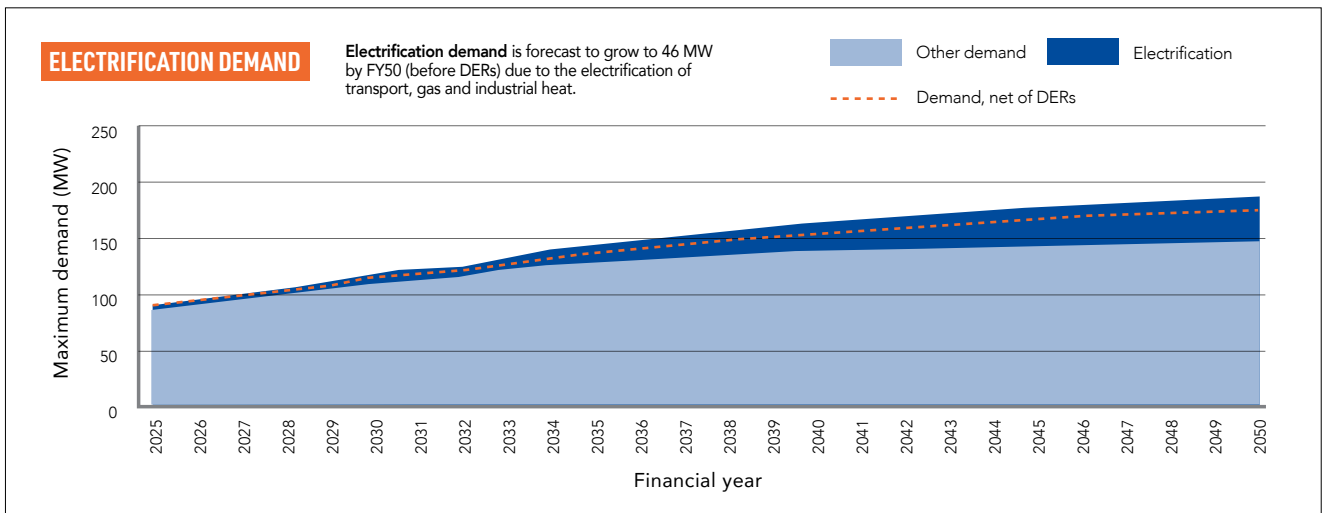


Figure 66: Electrification demand

6.4 The ageing of the asset fleet

Our network is relatively young, with an average age of around 14 years.⁶³ The asset base is comparatively young due to the value of our 110kV line between Hangatiki and Te Awamutu, installed in FY16, and the addition of new distribution assets as our network expanded to accommodate recent growth.

However, as shown in figure 67 through figure 72, several asset classes will see the emergence of end-of-life drivers over the coming decade. For some of our assets, where determining age and assessing condition is difficult (such as conductors, cables, and some types of overhead switchgear), we are indicating a risk that end-of-life drivers will emerge. Our pole fleet is in good condition, and recent inspections have confirmed this. However, wooden crossarms have a

life expectancy of about half that of concrete poles (which is the reason for the increase in end-of-life drivers for that fleet). We don't have good age data on crossarms, and our condition data covers only 22% of the fleet. Hence, figure 69 is only a general indication. We are focusing on improving data and understanding of the fleet.

Overall, our ageing fleet isn't currently a significant issue for our business. However, we must understand and manage asset health through our inspection, maintenance, and renewal programmes. In Section 9.6.3, we explain how we plan to improve asset data, and in Section 13, we explain how we are assessing these risks and addressing end-of-life issues for our asset fleets.

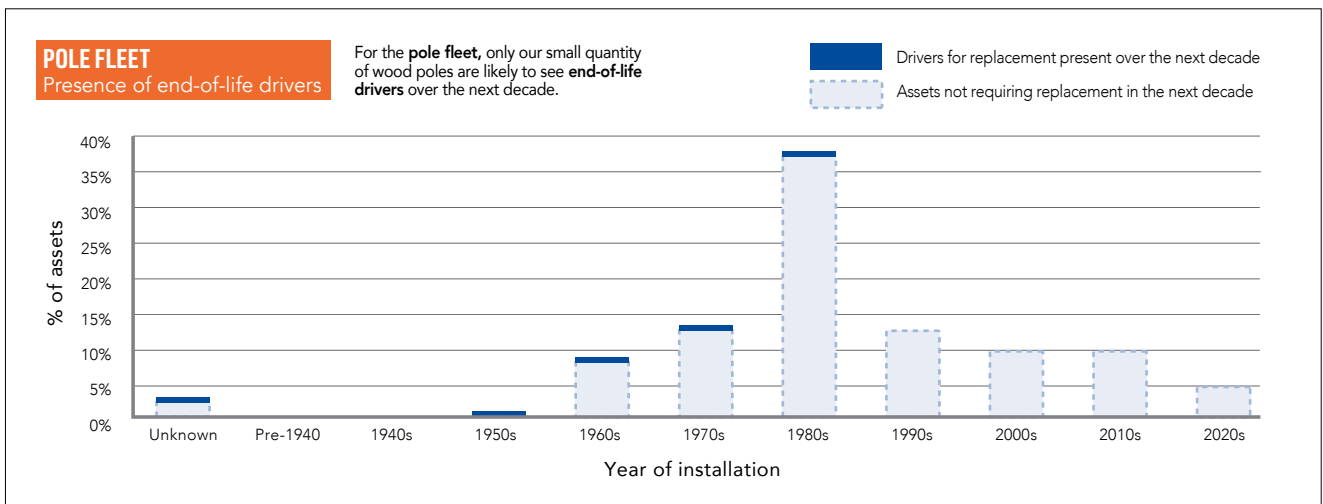


Figure 67: Pole fleet, presence of end-of-life drivers

⁶³ Calculated using RAB values and standard asset lives. The current average age has reduced since the 2024 AMP as new assets has been greater than depreciation.

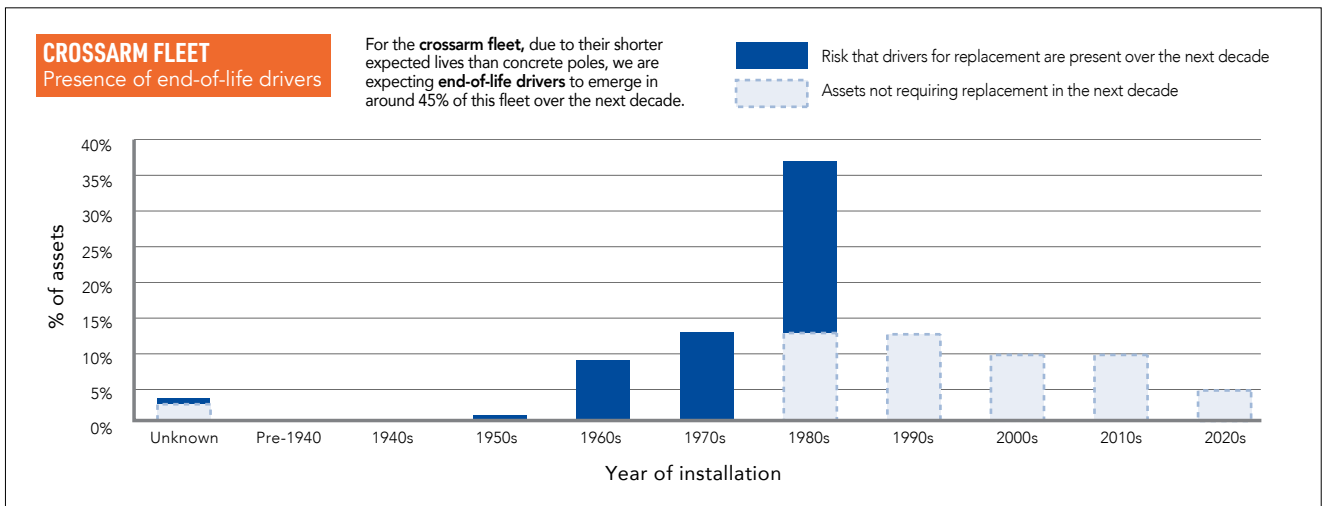


Figure 68: Crossarm fleet, presence of end-of-life drivers

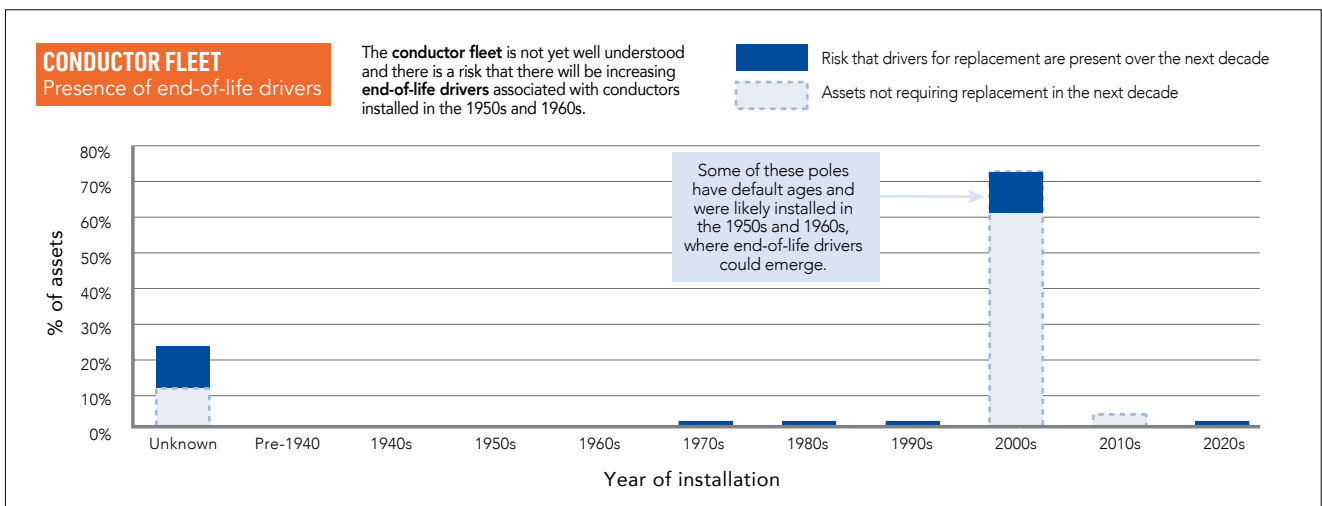


Figure 69: Conductor fleet, presence of end-of-life drivers

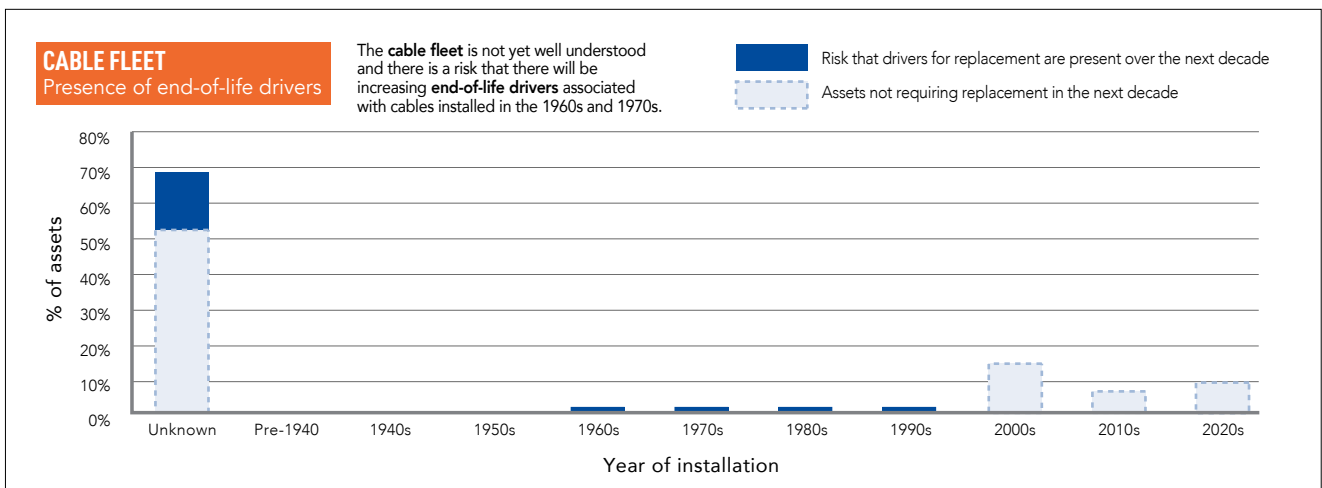


Figure 70: Cable fleet, presence of end-of-life drivers

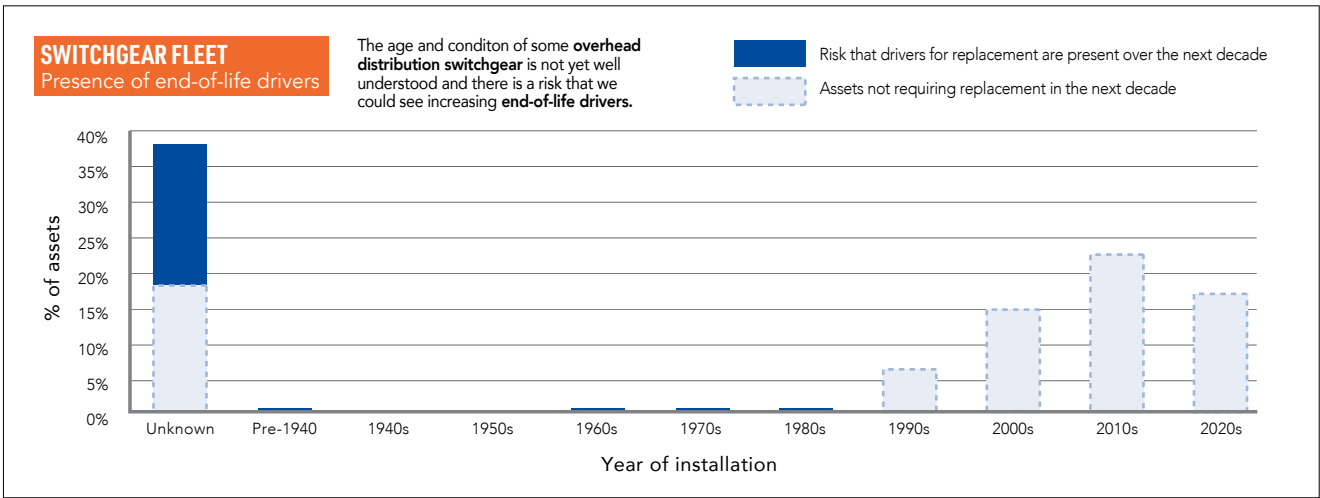


Figure 71: Switchgear fleet, presence of end-of-life drivers

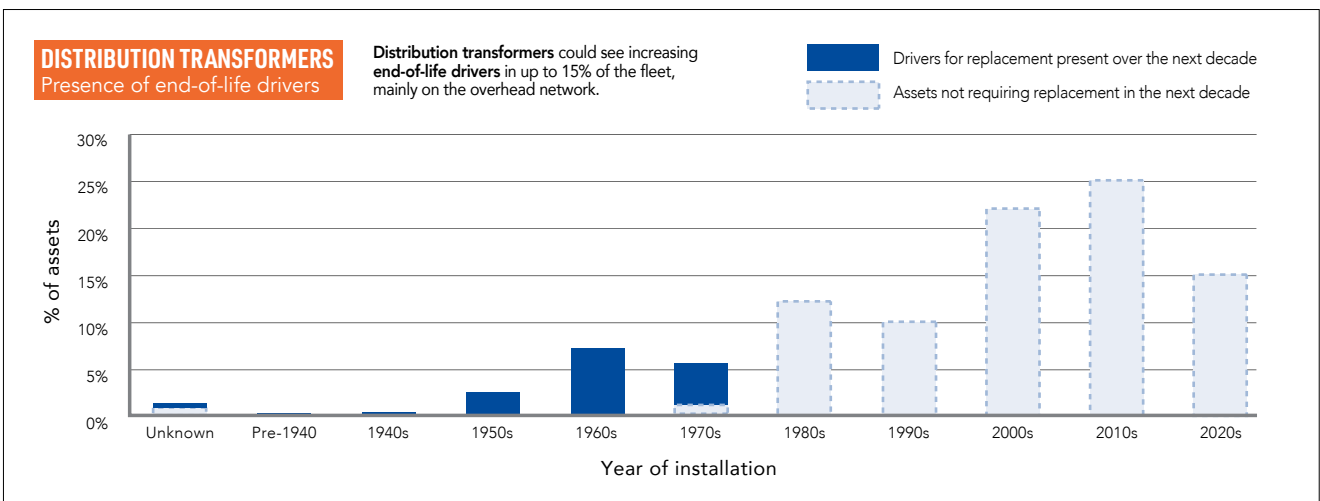


Figure 72: Distribution transformers, presence of end-of-life drivers



6.5 The increasing incidents and impact of adverse weather events

Our 11kV network is predominantly overhead (88%), and as a result, we have experienced significant impacts from adverse weather events in recent years, as shown in figure 73. Much of this was related to Cyclone Dovi and Gabrielle in FY22 and FY23. Those events affected many networks; however, we need to consider that climate change-driven weather is likely to result in an increased number of major storm events. These need to be considered when reviewing network resilience, design standards and asset renewals. High winds were the main drivers of outages during adverse weather events (refer to Section 5.5.4), and reliability was affected by the time required to restore electricity due to the extent and severity of the network damage.

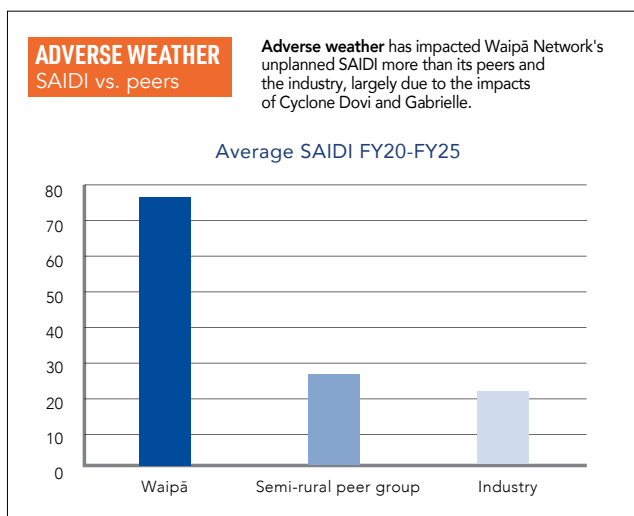
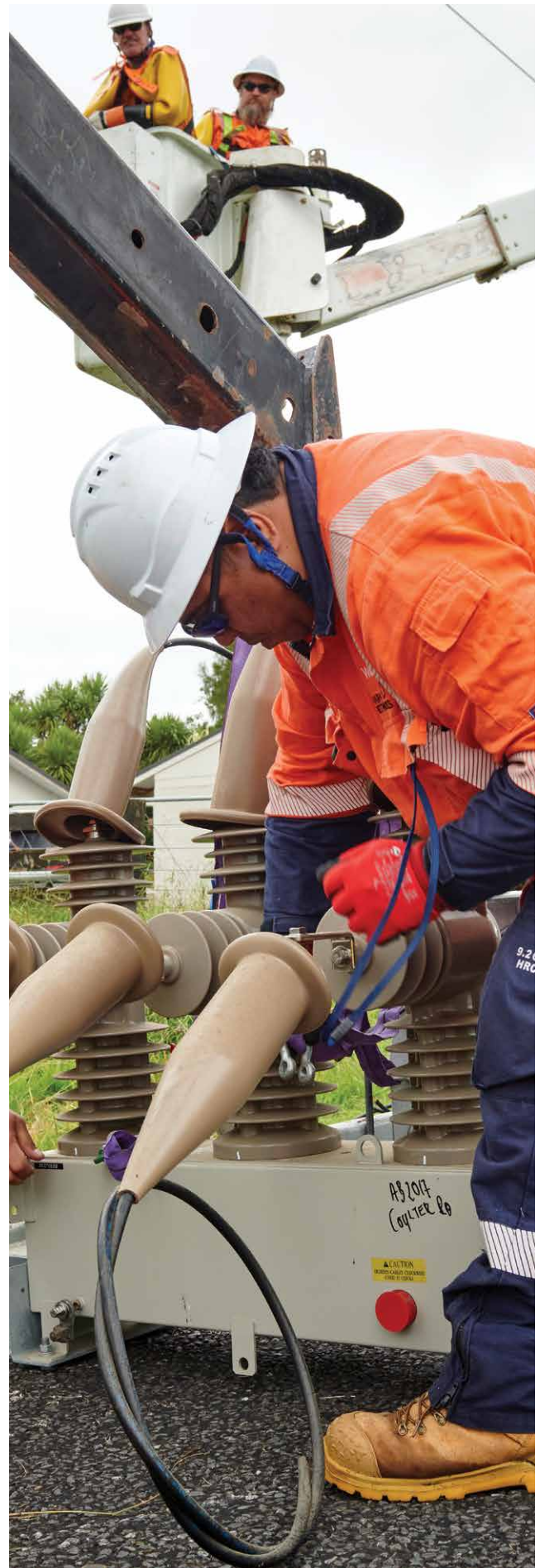


Figure 73: Adverse weather SAIDI vs. peers

Whilst we could suggest that FY20 to FY25 was just due to unfortunate circumstances, the impact of climate change means the risk of more severe weather events is rising. As reliance on electricity grows, ensuring our network is resilient to these events becomes increasingly important.

We are focused on improving resilience to ensure our network remains fit for purpose for decades to come. Our approach to improving resilience is outlined in our resilience strategy included in Section 8.4.



6.6 The need for greater asset management maturity

We have independently reviewed our asset management practices against the AMMAT questionnaire in Schedule 13 of the EDB information disclosures. The report on Asset Management Maturity is attached as an appendix to this AMP. The assessment covers all aspects of asset management, including strategy, communication, competency, documentation, structure, systems, and information. Figure 74 summarises the results of our asset management maturity assessment prepared for this AMP and provides a comparison to the industry.

Since our 2024 AMP, we have made improvements in contingency planning, communication, information and documentation.

Our current AMMAT indicates that in some areas of our asset management system, the system is fully developed, while in others, implementation is still ongoing and not yet fully integrated. Our AMMAT score of 2.6 is below the industry average of 2.8 and the upper quartile of 3.1. Most of these gaps relate to processes (some of which also require information and system improvements).

Our asset management maturity has historically been satisfactory during a period when our assets supported growth, showed limited signs of ageing, and customers were only beginning their energy transformation. However, improvement is now required to ensure we have the systems, information, and capabilities to manage the strong demand growth, the complexity of the energy transformation, the increasing threats from climate change, and our ageing asset fleet. We need to improve the quality of information, improve engagement with customers, consider a wider band of solutions, undertake more complex modelling and analysis, and operate within a more interconnected and complex electricity sector that is rapidly approaching.

These demands require us to reach a higher level of asset management maturity over the next three years. We have developed an asset management information plan to enhance our maturity, which is discussed in Section 9.6.

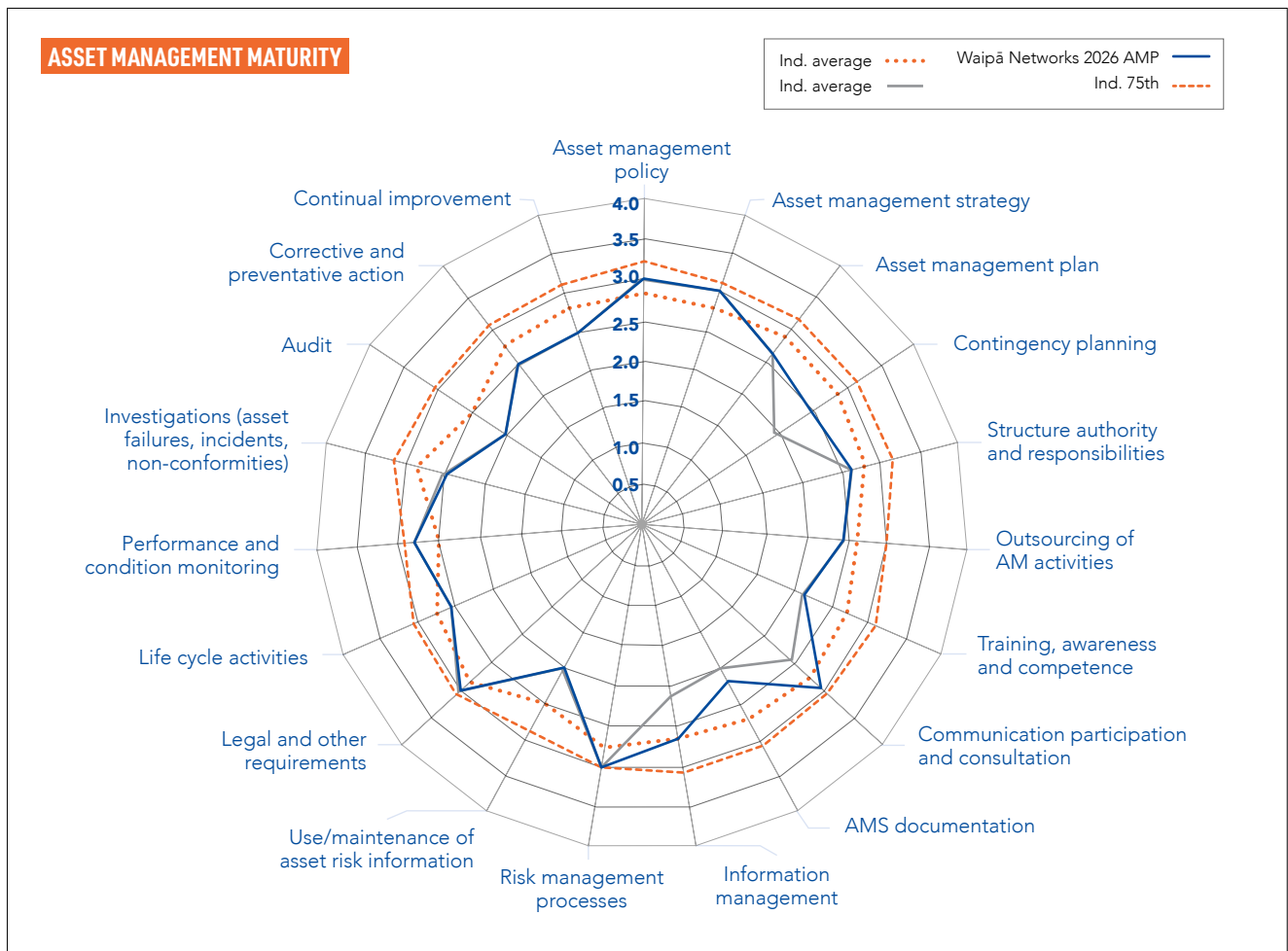


Figure 74: AMMAT summary results

PART 2:

OUR ASSET MANAGEMENT STRATEGY



7. ASSET MANAGEMENT POLICY, STRATEGY AND PERFORMANCE TARGETS

7.1 Introduction

This section outlines our Asset Management Policy, strategies, and performance targets that guide our asset management activities. The policy and strategy define the principles and objectives to guide the more detailed strategies and plans contained in Part Three of the AMP.

This AMP is a complex document, and we have also included a view of how all the strategies and plans within it support our overall objectives.

7.2 Asset management policy

We are committed to meeting the needs of current and future customers by providing a safe, resilient, reliable and cost-effective network that is sustainably managed.

Our Asset Management Policy sets out the principles that guide how we manage the electricity network. It outlines our commitment to responsible stewardship of our network assets.

The policy was reviewed and approved in February 2025 and sits alongside our Health and Safety Policy, Risk Policy, Environmental Policy, Procurement Policy and other key corporate policies.

Members of the Senior Leadership Team are accountable for resourcing and delivering the outcomes of the Asset Management Policy by:

- Setting and regularly reviewing the policy
- Monitoring and continually improving our asset management systems
- Monitoring and reporting proactively on investment plans, service performance, and risk.

The Asset Management Policy is reviewed by the Asset Management Subcommittee of the Board and approved by the Board. Appropriate reporting on investment plans, service performance, and risk is also provided to the Asset Management subcommittee and approved by the Board.

This AMP is crucial to delivering on our policy commitments.

Asset Management Policy



Purpose

At Waipā Networks Limited we are committed to meeting the needs of existing and future customers through the provision of a safe, resilient, reliable and cost-effective network in a sustainable manner. This asset management policy sets the principles for how asset management is applied at Waipā Networks Limited.

Scope

This policy applies to all employees, contractors and consultants involved in any activity regarding network assets. Our Asset Management Policy highlights the expectations from our Board of Directors and management regarding how we will make asset management decisions.

The policy

This policy sets out the key principles that link our strategic framework to our asset management objectives and direct our asset management activities:

- 1) **Safety:** We prioritise safety for our people, service providers and the public in all asset management decisions.
- 2) **Alignment to our company values and purpose:** Asset management decisions are aligned with Waipā Network's values of: Manākitanga, Kotahitanga, Tūturu, Excellence and Challenge. This ensures we obtain our purpose of "powering our community's success".
- 3) **Realising value for our customers and community:** We seek to realise value for our customers through balancing the opportunities, risks, desired performance and cost of our network assets over the long term. We will continually enhance customer satisfaction through engagement and informed improvements to our asset management practices.
- 4) **Capability and culture:** We maintain and enhance our asset management capability by recruiting, developing, and retaining great people and partnering with service providers that strengthen our capability. We instil a culture of Kotahitanga or 'an organisation act-as-one' to deliver our asset management objectives.
- 5) **Evidence based decision making:** Asset management decisions are evidence-based to optimise outcomes. We are committed to improving the quality of our asset and network data to ensure effective discussion.
- 6) **Future-focused:** We consider future challenges and opportunities, technological advancements, and changing demands to ensure our network, services, and asset management practices continue to meet our customers' changing needs.
- 7) **Risks:** We proactively identify, assess, and manage risks in accordance with our risk management framework.
- 8) **Innovative solutions:** We apply whole-of-system thinking to address the network's needs through well-coordinated planning, adoption of new technologies and tools, data-driven decision-making, increased customer engagement, and consideration of non-conventional solutions.
- 9) **Compliance:** All asset management activities comply with relevant laws, regulatory requirements, and company policies.
- 10) **Continuous improvement:** We will continually monitor the performance of the assets, the network and the business to calibrate our asset management decisions and strive to progressively improve the quality and consistency of our people, processes, and systems at all business levels.
- 11) **Collaboration:** We believe collaboration with our peers and partners, both within and outside our industry, will foster a greater outcome for the industry and our business. We will draw on the experiences and expertise of others to enhance our network and business. In turn, we will share our insights with the wider industry.

7.3 Asset management strategy

Our asset management strategy has been developed to respond to the evolving needs of our customers and the network, to enhance network performance, and to respond to the key factors driving investment and performance (discussed in Sections 3 to 6). The strategy supports the asset management objectives (discussed in Section 2) and provides the link between our corporate strategy and the detailed development, renewal, and improvement plans.

The strategic initiatives were included in the 2023 AMP and 2024 AMP. They were reviewed in the 2025 AMP update, which included some minor wording changes to enhance the scope of the strategic initiatives⁶⁴. We have added an additional customer engagement strategy, reflecting its growing importance in understanding customer needs, co-developing solutions, and building enduring relationships.

Our Asset Management Strategy comprises seven initiatives:

Initiative	In response to...
1. Enhance our customer and stakeholder engagement	<ul style="list-style-type: none"> Significant change in customers' energy needs The potential for co-designed solutions that have significant advantages over traditional network solutions alone.
2. Improve regional supply capacity and security	<ul style="list-style-type: none"> High population and demand growth across the network Future demand growth due to electrification The recent and forecasted growth on Te Awamutu's network, which is reaching the limits of regional capacity and capability of the 11kV-only network.
3. Develop and implement a network transformation roadmap to further prepare for decarbonisation	<ul style="list-style-type: none"> The central role electricity will play in meeting New Zealand's 2050 emissions reduction goal by enabling the widespread electrification of transport and industry Customers' future usage of the network, including enabling customers' adoption of new technology and ensuring that our network supports them, maximising the benefits of that investment New regulatory rules in relation to DERs and flexibility The opportunity that flexibility markets could provide as an alternative to capacity.
4. Improve the reliability and resilience of our network	<ul style="list-style-type: none"> The greater reliance on electricity as a single source of energy for our customers Our significant proportion of overhead network is exposed to increasing incidents and intensity of adverse weather The high number of incidents of third-party damage Ensuring our reliability targets are aligned to customer needs.
5. Maintain comprehensive fleet plans and renewal forecasts	<ul style="list-style-type: none"> Ageing of our asset fleet and the emergence of end-of-life drivers over the coming decades Increasing requirement for asset renewals and the need to optimise these to ensure spend is efficient.
6. Improve asset management maturity	<ul style="list-style-type: none"> A need to make quality decisions based on quality data The need to improve asset information gaps to support renewal optimisation Increasing business complexity that is associated with the energy transformation and how customers could use the network in the future.
7. Reduce the impact of vegetation on the network	<ul style="list-style-type: none"> Continued material impact of vegetation interference on reliability.

Table 28: Our asset management strategic initiatives

Pursuing these initiatives will require investment in network assets, information, systems, and people. We have outlined many of these investments in this AMP, but some of them have yet to be fully considered (and will be defined in future AMPs).

The extent and pace of investment will be optimised using customer engagement to inform future needs and trade-offs.

⁶⁴ Initiative one now includes the wording capacity and security. Initiative three now includes reliability and resilience.

Key actions that are aligned with the asset management strategy

The strategic initiatives guide our asset management activities in accordance with our asset management policy, customer strategy, and service standards. Table 29 shows the key actions that align with the strategic initiatives. These actions are included in the development plan (Section 11), the fleet plans (Section 13), and the asset management improvement plan (Section 9).

The strategic initiatives are long-term, with many actions progressing well. Recent achievements include:

- Improving supply capacity in Cambridge (initiative #2)
- Progressing the network architecture for Te Awamutu (initiative #2)
- Comprehensive fleet plans for our material 11kV asset classes were included in the 2024 AMP and drove the health and renewal forecasts in the 2025 AMP (initiative #5)
- The development of an asset management improvement plan, a summary of which is included in this AMP (initiative #6)
- Implementation of a new vegetation management strategy in FY24, and achieving our improvement targets in FY24 and FY25 (initiative #7).

Initiative		
1. Enhance our customer and stakeholder engagement	<p>Implement our customer and stakeholder engagement strategy and plans:</p> <ul style="list-style-type: none"> • Incorporate customer and stakeholder interests in setting performance targets and development planning • Incorporate customer and stakeholder interests in our energy trilemma balance • Undertake detailed customer engagement in the Kāwhia region as part of a place-based engagement pilot. 	<ul style="list-style-type: none"> • Section 3.3 and 3.4 • Sections 7.8 and 12 • Section 7.13 • Section 3.4 and 11.12.2
2. Improve regional supply capacity and security	<p>Ensure regional supply and security is appropriate to support future demand growth, including:</p> <ul style="list-style-type: none"> • The new Cambridge subtransmission network and Forrest Road substation have been commissioned and the feeder integration work completed • The network architecture for the supply to the Te Awamutu area • Preparing the new distribution architecture plan for the Te Awamutu area, with a pilot program underway for the Kāwhia area 	<ul style="list-style-type: none"> • Section 11 • Section 11.7 • Section 11.9 • Section 11.11 and 11.12
3. Develop and implement a network transformation roadmap to further prepare for decarbonisation	<p>Our network transformation roadmap is being prepared alongside the Te Awamutu architecture plan and includes:</p> <ul style="list-style-type: none"> • Implementation of an ADMS (in progress) • Developing our business model to engage with customers, other industry players and flexibility markets as these develop • Establishing our approach for enhanced network monitoring and DER management • Developing the tools and analysis to optimise network investments, including utilising non-network alternatives • Developing standards to improve resilience and minimise complexity, network risks and operating costs • Building people and system capabilities to support the transition. 	<ul style="list-style-type: none"> • Section 10 • Section 9.7.3 • Section 10.9 • Section 10.9 • Section 10.9 • Section 10.9 • Section 10.9
4. Improve the reliability and resilience of our network	<p>Ensure reliability and resilience meets current and future needs of customers:</p> <ul style="list-style-type: none"> • Developing and implementing an improvement in our RMMAT score to three in key areas, including finalising our contingency plans and operational management • Assessing natural hazard risk and increasing physical resilience of critical assets and vulnerable locations • Increasing the resilience of our asset design • Enhancing community support in areas where natural hazard risks are high • Improving the performance of the Kāwhia feeder and other worst performing feeders (our plans for Kāwhia are outlined in this AMP) • Implementing asset criticality grading. 	<ul style="list-style-type: none"> • Section 7.8 and 8.4 • Section 8.4 • Section 8.4 • Section 8.4 • Section 8.4 • Section 8.4 • Section 11.12.2 • Sections 9.6.3 and 13.4.2

Initiative		
5. Maintain comprehensive fleet plans and renewal forecasts	<p>Develop comprehensive risk-based fleet plans and renewal forecasts to better manage our asset fleet:</p> <ul style="list-style-type: none"> • Comprehensive health-based fleet plans were completed in FY24 for 11kV assets, and new fleet plans for the Forrest Road substation assets are included in this AMP • Prepare condition input data in Field Maps for key asset classes (this has been completed for some 11kV assets and the remaining scheduled for CY26 Q2) • Prepare asset criticality grades for all assets (in progress) • Transition from health-based to risk-based renewal forecasting. 	<ul style="list-style-type: none"> • Section 13 • Section 13 • Section 9.6.3 and 13.4 • As above • As above
6. Improve asset management maturity	<p>Improve asset management maturity to improve asset knowledge, asset management practices, and support quality decisions based on quality data:</p> <ul style="list-style-type: none"> • Prepare an asset management improvement plan (completed and a summary is included in this AMP) • Implement the process improvement and data improvement actions (in progress) • Develop the capability improvement initiatives in the next iteration of the plan. 	<ul style="list-style-type: none"> • Section 9.6 • Section 9.6 • Section 9.6.2 and 9.6.3
7. Reduce the impact of vegetation on the network	<p>Reduce the impact of vegetation on our network to address the continued material impact of vegetation interference on reliability:</p> <ul style="list-style-type: none"> • Revise the vegetation management policy and strategy in alignment with the new regulations (completed in July 2025) • Align inspection regime with asset criticality • Apply a risk-based approach, considering asset criticality, vegetation type and recent feeder reliability. 	<ul style="list-style-type: none"> • Section 13.24

Table 29: Key actions that support the asset management strategy

7.4 Coordinated strategies and plans

This is a large and complex document that includes a range of strategies and plans oriented to meet our overall asset management objectives, strategy, and policy. Figure 75 illustrates the various strategies and plans within this document (and key support plans). This illustration takes an asset management-centric view and excludes a range of other strategies and plans used across the wider business.



In the AMP

Primary strategy/plan	Purpose	Influence on performance	Section reference
ASSET MANAGEMENT STRATEGY	To define the high-level initiatives that guide asset management and influence other plans	<ul style="list-style-type: none"> Achieve our asset management objectives, corporate strategy and SCI 	Section 7
EFFICIENCY STRATEGY	To improve the efficiency of our assets and our expenditure	<ul style="list-style-type: none"> Improve asset efficiency Improve opex efficiency Improve load factor 	Section 7
RESILIENCE STRATEGY	To ensure the network is resilient to low-probability and high-consequence events	<ul style="list-style-type: none"> Major events have a lower impact on customers 	Section 8
ASSET MANAGEMENT IMPROVEMENT ROADMAP	To develop the Te Awamutu network to meet customer service, resilience and customer growth in a manner that is affordable with tolerable risk	<ul style="list-style-type: none"> AMMAT increases to Level 3 ID data accuracy improved to 3 or 4 for material assets 	Section 9
NETWORK DEVELOPMENT PLANS	To ensure the network meets capacity, security, reliability, hosting capacity, and future needs in an efficient manner	<ul style="list-style-type: none"> Can connect customers and meet their reliability, capacity and network needs 	Section 12
TE AWAMUTU ARCHITECTURE REVIEW	To ensure the optimal future development of the Te Awamutu region (across customer service, resilience and serving new growth)	<ul style="list-style-type: none"> Can connect customers and meet their reliability, capacity and network needs 	Section 12
ASSET FLEET PLANS	To maintain the health and risk ratings of the assets	<ul style="list-style-type: none"> Assets health and risk ratings meet fleet strategy tolerances Reliability meets target 	Section 13
ENERGY TRANSFORMATION ROADMAP	To prepare for the energy transformation and enable customers to benefit from the transformation	<ul style="list-style-type: none"> Meet customers future needs Lower overall energy costs for customers 	Section 10
DELIVERY PLAN	To provide the resources to deliver the AMP	<ul style="list-style-type: none"> Cost effective delivery of the field work 	Section 14
CUSTOMER & STAKEHOLDER ENGAGEMENT STRATEGY	To provide customer and stakeholder views on the price-quality trade-off, their future needs, and that views on major initiatives	<ul style="list-style-type: none"> Ensures our plans meet customer needs 	Overview presented in Section 3
INFORMATION SYSTEM STRATEGIC PLAN	To develop systems and data to support asset management	<ul style="list-style-type: none"> Improve data maturity Improve process efficiency Maintain quality/compliance 	Overview presented in Section 9
RISK MANAGEMENT FRAMEWORK & PLANS	To reduce the risk of asset management objectives and performance not being met	<ul style="list-style-type: none"> Reduction in business risk 	Overview presented in Section 8
HEALTH & SAFETY STRATEGY	To ensure the health and safety of our people, contractors and the public	<ul style="list-style-type: none"> Reduction in safety risk 	Overview presented in Section 8

Figure 75: Coordinated planning

7.5 Efficiency strategy

Ensuring the efficiency of our assets and operations is a key focus for Waipā. We have defined four principles and practical commitments focused on affordability, enablement, efficiency, and improved customer outcomes. These are:

- 1. Affordability through discipline and efficiency:**
We will pursue cost efficiency and productivity improvements that reduce duplication and keep downward pressure on the total cost to serve, while protecting reliability and safety outcomes.
- 2. Enablement of electrification and customer choice:**
We will support customer and business electrification by improving the consistency, transparency and value of customer-facing processes, and by planning for growth in a way that avoids unnecessary cost.
- 3. Efficiency through collaboration and shared services where it benefits customers:** We will participate in shared services and collaboration initiatives where the business case shows net customer benefit and reflects recognised best practice.
- 4. Standardisation of customer-facing processes to best practice:** We support standardisation around customer-facing processes (including connection processes) where it improves customer outcomes, and supports consistency across regions, and aligns it to best practice.

Our actions to improve asset efficiency and its impact on cost-to-serve include:

- Establishing planning horizons that are suitable to ensure that assets are efficiently sized and commissioned at the required time to meet expected demand (our planning horizon is discussed in Section 11.4.2)
- Increasing our focus on using a blend of traditional network and non-network solutions to deliver resilience and optimise capital investment (refer to the Te Awamutu architecture review in Section 11.9 and subsequent development plans)
- Co-designing solutions with customers to improve outcomes, which will likely lead to greater uptake of non-network solutions that could share benefits with customers
- Optimising line design to achieve capacity and voltage requirements utilising optimal conductor sizing and pole spacing

- Optimising the distribution transformer capacity, including considering future demand requirements and power factor requirements when selecting new or replacement distribution transformers
- Improving our engagement with customers to ensure our assets are right-sized for customer needs
- Implementing time-of-use-pricing that incentivises the use of energy at lower demand (off-peak) times to minimise peak demand and to improve our load factor. Refer to our pricing roadmap⁶⁵
- Standardisation of equipment and materials. This enables training, spares, and purchasing scale efficiencies (refer to Section 12.3.3)
- Purchasing processes that seek to make efficient purchasing decisions (refer to Section 12.3.4)
- Increasing our standard export capacity for DERs to 10kW, which will enable customers to more simply and efficiently increase the use of DERs
- Optimising vegetation management vs. risk (refer to the fleet plans in Section 13)
- Optimising our asset renewal vs. risk (refer to the asset renewal strategy in Section 13.24)
- Our recent investment in the Hautapu GXP has created capacity and operational flexibility that could extend beyond our own network. This could enable practical regional solutions that can materially reduce the need for future transmission and distribution augmentation. Early analysis indicates that these coordinated solutions could avoid or defer future transmission and GXP investments.

Our actions to improve operating efficiency and its impact on cost-to-serve include:

- Outsourcing of our control room and associated ADMS support to exploit economies of scale and resourcing for major event management (refer to Sections 9.4.8 and 9.7.3)
- Improved delivery efficiency by grouping of works
- Improved delivery efficiency standardisation
- Evaluation of shared services. This is in its early stages.

7.6 Overview of our performance targets

Our performance level targets cover all relevant aspects of asset management and include:

- Safety performance
- Network customer service
- Customer satisfaction (included in Section 3.10)
- Network reliability and quality
- Asset utilisation and efficiency
- Work delivery
- Environmental performance.

We have targets for our asset management maturity. These are included as part of our Asset Management Improvement Plan presented in Section 9.

These performance measures align with our Statement of Corporate Intent, stakeholder requirements, business strategy, and the asset management objectives set out in Sections 2 and 3. Our asset management strategies are designed to enable us to achieve our targets, reduce performance volatility and deliver improved customer service.

We present the targets and discuss how they were set in the following sections. Our performance against these targets is discussed in Section 5.

⁶⁵ <https://waipanetworks.co.nz/partners/retailers/pricingroadmap/>

7.7 Safety performance targets

Our safety performance targets (shown in table 30) support our Safety Strategy and plans as presented in Section 8. These measures cover our asset management responsibilities and provide a good indication of our safety performance.

We have moved to a leading indicator approach to setting health and safety targets. While we still record TRIFR, we do not report this. We will align our reporting against these measures in the 2027 AMP.

Key performance indicator	Type	Target FY25	Target FY26	Target FY27	Target FY28	Target FY29-31
Number of safety observations	Leading	420	420	420	420	420
Number of worksite safety audits	Leading	288	288	288	288	288
Public safety compliance	Leading	Compliant	Compliant	Compliant	Compliant	Compliant
Number of serious harm injuries ⁶⁶	Lagging	Nil	Nil	Nil	Nil	Nil

Table 30: Health and safety measures

We will investigate the cause of any injury to eliminate or mitigate future risks.

7.8 Network customer service targets

Providing a reliable network service is a core part of our customer service strategy. Our network customer service targets assess the overall reliability of the network using industry-standard metrics.

- SAIDI (System Average Interruption Duration Index) quantifies the average total duration that a customer experiences power outages. SAIDI indicates the mean length of time customers are without electrical service due to interruptions.
- SAIFI (System Average Interruption Frequency Index) measures the average number of power outage occurrences per customer. This provides insight into the frequency of service interruptions rather than their duration.

We separate the SAIDI and SAIFI targets into planned and unplanned categories. Planned outages happen when work is done on the network, with notice given to customers in advance. This gives customers the chance to adjust their plans and minimise the inconvenience. Unplanned outages are unexpected and often occur due to adverse weather, vehicle damage, vegetation, wildlife, or equipment failure. These can be more disruptive since they occur without warning.

Table 4 shows our network customer service targets for FY25, FY26 and the next five years. Since FY21, we've adopted the Commerce Commission's DDP3 methodology to set our reliability targets, enabling better comparison and benchmarking against other EDBs subject to price-quality regulation. This process used normalised reliability

data, which involves adjusting reliability data to remove the impact of major events beyond EDBs' control. This ensures that performance metrics, such as SAIDI and SAIFI, reflect the network's underlying reliability rather than being skewed by rare, high-impact events, such as severe storms or natural disasters.⁶⁷

Whilst we have adopted a shadow regulatory reliability target, we will give greater consideration and weight to customer feedback on reliability to ensure the targets remain appropriate. This will be informed by our enhanced customer engagement process (as mentioned in Section 3.7). This information will provide a stronger basis for assessing future customer needs and determining whether our reliability targets remain appropriate. We will also be assessing what future measures may provide additional insight to improving the customer experience. This work has the potential to significantly change the way we view reliability and how we prioritise improvements. The goal of this work is to improve the reliability of all customers to an appropriate level. As customers decarbonise their energy needs, reliance on electricity will continue to grow, therefore it is important that we consider measures that will continue to adapt to meet the future needs of our customers.

The current view from customers indicates that most are comfortable with maintaining the current price-quality trade-off and have a positive or neutral view on current reliability (refer to Section 3.5.2 and 3.5.3).

⁶⁶ Serious harm is defined as a notifiable event under the Health and Safety at Work Act guidelines published by WorkSafe NZ.

⁶⁷ https://www.comcom.govt.nz/assets/pdf_file/0027/363285/EDB-DPP4-Final-decision-Reasons-paper-Attachment-E-Setting-quality-standards-and-incentives-20-November-2024.pdf

Network customer service targets	Target FY25	Target FY26	Target FY27	Target FY28	Target FY29	Target FY30	Target FY31
SAIDI unplanned	109.3	109.3	109.3	109.3	109.3	109.3	109.3
SAIFI unplanned	1.73	1.73	1.73	1.73	1.73	1.73	1.73
SAIDI planned	126.2	126.2	126.2	126.2	126.2	126.2	126.2
SAIFI planned	0.48	0.48	0.48	0.48	0.48	0.48	0.48

Table 31: Network customer service targets

Note: the measurement of planned SAIDI and SAIFI is on the sum of the five years from FY26 to FY30.

Figure 76 shows our forecast of average performance over the next 10 years, assuming the same instances of external events (e.g. major storms, vehicle damage and vegetation) and implementing the planned reliability and security improvements. This provides a view of the ongoing risk to reliability while we implement the planned improvements.

Consistent with our asset management strategy (in particular, strategic initiatives 2, 4, and 7), we have estimated the improvement in unplanned SAIDI that could result (refer to figure 78). In an average year, these are estimated to provide a 35 SAIDI improvement, resulting in a 50% probability (P50) of achieving the target by FY31 and a 75% probability (P75) by FY36. Modelling reliability improvements is a complex exercise, and this is the first year we have disclosed a forward view of improvements. We will be refining our estimates over the next year, which may alter our view in the 2027 AMP. Our view on whether targeting P50 or P75 (or another probability) is appropriate will also be informed by our customer engagement.

Our planned work is increasing, which will put pressure on our planned work targets, as we are holding these constant. We are focused on ensuring that our planned outages are coordinated to minimise the impact of the increase in work volume. Given the increase in work volume, this is an ambitious goal, and we will continue to evaluate over the next couple of years.

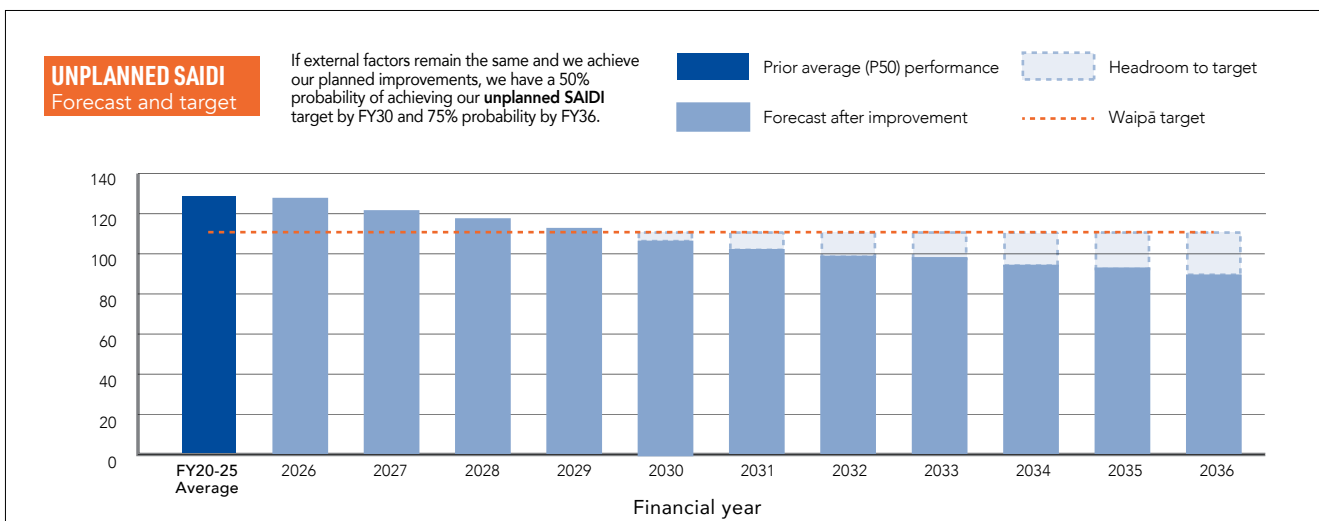


Figure 76: Unplanned SAIDI forecast and target

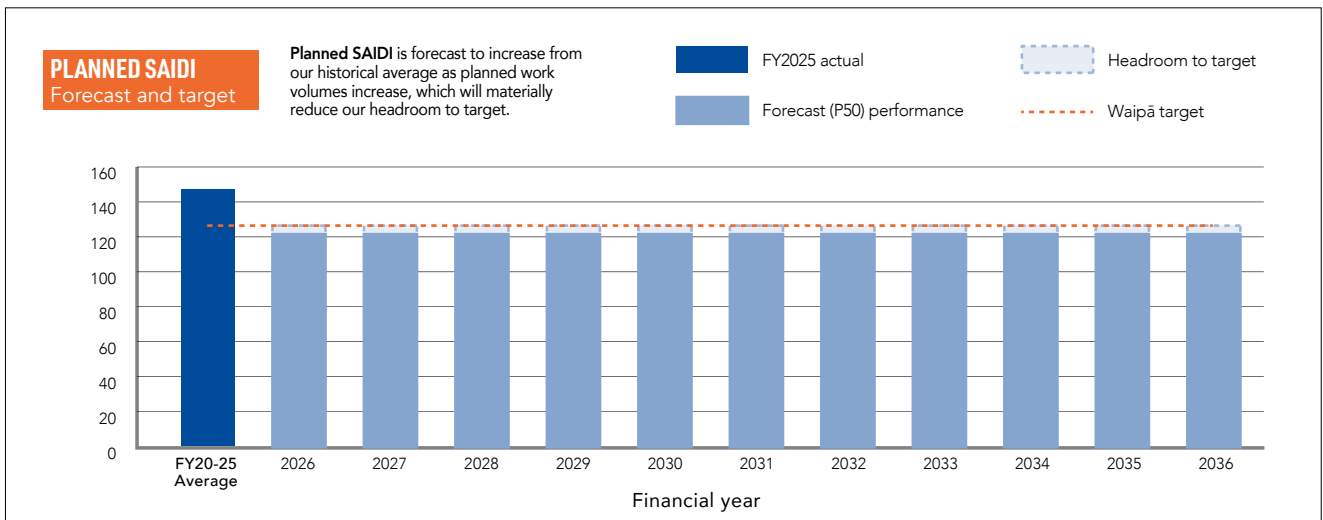


Figure 77: Planned SAIDI forecast and target

The programmes and projects that have been included in the improvement forecasts are:

- Improvements in relation to the Kāwhia feeders, which are still at the concept phase (refer to Sections 11.12.2 and 11.12.3)
 - Improvements on other worst-performing feeders (refer to table 23 in Section 5.5.9)
 - The security improvements resulting from the addition of the four new feeders from the Forrest Road substation (refer to Section 11.8.2)
 - The reduction in vegetation outages from our vegetation management strategy (refer to table 32 and Section 13.24)
 - An initial estimate in relation to the reliability benefits that will arise from the Te Awamutu architecture review and subsequent projects (refer to Sections 11.9 and 11.12)
 - An initial estimate of the benefits from resilience improvements (refer to Section 8.4)⁶⁸.
- Other benefits from future work on third-party damage and extended-duration outages are not yet included.

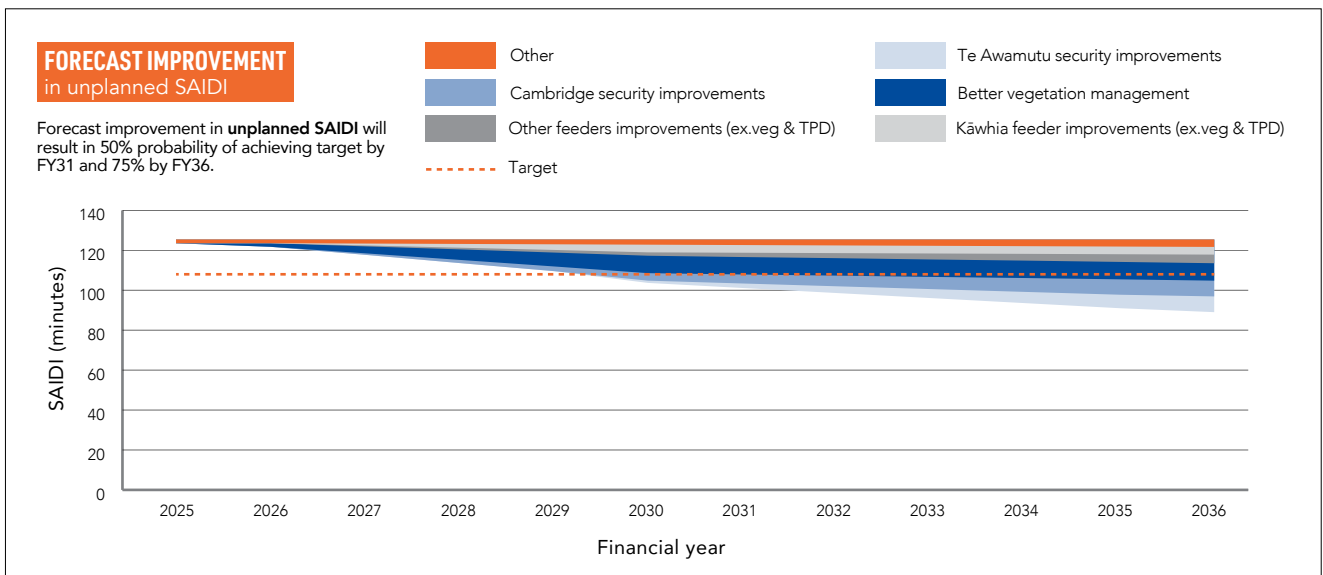


Figure 78: Forecast of SAIDI improvements

As noted in Section 5, our reliability issues are generally related to SAIDI, and the probability of achieving our SAIFI target is significantly higher and will improve with the programmes mentioned above.

⁶⁸ Resilience improvements are important; however, there improvement on our normalised reliability will be smaller than other initiatives as they target low-probability high-consequence events that are more likely to be normalised.

Case Study: Why we didn't reset our unplanned reliability target from FY26

Reliability targets for regulated EDBs were reset from FY26 (for the next five years). We evaluated resetting our targets but have retained our prior targets for FY26 as a reset would have led to a deterioration in the target.

The deterioration in the target (if we reset it) was due to the higher proportion of poor performance over the past five years. The poor performance was primarily driven by adverse weather conditions, largely caused by Cyclones Dovi and Gabrielle.

We believe that increasing our targets (i.e. targeting a lower performance) is not appropriate as our:

- SCI statement states that we're committed to providing a safe, reliable and cost-effective network
- In our most recent customer perception survey, when customers were asked about electricity use and future infrastructure, reliability of supply was the highest-ranked electricity feature (refer to Section 4.4)

- In our most recent customer perception survey, most customers were satisfied with our reliability performance. We believe their perceptions were informed by the good performance in FY24 and were not impacted by the reliability during the Cyclones in FY22 and FY23
- The regulatory purpose of the regulated quality targets is to ensure that there is no material deterioration in reliability.

7.9 Network reliability and quality target

7.9.1 Network reliability targets

We undertake detailed reliability monitoring to ensure that we meet our network customer service targets (presented in Section 7.8). The detailed performance monitoring uses RAW reliability data (i.e., excluding normalisation for major events). Customers experience all types of outages, so we must understand how each type of outage impacts our overall performance.

The targets in this section either reference our peer group or aim to improve performance compared to a historical average. These benchmarks will evolve as we understand customer needs better. We are monitoring trends in performance, rather than assessing a single year, as external factors can have a material impact on performance in any particular year. We haven't yet completed all our analytical work or considered customer views to set targets in all areas. We are looking to complete this work over the next year.

As above	Unit	Average FY23-25	Target FY26	Target FY27	Target FY28	Target FY29	Target FY30	Target FY31
Unplanned SAIDI vs. peers	SAIDI	Better	Better than the semi-rural peer group average					
Unplanned fault rate vs. peers	Faults/100km	Better	Better than the semi-rural peer group average					
Defective equipment SAIDI vs. peers	SAIDI	Better	Better than the semi-rural peer group average					

Table 32: Network reliability targets⁶⁹

7.9.2 Power quality

Our target for power quality is to meet statutory requirements and adhere to good industry practices. This includes:

- Meet the minimum of statutory levels or agreed terms for supply voltage
- Endeavour to limit flicker to levels specified by AS/NZS 61000.3.7:2001
- Endeavour to limit harmonics to levels specified in ECP 36:1993 and AS/NZS 61000.3.2:2013
- Target an overall power factor greater than or equal to 0.95 lagging at times of high load on our network and require that all ICPs meet this requirement.

Our monitoring of these targets is on a by-exception basis. That is, we investigate and resolve power quality issues as soon as these are identified through our SCADA, network monitoring or customer notification.

⁶⁹ These use raw SAIDI. Normalised peer group comparison and detailed cause analysis is not possible using normalised data.

7.9.3 Review into future reliability measures

SAIDI and SAIFI are important measures and, as such, are the two most widely reported distribution reliability indices globally. These two measures will remain to form the basis of our reporting, particularly regulatory reporting. However, SAIDI and SAIFI, used alone, can drive improvements in urban, high-density areas where reliability may already be adequate for customers' needs.

As part of our new customer engagement process, we will be investigating whether we can improve our network customer service measures. We are currently exploring how we measure reliability and what measures will inform and drive improvements in a DER-enabled network and a customer-focused business.

Customer satisfaction is typically non-linear with respect to electricity availability; therefore, identifying and addressing customers who have an experience that does not meet expectations with respect to electricity availability is more important than further improving customers who already have an acceptable experience.

7.10 Asset utilisation and efficiency targets

7.10.1 Efficiency

We are working on improving how we understand and communicate the efficiency of our network and operations. Efficiency in the electricity distribution context broadly relates to how effectively resources, including capital investment and operating expenditure, are used to deliver outcomes for customers.

This work is still developing and requires further refinement before detailed performance measures are disclosed. Future AMPs are expected to include clear efficiency indicators and trend analysis once we have developed measures that drive real improvement and enable clear communication. At this stage, the emphasis is on embedding efficient decision-making within our planning processes, improving how we design and deliver works, and strengthening transparency around the drivers of cost and performance.

Our approach will differ from the Total Factor Productivity (TFP) used by the CEPA in their work for the Commerce Commission⁷⁰. Our view is that TFP is not the appropriate measure as it is too complex for us to implement internally and communicate clearly to our customers. TFP is a macroeconomic concept used to measure the productivity of an economy or a large system after controlling for labour and capital growth. This approach differs from efficiency, which is a more holistic measure focused on how well resources are used to achieve a specific outcome.

7.10.2 Asset utilisation

We are assessing how asset utilisation will change in a DER-centric network. In particular, how solar production will offset demand in the middle of the day and has the potential to drive reverse power flow. It is possible that rather than being a performance measure, we may use it to determine the type of solution recommended.

7.10.3 Load factor

The load factor for an electricity network measures how efficiently customers utilise the network. It is calculated by dividing the total amount of electricity (kWh) delivered over the network in a year by the product of the maximum demand (kW) and the total hours in the year. A higher load factor indicates that the network is being used more consistently (and hence efficiently), reducing the need for costly infrastructure upgrades and making better use of existing assets. Conversely, a low load factor can signal underutilisation and higher costs per unit of electricity delivered. As stated in our 2024 AMP, load factor is no longer a key performance measure for our network.

7.10.4 Loss ratio

The loss ratio measures the ratio of kWh lost on the distribution network to kWh injected into our network from the GXP's per year. Lost units differ between metered sales to customers, metered purchases at each Transpower GXP, and distributed generation supplied to our network.

Losses are physical losses (heating of distribution assets), unmetered supply and theft. Losses are difficult to measure accurately because all unit sales through retailers' meters need to be read instantaneously at year-end to calculate the difference between energy conveyed and energy sold. Currently, only time-of-use meters in customers' installations can supply the required data accuracy.

The loss ratio target has been set at 5.7% to match recent historical performance. Increased levels of smart meter installations appear to reduce losses as smart meters improve reconciliation accuracy.

Table 33 shows our target for the loss ratio. The loss ratio depends on the physical aspects of our network equipment and configuration, and changes if there is a change in the relative utilisation of the parts of our network or its configuration. We are also considering how generation and batteries might be used to improve our network losses.

Network customer service targets	Target FY25	Target FY26	Target FY27	Target FY28	Target FY29	Target FY30	Target FY31
Loss ratio	<5.7%	<5.7%	<5.7%	<5.7%	<5.7%	<5.7%	<5.7%

Table 33: System losses targets

⁷⁰ https://www.comcom.govt.nz/assets/pdf_file/0033/356757/CEPA-EDB-Productivity-Study-A-report-prepared-for-the-Commerce-Commission-24-June-2024.pdf

7.11 Work delivery targets

We have developed a range of work delivery measures, as shown in table 34. These measures reflect realistic delivery expectations. Over time, we expect the delivery strategy (in Section 14) to improve the target variance to <5% across all measures.

Category	Variance target FY24-FY25	Variance target FY26+	Commentary
Network capex, excluding customer connections	<15%	<15%	A higher variance is being allowed in the targets due to the influences of consenting on project timelines.
Customer connection capex	–	–	No target, as these vary due to customer demand.
System interruption and emergency opex⁷¹	<5%	<5%	This target excludes major weather events that can cause significant variation in fault costs.
Network maintenance and inspections opex⁷²	<5%	<5%	Our target is to achieve practical completion for inspection, planned maintenance, and refurbishment. Some variation can be expected due to land access requirements for some inspection and maintenance work.
Vegetation management opex	<10%	<10%	We have a higher variance for vegetation management, as these costs can vary due to weather events.
Major project expenditure	<15%	<15%	A higher variance is being allowed in the targets due to the influences of consenting on project timelines.
Asset condition assessments	>95%	>95%	We are seeking to completion inspections on 95% of our assets within the inspection cycle. We have set a realistic target as there are external factors that can delay access to assets.

Table 34: Specific works delivery measures

7.12 Environmental performance targets

We will ensure that everything we do manages resources sustainably and that we work with mana whenua, key stakeholders, and the community to preserve and restore our planet now and for future generations. Our stakeholder consultation is presented in Section 3.

We are developing a framework to monitor our environmental performance, and additional measures will be added in the 2027 AMP. Table 35 shows our current environmental performance targets. Our SCI includes additional environmental performance targets.⁷³

Network customer service targets	Type	Target FY25	Target FY26	Target FY27	Target FY28	Target FY29	Target FY30	Target FY31
Number of environmental incidents	Lagging	Nil	Nil	Nil	Nil	Nil	Nil	Nil

Table 35: Environmental performance targets

⁷¹ Excluding major events.

⁷² Reactive and corrective maintenance and inspection, and asset replacement and renewal opex.

⁷³ <https://waipanetworks.co.nz/wp-content/uploads/2025/06/Waipā-Networks---SCI-2025-FINAL.pdf>



7.13 Our role towards a sustainable future

We understand we have a key role in enabling our region's transition to a sustainable future through electrification, and we are starting to prepare for this role.

Managing infrastructure assets requires considering a range of factors. Ensuring our services support New Zealand's efforts towards a decarbonised and sustainable future, understanding and delivering the future security and resilience levels expected by our customers, and ensuring a just and fair energy transition for all customers are material issues for the business and our industry. The transition to a low-emissions New Zealand will take time; we must clearly understand how best to support the areas we service.

Addressing these factors requires consultation, information, innovation, and good decision-making. This AMP is the first step in explaining how we consider these factors.

7.13.1 Framework

The Energy Trilemma⁷⁴ is a well-recognised and useful framework (see figure 79) when considering the energy transition. We have referenced this framework as it is aligned with how Central Government (and related agencies, such as the Climate Change Commission, MBIE and Electricity Authority) are considering energy strategy. It is also a core part of the terms of reference for developing NZ's Energy Strategy.

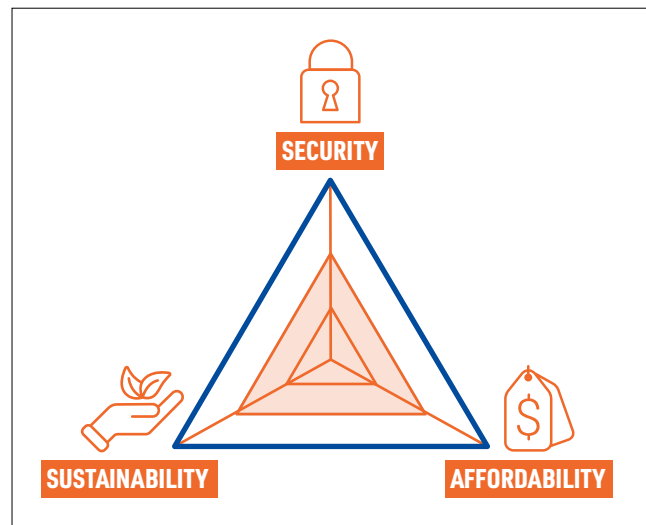


Figure 79: The energy trilemma

In the energy context, the three limbs refer to:

- **Sustainability:** meaning the ability to support New Zealand's energy transformation, minimise emissions, and adapt to climate change.
- **Security:** meaning the ability to meet current and future energy demands reliably, as needed by our customers, including being resilient to external events.
- **Affordability:** meaning the cost of, and access to, energy (of which electricity is an increasingly important component).

⁷⁴ Source: World Energy Council.

7.13.2 How we are considering the factors

Figure 80 illustrates our initial assessment against the three limbs of the energy trilemma framework. This assessment indicates our current view on the direction of travel over the 10-year horizon of this AMP and is in the following order of consideration:

Sustainability is expected to improve as New Zealand moves towards a sustainable and electrified future⁷⁵. This will be supported by the asset management initiative discussed above:

- #1 (customer engagement)
- #2 (regional security)
- #3 (energy transformation).

This is also backed by our core investment into our people and systems in initiative #6 (asset management maturity) to manage the increasing complexity from energy transformation.

Our customers expect improvements in security and reliability. As dependence on electricity grows, we expect our customers to require a more secure and reliable supply. We will engage with our community to better understand and define our customer service level expectations now and in the future. This is on the back of investments to support asset management initiatives #1 (customer engagement), #2 (regional security), #4 (resilience), and #7 (vegetation).

Electricity distribution costs will likely increase, but overall energy affordability should improve. Therefore, we must ensure a just and fair energy transition for all customers. Improving sustainability and security simultaneously will require considerable investment in the network.

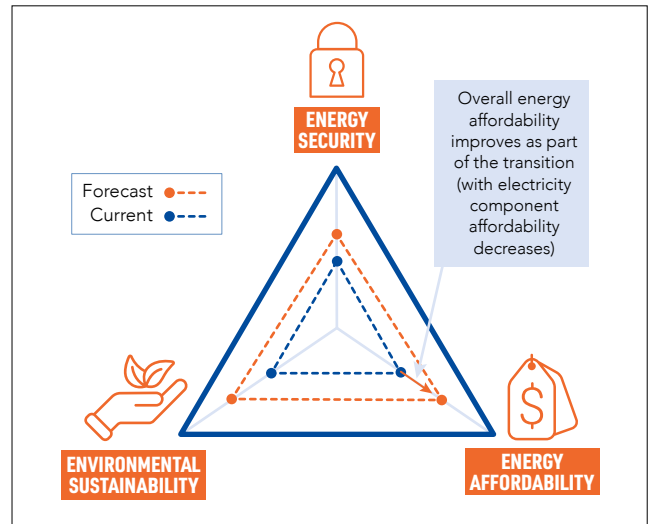


Figure 80: Assessment against the energy trilemma framework

Increasing investment will lead to an increased cost of electricity supply. While the cost of electricity may increase, the overall energy affordability should improve because of electrification⁷⁶. We must ensure that transitioning to a low-emissions economy is just and fair for all customers. This will include non-asset and/or non-network initiatives to help alleviate energy hardship, targeting those customers who require support.

In summary, we anticipate that, in the future, customers will experience lower overall energy costs, with a higher electricity component, and a more secure and resilient network.

⁷⁵ Report by Boston Consulting Group "Climate Change in New Zealand: The Future is Electric" <https://www.bcg.com/publications/2022/climate-change-in-new-zealand>

⁷⁶ Assessed by Sapere in their recent report for Electricity Networks Aotearoa <https://www.ena.org.nz/news-and-events/news/total-household-energy-cost-to-reduce-over-time/>



PART 3:

IMPLEMENTATION PLANS TO DELIVER THE STRATEGY AND THE REQUIRED PERFORMANCE

8. RISK MANAGEMENT

8.1 Introduction

In this section, we describe our risk management framework, outline our material risks, and summarise our risk reduction, readiness, response, and recovery plans.

We have initiated a significant strategy (asset management strategy #3) to increase the network's resilience to natural hazards and other hazards. Our resilience strategy is described in this section.

8.2 Risk management framework

8.2.1 Our risk context

Risk is the effect of uncertainty on objectives.⁷⁷ We operate in an inherently uncertain environment, and as we undertake business activities, there is a chance we will not achieve the originally intended results. The effect of this uncertainty may be positive or negative in nature.

In risk management, uncertainty exists where knowledge of an event, its likelihood, or its consequences is incomplete. All of our business activities involve risk, and those risks should be identified and managed in line with our risk tolerance.

In the context of this AMP, electricity is a hazard, and its conveyance has associated safety risks. The electricity network is also exposed to risk (from natural and other hazards). Managing these risks is essential to achieve our asset management objectives and to manage our business risk to a tolerable level.

8.2.2 Risk management process

We have adopted a systematic approach to risk management following the Australian/New Zealand standards ISO 31000:2019 Risk Management and NZS 7901:2014 Electricity and gas industries – Safety management systems for public safety.

Figure 81 shows the risk management process. We updated our Risk Management Policy and Risk Management Framework in FY2024.

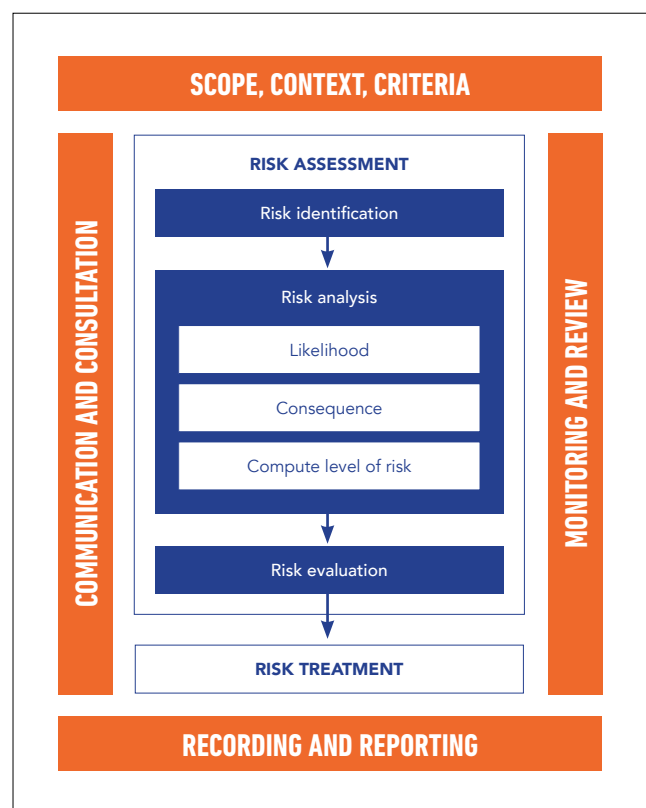


Figure 81: Risk management process

⁷⁷ As defined in AS/NZS ISO 31000:2018.

8.2.3 Risk scope, context and criteria

Our risk management process applies to the entire Waipā Networks business, including the network. Our consequences (risk categories) are:

- Health and safety, including public safety
- Environmental
- Stakeholder and community confidence and reputation
- Cultural
- Financial (impact on business cash flow)
- Operational: These are risks that impact the ability of the network to meet demand, respond to growth, or maintain a reliable supply of electricity
- Compliance.

We have developed probability and likelihood criteria for each risk category based on the impact it could have on our business.

We also established risk tolerances that are acceptable to the business for each risk category. These range from open (i.e., willing to take an innovative approach that may carry a high inherent risk but will not have a material impact on the business) to adverse (where we aim to eliminate the risk or implement the most effective controls to reduce it to an acceptable level).

8.2.4 Risk identification

Our risks are identified by a variety of methods, including:

- On-site checklists before starting work (tailgates)
- Work site reassessments during the day as our work environment changes
- Regular visual hazard inspections of work areas
- Root-cause analysis of accidents/incidents or near misses
- Asset condition assessment for the likelihood of asset failure (for which public safety hazards would feature, and potentially other hazards such as loss of supply, financial loss and environmental hazards)
- Defect notification
- Risk workshops and management review
- External risk reviews and audits
- Industry information and external information from specialists (e.g. equipment hazards reported by other EDBs).



8.2.5 Risk analysis and evaluation

We assess all risks to identify the inherent risk by identifying the likelihood of an event occurring and its associated consequence, which involves:

- Identify the source and cause of the risk
- Assess current controls and their effectiveness and identify any gaps
- Consider how likely the risk is to occur and the impacts (likelihood and consequences) and determine the risk rating (likelihood x consequence) based on our corporate risk criteria and matrix to analyse risks. This categorises likelihood into five categories (rare to almost certain) and consequence into five categories (low to severe). This analysis is performed on the inherent (uncontrolled) risk and then again on the residual (controlled) risk.

Our risk profile is mapped onto a risk matrix, allowing us to identify which risks exceed our risk tolerance. Where necessary, we:

- Communicate the risk to the appropriate reporting levels
- Consider options for implementing additional treatments (e.g. additional risk controls) to reduce the risk to an acceptable level
- Prioritise, resource and allocate responsibility for treatment and ongoing management.

8.2.6 Risk treatment

Risks are treated either through elimination or through the application of controls to reduce their likelihood and/or consequences. We seek to put rules in place that will reduce risk tolerably. Treatments may avoid, transfer, reduce, remove, modify, or accept the likelihood and/or consequence of risk(s) for non-health and safety-related risks. Non-health and safety risks may be treated in a variety of ways.

Some examples of controls include:

- Policies, systems, and processes
- Improving plant and equipment or redesigning the equipment or construction methodology
- Applying new or different technology
- Training and education, including tailgate sessions
- Inspections and testing or adjusting the type or nature of inspections and testing.

Under the Health and Safety at Work Act 2015, when determining the appropriate control to manage a health and safety-related risk effectively, and to conform to our health and safety policy, a specified sequence of rules is followed. Our Health and Safety Management System includes the health and safety risk management details.

8.2.7 Risk monitoring and review

Routine monitoring of risks, the effectiveness of controls, and the implementation of treatments. This process assures that the controls in place are being implemented and remain effective.

We have a proactive approach to public safety and safety for our staff, contractors, and customers. Work on the network is regularly reviewed by our senior management. These reviews focus on ensuring that the controls in place are effective and efficient.

Regular surveillance and monitoring related to safety are conducted concerning network assets, including ongoing measurement of line heights, inspections of substations and pillar boxes, and aerial and ground surveillance of lines and vegetation near our lines. Network inspection criteria and planned maintenance procedures prescribe the standards for network survey activities.

Serious incidents and near misses are investigated following the recognised incident cause analysis method (ICAM) to identify the cause and better enable their prevention in the future.

The importance of leading and lagging safety indicators is recognised within our business, emphasising proactivity (informed by lead indicators).

8.2.8 Communication and consultation

Risk evaluation and communication are integrated within our daily operations and processes, including Board meetings, Health and Safety Committee meetings, Senior Leadership weekly meetings, team meetings, training, visitor and employee induction, inspections, etc., where appropriate specific meetings are held with industry groups.

8.2.9 Recording and reporting

Different types of risks are held in respective registers. A common assessment methodology is used, as set out in our Risk Management Framework.

8.2.10 Responsibilities for risk management

We are in the process of improving responsibility and accountability for risk management. We intend to assign risk responsibility across the business more formally, based on potential severity. Significant (what we call Tier 1 risks) are assigned to the Senior Leadership Team. Lower-level risks will be assigned to an appropriate manager within the business, and the review of Tier 1 risks and their associated treatment will be provided to the Board twice yearly or more frequently if required.

8.3 Material risks and controls

8.3.1 Health and safety

Operating and maintaining an electricity network involves hazardous situations with risks that cannot be entirely eliminated. Safety is fundamental to the way we undertake any activity. We prioritise the safety and well-being of our employees, contractors, customers, and communities.

Where we can, we will eliminate risks that may cause harm to our people or the public. We will not accept unsafe work practices which would cause harm to our employees, contractors, customers or the public. We will not accept trading off health and safety for any other objectives.

We may be willing to accept working in hazardous environments with adequate mitigation measures to protect staff, subcontractors and the public from harm. We may be willing to accept uneconomic investment in our network design and equipment to ensure safe, best practice outcomes.

Our employee, contractor and public health and safety is supported by a comprehensive safety management system, which includes:

- **Managing critical risks.** We understand the importance of identifying and reducing critical risks to create a safe and accident-free workplace. The Health & Safety Management System details the methods and procedures for pinpointing, evaluating, and managing critical operational risks. This equips our team with the knowledge and tools to proactively spot potential risks, apply effective control measures, and keep the workplace safe.
- **The health, safety, and environmental risk register.** This is a comprehensive database of potential risks associated with our activities. This living document continuously evolves as we identify and analyse new hazards, ensuring we stay ahead of emerging threats. Each risk entry includes detailed information about the identified hazard, its potential consequences, and the control measures to mitigate it. This register enables us to prioritise risk management efforts, allocate resources effectively, and maintain transparency throughout the organisation, fostering a culture of safety and vigilance.
- **The health & safety management system** details how people should identify and manage risk in the workplace. It provides a structured approach to efficiently and effectively address risks and the role of controls in eliminating or reducing the likelihood or outcome of risks.
- **Work method statements.** We implement Safe Work Method Statements (SWMS) as a fundamental component of our operational practices to uphold our commitment to a safe and secure work environment.
- **Standard operating procedures.** Operating Procedures (SOPs) govern every aspect of our network construction and operation. The SOPs serve as the best practice guides that ensure the smooth operation of our network and the safe delivery of services to our valued customers.
- **The health & safety committee (HSC).** The HSC ensures a safe and secure work environment for everyone associated with our organisation. The primary function of our HSC is to ensure that we focus on

measures that prioritise the workforce's wellbeing. The HSC meets monthly to address issues raised by staff or reported through Assura.

- **Assura**, a workflow management application we have chosen to capture and manage health and safety-related events, network defects and other information (refer to Section 9.4.6 for a description of the system).

We have implemented a Public Safety Management System (PSMS) in addition to the systems and processes mentioned above. Our PSMS framework is built on and supported by our Health and Safety Management policies, procedures, and guidelines relevant to the safe design and management of the assets. The PSMS helps ensure that assets installed in public areas do not pose a risk to public safety.

The PSMS meets the compliance requirement for electricity distributors to implement and maintain a safety management system for public safety set out in Regulations 47 and 48 of the Electricity (Safety) Regulations 2010. Our PSMS system complies with NZS 7901:2014 and is externally audited and certified by Telarc.

8.3.2 Natural hazards

Our network is exposed to natural hazards, including strong winds and adverse weather, lightning, floods and land erosion, earthquakes, volcanic eruptions, and geothermal activity. Our general view of the risks from natural hazards is outlined below.

Strong winds and adverse weather events

Our network is in an area of New Zealand that has one of the lowest recorded average wind speeds. However, strong winds occasionally blow debris into the 11kV pole lines. Because of generally low winds, trees tend to be weak and easily damaged by stronger winds. Our vegetation management programme is intended to reduce the incidents caused by wind-blown vegetation.

Wind presents a high threat to network assets during significant storms. While the damage caused by wind-borne debris is easily fixed under normal circumstances, a powerful tropical cyclone could result in widespread network damage from downed trees, requiring a long period to reinstate and restore supply. Access to our network is likely to be complicated by wet ground conditions, further complicating supply restoration.

In major storms, such as the 2003 "weather bomb", February 2022 Cyclone Dovi and February 2023 Cyclone Gabrielle, our network suffered numerous outages with significant damage caused by trees well outside the regulatory growth limit zone being blown over our lines. This resulted in substantial restoration works.

Lightning

Lightning occurs sporadically across the Waipā district, with incidents typically concentrated during thunderstorms associated with seasonal weather patterns. While the region does not experience the highest frequency of lightning strikes in New Zealand, events do pose operational challenges for our network. The assets most affected by lightning are rural 11kV lines on which normal 11kV lightning protection

devices are used to localise and minimise lightning damage. Installation of surge arrestors on pole-mounted distribution transformers has been included in the standard design for new installations to protect these assets from lightning.

Floods and land erosion

Our network area is subject to frequent and often heavy rainfall. There are numerous streams and rivers whose flow paths change over time. The effect of such erosion on network assets is currently minimal, affecting only one or two poles at any time, which are relatively easy to reinstate. However, erosion can significantly affect some roads in our region. Access into Kāwhia is particularly vulnerable, and when erosion occurs, it can isolate the community.

Earthquakes

Earthquake risk in our network area is medium risk, based on seismic risk areas as defined in the Building Act 2004⁷⁸. However, a significant earthquake in the Waikato region is expected to result in widespread liquefaction due to the wide presence of peat soil.

In addition, Transpower has established three seismic risk zones across New Zealand: Zone A (high risk), Zone B (medium risk), and Zone C (low risk). For each zone, a specific seismic risk factor is applied to construction works to ensure the integrity of structures and buildings. These risk factors guide engineering requirements to mitigate potential damage and ensure a resilient network.

Our network is in the medium seismic risk zone, which has a risk factor ranging from 1.01 to 1.06 (depending on equipment type). In our area, the predominance of rural 11kV pole lines means repairs can be carried out relatively efficiently. We consider this an acceptable risk to manage because rural 11kV pole lines are relatively easy and inexpensive network assets to repair if an earthquake damages them.

Our zone substation building is designed to an Importance Level 4 and must remain operational after a major earthquake as critical Infrastructure.

Underground cable assets may be more susceptible to earthquake damage due to their exposure to liquefaction and permanent ground deformation. Evidence from the Canterbury earthquakes indicates that cable damage is widespread in severe seismic events, with failures concentrated at joints, terminations, and constrained interfaces. Faults are often not visible at the surface, making detection and repair time-consuming, particularly where access is limited by ground damage. As a result, restoration of underground cable networks following a major earthquake is typically slower and more resource-intensive than for overhead assets, with an increased likelihood of ongoing faults and reduced asset life after the event.

Tsunami

Only a very small part of our network would be impacted by a potential tsunami, including settlements at Aotea and Kāwhia and around the Kāwhia Harbour.

The West Coast Tsunami Risk Study, commissioned by the Waikato District Council, Waikato Regional Council and WEL Networks, assessed the risk of network inundation from a tsunami affecting the West Coast. The study covered Aotea Harbour in our supply areas, but excluded Kāwhia Harbour. We applied a similar Tsunami event for Kāwhia.

- The study indicated that the water level rise at the Aotea Harbour mouth is expected to be like a fast-rising tide, not a "wall of water", so damage and erosion from water inrush are not likely.⁷⁹ Our network in this area is overhead, hence any network damage is unlikely to be material.
- Assuming the water level rise at Kāwhia Harbour heads is 2.5 metres (same as at Aotea), there is a risk to the network on the Kāwhia settlement waterfront where ground-mounted transformers, pillars, and cables are located. In the event of a tsunami, inspection and repairs would be required. However, the network in these areas is small and well within our capabilities to resolve. We wouldn't expect the outage times to be substantial.

We have an overhead network in low-lying areas around Kāwhia Harbour that would experience a rise in water level, depending on how much the harbour mouth attenuates the water level rise. However, our network in these areas is overhead distribution, so no material supply issues are expected.

Several access roads to Kāwhia are low-lying. Depending on the depth of inundation, this may delay access, but it is unlikely to be material.

Overall, the study and our assessment indicate that the impact on our network if this event were to occur is relatively minor. This is consistent with the Ōtorohanga District Council and Waitomo District Council, who have indicated that there are no red, orange or yellow tsunami risk zones for the Aotea and Kāwhia areas.

Volcanic eruption

The network area has several old volcanic cones, but there are no known active volcanoes in our distribution area. The Mount Ruapehu eruption in 1995 had no adverse impact on our assets because of the prevailing winds. If volcanic ash had been deposited over the rural 11kV lines, we would have continued operating our distribution networks until there was clear evidence of insulation failure. A water shortage to wash insulators from an ash fall is an expected risk, given that many parties will simultaneously attempt to wash plants and equipment.

Geothermal

There is no significant geothermal activity in our reticulation area other than a hot water beach in Kāwhia. Therefore, there is no corrosive atmosphere to contaminate the overhead lines or hot ground, gases or liquids constraining cable ratings or corrosive liquids damaging cable insulation and conductors. We conclude that there is minimal risk to our network from geothermal activity.

⁷⁸ <https://www.building.govt.nz/assets/Uploads/managing-buildings/earthquake-prone-buildings/seismic-risk-areas-map.pdf>

⁷⁹ The water level rise at the Aotea Harbour mouth resulting from the worst-case event is generated from an earthquake on the Puyseger Trench to the south and west of the South Island. The sea level rise at the heads of Aotea Harbour is a maximum of 2.5 metres, but it is attenuated to around 1.5 metres at the Aotea settlement.

The impact of climate change

We are already seeing the impact of climate change in terms of the increased frequency of extreme weather events. Also, warmer and wetter environments result in higher vegetation growth rates that can impact the effectiveness of established vegetation management programs. The impact of climate change in terms of intensification and increased frequency of weather events is expected to increase this risk from wind, floods, and land erosion over time (and this is being considered as part of our resilience strategy).

We are presently undertaking a natural hazard review of the network. This is discussed further in Section 8.4.

8.3.3 Connecting customers and responding to the energy transformation

There is a risk that we might not be able to connect new customers because of limited capacity, or we may not be prepared to respond to the evolving needs of customers due to energy transformation.

Ensuring that our network can meet demand, accommodate growth and meet future needs is a focus for our asset management strategy and a core part of this AMP and includes:

- Demand forecasting and network planning to ensure that the network is developed to meet future customer needs. Our development plans are outlined in Section 11
- Actively engaging with customers and developers to understand their requirements well in advance of need (refer to Section 3.4)
- Developing an energy transformation roadmap (ETR) to prepare the network for the future needs of customers (refer to Section 10).

8.3.4 Asset health and reliability risk

We are averse to risks that could materially impact on the health of our assets or result in the inability to achieve our network customer service targets over the long term. Managing these risks is a core focus of our asset management strategy and this AMP, and includes:

- Mitigating the consequences of network faults (regardless of cause) through network security. Network security is a planning standard that the network is designed to meet (refer to Section 11.4). Security defines redundancy or backup supply in case of a network fault
- Mitigating the likelihood of asset failures as asset age and their health deteriorate. All network assets are inspected to ensure we understand their condition and to identify any end-of-life drivers. We have comprehensive fleet plans that use age and condition models to determine an asset's health and schedule the asset for replacement ahead of the health deteriorating to an unacceptable level (refer to Section 13)
- Various reliability improvements and operational controls that reduce the probability of occurrence or potential consequences of health and reliability risk
- Our resilience strategy (refer to Section 8.4)
- Mitigating other network risks (refer to the next section).



8.3.5 Other network risks

The network assets are exposed to a range of other risks (in addition to the risks mentioned above). Table 36 summarises these typical risks and the controls in place.

Typical risks	Asset	Controls
Oil leaks leading to contamination of the environment	Transformers and switchgear	<ul style="list-style-type: none"> The Forrest Road substation transformers have individual oil containment and water/oil separators and an oil spill kits located at the zone substation in case of other spills. Where a distribution transformer or switchgear has leaked, all affected ground is removed and suitably disposed of in accordance with local by-laws.
Vehicle accidents damaging assets and causing loss of supply	Overhead lines and ground mounted equipment	<ul style="list-style-type: none"> We recently assessed vehicle damage locations, which showed network damage from vehicles was not concentrated, making targeted remediation difficult (refer to Section 5.5.6). However, we review all vehicle damage incidents to see if improvements need to be made. All ground mounted assets are located away from the road carriageway or physical barriers are installed.
Vegetation contact causing asset damage and outages	Overhead lines	<ul style="list-style-type: none"> We have an ongoing programme of vegetation control to minimise interruptions caused by vegetation (refer Section 13.24).
Coastal conditions deteriorating asset health leading to asset failure and outages	Overhead assets	<ul style="list-style-type: none"> We have limited lines near the coastal areas. Additional inspection and maintenance are required. Including treatment of transformers and managing salt build-up on insulators and concrete spalling.
Contractors damaging cables and causing outages	Underground cables	<ul style="list-style-type: none"> All contractors excavating in the road reserve are required to obtain plans for all underground utilities and cable location and safety stand-over services are also provided as required. We review all contractor damage incidents to see if improvements need to be made.
Poor work quality leading to asset failure	All	<ul style="list-style-type: none"> We have design, construction and maintenance standards and these are available to the Operations Team and contractors to ensure work quality. We established a Technical Service team with specialist trades such as fitters, jointers and technicians to support the increasing volume of underground and substation assets. Field work is audited regularly and any defects found are notified to the Delivery team or contractor for remediation.
Inability to access the network to operate or perform maintenance	Assets on private property	<ul style="list-style-type: none"> All new assets on private property are suitably protected by registered easements or are protected by existing use rights.

Table 36: Typical network risks

8.3.6 Cyber threats

The increased reliance on connected digital devices increases the potential business impact of cyberattacks. A cyberattack on a power utility's Operating Technology network could affect the physical electricity network, potentially causing equipment overload or erroneous/unintended operations.

The risk of cyberattack on our network requires ongoing vigilance. We continue to monitor this risk and are implementing further improvements to the security of the SCADA and business systems. Our Operating Technology system environment is separated from the corporate environment by design, with tight security controls for any designated data integration connection.

We are investing more in training, systems and processes that enhance our cybersecurity posture to reduce the likelihood and impact of a cyberattack. Enabling the business to respond proactively aims to fortify the business's resilience, ensuring minimal disruption to service continuity for our customers during a cyber incident.

Increased security measures that we have implemented to protect against cybersecurity events include:

- User awareness and training initiatives
- NIST's cybersecurity framework alignment
- Increased security policies across identity/devices
- Real-time monitoring of technology across identity/hardware
- Threat landscape services
- Proactive Security Operations Centre (SOC).

We are updating our IT Disaster recovery plan to improve our business resilience and return-to-operation processes. Additional controls include external reviews of security controls, remediation of any vulnerabilities, and regular assessments/reporting.

8.3.7 Pandemic

As an essential service, we must maintain our ability to operate a reliable distribution network during a pandemic. Loss of operating capability would occur if we could not maintain a minimum find-fault-and-fix capability of our field crews. This can be due to team members being unable to work due to illness (individual or their dependents), operational control room capability, and availability of equipment and materials due to impacts on our supply chain.

We have maintained a Pandemic Response Plan initially developed in response to the SARS and avian bird flu incidents internationally, and then activated the pandemic response during the COVID-19 pandemic from 2019 onwards. The experience of implementing a CIMS management structure, allocating field crews into isolated "operating pods", developing contact recording and work crew operating procedures, holding higher equipment stock levels, and moving office workers to remote working has been very valuable in strengthening the organisation's preparedness for further pandemic disruptions.

8.3.8 Work plan delivery

This is a new material risk for the business, given the increase in network work. We are forecasting approximately \$27m of work requiring external delivery over the next three years, involving a long-term contracting partner and major project contracts.

The long-term contracting partner arrangement is to support our core workload. Managing delivery risks associated with this arrangement is achieved through the initial trial process (to test capabilities, pricing, quality, and safety) and by supporting the contractor by maintaining a base work commitment to ensure resource availability. The contractor partner will be subject to our quality and safety standards, reporting, and auditing to manage safety and quality risks.

To ensure we deliver major contracts through the external market, we will use industry-standard contracting arrangements, tender large work packs to improve efficiency, provide appropriate tender lead times, and implement standard safety and quality controls. We plan to engage with the external market to communicate our work requirements and also to understand major project timelines from other nearby EDBs to manage market access timing where possible. We are confident about external market capacity (Section 14.8.2).

We will also review our internal capabilities, such as contract management and project engineering resource level, to support this major increase in expenditure and external delivery model.

8.3.9 Other business risks

We are monitoring the current global political/stability situation and potential impact on fuel supply and the associated risk to cost of delivery and delivery of materials.

We have a range of other low-level risks that are captured in our risk register, and appropriate controls are in place.

8.4 Resilience strategy

8.4.1 Importance of resilience

The increasing use of electricity to decarbonise transport, industrial process heat, and commercial and domestic heating will increase the reliance on electricity and reduce fuel diversity. As a result, in the future, a loss of supply will have more significant community and economic consequences and impact more sectors. Therefore, Waipā Networks' (and the electricity sector's) resilience must be commensurate with its increasing dominance and linkage of electricity supply to economic activity.

8.4.2 Definition of resilience

In the modern context, resilience means⁸⁰:

- The capacity of the network to absorb a shock; recover from disruptions; adapt to changing conditions; and retain essentially the same function as it had before
- Having the capacity to adapt to those shocks and rapidly recover, even if that means providing services differently.

For the electricity distribution businesses, this means:

- Minimising the potential number of customers interrupted during a major event (generally by way of risk reduction)
- Minimising the duration of the interruptions that occur during a major event (generally by way of readiness and response)
- Communicating with customers and stakeholders so that they can be informed in their decision-making and so that restoration can be effectively coordinated and targeted, allowing us to optimise between what the network can reasonably deliver and how long it may take to recover against what customers can tolerate and what they can do to give them greater control and certainty
- Recovering to the pre-event state.

⁸⁰ Department of the Prime Minister and Cabinet "Strengthening the resilience of Aotearoa New Zealand's critical infrastructure system", June 2023.

8.4.3 Objective of our resilience strategy

The objective of our resilience strategy is to:

Improve the resilience of our network to reduce the impact within acceptable customers' tolerances of increasing incidents and intensity of adverse weather and other major events as the economy increases reliance on electricity, while ensuring investment is in the right place.

The desired outcomes of this strategy are:

- An improvement in our RMMAT score to three in all key areas over three years
- A reduction in the duration of loss of supply to customers and the number of customers affected during major adverse weather events and other natural hazards (in particular, to asset failures and vegetation outages)

- Assessment and adaption to climate change
- Improved emergency management response and community support.

The Improve Regional Supply Capacity and Security Strategy (#1) supports the resilience strategy, as network security improvements generally make our network more resilient, and the Vegetation Management Strategy (#6), as vegetation is a key cause of outages during major events.

The resilience strategy supports our Network Transformation Strategy (#2) as greater resilience is required to support electrification.

Whilst our objective focuses on resilience to adverse weather, many of the actions will improve resilience to various natural and other hazards. Our resilience strategy excludes cybersecurity; however, this is not excluded from a business perspective, and our work on cybersecurity is discussed in Section 8.3.6.



8.4.4 Resilience strategy

Improving resilience will take a multi-faceted approach over the next decade. This will be addressed principally through risk reduction, readiness and response activities. To provide a comprehensive view of resilience, our strategy includes new initiatives and existing programmes that enhance resilience.

We experienced some delays in our resilience work programme and some dates have moved out from one to two years. We have resolved most of these constraints and are now making progress with this work.

Our strategy is shown in figure 82.

		STRATEGY ACTION	DESCRIPTION	STATUS	
COMMUNITY ENGAGEMENT	Review	Conduct a RMMAT assessment	Assess our resilience maturity and determine improvement activities	Assessment complete	
	Risk reduction actions	Undertake a natural hazard risk assessment, including the impacts of climate change	<ul style="list-style-type: none"> Assess the impact of climate change on natural hazards Assess the vulnerability of the network to natural hazards (wind, seismic, snow/ice, river flooding, coastal inundation, peak rainfall, land stability) 	In progress – analysis complete in FY27	
		Increase resilience in asset design	Revise design standards to withstand natural hazards	To commence	
		Increase the physical resilience of critical assets in vulnerable locations	Assess the options to increase the resilience of critical assets that are vulnerable to natural hazards	To commence	
	Response and readiness actions	Minimise the impact of outages when they occur	<ul style="list-style-type: none"> Reduce outage impact through sectionalisation and automation Upgrade network to improve back-feed capability (this is covered through our annual work plan and GXP work) 	Ongoing programme	
		Enhance operational management of major events	Establish a modern SCADA master station and fit-for-purpose control room operating arrangement	In progress	
		Improve major event response	<ul style="list-style-type: none"> Review of response to storms and implement actions to improve our processes Develop business continuity and contingency plans <ul style="list-style-type: none"> Incident management team training Enhance mutual aid arrangements 	In progress	
		Enhance community support	Engage with our customers and communities to understand how best to build resilience in the community and co-design solutions	To commence	
				Following Cyclone Gabrielle, the government is looking at increasing support of community resilience. We will support these initiatives	Awaiting government recommendation
	IMPROVEMENT IN ASSET RESILIENCE				

Figure 82: Resilience strategy

We have commented further on the resilience activities below. The activities in Sections 8.4.6 to 8.4.8 cover our work on climate change assessment and adaptation.

8.4.5 The outcome of our resilience review

Figure 83 shows the results of the independent review of our resilience practices undertaken in FY23.

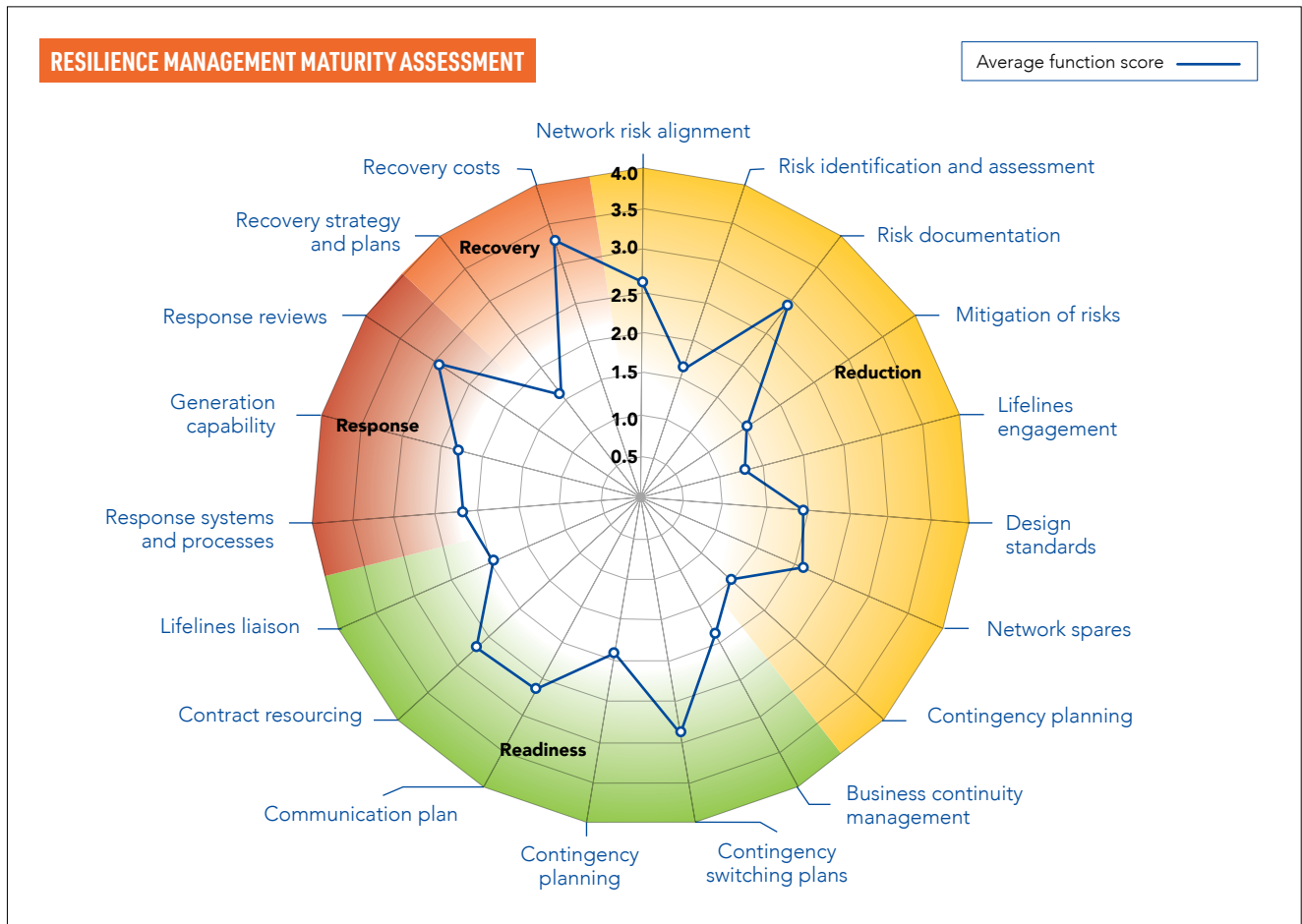


Figure 83: Resilience management maturity assessment (score 0 indicates not aware and 4 indicates excellent)

We used the resilience management maturity assessment tool (RMMAT) to assess our work on reduction, readiness, response and recovery (the 4Rs of resilience). The key areas for improvement identified in the review were risk assessment and reduction, contingency planning and response systems. The resilience strategy incorporates a range of actions that address these areas. We are focusing on natural hazard study and have deferred other resilience improvement works due to internal capacity and reprioritisation of all initiatives. We expect to see further improvements in our RMMAT score by the end of FY28, and our long-term goal is to achieve RMMAT scores of three in all key areas.

8.4.6 Natural hazard assessment

We completed an initial broad review of the risks posed by natural hazards. This is presented in Section 8.3.2.

The risks posed by natural hazards are changing due to climate change. We have started work to engage capable service providers to carry out localised future modelling of our region. This will help provide a comprehensive review of the impact of climate change on natural hazards, particularly wind, river flooding, coastal inundation, rainfall intensity, and land stability. These hazards are most impacted by climate change. This work is expected to be completed by the time this AMP is published.

We will then review the network to assess vulnerabilities to those hazards. This will be in two parts:

1. Assessing our materials and design standards to determine if they are suitable for future conditions.
2. Assessing critical assets to determine if any are vulnerable to natural hazards. This will take a risk-based approach, considering the consequence, return period and the asset's criticality.⁸¹

⁸¹ This requires completion of the asset criticality work in GIS. Refer to Section 13.4.2.

8.4.7 Revision to design standards

Based on the natural hazard assessment outcome, we will revise materials and design standards to improve their resilience. The new design standards are expected to be implemented as new assets are installed or as assets are renewed. Hence, resilience improvements will be incremental.

Work is underway to improve asset resilience as outlined in our distribution structure fleet plan (concerning accelerating the replacement of assets with known weaknesses) (refer to Section 13.10). This includes wood poles, crossarms, and mass-reinforced poles on critical feeders.

Work has also begun to replace voltage regulator structures to enhance seismic resilience. Risk assessment has identified the need to improve the strength of many of our current fleet of voltage regulator structures, which are being replaced with structures that comply with current structural standards (refer to Sections 11.8.3 and 11.12.3).

Following the revision of the design standards, there may be other resilience-driven projects (under network development) or changes in asset renewal priorities (in the fleet plans).

8.4.8 Increasing the physical resilience of critical assets in vulnerable locations

Based on the natural hazard assessment outcome, there may be areas where assets need to be strengthened, protected or moved to enhance resilience.

Work is already underway to improve the supply's resilience to Kāwhia. The Kāwhia feeder is one of our worst-performing feeders and is susceptible to adverse weather. Replacement of wooden structures with modern concrete/steel structures is being prioritised in this area (refer to Section 13.11.13), and a line deviation is planned to eliminate land stability risks (refer to Section 11.7.3). We are also considering whether Kāwhia is an appropriate location for generation support (refer to Section 11.7.6).

Following the completion of the natural hazard assessment, there may be other resilience-driven projects (under network development) or changes in asset renewal priorities (in the fleet plans).

Whilst this strategy focuses on natural hazards, resilience is also supported by our work on reducing the impact of third-party damage incidence, outlined in the distribution structure fleet plan (Section 12.11.4).

8.4.9 Minimising the impact of outages where they occur

Reducing outages through sectionalisation, automation and improving back feed capabilities are existing development programmes (refer to Section 11.7.1). These programmes improve reliability and resilience.

The natural hazard assessment results may alter programme priorities and targeting.

8.4.10 Enhance operational management of events

The replacement of the SCADA system is required due to end-of-life drivers. The opportunity is being taken to enhance the system's functionality to improve outage and emergency management functionality. Refer to Section 13.9.5.

8.4.11 Improve major event response

The RMMAT review highlighted the need to improve some of our operational processes and practices. We have identified a range of activities that will enhance our response to major events and emergencies, and these include:

- Review of our response to storms. We need to incorporate specific learning from recent events into our contingency plans and operational procedure revisions
- Develop business continuity and contingency plans. Whilst we have developed a range of contingency plans (refer to Section 8.5.2), the review identified that these could be further enhanced and additional contingency plans added where needs are identified
- Incident management team training. We will need to refine our Incident and Emergency Management Plan further and provide further training to the team to execute the plan under the Coordinated Incident Management framework
- Further formalised mutual aid arrangements between EDBs enable us to increase resources in a major event further.

These process improvements will enhance our response to natural and other major events.

8.4.12 Enhance community support

Following Cyclone Gabrielle, a recommendation by the electricity sector was made to the cyclone recovery task force to develop secure community hubs. Due to our topography, vulnerabilities in the roading networks, and the types of damage that can occur, there will always be some hard-to-restore consumers. For these consumers and communities, having community hubs with a secure standalone supply of electricity and communication will provide support while restoration or alternatives can be brought online. Community hubs will be an important safety net while hazard reduction and other improvements are made.

The outcome of the task force's work and the potential for government funding of community hubs is unclear. We are currently monitoring this work.

8.4.13 Resilience expenditure

Our expenditure forecasts include current programmes and projects that link to resilience. This includes work on seismic strengthening, Kāwhia area resilience, segregation and automation and SCADA system. These are already captured under the Asset Renewal and Network Development capex schedules.

After completing the natural hazard assessment (as a network opex) and related work, we expect an increase in our forecast for resilience-related capex expenditure. This increase will be visible in the 2027 and 2028 AMPs.

8.5 Risk readiness, response and recovery plans

8.5.1 Emergency management system

We have developed a suite of business continuity plans (BCPs) for significant incident types, and we will continuously improve these plans. All our BCPs have adopted the Coordinated Incident Management framework. Development of our BCPs continues with consideration given to various “what-if” scenarios. This prepares our team for multiple scenarios and events.

8.5.2 Contingency planning and preparedness

We have considered contingency events in the configuration of our key systems. We have also developed a range of BCPs in the event of a major incident and emergency. These cover all key areas of our business. Table 37 summarises our contingency planning for key areas of our business.

Business area/event	Contingency planning and plans
Severe weather	<ul style="list-style-type: none"> We have developed a BCP for the management of severe weather events. The purpose of this BCP is to restore power to the network, minimising the number of customers impacted, and to communicate effectively with all key stakeholders.
Major earthquake	<ul style="list-style-type: none"> We have developed a BCP for the management of a significant earthquake. The purpose of this BCP is to ensure team member and public safety by making safe any live or damaged assets. It is then to restore power to the network and focus on minimising the number of customers impacted.
Business relocation	<ul style="list-style-type: none"> We have developed a BCP in the event we need to establish a new office. The purpose of this BCP is to ensure the safety of all team members involved and establish a suitable location to maintain operations.
Serious harm or fatality	<ul style="list-style-type: none"> We have developed a BCP for serious harm or fatality to ensure the safety of all team members involved and communicate effectively with all team members, whānau and stakeholders. The BCP ensures that we work professionally to support the Worksafe investigation and ensures effective communication both internally and externally to convey information to all stakeholders.
Major environmental incident	<ul style="list-style-type: none"> We have developed a BCP to ensure the effective management of a major environmental incident.
Financial and business systems	<ul style="list-style-type: none"> Our financial (MagiQ Integrated Data Warehouse) and all core business systems are now cloud-hosted (e.g. GIS, ARC, SharePoint drives, AutoCAD, email, and phone systems), so operation and continuity are independent of our Harrison Drive depot. Minor software (DigSILENT, for network modelling) still requires access to an ‘on-premises’ server for licensing. There is no cloud-based option, however, the license server can be installed on engineer’s laptops when required.
SCADA	<ul style="list-style-type: none"> Our current ABBEY SCADA system comprises a master station and a “hot standby” backup station in our control room in Te Awamutu and two remote operating terminals in the WEL Networks Control Centre in Hamilton. WEL networks also run two disaster recovery sites. Both sites are linked via WEL’s fibre network, so in the event of COVID or similar events, WEL can operate from these emergency sites to provide full control services in case one control centre goes down. WEL Control has four laptops, enabling the controllers to access SCADA via a secure cloud network. The SCADA network configuration and operating schematics are backed up each day. The daily backup is held off-site, and we can recreate the SCADA network configuration and operating schematics after a catastrophic event. The SCADA system is continuously monitored through self-checking and third-party monitoring systems. The communications network is part of this monitoring system and alerts operators to communication failures or overload issues. We currently hold limited spares for critical SCADA hub devices, with support from the supplier. We are progressing with the implementation of an ADMS system to replace ABBEY SCADA. The ADMS system and associated infrastructure will improve the resilience of the system by design. We are planning to implement the ADMS through a co-hosting environment with WEL Network, hence we will benefit from WEL’s existing diversity arrangements in infrastructure and operating locations. We will have some temporary concentration of communication risk via our Harrison Street site, but this will be resolved when the communication upgrade is complete.
Network communication system	<ul style="list-style-type: none"> We operate our independent radiotelephone system. Should one or more repeaters fail, the system can have short-range point-to-point communications, which will continue functioning. Power restoration will be inherently slow under these circumstances. Most repairs required on the networks would be identified by physically patrolling the pole line feeders. We recently commissioned the new digital network backbone, with a ‘self-healing’ ring architecture providing enhanced resilience. The full benefit will be realised as we complete the transfer of the field radio upgrade within the next three years.

Table 37: BCPs and contingency planning

8.5.3 Coordination

We're an active participant in the Waikato Lifeline Utilities Group as required by the National Emergency Management Agency (NEMA). We coordinate with the Waikato Civil Defence and Emergency Management Centre during major events and emergencies. This ensures that our response and recovery efforts are coordinated with national, regional, and local priorities and other utilities.

We participate in the Waikato Lifelines Utilities Group and expect that NEMA, in conjunction with other utility owners and local authorities, will prioritise areas for power restoration.

8.5.4 Critical spares

We carry sufficient spares in our store to construct several kilometres of pole line. Our store holdings are considered appropriate to respond to foreseeable emergencies on the network. Should these be exceeded, we would call on other local distribution businesses (as mentioned below) to assist.

8.5.5 Resources

We're experienced at self-managing our network restoration resources during storm conditions and will interact and communicate with NEMA authorities and the public during these events. Our internal crews successfully reinstated our network during the February 2004, April 2011, January 2018, February 2022 (Cyclone Dovi), February 2023 (Cyclone Gabrielle) storms and the February 2026 flood.

We have sufficient internal field crews and equipment to respond to foreseeable emergencies on the network. We also have agreements with three other local distribution businesses and one contractor to use their field resources. Should the emergency event exceed our internal capabilities, we can call on additional resources outside our region.

8.5.6 Exercises

Our emergency management procedures are tested regularly during our response to weather events. We also participate in the Waikato Lifeline Utilities Group and the group's risk assessment exercises. We also participate in the Grid Emergency Event exercises with Transpower System Operators.

8.6 Risk transfer (insurance)

We transfer risk via insurance where it is economically feasible to do so. Our insurance program covers professional and director's indemnity, public liability, material damage, fire and business interruption for buildings and plant, and vehicle cover. Other than the new Forrest Road substation, we cannot economically insure the electricity network for material damage at this point. Further work is in progress to investigate whether we can economically extend the insurance to ground-mounted assets.

We require design consultants to hold professional indemnity insurance and contractors to hold contract work and public liability insurance. In 2021 we established an investment fund (held in Waipā Networks Growth Limited) from the proceeds of the Ultra Fast Fibre sale. This provides a separate structure to ring fence, manage and grow the investment portfolio. One of the purposes of this fund is to support the network in the event of a significant event that impacts the network.





9. ASSET MANAGEMENT SYSTEM AND IMPROVEMENT PLAN

9.1 Introduction

We invest in systems to support our electricity network. These include processes, information systems, operational systems and data. This section describes our asset management system and our current information technology (IT) and operational technology (OT) systems that support it. It also includes an overview of our IT and OT development plans and our plans to improve the maturity of our asset management system.

We recognise the importance of asset management systems in supporting our business. These systems help ensure we work safely, make decisions based on quality data, operate efficiently, and provide confidence and transparency to stakeholders. We have adopted various management practices consistent with recognised standards and best practices.

9.2 Summary

The key points from this section are:

- Our current asset management maturity has improved, but further improvements are needed as our assets age and we prepare for an increasingly complex future. We are actively working to improve the maturity of our asset management system, with ongoing initiatives to reach our target maturity level (an AMMAT score of 3.0 by the end of FY28)
- Our asset data is generally good; however, we have gaps in asset information for conductors and cables, which we are addressing through our information improvement plan. This work will also enable the next generation of operational technology
- The maturity and information improvements will reduce asset-related risks and support evidence-based decision-making, leading to more efficient and better-targeted asset renewals. This will lead to better outcomes for customers over time
- We are progressing with the implementation of an advanced distribution management system (ADMS). This is a key OT system that will enhance network operations and improve customer outcomes.

9.3 Asset management system

9.3.1 Asset management system overview

Our asset management system is shown in figure 84. The purpose of the asset management system is to provide a structured and systematic approach to managing network and non-network assets across their lifecycle. It ensures assets are managed efficiently and effectively to achieve our business and asset management strategies, optimise value,

and manage risk. When implemented to our target maturity level (refer to Section 9.6.1), the system will improve decision-making, enhance performance, and ensure asset-related activities are consistent, transparent, and aligned with our objectives. The core elements of our asset management system are aligned to ISO 55000 (although we have no plans to formally adopt that standard).

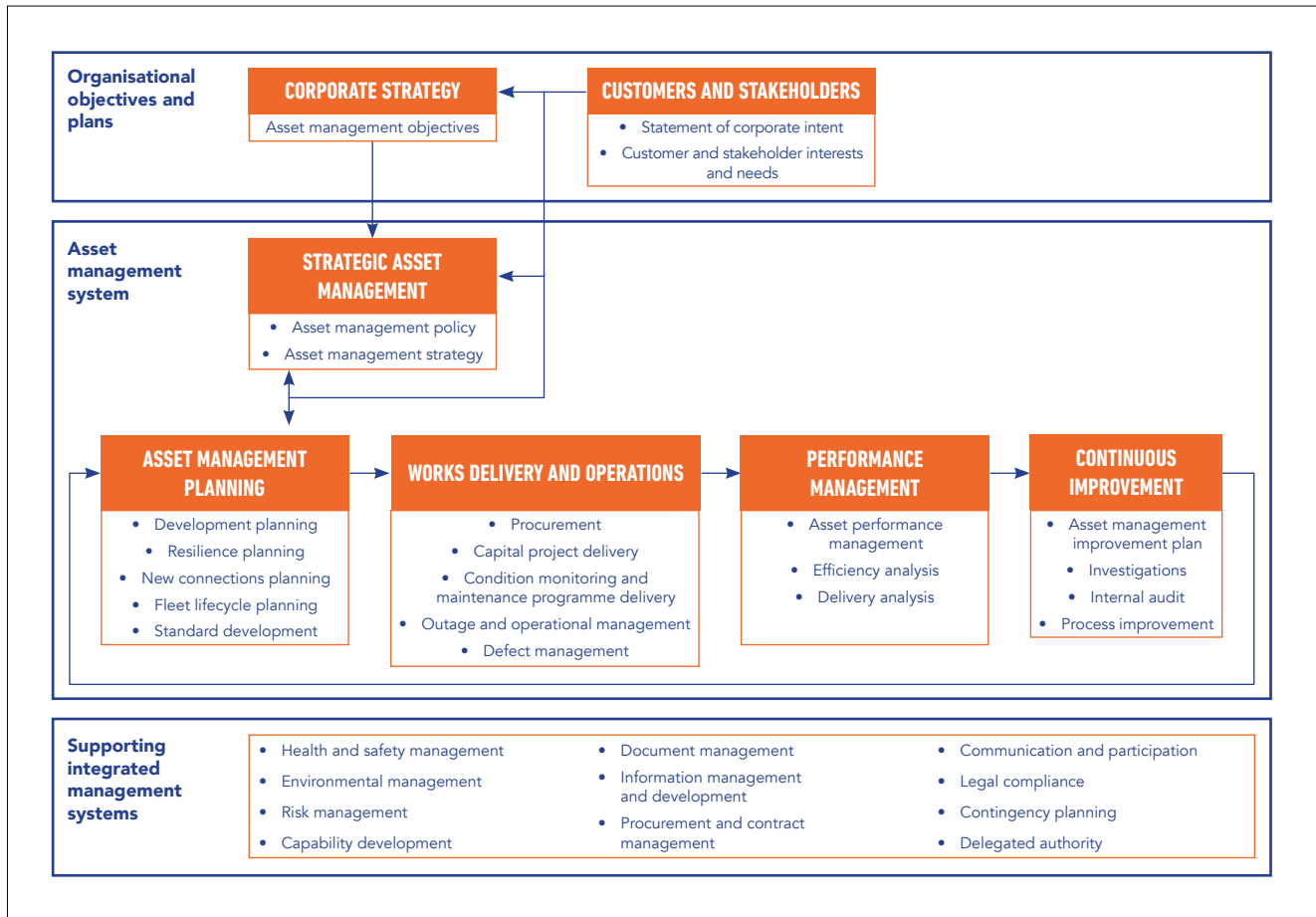


Figure 84: Waipā asset management system

9.3.2 Asset management system documentation

We have a range of documents that support our asset management system. These documents include the following:

- Our Asset Management Policy and Asset Management Strategy and performance targets (these are included in Section 7)
- Development planning standards and our various development plans (included in Section 11)
- Standards for asset health, criticality and risk and fleet plans on our assets (included in Section 13)
- A suite of procurement, design, construction, maintenance and inspection standards and associated technical drawings that support our delivery activities
- Procedures and contingency plans to support the operation of the network asset.

Documents, such as policies, specifications, drawings, operations and maintenance standards, and guidelines, follow the structure of the controlled document process, with a formalised review and approval process for new and substantially revised documents. Generally, controlled documents are intended to be reviewed every three years. However, some documents are subject to more frequent reviews due to their nature or criticality to business functions. Table 38 provides further details on the review and communication approach for our key documentation.

AMS documentation	Overview and review process	Communication and usage
Asset management policy	<ul style="list-style-type: none"> Prepared and reviewed by the Network team, Network Intelligence team Reviewed by the CE and Management Team Reviewed by the Asset Management subcommittee and approved by the Board 	Communicated via the AMP, and available in Waipā's document management system.
Asset management plan	<ul style="list-style-type: none"> Prepared by the Network team and Network Intelligence team. Reviewed by the CE, Management Team, and Asset Management subcommittee Approved by the Board 	Communicated to relevant stakeholders and available to the public on our website.
Asset management strategies	<ul style="list-style-type: none"> Prepared by the Network team and Network Intelligence team. Reviewed by the CE, Management Team, and Asset Management subcommittee 	Communicated via the AMP.
Performance targets	<ul style="list-style-type: none"> As above. 	Communicated via the AMP.
Design manual	<ul style="list-style-type: none"> The design manual is driven by safety and recognised good industry practice The manual is reviewed and updated by the Network Team and Delivery Team on an as-needed basis. Reviews involve the internal design team, operations delivery team. External consultants are used to provide specialist support as required. 	<p>The Design team use the design manual for designing projects for the network.</p> <p>This standard is disseminated to external consultants as required, where they are undertaking design work.</p>
Other design standards	<ul style="list-style-type: none"> For designs outside of the design manual that are prepared following good industry practices and applicable standards. 	The required design standards are communicated to the Design Team or external consultants when design work commences.
Construction manual	<ul style="list-style-type: none"> The construction manual is reviewed and updated primarily by the Delivery Team (design and operations). 	<p>The Delivery Team uses the construction manual for constructing and installing equipment on the network.</p> <p>This standard is disseminated to Contractors as required. Waipā will instruct contractors as part of the procurement process that works are to be undertaken per applicable elements of the construction manual.</p>
Maintenance and network inspection standards	<ul style="list-style-type: none"> These standards are prepared by the Network Team and reflect good industry practices, manufacturers' requirements, and the requirements of the fleet plans included in this AMP. The Delivery Team is consulted during the review of these standards. 	<p>These standards are communicated to the Delivery Team.</p> <p>In-house management of the maintenance standards by Waipā Networks.</p>
Safety management system	<ul style="list-style-type: none"> The Health & Safety Management System is owned and managed by the People, Safety & Sustainability team 	All policies and procedures are available in the Waipā Networks document management system.
Public safety management system (PSMS)	<ul style="list-style-type: none"> The PSMS is managed by the People, Safety & Sustainability team in consultation with the Network team The PSMS is audited externally on an annual basis 	As above.
Monthly reporting on delivery performance	<ul style="list-style-type: none"> These are prepared by members of the relevant team and are reviewed by the Management Team (GMs and CE) and Board. 	The General Manager Network provides monthly reports to the Board on progress against our performance targets and progress against our development and lifecycle plans.

Table 38: How our asset management system documentations are reviewed and communicated

Documentation for some elements of the asset management system is not yet fully mature. These gaps are discussed in Section 9.3.3 below.

9.3.3 Asset management system maturity

Figure 85 shows our most recent assessment of our asset management maturity. Our AMMAT score of 2.6 is below the industry average of 2.8 and the upper quartile of 3. Our maturity has improved since 2024. Improvements were in contingency planning, information management, documentation and communication.

The latest AMMAT indicates that in some areas of our asset management system, development is complete, while in others, implementation is still ongoing and not yet fully integrated. Key gaps include finalising contingency plans for

major risks, increasing the formality of reviewing and aligning resources and competencies, and fully documenting all components of the asset management system. Although standards for planning, design, and construction are steadily improving, further action is underway to close maturity gaps, with expectations of substantial progress over the next 12 months. The establishment of robust investigation and internal audit processes is needed to ensure compliance and drive continuous improvement across the asset management system.

Our improvement plan is presented in Section 9.6.

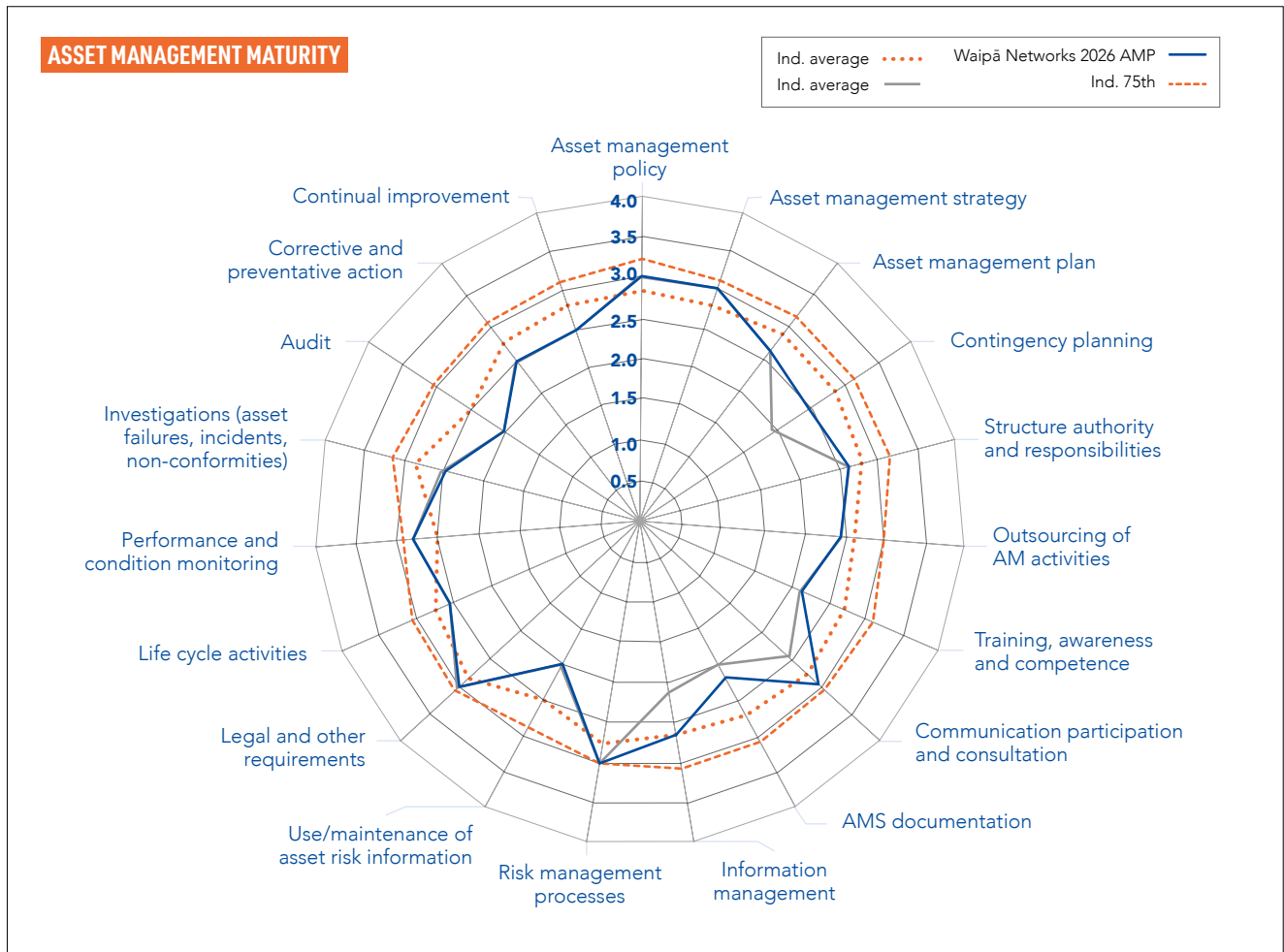


Figure 85: Waipā current asset management maturity

9.4 Our current IT and OT systems

9.4.1 Asset management information systems

We operate asset management information systems to manage our existing assets, plan network development and measure network performance. These comprise systems for

operational control and monitoring of network equipment, as well as systems for network analysis and corporate information management.

Table 39 summarises existing asset management information systems that support these functions.

System	Uses	Data held
ARC	<ul style="list-style-type: none"> • New connection process • ICP management • Logging and dispatch for service jobs, and for faults • Outage notifications and reporting 	<ul style="list-style-type: none"> • Master ICP data • ICP management data • Billing data • Service job information • Outage data, including SAIDI and SAIFI for all outages
MagiQ Cloud	Finance and payroll	<ul style="list-style-type: none"> • General ledger • Fixed asset register/RAB • Debtors and creditors • Purchase orders and invoicing • Stores and inventory management • Project accounting • Payroll
ArcGIS Geographic Information System	Geospatial asset database and reporting	<ul style="list-style-type: none"> • Asset geographical location • Owner, road, and property boundary • Asset data (attributes, age) • Asset health and asset condition are accessible
Field Maps Survey 123	<ul style="list-style-type: none"> • Field availability of GIS data • Capture of asset condition and maintenance information 	<ul style="list-style-type: none"> • Copy of GIS data • Inspection and maintenance forms • Asset condition and maintenance information
AutoCAD	Engineering design and drafting application	<ul style="list-style-type: none"> • System schematics and reticulation plans • Design drawings
Abbey SCADA (Supervisory Control and Data Acquisition)	Provides network visibility, monitoring, and control functions	<ul style="list-style-type: none"> • Operational status • Network loading data • Node voltage data • Alarm and fault data
Assura/Safety Culture	<ul style="list-style-type: none"> • Defects reporting and workflow monitoring • Health and safety management and reporting system – worksite safety risk management and capture field observations on asset condition 	<ul style="list-style-type: none"> • Defects and hazards – reporting and management • Worksite safety plans • Work permit (SWMS)
DigSILENT Powerfactory Network Modelling Software	<ul style="list-style-type: none"> • Loadflow modelling of the current and future network under steady state and fault conditions • Used to model the impact of proposed system enhancements and future demand 	<ul style="list-style-type: none"> • Network assets electrical attributes • Network architecture and connectivity
TVD/Avalanche Outage Communication Platform	An outage communication platform updates customers with known outage information and expected restoration times. This information is sourced from SCADA	No unique data held
Asset health and forecasting model	Calculate asset health and forecast renewals using GIS and asset condition data	<ul style="list-style-type: none"> • Asset health • Asset condition
Historian	Stores SCADA data	SCADA data
Microsoft Sharepoint and Teams	Stores and shares our documentation across the business	<ul style="list-style-type: none"> • Policies, procedures, standards, and various network, asset and project records

Table 39: Overview of our current asset management system

Our key systems are described in more detail in Section 9.4.3 to 9.4.8. We comment further on asset data in Section 9.5.

9.4.2 Recent improvements

Over the past three years (FY23 to FY25), we have implemented significant improvements to our IT systems. These include:

- Implementing the MagiQ Cloud system. This system provides our core finance, inventory, and project accounting functionality
- Implementing ARC for billing, ICP management, service management and outage notification and reporting. This replaced a range of legacy systems
- Deploying a GIS that consolidated our asset information. This includes the in-field data access and data collection tools
- Implementing DigSILENT for power systems modelling. This is a best-in-class loadflow modelling solution that enables load and fault modelling of our network
- Implementing Assura, our health and safety system. This system provides our people access to information and process documentation in the field and facilitates improved safety management and reporting.

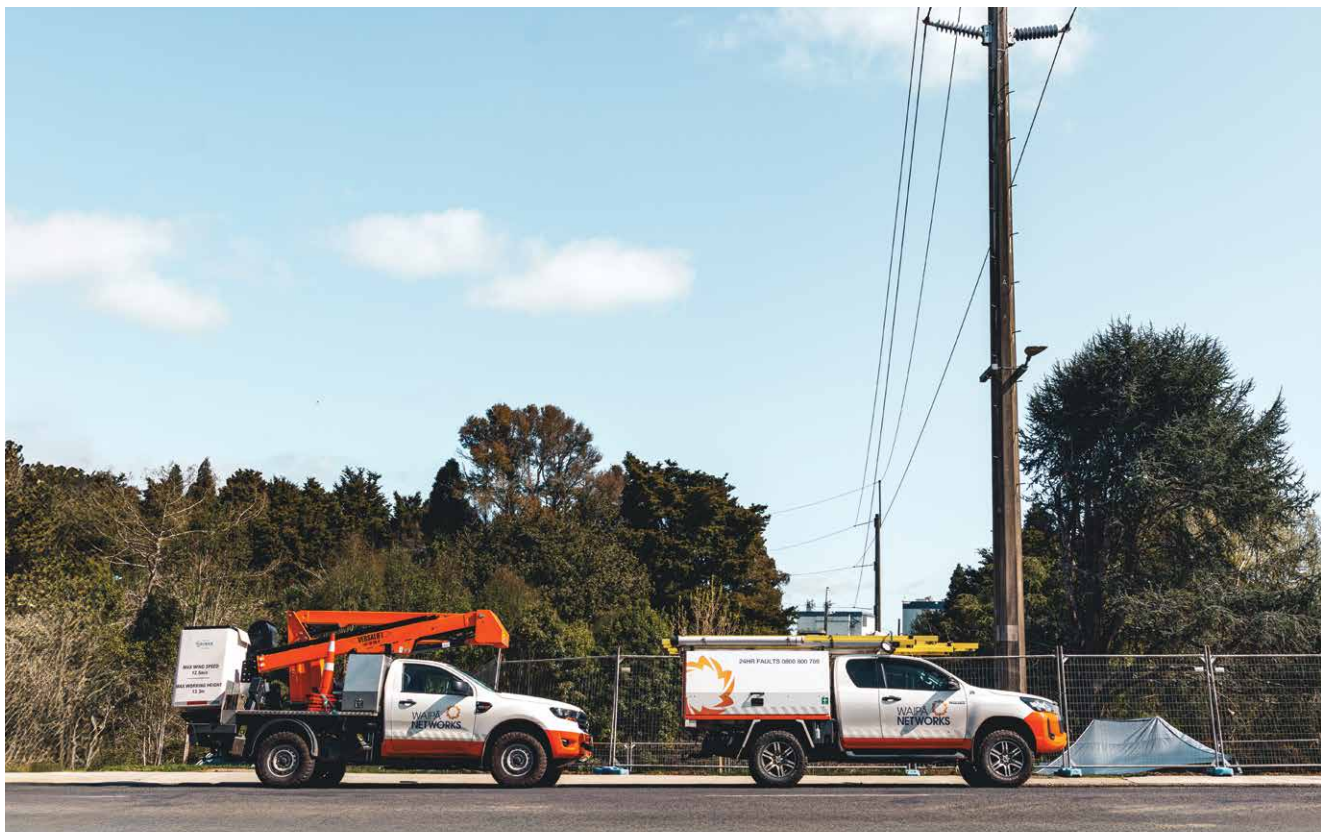
We have made the following progress in FY26:

- Consolidation of the GIS system infrastructure and data structure
- Discovery and approval of the Advanced Distribution Management System
- Discovery, high-level design and approval of a customer system as part of the Customer Process and Efficiency Project.
- Discovery work of the Works Management System
- Continues review and refinement of our ISSP.

9.4.3 ARC

The ARC system is used for customer connection management, service requests and faults management, and outage notifications and reporting. This includes:

- **ICP management:** The Customer Services Team uses the ICP database for daily operations and to provide source information to the outage notifications and reporting module. The ICP database contains a complete history of all outages and associated customer comments. ICP data comes from customers, retailers, electrical inspectors, and our processes. The ICP database is continually updated with new and disconnected customer information.
- **Billing:** The billing module is used to conduct day-to-day billing operations.
- **Service and fault management:** Customer service requests and fault jobs are managed within the ARC services module. The Customer Services team (and after-hours call centre) create, edit, and manage customer requests and faults.
- **Outage notifications & reporting:** The outages module contains details of planned and unplanned outages on the network. The module contains information on the physical network model and can accurately calculate the number of ICPs affected by each outage. The module provides functionality to notify retailers of outages in accordance with regulatory requirements (e.g., EIEP5A/5B notifications). Affected ICPs for planned and unplanned outages are sourced from the ICP database. This data enables the calculation of outage statistics to measure network performance for disclosure purposes and identify potential network problems.



9.4.4 MagiQ Cloud

MagiQ Cloud is the corporate finance and payroll system. It is a software-as-a-service solution provided by MagiQ Software. This includes:

- **Financial management functionality:** The MagiQ Cloud solution provides typical financial, asset register, purchasing, project accounting, payroll, stores and inventory management
- **Quoting:** The quoting database is a register of work orders within the MagiQ Cloud system and is used to maintain the status of each work order through its lifecycle. Other systems are used to capture the details of each work order (designs, quote details, etc.).

9.4.5 GIS and associated field deployment

We implement the ESRI suite of GIS products, including ArcGIS, Field Maps, and Survey123. These tools provide a robust platform for managing, optimising, and deploying asset information, as well as supporting field operations. We migrated asset data from our CAD environment and our legacy NCS enterprise database to the GIS.

ArcGIS serves as our central enterprise GIS platform, enabling the management of asset data through network connectivity and attribute rules, thereby enhancing data accuracy and accessibility for both internal and external stakeholders via desktop, web, and mobile devices. Field Maps facilitates the deployment of GIS data to field personnel, supporting efficient fieldwork by providing up-to-date asset information and enabling the creation of asset identifiers at the point of receipt, which ensures consistency across GIS, asset, and financial systems. Survey123 is used to conduct field asset condition surveys, providing valuable data that informs asset health assessments and helps prioritise preventive maintenance programmes.

Additional mobile products have been developed to support the creation of asset identifiers when a discrete asset (such as transformers, RMU, reclosers, air-break switches, etc.) arrives in our asset stores. This removes the need to re-enter asset information when equipment is installed and supports a consistent asset identifier across our GIS, assets, and financial systems.

9.4.6 Assura

This health and safety management and reporting system was implemented as part of the field mobility initiative. The system is also available on mobile devices. It enables our field services to manage worksite safety risks and provide field access to digital health and safety system documentation. It provides a framework for identifying and managing hazards, serves as a platform to complete worksite safety plans, captures field observations on asset conditions (defects), and supports management of the work crew and visitor induction (tailgate sign-on).

9.4.7 DigSILENT PowerFactory

We use DigSILENT PowerFactory network modelling software to assess the impact of increased demand and new connections on the network. The software is used to model the electrical network, perform load flow analysis, and calculate short-circuit current flows, aiding electrical network design and effective operational configurations.

9.4.8 Supervisory control and data acquisition system (SCADA)

Our SCADA provides network visibility and remote control, enabling safe and efficient network operation. The SCADA system also manages the ripple injection plants at Cambridge and Te Awamutu to control the load over peak times at GXP or feeders. It comprises a master station and a “hot standby” backup station in our control room in Te Awamutu and two remote operating terminals in the WEL Networks Control Centre in Hamilton (we contract our network control function to WEL Networks, which operates the SCADA system on our behalf).

The SCADA central server communicates with remote terminal units (RTUs) over UHF and VHF radio communications (refer to Section 13.19). The RTUs provide the interface with network equipment such as recloser control systems. The data collected includes feeder currents, voltages, real and reactive power, power factor and switch states. This information is used to inform operations, maintenance programs, network development planning, and to measure network performance.

The key risk for the SCADA system is the loss of network visibility and control. Cybersecurity is discussed in Section 8.3.6, and our SCADA contingency planning and plans are discussed in Section 8.5.2.

The current Abbey SCADA system is reaching end-of-life due to technical obsolescence. The current system cannot support the development of advanced functionality that will be required in the future. It is planned for replacement (refer to Section 9.7.4).

9.4.9 Cybersecurity

Cyberattacks are a key risk for our business, and we maintain an effective cybersecurity programme. This is described in our risk management Section 8.3.6.

9.4.10 Management approach

We operate a fit-for-purpose management model of our IT/OT. This includes in-house management of our IT infrastructure and user support. In some cases, local IT is provided as a hosted infrastructure solution to reduce maintenance effort and risk and maximise our access to experts. We also use a range of technology partners to provide expertise in specialist areas (e.g. cybersecurity). Many of our systems are now software-as-a-service (SaaS), which offers the advantage of reducing infrastructure management overheads while enabling easier access to the latest features and expert support.

9.5 Asset management information

9.5.1 Requirements for asset information

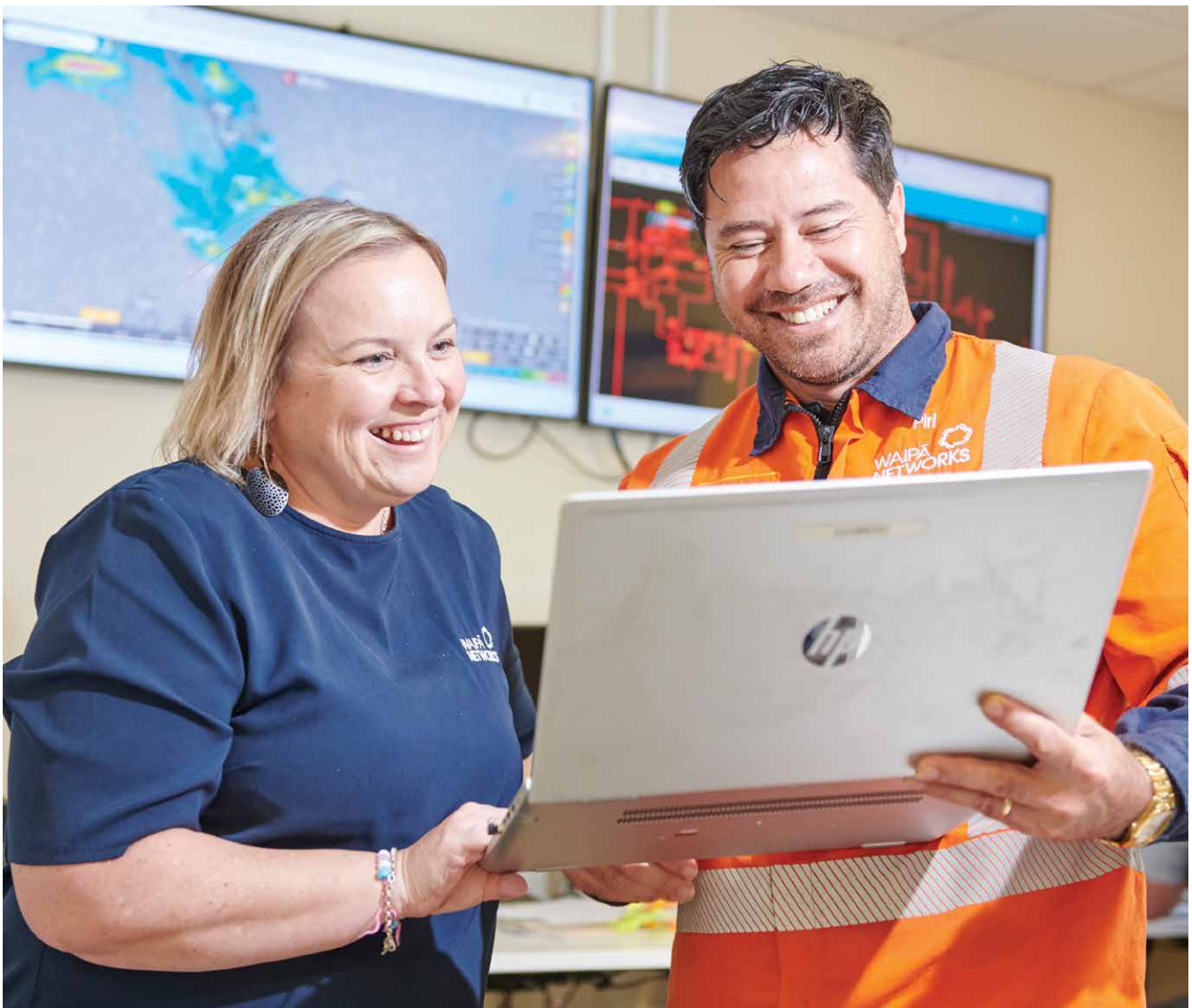
Good asset management is dependent on accurate asset data. The quality of our data on asset attributes, quantities, age, and condition supports our asset management strategy initiative #4, which aims to develop and maintain comprehensive fleet plans and renewal forecasts. It also supports our asset management strategy initiative #5, which is focused on improving the maturity of our asset management activities.

Our approach is to maintain asset information of the requisite quality to enable us to:

- **Manage safety effectively:** Knowing the location and condition of our assets to facilitate the safe operation of the network
- **Manage asset health:** Knowing the types of assets, their location, condition, and criticality, so we can determine their current and forecast asset health and risk
- **Manage asset failure risk:** Knowing the defects on the network, so these can be assessed and remediated promptly

- **Model the network to meet future customer needs:** Knowing the capacity and connectivity between assets to allow us to model the impact of future customer needs
- **Meet our regulatory requirements:** Providing accurate information to meet our regulatory disclosure requirements
- **Ensure efficient operation of the business:** Capturing capex and opex information that allows for analysis of cost trends and factors that could be impacting efficiency and delivery.

Table 40 presents our key asset management information requirements to support the asset management system. Our GIS system acts as the main repository for asset data, supported by Survey123, FieldMaps, and our health and renewal forecast models. Operational data is held with a number of systems, including AutoCAD, SCADA and ARC. Assura retains risk, safety and asset defect information.



Information	Why required	System repository
ASSET INFORMATION		
Asset attributes ⁸²	Used for asset health assessment and IDs.	<ul style="list-style-type: none"> • ArcGIS
Asset health, criticality and risk	Used for asset renewal forecast, defining renewal projects and IDs.	<ul style="list-style-type: none"> • Health and renewal models • ArcGIS
Asset condition and maintenance	Used for asset health assessment.	<ul style="list-style-type: none"> • FieldMap • Survey123
Asset connectivity	Used for asset accurate loadflow modelling and outage management in ADMS. Will be required for DERMS.	<ul style="list-style-type: none"> • ArcGIS • ADMS*
Operational data (loadings, etc.)	Support loadflow modelling to understand network constraints and IDs.	<ul style="list-style-type: none"> • Abbey SCADA • Historian • ADMS*
HV Load flow model	Used for modelling constraints and future extensions to the network.	<ul style="list-style-type: none"> • DigSILENT
Vegetation records	Used to prioritise and control vegetation.	<ul style="list-style-type: none"> • ArcGIS
Protection settings	Ensures the correct operation and coordination of network protection.	<ul style="list-style-type: none"> • Spreadsheets
Asset financial records	Required for financial and IDs.	<ul style="list-style-type: none"> • MagiQ Cloud
OPERATIONS		
As-built drawings	Retained as a record of work completed.	<ul style="list-style-type: none"> • AutoCAD • ArcGIS
Fault and reliability records	Used to analyse faults, network performance and IDs.	<ul style="list-style-type: none"> • ARC • ADMS*
Asset defects work orders	Used to control defect repairs. Can be used to analyse for latent defects on assets.	<ul style="list-style-type: none"> • Assura/Safety Culture
RISK MANAGEMENT		
Asset risks, controls and treatments	Used to manage risks associated with network assets	<ul style="list-style-type: none"> • Risk register • Assura
Assura		

Table 40: Summary of asset management information requirements

* The ADMS is under development.

⁸² Attributes cover the asset type, manufacturer and model, capacity, configuration, date of manufacture, data of installation, date of retirement, location, etc.

9.5.2 Definitions for data accuracy

We have assessed our data accuracy based on the Commerce Commission data accuracy score, with the addition of measurable definitions (which can be applied to data audits). These are shown in table 41.

ID data accuracy	Commerce commission definition	Measurable definition
4 – Very good	Good quality data is available for all assets.	Data is available for all assets. Data accuracy is greater than 99% (error rate less than 1/100).
3 – Good	Data is available for all assets but includes a level of estimate where there is some poor data.	Uncounted assets less than 1%. Data accuracy is greater than 90% but less than 99% (error rate between 10/100 and 1/100).
2 – Average	Good quality data is available for some assets and includes estimates for uncounted assets.	Uncounted assets between 1% and 10%. Data accuracy is greater than 50% but less than 90% (error rate between 50/100 and 10/100).
1 – Poor	Good quality data is not available for any assets, and estimates are likely to contain significant errors.	Uncounted assets greater than 10%. Data accuracy is less than 50%.

Table 41: Data accuracy definitions

9.5.3 Maintenance of our asset information

The Engineering, Network information and administrative staff manage the asset information. Our asset inspections are the main process by which we maintain the accuracy of asset information. Field crews record changes or corrections to asset information (and some asset components) during the inspection process. We have also undertaken specific audits of particular asset types (e.g., ABSs to determine manufacturer type and identify latent defects).

Our inspection and testing are defined in the fleet plans (refer to Section 13) and are focused on identifying end-of-life drivers (e.g., major spalling on a reinforced concrete pole or rust on distribution transformer tanks).

Asset defect information (that has health and safety implications) is captured via Assura. The data drives corrective work and tracks health and safety measures.

9.5.4 Data quality and limitations

Our network was established approximately 100 years ago. Data has not always been captured in accordance with current standards. Records have sometimes been lost or compromised over time, meaning asset records today are not always complete and accurate. Our recent surveys were conducted in 2019, and an aerial LiDAR survey was conducted in 2021, including high-resolution pole-top images on rural poles, and have added to the overhead asset information available for asset management. In FY24 and FY25, we surveyed poles not covered in 2021, mainly in the urban and rural townships and some rural areas.

Table 42 and table 43 summarise the accuracy of our asset data. We have good data on poles and name-plated assets. The quality data on poles reflects that this has been a focus for the business (where we completed comprehensive pole

top surveys across our rural and urban assets). Whilst we do not have condition data on all crossarms, switchgear and transformers, this will eventually reach close to 100% as the inspection cycles are completed (in a form that allows input into our systems).

We have limitations in our asset age data for some conductors and cables. The installation age of our overhead conductor was not well recorded, particularly for LV assets (which was not uncommon at the time). We have used pole data to provide an age indicator where possible.

We have limitations in our asset condition data for the conductor and cables. For aerial conductors, there is no common, practical, or non-invasive means of assessing conductor condition other than visual observation (which does not always provide sufficient information). For underground cables, condition assessment can only be undertaken through cable testing, and depending on how the cable is terminated, this can be expensive and problematic. In the absence of condition data, reliable age and performance data (for example, fault history) is required to forecast renewals.

We have limitations for some underground cable locations. Historically, there are cables whose plotted location is less accurate than the current requirements under the Utilities Code. The risk is currently being managed by the beforeUdig process and our cable locates service.

Historically, detailed knowledge of the LV network connectivity and operational visibility was not required, as field staff generally resolved issues during fault management, new connections, or follow-up to customer complaints. We are forming a strategy to improve LV network visibility. This is included in our Asset Data Improvement Roadmap and future meter data analytics project.

Asset class	ID age profile data accuracy	% with accurate age	% of assets with condition data	ID health grade data accuracy	Current accuracy
Poles	3	97%	84%	3	Good
Crossarms	–	95% based on pole age	55%	–	Average
11kV conductor	1	75%	0%	2	Poor
11kV cables	1	38%	0%	1	Poor
OH switchgear	1	60%	5%	1	Poor
Ringmain units	3	95%	20%	3	Good
LV lines	2	74%	0%	2	Poor
LV cables	1	29%	0%	1	Poor
OH transformers	3	99%	82%	3	Good
GM transformers	3	98%	49%	3	Good
Voltage regulators	3	100%	36%	3	Good

Table 42: Summary view of asset data accuracy (from an information disclosure perspective)

Asset class	Gap	Why required
11kV conductor	Missing conductor types.	Enables accurate loadflow and fault modelling.
LV conductor	Missing conductor types.	As above.
11kV cables	<ul style="list-style-type: none"> Missing cable types Inaccurate location for some cables Cable joint location. 	<ul style="list-style-type: none"> Enables accurate loadflow and fault modelling Enables accurate cable location maps, reducing the need for field locations which improves efficiency Providing additional attributes for asset health assessment.
LV cables	<ul style="list-style-type: none"> Missing cable types Inaccurate location for some cables. 	As above.

Table 43: Other known asset information gaps

Asset attributes, age and condition are not the only data that can be used to determine asset health. Understanding the rate of asset deterioration and having access to data on subcomponent issues can inform our health assessments over time. Hence, increasing the linkage between asset-related information to improve asset health assessment, including:

- Linking fault and defects data to assets (in the GIS) to enable us to maintain a history of faults and defects for asset types. Over time, this will enhance our knowledge of failure modes that we experience in our region, which would support the adoption of Waipā Networks-specific expected lives and when the onset of unreliability can be expected (this is industry-wide data)
- Recording cable joint location. This is a useful input into determining the health of cables
- Linking hazard information to asset types. Having safety notices linked to assets would provide useful data to support criticality and health assessments.

We have various plans to improve the quality of our asset data, which are presented in Section 9.6.

9.6 Asset management improvement plan

9.6.1 Objectives and targets

The Asset Management Improvement Plan (AMIP) is a strategic improvement roadmap that will strengthen our asset management capability to deliver better business and customer outcomes through more reliable, efficient, and evidence-based investment in network assets and operations.

The plan addresses key business weaknesses identified using the Asset Management Maturity Assessment Test (AMMAT) self-assessment framework and provides a structured pathway to align with good industry practice.

We have defined targets in relation to asset management maturity, information and systems:

- Process Maturity: Achieve an Asset Management Maturity Assessment Tool (AMMAT) score of 3.0 by the end of FY28, ensuring all elements of the asset management system are in place and integrated
- Information: Improve asset data accuracy, aiming for a score of 4 (error rate <1%) for critical assets and 3 (error rate <10%) for others, validated through audit
- Data systems: Ensure all important asset data is available and integrated in GIS
- Note: The AMIP only considers the GIS and related systems. Other information system improvements are discussed in Section 9.7.

Figure 86 illustrates the overall plan timing and sequence. We are phasing the activities over the next two years to achieve completion by the end of FY28 and inclusion in the 2028 AMP.

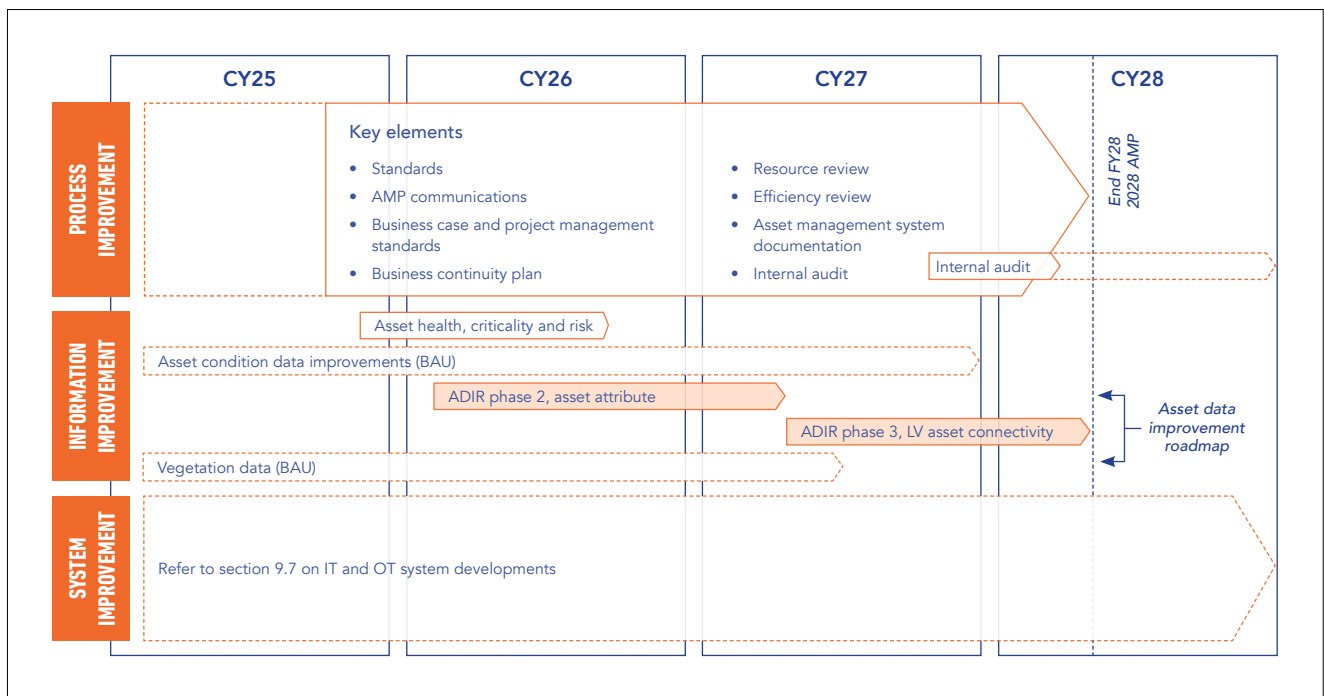


Figure 86: Overview of the improvement plan

9.6.2 Process improvements

Table 44 shows the key process improvement activities and elements that are required. We are developing a resourcing plan that would be required to undertake the work by FY28. Post completion, we will move into a continuous improvement phase supported by internal audit.

Improvement activity	AMS or IMS element
Completion of the remaining planning standards	Development planning
Completion of the design, construction, condition assessment and maintenance standards	Standards development
Enhance communication and responsibilities in relation to asset management	Communication and participation
Continual improvement of fleet plans	Fleet planning
Define the asset management information system requirements ⁸³	Information management and development
Develop a business case guide	Delegated Authority
Develop project scoping guides covering project definition, concept design and cost estimation standard	Development planning Lifecycle planning
Finalise the existing BCP contingency plans and develop any new plans	Contingency planning
Undertake formal asset management resources and capability planning	Capability development
Undertake an efficiency assessment of asset management processes and asset management information systems	Efficiency analysis
Complete document of the AMS, including contractor management, investigation, corrective and preventative actions	Overall, AMS, procurement and contract management, investigations, and defect management
Commence internal audits on risk management, information management, and continual improvement	Internal audit

Table 44: Process improvement elements

9.6.3 Asset management information improvements

We have developed an asset information improvement plan, which is shown in table 45 and table 46 (the plan was subject to approval at the time of writing the AMP). These focus on addressing identified gaps in asset management information by implementing targeted improvements. These include enhancing asset attribute data, improving the accuracy of age and condition data for health forecasting, and capturing LV connectivity. In particular:

- Asset Data Improvement Road Map – Phase 2, aims to close the asset data gaps primarily for conductor and cable types of attributes. The plan involves additional resources, such as temporary GIS operators and field staff, to support data validation and ensure the reliability of asset information.

- Asset Data Improvement Road Map – Phase 3, aims to develop a full LV network connectivity model. This is future work. The scope is broadly defined, with the methodology to be further optimised. Budgetary implications will then be established.

Table 46 describes the asset attribute improvement actions. For some assets, where capturing age data is problematic, we will rely on condition data (which will be progressively improved as condition inspection standards evolve and inspections are completed). However, for some assets where condition assessments are challenging, we need to improve age data to enable more accurate health forecasting.

⁸³ Attributes cover the asset type, manufacturer and model, capacity, configuration, date of manufacture, data of installation, date of retirement, location etc.

Information	System	Improvement activity	Target completion
Asset health, criticality and risk	ArcGIS	Add a temporal view of asset health, criticality and risk.	CY26 Q3
Asset condition and maintenance	Field Maps	Configure Field Maps with the new condition assessment and maintenance standards (part of BAU process).	CY26 Q2
Asset attributes ⁸⁴	ArcGIS	Improvement to attributes, age and location data required for assets. The material work is required on conductor and cable. Refer to table 46 below for details.	CY27 Q1
Asset connectivity	ArcGIS	Develop LV connectivity in GIS (which can later be used in congestion mapping and LV management).	Subject to business case
Vegetation records ⁸⁵	ArcGIS	<ul style="list-style-type: none"> Complete the capture of vegetation data (as part of BAU survey process) Integrate owner and notification information. 	CY27 Q1

Table 45: Asset management information improvements

Asset class	Improvement actions	Notes
11kV conductor	<ul style="list-style-type: none"> Standardise conductor types Update conductor types and age from primary records 	Age and faults will be a primary source for asset health forecasting until condition assessments (i.e. sampling and testing) are undertaken.
11kV cables	<ul style="list-style-type: none"> Standardise cable types Update cable age, type, location and cable joint location from primary records 	Age and faults will be a primary source for asset health forecasting until condition assessments evolve.
LV conductor	<ul style="list-style-type: none"> Standardise conductor types Update conductor types and age from primary records 	Age and faults will be a primary source for asset health forecasting.
LV cables	<ul style="list-style-type: none"> Standardise cable types Update cable age, type and location from primary records 	As above.
OH switchgear	<ul style="list-style-type: none"> Utilise inspection records to update attributes 	Condition will be used for health forecasting, as capturing age data is not practical.
Poles Crossarms ringmain units OH transformers GM transformers Voltage regulators	<ul style="list-style-type: none"> Utilise inspection records to update attributes, including age 	Condition and age data will be used for health forecasting.
LV Network Connectivity	<ul style="list-style-type: none"> Establish a connectivity model for LV network 	This will be used for future network capacity hosting and congestion modelling, and LV works management. This is future work. The scope is broadly defined, and the methodology is to be optimised. Budgetary implications yet to be established.

Table 46: Asset attribute information improvements

⁸⁴ Attributes cover the asset type, manufacturer and model, capacity, configuration, date of manufacture, data of installation, date of retirement, location etc.

⁸⁵ This includes the tree location, owner, notification, owner responses and trimming history.

9.6.4 Expenditure forecasts

While we are working to better define and forecast Asset Data Improvement – Phase 3 and process improvement workstream, the benefits of \$240k of opex investment related to asset data improvements will mainly enhance data quality, and reduce risks (rather than offer direct cost savings). These improvements will lower asset-related risks and support

evidence-based decision-making, leading to more efficient and optimal asset renewals. Making optimal and efficient decisions will result in better outcomes for consumers. Additionally, data enhancements lay the groundwork for the next generation of operational technology.

These programmes are aligned to our Asset Management Policy and Asset Management Strategy.

Project/programme	Description	Forecast	Timing
Asset data improvement – phase 2	As per Section 9.6.3	\$240k SONS opex	FY27
Asset data improvement – phase 3	As per Section 9.6.3	Being quantified	Tentatively FY28
Process improvements	As per Section 9.6.2	Being quantified	Tentatively FY27-FY28

Table 47: Programme budget and timing

FY26 real \$

9.7 Planned IT and OT system developments

9.7.1 Information system strategic plan

The Information Technology team produced a draft information system strategy plan (ISSP) consisting of key asset management and corporate workstreams. From Q4 FY26, we began the process of refreshing the ISSP to reflect the key initiatives required to support our new business strategy (see Section 2.3.2). As a part of this improvement journey, we will first develop a business capability model to inform the ISSP development, then define the IT and OT system needs.

While the ISSP update is undergoing refinements, several low-regret projects are progressing, including:

- Network stream: SCADA replacement and ADMS development (see Section 9.7.3)
- Customer and community engagement stream: Phase one of a new customer system (see Section 9.7.2)
- Works management process: (see Section 9.7.2).

9.7.2 IT development plan

Customer system – phase 1

In FY26-27, we will implement the first phase of a new customer system delivered by One NZ, using Amazon Connect as the enabling platform. This phase provides the minimum viable capability required to meet new customer and complaints regulatory obligations that start

coming into effect from April 2026, while establishing a scalable foundation for future improvements. It will replace fragmented, manual processes with a centralised customer record and interaction history, systemised workflows and SLA tracking for key customer processes, and improved reporting to support audit, performance management and regulatory reporting.

Phase Two would extend workflows and customer self-service functionality once Phase One is operational. This is under investigation and subject to separate approval, and is currently not included in the expenditure forecast.

Works management system

Process mapping and future state design for a delivery project lifecycle confirmed the need for a dedicated works management system to enable end-to-end workstream tracking. We completed market research and proof of concept trials in CY25, and a recommendation on implementation will be made once the ISSP digital roadmap and integration with existing systems have been confirmed as viable.

Expenditure forecasts

Table 48 shows our current view of our IT system developments. As noted above, we are still refining our view of the ISSP and related IT development projects, and no capex related to these projects has been included in this AMP. This will be updated in future AMPs.

System	Indicative or planned developments	Forecast	Timing
Computer equipment	General provision for office infrastructure and desktop hardware	Average of \$86k p.a. Non-Network Asset capex	FY27-FY36
Computer software	General provision for software purchase (non-SaaS)	Average of \$86k p.a. Non-Network Asset capex	FY27-FY36

Table 48: Indicative or planned IT system developments

FY26 real \$

9.7.3 OT development plan

We are progressing two significant OT system initiatives:

- ADMS development.
- SCADA replacement.

ADMS development

During FY25, we approved the direction to implement an advanced distribution management system (ADMS) and GE PowerOn was selected in conjunction with the renewal of a new 15-year control room service contract with WEL Network.

In FY26, we completed discovery and scoping work, and assessed two options:

- **Option one** – set up a Waipā Networks-owned ADMS for WEL Networks’ control room to operate.
- **Option two** – extend WEL Networks’ existing ADMS and infrastructure to co-host our network and SCADA, and interface with our corporate systems.

We did a joint investigation with WEL Networks that confirmed option two as the preferred solution. It offers greater benefits in terms of efficiency, cost and risk for both organisations. The Board approved the business case in December 2025. In Q4 FY26, we’ll engage and secure implementation partners, including WEL Networks. Implementation will begin in FY27, with core features commissioned in Q3 FY27. We’ll roll out peripheral features through FY28.

The GE system provides an advanced, data-driven, customer-focused, and integrated network operation and reporting platform while supporting future integration of DER and LV network platforms. The following are the core modules and features being implemented:

- **Distribution management system (DMS):** This offers core features such as HV Diagram, Works Package Management (e.g., switching and permitting), and GeoView, which support efficient network operations and restoration activities.
- **SCADA:** This provides the SCADA interfaces with field devices, indication, alarm and control.
- **Outage management system (OMS):** This provides tools for outage detection, management, and restoration, including incident management and outage reporting.

- **A suite of customised features and peripheral features in ADMS:** Key features include outage notification (registry and customer), historical outage map Power BI reliability reporting, field mobility, and load controls.

This system brings significant benefits to customers and the network. Customers will experience faster detection and restoration of power outages and improved communication during incidents. The system enables proactive identification and resolution of network issues, leading to better power quality and fewer unexpected disruptions. The system will also provide dashboards, reliability statistics and reports to support asset management, regulatory compliance, and continuous improvement initiatives.

The future work plan is to integrate ADMS with our future customer system (once confirmed) and unlock future capabilities, including LV management, field mobility, and meter data/insight integration.

SCADA replacement

Our current SCADA system is entirely built on the proprietary ABBEY system, which comprises of the PowerLink SCADA software and TopCat RTU/Radio in the field and master station. The ABBEY system is reaching end-of-life and presents a material technology support and obsolescence risk. The existing Abbey system will be replaced as follows:

- The SCADA software will be replaced by the GE ADMS system as above. The GE systems offer enhanced functionality to improve operational efficiency and manage switching and outage restoration. It offers a technology pathway for future LV network management, LV works management and interface with DER. The GE SCADA is expected to be operational in FY27
- The RTU/Radio hardware will be replaced by our Communication Network upgrade project under Network Development as network capex 9.6.5. The new communication system comprises of digital microwave backbone, which also resolves the current communication channel congestion issues as well as replacing legacy assets, enabling further network automation devices to be incorporated.

Expenditure forecasts

Table 49 shows our indicative and planned OT developments.

System	Indicative or planned developments	Forecast	Timing
ADMS implementation (SCADA replacement)	Replacement of Abbey SCADA Systems by implementing GE ADMS co-hosted with WEL. Refer to the above text.	\$2.3m SONS opex	FY27-FY28
ADMS operation and maintenance costs	ADMS BAU maintenance and co-hosting service provided by WEL. Components include costs of ADMS licensing, WEL ADMS support and co-hosting and Waipā’s contribution towards annualised four-yearly major version upgrade.	\$805k per annum SONS opex (FY27 cost will be lower as a part year)	FY27-FY36

Table 49: Indicative or planned OT system developments

FY26 real \$

9.8 Business support

9.8.1 Function overview

Business support (BS) comprises our function that indirectly supports the electricity network operations. Referring to the asset management system (see figure 87), BS covers:

- Corporate strategy
- Customer and stakeholder management
- The majority of the aspects of the integrated management system (e.g. health and safety, environmental, risk, information management and IT)
- Other corporate activities include HR, finance, legal, communications, commercial, pricing, regulatory, and property management.

9.8.2 Forecast expenditure

Business support opex in the 2026 AMP totals \$82.9m for the 10-year period FY27 to FY36. There is a 23% increase in business support expenditure included in the 2025 AMP⁸⁶ due to:

- Reallocation of funds between Business Support and System Operations and Network Support as we've refined the methodology used to forecast and allocate non-network opex to better reflect projected costs and planning assumption
- Labour rates increase.

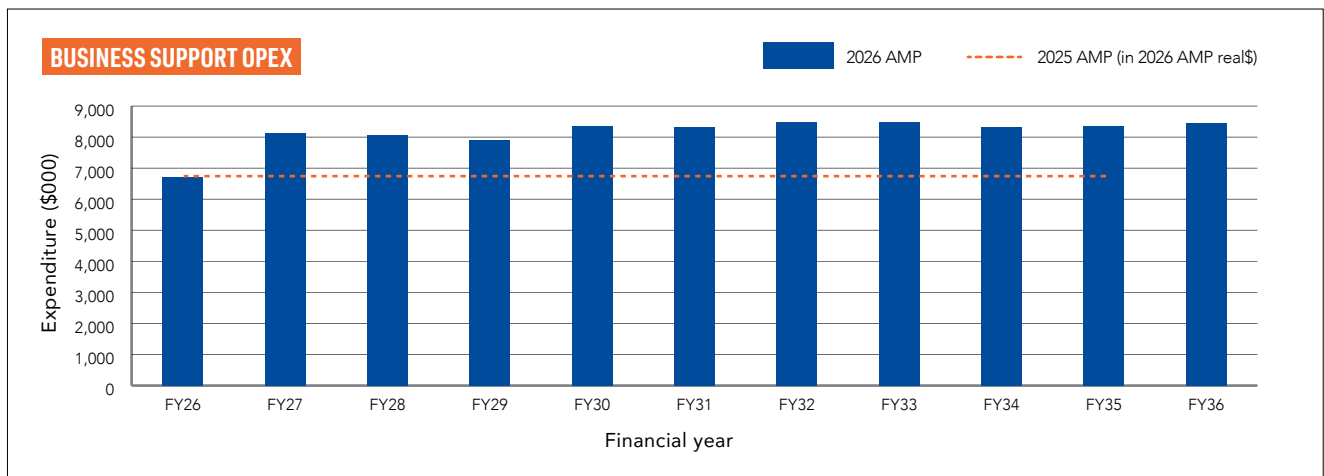


Figure 87: Business support forecast operational expenditure

Description	FY27	FY28	FY29	FY30	FY31	FY32-36	Total
Base business support ⁸⁷	8,128	8,054	7,893	8,365	8,328	42,129	83,282

Table 50: Forecast expenditure

FY26 real \$000

⁸⁶ The 2026 AMP period is FY27 to FY36 and the 2025 AMP period is FY26 to FY35. Hence, the periods are not directly comparable, but provide an indicator the scale of the change. The variances refer to the comparable FY27 to FY35 period, therefore the total of variances for the comparable range does not equal the total variances for the 10-year forecast. Both values for 2026 AMP and 2025 AMP in 2026 real\$.

⁸⁷ Based on FY26 forecast, excluding project and one-off costs.

9.9 System operations and network support

9.9.1 Function overview

System operations and network support (SONS) comprises our function that directly supports the electricity network operations. Referring to the asset management system (see figure 84 in 9.3.1), SONS covers:

- Aspects of network operation and work delivery, including WEL's control room service, ADMS-related services and outage and operational management
- Strategic asset management
- Asset management planning (covering development, fleet lifecycle, new connections, resilience and standards development)
- Performance management
- Continuous improvement
- Contingency planning in relation to the network
- Information management in relation to the network system.

9.9.2 Forecast expenditure

We've refined the methodology used to forecast and allocate Non-Network Opex to better reflect projected costs and planning assumptions including refinement in the allocation of overhead costs.

There is a 7% reduction in SONS expenditure compared to 2025 AMP⁸⁸ due to a reallocation of funds between Business Support and System Operations and Network Support.

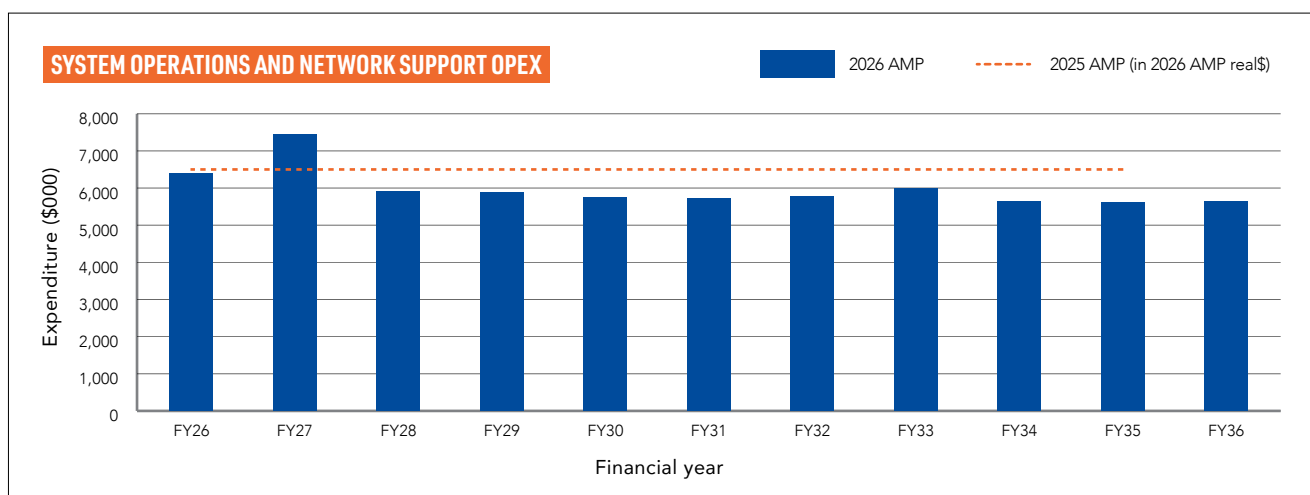


Figure 88: System operations and network support forecast operational expenditure

Description	FY27	FY28	FY29	FY30	FY31	FY32-36	Total
Base SONS ⁸⁹	4,959	4,599	4,480	4,642	4,593	23,274	41,458
Asset data improvement – Phase 2	240	–	–	–	–	–	240
ADMS implementation	2,140	200	–	–	–	–	2,340
ADMS support and maintenance	150	743	1,041	748	751	4,105	7,538
Digital communication network OT support	70	70	70	70	70	350	700
Total	7,439	5,912	5,891	5,760	5,714	28,637	58,754

Table 51: Forecast expenditure

FY26 real \$000

⁸⁸ The 2026 AMP period is FY27 to FY36 and the 2025 AMP period is FY26 to FY35. Hence, the periods are not directly comparable, but provide an indicator the scale of the change. The variances refer to the comparable FY27 to FY35 period. Both values for 2026 AMP and 2025 AMP in 2026 real\$.

⁸⁹ Based on FY26 forecast, excluding project and one-off costs.



10. NETWORK TRANSFORMATION

10.1 Introduction

New Zealand is transitioning in terms of how it produces and uses energy. Reducing emissions through electrification and increasing renewable generation is essential for New Zealand to meet its emission targets; at the same time, technological advances are making alternative energy options more economically accessible to customers.

In this section, we describe what is driving the energy transformation, how these drivers could impact Waipā Networks, the actions we are currently taking, the areas for future work, and how we intend to progress the development of a roadmap.

Developing and implementing a network transformation roadmap (the “roadmap”) is a key asset management strategy for Waipā Networks (asset management strategy #3). We must ensure that our services support our region’s decarbonisation efforts and customer choices to secure a sustainable future in New Zealand.

Customer and community engagement is central to how we understand, respond to, and sequence the energy transformation. Customer and community engagement is intended to improve our understanding of how different communities experience the network today, how they perceive the impacts of change, and what trade-offs matter most to them. This insight will be used to test assumptions and inform future decisions, rather than predetermining outcomes. That is why our current focus has been on establishing an engagement framework and how we will

use this to reshape our distribution planning, starting with a trial in the Kāwhia area. The intent is to better understand the lived experience of supply reliability, affordability, and resilience within that community, and how network decisions are perceived locally. This work is expected to be iterative and may take longer than initially anticipated, and may be refined for future engagement. It will also inform broader questions around cost allocation and affordability, including whether and how costs associated with place-based outcomes should be shared across the wider customer base.

Together, Sections 3 and 10 describe how Waipā Networks is responding to energy transformation through a combination of technical planning, system capability, and sustained customer and community engagement, recognising that long-term network outcomes depend on shared understanding and informed choices.

This roadmap represents an early stage in Waipā Networks’ response to energy transformation. Our current focus is on building understanding, capability, and evidence rather than defining final solutions. Many elements described in this section are intentionally directional and will be refined as customer engagement, system insight, and industry settings evolve. Our approach to the continued development of our network transformation roadmap is guided by the assessment of what best serves our customers over the long term is the best course of action. Where our views differ from prevailing regulatory or industry assumptions, we plan to explain our reasoning transparently.

10.2 Summary

Our work on understanding the energy transformation and building our network transformation roadmap continues. The key takeaways from this work are:

- There is significant uncertainty regarding the impact of the energy transformation on our network. The most critical uncertainties relate to the pace of electrification, technology adoption, future demand growth, and the range of network service offerings that may emerge. How these factors play out could significantly impact network demand, the complexity of operating the network, and the extent of investment required in new network capacity and organisational capabilities. Achieving clarity on these factors will take time.
- We have updated our demand forecast scenarios, indicating that network demand in FY50 could range from 148 MW to 244 MW, a difference of 96 MW. The forecasts consider a range of possible outcomes, from rapid growth driven by widespread electrification and technology uptake to more moderate increases if adoption is slower or flexibility is limited. This range highlights significant uncertainty regarding future network demand.
- Current challenges include predicting the pace and scale of network demand growth, managing operational complexity, and identifying investments that will not be stranded in the future. Hence, our focus in the short to medium term is to progress “low regret” investments and capability building. That is, we will continue to progress investments that will be utilised (as far as can be reasonably foreseen) across the range of scenarios. Our work on the Te Awamutu architecture review will provide a view of our investment choices and identify low-regret investments to support growth and transformation in that region.
- We continue to monitor market developments to deepen our understanding, refine our thinking, and establish our positions in areas we have yet to explore thoroughly. This uncertainty requires flexible investment strategies to avoid stranded assets and to ensure the network can adapt to changing demands. The next 12 months will focus on developing and implementing a network transformation roadmap, with ongoing monitoring of market developments and refinement of strategic position.
- Low voltage (LV) monitoring is a key component, helping us understand network performance and inform future investment and operational decisions. This work continues to progress.
- Given the scale of uncertainty, customer and community engagement is critical to testing assumptions, shaping acceptable service outcomes, and informing the timing and sequencing of transformation investments.

10.3 Drivers of the energy transition

Multiple drivers of energy transition exist, including government policy initiatives, regulatory frameworks, technological advancements, cost reductions, and customer choices. However, ultimately, customer actions will lead to the adoption of new technology and changes in how the electricity system is used.

While policy, technology, and economics set the context for the energy transition, customer choices ultimately determine how and when these drivers translate into network demand and operational change. Understanding customer intent, constraints, and preferences is therefore essential to effective network transformation planning.

10.3.1 Policy perspective

The central pillars of decarbonisation are the electrification of transport and heat (both process and general). This is supported by expanding the use of distributed energy resources (DERs), increasing the availability and use of flexibility services, and 100% renewable electricity.

From a policy perspective, New Zealand has committed to emissions reduction goals by 2050 and set emissions budgets for 2022 to 2035 (the total permitted emissions for the 2022-25, 2026-30, and 2031-35 periods).

New Zealand's second emissions reduction plan (ERP2), released in December 2024, outlines actions for the 2026–2030 period to meet the second emissions budget. ERP2 places greater emphasis on decarbonising transport, doubling renewable electricity generation, improving waste management, and implementing nature-based solutions like wetland restoration (compared to ERP1). It also introduces more detailed actions for the 2026–2030 period, aiming for a 17% reduction in emissions between 2022 and 2035.⁹⁰

ERP2 goals and strategies are:

- Ensuring New Zealand stays within its second emissions budget, with a limit of no more than 305 megatonnes of emissions between 2026 and 2030
- Reducing transport emissions by 41% by 2035 by reducing total light vehicle kilometres travelled, increasing zero-emissions vehicles in the light fleet, reducing freight emissions, and decreasing the emissions intensity of transport fuel
- Reducing waste emissions through increased investment in the Waste Minimisation Fund, capturing gases from organic waste and landfills, and implementing a stewardship scheme for refrigerants
- Supporting the goal of doubling renewable electricity generation to reduce overall emissions.
- Progressing plans for nature-based solutions like restoring wetlands, which help absorb carbon dioxide.

⁹⁰ Emissions reduction plan, <https://environment.govt.nz/what-government-is-doing/areas-of-work/climate-change/emissions-reduction-plan/>

Since the election of the National-led government, there have been some adjustments to the priorities and approaches for achieving New Zealand's 2050 emission goals. While the overarching commitment to net-zero emissions remains in place, the government has signalled a greater focus on practical, technology-driven solutions and economic growth. There is a renewed interest in leveraging market mechanisms and supporting infrastructure development to accelerate the adoption of low-emissions technologies, while maintaining flexibility for businesses and consumers.

10.3.2 Technological advancements and cost reductions

In a recent report from Sapere, they conclude that, from 2026, all-electric households can expect their total annual electricity cost, including capital costs, to be lower than the combined petrol, gas, and electricity bills (including the relevant capital costs) they would otherwise pay.⁹¹ We suspect this to be an optimistic view, however there will come a time when this will hold true.

New technology continues to advance, and costs are forecast to fall further. The continued reduction in the cost of solar PV installations, batteries, and EVs (and the increasing fossil fuel costs) will increase customers' adoption of these technologies.⁹² Electric vehicle prices have fallen significantly over the past three years. These price drops are due to a combination of factors, including reduced demand, a softening of government incentives, production overcapacity in China, and increased supply of used models from corporate fleets.

As the technology that enables the electrification of industrial process heat improves, the economics of the technology are improving. Heat pumps can have a high coefficient of performance (COP), meaning operating costs are around 45% to 75% of a natural gas or coal boiler. Industrial heat pumps can currently reach temperatures of up to 185°C, with some prototypes achieving even higher temperatures and industry experts predicting they will exceed 200°C in the near future. While many common applications operate below 100°C, newer high-temperature models are suitable for a growing range of industrial processes, such as drying, sterilisation, and steam generation.⁹³

10.3.3 Customer choices

Technological advancements and cost reductions lead to greater customer choice.

Customers are at the centre of the energy transformation. This reinforces the need for us to engage early and regularly with customers and communities to understand how different customer groups wish to participate in the transition, and what trade-offs they consider acceptable between affordability, reliability, resilience, and sustainability. Some customers are changing how they want to use distribution services. New technologies enable alternative ways to generate and store electricity, changing how customers interact with the network. Energy Networks Aotearoa's (ENA) network transformation roadmap portrays a spectrum of customer behaviours, and we are already seeing some customers becoming living examples:

- At one end, passive customers focus on things other than electricity and rely on the utilities that provide them with energy. Passive customers let the utility decide their electricity supply. Utilities and third parties assist customers to transition to more renewable electricity use to meet their energy requirements.
- On the other hand, active customers actively engage with their electricity supply, consumption, production, and new technology, and these are referred to as prosumers. Through technology, the prosumer actively decides on and changes their service level over time based on price. They actively provide demand response from load and batteries for various services in the electricity supply chain and gain cost reductions. Prosumers optimise their usage and on-site distributed generation and sell it across the distribution and transmission network.

Waipā Networks' role is to ensure our services can cater for all types of customers, regardless of where they are on the spectrum. Our engagement approach, described in Section 3, is intended to ensure these differing needs are understood and reflected in how we design services, assess options, and prioritise investment.

⁹¹ <https://srgexpert.com/resource/total-household-energy-costs-nz/>

⁹² https://www.seanz.org.nz/rising_power_prices_vs_solar_savings. According to SEANZ the average cost of a 5kW solar system has fallen from 15,000 in 2019 to \$10,000 in 2025.

⁹³ <https://www.eeca.govt.nz/insights/eeca-insights/industrial-heat-pumps-for-process-heat>

10.4 Waipā Networks' perspectives

10.4.1 Regional review

We completed a regional review in 2024. The regional review identified potential drivers of change within our network and produced Waipā Networks-specific growth scenarios for future energy usage patterns. The scenarios were not forecasts per se, but pictures of what a net-zero world might look like and the implications for Waipā. The regional review also looked at factors beyond the energy transformation.

The regional review provided a 30-year view, including an overview of the drivers of demand growth. It highlighted the impact of housing growth to meet population trends, industrial and commercial developments, and the decarbonisation programme. This long-term view provided context for the more detailed 10-year AMP planning forecasts.

The regional review's output will feed into other aspects of our network transformation roadmap. In the 2024 AMP, the regional review output guided the demand forecasts, however these have since been updated to reflect current inputs.

10.4.2 View of the Waipā district in 2050

Predicting the exact future state of a district like Waipā in 2050 is challenging and speculative. However, based on general trends and potential developments, we have sketched a view of what the Waipā district might be like in 2050. The regional review considered this future view when forming the demand scenarios.

10.4.3 Population growth and urbanisation

The population of the Waipā district is likely to continue growing, driven by factors such as migration, urbanisation, and economic opportunities. The towns of Te Awamutu and Cambridge are expected to expand, with increased residential areas, infrastructure, and services to accommodate the growing population. This is as reflected in Section 6.2.

10.4.4 Sustainable practices

As global awareness of environmental issues grows, sustainability will play a crucial role in the future. The Waipā district will likely see increased adoption of sustainable farming practices, renewable energy generation, and environmental conservation efforts. The district could become a leader in environmentally friendly initiatives.

10.4.5 Technological advancements

Technological advancements are expected to have a significant impact on various aspects of life by 2050. The Waipā district will see increased integration of smart technologies, renewable energy systems, and efficient infrastructure. Automation and digitalisation may influence the agricultural sector, improving productivity and sustainability. We now also expect artificial intelligence to further improve productivity and sustainability.

10.4.6 Diversification of industries

While agriculture is currently a dominant industry in the Waipā district, economic activities will diversify by 2050. New industries, such as technology, research, and innovation, could attract businesses and foster new job opportunities.

10.4.7 Enhanced connectivity

The transportation and connectivity infrastructure of the Waipā district will continue to improve, facilitating easier movement within and beyond the district (e.g., the Southern Links project⁹⁴). Upgraded road networks and improved public transportation systems could enhance connectivity with neighbouring regions.

10.5 Demand growth drivers in the Waipā district

10.5.1 Update to demand forecast scenarios

In the 2024 AMP, we used the regional study's output to develop a range of demand-growth scenarios. Whilst the regional study still influences our view, we have revised our view of demand growth drivers. Our updated view is more moderate about future growth. The change reflects the impact of a general economic slowdown, delays in some subdivision developments, changes in government policy on EV subsidies, and the cessation of the GIDI fund⁹⁵.

We have retained three demand forecast scenarios. Our assumptions are presented in Appendix D. The scenario range reflects significant uncertainty about how the energy transformation will unfold. In broad terms, the scenarios represent:

- **Low:** This scenario assumes a low yield from decarbonisation-driven electrification as some loads convert to non-electric options such as biomass, biogas and hydrogen (where hydrogen plants are not connected to our distribution network). Regional population growth and industrial expansion are weaker than they have been. The uptake of EVs and distributed generation is slower, and the charging of EVs generally occurs at off-peak time
- **Predicted:** This is a middle-growth scenario, with continued strong population growth and industrial expansion. Light transport and gas energy is converted to electricity within a reasonable timeframe
- **High:** This scenario sees strong conversion of transport and gas energy. There is strong population growth and industrial expansion, driving strong demand growth. EV charging is not fully controlled, which contributes significantly to peak demand.

⁹⁴ <https://www.nzta.govt.nz/projects/southern-links>

⁹⁵ The GIDI Fund provided support for businesses to switch from fossil fuels to cleaner, more efficient energy sources across the industrial and commercial sectors. The National-led government ended the fund. Its preference is to enhance the emissions trading scheme (ETS).

10.6 Demand scenario

Figure 89 shows the predicted demand growth for the combined Te Awamutu and Cambridge areas. For our predicted scenario, which we use for planning purposes, demand is expected to increase by 101% from 92 MW in FY25 to 185 MW in FY50. Most of this demand growth (59%) is due to population growth and commercial/industrial expansion (discussed in Section 6.2), with the electrification of transport and heat accounting for the other 41%.

Customer engagement is critical to testing these scenarios, particularly assumptions about electrification uptake, charging behaviour, flexibility participation, and willingness to adjust demand in response to price or service signals. Hence, we plan to review our demand forecasts annually to ensure they reflect the outcomes of our ongoing customer engagement.

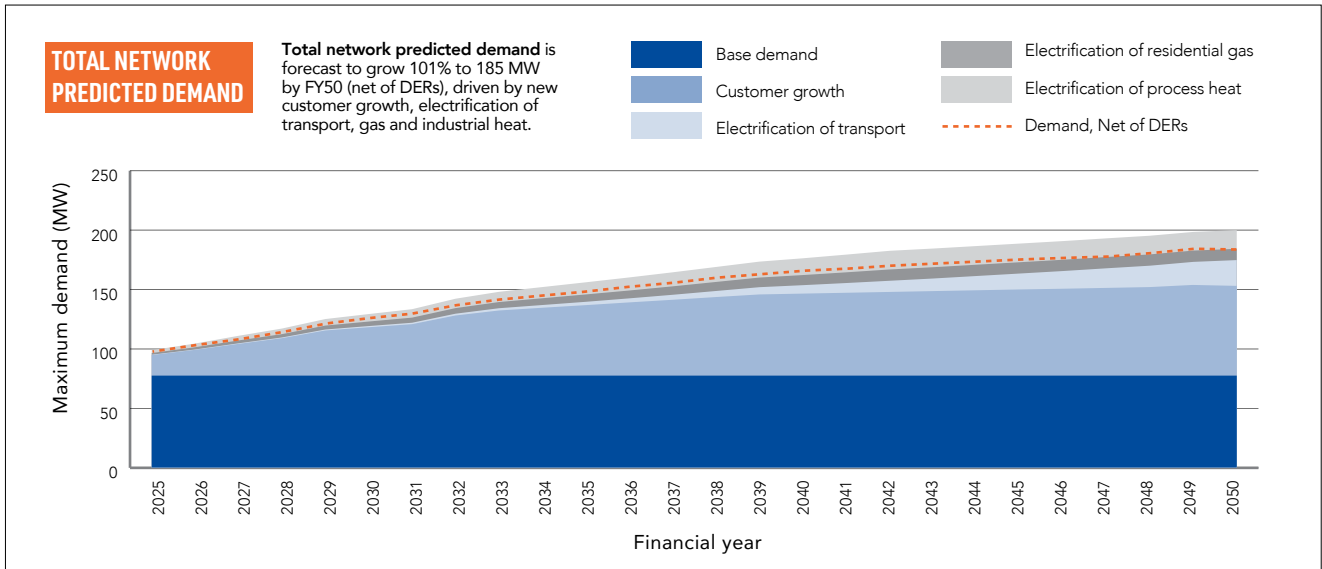


Figure 89: Total system predicted demand forecast

Figure 90 shows that the 2050 demand could range from 148 MW to 244 MW, a difference of 96 MW. A key driver of the differences between the high and low scenarios is the flexibility (i.e., demand response) associated with EV charging and DERs. It is not yet clear how the industry will deploy flexibility, as 66% of the benefits can be attributable to non-distribution sectors⁹⁶. Given the forecast increase in intermittent renewable generation, flexibility could be more valuable for generation firming. It is also unclear how strong the incentive will be to charge EVs during off-peak hours, which could have a material impact on demand. These two factors represent a 60 MW shift between the low and high scenario⁹⁷.

We have applied the predicted scenario for planning purposes. Our planning approach includes testing the impact of low – and high-scenario outcomes for major projects.



⁹⁶ <https://srgexpert.com/wp-content/uploads/2024/05/Distributed-Energy-Resources-Understanding-the-potential-main-report-final.pdf>

⁹⁷ Not adjusting for the different EV uptake rates.

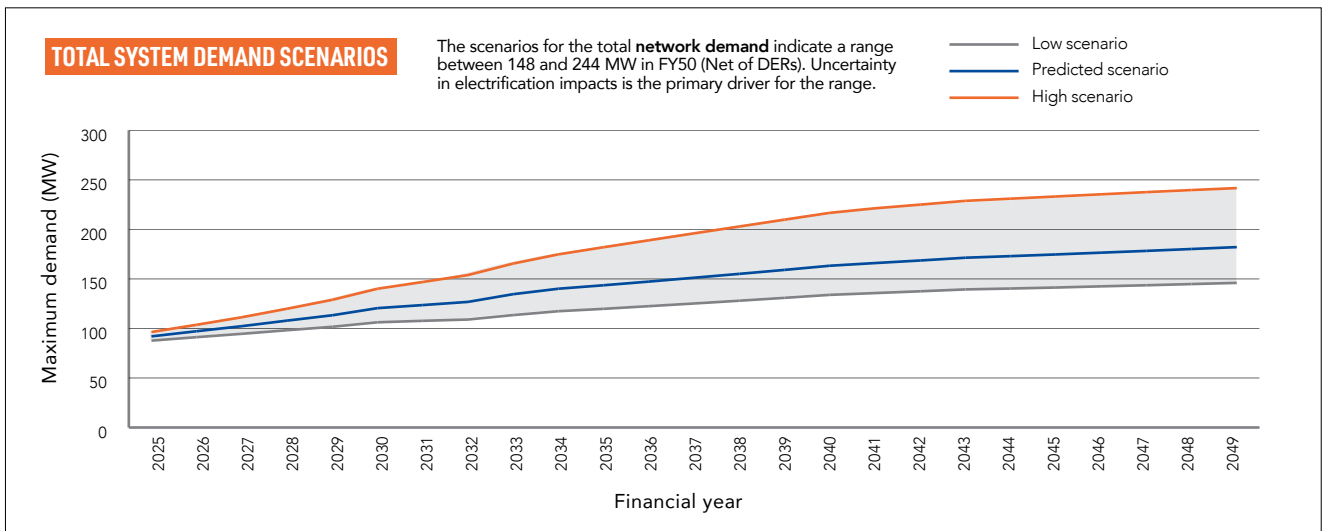


Figure 90: Total system demand scenarios

10.7 The challenge facing Waipā Networks and distribution businesses

Many of the challenges arising from the energy transformation involve judgments and trade-offs that cannot be resolved through technical analysis alone and require input from customers and communities. The energy transformation presents a range of challenges for Waipā Networks. These challenges are broadly consistent with those faced by distribution businesses in New Zealand.

These challenges include responding to demand growth, managing two-way power flows, managing the risk of demand response herding, managing the increasing complexity of operating the network, improving resilience, and building capabilities and resources.

10.7.1 Responding to demand growth

Our forecasts predict significant demand growth driven by the electrification of transport, residential and commercial gas, and process heat (in addition to continued population growth and industrial expansion). Responding to demand growth is particularly challenging for Waipā Networks, where we are at a crossroads in developing the network due to a decade of strong customer growth for a network initially designed to supply a large rural area.

Significant demand growth will require investment in additional network capacity or alternatives. Investment in capacity must be made ahead of the customer need, but not so far ahead that it risks the assets becoming stranded should circumstances change. Engagement with customers and communities is therefore important to understanding growth drivers by place, testing appetite for alternative solutions, and informing the timing and scale of investment.

10.7.2 Managing two-way power flows

Historically, the distribution network was designed to deliver electricity to customer premises in a one-way power flow. With the growth in customers adopting solar PV generation and batteries, the future network must facilitate two-way power flows. The future network will need to supply electricity from the grid to customers' premises and enable electricity to be distributed from one premise to another. Networks must support two-way power flows to enable growth in renewable generation and ensure customers benefit from their investments.

10.7.3 Managing demand response herding

Electricity demand herding occurs when customers respond similarly to demand-control incentives, resulting in synchronised consumption patterns that can amplify peak loads. These incentives, often designed to balance supply and demand or reduce costs, can lead to synchronised consumption behaviours, amplifying peak loads (this would occur outside of the normal peak periods), rather than reducing them. Herding effects can complicate demand forecasting and may require sophisticated demand management strategies that promote diverse consumption patterns. Addressing demand response herding will require clear communication with customers about price signals, incentives, and expected behaviours, and ongoing engagement to test whether these mechanisms operate as intended.

10.7.4 Managing increasing complexity

Prosumers will connect new types of devices that allow new ways of using the network. Managing different power flows, ensuring the network operates within voltage capacity and power quality limits, enabling customers to participate in energy and flexibility markets, and accessing flexibility for our network needs will be complex. Additional data from customer meters, LV monitoring, HV monitoring, and flexibility markets will need to be managed and used.

We need to manage this complexity so that all customers and energy markets can enjoy the full benefits of new technology.

10.7.5 Improving resilience

The increasing use of electricity to decarbonise transport, industrial process heat, and commercial and domestic gas will increase the reliance on electricity and reduce fuel diversity. In the future, a loss of supply will have more significant community and economic consequences and impact more sectors.

We have developed a resilience strategy to reduce the impact of increasing incidents and intensity of adverse weather and other major events (refer to Section 8.4). Understanding community priorities for resilience, particularly in areas with higher outage harm, is essential to determining appropriate service levels and investment responses, consistent with the place-based engagement approach described in Section 3.

10.7.6 Building capabilities and resources

Building capabilities and resources to manage the changing operation of the network and its complexity is a challenge for the sector. Building people skills, business models, processes, tools, and systems to deliver a network appropriate for the future will be a material undertaking for Waipā Networks and the distribution industry. The timing for building capacities must be undertaken before the changes, but not so far ahead that it creates inefficiencies.



10.8 Actions currently underway

Our goal is to make the necessary investments to ensure we deliver the services customers need when they need them, while having confidence that the investments will not be stranded in the future. These actions are being progressed alongside enhanced customer and community engagement with the intent that transformation investments remain aligned with customer needs and expectations as they evolve.

We have commenced work supporting our region's energy transformation and future state. Our current focus is on "low regret" investments and activities that we believe will be required across the range of future scenarios outlined in Section 10.6.

The work currently underway is:

- The Cambridge capacity and security development programme. This is a significant programme of work involving a new Hautapu GXP in Cambridge and a new Forrest Road Substation. This work has been commissioned, and the Hautapu GXP provides network capacity to 2050. The programme was required even if a low scenario occurred. Should the high growth scenario occur, an upgrade pathway has been included in the design, which could be required from the mid-2040s
- We are undertaking planning for the future network architecture in Te Awamutu. Due to growth, we need to provide additional regional capacity and to transition this network from 11kV-only; however, we need to assess options to ensure we meet future customer service needs, resilience, affordability, and can service new growth. This is discussed further in Section 11.9

- Upgrading our existing radio and communication network to handle more data. The first step, a digital microwave backbone, has been commissioned. This laid the foundation for further network automation and obtaining an increase in operating and asset data
- We are replacing our SCADA system (refer to Section 9.7.4). The new SCADA system offers enhanced functionality to improve operational efficiency and manage switching and outage restoration
- We are proceeding with the installation of an advanced distribution management (ADMS). The ADMS will enable faster detection and restoration of power outages, improving customer service
- We are continuing to work on constraint and solution modelling on the distribution network. This will identify future constraints arising from energy transformation and growth drivers. Future work includes assessing hosting capacity, non-network options and how these can influence responsiveness to the transformation and customer service standards
- Through the Ara Ake Decarbonisation Innovation Challenge, we completed a proof-of-value trial of the Gridsight platform to increase the visibility of the LV network; Introduction of meter data visualisation and analytics is reprioritised to commence in Q3 CY2026 (delayed due to meter data availability)
- Our Asset Data Improvement Roadmap Phases 2 and 3 define network model improvement, with Phase 2 commencing from Q2 CY2026.

10.9 Development of a network transformation roadmap

We have started developing a network transformation roadmap for Waipā Networks. We monitor government, regulatory, industry, and technology developments to ensure our roadmap aligns with our operating environment. Customer and community engagement will be a core input to the roadmap, informing service definitions, acceptable trade-offs, investment sequencing, and the role customers may play in delivering or supporting solutions.

Our roadmap development aims to ensure that we can support New Zealand's energy transformation and decarbonisation at the least cost to our customers over the long term. The roadmap will ensure that:

- We have the capability, services, and network capacity to allow customers to increase their electricity use to replace fossil fuels
- We can connect and integrate DERs into the network and allow the owners of DERs to participate in energy markets and flexibility markets
- We progress "low regret" investments and capability building to ensure our network will be able to deliver the services customers require when they require them and that there is a low risk of future investment stranding
- We achieve network security and reliability that meets customer expectations
- Provide transparency on how customer and community input has influenced transformation choices and the rationale for decisions taken.

Community engagement is important and will be part of various activities. It will be essential for services and pricing.

It is intended that the roadmap will provide direction on how we will:

- Build our people and system capabilities to respond to the transition
- Develop the network and its architecture to meet customers' future needs
- Monitor the network (in particular, LV) to ensure reliability and security is maintained
- Develop our business model to engage with customers, other industry players and flexibility markets
- Develop our prices to influence customer behaviour to reduce peak demand
- Optimise network investments, including utilising non-network alternatives
- Develop standards to improve resilience and minimise complexity, network risks and operating costs.

Regulators, the industry, and Waipā Networks need to consider a range of decisions. We discuss some of these in the next section.

The development of the network transformation roadmap is ongoing. This is a significant undertaking, and we want to ensure we understand customer needs and industry developments. Our work on the Te Awamutu architecture review is an important input into the roadmap. It is likely that during the customer engagement that we are undertaking, our roadmap will continue to evolve and change.

10.10 Direction and considerations for the network transformation roadmap

The considerations below reflect both technical assessment and the need to align network transformation with customer values, behaviours, and expectations.

10.10.1 Assessing industry direction and fit with Waipā's strategy

We're developing a network transformation roadmap that supports our long-term strategy. This work includes assessing industry direction, considering how it aligns with our strategy, and firming up possible solutions. We comment on aspects of the roadmap below.

10.10.2 Developing the network and its architecture to meet customers' future needs

Our network is currently highly loaded, and we have expanded capacity for Cambridge and are reviewing the future architecture for Te Awamutu. This work considers both regional and distribution capacity and architecture.

On the distribution network, feeders operate in a radial configuration, with limited interconnection capability and significant use of voltage regulators and reclosers. The network is fully utilised and has reached the limit for achieving effective capacity and performance improvements through the addition of more voltage regulators and reclosers. The network now requires enhancement to supplement the distribution feeders.

Assessing network architecture alternatives and how they can influence responsiveness to the transformation and customer service standards is now underway as part of the Te Awamutu architecture review. This will feed into the roadmap development.

10.10.3 Building people and system capabilities to respond to the transition

New skills, systems and processes will be required to ensure that the distribution businesses have the services and network capacity to meet future needs. The industry needs new skills in data management, technicians with enhanced IT skills, market management and trading (for flexibility). These new skills come from recognised shortages of line mechanics, cable jointers, substation maintainers and technicians. Developing a plan to build these skills is a key focus for our roadmap.

New systems will be required to deliver future services to customers and for distributors to fulfil their role within the electricity supply chain. The new systems will include:

- Advanced Distribution Management System (ADMS), which is progressing
- Meter data management, analytics and insights – to enhance the real-time visibility of the LV network, with eventual integration or embedment of the operating insights into the ADMS
- Interfaces with Distribution Energy Resource Management System (DERMS) – This is software, and digital information flows that enable the control of DERs and deliver the business processes for selling, contracting with, operating, and paying for controllable DERs
- Enhanced cyber security – with increased digitisation, ensuring safe and secure connectivity and data management is critical.

System requirements are evolving as regulatory rules are developed and the electricity sector business model evolves. The Electricity Authority is currently working on flexibility markets (refer to Section 10.3.2), and there is industry work currently afoot in relation to distribution system operators⁹⁸. There is uncertainty about how this will unfold, and we are currently monitoring industry developments.

How these systems are deployed (e.g. internally or externally) is part of our roadmap development.

10.10.4 Monitoring the distribution and LV network

Like other distribution businesses, we have traditionally monitored network parameters in real time on primary distribution assets (feeder circuit breakers and reclosers). However, with changing network use patterns, it is necessary to extend network visibility and controllability to cover the entire network.

As customers add more DERs to the network and demand increases due to electrification, new constraints that could be managed flexibly will likely emerge. The industry will need the ability to monitor use patterns and demand at a more granular level to utilise flexibility where practical.

We talk in detail about our LV monitoring Section 10.11.

10.10.5 Evolution of our business model to support customers in the transition

Distribution businesses form a critical link between customers and energy markets and can enable greater customer participation in the decarbonisation efforts. A key role for the industry is how DERs will be deployed and optimised to obtain the highest value from them. Optimisation will be essential to improve the use of DERs for flexibility services within network stability constraints. Waipā Networks is monitoring the evolution of Distribution System Operators (DSO)s. Our network transformation roadmap will consider the level of visibility that will be required, how we will communicate and engage with other industry participants, how we engage, communicate and involve customers, communities, iwi and a wide range of potential stakeholders. It is currently clear that we need to develop and operate the distribution network to integrate DERs, support bidirectional power flow, and enable flexibility. This will require us to invest in systems that support open access to the distribution network for a wide range of customers and DERs.

We are closely monitoring the work in this area to ensure that any development work we do (concerning LV monitoring, communication systems, and ADMS) is future-proofed. Our roadmap will be informed by the customer engagement program that is currently underway and will outline how we see this evolving and the least-regret investments we plan to make.

10.10.6 Develop pricing to influence demand response

Waipā Networks has developed a pricing roadmap that sets out the direction for price changes. As signalled in the pricing roadmap, our pricing will evolve to incorporate demand, capacity options, and products to influence demand response. Pricing is a key linkage to our network transformation roadmap.

10.10.7 Optimise network investments, including utilising non-network alternatives

The current direction set by the EA (consistent with other jurisdictions) is that distribution businesses should evaluate non-network alternatives before making significant development investments. We are currently considering network alternatives when developing project proposals. However, this does not extend to a formalised process or request for information/proposal process.

We intend to develop a non-network procurement policy, standards, and evaluation criteria as part of our roadmap. These will define performance standards for non-network alternatives. Initially, this will apply to our large development projects. Where non-network alternatives are deployed or procured, we need to develop processes for monitoring their performance to ensure the benefits procured are delivered. Appendix G2 contains our current policy on non-network solutions.

⁹⁸ <https://www.ena.org.nz/our-work/news/new-report/document/1544>

10.10.8 Develop standards to improve resilience, minimise complexity, network risks and operating costs

Distribution businesses need appropriate standards to control the quality of the connected load, generation, or DERs to manage their impact on the network. Our approach will be to adopt industry-led standards where possible.

We have a process for DG connections, but not for other DERs, such as EV chargers. We are working with industry groups to address limited visibility and improve our ability to monitor DER uptake. There is a range of options being considered by the industry, and we are keeping abreast of these developments, including how the compliance of new technology with the network's standards for two-way power flows is overseen.

As power flows change, we may experience congestion on parts of the network due to generation. Other distribution businesses have introduced congestion standards, and we will develop standards for managing congestion across competing generators. These will need to complement flexibility markets as they evolve.

We will assess the materials and design standards to enhance our fleet plans to improve resilience to energy transformation and natural hazards. Our review will consider the costs and benefits of incrementally increasing the capacity of current

carrying components. This will include assessing the impact on mechanical loadings, fault repair, maintenance, tooling, training, spares, and other downstream implications.

While traditional reliability metrics such as SAIDI and SAIFI remain important regulatory indicators, they do not fully reflect customer experience or service stability. Our focus is on understanding our customers' lived experience and identifying measures that will drive meaningful change in how they experience network outages. We believe this will drive consistent service delivery across the network and meaningful improvements in the customer experience, rather than pursuing isolated improvements driven by individual feeders or focusing on performance and areas with little material impact.

We will provide more details on these initiatives as our roadmap continues to develop.

10.10.9 Supporting programmes

Our resilience and reliability improvement strategies will support the network transformation roadmap. Given the increasing reliance on electricity, improvements in reliability and resilience will become increasingly important (and failure to do so will undermine electrification and decarbonisation). These initiatives are outlined in Section 9.4 and Section 9.7.



10.11 LV monitoring

10.11.1 Current practices

Load and injection constraints identified by us or reported by customers. These constraints can impact new load and connection requests.

We monitor the extent to which network loading approaches or has the potential to breach equipment ratings. However, apart from the Maximum Demand Indicator installed in distribution transformers, we traditionally do not have permanent load monitoring for the low-voltage (LV) network. Our current practice is to respond to issues as they arise. We rely on:

- For load only, the maximum demand indicators are installed in our ground-mounted transformers. Our regular asset inspections note the maximum demand recorded via the Maximum Demand indicators on our ground-mounted distribution transformers. Any recording breaching the transformer capacity triggers a detailed investigation using portable data loggers
- For load only, real-time transformer LV monitoring devices are trialled on a few select distribution transformer sites
- For load and injection, reactive monitoring using portable LV loggers is applied based on new load or distributed generation connection requests or customer feedback on power quality issues caused by load or injections.

10.11.2 Planned practices

Our planned approach for monitoring the LV network for load and injection constraints is to:

- Use smart meter data or other data sources to monitor load aggregation and voltage constraints. This will allow us to investigate LV issues faster with fewer data logger deployments
- Use ICP-based transformer loading data to reduce the need for ADMD assumption-based calculations and field-based data logging. This will improve the connection application assessment process and enable data-driven transformer and LV circuit overloading detection and upgrade planning
- Develop a complete LV connectivity model to further improve the granularity of meter data aggregation at LV circuit level. This will enable system hosting capacity and congestion mapping. This is defined in our Asset Data Improvement Roadmap phase 3 (refer to Section 9.6.3)
- Detect, model and account for DERs by integrating data on DERs in our ADMS and load flow modelling for improved forecasting and planning.

10.11.3 Progress

Progress towards collecting and procuring data that enable us to assess current and forecast constraints on our low voltage network includes:

- We have completed the proof of value trial of the GridSight platform, which provides visibility of the low-voltage network using data from smart revenue meters at customer premises
- At present, access to meter data coverage is a barrier, though the situation is improving as MEPs start offering data-provisioning services. There are also new sources of data that can be leveraged. Work in this area is reprioritised to commence in Q3 FY27.

10.11.4 GridSight innovation and trial

We worked with Ara Ake on the GridSight platform. GridSight is an Australian company developing software to increase the visibility of the LV network. The GridSight platform aggregates and analyses smart meter data, helping us to:

- Identify LV power quality issues
- Assess distribution transformer utilisation and LV phase balancing
- Detect solar PV generation, network-connected batteries and EV chargers on the network.

The GridSight system will enhance the visibility required to engage with flexible markets.

This work is in the trial phase and is being supported by Ara Ake as part of their work to develop solutions to help decarbonisation via electrification.

Based on the trial findings, we plan to select and deploy a suitable LV visibility product and prepare an LV visibility and management roadmap. This is reprioritised to commence in Q3 FY27 due to meter data access challenges as detailed below.

10.11.5 Current challenges

Challenges we face in accessing metering data that informs us of current and forecast constraints on our low voltage network include:

- Only 52% of the ICPs have half-hourly consumption and network operation data that can be made available at scale. We are monitoring the progress and envisage that this penetration will improve to 75-90% in FY27
- Metering data costs are still considerable
- Unfavourable economics of extending monitoring capability to cover the entire low-voltage network
- Technologies maturing include utilising existing smart meters to predict loading on the low-voltage network (for areas with a low meter penetration rate).

10.11.6 LV analysis and monitoring

We have completed the LV visibility technology trials based on meter data. We currently do not perform analysis and modelling using meter data. We will resume the evaluation of LV visibility platform options and cost benefits in CY26. Based on insights from recent technology trials, a few proven use cases for visualising and predicting network performance from loading data and network models include:

- Predicting developing faults and power quality issues allows us to respond proactively
- Determine available capacity margins across the network (dynamic operating envelopes) to inform operational planning.

The modelling outputs can be shared with customers who can support the network needs by adjusting their network usage, either through injecting power or reducing their power offtake. This creates opportunities for customers to actively support network needs through informed changes to their consumption or generation behaviour, reinforcing the shift toward shared solutions described in Section 3.

10.11.7 Limitations and assumptions

Customer participation in flexibility markets – directly or via aggregators – could improve the utilisation of existing network assets and has the potential to reduce network expenditure. However, in many cases, flexibility may defer investment rather than avoid it, and it may shift costs or risks between customer groups. Therefore, as part of our customer engagement and network transformation road map, we plan to understand where it makes sense and how we might ensure that it does not transfer cost or risk to vulnerable or less flexible members of the community.

Additional assumptions that we still need to clarify are:

- The cost of establishing requisite systems/platforms (to acquire loading data, model and analyse, and disseminate the results) plus the cost to acquire flexibility services will be lower than that of traditional network development
- Modelling inputs will be available in time, modelling outputs will be communicated to customers in a timely manner and can be used to signal the deployment of flexibility
- There will be value of flexibility payments to customers will be sufficient to incentivise their participation in flexibility markets
- Information from the limited metering available at every low-voltage feeder or distribution transformer can be extrapolated to provide a sufficiently accurate view of loading and/or injection at that point on the network.

10.11.8 Communicating load and injection constraints

Our Asset Management Plan is the main channel for communicating load and injection constraints for the 11kV distribution (MV) network. Another opportunity is when a developer or existing customer engages us to connect the new load, and we communicate any constraints relevant to their target connection point.

For the LV network, we communicate with customers at the time of application about any constraints that affect their proposed connection (either load or injection).



11. NETWORK DEVELOPMENT

11.1 Introduction

This section outlines the planned network development in response to changes in demand, service levels, and current and future network constraints. This section also outlines the network development projects for the next 10 years. We also outline material projects under consideration that still need to be fully developed.

The previous section summarised our view of energy transformation, the impacts of decarbonisation, and the impact of changing customer energy usage on future service levels. We incorporated these factors into the revised demand scenarios used for planning purposes (presented in Sections 11.5, 11.6 and 11.11). We recognise that we face challenges from the ongoing regional (baseload) growth and the emerging decarbonisation (electrification) growth.

From a development standpoint, the existing distribution network has a range of challenges, including:

- Demand on some feeders that are near or at their capacity
- High fault levels on feeders due to the current network configuration
- Many rural feeders have limited backfeed capability, which limits the ability to restore power to customers in the event of a component failure, impacting reliability performance.

Some capacity constraints in the Cambridge area are now being eased as demand for some heavily loaded feeders is being transferred to the new Forrest Road substation. Given the capacity available at Hautapu GXP and Forrest Road substation, we now have the ability to connect large electricity-intensive loads in and around Hautapu.

To maximise investment efficiency for system capacity, we plan to develop the HV network to accommodate regional growth while also building in a margin to support decarbonisation with relatively small incremental investment. The focus during FY26 (which will continue into FY27) is to define the long-term subtransmission and distribution network architecture that can serve the demand scenarios identified in the previous section. In this AMP, we outline our current thinking on addressing the demand growth in the Te Awamutu area, where capacity constraints are anticipated in the latter part of the forecast period.

The network solution we need will likely have significant financial implications, so we must balance customer demands, our required service levels, costs, and the overall vision for the region. The cost of the proposed future architecture (including subtransmission, zone substations, and distribution) has now been defined and included in the expenditure forecast schedules.

Currently, the distribution development plan is being developed using traditional methods. As we continue our work on the distribution architecture, in partnership with our customers, we will identify alternative solutions. This will change the proposed expenditure by shifting it to either non-network capex or opex. We anticipate that the overall cost could decrease.

Our development plans focus on addressing:

- Capacity – integrating the new Forrest Road substation into the Cambridge network to relieve capacity constraints
- Capacity – developing the network architecture roadmap for the Te Awamutu area
- Security and reliability – improving network performance
- Power quality – focusing on voltage constraints in rural areas.

This section covers:

- How the development plan aligns with the asset management strategy
- The network planning criteria that trigger development activities
- Network demand forecasts
- Our subtransmission and zone substation development plan for the Cambridge area
- Our subtransmission and zone substation development plan for the Te Awamutu area
- Our plans in relation to distribution transformers, LV and other assets
- A summary of expenditure forecasts.



11.2 Alignment to our asset management strategy

The network development plan gives effect to our asset management strategies, with particular alignment to Strategic initiative #1 (enhance our customer and stakeholder engagement), Strategy #2 (improve regional supply capacity and security), and Strategic initiative #4 (improve the reliability and resilience of our network).

Consistent with our customer strategy, network development will increasingly be shaped by early and ongoing customer and community involvement. We recognise that meeting forecast demand and managing emerging constraints will require a shift in how we define problems, assess options, and sequence investment. Traditional reinforcement will remain an important tool, but it will no longer be the default response where credible customer, community, or non-network alternatives exist.

This AMP represents a transition period. Our enhanced customer engagement approach is in its early stages; therefore, the development projects outlined in this section have largely been identified prior to structured customer engagement. Projects that are already in progress, form part of a dependent programme of works, or are required to connect new customers will continue as planned. However, for new and future development initiatives, we intend to engage with customers and communities earlier to jointly define needs, test assumptions, and assess trade-offs between affordability, reliability, resilience, sustainability, and power quality. As this approach matures, customer insights may lead to changes in investment timing, scope, or preferred solutions in future AMPs.

Planning within this section also reflects the continuation of current service and reliability standards. Work to review and refine service standards based on customer priorities is still underway. As those standards evolve through engagement and testing, they will directly inform future network development decisions, including how much reliability and resilience is provided, where it is prioritised, and at what cost.

Over the coming planning cycles, we will progressively integrate customer insight into network development by:

- Testing non-traditional options such as demand response, distributed generation, and storage alongside conventional reinforcement
- Using place-based engagement to inform investment choices in constrained or high-impact areas
- Making price-quality trade-offs explicit and transparent in development decisions
- Maintaining a clear record of how customer input has influenced outcomes.

This approach ensures that network development remains technically sound while being increasingly aligned with what our customers value and what delivers the best long-term outcomes for our network.

Regarding #2, projects completed over the past decade have improved regional supply capacity and security. These include the second 110kV line into the Te Awamutu GXP, the generation that supported the Cambridge GXP firm capacity, the removal of protection constraints that impacted Te Awamutu GXP capacity, and, most recently, the construction of the new Hautapu GXP west of Cambridge.

In this AMP, we outline further plans aligned to #2 improving regional supply capacity and security, including:

- Installing two 33kV cables (initially operated at 11kV) into the south Cambridge area as a provision for a third zone substation in Cambridge
- Increasing the number of feeders in the Cambridge area and transferring load from existing feeders to the new Forrest Road substation
- Outlining the architecture for regional supply into Te Awamutu
- Defining the initial projects for the hybrid network and non-network architecture in Te Awamutu. This includes subtransmission circuits from Hautapu GXP to a zone substation near Waikeria Prison, and towards the end of the planning period, a new zone substation near Pirongia
- Defining a range of specific distribution projects to address near-term capacity issues and the broad programmes to address long-term issues
- Outlining the non-network solutions that will support the regional supply into Te Awamutu (and indicating the broad programme of non-network alternatives for the distribution network).

Regarding #4, our work in recent years to improve the reliability and resilience of our network has included defining our resilience strategy (in Section 8.4.4), progressing the natural hazard assessment of our region (which is ongoing), and our recloser and automation programmes.

We outline further plans aligned to #4 improving the reliability and resilience of our network, including:

- Projects to improve security in the Cambridge area (this includes a specific project for Cambridge East and the increase in the number of feeders in the region, as mentioned above)
- New projects and programmes to improve the security in the Te Awamutu area (these are programmes that address both capacity and security)
- A continuation of our 11kV recloser installation programme
- A continuation of the switch automation programme.

11.3 Improvement to our planning process

Over the past two years, we have worked to understand our network, improve the tools, systems, and processes we use to visualise what is happening on it, and build our people's capacity and capability to advance capital projects that

will secure capacity for the region and its customers. While this work is ongoing, we have improved the information contained in this section.

11.4 Network planning criteria

11.4.1 Development planning criteria

Our planning criteria are designed to provide network capacity, maintain supply quality, increase asset utilisation, reduce system losses, and balance capital and operational expenditure. They provide the foundation to match the security of supply with customer requirements. Whenever the planning criteria are breached (or forecast to be breached), we trigger network investigations, which may lead to network development projects or non-network alternatives to prevent constraints from forming on the network. Our assessment of major development projects includes co-designed solutions through our engagement process.

The commissioning of the Forrest Road zone substation marks the beginning of a new chapter for our network development plan, and we have developed specific planning criteria to ensure we plan, design, and build our future network correctly.

Table 52 summarises the key elements of our planning criteria. We will further review these criteria regarding the EEA Security of Supply Guide.

Element	Capacity	Security	Reliability	Voltage	Location
GXP	Load exceeds 100% of normal rating	N-1 using cyclic rating	Fault rate above industry standard	Voltage does not meet electricity code requirements	N/A
Sub-transmission and transmission feeders	Load exceeds 100% of normal rating	N-1 using cyclic rating	Fault rate above industry standard	Voltage drop that cannot be compensated for at the substation	The distribution network cannot reasonably supply the load and requires a new substation
Zone substations	Load (during contingency) exceeds 100% of the nameplate rating over 10 consecutive half hours per year	The load exceeds 100% of N-1 capacity, more than 10 consecutive half hours per year	Fault rate above industry standard	Distribution voltage depression that cannot be compensated for locally	The substation is not efficiently located to load
Distribution feeders	The load exceeds 100% of the thermal rating for over 10 consecutive half hours per year	The load exceeds 66% of the thermal rating for over 30 half-hours per year	The fault rate is above industry standards or identified as a worst-performing feeder ⁹⁹	The voltage at the HV terminals of the transformer consistently drops below 10.5kV. Local tap settings cannot compensate for it without causing a high voltage in the LV during the low-load period	LV configuration cannot reasonably supply the customer load; therefore, it requires an allowance for short duration overloading of the transformer, a non-network solution, new distribution lines or cables and distribution transformer
Distribution substation	MDI or data logger readings exceed 100% of the nameplate rating	N/A	Fault rate above industry standard	See below	See above
Low voltage system	Load exceeds 100% of thermal rating	N/A	Fault rate above industry standard	The voltage at the customer's point of supply does not meet regulatory requirements ¹⁰⁰	Existing LV circuits do not reach new customers

Table 52: Network planning criteria (development triggers)

To further enhance the planning criteria, we have defined additional distribution feeder planning criteria. This criterion ensures that we configure our feeders and segments to manage outage areas and support the restoration of supply (see table 53).

⁹⁹ Worst-performing feeder means the feeder lines on an EDB's network that, in respect of the most recent disclosure year, are in the 90th percentile or higher for one or both of the following: (a) feeder SAIDI; and (b) feeder SAIFI.

¹⁰⁰ New Zealand's regulated low voltage has moved from 230V ±6% to 230V ±10%, a change reflecting increased solar and EV charging, aligning with international standards.

Network level	Feeder type	Maximum numbers of ICPs	Maximum number of ICPs per switch segment	Minimum number of interconnection feeders
Distribution feeders	Urban	1,500	300	3
	Rural	1,000	200	2

Table 53: Additional distribution feeder planning criteria (investigation triggers)

11.4.2 Asset capacity and planning horizons

We have established standard capacity and planning horizons for each network element to guide our development plan. We have established planning horizons so that upgrading existing capacity and installing new capacity takes a suitably long view of future demand to maximise fixed construction costs (e.g., trenching or building work) and avoid the need for uneconomic near-term reinforcement.

In establishing the planning horizons, we have considered the future use of the network. Electricity is an essential service, and reliance on it will grow as decarbonisation through electrification progresses. For this reason, we believe that understanding customers' needs and plans and developing flexible solutions will be critical to enabling growth within the region.

We have defined standard capacities for network elements to guide material and equipment selection and to achieve standardisation, purchasing, and construction efficiencies. The standard capacities and planning horizons outlined in table 54 reflect the standard cable, conductor, switchgear, and transformers typically available.

Element	Standard capacity	Planning horizon	Description
GXP	N/A	30+ years	We apply a long planning horizon as development can take up to 10 years, and the incremental cost of higher capacity at the time of construction is generally low. There is no standard capacity; however, increments will generally be aligned with Transpower's standard transformer sizes.
Sub-transmission feeders	N/A	20-30 years	We apply a long planning horizon due to the long route selection and procurement. The capacity is sized to the number of current and forecast zone substations that must be supplied.
Zone substations	Typical nominal rating is 24 MVA (N-1) for urban or smaller for remote rural areas	20 years	We apply a long planning horizon due to the time required to consent and develop a zone substation. The standard substation capacity is typical in New Zealand for urban and semi-rural substations (increasing the availability of equipment and spares). When capacity is reached, the load is transferred to an adjacent zone substation, or a new substation will be developed.
Non-network solutions	Location specific	Aligned to the constrained assets	We apply a medium planning horizon, and work can typically be completed in 2-3 years. Non-network solutions, such as demand response, flexible connections, distributed generation, and battery storage, may be used to manage capacity constraints, improve resilience, or defer traditional network reinforcement. These options will be assessed alongside conventional solutions, particularly where constraints are driven by peak demand, contingency requirements, or where reinforcement costs are high. Customer and community preferences will inform the selection and timing of non-network solutions.
Distribution feeders	4-6 MVA typically for urban feeders, and 2-3 MVA for rural feeders	10 years	We apply a medium planning horizon, and distribution work can typically be completed in 1-2 years. The standard feeder capacity (normal/backfeeding) is typical in New Zealand for urban and semi-rural feeders and is reflective of standard cable and conductor sizes. When capacity is reached, the load is transferred to adjacent feeders or a new feeder or zone substation is developed.
Distribution substation, industrial	Customer-specific	10 years	A 10-year view of capacity is generally appropriate for industrial customers. Distribution transformers can be incrementally upgraded in most cases.
Distribution substation, commercial	500-1,000 kVA	10 years	A 10-year view of capacity is generally appropriate for commercial areas – the selected capacity needs to have suitable spare capacity for back-feeding adjacent loads. Distribution transformers can be incrementally upgraded in most cases.

Element	Standard capacity	Planning horizon	Description
Distribution substation, urban	200-300 kVA	10 years	A 10-year view of capacity is generally appropriate for residential areas. The selected capacity must have suitable spare capacity for back-feeding adjacent loads in case of a cable fault. Distribution transformers can be incrementally upgraded.
Low voltage, underground	N/A	10 years	Capacity is based on standard cable size, and LV runs are limited to maintaining voltage and capacity compliance.
Low voltage, overhead	N/A	10 years	With capacity based on standard conductor sizes, LV runs are limited to maintaining voltage and capacity compliance.
Residential customer demand	3 kVA ADMD (Distribution Tx level)	N/A	This is the maximum demand of a residential customer used for planning purposes. The diversity is measured at the urban distribution transformer. We will review the ADMD (e.g., at the ICP or LV feeder level) we use for planning as part of our energy transformation work.
Other customer demand	Customer-specific	N/A	These shall be determined in consultation with the developer or customer.

Table 54: Asset capacity and planning horizon

Ongoing review of our planning standards will be necessary to ensure they stay aligned with customer expectations that may evolve in a highly electrified New Zealand, where reliability expectations differ from the present day.

11.4.3 Standardisation of equipment and materials

We have developed Waipā Networks standards for designing and constructing network assets. These standards are based on a safety-by-design that ensures safety is considered at all stages of the equipment lifecycle. This supports compliance with the Electricity (Safety) Regulations 2010 and the Health and Safety at Work Act (2015).

By standardising our designs and assets, we achieve the following benefits:

- Safety from the use of proven construction and maintenance techniques

- Improved reliability through verified equipment performance
- Fewer manufacturers and asset types reduce stockholding costs and increase staff familiarity and productivity. We have not yet assessed the impact of such an arrangement on competition in our materials supply chain
- We achieve value for money by aggregating purchasing volume and greater familiarity with their operation and maintenance.

To help us develop and update our standards, we subscribe to Powerco's Contract Works and Network Operations standards library. This promotes greater efficiency and standardisation of practices across the industry.

Generally, we use only materials and equipment that meet recognised industry standards and are approved by our internal standards and policies.

Asset category	Standardised features	Standardising methods
Distribution and LV lines	Standard suite of conductors and cables. These are limited to generally available sizes and types.	Our Design Manual. Non-standard types require specific network review and management approval.
Distribution transformers	Pole-mounted transformers are limited to generally available sizes of less than 100kVA, with no customisation. Ground-mounted transformers are limited to generally available sizes, with no customisation.	Our Construction Manual. Non-standard ground-mounted transformers may be required for some industrial customers. These require specific network review and management approval.
Distribution switchgear	Selection is generally from preferred suppliers of off-the-shelf equipment commonly used in New Zealand.	Our preferred suppliers list. Non-standard switchgear may be required for some applications. These require specific network review and management approval.
Poles	New concrete poles are pre-stressed type with standard configuration. Planned pole renewals shall be designed for the site and loadings. The pole type shall be selected from approved manufacturers and standard configurations.	Our Construction Manual. Relevant utility pole standards to apply to new poles.
Other network assets	Generally, procure from preferred (i.e., pre-approved) suppliers.	Our preferred suppliers' list and Design Manual.

Table 55: Asset standardisation

11.4.4 Other purchasing considerations

In addition to the standardisation of assets mentioned above, our purchasing decisions consider the following:

- We only use materials and equipment that meet recognised industry standards approved by our internal standards and policies
- The total lifecycle costs of assets, taking into account purchasing, operating, useful life, and end-of-life disposal
- The environmental impacts of the creation, operation, and disposal.

11.4.5 Resilience standard

Table 56 shows our draft resilience standard. This will be refined over the next 1-2 years. We apply this standard to existing structures, taking into account site limitations, aiming for the best possible outcome or alternative supply options during natural disasters.

Hazard	Draft Standard
Seismic, wind, snow and ice	All new zone substations, 11kV switching stations, control room and 11kV structures supplying critical infrastructure shall meet Importance Level 4 (IL4) defined in the National Building Standard. IL4 requires buildings to remain operational after a natural disaster (concerning earthquake, wind and snow structural loading). 11kV buildings and fixings for ground-mounted assets shall meet IL3. These buildings have increased performance requirements as they fulfil a role of increased importance to the local community. New mainline overhead shall meet security level 3 (under AS/NZS7000). Level 3 applies to lines where failure would cause increased risk to life or economic loss, or where post-disaster function is required. We apply level 2 for remote spurs.
Flooding and coastal inundation	Not yet defined. Historically, flood protection was designed on a 1:100 return period ¹⁰¹ plus 1-1.5m sea level rise. This return period is below that applied for other hazards. Other distribution businesses apply 1:350 (0.35% AEP) or 1:500 (0.2% AEP). We are currently reviewing what standard is appropriate for Waipā Networks.
Landslips and subsidence	Not yet defined. We currently assess this during site selection.
Vehicle damage	Not yet defined. We currently assess this during site selection.
Third-party contractor damage	Not defined. We currently assess this during site selection.

Table 56: Draft resilience standard



¹⁰¹ 1% annual exceedance probability (AEP).

11.5 Demand forecasts

11.5.1 Historical demand

Figure 91 and figure 92 show the historical demand. Electricity demand in Cambridge has been growing faster than in Te Awamutu. Since FY14, demand has grown from less than 30 MW to 50 MW in FY25, which equates to a CAGR of around 4.5%. Demand at Te Awamutu has grown from less than 33 MW in FY14 to nearly 42 MW in FY25, which equates to a CAGR of 2.1%.

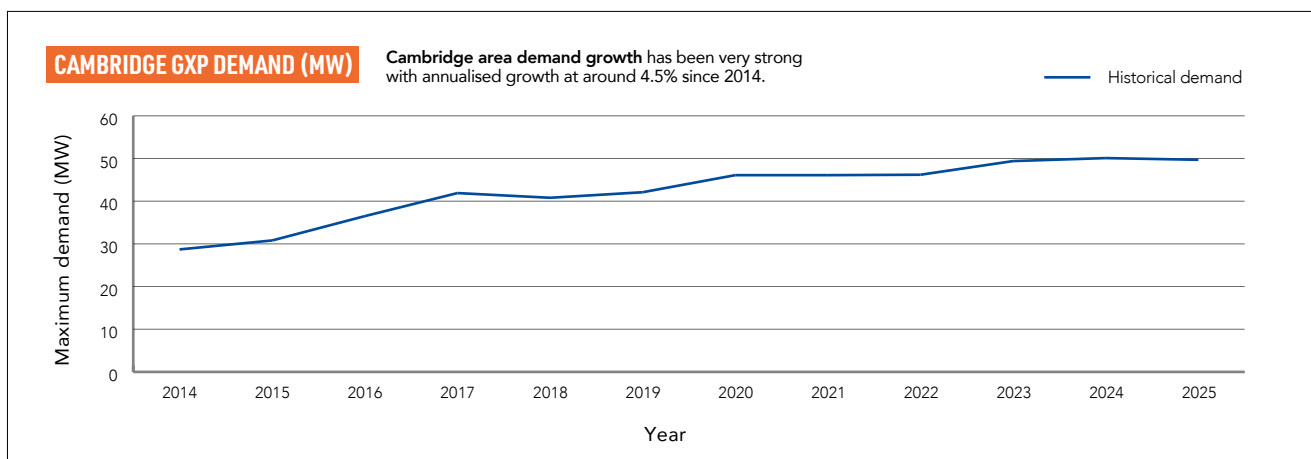


Figure 91: Cambridge GXP demand (MW)

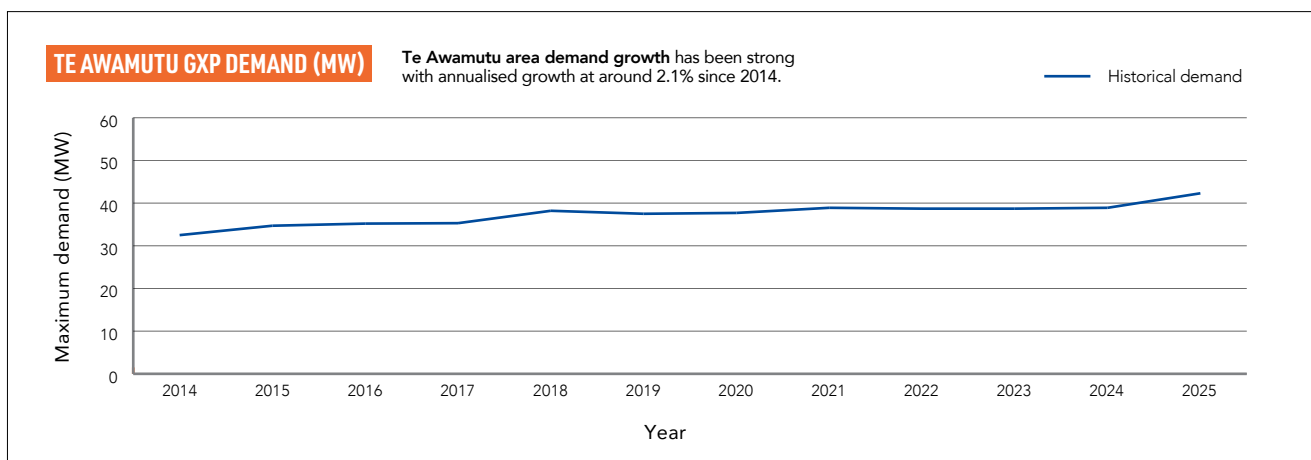


Figure 92: Te Awamutu GXP demand (MW)

11.5.2 Demand forecasting

Electricity demand, measured in MW or MVA, is the primary factor determining the network's future needs. Traditionally, demand growth trends were used to derive future demand scenarios. However, given that we are in a transition phase in which our reliance on electricity is increasing, historical demand trends and growth (or decline) are less relevant to future demand scenarios.

Understanding the factors that drive demand is crucial to optimise investment and efficiently meet customers' future requirements. As we are currently in a transitional phase, getting this right becomes even more important. Failing to do so risks mistimed investments. Investing too early risks unnecessary price increases or stranded assets. On the other hand, investing too late risks needing to make immediate or

unplanned expenditure to address the issue in the shorter term (which often comes at a higher cost and hidden societal costs like loss of supply to consumers or ongoing costs of energy losses) or not meeting the needs of our customers and communities. We use our demand forecasts to develop least-regret investment plans, which can be adjusted as demand forecasts change over time.

We assessed the demand forecast scenarios in Section 10.6. Future demand is influenced by many factors, such as population growth (driven by immigration into the region), new commercial and industrial load, changes in electricity usage, land usage changes (e.g., dairy conversions), and electrification of gas, process heat and transport. Our assessment of these demand drivers are discussed in Appendix D.

Our demand forecasting process is initially conducted at the GXP level. To develop feeder demand forecasts, we applied the demand driver defined at the GXP level to each feeder, based on the feeder's customer composition. The sum of feeder peak demands exceeds the GXP peak; however, due to diversity, the actual peak is lower, as feeder peaks do not occur simultaneously.

We have defined a planning scenario (the predicted scenario) between the high and low scenarios. The assumptions behind the predicted scenario are discussed in Appendix D. The demand forecasts exclude future major distributed generation connections.

Our demand forecasts for the Cambridge and Te Awamutu areas are presented in Sections 11.6 and 11.10.

11.6 Cambridge area demand forecast

11.6.1 Regional demand growth

The Cambridge area demand forecasts are shown in figure 93. In the predicted scenario, Cambridge demand is forecast to grow from 50 MW to 87 MW by FY36 and to 110 MW by FY50 (with an FY50 low/high range of 88 MW to 140 MW).

This equates to a growth rate of 3.2%, with a low/high range of 2.5% to 4.0%. The demand forecast incorporates the significant connections and growth assumptions outlined in the next section. This demand growth is high but it is below what we experienced between FY14 and FY25.

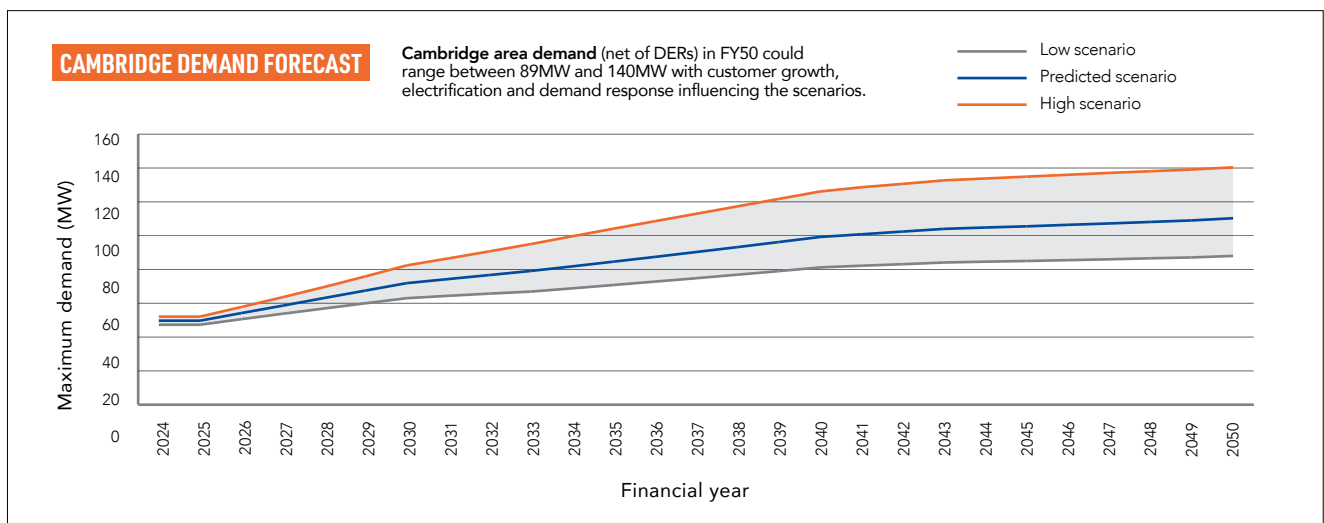
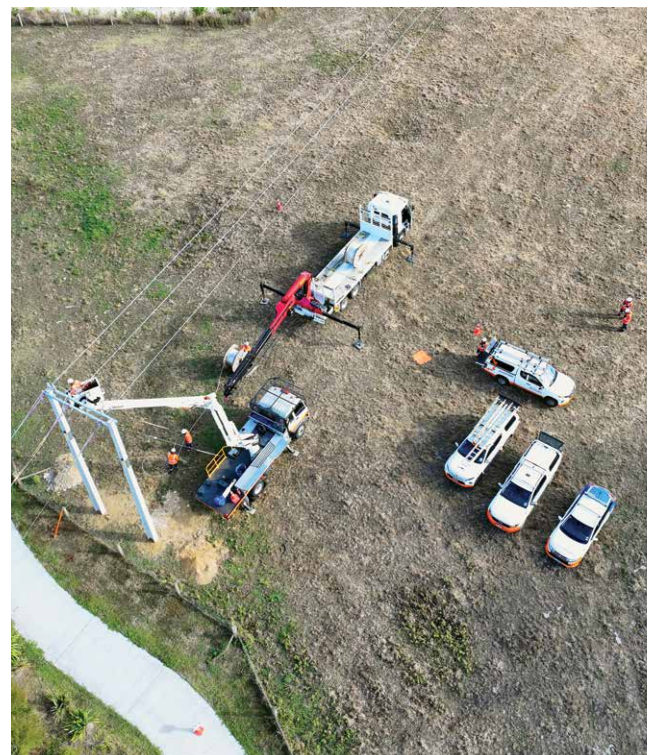


Figure 93: Cambridge area demand forecast

11.6.2 Distribution demand growth

Waipā District Council has developed regional growth cells that define the areas and scope of land developments. Figure 94 and table 57 outline the growth cells and expected growth in the Cambridge area, which is estimated at 22 MW to 25 MW by FY36. The growth is predicted to occur in cells C1 to C5, C8 and C10. Growth in cells C6 and C7 is forecast to occur beyond the planning period of this AMP; however, we need to be preparing for this growth towards the end of this planning period.

We are also aware of specific customer demand growth, in addition to the growth mentioned above (see table 58). This is estimated at a further 13.5 MW by FY29.



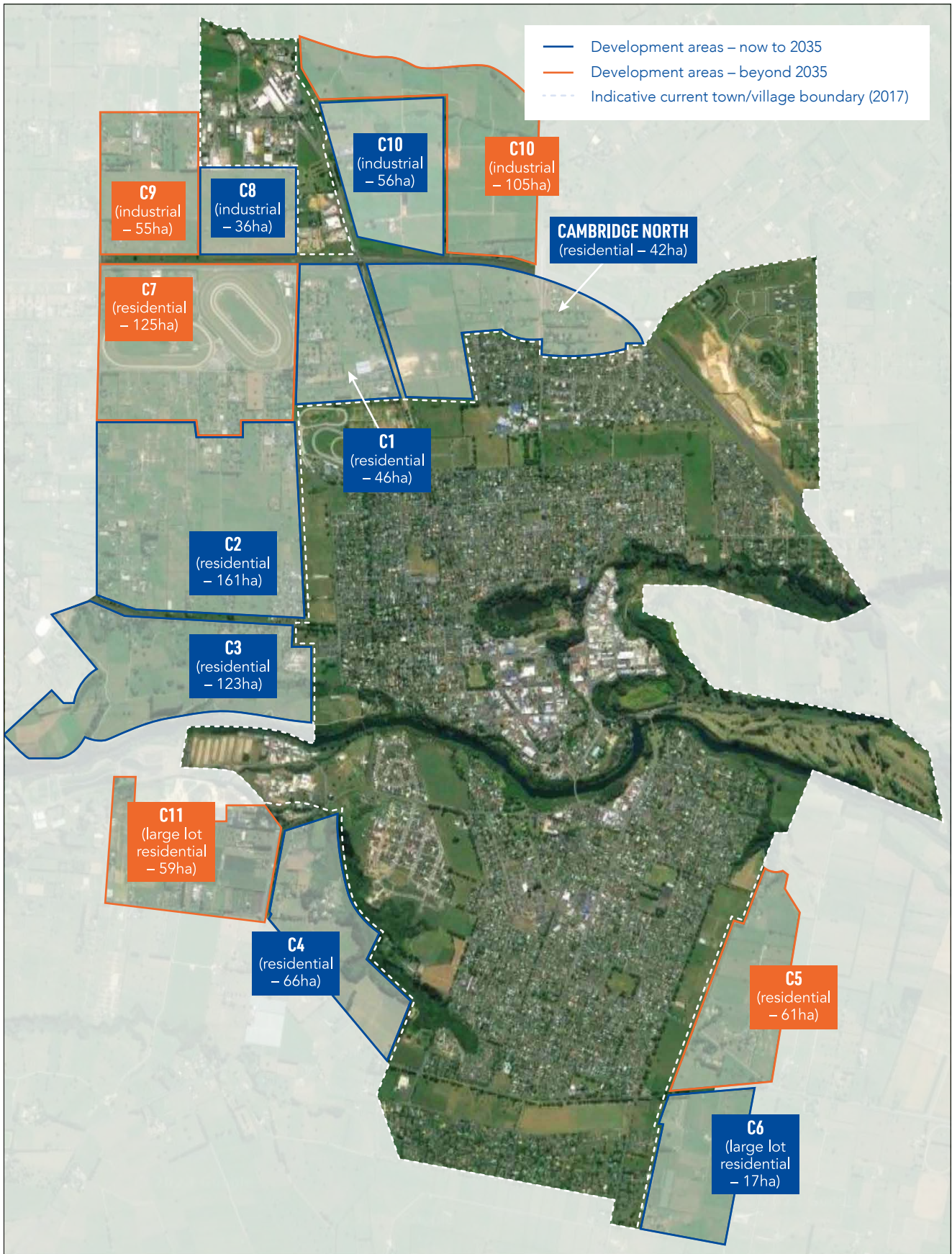


Figure 94: Cambridge growth cells

Growth cell development	Feeder	Estimated load and timing
C1 development – overall density of 12-15 dwellings per ha. The land parcel size is 46ha, with 550 residential connections.	Cambridge North	1.5 MW, estimated from FY24-FY30
C2 development – 3MS and St Peters growth and residential developments. There are up to 1,000 connections between now and 2030 and some commercial growth.	Cambridge West*	5 MW, estimated from FY24-FY31
C3 development – Potentially up to 123ha of land conversion.	Cambridge West*	1.2 MW, estimated from FY24 to FY31 2.0 MW, estimated from FY32 to FY36
C4 development – 66ha (approximately 790 dwellings) of residential load forecast between now and 2030.	Monavale	2.0 MW, estimated from FY24 to FY31
C5 development – 61 ha of land to be converted to residential housing residential housing and community facilities. Originally scheduled beyond 2035, it is now fast-tracked.	Leamington Roto-o-Rangi	4-5 MW, estimated from FY26 to FY36+
C6 development.	Leamington Roto-o-Rangi	Growth predicted outside of the forecast period
C7 development.	Cambridge West*	Growth predicted outside of the forecast period
C8 development – Rezoning 15ha north of Hautapu Road to industrial zone.	Pencarrow*	1.2 MW, estimated from FY24 to FY31
C9 development.	Pencarrow*	Growth predicted outside of the forecast period
C10 northeastern development – 105ha converted to industrial zone. Load use in industrial subdivisions is a lot higher than residential. The council plan indicates development timing beyond 2035. However, we have already received an inquiry in 2023 about the availability of electricity supply.	Bruntwood	5-7 MW, estimated from FY28
C11 development.	Monavale Kaipaki*	Growth predicted outside of the forecast period

Table 57: Cambridge area land developments

* New feeder from Forrest Road substation.

Major point loads connections	Feeder	Estimated load and timing
C10 southwestern development – An industrial customer has indicated significant upgrades to load requirements over the next five years.	APL	1 MW in FY26 8 MW FY27 to FY29
Horticultural upgrade and wastewater treatment plant installation.	Kaipaki*	2.5 MW, estimated by FY26
Fonterra is constructing a new wastewater treatment plant and has indicated other plans for load increase; however, it has yet to indicate size and timing.	Hautapu A Hautapu B	2.0 MW, estimated by FY27

Table 58: Cambridge area major new connections

* New feeder from Forrest Road substation.

11.7 Cambridge area: GXP, sub-transmission and zone substation development plan

11.7.1 Subtransmission and zone substation developments to meet capacity requirements

Constraints

The new Hautapu GXP and Forrest Road substation (commissioned in FY26) has resolved the immediate Cambridge GXP constraint and laid the foundation for relieving feeder constraints. We now have the ability to connect large electricity-intensive loads in and around Hautapu.

During this planning period, the constraints on the 11kV feeder supplying APL (around ~10 MW) will need to be resolved by a new zone substation (see table 59). The Leamington and Roto-o-Rangi constraints are resolved through a mix of distribution developments (see Sections 11.8.1 and 11.8.2) and a zone substation development that will commence at the end of the planning period.



Feeder	Growth area	Constraint	Date binding	Project
Cambridge GXP	Strong regional growth across C1-C10	N-1 capacity (40/47 MVA) is projected to be exceeded due to regional growth	FY27 ¹⁰²	Project 1
APL	C10 southwestern, specific industrial customer growth	10 MW demand growth will exceed the capacity of APL and adjacent feeders	FY29	Projects 2 to 4
Leamington Roto-o-Rangi	C5 Leamington area	4-5 MW demand growth will exceed feeder capacity	~FY30+	Project 6 & 7 (distribution) Project 8

Table 59: Current and emerging constraints



Network solutions

We are planning to spend \$25m on subtransmission and zone substation projects to address the constraints mentioned above (see table 60). We are planning two new zone substations in the Cambridge area, bringing the total to three zone substations and the Cambridge 11kV GXP supplying the distribution network.

When completed, the zone substations and 11kV GXP will be well positioned around Cambridge to support the township and growth zones, with Bardowie to the North, Cambridge GXP to the North-East, Leamington to the South-East, and Forrest Road to the West (see figure 95).

Feeders from the Forrest Road substation will be able to service Growth Cells C2, C3, C7 to C9 and some of C10. The Leamington capacity development (a three-stage programme) will support Growth Cells C4 to C6. Growth Cell C1 will be supported from the existing Cambridge GXP.

¹⁰² Including the 3 MW of distributed generation.

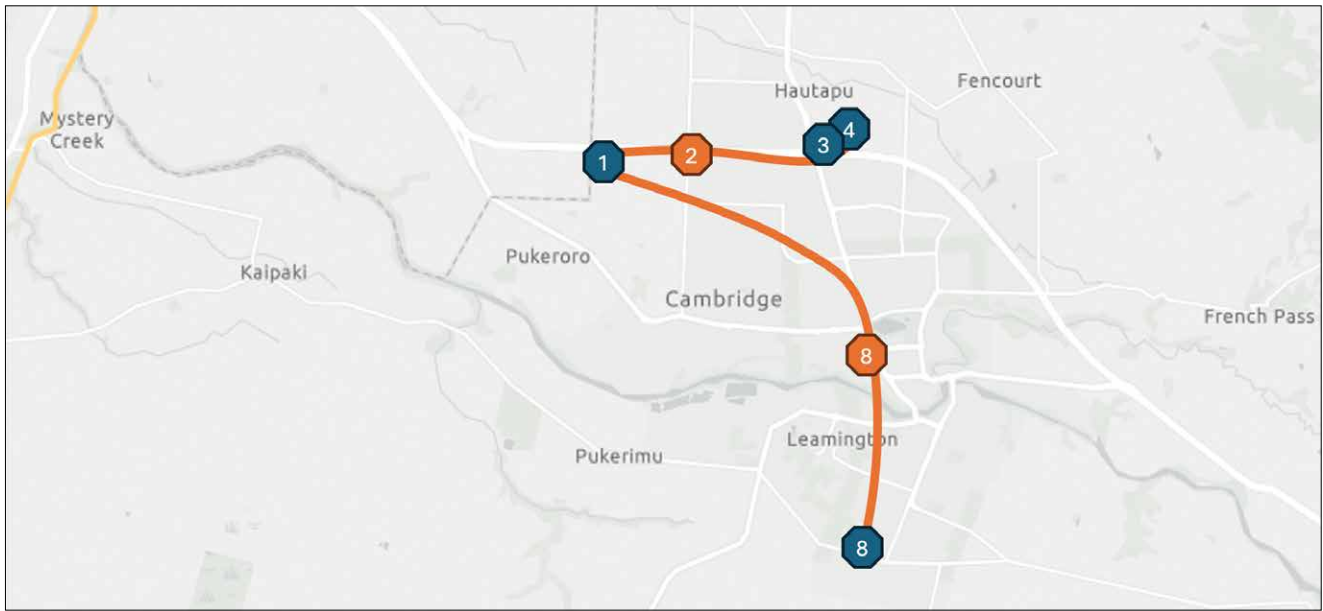


Figure 95: Proposed subtransmission and zone substation projects

Project	Issue	Solution	Cost/timing
1. Forrest Road substation	Capacity, Cambridge GXP	Develop new GXP and Forrest Road substation. The project was commissioned in FY26. Minor post-commissioning work required.	\$154k FY27
2. 33kV cable from Forrest Road to Bardowie	Capacity, APL feeder	New 33kV underground double circuit cable from the Forrest Road substation to APL site.	\$4.9m FY28-29
3. Bardowie land purchase	As above	Purchase of land for substation.	\$1.4m FY29
4. Bardowie zone substation	As above	Construction of a new 16/24 MVA N-1 substation Note: A capital contribution is expected for this project.	\$10.3m FY29-31
8. Leamington zone substation (stage three)	Capacity, Leamington Roto-o-Rangi	This is part of a long-term project to increase capacity in the Leamington area. Stage one: 33kV cables installed first, operated at 11kV. Stage two: integrated into existing feeders (see table 62). Stage three: Development of a new 16/24 MVA N-1 zone substation in the Leamington area that will be supplied by double circuit 33kV cables from the Forrest Road substation.	\$8.3m FY35-36 (Total of \$13.5m FY35-37)
Total		System growth capex	\$24.9m FY27-31

Table 60: Proposed solutions

11.7.2 Developments to meet other drivers

There are currently no subtransmission or zone substation projects planned to meet other drivers. This is as expected, as our subtransmission and zone substation are new and were designed to meet security, voltage, location, planning horizon, environmental and resilience requirements.

11.7.3 Justification for the development projects

Capacity-driven projects are required to meet demand from new customers and support future growth from existing customers. This is an essential requirement for Waipā Networks.

11.7.4 Managing demand growth uncertainty

The subtransmission and zone substation development plan has been prepared to meet the predicted demand growth to the planning horizon. The timing of the new Bardowie substation will be adjusted to meet the requirements of the major customers (subject to major material lead times). The new Leamington zone substation is part of a multi-stage project that is responding to forecast demand growth in the wider Leamington region. We have flexibility with the substation timing, so that can be optimised based on how growth is tracking.

11.7.5 Consideration of options and non-network alternatives

In respect of the Bardowie zone substation, due to the location, size, and profile of the new load, a new substation is required as this load cannot be supplied by 11kV. In our option analysis, we considered different substation sizes but recommended using our standard size to accommodate future growth and maintain standardisation. Given the location, size, and profile of the new industrial load driving the Bardowie substation, merchant flexibility was not considered viable.

For the Leamington substation, given the new demand of approximately 6-7 MW, a network solution will be needed to supply this demand from new customers. However, as part of the business case development, we will evaluate whether merchant flexibility could enable short – to medium-term deferment. Mass-market flexibility is not explicitly considered as an alternative, as the predicted demand assumes the use of flexibility to shift EV charging and hot water load, along with utilising DERs to support peak demand.

11.8 Cambridge area: distribution development plan

11.8.1 Developments to meet capacity and customer requirements

Forecast feeder constraints

Of the ~37 MW of demand growth by FY36, approximately 9 MW is planned to be met through subtransmission and zone substation developments. The remaining demand growth will be served by the distribution network, either by utilising

existing feeder spare capacity, extending feeders from the new Forrest Road substation, or augmenting existing feeders.

Feeders from the Forrest Road substation will be able to service Growth Cells C2, C3, C7 to C9 and some of C10. The current and emerging constraints relate to growth cells C4 to C6 in the Leamington area, and to organic growth on the existing feeder supplying Cambridge township and areas to the south and east (see figure 96 and table 61).

Feeder	Growth Area	Constraint	Date binding	Project
Roto-o-Rangi	C5 Leamington	Demand is forecast to exceed firm capacity	FY30	Project 6 & 7
Leamington	C5 Leamington	Demand is forecast to exceed firm capacity	FY32	Project 6 & 7 Project 8 (sub)
Kaipaki*	New wastewater treatment plant	2.5 MW of new industrial demand will exceed feeder capacity	FY26	Project 5 (completed in FY26)
Monavale	N/A	Demand is forecast to exceed firm capacity	FY29-30	Project 6 & 7 Project 8 (sub)
Cambridge West*	C2 & C3 Cambridge West	Demand is forecast to exceed some sections of the line that supply Growth Cells C2 and C3	FY27-31	Project 9
Cambridge Town	N/A	Demand is forecast to exceed firm capacity	FY30-31	Projects 10-11
Cambridge North	N/A	Demand is forecast to exceed firm capacity	FY27-28	As above
St Kilda	N/A	Demand is forecast to exceed firm capacity	FY30-31	As above
French Pass	N/A	Demand is forecast to exceed firm capacity	FY33	As above
Cambridge East	N/A	Demand is forecast to exceed firm capacity	FY33-34	Project 13

Table 61: Current and emerging constraints

* New feeder from Forrest Road substation.

Network solutions

We are planning to spend \$20m on distribution projects to address the growth-related constraints in the Cambridge area (see table 62). These projects address the immediate constraints and include programmes to support incremental upgrading and reconfiguration of the network to address future constraints. Several emerging constraints from FY30 have not yet been analysed in detail, and we will add specific projects to address these issues in future AMPs (and reduce the general programme amounts accordingly).

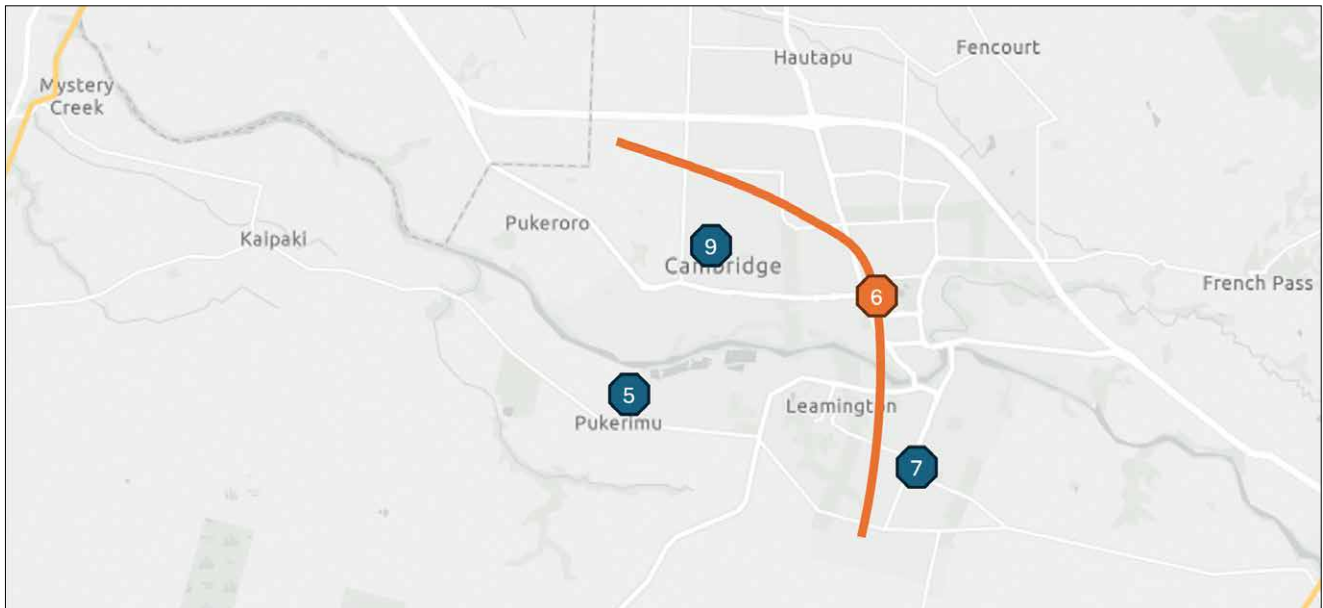


Figure 96: Proposed distribution projects

Project	Issue	Solution	Cost/timing
5. Upgrade capacity on Monavale feeder and transfer to Forrest Rd	Capacity Monavale	Upgrade the poles and conductors on Pukerimu lane which supplies the new connections and rearrange the feeder layout to supply it from Forrest Road Substation.	Project completed in FY26
6. 11kV link (using 33kV cable) from Forrest Road to the Leamington area (stage one)	Capacity Customer numbers Leamington Roto-o-Rangi	This is part of a long-term project to increase capacity in the Leamington area. Stage one: Installation of double circuit 33kV cables (operate at 11kV) from Forrest Road substation into Leamington area.	\$7.2m FY27-28
7. Reconfigure 11kV feeders in Leamington area (stage two)	Capacity Customer numbers Leamington Roto-o-Rangi	This is part of a long-term project to increase capacity in the Leamington area. Stage two: Reconfigure the Leamington and Roto-o-Rangi feeders to transfer customers onto the two temporary feeders from Forrest Road substation.	\$1.2m FY27-28
9. Cambridge West feeder (stage two)*	Capacity	Upgrade sections of small conductor on the New Cambridge West feeder and replace ABS.	\$260k FY27 ¹⁰³
10. 11kV overhead network upgrades	Capacity	Provision for an ongoing programme to upgrade the capacity of the overhead network, including poles, conductors, switchgear and network reconfiguration.	\$2.0m FY27-36
11. 11kV underground upgrades	Capacity	Provision for ongoing programme to upgrade the capacity of the underground network, including cables switchgear and network reconfiguration.	\$8.2m FY27-36
Total		System growth capex	\$20.0m FY27-36

Table 62: Proposed solutions

FY26 real \$

* New feeder from Forrest Road substation.

¹⁰³ The project commenced in FY26 and has a total cost of \$820k.

11.8.2 Developments to meet security and requirements

Distribution feeder security and reliability constraints

Our planning work to date has identified breaches of the security-related planning criteria for customer numbers on three urban feeders in the Cambridge area. Two of these are in the Leamington area and are resolved by the related capacity-driven project (Projects 6 to 8).

We also have an ongoing reliability challenge on the network. In the Cambridge area, the Victoria, Roto-o-Rangi, and French Pass feeders are among the worst-performing. The issues with the new Victoria feeder (formerly Pencarrow) predate the splitting of the feeder between the existing Cambridge GXP and the new Forrest Road substation, which is expected to improve performance.

Feeder	Constraint	Date binding	Project
Leamington	Customer count approaching 2,400, well above planning criteria of 1,500	Current	Project 6 & 7 Project 8 (sub)
Roto-o-Rangi	Customer count approaching 1,800, above planning criteria of 1,500	Current	As above
Cambridge East	Customer count is around 2,100, well above planning criteria of 1,500	Current	Project 13
Worst performing feeders	Reliability performance has been challenging on some of our feeders, particularly on our worst performing feeders (see Section 5.5.9)	Current	Projects 14-16

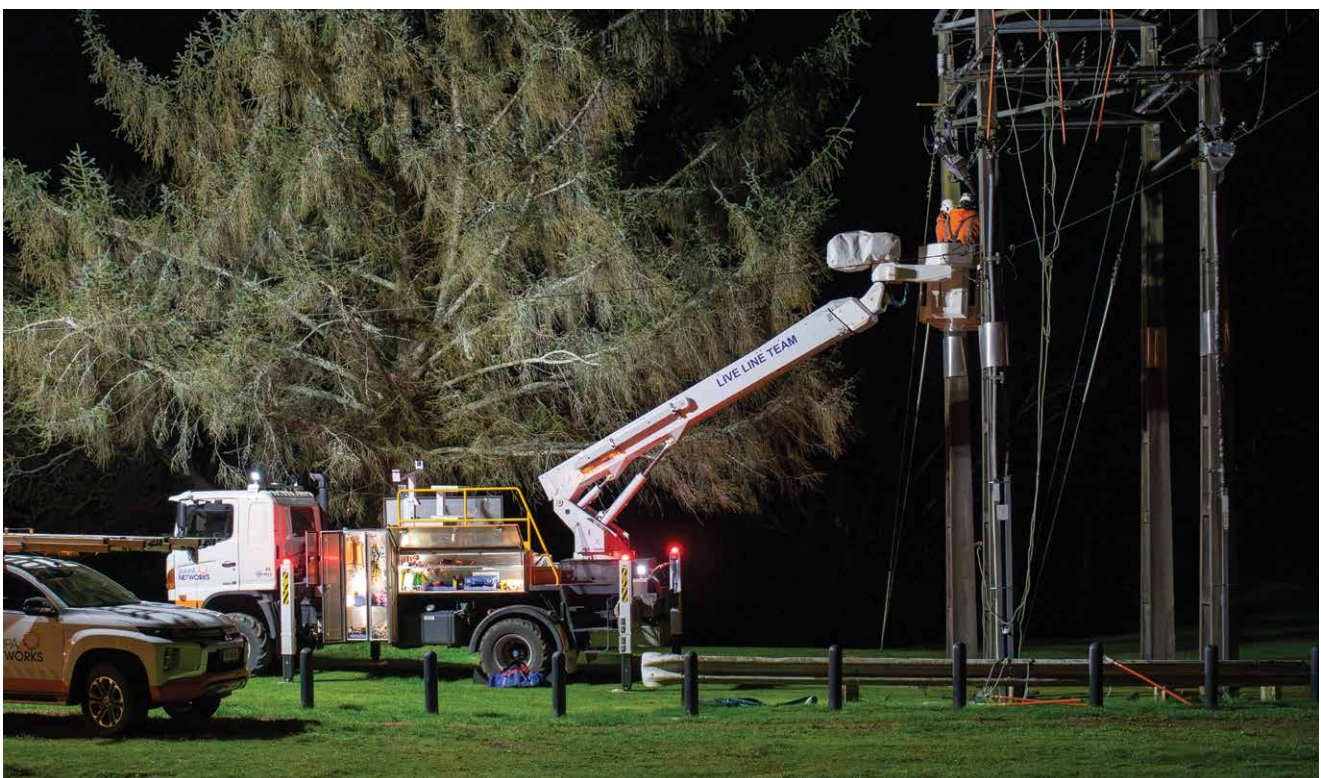
Table 63: Current and emerging constraints

Proposed network solutions

We are planning to spend \$2.9m on distribution projects to address the security and reliability constraints in the Cambridge area (in table 63). The work includes rebalancing customer numbers on feeders supplying the Cambridge township (now that customers have been transferred to the new Forrest Road substation) and progressing reliability improvement programmes (see table 64).

Whilst we are addressing causes of reliability issues (e.g., vegetation and defective equipment), we will also investigate whether security improvements are warranted.

This requires detailed network configuration, protection coordination analysis and customer engagement, and may result in the placement of additional line reclosers (to reduce the outage areas), switch automation (to improve restoration times), adding spur/service fusing for better protection coordination, or an alternative solution. Our work on the Kāwhia feeder (see Section 11.12.2) serves as a case study of how we aim to address reliability issues. Hence, we will likely include more specific reliability improvement projects in future AMPs.



Our existing reliability improvement programme

We have an ongoing programme to improve reliability. This work includes installing reclosers to segment feeders and increasing switch automation.

Using reclosers, sectionalisers, and fuses reduces the number of consumers impacted when faults occur. Reclosers allow intelligent sectionalisation of the network. Comparisons to other EDBs show that we have a high ratio of reclosers per line length compared to other EDBs, as shown in figure 97. However, there is still further scope to increase their usage (following the upgrading of our communication system).

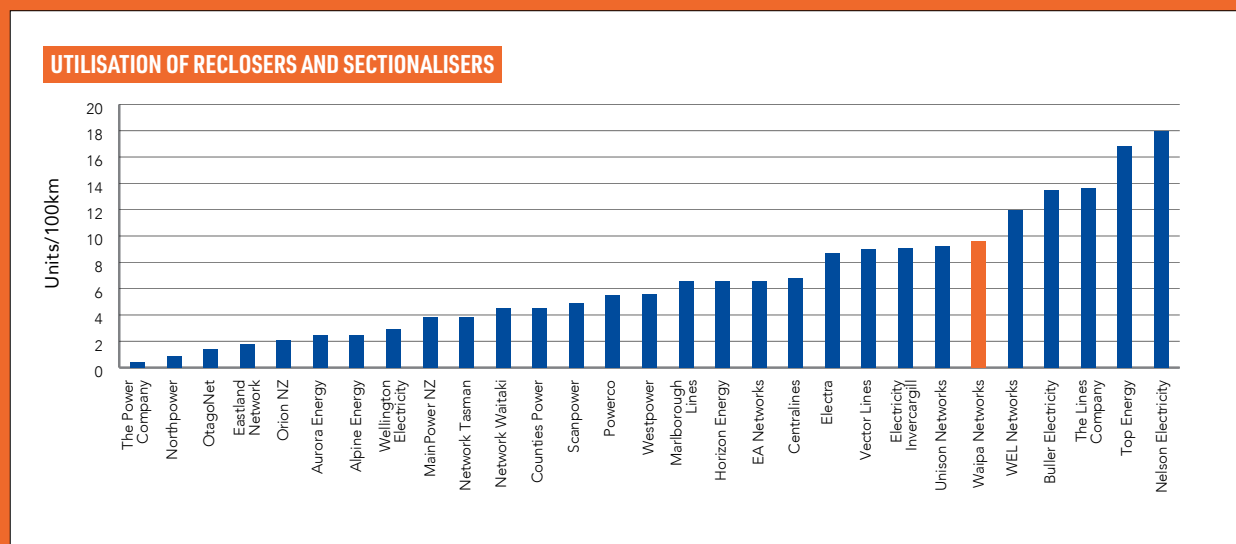


Figure 97: Recloser utilisation

Upgrading non-automated air-break and load-break switches to automated enclosed load-break switches reduces restoration times and allows unfaulted sections of the network to be restored without field visits.

The improvement projects in table 64 account for approximately 70% of the projects required to achieve the improvement forecast in figure 78 Section 7.8. Therefore, we expect to include additional reliability-improvement projects in future AMPs.

Project	Issue	Solution	Cost/timing
13. Transfer Cambridge East customers to Vogel St ¹⁰⁴	Customer numbers, Cambridge East	Most of the Vogel Street load was transferred to the new Cambridge West feeder supplied from Forrest Road substation. This allows Cambridge East customers to be transferred to Vogel Street.	\$660k FY27 ¹⁰⁵
14. 11kV automation recloser additions	Reliability	Analysis of reliability issues and installation of reclosers to reduce the impact of outages (1 p.a.).	\$308k FY27-36
15. Install remote control switches and automation	Reliability	Replace ABSs with automated enclosed load-break switches to reduce switching time and outage time for customers.	\$1.8m FY27-36
16. Install HV fuses on spur and service lines	Reliability	We will install HV fuses on spur and service lines when grouped fusing issues are identified during our reliability analysis.	\$54k FY27-36
Total		Quality of supply capex	\$2.9m FY27-36

Table 64: Proposed solutions

FY26 real \$

¹⁰⁴ Vogel Street feeder is the former Kaipaki feeder from the Cambridge GXP.

¹⁰⁵ The project commenced in FY26 and the total project cost is \$813k.

11.8.3 Developments to meet voltage and other requirements

Issue/constraints

In this section, we consider constraints with respect to voltage, resilience, legislative and regulatory requirements, and other drivers in the Cambridge area (see table 65).

Our analysis has identified four feeders on which the voltage falls below our planning criteria under high load or during backfeeding in contingency scenarios. The voltage constraints on the St Kilda and Roto-o-Rangi feeder were identified during backfeed studies, and we are undertaking further work

to confirm the extent of these issues and whether a specific project is required. This should be confirmed in the 2027 AMP.

We undertook a review of all our voltage regulator structures against seismic standards. The study identified that our structures were built to old standards and did not meet the current requirements of our resilience standard. A programme to remediate the sites is ongoing.

Over time, road heights increase due to reconstruction and realignment. Poles and conductors also shift due to ground conditions and wind/storm loadings. This can result in line clearances falling below the required standards. When clearance issues are identified during inspection or line patrols, we remediate them.

Feeder	Constraint	Date binding	Project
Pencarrow*	The transfer of the Pencarrow feeder to the Forrest Road substation has resulted in the existing voltage regulator being in a less effective location.	Current	Project 17
French Pass	Feeder voltage has dropped below planning criteria.	Current	Project 18
St Kilda	Our modelling indicates that the voltage will be below the planning criteria during high load situations and backfeeding. Further investigations are underway.	TBC	Project 19
Roto-o-Rangi	As above.	TBC	Project 19
Various	Our current voltage regulator sites do not meet seismic strength requirements of our resilience standard.	Current	Project 20
Various	We have some 11kV and LV road crossings that are below the clearance requirement across roads.	When identified	Project 21

Table 65: Current and emerging constraints

* New feeder from Forrest Road substation.

Proposed network solutions

We are planning \$3.4m in distribution projects to address the voltage and other constraints in the Cambridge area (see table 66). This work addresses the specific voltage

constraints mentioned above. We have not yet identified specific projects for St Kilda and Roto-o-Rangi, but this will likely be funded from the generic voltage improvement programme. The voltage regulator strengthening and the improvement to high-load road crossings are a continuation of existing work programme.

Project	Issue	Solution	Cost/timing
17. Reconfigure regulators on Pencarrow*	Voltage, Pencarrow*	The configuration of Pencarrow has changed as it now supplied from the Forrest Road substation. The existing VR needs to be relocated further along the feeder to be effective.	\$413k FY27
18. New voltage regulator on the French Pass	Voltage, French Pass	New voltage regulator is required and an existing regulator will be moved further along the feeder.	\$513k FY28
19. Voltage improvements	Voltage	Programme for ongoing voltage improvements.	\$1.3m FY29-36
20. Strengthen voltage regulator structures	Resilience	Programme to strengthen existing voltage regulator structures to meet seismic strength requirements of our resilience standard.	\$674k FY27-34
21. Improve high-load roadcrossings	Regulatory	Programme to increase the height of 11kV and LV roadcrossings on main traffic routes.	\$525k FY27-36
Total		Reliability, safety and environmental capex	\$3.4m FY27-36

Table 66: Proposed solutions

FY26 real \$

* New feeder from Forrest Road substation.

11.8.4 Justification for the development projects

The capacity-driven projects are required to meet demand from new customers and support future growth in demand from existing customers. Extending and upgrading the network to meet demand is essential for Waipā and has no feasible do-nothing option.

The security and reliability projects are required to support our asset management strategy #4. The \$2.9m in projects requires a pre-normalisation SCADA improvement of approximately 11 SAIDI minutes to deliver a net economic benefit to customers¹⁰⁶. Around 70% of this improvement will flow through to our normalised actual performance (due to the major event normalisation process¹⁰⁷). We are still working through the specific benefits for each project, but are generally comfortable that their business case will be viable.

Voltage, resilience, and regulatory-driven projects are required to meet specific regulatory and planning criteria, for which there is no viable do-nothing option. That is, maintaining voltage at customers premises, bringing critical assets up to an appropriate building code, and maintaining overhead conductor clearance is a business requirement.

11.8.5 Managing demand growth uncertainty

Capacity-related developments have been prepared to meet predicted demand growth. Distribution developments have a relatively short planning horizon and are generally easier to plan and execute. Hence, there is no need to accommodate the high demand growth explicitly. Should the high-demand scenario occur, additional capacity-related distribution development projects will be required. Generally, selecting standard-size conductors and cables accommodates some future demand growth. Should we see low-demand growth, deferring distribution development projects is possible.

11.8.6 Consideration of options and non-network alternatives

For capacity-driven projects, our general approach is to evaluate a range of network alternatives and select the option that provides the lowest cost to meet the required capacity upgrade, consistent with our planning and design standards. Mass-market flexibility was not explicitly considered as an option, since the expected demand (under the predicted demand forecast) relies on using flexibility to shift EV charging and hot water loads, and to utilise DERs for supporting peak demand. We are not proposing to use merchant flexibility as a non-network alternative for the projects proposed for FY27 and FY28, as the market and our ability to call on this flexibility are not yet sufficiently mature.

For capacity-driven projects serving new customers, merchant flexibility was deemed infeasible because the network must be expanded to reach the new customers.

In relation to reliability, security and voltage projects, given the pressing need to resolve the immediate issues, we are not proposing to use merchant flexibility as a non-network alternative for the projects proposed for FY27 and FY28, as the market and our ability to call on this flexibility are not yet sufficiently mature. However, the use of merchant flexibility will be explored for projects beyond FY28 in subsequent AMPs. The Te Awamutu architecture review and the Kāwhia project are assessing non-network alternatives in detail. The outcome of this work will inform the options available for the Cambridge network.

There are no non-network alternatives to the resilience and regulatory-driven projects.



¹⁰⁶ Based on Waipā Networks' average VOLL of \$29,000 per MWh, which equates to around \$25,000 per SAIDI minute.

¹⁰⁷ Based on the extent of normalisation in recent years.

11.9 Te Awamutu architecture review

11.9.1 Introduction

As noted in our 2024 and 2025 AMPs, we have been conducting a review of Te Awamutu Architecture (the TA Review). Work on the TA Review began in earnest in FY25 and has continued into FY26. In this section, we provide an overview of the review.

11.9.2 Background

Waipā Networks has experienced strong demand growth in the Te Awamutu area over the past decade, and this trend is expected to continue over the coming decades, driven by population growth and decarbonisation (via electrification). To date, demand growth has led to voltage constraints and reliability issues, while high feeder loadings and network configurations are compromising security and resilience.

The issues facing the Te Awamutu area are complex. They include regional transmission security constraints, GXP security constraints, voltage and distribution network limitations, low reliability, feeder configurations that compromise resilience, and impact of climate change driven weather events. These issues are expected to worsen as demand grows.

New technology enables customers to generate and store electricity, changing how they interact with the network. Waipā Networks must ensure our network provides a foundation for all types of customers to use it, including those who will continue to rely on it for energy and those who will actively respond to price signals to provide demand response and sell generation output.

In 2021, the need to develop a solution for Te Awamutu was considered urgent due to a range of GXP and distribution constraints. However, recent projects undertaken by Transpower and the front-end feeder cable upgrades have given us time to evaluate options for developing a network architecture to improve performance, prepare for new customers and demand growth, and adapt to changing network use.

We are taking a fresh approach to generating the solution, ensuring our customers' and stakeholders' needs and opinions are heard and they help co-design innovative solutions. The projects outlined in this section are pre-customer engagement. We intend to engage with customers to ensure that project benefits and costs align with customer expectations. This engagement process may see some changes to our development plan for future AMPs.

11.9.3 Overview of the issues facing the Te Awamutu network and customers

The key issues for the region are:

- Recent strong growth with a continuing demand growth (see Section 11.10)
- Changes in the way that customers may use the network (see Section 10.3.3)
- Current and forecast network issues (see below).

Current and forecast network issues include:

- Transpower's annual planning report indicates the 110kV grid will become constrained, impacting

Te Awamutu security in various contingency situations. Waipā Networks (and other connecting EDBs) will be forced to disconnect customers or invest in generation to alleviate the constraints (under certain transmission contingency situations)

- Demand at the Te Awamutu GXP is forecast to exceed firm (N-1) security criteria sometime after FY28 (see Section 11.11.1)
- Feeders are long, highly loaded, have a high number of customers connected, and have limited backfeeding capability due to thermal and voltage constraints (see Section 11.12.1 and 11.12.2)
- The high load and long length contribute to the voltage constraints we are currently experiencing (see Section 11.12.3)
- The low level of security provided to customers has contributed to poor reliability outcomes. Longer outage durations are common, as backfeeding constraints mean many customers remain without supply until repairs are completed (see Section 5.5 and 11.12.2)
- Te Awamutu GXP supplies the distribution network at 11kV via 16 feeders (or 14 after excluding the dedicated supply to Fonterra). Typical zone substations on a semi-rural network have six to eight feeders. The high number of feeders leaving a single site has led to many feeders, mainly rural, sharing the same pole structure. Sharing structures reduces the network's mechanical security and resilience to physical damage and increases outage areas during maintenance and renewal work.

11.9.4 Objectives of the TA review

The objective of the TA Review is to define a solution for the Te Awamutu area that:

- Best resolves the customer service, resilience, and servicing new growth issues (mentioned above)
- Has manageable risk and reduces our overall business risk
- Is affordable for customers
- Meets Waipā Networks' financial requirements.

11.9.5 Outcomes of the TA review included in this AMP

The TA Review outcomes related to demand forecasting and subtransmission and zone substation development are included in Sections 11.10 and 11.11. The next phase of the TA Review is to establish the distribution network architecture.

Currently, the distribution development plan outlines the constraints and projects to address urgent issues. It also includes broader development programmes that will be guided by the TA Review. We have included these general programmes as they offer a reasonable estimate of future expenditure. These programmes have not yet been assessed for non-network alternatives and therefore currently reflect the cost of traditional network solutions. We expect that these capex programmes will decrease, and our expenditure on non-network solutions will increase (some of which may be opex for merchant flexibility services).

11.10 Te Awamutu area: demand forecast

11.10.1 Regional demand growth

The Te Awamutu demand forecasts are shown in figure 98. For the predicted scenario, Te Awamutu demand is expected to increase from 42 MW to 60 MW by FY36, then to 75 MW by 2050 (with a low/high range of 60 MW to 104 MW). This represents a growth rate of 2.3%, with a low/high range of 1.6% to 3.5%. The strong growth is partly driven by industrial demand increases, including Waikeria Prison developments and the decommissioning of the cogeneration plant at Fonterra.

The demand forecast incorporates the significant connections and growth assumptions outlined in the next section. The forecasts include the end-of-life decommissioning of Fonterra's 5 MVA generator in 2033. The decommissioning of this unit will materially affect the GXP demand. We continue to engage with Fonterra to ensure any updates regarding the generator are known and accounted for.

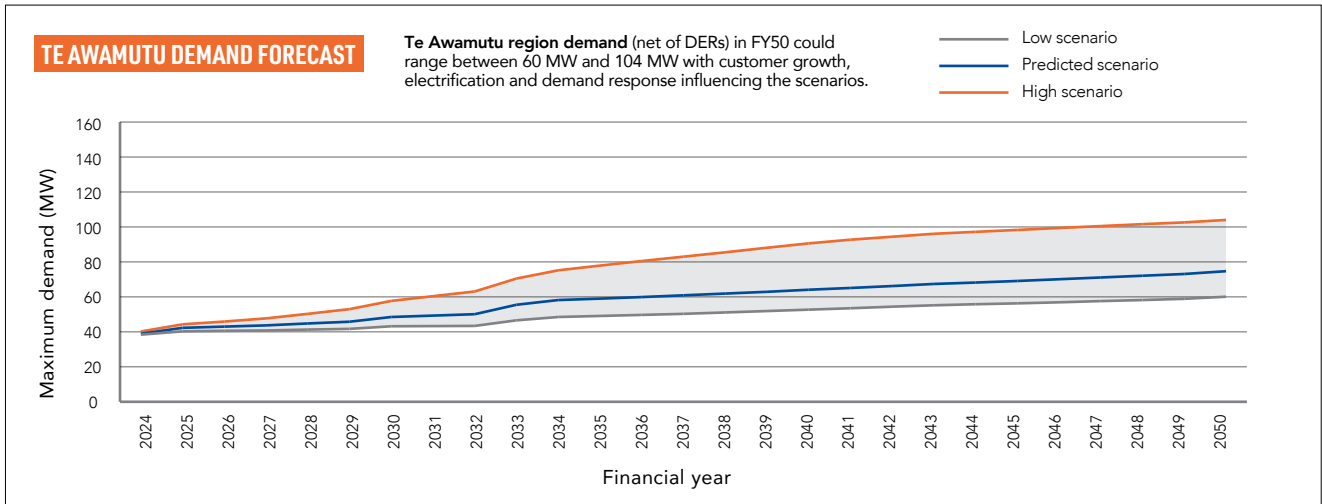


Figure 98: Te Awamutu area demand forecast

11.10.2 Distribution demand growth

Waipā District Council has developed regional growth cells that define the areas and scope of land developments. Figure 99, table 67 and table 68 outline the growth cells and expected growth in the Te Awamutu area, which is estimated to be around 6 MW by FY36. Connection growth is expected across most cells, except for T13 to T15, which is forecast to occur beyond the planning period of this AMP. Most of the growth will be to the West and South of Te Awamutu.

We are also aware of specific customer demand growth, in addition to the growth mentioned above (see table 69). This is estimated to be an additional 12-19 MW by FY36.



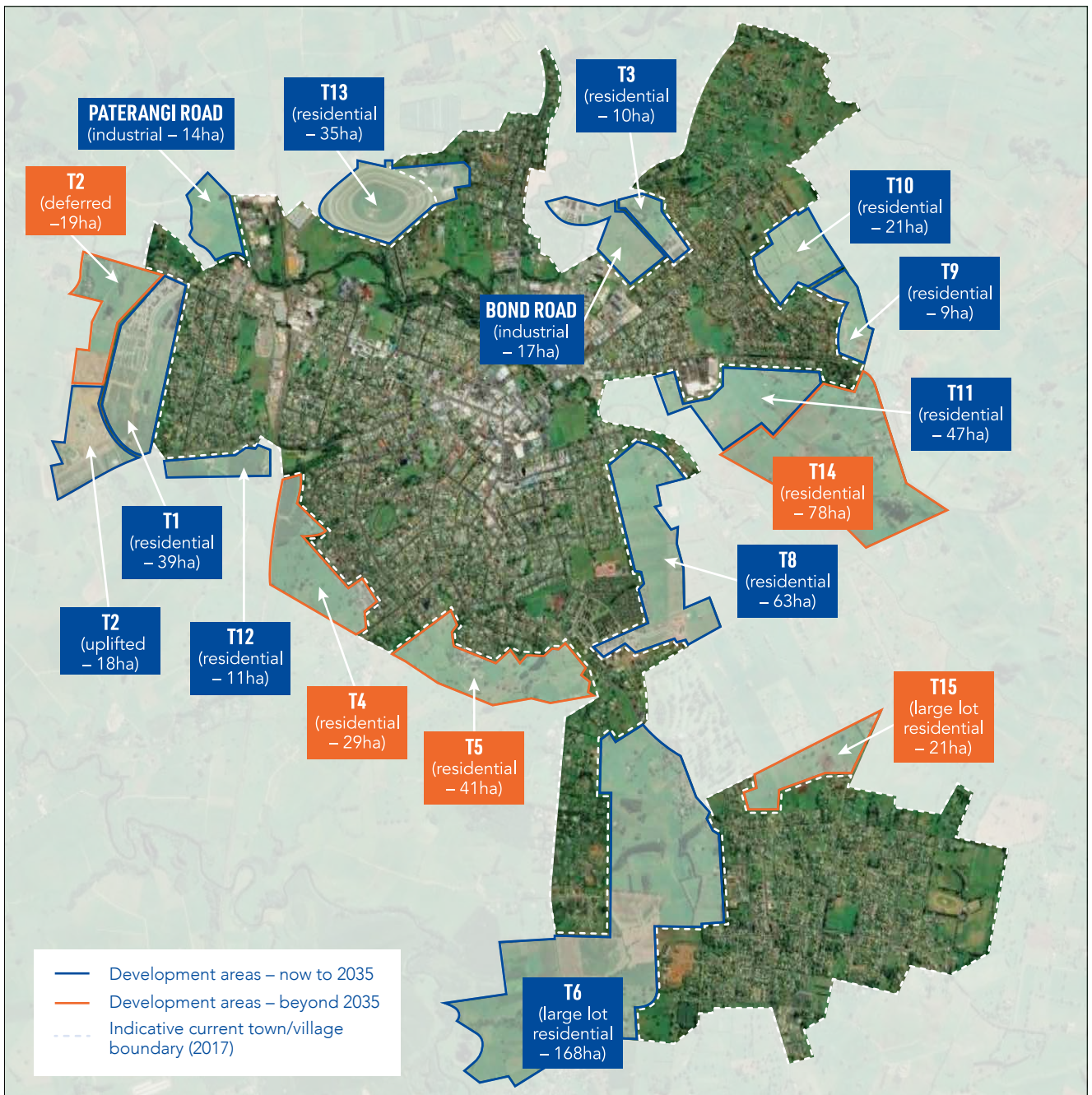


Figure 99: Te Awamutu growth cell map

Growth cell development	Feeder	Estimated load and timing
T1 and T2 development, total of over 1,000 new lots through to FY40. Includes the Frontier Estate subdivision, Kotare Height subdivision, and Te Awamutu Country Club retirement village. The second half of the T1 growth cell is on hold which is 39 hectares of residential land development (444 new houses)	Pirongia	2.5 MW FY25 to FY36
T3 development, total of 120 new lots from FY31 to FY40	Hairini	200 kVA FY31-36
T4 development, total of 250 new lots beyond FY50	Kiokio	Beyond the planning period
T5 development, around 500 new lots from FY41	Pirongia	Beyond the planning period
T6 development, around 600 new lots from FY24 to FY40	Pirongia	1.0 MVA FY27-36
T7 development is complete		
T8 development, around 564 new lots. The first development has been completed with further development planned	Kihikihi	1.0 MVA FY27-30
T9 development, around 200 lots, in progress to FY30	Hairini	350 kVA FY27-36
T10 development, around 350 lots from FY31 to FY40	Hairini	500 kVA FY27-36
T11 development, around 300 lots from FY31 to FY50	Hairini	250 kVA FY27-36
T12 development, 132 new houses. The development has been completed, and demand will slowly grow as houses are built.	Te Awamutu West	Up to 0.5 MVA from FY27
T13 to T15 developments are around 1,000 new lots commencing around FY40	Mystery Creek Hairini Kihikihi	Beyond the planning period

Table 67: Te Awamutu area land developments

Growth cell development	Feeder	Estimated load and timing
Pirongia development forecast to be within the current town boundaries. Up to 40 new lots possible	Pirongia	100kVA from FY27 to FY36
O1-O4 development adjacent to the Ōhaupō township. Up to 80 new lots	Ōhaupō	200kVA from FY27 to FY36
P1 to P2 development adjacent to the Pukeatua township	Pukeatua	No material growth
TP1 to TP4 development adjacent to the Te Pahu township	Paterangi	No material growth

Table 68: Other land developments in the Te Awamutu area

Growth cell development	Feeder	Estimated load and timing
Expansion of the Waikeria Prison	Waikeria	4.0 MW by FY26 Further 3.0 MW by FY29-30 Further 2.9 MW FY30+
Fonterra has indicated that the 5/7.5 MVA generation scheme may reach end-of-life within the 10-year planning period 5MVA step change in load at the GXP. There is no timing confirmation, but it is a significant step in the load for the TMU GXP, which is being monitored closely	Fonterra A and Fonterra B	Current estimated is 5 MW in FY33
Industrial site electrification	Hairini	This could be up to 4 MW

Table 69: Te Awamutu area major connections

11.11 Te Awamutu area: GXP, sub-transmission and zone substation development plan

11.11.1 Subtransmission and zone substation developments to meet security and capacity requirements

Constraints

Sections 11.10.1 and 11.10.2 show that demand is likely to grow by around 18-20 MW by FY36 under the predicted scenario. From a regional supply point of view, the TA review considered two main challenges:

- The forecast demand surpassing current regional capacity (i.e., the ability to service new growth)
- Efficiently distributing the required capacity across the region (which impacts network voltage and security¹⁰⁸).

Currently, the Te Awamutu area is served by a single GXP with a maximum winter capacity of 54 MVA and lacks a supporting sub-transmission network. In the predicted scenario, demand will surpass 54 MVA by FY32 (see figure 100). By then, reliance on a single GXP supply point will create operational challenges, as power must be delivered over long distribution feeders to reach customers, resulting in additional voltage constraints and reduced network security and reliability. These constraints also lead to high electrical losses and reduced hosting capacity for new loads or distributed generation.

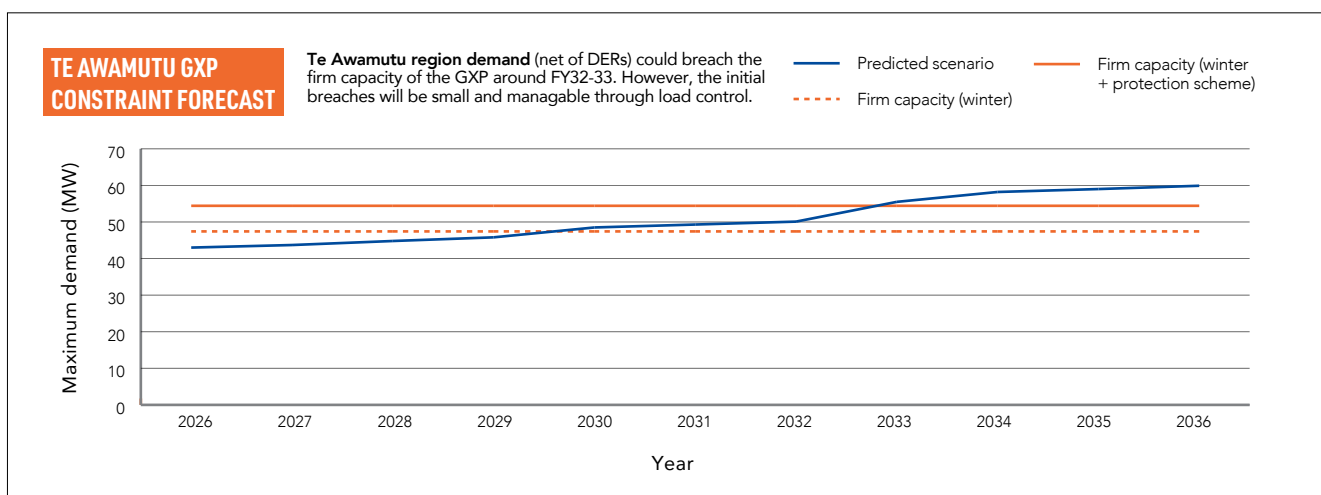


Figure 100: Te Awamutu GXP constraint forecast

Location/feeder	Driver	Constraint	Date binding	Project
Te Awamutu GXP	Strong regional growth across T1-T12 and industrial growth	N-1 capacity (53MVA with the special protection scheme) is projected to be exceeded due to regional growth	FY32	Projects 30 to 35
Waikeria	Expansion of the Prison	Demand exceeds capacity of the Feeder	FY29-30	Project 60 to 63

Table 70: Current and emerging constraints

A suitable solution must address the regional capacity constraint at Te Awamutu GXP (TMU) and the power distribution issues associated with the current network architecture.

Options considered

Concerning the regional supply, the TA Review considered three main options:

- Option 1: Expand the existing TMU GXP
- Option 2: New GXP at Pirongia
- Option 3: Hybrid network/non-network solution (our recommended option).

Expanding the existing Te Awamutu GXP (Option 1) involves upgrading the existing TMU transformers at the GXP site and constructing a sub-transmission line to supply a zone substation at Waikeria (for the low and predicted scenarios), as well as another substation at Pirongia (for the high scenario). Option 1 is estimated to cost \$105m to meet the predicted demand, with costs ranging from \$45m to \$130m depending on whether the low – or high-demand scenario occurs.

¹⁰⁸ Where network security is a key driver of reliability.

A new GXP at Pirongia (Option 2) involves developing a GXP on the 220kV line west of Te Awamutu and constructing a new sub-transmission line to supply a zone substation at Pirongia for the low and predicted demand scenarios, with two additional substations at Waikeria for the high scenario. Option 2 would cost \$85m to support the predicted demand and could range from \$50m to \$100m if the low or high-demand scenario occurs.

The hybrid solution (Option 3, our recommended choice) merges network and non-network solutions. An incremental approach is adopted to increase capacity. This option involves building a zone substation at Waikeria, supplied by Hautapu GXP in Cambridge via Leamington and supported by an 11kV fast-transfer scheme. Then, building a zone substation at Pirongia supplied directly from the Hautapu GXP and an 11kV fast-transfer scheme. Non-network solutions are used to reduce peak demand and allow for staged capacity augmentation (see figure 101). The type of flexibility procured can vary depending on cost and market availability. Our initial assessment indicates that the maximum value we could pay for flexibility will be sufficient to procure an acceptable solution.

Option 3 would cost \$60m to support the predicted demand and could range from \$22m to \$80m if the low or high demand scenario occurs¹⁰⁹. These costs include an estimate of the capital cost of non-network solutions, which range from \$3m to \$11m depending on the demand growth scenario. Option 3 is the least-cost option to meet regional demand under all scenarios.

All options involve expanding the number of distribution feeders to achieve capacity and security requirements (and we have included an estimate of these programme costs in Section 11.12.1).

The adaptability of Option 3 mitigates the risk of over-investment or inability to meet demand. It is the most cost-effective option to cover the range of demand growth scenarios and maintain the ability to utilise lower-cost flexibility should it become available in the market.

Proposed network solutions

The hybrid solution (Option 3, our recommended choice from the TA Review) utilises both network and non-network solutions to deliver incremental capacity that best matches forecast demand growth (see figure 101). This option comprises:

- Building a zone substation at Waikeria, supplied from a 33 kV single-circuit line from the Hautapu GXP via Leamington. This can deliver up to 10 MW of firm capacity for the Waikeria Prison when supported by an 11kV fast-transfer system between the substation and Te Awamutu GXP. This is a customer connection project (the costs are included in Section 12.2.6)
- Building a zone substation at Pirongia, supplied from a 33 kV single-circuit line from the Hautapu GXP. This can initially deliver up to 7 MW of firm capacity for the region when supported by an 11kV fast-transfer system between the substation and Te Awamutu GXP
- As demand grows (for the high scenario), a further zone substation can be constructed at Ōhaupō. This will initially be supplied by the Pirongia single 33kV circuit, supported by an 11kV fast-transfer circuit
- As demand grows, firm capacity will be increased by installing a 33 kV circuit between Pirongia and Waikeria (to form a 33 kV ring circuit) and an additional transformer can be installed at the Te Awamutu GXP if needed
- A mix of non-network solutions will also be used during this period to reduce peak demand. 1 MW will be required in FY30, with an additional 4 MW of non-network solutions planned. The type of flexibility procured can vary depending on cost and market availability. Our initial assessment indicates that the maximum value we could pay for flexibility will be sufficient to procure an acceptable solution.

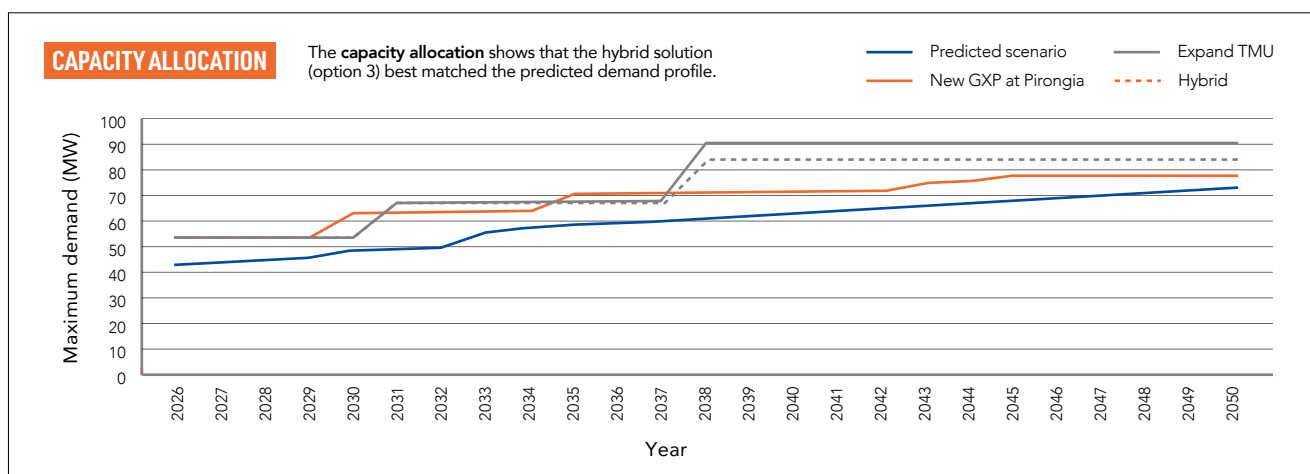


Figure 101: Capacity allocation for the recommended hybrid solution

¹⁰⁹ This includes the 33kV cable and zone substation customer connection capex for the Waikeria Prison before deducting capital contribution. That is, it is the total capital cost to the economy to allow a like-for-like comparison. It includes subtransmission, zone substation and distribution capex associated with the option.

The large step increase in capacity around FY30 (see figure 101) is to meet demand at Waikeria Prison. It is required to address an 11kV capacity issue in the first instance and provide GXP capacity relief later in the planning period.

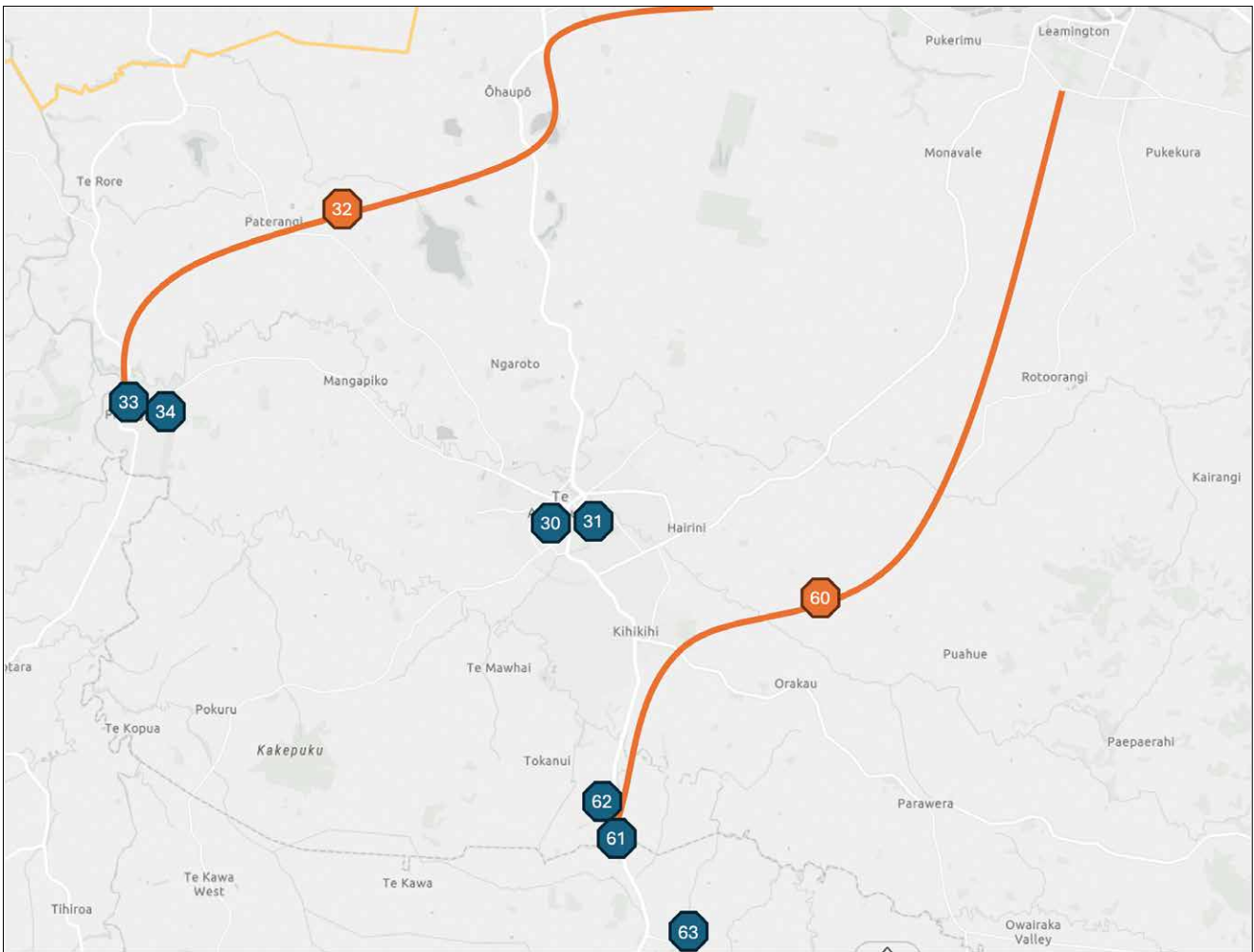


Figure 102: Proposed subtransmission and zone substation projects



Project	Issue	Solution	Cost/timing
60. 33kV circuit to Waikeria	Capacity Waikeria Prison	33kV 25 MVA single circuit cable from Leamington to Waikeria Prison.	Customer connection FY27-29
61. Waikeria zone substation	As above	Single bank 16/24 MVA zone substation adjacent to the Waikeria Prison. Firm capacity is initially 10 MW when operated with the 11kV fast transfer circuit Reconfiguration of the 11kV supply to Waikeria Prison.	As above
62. Waikeria 11kV fast transfer	As above	11kV 10 MVA fast-transfer circuit between Waikeria zone substation and Te Awamutu GXP. This circuit provides N-1 switched support to the Waikeria zone substation.	As above
63. Waikeria 1 MW x 1 MWh BESS	As above	BESS to supply the shortfall on the 11kV when load growth exceeds 9 MVA.	As above
30. 1 MW x 1.2 MWh BESS	Capacity, Te Awamutu GXP	BESS to provide first 1 MW of peak reduction at Te Awamutu GXP (approx. 2% of peak) requires 1.2 MWh of storage The preferred location is on the distribution network where it could also support backfeeding voltage and capacity constraints.	\$1.3m FY31-32
31. 1 MW x 1.4 MWh BESS	As above	BESS to provide second MW of peak reduction at TMU GXP (total of 4% of peak) requires additional 1.4MWh of storage The preferred location is on the distribution network where it could also support backfeeding voltage and capacity constraints.	\$1.4m FY33-34
32. 33kV single circuit line from Hautapu GXP to Pirongia	As above	33kV 26 MVA single-circuit line from Hautapu GXP to Pirongia.	\$13.9m FY33-35
33. Pirongia zone substation	As above	Single bank 12/15 MVA transformer zone substation at Pirongia Firm capacity is initially 7 MW when operated with the 11kV fast transfer circuit.	\$7.2m FY33-35
34. 11kV fast-transfer between Pirongia and Te Awamutu	As above	11kV 7 MVA fast-transfer circuit between Pirongia zone substation and Te Awamutu GXP. This circuit provides N-1 switched support to the Pirongia zone substation.	\$1.6m FY33-35
Total		System growth capex	\$25.4m FY27-36

Table 71: Proposed solutions

FY26 real \$

Beyond the planning, for the predicted demand scenario, this hybrid solution will utilise:

- 1.5 MW of generation, contracted for peak-demand reduction, around FY37
- 3.0 MW of additional 11kV fast-transfer capacity, around FY43
- Further BESS and generation as required.

11.11.2 Developments to meet other drivers

There are no subtransmission or zone substation projects planned to meet other drivers. This is as expected, as our subtransmission and zone substation will be new and designed to meet security, voltage, location, planning horizon, environmental and resilience requirements.

11.11.3 Justification for the development projects

There is a need to increase capacity in the Te Awamutu area to support expected demand growth. There is no do-nothing option that does not curtail regional economic and population growth.

The hybrid solution (Option 3) is the least-cost option for meeting regional demand across all scenarios (including the capital cost for the non-network solution). It offers incremental benefits for customer service and resilience, as non-network solutions can support the restoration of supply and voltage and enable islanded operation to serve remote communities.

The hybrid solution offers advantages over traditional approaches by adapting to diverse demand scenarios and emerging markets. It emphasises incremental expenditure, which is advantageous in a region facing uncertain projected growth and a developing flexible market.

The hybrid solution offers the lowest capital cost to provide the required capacity across all demand scenarios. There will be additional operating costs associated with non-network solutions. However, the capital cost of the hybrid solution is significantly lower, leaving sufficient room to absorb higher operating costs.

11.11.4 Managing demand growth uncertainty

The hybrid solution (Option 3) incrementally delivers the required capacity and regional security by leveraging capacity from the Hautapu GXP and non-network solutions. This solution prioritises incremental sub-transmission build and non-network solutions over increasing the GXP capacity. The adaptability of the hybrid solution is important given the uncertainty around the pace of decarbonisation and electrification, population and housing growth, the evolution of flexibility markets, and customer uptake of DERs.

11.11.5 Consideration of non-network alternatives

The hybrid solution (Option 3) fully considers and utilises non-network solutions. Presently, these costs are included in the capex forecasts (this is to provide a view of total costs). We will seek market offers for non-network solutions as part of our delivery process. Hence, there will likely be a shift between capex and opex over time.

11.12 Te Awamutu area: distribution development plan

11.12.1 Developments to meet capacity and customer requirements

Forecast feeder constraints

Sections 11.10.1 and 11.10.2 indicate that demand is likely to increase by about 21 MW by FY36 under the predicted scenario. Section 11.11 outlined the solutions that will provide this capacity at a regional level. For this capacity to be available at a distribution level, 11kV capacity-related issues must be addressed. As mentioned in Section 11.9.3,

the TA Review has identified a range of capacity issues on the Te Awamutu network. The demand growth will ultimately be served by the distribution network, either by utilising existing feeder spare capacity, extending feeders from the new zone substation, or augmenting existing feeders.

In this section, we have outlined the current capacity-related constraints (see table 72). There is a strong overlap between the capacity constraints in table 72 and the security constraints in table 62, as the capacity constraints also manifest as security constraints (arising from demand growth).

Feeder	Growth area	Constraint	Date binding	Project
Waikeria	Waikeria Prison	There is a small section of conductor that is constraining the first 4.0 MW of the supply upgrade to the prison	FY26	Complete in FY26
Pirongia	N/A	Current demand is above firm capacity (front-end cable is limited)	Current	Completed in FY26
Hairini	N/A	As above	Current	Project 37
Kihikihi	N/A	As above	Current	Project 37
TA East	N/A	As above	Current	Project 38
TA West	N/A	As above	Current	Project 39
Pirongia	Growth Cells T1, T2 and T6	An additional 3.5 MW of growth is expected to the West and South of Te Awamutu	~FY30	Project 40 & 41
Hairini	Growth Cells T3, T9 to T11	Demand is forecast to exceed firm capacity (after front-end upgrade)	~FY30	As above
TA West	Growth Cells T12	As above	~FY32	As above
TA East	N/A	As above	~FY34	As above
Kihikihi	Growth Cells T8	As above	~FY35	As above
Paterangi	N/A	Conductor constraints that limit operational flexibility and backfeeding	FY31	Project 40
Pukeatua	N/A	Conductor constraints that limit operational flexibility and backfeeding	FY32	Project 40

Table 72: Current and emerging constraints

Proposed network solutions

We are planning \$30m of distribution projects to address the growth-related constraints in the Te Awamutu area (see figure 103 and table 73). These projects address immediate constraints and include preliminary programmes to support incremental upgrading, network reconfiguration, and non-network solutions to address future constraints resulting from the TA review.

Regarding immediate issues, we have a programme to upgrade the 11kV cables from the Te Awamutu GXP circuit breakers to the overhead network connection, as they are constraining feeder capacity. Upgrades to the Paterangi and Pokuru cables have been completed, and the upgrade to the Pirongia feeder is due for completion in FY26. In some cases, this will only provide short-term relief, as additional growth is forecast.

The various capacity constraints (beyond the front-end cables) are still in the planning phase and are presently linked to the general programmes (Projects 40 to 42). The TA Review is guiding the resolution of these capacity constraints. As we define the future architecture for the region, complete our analytical work, and engage with customers, we will expand our list of specific upgrade projects in future AMPs (and reduce the general programmes). We expect many of the specific projects (within the scope of projects 40 to 42 below) to be non-network solutions. This will result in a shift from capex to opex.

Resolving capacity constraints will also address related security constraints stemming from historical demand growth.

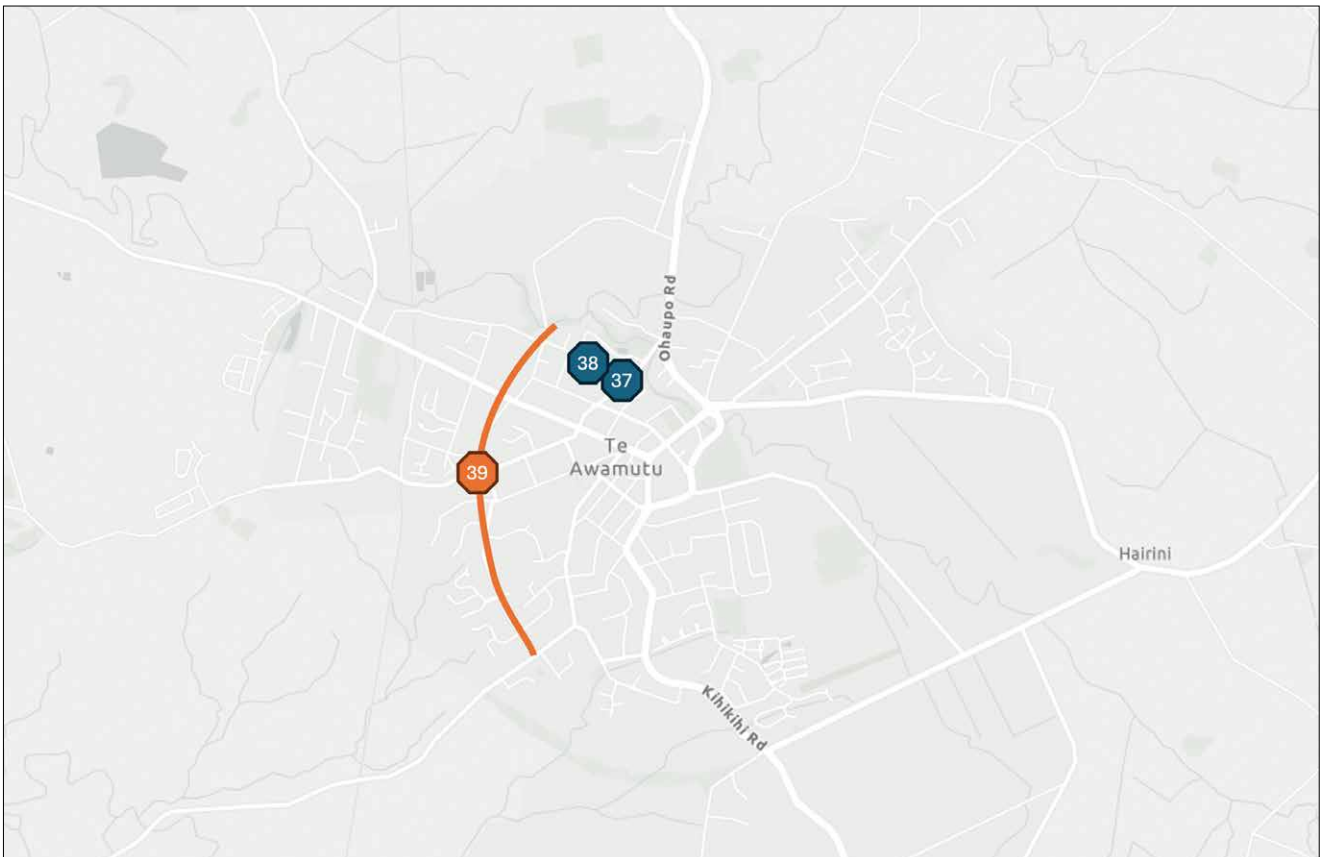
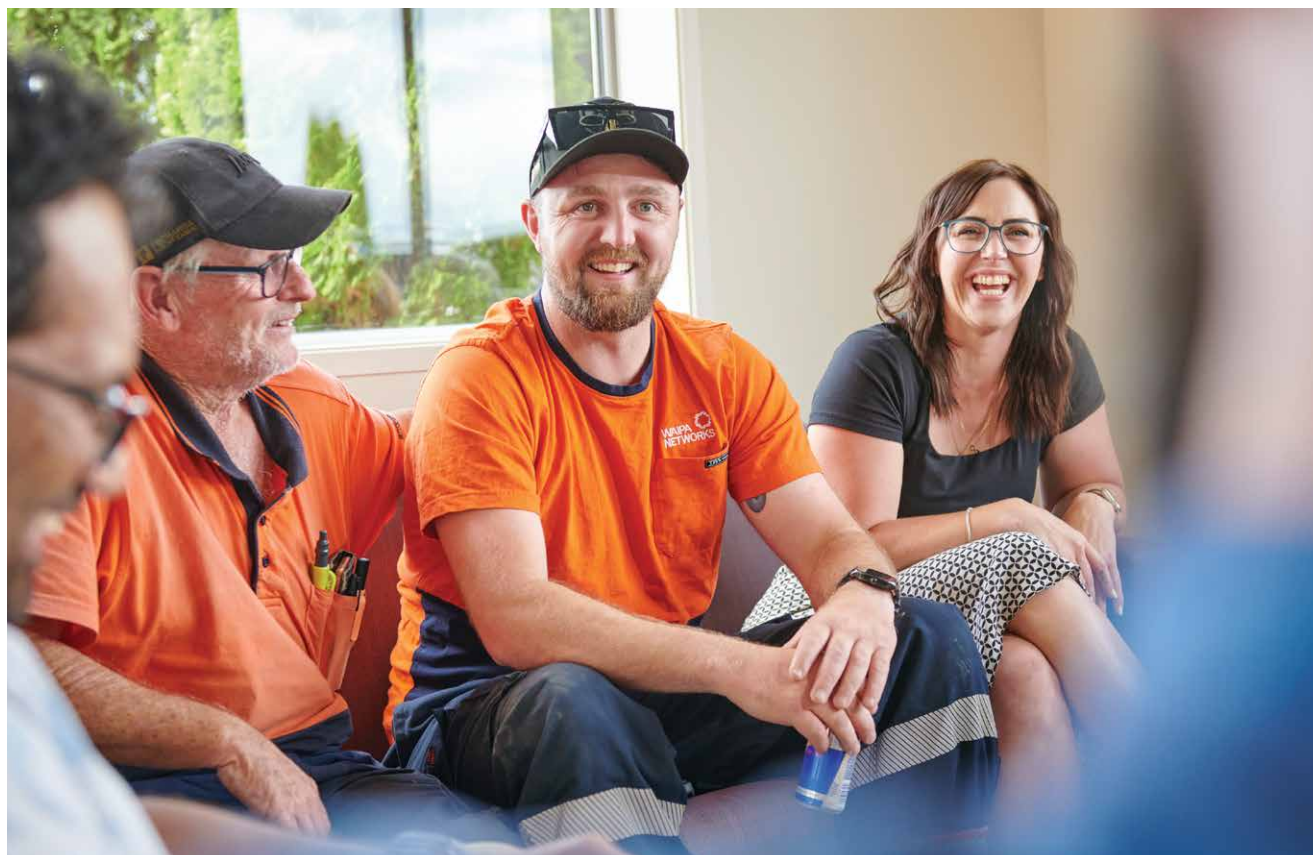


Figure 103: Proposed distribution projects

Project	Issue	Solution	Cost/timing
37. Hairini, Kihikihi front end upgrade	Capacity	Underground 850m of both the Hairini and Kihikihi Feeders along Mangapiko Street and Mutu Street. This will remove the constraint and also remove two circuits from the three circuit poles. Install a third spare duct for the TA East feeder (Mangapiko St).	\$663k ¹¹⁰ FY27
38. TA East Feeder front end upgrade	Capacity	Install 500m of cable in the spare duct (Mangapiko St) and further underground another 600m. Installing three automated RMUs to tie TA West feeder to provide greater capacity and security to the Te Awamutu business district.	\$925k FY27-28
39. TA West Feeder upgrade and reconfiguration	Capacity Security	Install 2.2km of cable to split the TA West feeder. Reconfigure the existing TA West and Pokuru OH circuits.	\$2.6m FY28-29
40. 11kV overhead network upgrades	Capacity Security	Programme to upgrade the capacity of the overhead network, including poles, conductor, switchgear and network reconfiguration. The scoping of this work is included in the TA review.	\$10.7m FY27-36
41. 11kV underground network upgrades	Capacity Security	Programme to upgrade the capacity of the underground network, including cables switchgear and network reconfiguration. The scope of this work is included in the TA review.	\$9.9m FY27-36
42. 11kV network and non-network solutions	Capacity Security	Programme to upgrade the capacity of the network, which may result in non-network solutions. The scope of this work is included in the TA review.	\$5.3m FY28-33
Total			\$30.0m FY27-36

Table 73: Proposed solutions

FY26 real \$



¹¹⁰ This project is in progress. Total cost is \$1.7m.

11.12.2 Developments to meet security and reliability requirements

Distribution feeder security and reliability constraints

As mentioned in Section 11.9.3, the TA Review has identified a range of issues on the Te Awamutu network. These include a high number of customers connected per feeder, limited backfeeding capability, and multi-circuit structures. These issues have affected reliability.

Table 63 identifies six feeders whose customer numbers are near or above our planning criteria thresholds. The high customer numbers reflect prior growth and are linked to the capacity constraints noted in table 72. The resolution of these constraints will be addressed concurrently with the

capacity work (which will include new feeders and feeder reconfigurations), with the details of how this will occur included in the TA Review.

We also have an ongoing reliability challenge on the network. In the Te Awamutu area, the Kāwhia, Pukeatua, Paterangi, Pokuru and Kiokio feeders are among the worst-performing. These are generally long feeders with high customer numbers. The Kāwhia feeder faces particular challenges, as Kāwhia township is at the end of a long rural line with no adjacent feeder to provide security support. We are conducting a detailed study of options to improve reliability on this feeder. This will involve a step change in our customer engagement process. The customer engagement aspect of the project is discussed in a case study in Section 3.4.1, and our work on the options is included in the Kāwhia case study.

Feeder	Constraint	Date binding	Project
TA West	Feeder significantly above customer number planning criteria	Current	Project 39
Kihikihi	As above	Current	TA Review Project 40 to 42 (Table 73)
Kāwhia	As above	Current	Kāwhia project
Kāwhia	Worst performing feeder for reliability	Current	Kāwhia project
Pirongia	Feeder at customer number planning criteria limit	Current	TA Review Project 40 to 42 (Table 73)
Hairini	As above	Current	As above
Pukeatua	As above	Current	As above
Pukeatua	The Bond Road industrial area is downstream of a rural reclose, hence industrial customers are experiencing interruptions to their supply	Current	Project 43
Pukeatua	One of the worst performing feeders for reliability	Current	TA Review Project 44 to 46
Paterangi	As above	Current	As above
Pokuru	As above	Current	As above
Kiokio	As above	Current	As above

Table 74: Current and emerging constraints

Proposed network solutions

We are currently planning \$2.3m of distribution projects to address the security and reliability constraints in the Te Awamutu area. These are a continuation of our current programmes, which may change following completion of our work on the Te Awamutu architecture review.

While we address the causes of the reliability issues (e.g., through asset renewals and vegetation management), we are also assessing whether security improvements are needed to enhance reliability regardless of the cause. This requires detailed network configuration, protection coordination analysis and customer engagement, and may

result in the placement of additional line reclosers (to reduce the outage areas), switch automation (to improve restoration times), adding spur/service fusing for better protection coordination, new or reconfigured feeders, or an alternative solution. Our work on the Kāwhia feeder serves as a case study of how we aim to address reliability issues.

The improvement projects in table 64 account for about 55% of the value of projects required to meet the improvement forecast in figure 78 in Section 7.8 for the Te Awamutu area. As we advance the TA Review to the distribution level (including lessons from the Kāwhia work), we plan to include additional reliability-enhancement projects in future AMPs.

Project	Issue	Solution	Cost/timing
43. Bond Road security improvement	Reliability	Install new automated enclosed switch as the tie point between Pukeatua and Hairini feeders along the bond road. Move and upgrade the existing recloser X5107 to the urban/rural boundary.	\$150k FY27
44. 11kV automation recloser additions	Reliability	Analysis of reliability issues and installation of reclosers to reduce the impact of outages (1 p.a.).	\$308k FY27-36
45. Install remote control switches and automation	Reliability	Replace ABSs with automated enclosed load-break switches to reduce switching time and outage time for customers.	\$1.8m FY27-36
46. Install HV fuses on spur and service lines	Reliability	We will install HV fuses on spur and service lines and grouped fusing issues when identified during our reliability analysis.	\$55k FY27-36
Total		Quality of supply capex	\$2.3m FY26-37

Table 75: Proposed solutions

Kāwhia reliability and resilience case study

Background

Given the large scope and complexity of the distribution network it is not possible nor prudent to attempt to assess reliability and resilience issues across the entire distribution network in one go. Instead, a single location has been singled out for in-depth study. The Kāwhia feeder has been selected for this purpose.

Kāwhia

Kāwhia and its surrounding area is isolated with predominantly rural communities. However, population swells seasonally, with visitor numbers reaching up to 3,000 to 4,000 during peak summer periods.

Reliability and capacity challenges

Residents are frustrated by the frequent power outages and concerned about power security during major events. Recently, residents, including marae, have started investigating installing large-scale solar, battery and generator solutions aimed at reducing power costs and improving energy security.

The feeder is our worst performing feeder (see Section 5.5.9). The absence of interconnections with other feeders close to Kāwhia township and voltage issues

on the feeder limit backfeeding during peak periods, resulting in long outages during faults or maintenance.

Future load growth at Kāwhia is limited due to capacity and voltage constraints, and the high costs to resolve these issues using traditional network solutions.

Project overview and status

We are approaching the review of Kāwhia in three stages:

- **Stage one:** Defining the requirements and opportunities
- **Stage two:** Option analysis and solution recommendation
- **Stage three:** Implementation

We have formed a multi-disciplined team of customer engagement, technical, and commercial specialists.

Customer engagement

The Kāwhia technical work is being undertaken in conjunction with the engagement pilot mentioned in Section 3.4.1. Given the differing requirements and engagement preferences of the community there will be many facets to the engagement pilot.

11.12.3 Developments to meet voltage and other requirements

Issue/constraints

As mentioned in Section 11.9.3, the TA Review has identified voltage and resilience issues on the Te Awamutu network. In this section, we consider constraints with respect to voltage, resilience, legislative and regulatory requirements, and other drivers in the Te Awamutu area (see table 65).

The TA Review identified immediate issues on three feeders where voltage falls below our planning criteria under high load or during backfeeding in contingency scenarios. The resolution of the voltage constraints on the Pirongia and Mystery Creek feeders is underway, and the issues with the Kāwhia feeder is part of the holistic Kāwhia improvement study (see the case study above).

The TA Review also identified resilience issues due to multi-circuit poles (i.e., poles near the GXP that carry two or more feeders). Damage (or maintenance) to these poles will require an outage affecting two or more feeders, significantly impacting customers.

We undertook a review of all our voltage regulator structures against seismic standards. The study identified that our structures were built to old standards and did not meet the current requirements of our resilience standard. A programme to remediate the sites is ongoing.

Over time, road heights increase due to reconstruction and realignment. Poles and conductors also shift due to ground conditions and wind/storm loadings. This can result in line clearances falling below the required standards. When clearance issues are identified during inspection or line patrols, we remediate them.

Feeder	Constraint	Date binding	Project
TA West	Feeder significantly above customer number planning criteria	Current	Project 39
Kihikihi	As above	Current	TA Review Project 40 to 42 (table 73)
Kāwhia	As above	Current	Kāwhia project
Kāwhia	Worst performing feeder for reliability	Current	Kāwhia project
Pirongia	Feeder at customer number planning criteria limit	Current	TA Review Project 40 to 42 (Table 73)
Hairini	As above	Current	As above
Pukeatua	As above	Current	As above
Pukeatua	The Bond Road industrial area is downstream of a rural reclose, hence industrial customers are experiencing interruptions to their supply	Current	Project 43
Pukeatua	One of the worst performing feeders for reliability	Current	TA Review Project 44 to 46
Paterangi	As above	Current	As above
Pokuru	As above	Current	As above
Kiokio	As above	Current	As above

Table 76: Current and emerging constraints

Proposed network solutions

We are planning \$3.7m of distribution projects to address the voltage and other constraints in the Te Awamutu area (see table 66). We have projects to address the voltage constraints, resilience, and line clearance issues mentioned above. Strengthening the voltage regulator and improving high-load road crossings are part of existing work programmes.

As noted in table 65, a number of the multi-circuit resilience issues are being resolved through the front-end cable upgrades mentioned in table 73.

Project	Issue	Solution	Cost/timing
47. Pirongia voltage improvement	Voltage	Install a new voltage regulator before Pirongia township	Due for completion in FY26
48. Mystery Creek voltage improvement	Voltage	Install 350m of new overhead line to connect Mystery Creek feeder to Kaipaki feeder and transfer customer at the end of Mystery Creek to Kaipaki	As above
49. Voltage quality improvement	Voltage	Programme to address voltage quality issues	\$1.3m FY27-36
50. Kāwhia line deviation	Resilience	Two sections of 11kV line require re-routing away from river	\$600k ¹¹¹ FY27
51. Te Rahu and SH3 intersection underground project	Resilience	Underground section of 11kV line at the Te Rahu and SH3 intersection to remove vehicle damage risk	\$220k ¹¹² FY27
52. Seismic strengthening of voltage regulator structures	Resilience	Programme to strengthen existing voltage regulator structures to meet seismic strength requirements of our resilience standard	\$680k FY27-36
53. Mutu St – Te Rahu Road underground project	Resilience Regulatory	Underground a section of 11kV line to resolve multi-circuit risk and building clearance issues	\$380k ¹¹³ FY27
54. Improve the high-load crossing	Regulatory	Improve the high-load crossing on major transport routes	\$530k FY27-36
Total			\$3.7m FY27-36

Table 77: Proposed solutions

FY26 real \$

11.12.4 Justification for the development projects

The capacity-driven projects are required to meet demand from new customers and support future growth among existing customers. Extending and upgrading the network to meet demand is essential for Waipā Networks and has no feasible 'do-nothing' option. Several capacity-related projects in the Te Awamutu area are addressing constraints stemming from historical demand growth. This has been a deferred while awaiting the Te Awamutu Architecture Review, which now requires attention.

The security and reliability projects are required to support our asset management strategy #4. These projects require an estimated 8.5 SAIDI minutes of pre-normalisation improvement to deliver a net economic benefit to customers¹¹⁴. Around 70% of this improvement will flow through to our normalised actual performance (due to the major event normalisation process¹¹⁵). We are still working through the specific benefits for each project, but are generally comfortable that their business case will be viable.

Voltage, resilience, and regulatory-driven projects are required to meet specific regulatory and planning criteria, with no viable do-nothing option. That is, maintaining voltage at customers' premises, bringing critical assets into compliance with applicable building codes, and maintaining overhead conductor clearance are regulatory requirements. Regarding multi-circuit issues, most are being resolved through capacity-related projects. For those projects that are not, they are removing potentially high consequent risks that have no viable alternative.

11.12.5 Managing demand growth uncertainty

The near-term capacity-related developments have been prepared to meet predicted demand growth or resolve historical issues. Distribution developments have a relatively short planning horizon and are generally easier to plan and execute. Hence, there is no need to accommodate the high demand growth explicitly. Should the high-demand scenario occur, additional capacity-related distribution development projects will be required. Generally, selecting standard-size conductors and cables accommodates future demand growth. Should we see low-demand growth, deferring distribution development projects is possible.

¹¹¹ Project commenced in FY26 with a total budget of \$800k.

¹¹² Project commenced in FY26 with a total budget of \$570k.

¹¹³ Project commenced in FY26 with a total budget of \$1,030k.

¹¹⁴ Based on Waipā's average VOLL of \$29,000 per MWh, which equates to around \$25,000 per SAIDI minute.

¹¹⁵ Based on the extent of normalisation in recent years.

11.12.6 Consideration of non-network alternatives

For capacity-driven projects, our general approach is to evaluate a range of network alternatives and select the option that provides the lowest cost to meet the required capacity upgrade, consistent with our planning and design standards. We are not proposing to use merchant flexibility as a non-network alternative for the projects proposed for FY27 and FY28, as the market and our ability to call on this flexibility are not yet sufficiently mature.

For capacity-driven projects serving new customers, merchant flexibility was deemed infeasible because the network must be expanded to reach the new customers.

In relation to reliability, security and voltage projects, given the pressing need to resolve the immediate issues, we are

not proposing to use merchant flexibility as a non-network alternative for the projects proposed for FY27 and FY28, as the market and our ability to call on this flexibility are not yet sufficiently mature.

However, the use of non-network alternatives is a key focus of the TA Review and the Kāwhia project, and these are being proposed for regional capacity support. As noted in the preceding sections, we expect to deploy non-network solutions to resolve constraints on the Te Awamutu distribution network. This will become visible in future AMPs.

There are no non-network alternatives proposed to the resilience and regulatory-driven projects currently stated, however, it is believed that the Kāwhia review will identify a number of opportunities to address resilience and regulatory-driven projects in the future.

11.13 All regions: distribution transformer and LV development plan

11.13.1 Distribution transformer developments to meet capacity and customer requirements

We have an ongoing programme to upgrade distribution transformer capacity in response to localised growth. We monitor the demand on our ground-mounted distribution transformers using the MDIs installed in the LV cabinet or our online power quality monitors. When we determine that demand is approaching nameplate capacity, we will consider a transformer upgrade. The transformer removed from the network is tidied and returned to stock. The programme is based on the historical upgrade rate.



Project	Issue	Solution	Cost/timing
55. Distribution transformer upgrade	Capacity	Programme to upgrade distribution transformers when capacity issues are identified during inspections	\$5.1m FY27-36
Total		System growth capex	\$5.1m FY27-36

Table 78: Proposed solutions

11.13.2 LV developments to meet capacity, security and voltage requirements

We have ongoing programmes to install new LV links and extend or modify the low-voltage network, or install a new distribution transformer in response to voltage complaints. This is a reactive programme based on historical upgrade rates.

Project	Issue	Solution	Cost/timing
56. LV voltage improvements	Voltage	Programme to upgrade distribution transformers or LV when voltage improvements are required	\$1.4m FY27-36
Total		Quality of supply capex	\$1.4m FY27-36

Table 79: Proposed solutions

11.13.3 Justification for the development projects

Resolving capacity and LV complaints is a business requirement. As noted in 11.13.5, we are not yet actively considering non-network alternatives for distribution transformers and LV constraints.

11.13.4 Managing demand growth uncertainty

Distribution transformer and LV developments have a short planning horizon and are generally easier to plan and execute. Hence, there is no need to accommodate the high demand growth explicitly. Should the high-demand scenario occur, additional projects will be required. Should we see low-demand growth, the need for capacity upgrades and the resolution of voltage complaints will decrease.

11.13.5 Consideration of non-network alternatives

This AMP does not consider non-network alternatives at the distribution transformer and LV level. We are monitoring developments in this area and intend to consider alternatives in future AMPs.

11.14 All regions: other network asset development plan

11.14.1 Communication network

The existing SCADA radio communications network is based on the proprietary ABBEY analogue radio system. It is running out of support by the vendor, the SCADA network is currently overloaded. SCADA communication with our fleet of voltage regulators and reclosers is creating congestion and long polling intervals (which creates latency issues on SCADA) and there is no further channel capacity to add new automated sites. Further, the voice radio (for hand-held radio) network has blind spots in the remote parts of our network.

We assessed a range of options and are proceeding with a transition to a digital radio system to carry both voice and SCADA communication traffic. We will be using digital

microwave links between the key repeater sites as the communication backbone, and digital multi-point to point radios between the repeater and field sites.

This is a comprehensive project that commenced in FY25. The work includes:

- Completed – Upgrading existing repeater sites and establishing sites and easements
- Completed – Installing new microwave links with backup power supplies (to meet our resilience requirements)
- Completed – Switch over the digital-capable hand-held voice radio currently running on the analogue network to the new digital network
- Replacing all existing field radio equipment.

Project	Issue	Solution	Cost/timing
57. Communication upgrade	Capacity	Upgrade the communication system backbone to a digital microwave network	\$1.14m FY27-FY28
Total		System Growth	\$1.14m

Table 80: Proposed solutions

11.15 Summary of development plan expenditure

The total development plan capex is shown in table 82.

Project	FY27	FY28	FY29	FY30	FY31	FY32	FY33	FY34	FY35	FY36	Total
System growth projects	8,832	9,929	13,487	9,814	14,270	7,041	7,767	13,855	13,355	8,532	106,883
Reliability, safety and environment projects	3,315	1,405	1,006	1,316	1,052	1,316	950	1,213	1,045	1,045	13,662
Total	12,147	11,334	14,493	11,130	15,322	8,356	8,717	15,068	14,400	9,576	120,544

Table 81: Total development plan capex

FY26 real \$000. Before capital contributions.



12. CUSTOMER WORKS

12.1 Introduction

This section outlines our approach to customer-initiated work and how we forecast related expenditure. Customer-initiated work includes new connections, upgrading existing connections, and relocating distribution assets. We are forecasting \$101m of customer-initiated work. This is a significant component of total network work, accounting for 36% of our total network capex (before capital contributions).

New connections or changing existing connections affect our long-term network planning and development. The process for connecting new customers is tailored to ensure fast, efficient, and cost-effective connections, while integrating with network development and fleet management plans.

We are required to relocate our assets when requested by external stakeholders, such as landowners, district councils, or Waka Kotahi/NZTA. This section outlines the typical reasons for asset relocation, how the relocation work is managed, and how it is funded.

12.2 New connections

12.2.1 Forecast new connections

As we stated in Section 6.2, we have the third-highest ICP growth rate in New Zealand. Most connections are residential customers, which have seen a 2.2% compound annual growth rate since 2013. This averages 520 new customers per year over the past five years.

Our forecast for new connections is based on council projections (again shown in Section 6.2), which are forecast at 12,800 by FY50, equating to around 510 p.a., most of which will be residential customers.

The number and timing of customer-initiated developments, including subdivisions, are determined by each site's developers. Known development areas are shown in Section 11.6.2 and 11.10.2.

12.2.2 Current connection process

Process overview

Our current practice for connecting new customers and customer-initiated network alterations follows a process that includes the following:

- Assessing the connection impact on the network demand and voltage. The extent of our analysis depends on the size of the new load. The engineering team assesses larger connections to determine whether upstream upgrades are needed before the design team confirms the installation arrangements, access requirements, and customer contributions.
- With the requirements confirmed, we create the ICP for new connections and execute the physical connection (our in-house field service team handles the construction to complete the requested connection/network alteration), then forward the information to the customer's retailer.

Residential customers

Residential customers requiring a new connection will often hire an electrician to submit an application to us on their behalf. The electrician will submit the proposed connection specifications and design and notify us of any special requirements, such as the need for an easement. This will be reviewed and approved, provided our distribution assets have sufficient capacity. Upon approval, our contracting division will plan and perform the installation.

Larger commercial customers and developers

Larger commercial customers, subdivision developers, and others will often contact us directly to discuss connection requirements or will work with engineering consultancies to develop suitably sized distribution systems for their proposed works. Connections of this size will often involve relatively significant infrastructure development, network extension or asset renewal. We work with these larger entities to facilitate the connection of large loads in a standardised and efficient manner.

Where asset replacement is required, we will review the connection on a case-by-case basis to determine the contribution level, if any, that we will provide. It is beneficial for us to work with developers during the connection process, as it allows upgrading assets approaching the end of life or near their capacity rating.

Our customer connection process and connections policy are set out in further detail on our website.

Typical challenges

For large-scale connections and subdivision developments, we sometimes face challenges aligning equipment with long-lead time for supply with customer requirements. To minimise these issues, we ensure our standard equipment stock is adequate for typical annual growth. We also face challenges in assessing current loading and spare capacity on the LV network, which is not monitored by SCADA. We expect this will largely be addressed as we adopt new technologies for LV network visibility.

12.2.3 Upcoming changes to the connection process and pricing methodology

The Electricity Authority's customer connection process and pricing reforms are reshaping how we manage new connection requests, with a strong emphasis on improving transparency, consistency, and cost clarity for customers. The formal determination introducing the new capital-contribution and connection-pricing requirements was made in September 2025, establishing a more standardised methodology that requires distributors to clearly outline how capital contributions are calculated and what costs are included. These requirements take effect from 1 April 2026, with the capacity-based costing provisions applying to connection applications received from 1 April 2027. We are actively progressing the necessary process updates, documentation changes, and system alignments to meet these milestones, ensuring our future connection process is compliant, transparent, and easier to understand. The new process will lead to greater standardisation and efficiency in the new connection process.

At the time of preparing this AMP submission, this work is still underway. In particular, the detailed implications for capital contributions are yet to be fully established and therefore have not been incorporated into this AMP. Until this work is completed, our assumptions regarding capital contributions for both connection and capacity costs within the expenditure profile remain unchanged.

12.2.4 Minimising costs to consumers

We use standard design and construction techniques to ensure purchasing and construction, maintain asset reliability and safety, and minimise cost to customers.

Where possible, we install equipment that allows for future upgrades or alterations, considering the area's growth profile and ensuring work common to different projects is done once. Over time, this reduces the cost of future connections.

Also see our efficiency strategy stated in Section 7.5.

12.2.5 Planning and managing communication with customers

We operate a web portal that enables customers or their representatives to submit applications for new connections or modifications to existing connections. Our interaction with the customer begins with acknowledging receipt of the application and confirming their requirements, followed by ongoing updates on the progress. These updates include the expected timeline for customer input to move the application forward, such as when they need to pay connection fees.

12.2.6 Major new connection projects

Waikeria Prison expansion – stage one completion

In 2019, we entered into an agreement with the Department of Corrections to connect a major 600-bed expansion at Waikeria Prison. Prison demand was forecast to increase from approximately 1.3 MVA to 4 MVA. The new Prison facility was commissioned in mid-2025, with the full muster and subsequent load increase expected to be completed by January 2026. This marks the end of stage one of the work.

The prison is located towards the end of a rural feeder, and a significant network upgrade was needed to connect the stage one load.

Waikeria Prison expansion – new stage two

In 2025, we were engaged by the Department of Corrections for the next phase of the expansion, and the two parties entered into an MoU to commence the design process. This stage two expansion is tied to a broader corrections funding boost (the Government's 2024 budget allocated \$1.9 billion over four years), including for this project and additional corrections officers.

The Prison has provided an extended view of future load growth, which includes future expansion and possible decarbonisation opportunities. This latest load forecast puts the total Prison load close to 10 MVA circa 2030 (post 2030 timeframe yet to be determined).

Total Load	FY26	FY29-30	FY30+	FY30+	FY30+
Stage one expansion – completed	4.0 MW ¹¹⁶				
Stage two expansion – In progress		7.0 MW			
Decarbonisation of low-security prison			7.4 MW		
Provision for future expansion				7.8 MW	
Possible decarbonisation of heating and hot water					9.9 MW

Table 82: Long-term load forecast at Waikeria Prison

The prison's future load requirements represent a significant increase in load for the Te Awamutu area (25% of existing demand) and affect the Te Awamutu architecture review (the TA Review). The forecast growth in demand has been fully accounted for in the TA Review, as discussed in Section 11.9 to 11.11.

The recommended solution involves building a new zone substation near the prison site, supplied from a single 33kV circuit from Hautapu GXP, with N-1 support via a reinforced 11kV network from the existing Te Awamutu network. A Battery Energy Storage Solution (BESS) will be installed on the 11kV when load growth exceeds 9 MVA (see table 83). The total cost of the substation, lines and battery is \$34.8m. Significant capital contributions from the Waikeria Prison are associated with the project.

Project	Issue	Solution	Cost/timing
60. 33kV circuit to Waikeria	Capacity	33kV 26 MVA single circuit cable from Hautapu GXP to Waikeria Prison	\$12.8m FY27-29
61. Waikeria zone substation	As above	Single bank 16/24 MVA zone substation adjacent to the Waikeria Prison. Firm capacity is initially 10 MW when operated with the 11kV fast transfer circuit Reconfiguration of the 11kV supply to Waikeria Prison	\$8.1m FY27-29
62. Waikeria 11kV fast transfer	As above	11kV 10 MVA fast-transfer circuit between Waikeria zone substation and Te Awamutu GXP. This circuit provides N-1 switched support to the Waikeria zone substation	\$1.6m FY29-30
63. Waikeria 11kV cable connection	As above	Upgrade of the 11kV connection to Waikeria Prison	\$10.3m FY27-29
64. Waikeria 1 MW x 1 MWh BESS	As above	BESS to supply the shortfall on the 11kV when load growth exceeds 9MVA	\$2.0m FY30
Total		Customer connection capex	\$34.8m FY27-30

Table 83: Proposed solutions

Note: Excluding capital contributions

¹¹⁶ Assuming close to unity power factor.

12.3 Asset relocations

12.3.1 Overview of asset relocations

Electricity distribution assets often have to be relocated because of changes in the surrounding environment or infrastructure. This usually happens due to activities by other utility providers working near our assets, such as replacing water pipes telecommunications cables, roadworks, or land development for agricultural, commercial, or urban growth.

We receive requests from our stakeholders to relocate assets. In most cases of asset relocation due to road works, we cover costs, often in materials, as required by legislation. We evaluate other projects on a case-by-case basis. Our capital contributions policy is available on our website.

Collaborating with our stakeholders on asset relocations enables us to upgrade parts of our network or replace old assets at a lower cost. Expenditure is capitalised when new assets are installed. Otherwise, relocating the same asset is considered an operational expenditure.

Where major works are required for asset relocation, such as major roading and other infrastructure projects, we will include the project in our capex forecasts. Projects of a smaller scope, where our contribution (if needed) can be accommodated within the general asset relocation programme, are included in the work plan for the current year.

12.3.2 Major asset relocation projects

NZTA SH1 expressway Cambridge to Piarere project

The SH1 Cambridge to Piarere project is a Roads of National Significance initiative to enhance safety, capacity and reliability along a critical transport corridor in the Waikato region. It aims to deliver a 16 km four-lane expressway extension from the southern end of the Waikato Expressway at Cambridge to

the newly completed intersection with SH29 at Piarere. New cycleways into Karapiro are also incorporated in consultation between NZTA and the local council.

Stage one work will upgrade the existing SH1 from Cambridge to Karapiro to a four-lane expressway, and stage two work will extend the expressway from Karapiro into Piarere, bypassing the current SH1 alignment.

To enable the stage one work, approximately 6km of overhead lines will be relocated to underground. Instead of a like-for-like relocation, the affected overhead HV switch will be rationalised to improve network reliability, and larger conductors will be used to improve feeder voltage. The relocation works will be carried out in accordance with NZTA's initial requirements. At the time of writing, the project estimation is being completed.

The scope for stage two work is yet to be released by NZTA. We do not foresee any major relocation work, as the proposed expressway will follow a new route and currently has no network assets. Network extension work might be required for minor loads such as lighting. We anticipate further updates in the 2027 AMP.

Resolving clearance issue with Transpower asset

Transpower has identified several sites where its transmission lines are too close to our overhead lines. To maintain public safety and meet clearance requirements, Transpower and Waipā Networks entered into an Under Clearance Works Agreement in 2025 to resolve these clearance issues. Transpower engaged us to carry out the work on a cost-sharing basis, as it offered mutual benefit. Three priority network locations will be assessed and upgraded, typically by undergrounding short sections of line to restore safe clearances. The work will be completed in FY27.

Project	Issue	Solution	Cost/timing
65. Undergrounding lines for Transpower	Asset relocation	Underground the overhead assets to improve clearances from transmission lines. The locations are identified by Transpower	\$513k FY27
66. SH1 Expressway	Asset relocation	Relocation of our assets to accommodate the widening the SH1 from Cambridge to Piarere. The current estimate is ~6km of lines and assets that require relocation	\$8.0m FY27-30
Total		Asset relocation capex	\$8.5m FY27-30

Table 84: Proposed projects

Note: Excluding capital contributions.

12.4 Expenditure forecast

It is not possible to accurately forecast customer-initiated work, as it is driven by factors outside our control. Our forecasts include the specific major works in table 83 and table 84 and general programmes covering new connections and asset relocations.

Our new connection programme is based on our forecast connection growth and subdivision development estimates (see Sections 11.6.2 and 11.10.2). Over the planning period,

we have assumed that residential development in the Te Awamutu and Cambridge areas will continue at a rate similar to recent years. We have also assumed that commercial development will continue at current rates.

Our asset relocation programme assumes a continuation of the historical trend.

Table 85 and table 86 show forecast expenditure for customer-initiated works over the next 10 years.

Customer-initiated works	FY27	FY28	FY29	FY30	FY31	FY32-36
Disconnecter switchgear additions	20	20	20	20	20	102
Dropout fuse additions	70	70	70	70	70	351
RMU additions	218	218	218	218	218	1,090
General line and cable extensions	3,668	3,668	3,668	3,668	3,668	18,340
Transformer additions	1,797	1,797	1,797	1,797	1,797	8,987
Waikeria Prison expansion, stage two	2,000	12,250	17,050	3,500	-	-
Total	7,556	17,806	22,606	9,056	5,556	27,780

Table 85: Customer-initiated works forecast

FY26 real \$000. Before capital contributions.

Relocations	FY27	FY28	FY29	FY30	FY31	FY32-36
General relocations	243	243	243	243	243	1,218
Asset relocations for NZTA Cambridge to Piarere project	2,350	2,350	2,350	930	-	-
Underground Waipā OH assets under transpower Lines	513	-	-	-	-	-
Total	3,106	2,593	2,593	1,173	243	1,218

Table 86: Relocation forecast

FY26 real \$000. Before capital contributions.



13. ASSET LIFECYCLE MANAGEMENT

13.1 Introduction

Asset lifecycle management describes the steps within an asset's lifespan and ensures that an asset (or asset fleet) delivers the required performance at the least overall lifecycle cost. The principal aims of our lifecycle management include:

- To manage the risk to staff, customers and the public
- To achieve our service levels and meet customer expectations
- To comply with our environmental policy
- To minimise the total cost of ownership and maximise the efficiency of our operations
- To satisfy legislative requirements.

Much of the existing network was developed in the 1970s and 1980s. The presence of end-of-life (EOL) drivers in these assets is increasing, requiring us to increase our focus on forecasting and managing EOL issues.

Historically, we have used a mixture of asset age and observations from planned and defect-driven inspections to inform asset renewal plans. We've started the transition from this approach to an asset health, criticality, and risk approach to inform our asset renewal plans. We continue to improve our assessment and forecasting of asset health, and revised asset health forecasting has been included in this AMP. We are still transitioning, as field capture of condition data (aligned with our revised approach) is in progress and will take several years to complete.

Our asset renewals are forecast based on asset health, with asset criticality considered at the project definition stage. Over the next 12 months, we intend to transition to a comprehensive risk-based approach using improved health forecasting and asset criticality. Hence, our fleet plans, renewal forecasts and expenditure forecasts may evolve further in subsequent AMPs.

The recent improvements and planned improvements align with Asset Management Strategic Initiative #4 (develop comprehensive fleet plans and renewal forecasts) and #5 (improve asset management maturity).

In this section, we cover:

- Alignment to our asset management strategy
- Lifecycle management
- Asset health, criticality and risk
- Improvements to our fleet plans included in this AMP
- Fleet strategies that apply to all our material asset classes
- Summary of material changes to the health of the fleet and our renewal plans
- Fleet plans
- Asset renewal and network maintenance expenditure forecasts.

13.2 Alignment to our asset management strategy

Three asset management strategic initiatives guide our lifecycle management. These are:

- **#3 Resilience:** Improve the resilience of our network to reduce the impact of increasing incidents, the intensity of adverse weather, and rising incidents of third-party damage on the network. As far as lifecycle management is concerned, the resilience strategy influences the design standards and approach for asset replacement – that is, progressive improvement in asset resilience as the network is renewed.
- **#4 Fleet management:** Develop comprehensive fleet plans and renewal forecasts to better manage our asset fleet. The outcome of this strategy can be seen in the improvements we have made (and plan to make) in our asset health, criticality, and risk approach, the development of fleet strategies, and the revised fleet plans presented later in this section.
- **#5 Asset management maturity:** Improve asset management maturity to address the need for quality decisions based on quality data. Regarding lifecycle management, this strategy drives improvements in inspection standards and the availability and use of condition data in fleet plans.

13.3 Lifecycle management

13.3.1 Stages in an asset's lifecycle

We consider our network assets within a lifecycle framework from design and procurement through installation, commissioning, operation, maintenance, renewal, and disposal (refer to figure 104).

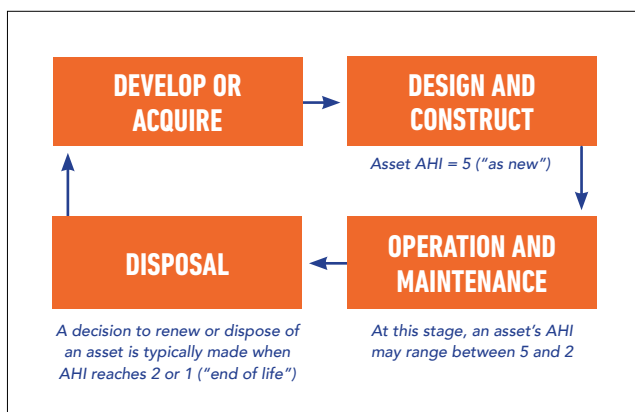


Figure 104: Asset lifecycle management

The goal of lifecycle management is to maximise asset utility while minimising total cost over an asset's life. Paying more up front may be more cost-effective if this reduces the total operating costs over the asset's lifetime. Practical examples include:

- Distribution transformers in salt-prone areas with galvanised tanks and longer insulators
- Selection of enclosed load break switches over open air break switches for extended life, lower maintenance, and improved reliability.

The lifecycle stages are described as follows.

13.3.2 Develop or acquire

This phase covers creating an asset by identifying the initial need, assessing options, and preparing the conceptual designs. We cover this phase in the Network Development and Customer Works sections.

13.3.3 Design and construct

This phase covers detailed design, procurement, construction and project management, and commissioning of new assets. This is a crucial phase in the asset lifecycle where risk can be designed out, and reliability, resilience and "smarts" can be designed in. Several asset management strategies influence this phase of the asset's lifecycle.

13.3.4 Operate, monitor, and maintain

Condition monitoring

Monitoring the assets (inspection or testing-based condition assessments) is a major input to determine the health of the assets and provide us with the information needed to assess safety risks and reliability issues.

The type and frequency of inspection or testing are influenced by many factors, including public safety, the criticality of the asset, network reliability, the risk of failure, the consequence of failure, the cost of the inspection or testing, and the time it takes for an asset to deteriorate from H2 to H1. These factors can be fleet-specific, and as a result, we have adopted a range of techniques, which are outlined in the fleet plans.

Condition-based and routine maintenance

We undertake condition-based and routine maintenance and inspections on assets. The output informs ongoing condition-based maintenance and condition monitoring activities. For some assets, we also undertake routine (time or operation-based) tasks where it is impossible to accurately identify condition triggers or where routine maintenance is needed to maintain the asset's utility. Where possible, we prefer condition-based maintenance over routine maintenance.

Corrective maintenance

Corrective maintenance typically occurs in response to a defect notice (and some defect notices will result in the replacement of an asset). Corrective maintenance may occur immediately upon identification of the defect, or it may be scheduled within a short period.

Fault repairs and response

We have a faults response team on duty 24/7 to resolve equipment failures leading to loss of supply to customers or posing immediate safety risks requiring emergency shutdown. Where significant repair is required to be undertaken this is handed over to the field services team.

13.3.5 Renew or dispose

This phase involves deciding when to renew or dispose of the assets.

Asset renewal

A variety of factors are considered when deciding if an asset is renewed. These include:

- Safety – an asset may be renewed when the risk to staff, customers, or the public is too high per our risk framework.
- Asset health, asset criticality, and asset risk – our current approach for deciding whether to renew or dispose of an asset is based on asset health. That is, the decision to renew an asset is considered when the asset's health declines to a point when the risk of failure is too high. This is typically before the asset reaches an asset health of H1. A few asset classes, such as some pole-mounted transformers, may be replaced on failure, depending on their criticality/consequence of failure.

Asset criticality is presently considered based on the judgement of our asset planners. We intend to evolve our asset renewal process based on asset risk by incorporating asset criticality. The combination of health and criticality provides a consolidated view of asset risk. Our approach is discussed in the next section.

- **Asset type risk** – an asset may be renewed where a specific issue exists with the material, construction, operation, or other issues for a particular type or manufacturer.
- **Construction efficiency** – we may replace assets ahead of health needs where there are advantages of doing so through economies of scale, for example, in undertaking whole line section renewal where most (but not all) poles and components in the line section are assessed in poor health. Such a strategy is economically efficient due to the one-off project and site set-up costs, especially in rural and remote locations, and the avoided cost of multiple customer interruptions.
- **Overall workforce efficiency** – we may seek to spread renewal expenditure as evenly as possible over several years to maintain overall work levels, maximise the efficiency of field crews, allow an orderly ramp-up (to allow training or recruitment to take place), or ramp down work levels.

Our fleet strategy and renewal methodology in the fleet plans describe our asset renewal decision process and related criteria.

Asset disposal

We dispose of assets when there is no longer a need for their service on the network (e.g., when the load they serve has disconnected) or when alternative connections make them obsolete.



13.4 Asset health, criticality, and risk

13.4.1 Asset health

We have adopted the EEA asset health indices (AHI) for asset health¹¹⁷. The AHI measures an asset's lifecycle stage and fitness to continue safe, compliant, cost-effective service. All fleet plans include an asset health assessment for all fleet assets.

Identifying end-of-life (EOL) drivers for an asset can be complex, as multiple factors often drive a decision to replace or dispose of it. For example, the decision to replace an asset may be due to one or more of the following factors:

- **Physical condition** – is in-service deterioration present that diminishes the capability or reliability of the asset to an intolerable level?
- **Functionality** – does the asset meet current and future requirements for functionality and capacity?
- **Operating economics** – are the operating economics of the asset viable? Is utilising a new asset or a different solution to meet the need less costly?
- **Compliance** – does the asset comply with current legislation, codes of practice, standards, or good practice?
- **Safety** – does the asset present a risk to staff, public or community due to its location, condition or configuration?

The AHI scores are shown in table 87.



AHI category	Serviceability Criteria	Drivers for replacement
H5	As new The asset is in a new condition	No EOL drivers for replacement
H4	Asset serviceable Normal deterioration occurs that does not impact the utility of the asset	No EOL drivers for replacement
H3	Onset of unreliability The asset is in a serviceable condition but showing deterioration. EOL drivers for replacement are first becoming evident, and there is an increasing asset-related risk	EOL drivers are present, but replacement is not yet required. Reinspection is necessary within a reasonable period. The asset may be included in a replacement programme for economic reasons
H2	Elevated risk EOL drivers for replacement are present, and there are high asset-related risks. Assets with EOL condition drivers may be left in service on a risk-assessed basis. Asset unreliability begins to materially increase, but is still within tolerable and manageable limit	EOL drivers for replacement are present, and the asset should be scheduled for replacement within an appropriate period (considering risk and criticality)
H1	End-of-life The asset has reached end-of-life. Significant EOL drivers that are likely to lead to failure are present. The probability of failure is higher than would normally be tolerated for an asset in service	Replacement or retirement is recommended, typically within six months, consistent with the risk

Table 87: Waipā's AHI scores with definitions

¹¹⁷ EEA Asset Health Indicator (AHI) Guidelines 2019.

13.4.2 Asset criticality

Our asset renewal planning considers criticality when determining specific projects and project priorities. This consideration is based on the judgement of our asset planners, who considered the factors mentioned below. We intend to adopt the EEA asset criticality indicator (ACI), as shown in table 88¹¹⁸.

AHI category	Criticality
C4	Minor Credible CoF is broadly tolerable and run to failure may be a valid strategy
C3	Typical Asset failure would cause some disruption and inconvenience, but systems are already in place to anticipate and manage the outcomes
C2	Elevated Asset failure would cause significant harm to people, assets, the business, or the environment. The consequences are tolerable but should be avoided or mitigated if it is practicable to do so
C1	Extreme The credible consequences of failure would be intolerable

Table 88: Waipā Networks' asset criticality levels (as per the EEA ACI)

Our initial approach will be to assign asset criticality at feeder and feeder-section levels. All assets within the feeder or section will be given the same ACI. Once an initial criticality assessment is completed, we will fine-tune the assessment to include an evaluation of the factors of criticality mentioned below.

Risk category	Criticality	Driver for replacement
R5	Risk grade 5 Low relative consequences of failure	There is no specific driver for replacement. Replacement would be based on efficiency or cost considerations
R4	Risk grade 4 Typical asset, in useful life phase	There is no specific driver for replacement. Replacement would be justified on efficiency or cost-benefit considerations
R3	Risk grade 3 Healthy but highly critical assets	There is no specific driver for replacement; however, monitoring and maintenance of the asset is required to avoid or manage the transition to R2
R2	Risk grade 2 A combination of criticality and health indicates elevated risk	Drivers for replacement are present, and the asset should be scheduled for replacement within an appropriate period
R1	Risk grade 1 A combination of high consequences of failure and reduced health indicates high risk	Replacement or retirement is recommended, typically within six months, consistent with the risk

Table 90: Waipā Networks' asset risk grades (as per the EEA guide)

Assessing asset criticality is multi-dimensional. We plan to apply the dimensions included in the EEA asset criticality guide. The impact of an asset will determine asset criticality:

- Public safety – the harm to the public that might arise due to the failure of an asset.
- Personnel safety – the harm to personnel that might arise due to the failure of an asset.
- Service levels – the economic impact of a supply failure on customers and the community.
- Direct Cost– substantial repair cost and/or secondary damage resulting from asset failure.
- Environmental – the harm of a failure on the environment.

13.4.3 Asset risk

We intend to adopt an overall risk approach consistent with the EEA asset criticality guide. Asset criticality will be used with asset health to define a risk-based approach for asset renewals, inspection and maintenance, and renewal programmes. The risk matrix is shown in table 89 below.

ACI	AHI				
	H5	H4	H3	H2	H1
C4	Risk grade 5				
C3	Risk grade 4			Risk grade 2	
C2	Risk grade 4			Risk grade 2	
C1	Risk grade 3		Risk grade 1		

Table 89: Asset risk matrix

The risk reporting matrix contains five risk-grade zones. Each zone represents a combination of health and criticality indicators within which the intervention response is likely to be broadly similar. Definitions of the risk grades are shown in table 90.

¹¹⁸ EEA Asset Criticality Guide 2019.

13.5 Improvements to our fleet plans included in this AMP

13.5.1 Improvements to our asset fleet plans

As Section 6.4 mentioned, we expect to observe more EOL condition drivers over the coming decade. Ensuring we have quality asset condition, asset health, and asset risk information will be essential to enable the optimal renewal of our network. Consistent with asset management strategy #4 (develop comprehensive fleet plans and renewal forecasts), we have developed comprehensive asset fleet plans for our material asset classes.

13.5.2 Improvements to asset condition data

We are revising our inspection standards to ensure they capture information on the EOL drivers for the assets. This information is needed to assess the health of the assets more accurately.

The EOL condition inputs in this AMP are a mix of old and new standards. For older inspection data, we spent time validating it and have used it in our health assessments. The validation included interpreting the data into a format consistent with the EEA standard for use in asset health models. As we progressively inspect the network, the old inspection data will be superseded by new inspections (to the latest EEA-aligned standard).

The status of our inspections is provided in table 26 in Section 5.7.3.

13.5.3 Improvements to our asset health assessment and health forecasting

Our asset health assessment continues to be a mix of age and condition-based.

As noted in our 2024 AMP, we considered adopting either the DNO Common Asset Indices methodology or the EEA AHI methodology. We have adopted the EEA AHI approach as this was the best fit for our assets (as the DNO methodology

did not incorporate several of our material asset classes). We have developed a new EEA AHI-based health assessment and forecasting model to predict asset health over the next 10 years. Our revised health assessment and forecasting model allows for age – or condition-based assessments. Where condition-based assessments are undertaken, the model allows up to 10 EOL drivers to be assessed per asset class (new drivers can be added without revising the model).

Where no asset condition data is available, the health assessment remains age-based, consistent with the EEA AHI guide.

Because the EEA AHI methodology does not include a condition-based health forecasting tool, one was developed. Our methodology forecasts the decline in asset health by applying an exponential decay curve to the current condition-based asset health. The change in the health of a distribution asset is modelled exponentially, as it is assumed that the processes involved as the asset deteriorates (e.g., corrosion, oil oxidation, insulation breakdown, etc.) are accelerated by the products of the deterioration process (this is consistent with condition-based health forecasting used in the DNO methodology).

The decay in health is modelled over the asset's maximum practical life (MPL). Different decay curves are applied to assets within the same fleet that have different MPLs due to asset-type or material-type differences. Figure 105 shows the comparison between the exponential and age-based approaches (noting that the shape of the EEA "curve" will change given the onset of unreliability (OOU)¹¹⁹). Figure 106 shows the decay in asset health for H3 and H2 assets. In this example, the impact of using an exponential decay curve is to shorten the forecast time an asset takes to deteriorate from H3 to H2 and from H2 to H1 than would be the case for an asset with an OOU of 20 and an MPL of 40. The exponential decay rates would be like a linear decay, with an OOU of 26 years and an MPL of 40.

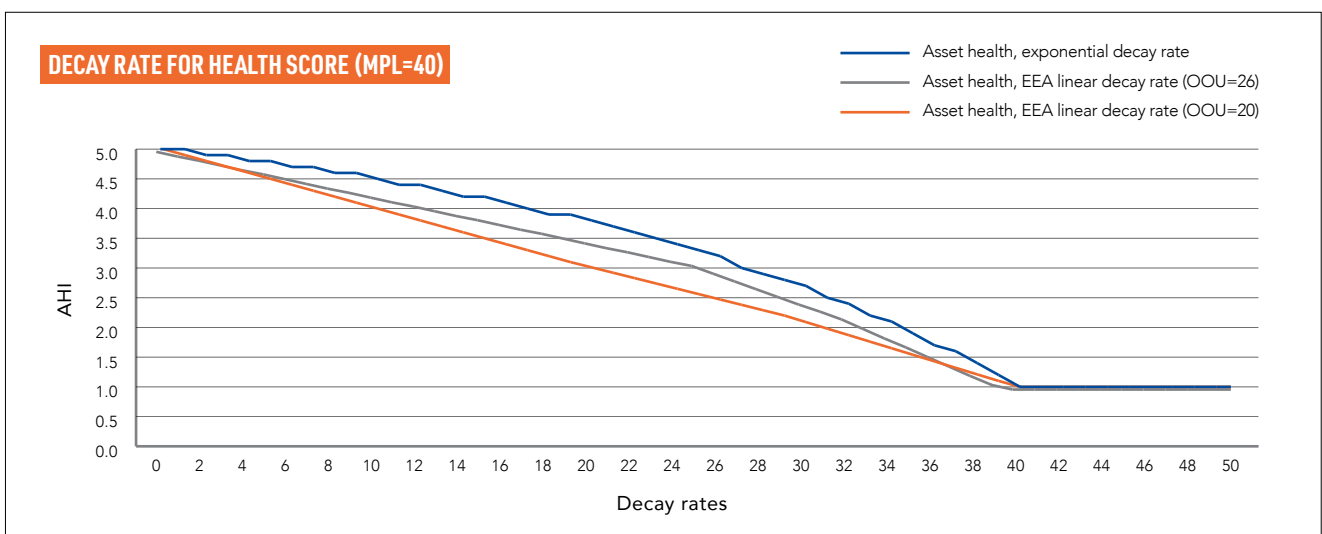


Figure 105: Exponential and EEA (linear) health decay

¹¹⁹ Onset of unreliability (OOU) is the nominal age at which replacement drivers first become evident within a population. Approximately defined as the age where 5% of assets would be retired for end-of-life reasons (excluding capacity-related reasons). The onset of unreliability (OOU) corresponds to an AHI of 3.

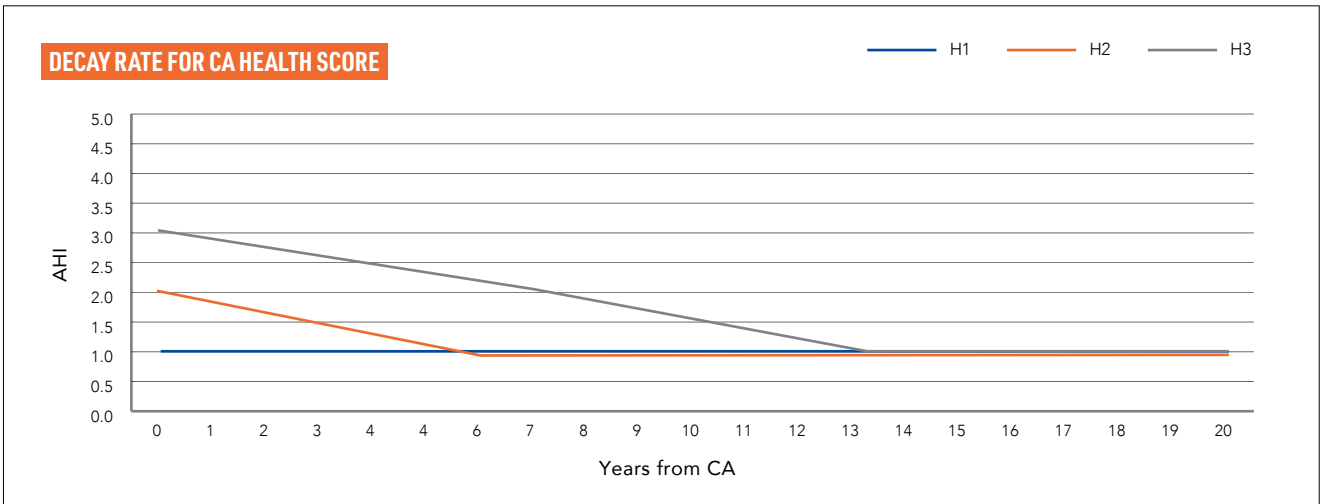


Figure 106: Exponential decay rates for AHI H3 and H2

We have also assessed asset condition and survival statistics and adjusted the standard EEA OOU and MPLs to incorporate Waipā Networks-specific life expectancies where possible¹²⁰. Life expectancies are also affected by asset refurbishment. Historically, we did not retain survival statistics for our assets; therefore, our ability to assess asset survival and adjust MPLs has been limited. Improvements to maintaining asset data will enable survival statistics to be evaluated.

The new model enables line-of-sight between current asset health (either age or condition-driven), 5/10-year forecast asset health, 5/10-year asset renewal forecasts, and 5/10-year expenditure forecasts. The models will significantly simplify renewal forecasting in future years, and the accuracy will improve as our condition data improves and Waipā Networks-specific life expectancies are included.



¹²⁰ As we only have limited survival data (dating back to 2013) we can only assess different OOU's for relatively new assets that were not subject to significant replacements programmes prior to 2013.

13.5.4 How condition data is being used and improved

Table 91 below shows the extent to which we are currently using condition data to drive current and forecast asset health. This provides a useful measure of the quality of our asset health forecasting.

Asset fleet	% of the fleet with condition-based asset health	% of 10-year forecast H1 and H2 assets that are condition-based	Target date for completion of condition-based health assessments and renewal forecasting
Power transformers ¹²¹	N/A	N/A	FY30
33kV and 11kV circuit breakers ¹²¹	N/A	N/A	FY30
Protection relays ¹⁰³	N/A	N/A	FY30
Subtransmission conductor and structures ¹²²	N/A	N/A	FY26-27
Distribution structures	37% concrete 99.7% wood	98% concrete 96% wood ¹²³	FY30
Distribution crossarms	22%	22%	FY30
Distribution overhead conductor	0%	0%	N/A ¹²⁴
Pole-mounted transformers	80%	95%	FY30
Voltage regulators	95%	94%	Complete
Reclosers and sectionalisers	95%	100%	Complete
Overhead switches	4%	8%	FY25-FY30
Distribution cables	0%	0%	N/A ¹²⁵
Ground-mounted transformers	76%	100%	FY27
Ring-main units	65%	92%	FY27

Table 91: Status of condition-based health assessment and renewal forecasting as of October 2025

Our overhead asset fleets will progressively transition to condition-based health assessments as the inspections under the new AHI-aligned standards are completed. These assets are on a 5-year inspection rotation.

We are investigating options for assessing the condition of overhead conductors. This will likely involve sampling and testing in areas where we suspect there are emerging condition issues. We are also monitoring options available

for condition assessment of underground cables, including partial discharge and tan-delta testing (these need to be practical to implement). Our approach to renewal forecasting and to determining renewal projects (as mentioned below) reflects the lack of condition data for these assets.

Refer to Section 7.10 for further details on our data issues and improvements.

¹²¹ These are new assets and condition data will be captured during the first round of routine inspection and testing.

¹²² For our subtransmission lines, the first condition assessment will occur in FY26 when the assets have been in service for 10 years.

¹²³ Only three wood poles are missing CA data, all are forecast to be H1 or H2.

¹²⁴ We do not current capture condition data for conductor and cables.

¹²⁵ We do not current capture condition data for conductor and cables.

13.5.5 How we are forecasting asset renewals and determining specific renewal projects

Table 92 below illustrates how we forecast asset renewals and determine specific renewal projects. Our approach differs for each fleet based on the quality of condition and age data, the mode of failure, and the expected repair or replacement times. These are discussed further in the fleet plans. As mentioned above, a risk-based approach is being introduced over the next 24 months.

Asset fleet	Asset renewal forecasting	Determining specific renewal projects
Power transformers	Condition-based asset health (from FY30)	Health-based, prioritised by criticality
33kV and 11kV circuit breakers	Condition-based asset health (from FY30)	Health-based, prioritised by criticality
Protection relays	Age-based assessment of technical obsolescence)	Technical obsolescence or defect
Subtransmission conductor and structures	Condition-based asset health (from FY26-27)	Health-based, prioritised by criticality
Distribution structures	Combination of age and condition-based asset health	Health-based, prioritised by criticality
Distribution crossarms	Combination of age and condition-based asset health	Health-based, prioritised by criticality
Distribution overhead conductor	Age-based asset health	Reliability-based in the short-medium term
Pole-mounted transformers	Combination of age and condition-based asset health	Urban units – health-based Rural units – failure and defect-based
Voltage regulators	Combination of age and condition-based asset health	Health-based, prioritised by criticality
Reclosers and sectionalisers	Combination of technological obsolescence, age, and condition-based asset health	Health-based, prioritised by criticality
Overhead switches	Mostly age and type-issue asset health	Health-based for ABSs and enclosed switches Failure and defect-based dropout fuses and links
Distribution cables	Age-based asset health	Reliability-based in the short-medium term
Ground-mounted transformers	Combination of age and condition-based asset health	Health-based, prioritised by criticality
Ring-main units	Combination of age and condition-based asset health	Health-based, prioritised by criticality

Table 92: Current approach for forecasting asset renewal and specific renewal projects

13.6 Fleet strategies applying across all material asset classes

Several fleet strategies apply to all our material asset classes. To avoid duplication, we describe these in detail in table 93 and make summary-level references to them in the fleet plans. The first three fleet strategies align with

asset management strategies #4 (develop comprehensive fleet plans and renewal forecasts) and #5 (improve asset management maturity).

Strategy	Description	Outcome
Enhance inspection standards and data	<ul style="list-style-type: none"> Develop new inspection standards to capture EOL condition drivers to support asset health assessment Capture condition data for the remaining assets in the next two years for ground-mounted assets and five years for overhead asset fleets Build inspection resources and capabilities to have a prioritised and continuous flow of inspections 	<ul style="list-style-type: none"> Condition data (aligned to EEA AHI standard) available for >95% of assets
Enhance asset health assessment and forecasting	<ul style="list-style-type: none"> Implement new outage codes to capture fault causes better Capture and analyse asset survival statistics to determine Waipā Networks-specific MPLs Analyse asset condition data to determine Waipā Networks-specific OOs 	<ul style="list-style-type: none"> Increase asset condition data accuracy score Increase in condition-based forecasting to >95%
Implement risk-based renewal forecasting	<ul style="list-style-type: none"> Develop an asset criticality and risk model to assist with developing replacement programmes 	<ul style="list-style-type: none"> Improve the quality of our asset health and renewal forecasting
Enhance renewal project selection and prioritisation	<ul style="list-style-type: none"> Develop asset health, risk, and reliability/fault maps to enhance the definition of project work packs and prioritisation 	<ul style="list-style-type: none"> Improved optimisation of work plans and project timing
Understand and reduce fleet risks	<ul style="list-style-type: none"> Assess asset fleet for safety risks or type risks Include safety risk and type risk as inputs into asset health assessments Enhance the quality of risk controls and treatments for asset fleets 	<ul style="list-style-type: none"> Reduce reliability and safety risks

Table 93: Common fleet strategy



13.7 Summary of material changes to the health of the fleets and our renewal plans (based on 5-year forecasts, consistent with Schedule 12a)

Figure 107 to figure 110 show the evolution of our asset health assessment and renewal forecasts for our material asset classes in this AMP. H1 or H2 refer to assets with low health, meaning EOL drivers are present, and there is a risk of asset failure. This indicates that asset replacement is required.

The material changes in our 5-year forecast asset health since the 2025 AMP (figure 107). These include:

- Crossarm forecast of low health assets has increased. This forecast was based on an extrapolation from assets with a reliable health assessment (22% of the fleet). This assessment likely overstates the extent of low health crossarms as we have undertaken a programme of crossarm replacement over the past three years (since the detailed inspection in FY2022). This data will improve as we complete our inspection programme over the next few years
- PM transformer forecast of low health assets has increased. This is based on condition data, but relates to H2 assets
- All voltage regulators have been inspected, and five sites (15 voltage regulator cans) have been identified as falling due for refurbishment over the next five years
- RMU forecast of low health assets has increased. Most of the assets have been inspected, and the condition issues relate to the tank and partial discharge.

Our five-year renewals are forecast to address low health assets, with a few exceptions (figure 108):

- The crossarm fleet forecast renewals reflect the continuation of our current programme (c. 500 p.a.). As noted above, we are awaiting more reliable health data before adjusting our renewal programme, as low-health assets identified in our prior inspections have been addressed, and we are not seeing an increasing trend in crossarm-related failures
- For pole-mounted transformers, our planned renewals are forecast to replace all H1 assets over the next five years. This is consistent with a failure – and defect-driven replacement strategy, given the relatively low consequence of failure for these assets
- The forecast RMU renewals address all tank issues and immediate partial discharge issues. We are taking a little more time to fully consider the partial discharge results, as these may not necessarily indicate the need for replacement (i.e. it could be a cable termination issue that needs cleaning or replacement).

Our zone substation and subtransmission assets are new or near-new; hence, low health issues have yet to emerge.

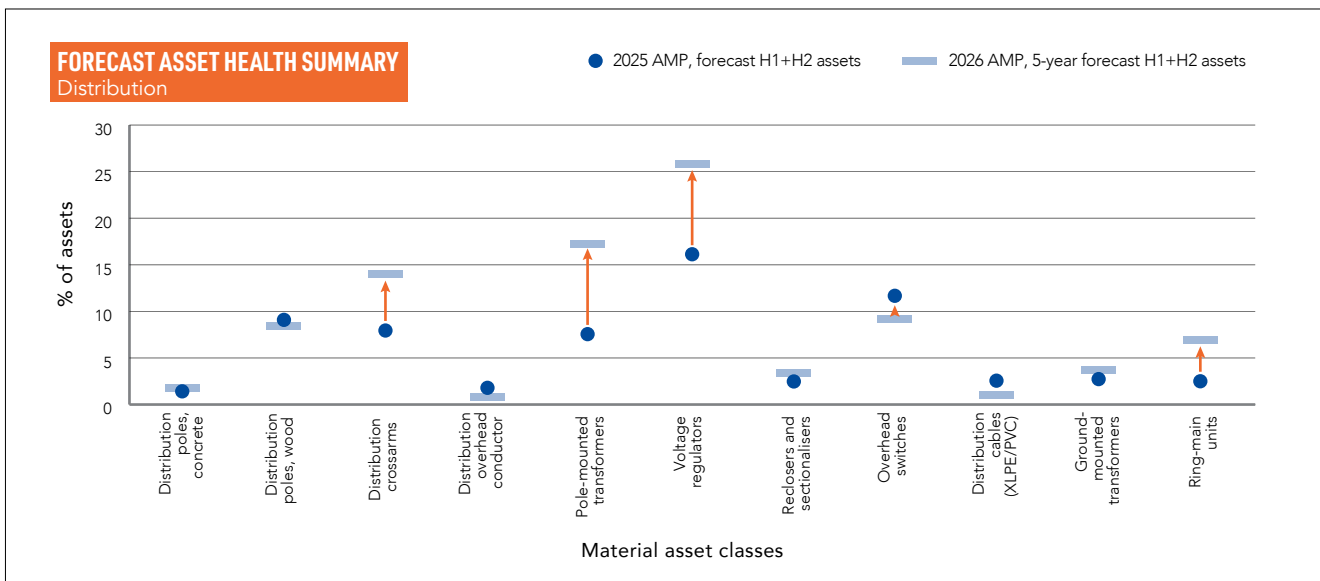


Figure 107: Forecast asset health summary, distribution assets

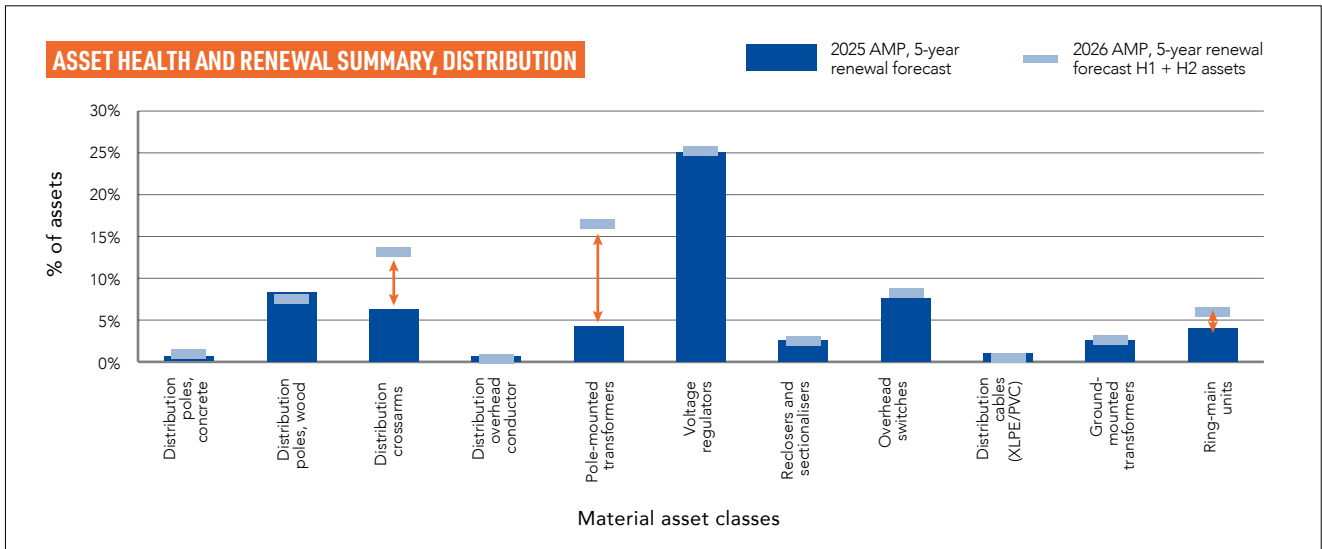


Figure 108: Forecast asset renewal summary, distribution assets

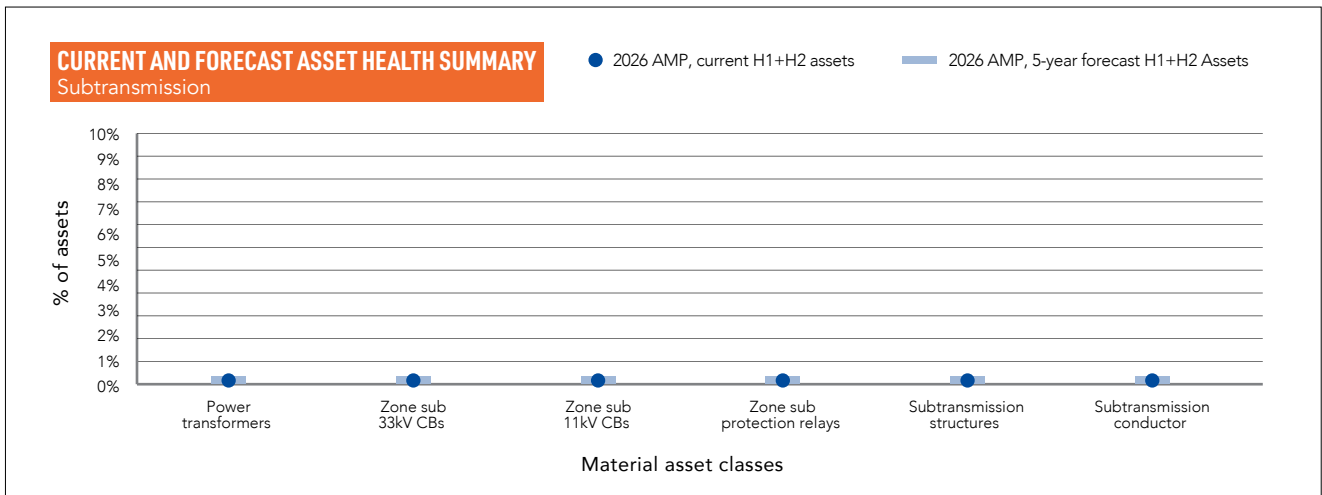


Figure 109: Forecast asset health summary, subtransmission and zone substation assets

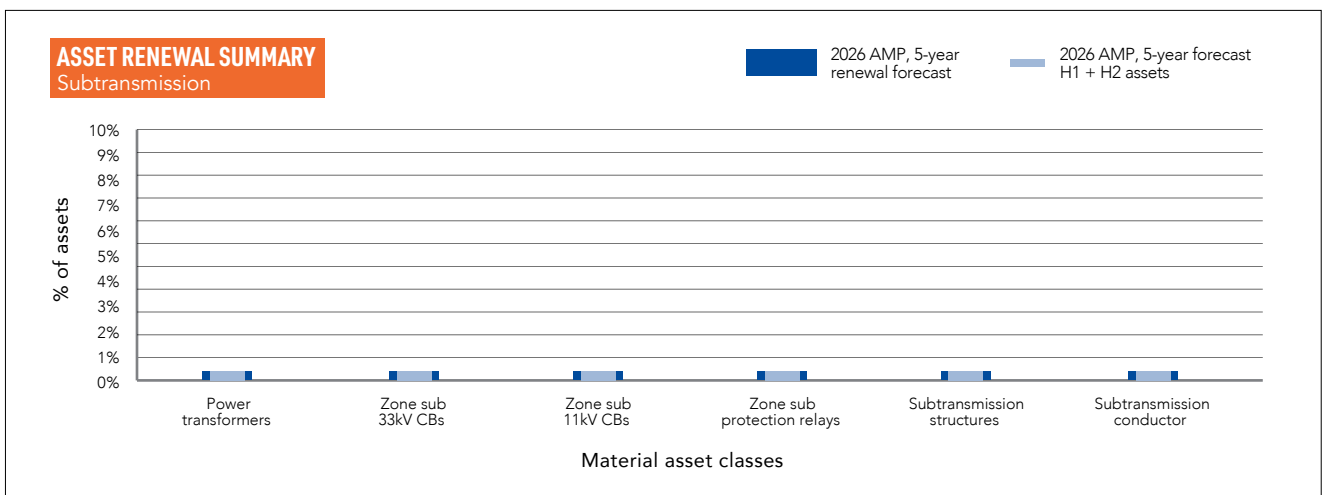


Figure 110: Forecast asset renewal summary, subtransmission and zone substation assets

Note: our fleet plans in this section present 10-year health and renewal data. This differs from the timeframe presented in Schedule 12a.

13.8 Asset fleet plans

Table 94 shows the material asset classes for Waipā Networks. Fleet plans for each of these material asset classes are included in this AMP.

Asset fleet	Asset classes (commerce commission definitions)	Unit	Quantity ¹²⁶
Power transformers	Zone substation transformers	No.	2
33kV and 11kV circuit breakers	11/22/33kV CB (Indoor)	No.	18
Protection relays	Protection relays (electromechanical, solid state and numeric)	No.	27
Subtransmission conductor and structures	Concrete / Steel Structures (110kV only)	No.	190
	Subtransmission OH 110kV+ Conductor	Km	33
Distribution structures and crossarms	Concrete / Steel Structures (excluding 110kV)	No.	21,286
	Wood poles	No.	896
	Crossarms ¹²⁷	No.	34,282
Distribution and LV overhead conductor	Distribution OH Open Wire Conductor	Km	1,231
	LV OH Conductor	Km	497
Pole-mounted transformers	Pole Mounted Transformers	No.	2,831
Voltage regulators	Voltage Regulators	No.	60
Reclosers and sectionalisers	3.3/6.6/11/22kV CB (pole mounted) – reclosers and sectionalisers	No.	115
Overhead switches (ABS, enclosed LBS, links, fuses)	3.3/6.6/11/22kV Switches and fuses (pole mounted)	No.	4,533
Distribution and LV cables	Distribution UG XLPE or PVC	Km	183
	Distribution UG PILC	Km	0.06
	LV UG Cable	Km	408
Ground-mounted transformers	Ground-Mounted Transformers	No.	953
Ring-main units	3.3/6.6/11/22kV RMU	No.	198

Table 94: Material asset fleets

We have included summary-level fleet plans concerning our other asset classes. These cover:

- LV OH/UG streetlighting circuits
- OH/UG consumer connections
- Protection relays
- SCADA and communication equipment
- Load control plants
- Load control relays.

Our fleet plans also consider relevant environmental factors, e.g., keeping trees clear of overhead lines. A significant part of the maintenance budget is allocated to vegetation control. Hence, we have included a summary of our vegetation management strategy in this section.

¹²⁶ These are quantities at October 2025, which is the date of extract from the GIS for our health forecasting.

¹²⁷ Not a Commerce Commission asset class. This includes all voltages.

13.9 Power transformer fleet plan

13.9.1 Fleet overview

Waipā Networks has two power transformers located at the new Forrest Road substation. These are 16/24 MVA units manufactured by Hitachi Energy and installed in June 2025. Power transformers convert energy from 33kV to 11kV. N-1 security is available for the transformers at Forrest Road.

Individually, power transformers are our most valuable assets. Power transformers have a high initial investment and operational costs. Therefore, the total lifecycle costs are assessed when purchasing new transformers.

From a fleet plan perspective, there are two major components to a power transformer – the transformer (consisting of the tank, windings, core and cooling system) and the tap-changer (which allows the output voltage to be changed while the transformer is carrying load).

The health of a power transformer is primarily determined by the condition of the insulating system (paper and oil), which is influenced by thermal and electrical stress, moisture, oil quality, and the natural degradation of the paper. We monitor these factors using SCADA and dissolved gas analysis of the insulating oil.

The transformers are vacuum-filled with no air-oil interface. They include a bladder inside the conservator with silica-gel breathers to compensate for oil expansion, reducing the risk of moisture ingress.

Power transformers are critical assets, and failures can result in a loss of supply or reduced supply security for an extended period. For this reason, we take a more conservative approach to their management than we do for distribution assets.



Figure 111: Power transformers at the Forrest Road substation

13.9.2 Fleet performance

These are new assets. There have been no performance issues since commissioning.

13.9.3 Fleet risks

Table 95 highlights the material risks, stakeholder impacts, and potential stakeholder impacts associated with the power transformer fleet.

Risk/failure modes	Stakeholder impact	Stakeholder linkage	Current controls or treatments
Tank and radiator corrosion can reduce asset life	Higher prices due to earlier renewal of the asset	Price	Regular visual condition monitoring of the tank and remediation of corrosion as required.
Overloading of the transformer can damage the winding insulation, reducing asset life and causing asset failure	Increase risk of outage Higher prices due to earlier renewal of the asset	Network customer service Price	SCADA monitoring transformer loading. The load can be transferred to the other transformer. Condition assessment (dissolved gas analysis) of the transformer oil.
Moisture ingress and contamination of transformer oil can damage the winding insulation, reducing asset life and causing asset failure	As above	As above	Regular oil moisture testing. The transformer oil may be changed or filtered as required.
Failure of a bushing or connection	Increase risk of outage	Network customer service	Inspection of bushing and thermal imaging of connection points with follow-up maintenance as required.
Mechanical failure of the tap-changer	Inability to meet regulated voltage requirements Increase risk of outage	Network quality Network customer service	Regular inspection and maintenance of the tap-changer.
Obsolescence due to the unavailability of spare parts	Higher prices due to earlier renewal of the asset	Price	Maintain suitable spares for the transformer and tap-changer.

Table 95: Fleet risks and failure modes

13.9.4 Fleet strategy

Power transformers are high-criticality assets that can take significant time to replace should they fail. Hence, the objective for this fleet is to operate, monitor, maintain, and renew the assets to ensure fleet health is maintained at H3 or better.

To achieve the fleet objective and address the fleet performance, risks, and other issues mentioned in the preceding sections, the 10-year strategy for this fleet is shown in table 96.

Strategy	Description	Outcome
Maintain the asset and subcomponents at H3 or better	<ul style="list-style-type: none"> Undertake condition monitoring, maintenance and defect repair as outlined in this fleet plan Maintain the assets consistent with the manufacturer's guidelines and Waipā Networks' standards 	Assets and subcomponents are at H3 or better
Maintain security	<ul style="list-style-type: none"> Operating the assets within the required security levels 	No sustained breaches of security
Reliability determine fleet health	<ul style="list-style-type: none"> Regular monitoring of the condition of the asset fleet to ensure asset health can be reliably predicted We are considering adopting the transformer age index model (TAIM) to assess the biological age of our fleet 	No unobserved deterioration in asset health
Timely replacement of defects	<ul style="list-style-type: none"> Given the potentially high consequence of failure, defect repairs or replacements shall occur promptly 	No subcomponent failures
Spares	<ul style="list-style-type: none"> Maintain appropriate spares 	Achieve full expected life from the asset

Table 96: Fleet strategy

13.9.5 Design and construct

Power transformers are designed, specified and purchased for each specific application. We have adopted the IEC/AS/NZS 60067 standard for the design, manufacturing, testing, and safety of power transformers.

13.9.6 Monitoring

Table 97 summarises the current inspection and testing regime for the power transformer fleet. The inspection and testing cover the transformer and tap-changer. Routine condition data is captured through regular inspections of the zone substation, and measured condition data (such as DGAs) is captured through specific testing. Appropriately qualified technicians perform visual inspections, testing and oil sampling.

Monitoring type	Description	Frequency
Routine inspection	<ul style="list-style-type: none"> Routine inspection checks for oil leaks, corrosion, oil levels and tap-changer operation. This is completed as part of the zone substation inspection programme 	Time-based, timing varies between monthly and yearly, depending on the condition
Monitoring electrical stress	<ul style="list-style-type: none"> Duty of the transformer and operation of the tap-changer Insulation resistance and winding resistance Insulation Power Factor (TanDelta) 	Continuous SCADA measurement Time-based, 3-yearly, in conjunction with maintenance
Monitoring thermal stress of components	<ul style="list-style-type: none"> Thermal imaging of connection points and checking for hot spots Temperature monitoring 	Time-based, annually Continuous SCADA measurement
Insulating system condition assessment	<ul style="list-style-type: none"> DGA and Furan analysis 	Time-based, annually

Table 97: Condition assessments

13.9.7 Maintaining

Power transformer maintenance typically includes work on the tap changer, as shown in table 98. Planned maintenance is based on the manufacturer's recommendations and good industry practice.

Type	Scope of maintenance	Trigger
Tap-changer preventive maintenance	Oil replacement, cleaning of components, removal of arcing products, contact alignment and tap resistance.	<ul style="list-style-type: none"> Time-based, 3-yearly
Transformer preventive maintenance	Detailed inspection of components, checking operation of secondary equipment, insulation resistance, winding resistance, and other recommended testing. Repairs and maintenance as required.	<ul style="list-style-type: none"> Time-based, at commissioning, then 3-yearly, in conjunction with the tap-changer maintenance
Defect repairs	Defects (on subcomponents of the assets) are repaired following identification during inspection, maintenance or fault.	<ul style="list-style-type: none"> Oil test results exceeding recommendations Poor results for tests such as TanDelta, Furan analysis, and paper sampling Integrity of gaskets and flexible seals on tank and fittings Oil leaks or staining suggest ongoing leakage Corrosion

Table 98: Corrective and preventive maintenance

13.9.8 Renewal

Our fleet renewal approach is shown in table 99.

Type	Drivers/triggers
Asset health and renewal forecasts	Asset health is determined using a combination of asset age, duty and condition. The condition inputs include routine inspections and the measured condition for oil moisture, oil dissolved gases, and furan tests, as shown in table 97. These measurements are generally applicable to both the transformer and the tap-changer.
Determining specific renewal projects	<p>Specific renewal or refurbishment projects are defined based on our engineering assessment, asset health and the specific condition inputs.</p> <p>We are considering adopting the transformer age index model (TAIM) to assess the biological age of our fleet, which will be used to determine specific replacement or refurbishment projects. The TAIM will assess oil impurity, acidity, gas content and moisture content to indicate deterioration of the insulation. Poor results for tests such as partial discharge, furan analysis, insulation resistance, winding resistance and/or paper sampling will be assessed. These measurements are generally applicable to both the transformer and the tap-changer. External input will be sought to make a thorough evaluation of the asset's health when the asset transitions into H3.</p> <p>Project timing considers the ability to manage the risks associated with the emergence of end-of-life drivers. This includes the redundancy available at the substation, critical spares, and spare availability.</p>
Assessing alternatives	The typical alternative to renewal is refurbishment. Refurbishment of power transformers may be feasible and provide an economic life extension (instead of renewal). Refurbishment will consider the capacity available to support future load growth, the transformer's age, the specific drivers of deteriorating health (and whether refurbishment will mitigate these drivers), and the overall lifecycle cost implications of refurbishment vs renewal.

Table 99: Fleet renewal forecasting

13.9.9 Population and age

Table 100 shows the population and age of the power transformers. The assets are new.

Type	Population	Average Age (years)	MPL (years)	Population within 5 years of MPL
3 Phase Transformer (including tap-changer)	2	<1	60-65	Nil

Table 100: Asset fleet quantity and age

13.9.10 Asset health

Figure 112 shows the health assessment for power transformers. It is based on the EEA asset health guide, including the health forecasting discussed in Section 13.4.1. As the assets are new, no low-health assets or subcomponents are forecast over the next 10 years.

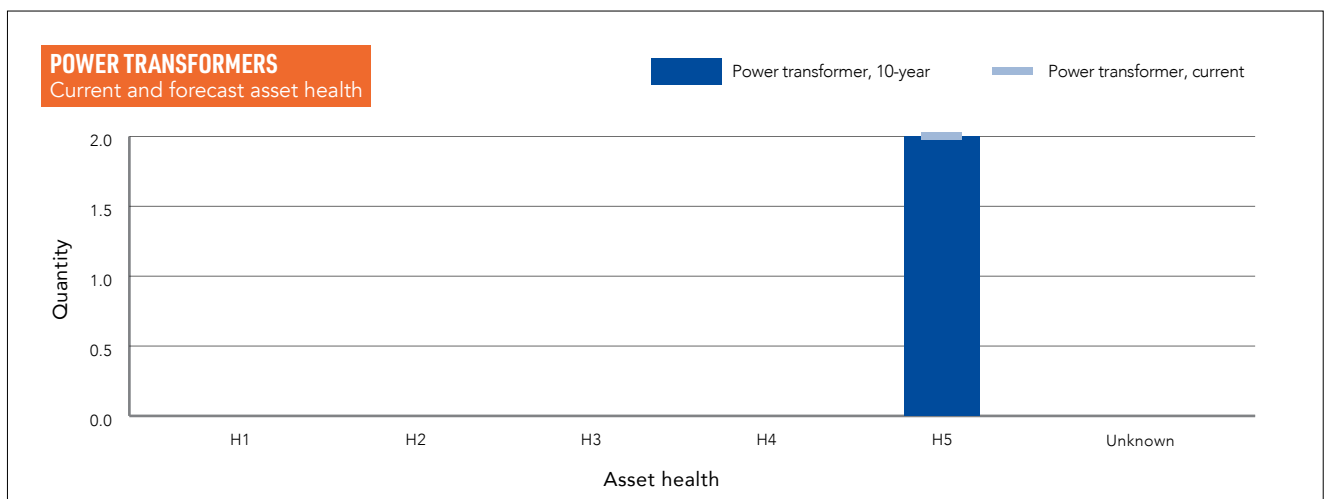


Figure 112: Current and forecast asset health (power transformers)

13.9.11 Expenditure forecasting

No renewal expenditure on the assets or their subcomponents is forecast over the next 10 years.

Routine condition monitoring for these assets is included in the reactive and corrective maintenance and inspection forecasts shown in Section 13.25.

13.10 Zone substation circuit breaker fleet plan

13.10.1 Fleet overview

Waipā Networks has nine 33kV and nine 11kV circuit breakers (CBs) at the new Forrest Road substation. The 33kV CBs switch and protect the 33kV bus and power transformers, and the 11kV CBs switch and protect the 11kV feeder circuits.

The 33kV switchboard is a Schneider GHA board: a fully integrated, non-rackable, SF₆-insulated indoor switchboard using vacuum circuit breaker technology. The board comprises two incomers, one bus coupler, two transformer feeders and four spare feeders for future use.

The 11kV switchboard is an RPS LMVP indoor board with vacuum circuit breakers, which is commonly used in NZ. Following the feeder changeover from the Cambridge GXP, there are four operational feeders, two spare CBs for future use, two incomers and one bus coupler.

CBs are critical assets, and failure can result in a loss of supply or reduced supply security, depending on the network security level of the zone substation. For this reason, we take a more conservative approach to managing them than we do for distribution assets.



Figure 113: 33kV and switchgear panel circuit breakers

13.10.2 Fleet performance

These are new assets. There have been no performance issues since commissioning.

13.10.3 Fleet risks

Table 101 highlights the material risks, stakeholder impacts and controls associated with the 33kV and 11kV circuit breaker fleet.

Risk/failure modes	Stakeholder impact	Stakeholder linkage	Current controls or treatments
Insulation failure	Potential customer outage	Network customer service	Inspection, gas leakage detection and partial discharge testing. The type of treatment is issue-dependent.
Mechanical or interlock failure	Potential customer outage Malfunctioning mechanical interlocks can lead to hazardous operations and risk to personnel	Network customer service Personnel safety	Inspection and maintenance to the manufacturer's requirements.
Connector or conductor issues leading to arc-flash	Potential customer outage Risk to personnel (if arc-flash cannot be contained)	As above	Inspection and maintenance to the manufacturer's requirements The new switchgear meets current arc-flash containment standards.
Obsolescence due to unavailability of spare parts	Higher prices due to earlier renewal of the asset	Price	Maintain suitable spares.

Table 101: Fleet risks and failure modes

13.10.4 Fleet strategy

Circuit breakers are critical assets and can disrupt supply should they fail. Hence, the objective for this fleet is to be operate, monitor, maintain, and renew the assets to ensure fleet health is maintained at H3 or better.

To achieve the fleet objective and address the fleet performance, risks, and other issues mentioned in the preceding sections, the 10-year strategy for this fleet is shown in table 102.

Strategy	Description	Outcome
Maintain the asset and subcomponents at H3 or better	<ul style="list-style-type: none"> Undertake condition monitoring, maintenance and defect repair as outlined in this fleet plan Maintain the assets consistent with the manufacturer's guidelines 	Assets and subcomponents are at H3 or better
Reliability determines fleet health	<ul style="list-style-type: none"> Regular monitoring of the condition of the asset fleet to ensure asset health can be reliably predicted 	No unobserved deterioration in asset health
Timely replacement of defects	<ul style="list-style-type: none"> Given the potentially high consequence of failure, defect repairs or replacements shall occur promptly 	No subcomponent failures
Spares	<ul style="list-style-type: none"> Maintain appropriate spares 	Achieve full expected life from the asset

Table 102: Fleet strategy

13.10.5 Design and construct

Circuit breakers are designed, specified and purchased for each specific application. We have adopted the IEC/AS/NZS 62271 standard for the design, manufacturing, testing, and safety of circuit breakers.

13.10.6 Monitoring

Table 103 summarises the current inspection and testing regime for circuit breakers. Appropriately qualified technicians perform visual inspections, monitoring and functional/wiring tests.

Type	Scope of assessment	Trigger
Operations	<ul style="list-style-type: none"> SCADA operational monitoring 	Continuous on-line
Visual inspections	<ul style="list-style-type: none"> External condition cabinet assessment Internal condition cabinet assessment (11kV) 	Routine, time-based, bi-monthly
Monitoring for insulation condition	<ul style="list-style-type: none"> Partial discharge assessment for electrical discharge that could indicate insulation breakdown or other condition issues Acoustic assessment for noise that could indicate condition-based issues Infra-red assessment for thermal or heating issues Insulation resistance testing Contact resistance testing (11kV) 	Routine, time-based, 3-yearly or after a high number of fault operations
Functional and operational testing	<ul style="list-style-type: none"> Breaker operation Mechanical and interlock functional tests Gas insulating system functional check (33kV) Gas detection (33kV) 	Routine, time-based, annually

Table 103: Condition assessments

13.10.7 Maintaining

CB maintenance is shown in table 104. Planned maintenance is based on the manufacturer's recommendations and good industry practice.

The 33kV Schneider GHA switchgear is a gas-insulated switchgear that is delivered to the site as a "sealed for life" system, with the main high-voltage components largely maintenance-free. The condition assessment (mentioned above) is the typical work required on the GHA switchgear.

Type	Scope of maintenance	Trigger
Wiring checks (33kV and 11kV)	Wiring and ferrule checks Current and voltage transformer checks	Routine, time-based, 5 yearly
Cleaning and lubrication (11kV)	Clean old grease and lubricate mechanical parts Remove dust and dirt from the interior and insulating surfaces	Routine, time-based, annually or number of operations
Defect repairs (33kV and 11kV)	Defects repair on subcomponents of the assets	Identification during monitoring

Table 104: Corrective and preventive maintenance

13.10.8 Renewal

Our fleet renewal approach is shown in table 105.

Type	Drivers/triggers
Asset health and renewal forecasts	Asset health is determined using a combination of asset age, insulator condition, functional testing and technical obsolescence (as shown in table 97).
Determining specific renewal projects	<p>Specific renewal or refurbishment projects are defined based on our engineering assessment of asset health and the specific condition inputs. External input will be sought to make a thorough evaluation of the asset health when the asset transitions into H3.</p> <p>Project timing considers the ability to manage the risks associated with the emergence of end-of-life drivers. This includes the redundancy available at the substation and the availability of spares.</p>
Assessing alternatives	Other than continued operation at higher risk, there are limited alternatives to replacement when end-of-life drivers are detected. Higher risk operation is unlikely to be acceptable due to the criticality of these assets.

Table 105: Fleet renewal forecasting

13.10.9 Population and age

Table 106 shows the 33kV and 11kV CB population and age. The assets are new.

Type	Population	Average Age (years)	MPL (years)	Population within 5 years of MPL
33kV circuit breakers (indoor)	9	<1	60	Nil
11kV circuit breakers (indoor)	9	<1	60	Nil

Table 106: Asset fleet quantity and age

13.10.10 Asset health

Figure 114 and figure 115 show the health assessment for circuit breakers. It is based on the EEA asset health guide, including the health forecasting discussed in Section 13.9.8. As the assets are new, no low-health assets or subcomponents are forecast over the next 10 years.

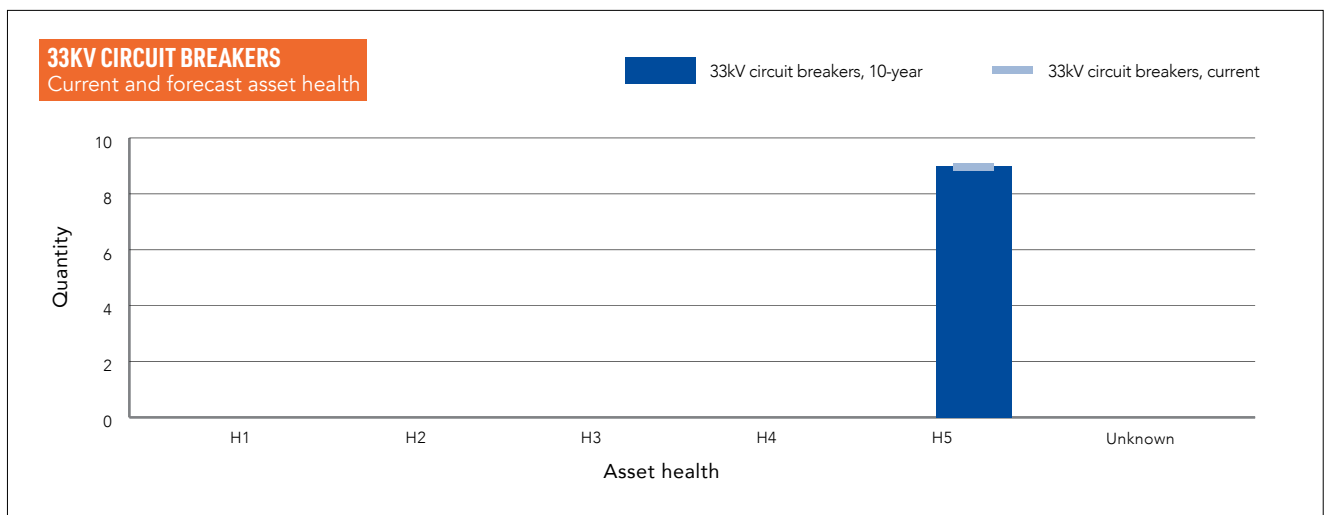


Figure 114: Current and Forecast Asset Health (33kV Circuit Breakers)

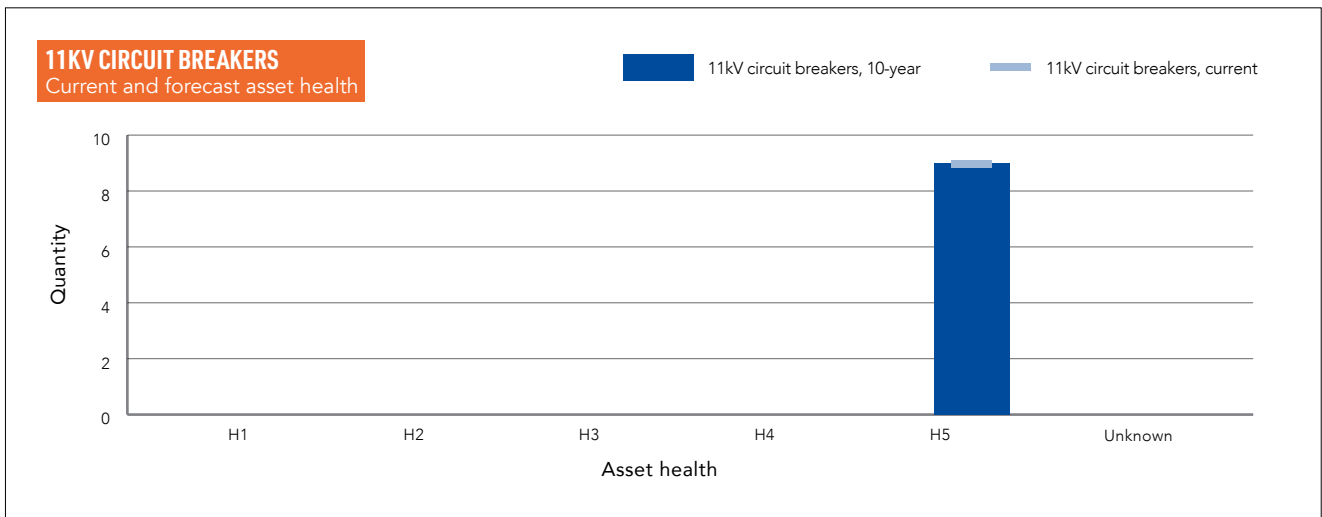


Figure 115: Current and Forecast Asset Health (11kV Circuit Breakers)

13.10.11 Expenditure forecasting

No renewal expenditure is forecast for the asset or its subcomponents over the next 10 years.

Routine condition monitoring for these assets is included in the reactive and corrective maintenance and inspection forecasts shown in Section 13.25.

13.11 Zone substation protection relays fleet plan

13.11.1 Fleet overview

Waipā Networks has 27 protection relays at the new Forrest Road substation. These protection relays (operating in conjunction with 33kV and 11kV circuit breakers) provide electrical protection for the 33kV and 11kV buses, power transformers, and 11kV feeders. There are two at the Cambridge GXP and 4 at the Te Awamutu GXP.

The fleet comprises modern numerical relays from SEL and Siemens. The relays provide bus-zone protection, transformer Buchholz and differential protection, and feeder overcurrent and earth-fault protection. Line differential protection is installed on the spare 33kV feeders for future use.

Protection relays are critical assets, and failure or maloperation can result in a loss of supply or reduced supply security or continued energising of faulted line or equipment. For this reason, we take a more conservative approach to managing them than we do for distribution assets.

Prior to the construction of the Forrest Road substation, we had limited protection relays on the network (we consider protection relays that operate in conjunction with reclosers to be part of the recloser, and not a separate asset).

We have installed new Automatic Under-Frequency Load Shedding (AUFLS) relays at the Cambridge and Te Awamutu GXPs to comply with the new 4-block AUFLS scheme. These are programmed to trip feeders if the system frequency drops below specific set points, as required by the System Operator. The Forrest Road substation includes the same four-block AUFLS scheme, but the protection function is included as part of the feeder protection relay.





Figure 116: Protection Relays at the Forrest Road Substation

13.11.2 Fleet performance

These are new assets. There have been no performance issues since commissioning.

13.11.3 Fleet risks

Table 107 highlights the material risks, stakeholder impacts and controls associated with the protection relays.

Risk/failure modes	Stakeholder impact	Stakeholder linkage	Current controls or treatments
Technical obsolescence (where support becomes unavailable and the relay setting cannot be managed)	Potential customer outage Maloperation resulting in a safety risk to personnel or the public or damage to equipment	Network customer service Personnel safety	Our plan is to adopt an MPL of around 20 years to ensure that protection schemes remain relevant, current and effective. This is in line with current industry standards
Scheme vulnerabilities	As above	As above	Primary and secondary injection testing Auditing of protection schemes
Type issues	As above	As above	Firmware upgrades or relay replacement (following supplier or industry recommendations)

Table 107: Fleet risks and failure modes

13.11.4 Fleet strategy

Protection relays are critical assets for managing safety and circuit loading, ensuring the network fails to safe. Hence, the objective for this fleet is to operate, monitor, maintain, and renew the assets so that fleet health is maintained at H3 or better.

To achieve the fleet objective and address the fleet performance, risks, and other issues mentioned in the preceding sections, the 10-year strategy for this fleet is shown in table 108.

Strategy	Description	Outcome
Implement a selective, sensitive, and stable protection scheme	Implement protection schemes that comply with good industry practice using modern numerical relays from significant manufacturers (e.g. SEL and Siemens)	Faults are cleared that meet regulatory requirements, without damage to equipment or exposure of personal or public to electrical hazards
Adopt an appropriate MPL to avoid technological obsolescence	Our plan is to adopt an MPL of around 20-25 years to ensure that protection schemes remain relevant, current and effective. This is in line with current industry standards	All relays can be managed effectively throughout their lifecycle
Timely remediation of errors or identified scheme issues	Given the potentially high consequence of failure, all errors should be resolved promptly	No unresolved relay errors or scheme issues
Spares	Maintain appropriate critical spares	Relays can be replaced immediately upon failure

Table 108: Fleet strategy

13.11.5 Design and construct

Protection relays are designed, specified and purchased for each specific application. We have adopted the IEC/AS/NZS 61850 standard for numerical protection relays.

13.11.6 Monitoring

Table 109 summarises the current inspection and testing regime for protection relays. Appropriately qualified technicians perform visual inspections and functional testing.

Type	Scope of assessment	Trigger
Error monitoring	SCADA monitoring for relay errors and operational performance	Continuous online
Visual inspections	Checking relay control panel for error messages	Routine, time-based, bi-monthly
Testing	Secondary injection tests	Routine, time-based, 9 yearly Suspected malfunction

Table 109: Condition assessments

13.11.7 Maintaining

There is no specific maintenance for protection relays. Wiring terminal checks are completed under CB maintenance.

13.11.8 Renewal

Our fleet renewal approach is shown in table 110.

Type	Drivers/triggers
Asset health and renewal forecasts	Asset health is determined using asset age (for technical obsolescence), type issues or the results of functional testing or operational issues.
Determining specific renewal projects	Specific renewal or refurbishment projects are defined based on our engineering assessment of asset health and the risks present.
Assessing alternatives	Other than continued operation at higher risk, there are limited alternatives to replacement when end-of-life drivers or obsolescence is determined. Higher risk operation is unlikely to be acceptable due to the criticality of these assets.

Table 110: Fleet renewal forecasting

13.11.9 Population and age

Table 111 shows the population and age of protection and AUFLS relays. The assets are new.

Type	Population	Average Age (years)	MPL (years)	Population within 5 years of MPL
Protection relays	27	<1	20-25	Nil
AUFLS relays	6	<3	20-25	Nil

Table 111: Asset fleet quantity and age

13.11.10 Asset health

Figure 117 shows the health assessment for protection relays. It is based on the health forecasting discussed in Section 13.9.8. As the assets are new, no low-health assets or subcomponents are forecast over the next 10 years.

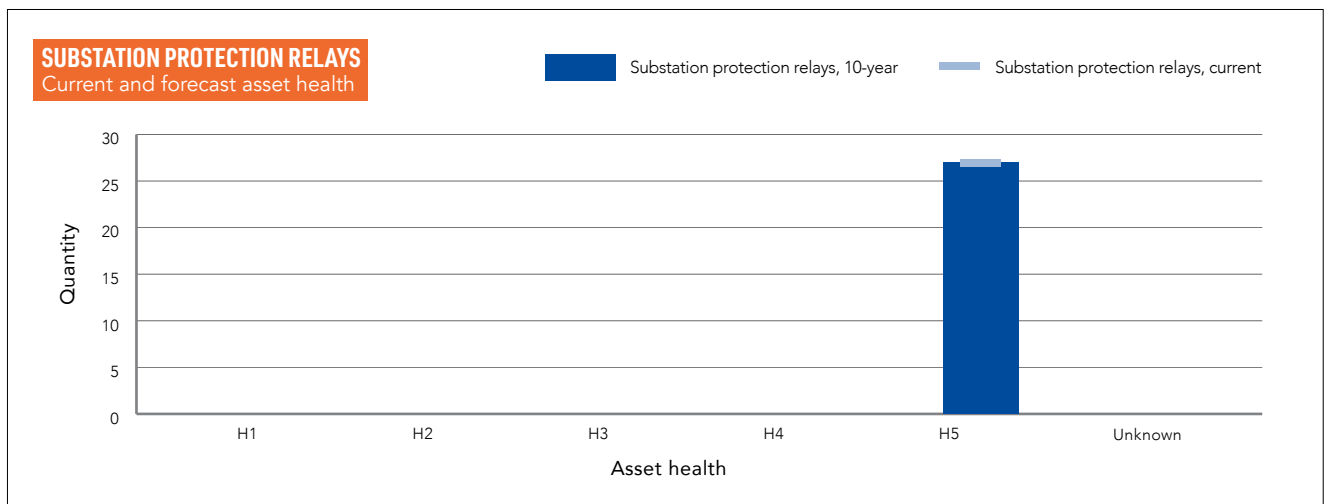


Figure 117: Current and forecast asset health (substation protection relays)

13.11.11 Expenditure forecasting

No renewal expenditure is forecast for the asset or its subcomponents over the next 10 years.

Routine condition monitoring for these assets is included in the reactive and corrective maintenance and inspection forecasts shown in Section 13.25.



13.12 110kV subtransmission structures and conductor

13.12.1 Fleet overview

We own the 110kV line from Transpower's Hanganiki GXP to the Te Awamutu GXP. This line was commissioned in 2016. The purpose of the line is to improve the security of supply to Te Awamutu.

The new subtransmission line consists of 175 steel poles and 15 concrete poles. It is planned to undertake a comprehensive condition assessment 10 years after commissioning, which is due in 2026. We will expand this fleet plan following the condition assessment.

There is a range of failure modes for concrete and steel poles and conductors. Failure modes for concrete poles and conductors are discussed in the relevant distribution fleet plans.

Concerning steel poles (used only on the subtransmission system), failure is driven by corrosion of the poles and their fixings. Corrosion is observable through visual inspection, and deterioration rates are slow, meaning failure between inspections is unlikely.

We have good quality data on the age and attributes of this fleet.

13.12.2 Fleet performance

There have been no faults on the 110kV line since its commissioning. There are presently no concerns with the fleet's performance.

13.12.3 Fleet risks

Table 112 highlights the material risks associated with the 110kV subtransmission fleet, their impact on stakeholders, and our response.

Risk	Stakeholder impact	Stakeholder linkage	Our response
Third-party interference (car vs. pole) damages overhead lines, causing outages and potential contact with live wires.	Given the criticality of this line, a car vs pole incident could limit security in Te Awamutu while the structure is repaired. Injury to members of the public	Public safety Network performance	The poles have been located away from the busy roadway or with setbacks, and structures are protected if necessary.
Failure of the 110kV above 11kV could cause hazardous over-voltages on the 11kV and LV systems	Injury to members of the public and/or equipment	Public safety	The 110kV line is inspected and maintained to Transpower standards. The health of subcomponents will be kept to H3, given the high criticality and risk.
Outages to multiple 11kV feeders may be required to maintain some 110kV subcomponents or assets.	This could result in significant customer outages	Network customer service	A review of the maintainability of complex structures is planned. Undergrounding of multi-circuit 11kV circuits is also linked to our Resilience Strategy.
Damage from vegetation	Network performance	Network customer service	The 110kV line is inspected and maintained to Transpower standards. It is patrolled annually, including detection and action for any vegetation issues.

Table 112: Fleet risks

Given the modern design of the 110kV line. The risks from adverse weather and adverse environmental factors were mitigated through the design process.

13.12.4 Fleet strategy

The objective for this fleet is to maintain N-1 security into the Te Awamutu GXP, while maintaining public safety and avoiding asset failures.

To achieve the fleet objective and address the fleet performance, risks, and other issues mentioned in the preceding sections, the 10-year fleet strategy is shown in table 113.

Strategy	Description	Outcome
Common fleet strategies (refer table 93 in Section 13.6)	<ul style="list-style-type: none"> Implement risk-based renewal forecasting (including all subcomponents) 	Improve the quality of our asset health and renewal forecasting
Maintain the asset and subcomponents at H3	<ul style="list-style-type: none"> Carry out annual patrol Condition assessed at 10-year intervals and maintain the asset to Transpower standards (see below) Maintain the assets and components at H3 Maintain or replace subcomponents as or before they transition to H2 	No H1 or H2 assets or subcomponents
Review the maintainability of complex structures.	<ul style="list-style-type: none"> A project will be initiated over the next three years to determine solutions to maintain the 110kV components above the 11kV circuits 	Optimal maintenance procedures
Timely replacement of defects	<ul style="list-style-type: none"> Given the potentially high consequence of failure, defect replacements shall occur promptly 	No failure of a subcomponent of the assets with defect notices

Table 113: Fleet strategy

13.12.5 Design and construct

The new 110kV lines comprise galvanised steel poles, steel post-arms, insulators, and aluminium conductors. 17 existing concrete poles were incorporated into the line route.

The line was designed per AS/NZS 7000:2010 Overhead Line Design, AS/NZS 1170 Structural Actions, and Transpower line design standards TP.DL 12.01 – Structure Loadings, TP.DL 12.02 – Structures Spacing and Distances, and NZECP34:2001 for electrical clearances.

The line and support structures were designed with a 50-year design life; however, the asset should achieve a 100-year service life if the various subcomponents are suitably maintained.

The 110kV pole also supports some 11kV circuits below the 110kV (up to three in some cases) at certain locations. This will impact on the future maintainability of the line (as it is not permitted to work above live lines) if the 11kV circuits cannot be readily isolated. Detailed maintenance procedures will be required as we approach the first round of maintenance on the steelwork, insulators, jumpers and fixings.

13.12.6 Monitoring

A maintenance manual was developed as part of the initial construction project. The 110kV subtransmission line will be monitored using specialised transmission contractors to Transpower standards. Northpower (a Transpower contractor in the Waikato region) has been contracted to undertake patrols, inspections, and maintenance. Table 114 describes our current fleet monitoring approach.

Monitoring type	Description	Frequency
Line patrols	<ul style="list-style-type: none"> Assess safety, structural integrity, structural damage, public safety risk, and operational risks Identify defects that are expected to deteriorate to below H3 within the next year Assess vegetation encroachment, animal interactions, and incompatible corridor use 	Annually
Detailed inspections and Condition assessment	<ul style="list-style-type: none"> Condition assessments monitor the condition of structures, foundations, conductors, and hardware. The assessment produces a score for various components on a scale from 100 (new) to 20 (replacement or decommissioning criteria) to one (where failure is likely under everyday conditions) It applies a consistent approach to assessing line components and allows extrapolation of the assessed condition into the future 	At year 10, then at intervals based on the asset condition after that

Table 114: Fleet monitoring

13.12.7 Maintaining

A maintenance manual was developed as part of the initial construction project. The 110kV subtransmission line will be maintained using specialised transmission contractors and to Transpower standards.

Monitoring type	Description	Frequency
Preventive maintenance	Preventative maintenance will be carried out as specified in the Transpower maintenance standards	As required
Condition-based maintenance	Detailed maintenance plans will be developed after each condition assessment to maintain the asset and subcomponents to achieve the intended service life and retain them to H3	As required
Defect repairs	Defect repairs will be completed in response to line patrols and condition assessments. Defects are compiled in our defect management system, and a rating is applied based on urgency	Defect notice

Table 115: Fleet maintenance

13.12.8 Renewal

Our fleet renewal approach is shown in table 116.

Decision	Description
Renewal forecasting	<ul style="list-style-type: none"> The forecast of asset renewals is as described in the fleet strategy
Maintenance forecasting	<ul style="list-style-type: none"> To be developed following the first condition assessment
Determining specific renewal projects	<ul style="list-style-type: none"> Specific renewal projects are identified from the health assessment Site inspections are undertaken to confirm the scope and design for the renewal The renewal projects are prioritised by criticality. The highest priority will be replacing assets in critical locations
Assessing alternatives	<ul style="list-style-type: none"> In normal circumstances, no other options are assessed The exception is where the transformer replacement resulted from a car vs. pole incident. If historical data on car vs. pole incidents indicate the transformer is in a high-risk area, we will consider relocating the transformer
Defect replacement	<ul style="list-style-type: none"> Defects are compiled in our defect management system, and a rating is applied based on urgency. The urgency rating considers the criticality of the asset

Table 116: Fleet renewal forecasting

13.12.9 Material Spares

We currently hold spare conductors and components, including insulators and line hardware. The spares are considered sufficient to cover all reasonably likely events.

The 110kV steel poles are designed for each location and are not interchangeable, and we currently do not hold spares. We must order replacements from the supplier (estimated supply time is at least 12 weeks from overseas manufacturing). We will seek Transpower's assistance with spare concrete poles, either as replacements for the concrete pole line section or as temporary replacements for steel pole section towers.

13.12.10 Population and age

The population and age of the 110kV subtransmission structures and conductor fleet are shown in figure 118 and figure 119. The graphs indicate that no assets are near OOU¹²⁸. The OOU for the structure and conductor are similar.

Our current data show that concrete poles in the 26-35 age bracket are likely to be mass-reinforced. The team will review the exact pole type and update the record accordingly.

¹²⁸ Our initial view is that OOU is somewhere between 50-70 years, with a service life of up to 100 years if properly maintained. For our initial modelling, we have set this at 100 years. The OOU for AAC conductors is 60 years.

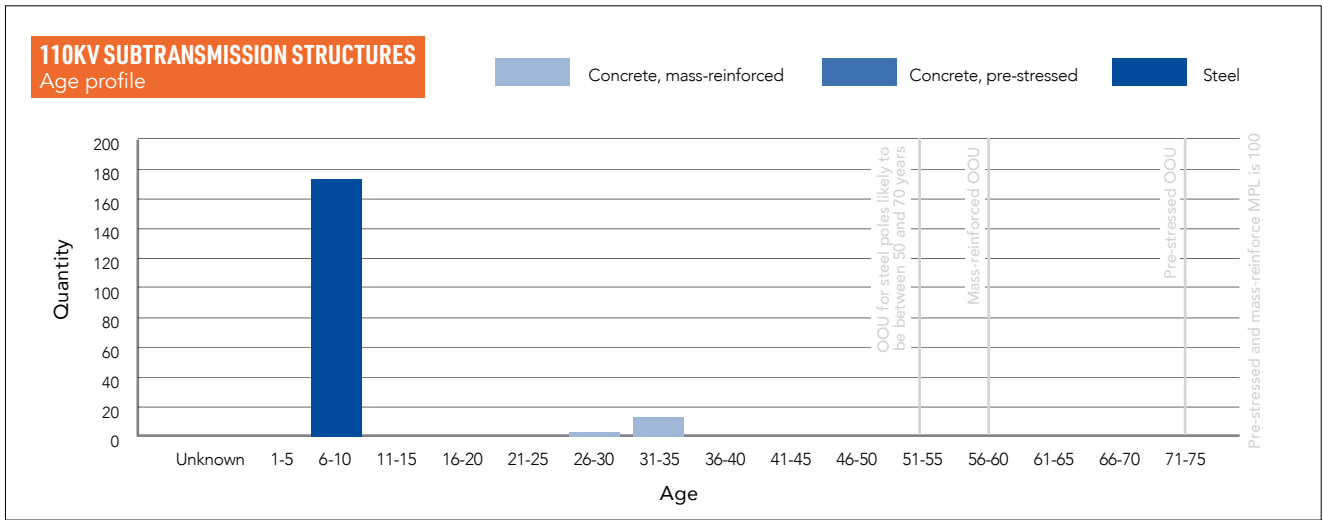


Figure 118: Age profile (110kV structures)

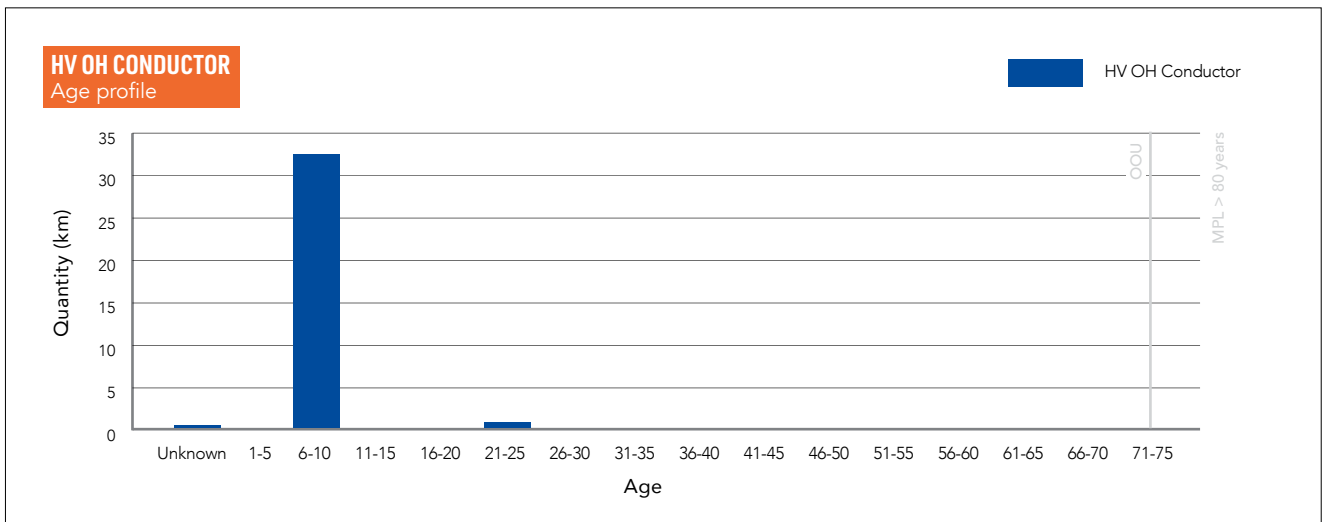
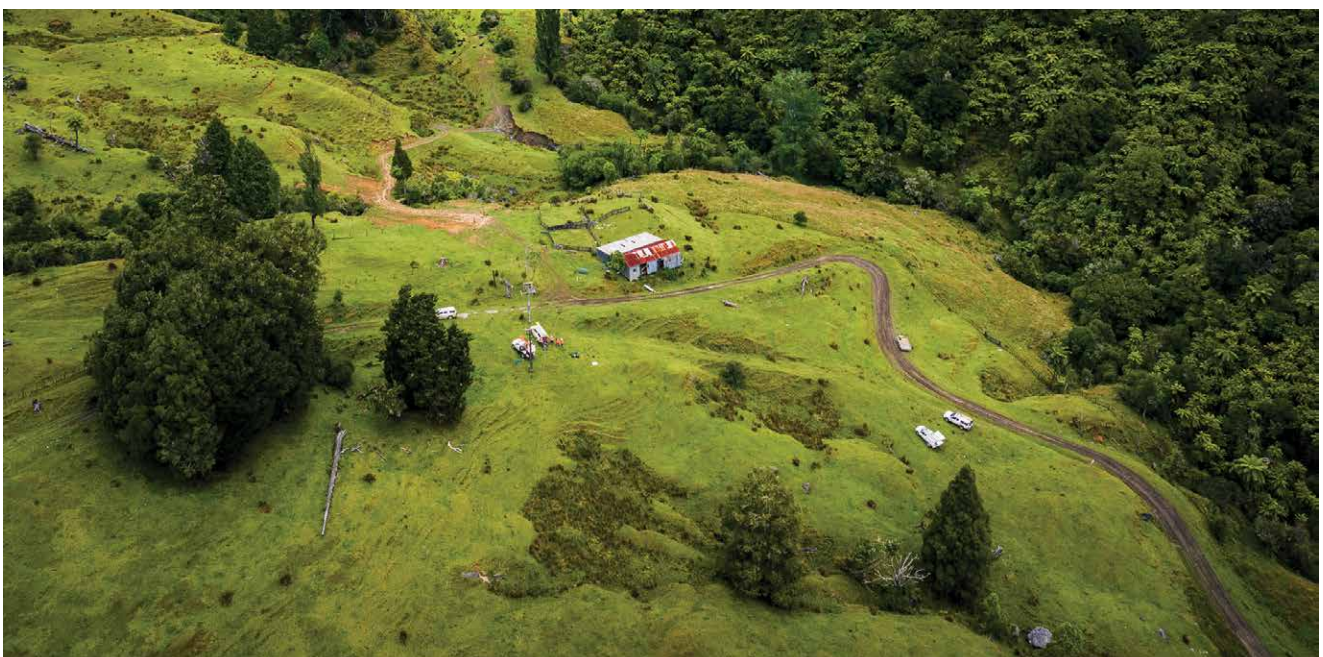


Figure 119: Age profile (110kV conductor)



13.12.11 Asset health

Figure 120 and figure 121 show the health assessment for 110kV subtransmission structures and conductor fleet. It is based on the EEA asset health guide, including the health forecasting discussed in Section 13.5.3. No low-health assets or subcomponents are forecast over the next 10 years. The forecasting is all age-based.

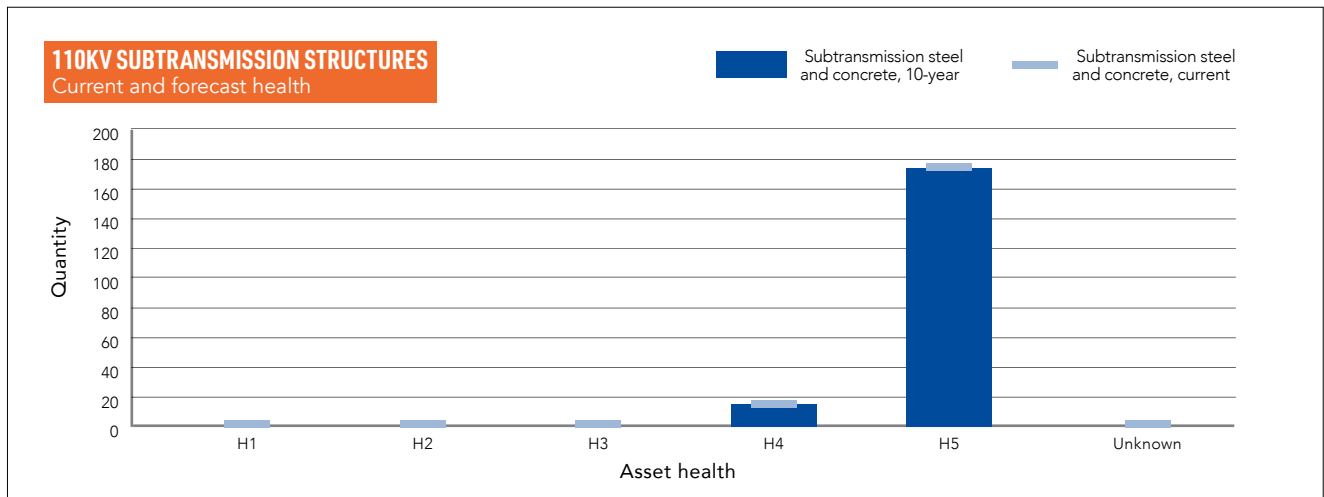


Figure 120: Current and forecast asset health (110kV structures)

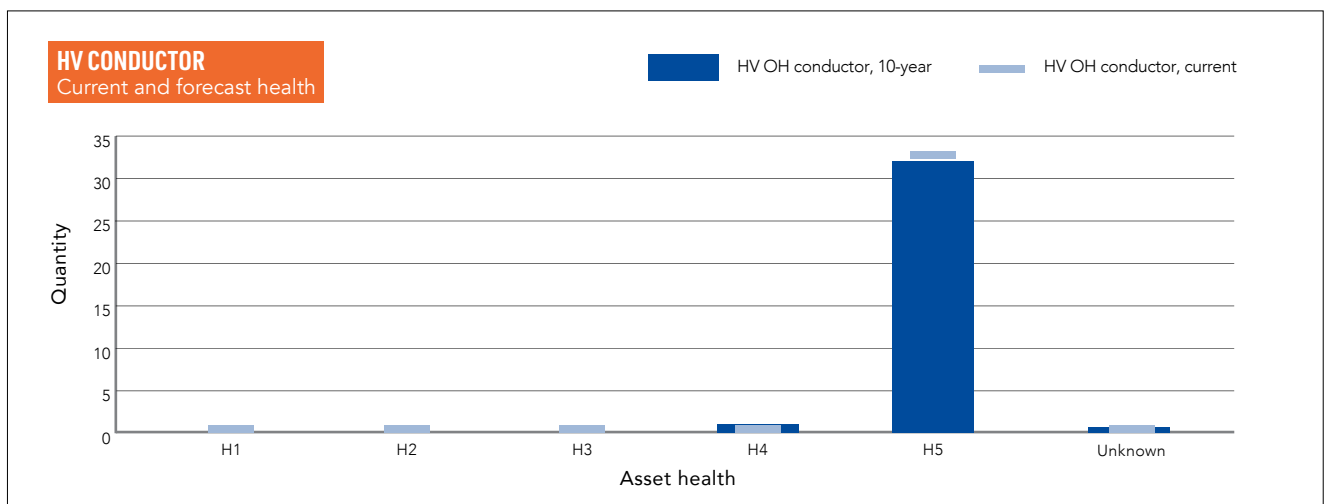


Figure 121: Current and forecast asset health (110kV conductor)

13.12.12 Asset replacements

No asset or subcomponent replacements are forecast over the next 10 years.

13.12.13 Expenditure forecast

No renewal expenditure on the assets or their subcomponents is forecast over the next 10 years.

The line is patrolled annually, and any defects or vegetation issues are promptly addressed, given its criticality.

We have not developed a replacement forecast for this asset. This will need to be prepared following the first condition assessment in 2026. While there is currently maintenance provision in the network opex forecast, some increase in maintenance may occur after the first condition assessment is completed.

13.13 Distribution structures (pole and crossarm) fleet plan

13.13.1 Fleet overview

Overhead lines account for 87% of Waipā Networks total 11kV distribution circuit length. Overhead lines include pole structures (covered in this fleet plan) and conductors (covered in the next fleet plan). Overhead lines are our most significant asset fleet by quantity and the largest by value. This section excludes the 110kV subtransmission structures covered in Section 13.12.

Overhead lines are the network's backbone and provide a means to safely and securely distribute electricity to consumers' homes and businesses. Overhead lines are a cost-effective way of conveying electricity and are generally easy to repair.

Most existing poles (~96%) are concrete of various types (Busck, Stresscrete heavy/light, Window, Brown Brother heavy/light, Bill Young, etc.). Wooden poles are predominantly softwood poles with small patches of hardwood remaining in isolated areas.

As indicated by the age profile (refer to figures 122 and 123), in the 1970s and 1980s, concrete poles were used for new construction and to replace wood poles. Using concrete poles has improved reliability, as failures are rare.

There is a range of failure modes for poles and crossarms. For prestressed concrete poles, cracking can allow water ingress and corrosion of the prestressed tendons, leading to a loss of strength and unexpected failure when load is applied. For mass-reinforced poles, corrosion of the internal reinforcing can occur if water penetrates through cracks. Corrosion of the reinforcing can lead to spalling (loss of concrete cover), further accelerating the corrosion; however, the loss of strength is generally gradual. This deterioration typically occurs slowly and is observable through our detailed inspections.

For wood poles, pole-top rot or ground-line rot are the primary drivers of strength loss that can lead to failure. Rotting is also the primary failure mode for wood crossarms. Pole-top rot is detectable during our pole-top visual inspections; however, ground-line rot requires close inspection and minor excavation. This is undertaken as a separate inspection.

Concrete poles and wooden crossarms have different MPLs. While concrete poles generally remain in serviceable condition, their associated crossarms exhibit end-of-life (EOL) condition drivers (e.g., rot). This mismatch led to a change in approach in 2018 when we commenced using steel crossarms instead of hardwood crossarms. While the initial cost is marginally higher for steel, it extends the structure's lifespan (by aligning pole and crossarm MPLs), increases its mechanical strength, and improves its overall resilience¹²⁹.

We consider the data we used for pole replacements robust. 100% of wood poles have condition data; 38% of concrete poles do. Crossarm data is less complete, with 22% having condition data. The percentage condition data has decreased since our 2024 AMP, as we are now using only

data collected in accordance with our revised assessment standards. We completed a groundline inspection of our wood poles in FY25; therefore, we are confident we understand their condition. Our inspections are ongoing, and the percentage of poles and crossarms with condition data will improve over the coming years.

There is a large quantity of privately owned poles connected to our network that impact our network performance. We will work with the owners of private lines to clarify their obligations as asset owners and offer services for the inspection and maintenance of those assets.

13.13.2 Fleet performance

Poles are generally located where the public can access them and, therefore, need to be installed and designed correctly to ensure public safety. There are no recorded public safety events due to unassisted pole failures.

Regarding reliability, we have recorded nine pole-related faults over the past six years, indicating a pole fault rate of 0.7 faults per 10,000 units per year, excluding adverse weather events (i.e., an unassisted fault rate)¹³⁰. For crossarms, the unassisted fault rate is around 1.6 faults per 10,000 units per year. Industry data on unassisted pole and crossarm fault rates is limited, but it does not indicate a failure rate issue¹³¹. From our data, the performance of poles and crossarms is good.



¹²⁹ Refer WNL's Asset Management strategy Initiative #3.

¹³⁰ Our fault data includes poles, pole stays and stay wire.

¹³¹ Historical data out of Australia reports unassisted pole failure (not faults) at between 2-5 per 10,000 units per year. Ergon Energy crossarm replacement business case to the AER indicated they were seeing unassisted failures at around 2.5 per 10,000 units.

13.13.3 Fleet risks

Table 117 highlights the predominant risks to the pole fleet, their impacts, and our response. The responses to the risk also feature in our fleet strategy.

Risk	Stakeholder impact	Stakeholder linkage	Our response
Third-party interference (Car vs. Pole) damages overhead lines, causing outages and potential contact with live wires.	Car vs. pole outages accounted for an average of 22% of unplanned SAIDI over the past six years. These events can result in injury to the public ¹³² .	Public safety Network performance	Our fleet strategy includes a mitigation plan.
Adverse environments, such as peat, swamps, or waterway eroding foundations, cause poles to lean or fall.	Poles are leaning, causing clearance issues.	Public safety, as clearances of lines can be reduced to unsafe levels	When an issue is identified, remediation is actioned through our defects process, which may include groundline reinforcement or pole relocation.
Major weather events, (e.g. cyclones) can result in wind speeds above older (pre-2000) design limits, causing damage or failure of the pole or crossarm. The fleet performed well over the 2022 cyclone Dovi and 2023 cyclone Gabrielle events, with minimal unassisted failures.	Adverse weather outages accounted for 31% of unplanned SAIDI over the past six years ¹³³ .	Network performance	New structures are designed to current standards that can withstand higher wind loadings. Use material such as steel crossarms to increase mechanical ratings. Appropriate stock holdings that can support asset replacements during major weather events.
Damage from vegetation.	Vegetation outages contributed 16% to unplanned SAIDI over the past six years ¹¹⁴ . Vegetation damage can result in pole failures.	Public safety Network performance	A vegetation management strategy has been developed (refer to Section 13.24.4).
Undetected rotting of larch poles causing pole failures. Industry experience suggests that Larch poles tend to rot from the inside with little visual indications of weakening. The rot could result in unassisted pole failures.	This is a known asset-type issue that requires further investigation.	Public safety, due to unassisted pole failures Network performance	Based on our recent groundline survey we consider this risk to be low.
The strength of some early mass-reinforced poles may be below their current mechanical loading.	A study is currently being undertaken; however it is yet to be determined; current information on failures does not indicate any recent issues.	Public safety, due to unassisted pole failures Network performance	This issue is being further investigated, including testing to confirm the strength of older mass-reinforced poles as a first step.
Unknown condition of private poles that could result in unassisted failures.	Customers may be unaware of their responsibilities or the condition of their poles.	Public safety, due to unassisted pole failures	This is an emerging risk, and we are developing a response strategy.
Asset component failure on poles carrying multi-circuit line sections could cause outages on multiple feeders.	Loss of supply to many customers with a longer time to restore.	Network performance	Acoustic survey for multi-circuit line sections to detect developing issues. Progressively remove multi-circuit setup from the network where the opportunity arises under Resilience, Growth or Renewal programmes.

Table 117: Fleet risks

¹³² The SAIDI data is prior to normalisation for major events.

¹³³ Up until FY24, Waipā included vegetation outages as part of adverse weather during major events. The SAIDI data is prior to normalisation for major events.

13.13.4 Fleet strategy

The objectives for this fleet are to manage the growing presence of EOL condition drivers and to improve resilience as assets are replaced incrementally.

To achieve the fleet objective and address the fleet performance, risks, and other issues mentioned in the preceding sections, the 10-year strategy for this fleet is shown in table 118.

Strategy	Description	Outcome
Common fleet strategies (refer to table 93 in Section 13.6)	<ul style="list-style-type: none"> • Capture condition on all assets to the revised standards within 5 years (FY30) • Enhance asset health assessment and forecasting • Implement risk-based renewal forecasting • Enhance renewal project selection and prioritisation • Understand and reduce fleet risk 	<ul style="list-style-type: none"> • Increase in asset condition data accuracy score • Increase in condition-based forecasting to >95% • Improve the quality of our asset health and renewal forecasting • Improved optimisation of work plans and project timing • Reduce reliability and safety risks
Eliminate all H1 poles and crossarms	<ul style="list-style-type: none"> • Ensure all H1 poles and crossarms (which include red-tagged poles¹³⁴) are replaced before failure • Ensure all H2 poles and crossarms are replaced before they become H1 	<ul style="list-style-type: none"> • Zero H1 poles and crossarms by the end of FY26
Eliminate all low-strength wood poles	<ul style="list-style-type: none"> • Replace all low-strength wood poles within 3-years¹³⁵ 	<ul style="list-style-type: none"> • Zero low-strength wood poles by the end of FY28
Improve the reliability of the worst-performing feeders	<ul style="list-style-type: none"> • The initial focus of the pole and crossarm renewal is on the worst-performing feeders 	<ul style="list-style-type: none"> • Improve the reliability of the worst-performing feeders
Vegetation strategy	<ul style="list-style-type: none"> • Refer to Section 13.24.4 	<ul style="list-style-type: none"> • Reduction in vegetation-related outages
Minimise private pole safety risks	<ul style="list-style-type: none"> • Consult with the industry (as this is a common issue) and leverage learnings from others. • Develop a plan and process for the management of private poles (and capture additional data if needed). 	<ul style="list-style-type: none"> • Minimise public safety risks SFARP
Reduce the number of car vs pole incidents.	<ul style="list-style-type: none"> • Develop a plan to mitigate car vs. pole incidents. This will include the analysis of car vs. pole data and developing solutions such as undergrounding, relocation or installing barriers 	<ul style="list-style-type: none"> • Minimise the impact of third-party incidents on the network performance
Enhance fleet resilience (refer to Section 9.4)	<ul style="list-style-type: none"> • Replace H2 wood crossarms with steel on critical feeders • Proactively replace H2 wood poles in critical feeders • Proactively identify and replace mass-reinforced poles under heavy loading (e.g., stayed, angle pole) in critical feeder sections • Ensure all pole renewals are designed to NZS7000 • Ensure all foundations are assessed for pole renewals • Investigate raising the wind-speed design limits (to future-proof current design) • Following the recent cyclones, the stock levels are being reviewed 	<ul style="list-style-type: none"> • Increase the mechanical strength of the structure • Potential increase in stock levels

Table 118: Fleet strategy

¹³⁴ Red tag poles are defined as poles which are unsafe to climb and cannot support the mechanical weight they are supporting. Recommended replacement time is within three months.

¹³⁵ As assessed during the wood pole ground line survey.

13.13.5 Design and construct

Waipā Networks designs new and replacement poles to the AS/NZS 7000 standard, which specifies the clearance requirements, seismic, wind and snow design parameters, and safety factors applicable to overhead line design. The standard defines a “security level” that establishes design parameters for the line’s safety and utility requirements. We apply the highest “level 3” requirement for all main lines and “level 2” for remote spur lines. This approach ensures the highest level of utility is applied to the core network and that remote areas, where few customers are connected, have a fit-for-purpose design.

Our current standard is to use prestressed concrete poles. These have higher mechanical strength and a higher OOU than other mass-reinforced concrete poles.

We have developed standard construction drawings and bills of materials for most typical pole-and-line configurations. These drawings were prepared with representatives from across the organisation to ensure they work in design, regulation, and practicality.

13.13.6 Monitoring

Capturing condition data for overhead assets (poles, crossarms, conductors¹³⁶, and pole-mounted fuses, switches, links, and ABSs) generally occurs during a single inspection. The exceptions are voltage regulators, reclosers and enclosed switches, which have a separate inspection routine (refer to the recloser fleet plan for details).

Our baseline inspection occurred in FY22 in rural areas and in FY24 and FY25 in urban areas. We are now inspecting on a five-year rolling plan. Table 119 describes our current fleet monitoring approach.



Monitoring type	Description	Frequency
Detailed line inspection	<ul style="list-style-type: none"> Our baseline visual inspection has been aerial using helicopters in rural areas and drones in urban areas. Inspections are now ground-based and utilise the new inspection standard, and capture asset attribute data as required The detailed visual inspection captures the EOL condition drivers, which (under the new standard) include the condition of the pole, crossarms, insulators, stays, jumpers, binders, terminations, other accessories attached to the poles, and foreign interference Defect notices are raised where priority repair or replacement is required 	Every five years
Acoustic survey for multi-circuit line sections	<ul style="list-style-type: none"> Carry out acoustic surveys for multi-circuit line sections to detect emerging failures early 	Every two years
Below-ground inspection	<ul style="list-style-type: none"> We undertook a below-ground inspection to capture additional condition data for wood poles in FY25. The additional EOL condition drivers will include the extent of rot and decay (and the diameter lost) An assessment was then made of the residual pole strength and health Defect notices were raised where priority repair or replacement is required 	First survey in FY25 Subsequent survey not yet scheduled
Line patrol	<ul style="list-style-type: none"> A drive-by patrol of the line and visual inspection for feeders of concern Minor repairs may be performed, or defect notices are raised where priority repair or replacement is required 	As required in response to fault issues or reliability trends

Table 119: Fleet monitoring

¹³⁶ Near to the pole only.

13.13.7 Maintaining

There are three maintenance activities that we undertake to ensure that poles are fit for purpose and can maximise their economic life; these are:

Maintenance	Description/scope of work	Trigger
Concrete repair	Patching concrete that has been hit/damaged or where corrosion has exposed reinforcing steel. This only occurs where we are comfortable that there has not been a material impact on the residual strength of the pole	Defect notification
Relocation or realignment	Relocating or realigning poles that are on a lean due to ground conditions (peat soil or soil erosion near waterways), high winds, broken stays, etc.	Defect notification
Subcomponent replacement	Replacement of components (insulators, binders, jumpers, stays, etc.) Identification of one component defect will typically result in all subcomponents being replaced to avoid further subcomponent defects being identified (as they will be typically of the same age)	Defect notification

Table 120: Fleet maintenance

Note: Waipā considers the replacement of crossarms to be a capital expenditure, and this work is included in the renewal section below.

13.13.8 Renewal

Our fleet renewal approach is shown in table 121. Resilience considerations occur at the works optimisation stage.

Decision	Description
Renewal forecasting	<ul style="list-style-type: none"> The forecast of asset renewals is as described in the fleet strategy.
Determining specific renewal projects	<ul style="list-style-type: none"> Specific renewal projects are identified from the health assessment and are grouped by location and feeder Site inspections are undertaken to confirm the scope and design for the renewal The renewal projects are prioritised by criticality, worst-performing feeder, and reliability trends. The highest priority will be replacing poles with compromised strength in critical locations that could present a public safety risk.
Assessing alternatives	<ul style="list-style-type: none"> Alternatives to like-for-like replacements are considered on a case-by-case basis and include: <ul style="list-style-type: none"> Undergrounding: This is considered if a line is in a high-density area or clearances cannot be maintained based on the contour of the land Relocating: If historical data on car vs. pole incidents indicate the pole is in a high-risk area, we will consider relocation or undergrounding to reduce or remove the risk Design: We will determine whether a like-for-like replacement is appropriate for the current situation and ensure that current design standards are met Opex/capex trade-off: Due to the high site establishment cost associated with line work, we tend to proceed with asset replacements rather than repairs (except as mentioned in the maintenance section) A cost/benefit analysis will be completed as part of the assessment.
Defect replacement	<ul style="list-style-type: none"> Defects are compiled in our defect management system, and a rating is applied based on urgency. The urgency rating considers the criticality of the asset Where possible, defects are combined into a single work-pack to maximise the work undertaken in a single network outage.

Table 121: Fleet renewal forecasting

13.13.9 Material Spares

Poles and crossarms are common assets that are exposed to adverse weather events. We hold sufficient stock to cover any reasonable situation that may arise. We increase our stockholding when supplier deliveries are constrained and lead times are extended.

13.13.10 Population and age – poles

The population and age of our pole fleet assets are shown in figure 122 and figure 123. These graphs indicate that:

- 19% of concrete mass-reinforced and unknown poles are above OOU¹³⁷. This is an age where signs of deterioration and the associated risks are growing. No concrete poles have reached MPL.

- 60% of hardwood poles are at or above OOU¹³⁸. The number of hardwood poles beyond OOU reflects the age profile of that fleet. Only one hardwood pole is above MPL (we assessed a Waipā Networks-specific MPL for hardwood poles at 70 years based on our survival statistics¹³⁹).
- 100% of the larch poles and 91% of the softwood poles are at or above OOU. This is based on a revised 30-year OOU (up from 15 years suggested by the EEA). We revised our OOU based on the results of our ground line survey. 11% of larch and 4% of softwood poles have reached MPL.

The data suggest that, by age, EOL condition drivers will begin to emerge for the mass-reinforced concrete and wood fleets.

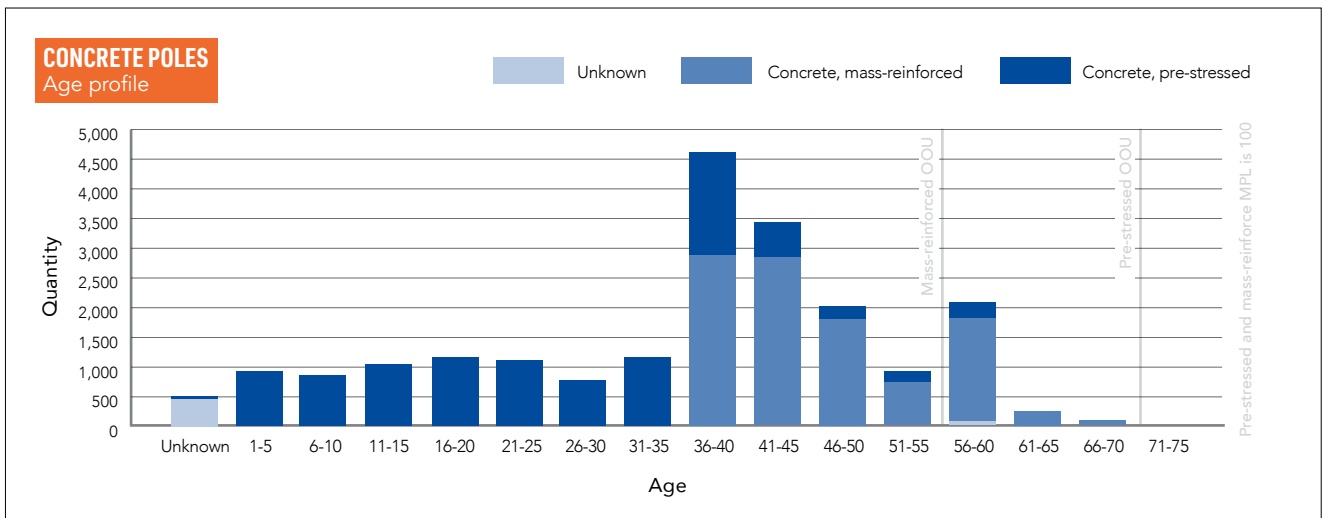


Figure 122: Concrete pole age profile

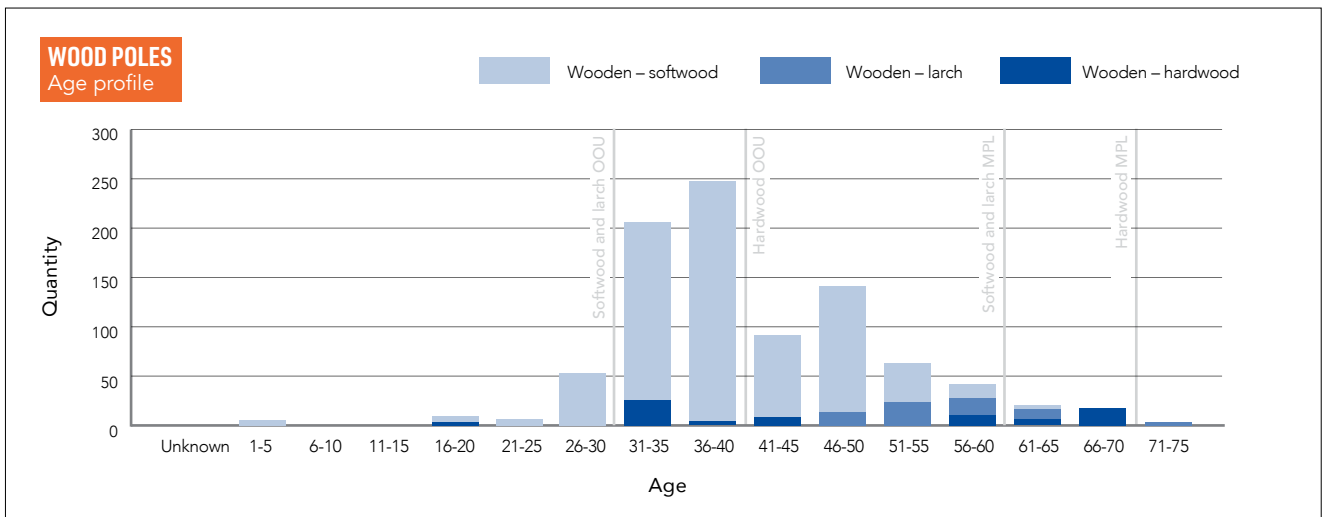


Figure 123: Wood pole age profile

¹³⁷ Mass-reinforced concrete poles have an OOU of 55 years and prestressed have an OOU of 70 years. MPL for all concrete poles is 100 years.

¹³⁸ Softwood and hardwood poles have an OOU of 15 and 40 years respectively, based on the EEA guide.

¹³⁹ MPL is defined as the age at which 95% of the poles could be expected to have been replaced. We increased the MPL of hardwood poles from 60 to 70 years based on survival statistics. This was based on disclosure data, which showed that 94% of 1950s poles (average age 68 years) have survived since 2013, and 79% of 1960s poles (average age 64 years) have survived since 2013. Whilst we don't have data prior to 2013, our understanding is that there has not been any extensive renewal programme prior to 2013; hence, the current data suggests that well more than 5% of the assesses are surviving beyond the 60-year MPL defined in the EEA standards. Management's view is that an MPL of 70 is reasonable for our fleet based on asset condition. This equates to assets being generally replaced between 60 and 70 years.

13.13.11 Asset health assessment – poles

The health assessment for poles is shown in figure 124 and figure 125, and is based on the EEA asset health guide, including the health forecasting discussed in Section 13.5. The data used for wood-pole health forecasting is robust,

with 100% of pole health being condition-based. For concrete poles, 38% is condition-based; however, given the age profile of those assets, health issues are not expected to be material.

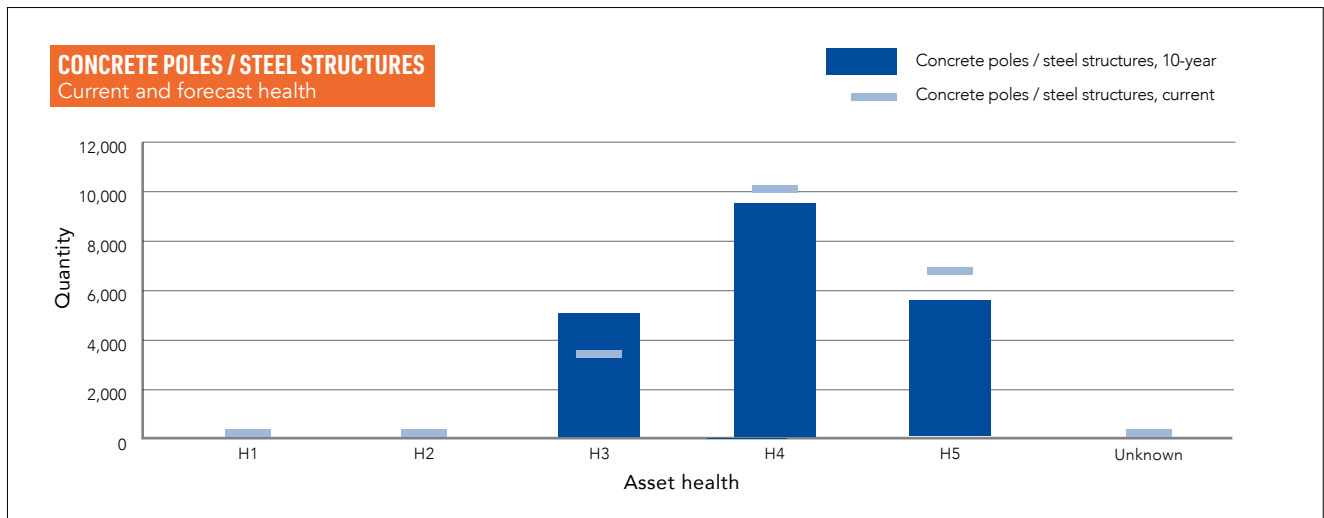


Figure 124: AHI concrete poles

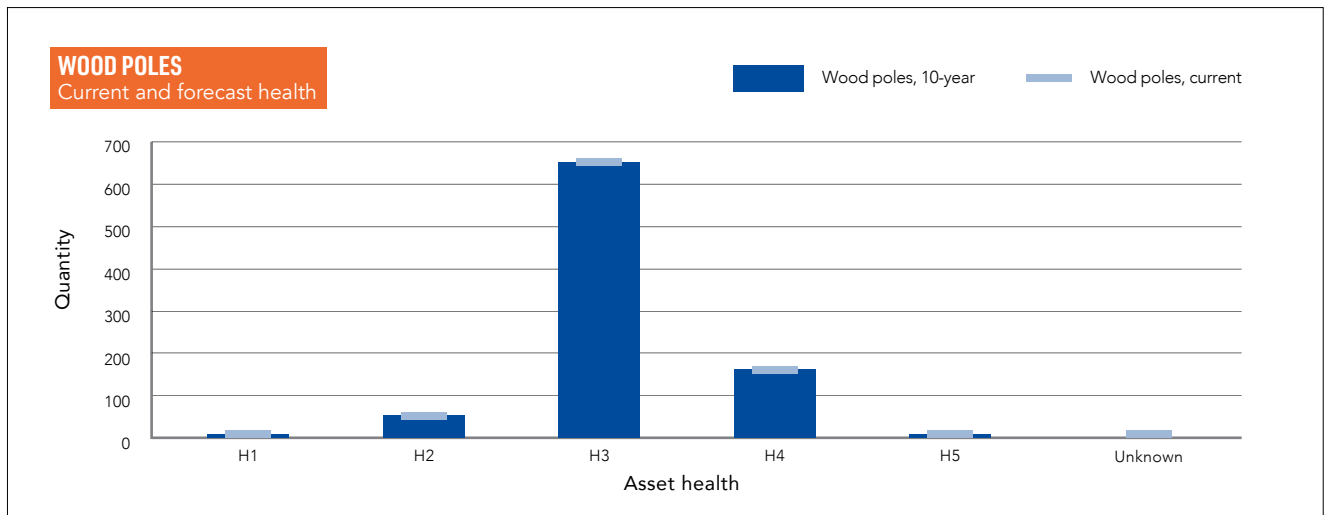


Figure 125: AHI wood poles

Table 122 shows the current and forecast quantities for low-health poles over the next 10 years. There is a significant population of wood poles (mostly softwood) that meet the criteria for renewals and a small number of mass-reinforced concrete poles. The forecast low health poles are almost all condition-based (98% for concrete and 96% for wood).

The quantity of wood pole renewals has reduced significantly from that included in the 2024 AMP. The 2024 AMP forecasts for wood poles were mostly age-based. Since that AMP, we have completed a ground-line survey of those poles, including the fleet, which was found to be in better health than age-based forecasts previously suggested.

Type	Quantity	Grade H1 & H2 (Current)	Grade H1 & H2 (+10yrs)	% of fleet at grade H1 & H2 (+10yrs)
Concrete Poles	21,286	192	196	0.9%
Wood Poles	896	66	68	7.6%
Total	22,182	258	264	1.2%

Table 122: Current and forecast asset health

13.13.12 Population and age – crossarms

The population and age of our crossarm fleet assets are shown in figure 126. Most of the age data is derived from the pole, with only 15% relating to the crossarm installation

date. The graph indicates that around 37% of hardwood crossarms are above OOU, but only around 1.5% above MPL. The data indicates that, based on age, EOL condition drivers are emerging.

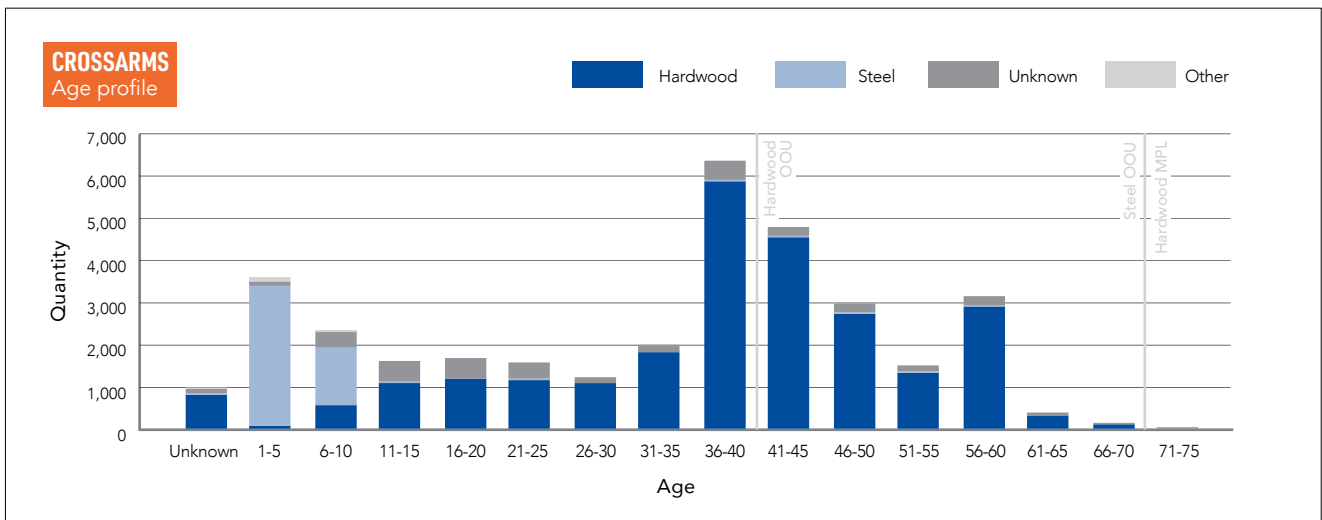


Figure 126: Age profile – crossarms

13.13.13 Asset health assessment – crossarms

The health assessment for crossarms is shown in figure 127 is based on the EEA asset health guide, including the health forecasting mentioned in Section 13.5.3.

The data used for crossarm health forecasting is not yet robust, with 22% of crossarms being condition-based and a large portion age-based, based on pole age. Our assessment of current and forecast asset health is based on extrapolating condition-based data. Hence, this should be taken as an indicator of the fleet’s health. We are inspecting one fifth of the network each year, so the quality of our forecasts will improve over the next couple of years. At which time, we will review the renewal forecasts.

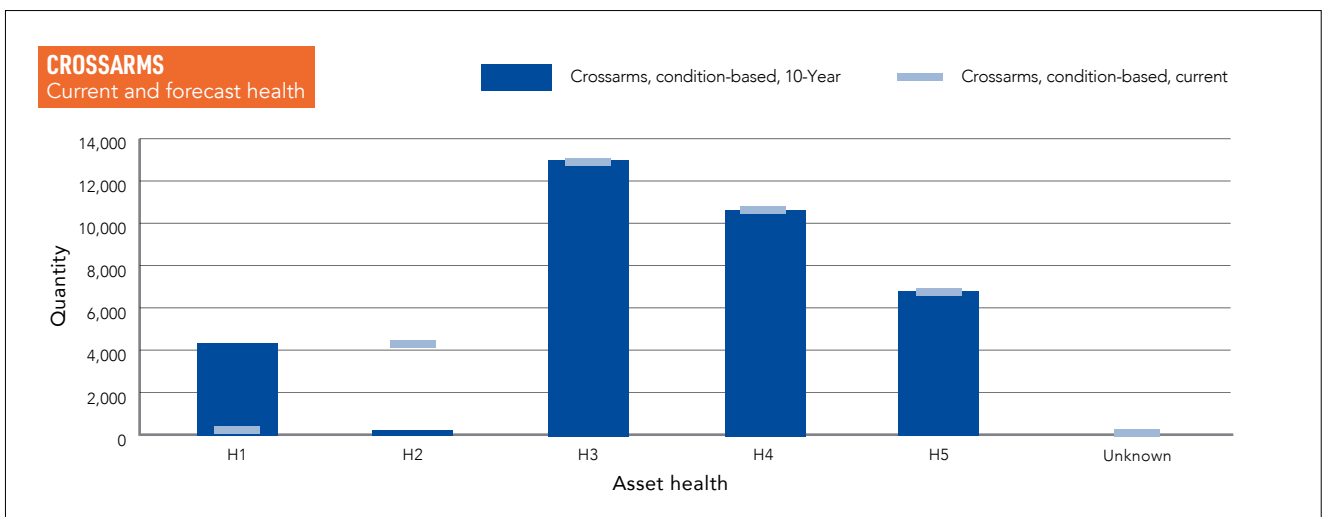


Figure 127: AH1 – crossarms

Table 123 shows the current and forecast quantities for low-health crossarms over the next 10 years. Based on extrapolating current health data, 13% of the fleet (all hardwood) meet the criteria for renewal. Concerning low health crossarms, only 18% are assessed based on condition.

Type	Quantity	Grade H1 & H2 (current)	Grade H1 & H2 (+10yrs)	% of fleet at grade H1 & H2 (+10yrs)
Crossarm	34,282 ¹⁴⁰	4,501	4,501	13.1%

Table 123: Current and forecast asset health

13.13.14 Replacement programme

Forecast renewals are shown in table 124. Our renewal strategy is to replace all H1 and H2 poles and crossarms over the next 10 years. The total concrete and wood pole replacements exceed the forecast H1+H2. We are forecasting to replace all H1+H2 wood poles over the next five years. We have extended wood pole replacements over the second five years in anticipation of the continuing deterioration of that fleet, and will undertake follow-up ground line survey over the next five years to provide new condition data.

Crossarm renewals are a continuation of that set in the 2025 AMP. The renewal rate is slightly behind the forecast for H1+H2 assets (an extrapolation of current health data); however, this will be adjusted as our crossarm health data improves over the next couple of years.

Type	Grade H1 & H2 (+10yrs)	10yr forecast replacements
Concrete poles	196	196
Wood poles	68	130
Crossarms	4,501	4,298

Table 124: Asset Renewal Forecast

Our approach for FY27 and FY28 is to prioritise crossarm and pole renewals on our worst-performing feeder (Kāwhia, Pukeatua, Roto-o-Rangī) and other feeders with a high concentration of low-health assets.

13.13.15 Expenditure forecast

Table 125 shows the forecast expenditure for this fleet. The forecast expenditure is \$25.9m, which is broadly consistent with the amount included in the 2025 AMP.

The renewal provision for "other drivers" accounts for storm (in a typical year) and vehicle damage.

Description	Type	Category	FY27	FY28	FY29	FY30	FY31	FY32-36
Concrete pole renewal	Planned	ARR	304	276	276	276	276	1,297
Wood pole renewal	Planned	ARR	221	221	193	193	193	773
Crossarm renewal	Planned	ARR	1,982	1,982	1,982	1,973	1,982	9,890
Pole replacement, other drivers	Unplanned	ARR	68	68	68	68	68	341
Crossarm replacement, other drivers	Unplanned	ARR	90	90	90	90	90	451
Total	-	-	2,664	2,637	2,609	2,600	2,609	12,752

Table 125: Forecast expenditure

¹⁴⁰ This quantity of crossarms has reduced over that included in the 2024 and 2025 AMP. This is a result of data improvements we are making to the GIS.

13.14 Distribution and LV overhead conductor fleet plan

13.14.1 Fleet overview

Overhead lines comprise 87% of our distribution circuit length and 55% of LV circuit length. Overhead lines include poles and crossarms (covered in the previous fleet plan) and conductors (covered in this fleet plan). This fleet plan includes 11kV and LV conductors, as shown in table 126.

Asset type	Quantity
11kV conductor	1,231km
LV conductor	497km

Table 126: Conductor fleet circuit length

Asset type	Approximate % of the fleet	Attributes
All aluminium conductor (AAC)	<1%	AAC uses high-purity aluminium, giving it good conductivity, minimal weight, and low strength. This limits the span lengths.
AAC covered	<1%	In many LV applications, the conductor is covered in PVC to provide a layer of insulation. AAC was typically used as span lengths are shorter in LV applications because of its good conductivity. We will validate this data, whether any are used for HV application.
Aluminium conductor steel reinforced (ACSR)	11%	ACSR has an inner core of solid or stranded steel and one or more outer layers of aluminium strands. This gives it high strength at a modest weight. ACSR is commonly used in rural areas where long spans make construction efficient. The steel core can be either greased or non-greased. The greased steel cores increase the OOU and MPL of the conductor.
All aluminium alloy conductor (AAAC)	2.6%	AAAC uses aluminium alloy, which gives it greater tensile strength than AAC and is significantly lighter than ACSR. AAAC also has good conducting properties. This type of conductor is now commonly used.
Copper	46%	Hardened copper was used early in the development of distribution networks. It is highly conductive, with good strength and weight, but is expensive.
Copper, covered	7%	As above, covered in PVC insulation. Typically used for LV.
Steel	<1%	Steel is very strong and was used for long spans on remote spur lines. Only small steel conductors (often No.8 wire) were used, so they were light but had poor conductivity. Steel is no longer used. The team will validate this data.
Unknown	32%	We have significant conductors of unknown type. It is challenging to determine conductor types from ground-based visual inspections. We suspect the unknown type was introduced during the NCS to GIS migration. We will go through a discovery and recovery process.

Table 127: Conductor type

There are a range of failure modes for conductors. These can be incremental, where health decays over time, or more acute, where failure is caused by foreign interference (e.g. vegetation). Incremental failure includes reductions in strength due to movement and wear, heat cycling, and corrosion. Other failure modes include failures of bindings, terminations, and joints (due to any of the reasons mentioned above). The location and environment can significantly impact the rate of deterioration.

Conductors need to have good conductivity (to minimise losses and voltage drop on long feeders), good strength (to optimise span lengths and withstand wind and mechanical loads), minimal weight (to optimise the strength of the poles needed), and resistance to wear (to minimise the risk of failure from movements due to wind forces over many years). There are seven main conductor types on the network. Each conductor type has its unique properties and differences in OOU and MPL. Table 127 summarises the main conductor types.

We do not have reliable age or health data for this fleet. Capturing condition inputs is complex and requires close-proximity inspection or sample analysis. As a result, our health forecasting is age-based for this fleet. Specific renewal projects are driven by failure and reliability data and detailed inspections, which give the best indication of asset health (in the absence of sampling). The challenge is reacting quickly to reliability trends to avoid impacting customers.

Note: This fleet plan excludes the 110kV subtransmission and streetlighting conductor.

13.14.2 Fleet performance

Overhead lines are generally located where the public can access them, therefore, conductor failures can have public safety implications. There are no recorded public safety events due to conductor failures.

We do not have detailed failure data for conductors (which are currently grouped with cable in our outage cause analysis). However, we have identified specific areas (Kāwhia, Pukeatua and Pokuru) that require further investigation to determine the causes of recent conductor faults. These investigations may drive specific renewal projects. Other than the identified areas, we do not have any concerns with the fleet performance.

Future changes to the fault recording system will provide additional data to enable analysis of fault trends.

From FY25 our fault recording now captures cable and conductor separately but it will be a while before we accumulate a dataset large enough to support detailed analysis.

13.14.3 Fleet risks

Table 128 highlights the predominant risks posed to the conductor fleet, its impact, and our response. The responses to the risk also feature in our fleet strategy or other strategies and programmes in this AMP.

Risk	Stakeholder impact	Stakeholder linkage	Our response
Damage from vegetation	Vegetation outages contributed 16% to unplanned SAIDI over the past six years ¹⁶ . Vegetation damage can result in conductors breaking and falling	Public safety Network performance	A vegetation management strategy has been developed (refer to Section 13.24.4)
Conductor failure leads to electrocution risk for people and livestock, either directly from the conductor or indirectly through the livening of fences or structures.	Electrocution or electric shock Loss of livestock Network outages	Public safety Network performance	Electrical protection at zone substations, reclosers, spur line fuses, and LV fuses (in the case of LV conductor) operating to isolate the line when faults occur. Prompt response to reliability trends, fault trends and defects to replace poor health conductors
Conductor failures lead to fires that impact forestry plantations, crops, and buildings.	Loss of property	Network performance	As above Fire mitigation policy also prohibits auto reclosing when a “high fire risk” is declared.
Vehicles or machinery contacting live conductors risk electrocution and equipment damage.	Electrocution or electric shock Damage to equipment Network outages	Public safety Network performance	Electrical protection, as mentioned above We have a public safety campaign to raise awareness of risks around live lines. Identifying low and high-risk conductors during detailed inspections and raising or undergrounding the line Using a permit procedure for working near live lines
Members of the public working near live conductors risk electrocution	Electrocution or electric shock Network outages	Public safety Network performance	We have a public safety campaign to raise awareness of risks around live lines. Using a permit procedure for working near live lines
Third-party interference (Car vs. Pole) damages overhead lines, causing outages and potential contact with live wires.	Car vs. pole outages accounted for an average of 22% of unplanned SAIDI over the past six years. Vehicle damage can result in conductors breaking and falling	Public safety Network performance	Our fleet strategy includes a mitigation plan

Table 128: Fleet risks

13.14.4 Fleet strategy

The objective for this fleet is to convey electricity to consumers reliably and efficiently, while managing public safety risks through prompt identification and remediation of low-health assets.

To achieve the fleet objective and address the fleet performance, risks, and other issues mentioned in the preceding sections, the 10-year strategy for this fleet is shown in table 129.

Strategy	Description	Outcome
Common fleet strategies (refer table 93 in section 13.6)	<ul style="list-style-type: none"> Enhance asset health assessment and forecasting (Note: this is a key strategy for this fleet as we are relying on improved fault and reliability analysis to identify low health assets and drive the renewal projects) Implement risk-based renewal forecasting Enhance renewal project selection and prioritisation Understand and reduce fleet risk 	<ul style="list-style-type: none"> Increase in asset condition data accuracy score Increase in condition-based forecasting to >95% Improve the quality of our asset health and renewal forecasting Improved optimisation of work plans and project timing Reduce reliability and safety risks
Improve conductor attribute and age data	<ul style="list-style-type: none"> Refer to the asset management improvement plan (Section 9.6.3) 	<ul style="list-style-type: none"> Age-based renewal forecasting
Assess new condition assessment techniques.	<ul style="list-style-type: none"> We will monitor industry development concerning conductor condition assessments. These will be adopted where practical to do so 	<ul style="list-style-type: none"> Improved condition assessment, more accurate health forecasting, and more proactive health-based renewals
Undertake conductor inspections and risk mitigations in areas with a high risk of failure.	<ul style="list-style-type: none"> Undertake a study to identify areas where conductor failures are at higher risk. This will include assessing reliability trends, fault trends, and environmental factors (high crosswind and coastal conditions) Undertake detailed inspections of conductor joints, jumpers and terminations to assess EOL drivers and the health of the conductors Consider renewal or remediation options (e.g. rebinding, vibration dampeners, etc) to reduce risk 	<ul style="list-style-type: none"> Replacement of low-health and high-risk conductors
Vegetation strategy	<ul style="list-style-type: none"> Refer to Section 13.24.4 	<ul style="list-style-type: none"> Reduction in vegetation-related outages
Maintain conductor clearances and remove high-risk road crossings	<ul style="list-style-type: none"> We have a specific program to maintain line clearances and remove high-risk road crossings. Refer to Section 12.7.4 	<ul style="list-style-type: none"> Reduce vehicle and machinery damage to conductors Minimise public safety risks SFARP
Public safety campaign to raise awareness of risks around live lines	<ul style="list-style-type: none"> Annual social media campaign as part of our Public Safety Management System and its KPI 	<ul style="list-style-type: none"> Minimise public safety risks SFARP
Reduce the impact on network performance of car vs. pole incidents	<ul style="list-style-type: none"> Develop a mitigation plan following the analysis. Refer to the Distribution Structures Fleet Plan 	<ul style="list-style-type: none"> Minimise the impact of third-party incidents on the network performance

Table 129: Fleet strategy

13.14.5 Design and construct

Conductor selection and design are integrated into the line design process, which complies with the AS/NZS 7000 standard. The standard specifies the clearance requirements, seismic, wind and snow design parameters, and safety factors applicable to overhead line design.

As a general guide, our standard conductor specifications are:

- Primarily AAAC conductor – some AAC used on LV
- ACSR where it is required for long spans in rural areas (typically based on mechanical loading).

Special consideration is given to unique circumstances, for example, the use of covered conductors in locations susceptible to windborne debris.

13.14.6 Monitoring

Capturing condition data for overhead assets (poles, crossarms, conductors¹⁴¹, and pole-mounted fuses, switches, links, and ABSs) generally occurs during a single inspection.

Our baseline inspection occurred in FY22 in rural areas and in FY24 and FY25 in urban areas. We are now inspecting a five-year rolling plan. Table 130 describes our current fleet monitoring approach.

Monitoring type	Description	Frequency
Detailed line inspection	<ul style="list-style-type: none"> This visual inspection provides some data on conductor binders and terminations, but its holistic nature may not reveal the specific condition. Refer to the Distribution Structures Fleet Plan for further details. 	Every five years
Detailed conductor inspection	<ul style="list-style-type: none"> This detailed visual inspection focuses on joints, binders, terminations, and near-pole conductors. This inspection will assess EOL drivers concerning wear damage, evidence of internal corrosion in ACSR (bird nesting), wear damage on binders and broken conductor strands Conductor samples may be taken if needed Defect notices are raised where priority repair or replacement is required. 	As required by the conductor performance and risk assessment
Line patrol	<ul style="list-style-type: none"> A drive-by patrol of the line and visual inspection at sites of concern Minor repairs may be performed, or defect notices are raised where priority repair or replacement is required. 	As required in response to fault issues, reliability trends or criticality

Table 130: Fleet monitoring

13.14.7 Maintaining

There are no specific maintenance servicing routines for conductors. We may undertake reactive binder and joint replacements when they are identified during inspections.

13.14.8 Renewal

Our fleet renewal approach is shown in table 131.

Decision	Description
Renewal forecasting	<ul style="list-style-type: none"> We do not have reliable asset health data for this fleet. Our current renewal forecast is based on historical estimates of conductor renewals. Known issues will be added to the forecast as required. We will move to age-based renewal forecasting when the age data improves.
Determining specific renewal projects	<ul style="list-style-type: none"> Renewal projects are determined from reliability trends, fault trends and detailed inspections. The assessments are prioritised by criticality and the worst-performing feeder.
Assessing alternatives	<ul style="list-style-type: none"> Alternatives to like-for-like replacements are considered on a case-by-case basis and include: <ul style="list-style-type: none"> Undergrounding: This is considered if a line is in a high-density area or clearances cannot be maintained based on the contour of the land Design: We will determine whether a like-for-like replacement is appropriate for the current situation, ensure that current design standards are met, and assess concurrent conductor capacity upgrade opportunities A cost/benefit analysis will be completed as part of the assessment.
Defect replacement	<ul style="list-style-type: none"> Defects are compiled in our defect management system, and a rating is applied based on urgency. The urgency rating considers the criticality of the asset Where possible, defects are combined into a single work-pack to maximise the work undertaken in a single network outage.

Table 131: Fleet renewal forecasting

¹⁴¹ Near to the pole only.

13.14.9 Material spares

Conductor is a common asset that is exposed to adverse weather events. We hold sufficient stock to cover reasonable situations, i.e., a range of conductor sizes to cover fault repairs, and we have supply arrangements to replenish spare stock and support new developments.

13.14.10 Population and age

The population and age of our conductor fleet assets are shown in figure 128. As discussed earlier, there is low confidence in the age and condition data for conductors. The age data has been derived from the installation date when known. For assets older than 20 years, their age is unknown or set to a default age. We are undertaking some further work (refer to Section 9.6.3 to populate conductor age from adjacent assets installed at similar times (e.g. pole).

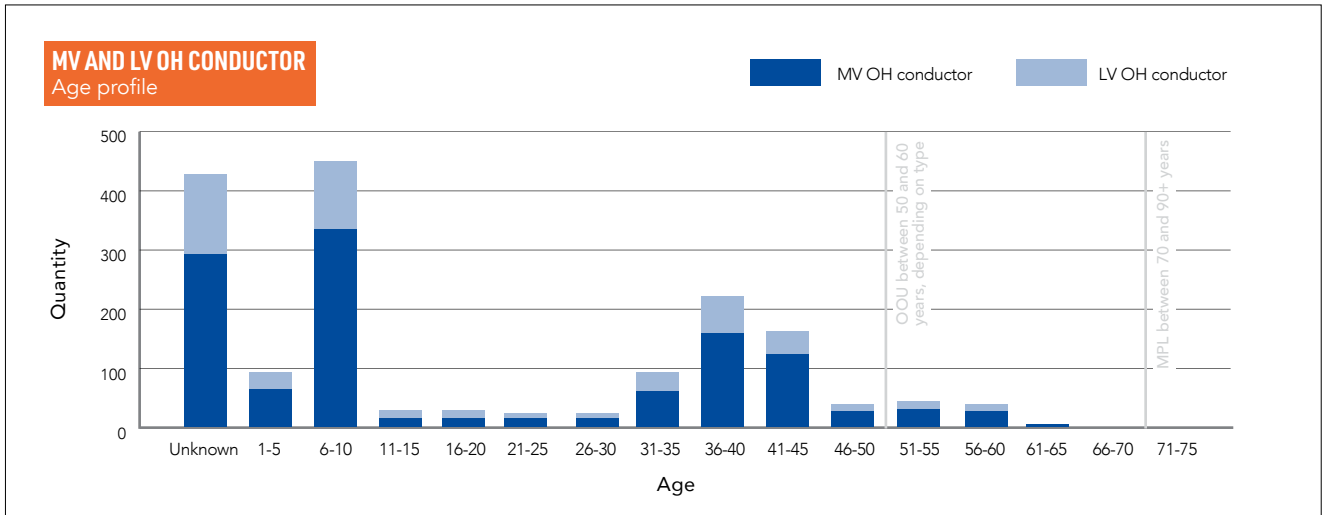


Figure 128: Age profile (km)

13.14.11 Asset health assessment

The health assessment for 11kV and LV conductors is shown in figure 129 and figure 130. The assessment is age-based using the EEA asset health guide, including the health forecasting discussed in Section 13.5. As noted above, the age data is unreliable, hence these forecasts are not yet reliable. Our health forecasting will improve following the data improvements.

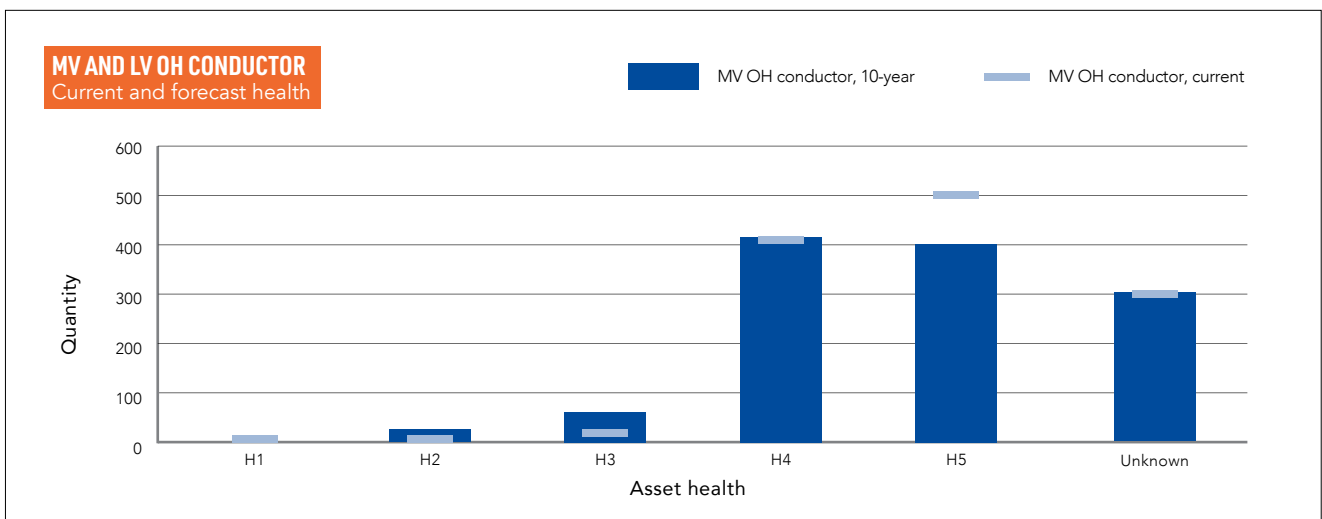


Figure 129: AHI, 11kV conductor (km)

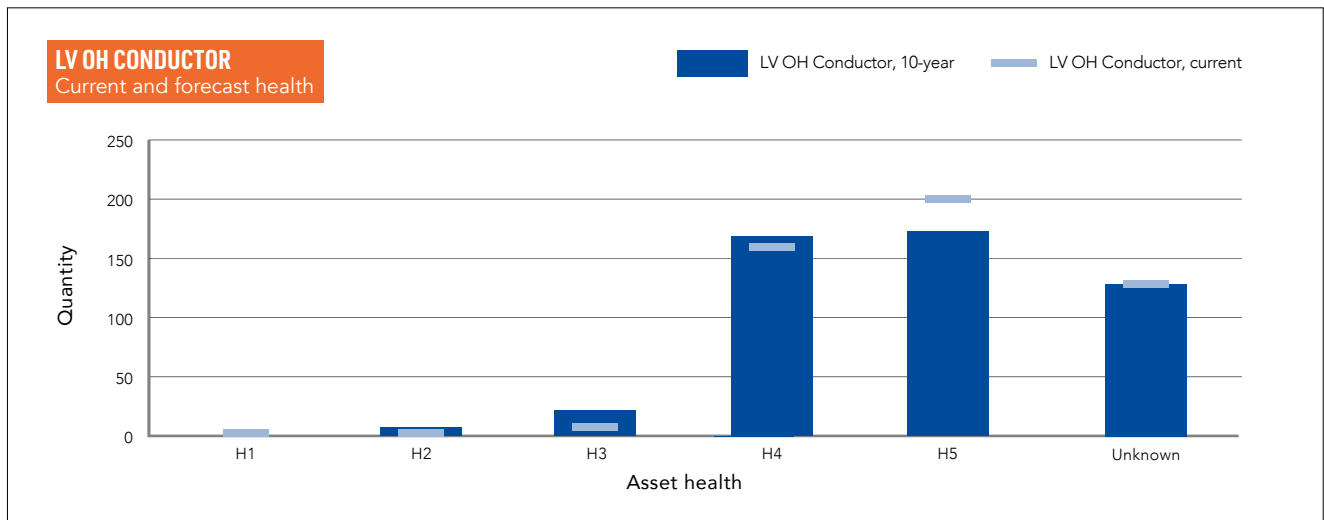


Figure 130: AHI, LV conductor (km)

We do not presently have a reliable estimate of the assets that will reach health grades H1 and H2 over the next 10 years (table 132). This will improve following the planned data improvements.

Type	Quantity	Grade H1 & H2 (Current)	Grade H1 & H2 (+10yrs)	% of fleet at grade H1 & H2 (+10yrs)
11kV conductor	1,231	Not reliable	Not reliable	Not reliable
LV conductor	497	Not reliable	Not reliable	Not reliable

Table 132: Current and forecast asset health (circuit km)

Note: Quantities are in km of circuit length. These are as at October 2025.

13.14.12 Replacement programme

We have estimated the quantity of assets to be renewed over the next 10 years (table 133). These are consistent with those used in the 2025 AMP.

Type	Grade H1 & H2 (+10yrs)	10yr forecast replacements
11kV conductor	Unreliable	19.0
LV conductor	Unreliable	7.6

Table 133: Asset renewal forecast

Note: quantities are in km.

Description	Type	Category	FY27	FY28	FY29	FY30	FY31	FY32-36
11kV conductor replacement	Planned	ARR	85	169	169	169	169	847
LV conductor replacement	Planned	ARR	30	61	61	61	61	305
Conductor replacement, other drivers	Unplanned	ARR	16	16	16	16	16	82
Total	-	ARR	132	247	247	247	247	1,234

Table 134: Forecast capital expenditure

FY26 real \$000

13.14.13 Expenditure forecast

Table 134 shows the forecast expenditure for this fleet. These forecasts are a continuation of prior forecasts (updated for unit rate increases) and are consistent with those included in the 2025 AMP. The renewal provision for "other drivers" accounts for storm (in a typical year) and vehicle damage.



13.15 Distribution pole-mounted transformers

13.15.1 Fleet overview

The purpose of distribution transformers is to convert the electricity from the distribution voltage (11kV) to low voltage (400V/230V) suitable for supply to residential, commercial and rural customers. A secondary purpose is to isolate the low-voltage network from common-mode voltage changes that can occur during asymmetrical earth faults on the 11kV network.

Pole-mounted distribution transformers have a capacity of up to 100kVA and are used in rural and semi-rural areas. If the transformer fails, it generally impacts a few customers and can be replaced quickly. We hold spare transformers in stock in the event of failure.

Table 135 summarises the population of pole-mounted distribution transformers by kVA rating. Approximately 90% are 50kVA or smaller.

Capacity	Quantity	% of total	Typical usage
≤ 15kVA	473	17%	Supplying 1-2 rural customers
> 15 and ≤ 30kVA	847	30%	Supplying 2-3 rural customers or a small farm
>30 and ≤ 50kVA	1215	43%	Supplying 3-5 rural customers or a small farm
>50 and ≤ 100kVA	296	10%	Supplying a small cluster of rural customers, a large farm, or an urban area
>100kVA	0	0%	These have been replaced with GM transformers
Total	2,831	100%	

Table 135: Pole-mounted distribution transformer population by kVA rating

We have good quality data on the age and attributes of this fleet. 100% of the assets have a date of manufacture, and only a handful of assets have missing transformer manufacturers. Asset condition data has been captured during our line inspections, and 80% of assets have condition data captured from FY24.

13.15.2 Fleet performance

Between FY20 and FY25, transformer faults average 8.5 p.a., or about 22 per 10,000 units (for both pole – and ground-mounted transformers). This failure rate reflects the run-to-defect/failure approach for pole-mounted transformers. There are presently no concerns with the fleet's performance.

13.15.3 Fleet risks

Table 136 highlights the material risks associated with the pole-mounted transformer fleet, their impact on stakeholders, and our response.

Risk	Stakeholder impact	Stakeholder linkage	Our response
Damage or failure of the structure that supports the transformer	Damage or failure of the structure could result in an outage and injury to members of the public.	Public safety Network performance	Refer to the Distribution Structures (Poles and Crossarm) fleet plan.
Widespread damage to transformers during lightning events	Lightning surges can damage multiple transformers, resulting in an outage for many customers.	Network performance	The Waipā region does not presently encounter significant lightning events. Lightning arrestors were not currently fitted to existing pole-mounted transformers but are now pre-fitted with new ones from FY24.
Widespread damage to transformers during major weather events	Adverse weather outages accounted for 31% of unplanned SAIDI over the past six years. ¹⁴²	Network performance	Appropriate stock holdings that can support asset replacements during major weather events.
Oil leaks that could cause environmental damage	Environmental damage.	Environmental damage	The assets are inspected five yearly, and assets with oil leaks are replaced. We have oil spill kits, and our field crews are trained to handle oil spills should a leak occur.
The earthing system is damaged, compromising electrical protection and risking fatal voltages	Proper earthing is critical to the multiple-earthed neutral (MEN) system in New Zealand.	Public safety Regulatory breach	The earth is inspected and tested every five years.
Transformer phase overloading due to load imbalance (caused by load changes post-installation)	Damage to the transformer and loss of supply to customers.	Network performance	Check load balance following voltage complaints of transformer damage due to overload and load rebalancing where needed.

Table 136: Fleet risks



¹⁴² Up until FY24, Waipā included vegetation outages as part of adverse weather during major events. The SAIDI data is prior to normalisation for major events.

13.15.4 Fleet strategy

The objective for this fleet is to provide reliable and compliant LV supply to customers.

To achieve the fleet objective and address fleet performance, risks, and other issues mentioned in the preceding sections, the 10-year fleet strategy is shown in table 137.

Strategy	Description	Outcome
Common fleet strategies (refer to table 93 in Section 13.6)	<ul style="list-style-type: none"> Capture condition on all assets to the revised standards within 5 years (FY30) Implement risk-based renewal forecasting 	<ul style="list-style-type: none"> Increase in asset condition data accuracy score Increase in condition-based forecasting to >95% Improve the quality of our asset health, risk and renewal forecasting
Remove all large two-pole structures	<ul style="list-style-type: none"> Undertake a programme to remove all two-pole transformer structures 	<ul style="list-style-type: none"> Complete
Timely replacement of defects and failures	<ul style="list-style-type: none"> For pole-mounted transformers, given the generally low consequence of failure, our strategy is to replace them when material defects are reported or at failure 	<ul style="list-style-type: none"> Replacement occurs within mandated customer response and restoration times
Enhance fleet resilience (refer to Section 11.4)	<ul style="list-style-type: none"> New pole-mounted transformers are limited to 100kVA and below, with standard designs detailing pole and foundation requirements Maintain stock holding to ensure it is sufficient for major weather events 	<ul style="list-style-type: none"> Increase the mechanical strength of the structures supporting the fleet Restoration of supply is not impacted by stock holding during major events
Reduce the incidents of car vs. poles	<ul style="list-style-type: none"> Concerning the structure, refer to the Distribution Structures (Poles and Structures) fleet plan 	<ul style="list-style-type: none"> Minimise the impact of third-party incidents on the network performance
Enhance fleet resilience		

Table 137: Fleet strategy

13.15.5 Design and construct

The standard pole structure and foundations design complies with the AS/NZS 7000, and the transformers design complies with the AS/NZS/IEC 60076 series. The design for these assets considers seismic resilience, as noted in the fleet strategy.

Due to exposure to environmental conditions, distribution transformers in salt-prone areas have galvanised tanks. The higher initial cost of galvanised tanks results in lower lifecycle costs than the more frequent replacement of steel tank transformers.

Waipā Networks has standard designs prepared for pole-mounted transformer structures.

We have standardised the size and type of transformers to enable us to hold efficient spares for major events.

13.15.6 Monitoring

Pole-mounted transformers are inspected, and their earthing systems are tested, separate from the detailed line inspection. Table 138 describes our current fleet monitoring approach.

Monitoring type	Description	Frequency
Detailed inspection	<ul style="list-style-type: none"> The detailed inspection captures the EOL condition drivers, which (under the new standard) include the condition of the external tank, oil leaks, insulators, mounting, earthing and accessories. Note: the fuse condition is captured as a separate asset Defect notices are raised where priority repair or replacement is required 	Every five years
Earth testing	<ul style="list-style-type: none"> Measure the resistance of earthing connections Visual inspection of the earthing system 	Every five years
Line patrol	<ul style="list-style-type: none"> A drive-by patrol of the line and visual inspection at sites of concern. Minor repairs may be performed, or defect notices are raised where priority repair or replacement is required 	As required in response to fault issues, reliability trends, or criticality

Table 138: Fleet monitoring

13.15.7 Maintaining

There are no specific maintenance routines for pole-mounted distribution transformers. However, earthing systems are maintained to achieve the same MPL as the transformer. If an existing transformer is recovered from the field, say, replaced for capacity reasons, it is serviced and added to spare stock.

13.15.8 Renewal

Our fleet renewal approach is shown in table 139.

Decision	Description
Renewal forecasting	<ul style="list-style-type: none"> The forecast of asset renewals is based on replacing all H1 assets over the forecast period Pole-mounted transformer renewals respond to defect notices or asset failures. Asset failures and significant defects are consistent with a health grade of H1. This approach is adopted due to the low consequence of failure for this fleet, as few customers are impacted, and replacement can be achieved quickly
Determining specific renewal projects	<ul style="list-style-type: none"> No specific renewal projects are determined (other than the exception mentioned below). See defect replacement
Assessing alternatives	<ul style="list-style-type: none"> In normal circumstances, no other options are assessed The exception is where the transformer replacement resulted from a car vs. pole incident. If historical data on car vs. pole incidents indicate the transformer is in a high-risk area, we will consider relocating the transformer as a planned project
Defect replacement	<ul style="list-style-type: none"> Defects are compiled in our defect management system, and a rating is applied based on urgency. The urgency rating considers the criticality of the asset

Table 139: Fleet renewal forecasting

13.15.9 Material Spares

Pole-mounted transformers are common assets that are exposed to adverse weather conditions. We maintain enough stock to handle any reasonable scenario, including a variety of transformer sizes for fault repairs. Our supply arrangements ensure stock replenishment and support for new developments. We increase our stock levels when supplier deliveries are delayed and lead times are longer.

13.15.10 Population and age

The population and age of our pole-mounted transformer fleet are shown in figure 131. The graph indicates that 31% of the fleet is above OOU (now 30 years), and 1% of assets are at MPL¹⁴³. We increased the OOU from 20 years (as per the EEA guide) to 30 years, as this better reflects the age at which we might expect to see some EOL drivers for our fleet.

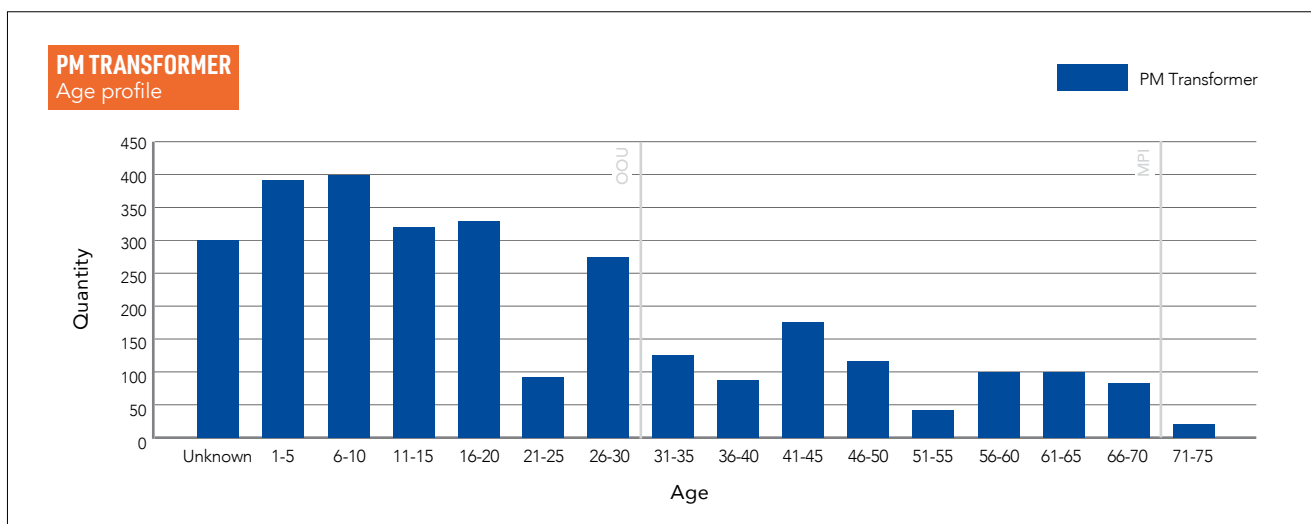


Figure 131: Age profile

¹⁴³ Pole-mounted transformers have an OOU of 30 years and an MPL of 70 years.

13.15.11 Asset health

The health assessment for pole-mounted distribution transformers is shown in figure 132. The assessment is based on the EEA asset health guide, including the health forecasting discussed in Section 13.5.3.

The data used for pole-mounted transformer health forecasting is robust, with 80% being condition-based. The remaining assets have good age data. The deterioration of pole-mounted transformers is relatively gradual, consistent with the long MPL for this fleet.

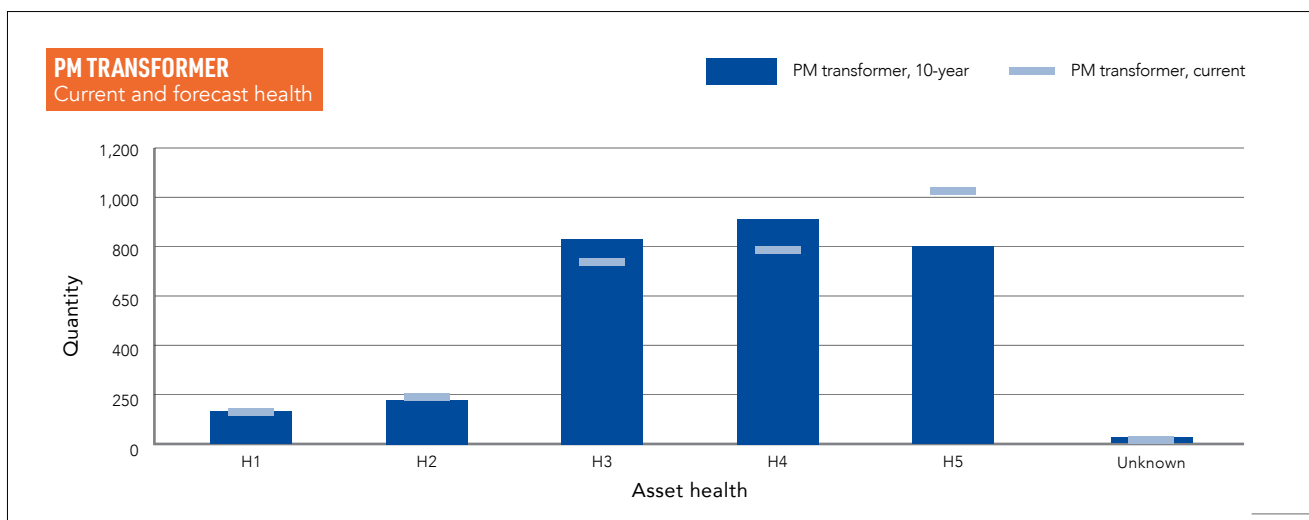


Figure 132: Current and forecast asset health

Table 140 shows the current and forecast numbers for low-health pole-mounted transformers over the next 10 years. 95% of low-health transformers are forecast based on condition.

Type	Quantity	Grade H1 (Current)	Grade H1 (+10yrs)	% of fleet at grade H1 (+10yrs)
Pole-mounted transformers	2,830	111	121	1.6%

Table 140: Current and forecast asset health

13.15.12 Asset replacements

Notwithstanding the improvement in forecast H1 assets, our 10-year replacement forecast remains unchanged from prior AMPs and is higher than the forecast for H1 transformers (table 141). This reflects the historical number of transformer replacements (excluding major weather events); although we have seen an increase in FY26, which may alter our view of future AMPs.

The choice of replacement transformer size will also consider factors such as future capacity requirements.

Type	Grade H1 (+10yrs)	10yr forecast replacements
Pole-mounted transformers	121	240

Table 141: Asset renewal forecast



13.15.13 Expenditure forecast

Table 142 shows the forecast expenditure for this fleet, totalling \$8.8m over the next 10 years. The forecast expenditure is about \$500k higher than the 2025 AMP,

reflecting higher replacement costs for storm – and vehicle-damage-related replacements. The “other replacement” renewals are for car vs pole and storm damage. The cost forecasts include the cost of associated dropout fuses.

Description	Type	Category	FY27	FY28	FY29	FY30	FY31	FY32-36
PM transformer, defect replacement	Unplanned	ARR	543	543	543	543	543	2,715
PM transformer, other replacement	Unplanned	ARR	339	339	339	339	339	1,697
Total	–	–	882	882	882	882	882	4,412

Table 142: Forecast expenditure

FY26 real \$000

13.16 Distribution voltage regulator fleet plan

13.16.1 Fleet overview

We install voltage regulators on the network to improve voltage along rural feeders and maintain it within regulatory limits. Voltage drop is the limiting factor on rural feeders, and voltage regulators are a cost-effective way to increase the feeder’s capacity by extending its voltage reach. We use voltage regulators extensively on the network. They have supported the load growth in rural areas as land use has changed and energy density has increased.

Voltage regulators are typically rated at 100, 200, or 300 amps at 11kV and are installed mainly in a closed delta configuration (3 tanks), with some older sites in an open delta configuration (2 tanks). The closed delta configuration is preferred for new sites with heavy loading, as it is less prone to voltage fluctuations during operation and can achieve a higher current rating. The open delta configuration is preferred for end-of-line locations with no backfeeding need. Single-phase controllers (one per tank) or a single multi-phase controller (one per site) are used to monitor and control voltage. The controller is connected to the SCADA system.

About 40% of our 11kV voltage regulators are on two-pole structures; the rest are on four-pole structures. Most old two-pole structures are not compliant with current seismic standards and are being proactively replaced as part of resilience efforts.

In response to asset condition, we commenced proactive replacement and refurbishment of voltage regulators in FY24.

We have good-quality data on the condition, age and attributes of this fleet. All sites were inspected over the past 12 months.

Note: The asset quantities in this fleet relate to the number of single-phase voltage regulator “cans” or “tanks”, where there can be two or three tanks per site.

13.16.2 Fleet performance

Operational issues due to controller and tap-changer failures have occurred. The controllers are progressively replaced due to age, ant infestation or condition. This is occurring in conjunction with the can refurbishments.

Tapchanger maintenance occurs as part of our tank refurbishment programme. We generally coincide the tank refurbishment with the pole structure seismic strengthening (Section 11.7.3).

13.16.3 Fleet risks

Table 143 highlights the material risks associated with the voltage regulator fleet, their impact on stakeholders, and our response.

Risk	Stakeholder impact	Stakeholder linkage	Our response
Third-party interference (Car vs. Pole) damages the structure and regulators, causing outages and potential contact with live wires	Regulator and structure damage could result in a large outage and injury to members of the public	Public safety Network performance	Old structures are being replaced, and relocation or protection is being considered for high-risk sites
Oil leaks that could cause environmental damage	Environmental damage	Environmental damage	The assets are inspected three yearly, and assets with oil leaks are replaced. We have oil spill kits, and our field crews are trained to handle oil spills should a leak occur
The strength of older structures is below current design standards (for seismic hazards)	The structures may fail in a seismic event, causing a loss of supply to customers and risk to the public	Public safety Network performance	Older structures are being proactively replaced

Table 143: Fleet risks

13.16.4 Fleet strategy

The objective for this fleet is to regulate the voltage on rural feeders to maintain it within regulatory limits, improve the fleet health, and improve fleet resilience.

To achieve the fleet objective and address the fleet performance, risks, and other issues mentioned in the preceding sections, the 10-year fleet strategy is shown in table 144.

Strategy	Description	Outcome
Common fleet strategies (refer to table 93 in Section 13.6)	<ul style="list-style-type: none"> Enhance inspection standards and data (complete) Enhance asset health assessment and forecasting Implement risk-based renewal forecasting Enhance renewal project selection and prioritisation 	<ul style="list-style-type: none"> Increase in asset condition data accuracy score (complete) Increase in condition-based forecasting to >95% (complete) Improve the quality of our asset health, risk and renewal forecasting Improved optimisation of work plans and project timing Reduce reliability and safety risks
Eliminate all H1 assets	<ul style="list-style-type: none"> Ensure all H1 voltage regulators are replaced before failure Ensure all H2 voltage regulators are replaced before they become H1 	<ul style="list-style-type: none"> Zero H1 voltage regulators by FY27
Enhance fleet resilience (refer to Section 11.4)	<ul style="list-style-type: none"> Replace or remediate all structures that are below current seismic ratings Consider flooding and geotechnical hazards (Peat soil) in the new site and structure design 	<ul style="list-style-type: none"> Improved asset resilience
Timely replacement of defects	<ul style="list-style-type: none"> For voltage regulators, given the potentially high consequence of failure, defect replacements shall occur promptly 	<ul style="list-style-type: none"> No failure of assets with defect notices

Table 144: Fleet strategy

13.16.5 Design and construct

We have standardised the selection of voltage regulator cans and a single controller type to aid with the management of spares and ensure consistent interfaces for field operators. The voltage regulator design complies with the AS/NZS/IEC 60076 standard series. The design for these assets considers seismic and wind resilience in the structural design standards. Flooding and geotechnical hazards are considered during site selection.

Given the physical size of these assets, a specific geotech design is prepared for each site.



13.16.6 Monitoring

Table 145 describes our current fleet monitoring approach.

Monitoring type	Description	Frequency
Annual inspection	<ul style="list-style-type: none"> Inspect the condition of the external tank, oil leaks, and controllers Inspect and check the controller, battery, and site signal strength Carry out pest control and battery replacement as required 	Annually
Detailed inspection	<ul style="list-style-type: none"> The detailed inspection captures the EOL condition drivers, which (under the new standard) include the condition of the external tank, oil leaks, controllers, aerial, connections Oil dielectric strength, acidity and moisture testing Tap-changer operational checks 	Every three years
Insulation testing	<ul style="list-style-type: none"> Winding insulation testing 	Every 12 years
Operational monitoring	<ul style="list-style-type: none"> SCADA monitors the operation of the voltage regulators. This alerts the operator to any operational issues 	–

Table 145: Fleet monitoring

13.16.7 Maintaining

Voltage regulator maintenance is shown in table 146.

Monitoring type	Description	Frequency
Routine maintenance	<ul style="list-style-type: none"> See annual inspection 	Annually
Preventive maintenance	<ul style="list-style-type: none"> Preventive maintenance is undertaken as per manufacturer recommendations Tap-changer and internal mechanism replacement 	Tap-changer counter Time-based
Condition-driven maintenance	<ul style="list-style-type: none"> Maintenance is carried out in response to the inspection and testing. This may include additional testing, spot repairs to the cans, replacement of fittings, or control box replacement 	As required

Table 146: Fleet maintenance

13.16.8 Renewal

Our fleet renewal approach is shown in table 147.

Decision	Description
Renewal forecasting	<ul style="list-style-type: none"> • Ensure all H1 voltage regulators are replaced before failure • Ensure all H2 voltage regulators are replaced before they become H1
Determining specific renewal projects	<ul style="list-style-type: none"> • Specific renewal projects are identified from the health assessment • Site inspections are undertaken to confirm the scope and design for the renewal • The renewal projects are prioritised by criticality. The highest priority will be replacing voltage regulators in critical locations
Assessing alternatives	<ul style="list-style-type: none"> • The regulator shall be assessed for refurbishment or replacement, based on the condition and technical obsolescence drivers • In some circumstances, evaluate the effectiveness of using switched capacitor banks or STACOM if a power factor mainly causes the feeder voltage issue • The exception is if historical data on car vs. pole incidents indicates the voltage regulator is in a high-risk area, we will consider relocating the voltage regulator
Defect repair and replacement	<ul style="list-style-type: none"> • Defects are compiled in our defect management system, and a rating is applied based on urgency. The urgency rating considers the criticality of the asset

Table 147: Fleet renewal forecasting

13.16.9 Spares

We hold stock sufficient to cover defect and damage replacements.

13.16.10 Population and age

The population and age of our voltage regulator fleet is shown in figure 133. The graph indicates that 30% of the fleet is above Waipā Networks-specific OOU, but no assets are at MPL¹⁴⁴.

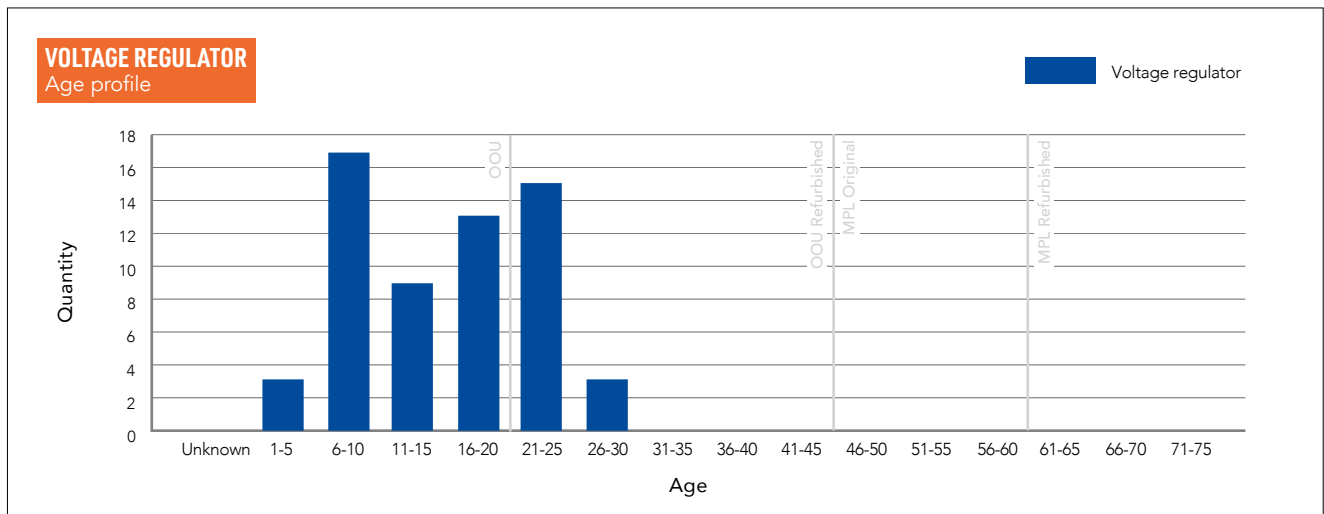


Figure 133: Age profile

13.16.11 Asset health

The health assessment for voltage regulators is shown in figure 134 and is based on the EEA asset health guide, including the health forecasting discussed in Section 13.5.3.

All voltage regulators have condition data. The condition assessments generally indicate that we are seeing EOL drivers emerge for the tank and controllers after 20 years.

¹⁴⁴ Voltage regulators have a OOU of 20 years and an MPL of 45 years. This is extended to an OOU of 45 year and a MPL of 60 years after refurbishment of the cans.

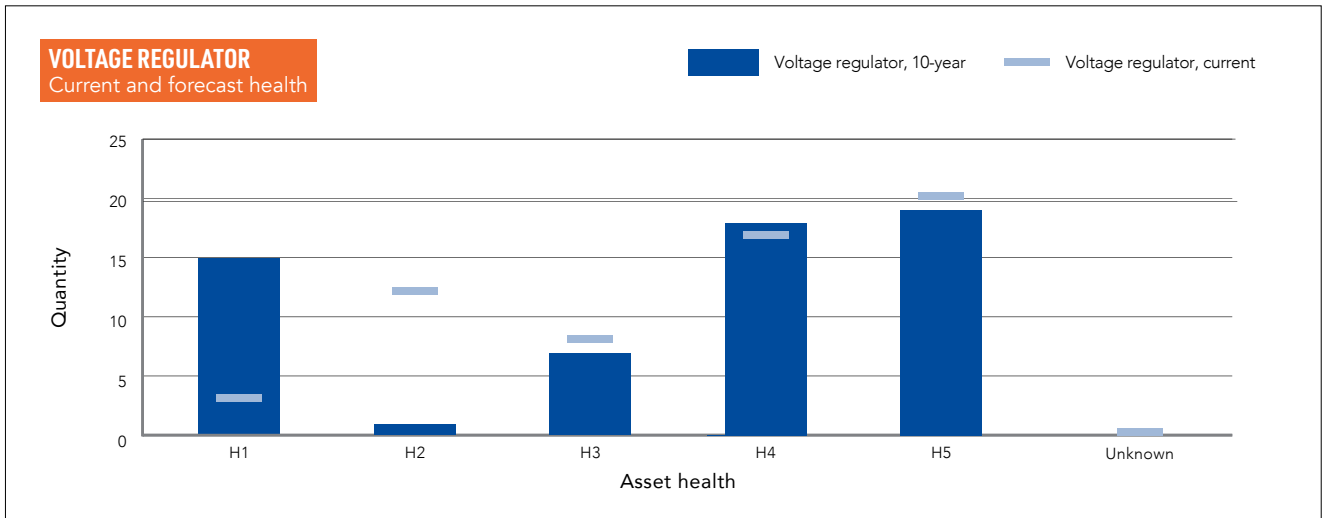


Figure 134: Current and forecast asset health

Table 148 shows the current forecast for low-health voltage regulators over the next 10 years. 67% of low-health voltage regulators are forecast based on condition, and the rest are based on age.

The low-grade structures are based on an initial assessment indicating they do not meet current seismic standards.

Type	Quantity	Grade H1 (Current)	Grade H1 (+10yrs)	% of fleet at grade H1 (+10yrs)
Pole-mounted transformers	2,830	111	121	1.6%

Table 148: Current and forecast asset health

13.16.12 Asset replacements

Consistent with our renewal strategy, we forecast replacing all H1 and H2 voltage regulators over the next 10 years (as shown in table 149). Five sites (15 cans) are scheduled for remediation, along with replacement controllers, over the first five years.

Type	Grade H1 & H2 (+10yrs)	10yr forecast replacements
Voltage regulators	24	24
Structures	17	17

Table 149: Asset renewal forecast

13.16.13 Expenditure forecast

Table 150 shows the forecast expenditure for this fleet, amounting to \$3.1m. This is materially lower than what is included in the 2025 AMP, as the regulators will be refurbished, rather than replaced with new ones. The controllers are being upgraded as the voltage regulators are refurbished. New regulators will be installed in FY30 and FY31, as the regulators planned for those years cannot be refurbished. For all other sites, the regulators are being refurbished.

For structures, the forecast expenditure is the same as the 2025 AMP (in 2026\$). This allows for the replacement of two sites per year (with the programme being completed in FY34). Note that structure replacement is a resilience initiative, specified in the Network Development Section 11.7.3, and is shown here for information.

Description	Type	Category	FY27	FY28	FY29	FY30	FY31	FY32-36
Voltage regulator, refurbishments and controller replacement	Planned	ARR	108	108	108	284	284	862
Structure replacements	Planned	RSE-other	168	168	168	168	168	505
Total	-	-	276	276	276	453	453	1,367

Table 150: Forecast expenditure

13.17 Distribution reclosers and sectionalisers fleet plan

13.17.1 Fleet overview

The purpose of reclosers and sectionalisers is to reduce the number of customers affected by outages. They operate along the feeder to isolate only the faulty section of the line, leaving the rest of the feeder in service. We use reclosers extensively on our network. There are 114 reclosers and two sectionalisers in the fleet.

We are progressively replacing the control and communication systems across the fleet. These units age more quickly than the reclosers themselves, typically lasting around half as long, and many are now approaching technical obsolescence.

We have good quality data on the age and attributes of this fleet. Any missing data is being captured during inspections. All assets have a known date of manufacture. Asset condition data (to the new standard) is available for 95% of the fleet.

13.17.2 Fleet performance

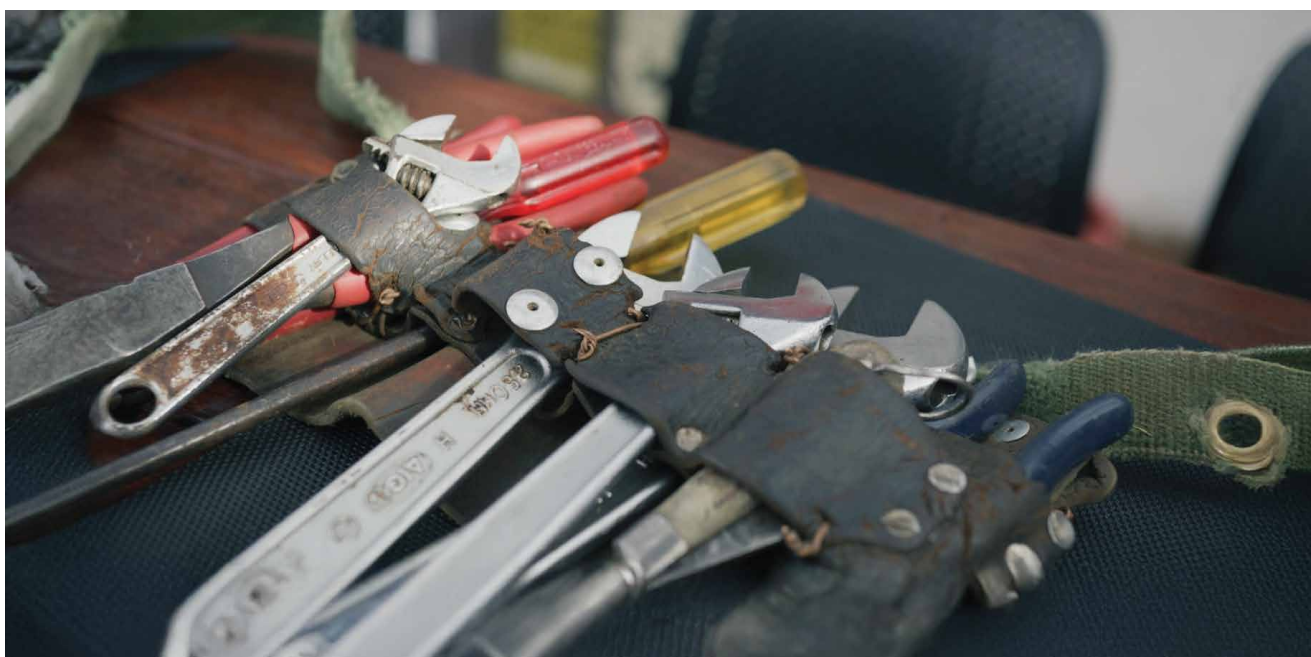
We have experienced increased operational issues with some of our older reclosers and RC-01 controllers. We are addressing the performance of the recloser units through inspection and maintenance, and the performance of the controllers through the controller replacement programme.

13.17.3 Fleet risks

Table 151 highlights the material risks associated with the reclosers and sectionalisers fleet, their impact on stakeholders, and our response.

Risk	Stakeholder impact	Stakeholder linkage	Our response
Damage or failure of the structure supporting the recloser	Damage or failure of the structure could result in an outage and injury to members of the public.	Public safety Network performance	Refer to the Distribution Structures (Poles and Crossarm) fleet plan
Third-party interference (Car vs. Pole) damages the structure and recloser, causing outages and potential contact with live wires	Recloser and structure damage could result in a large outage and injury to members of the public.	Public safety Network performance	Relocation or protection is being considered for high-risk sites
Control and communication systems reach technological obsolescence and become incompatible with SCADA	Reclosers fail to operate, increasing the number of customers impacted by an outage.	Network performance	Upgrading the control and communication systems
Non-discrimination of protection when three or four reclosers are installed on a single feeder	Incorrect recloser operation, increasing the number of customers impacted by an outage.	Network performance	Review recloser placement and protection settings to ensure they can operate correctly

Table 151: Fleet risks



13.17.4 Fleet strategy

The objective for this fleet is to maintain operational performance and health of the assets, ensuring the reclosers operate correctly and reliably.

To achieve the fleet objective and address the fleet performance, risks, and other issues mentioned in the preceding sections, the 10-year fleet strategy is shown in table 152.

Strategy	Description	Outcome
Common fleet strategies (refer to table 93 in Section 13.6)	<ul style="list-style-type: none"> Enhance inspection standards and data (complete) Enhance asset health assessment and forecasting Implement risk-based renewal forecasting 	<ul style="list-style-type: none"> Increase in asset condition data accuracy score (complete) Increase in condition-based forecasting to >95% (complete) Improve the quality of our asset health and renewal forecasting
Eliminate all H1 assets by the end of FY29 (current health issues driven by controllers)	<ul style="list-style-type: none"> Ensure all H1 reclosers and sectionalisers are replaced before failure Ensure all H2 reclosers and sectionalisers are replaced before they become H1 Replace the last oil unit with a modern equivalent (complete) 	<ul style="list-style-type: none"> Zero H1 reclosers and sectionalisers by FY29
Enhance operational performance	<ul style="list-style-type: none"> Inspect the controllers, carry out pest controls and replace defective batteries by the end of FY24 (complete) Replace all older RC-01 controllers by the end of FY34 Catch-up on all 10-yearly maintenance Calibrate all CTs as part of 10-yearly maintenance Confirm protection discrimination when there are multiple reclosers on the feeder 	<ul style="list-style-type: none"> Improve operational reliability
Reduce the incidents of car vs. poles	<ul style="list-style-type: none"> Concerning the structure, refer to the Distribution Structures (Poles and Structures) fleet plan 	<ul style="list-style-type: none"> Refer to the Distribution Structures (Poles and Structures) fleet plan
Enhance fleet resilience		

Table 152: Fleet strategy

13.17.5 Design and construct

Reclosers and sectionaliser structures are designed to AS/NZS 7000 and the structural design standards (NZS 1170 series). The design for these assets considers the following:

- Seismic and wind resilience in the structural design standards. Flooding and geotechnical hazards are considered during site selection.

- Capacity to suit application point, regulation range, uni-/bi-directional capability, and firmware.

Waipā Networks has standard designs for pole-mounted recloser structures.

13.17.6 Monitoring

Table 153 describes our current fleet monitoring approach.

Monitoring type	Description	Frequency
Annual inspection	<ul style="list-style-type: none"> Inspect and check the controller, battery, and site signal strength Carry out pest control and battery replacement as required 	Annually
Detailed inspection	<ul style="list-style-type: none"> The detailed inspection captures the EOL condition drivers, which include the condition of the recloser/sectionaliser unit, control box, associated fuses and switches, structure, etc. Operational and communication checks 	Every three years
Operational monitoring	<ul style="list-style-type: none"> The operation of the reclosers and sectionalisers is monitored by SCADA. This alerts you of any operational issues 	–

Table 153: Fleet monitoring

13.17.7 Maintaining

The maintenance of reclosers and sectionalisers is shown in table 154.

Monitoring type	Description	Frequency
Routine maintenance	<ul style="list-style-type: none"> See annual inspection 	Annually
Preventive maintenance, oil sectionaliser	<ul style="list-style-type: none"> The last oil unit is planned for replacement; hence, there is no further planned maintenance activity 	N/A
Preventative maintenance, vacuum and SF6 reclosers	<ul style="list-style-type: none"> Preventive maintenance on the operating mechanism is undertaken as per manufacturer recommendations Thermal scan to check the integrity of load-carrying components Calibration of CTs Battery replacement 	Every 10 years
Condition-driven maintenance	<ul style="list-style-type: none"> Maintenance is carried out in response to the inspection and testing. This may include maintenance on the unit, replacement of the controller, RTU, antenna, battery, or other components 	As required

Table 154: Fleet maintenance

We currently have a backlog of maintenance on the fleet, as many reclosers were installed between 2010 and 2015, and these are now due for their first 10-yearly maintenance. This work is underway and should be completed by the end of FY26.

13.17.8 Renewal

Our fleet renewal forecasting approach is shown in table 155.

Decision	Description
Renewal forecasting	<ul style="list-style-type: none"> The forecast of asset renewals is as per the fleet strategy
Determining specific renewal projects	<ul style="list-style-type: none"> Specific renewal projects are identified from the health assessment and known controller-type issues Site inspections are undertaken to confirm the scope and design for the renewal The renewal projects are prioritised by the criticality of the feeder
Assessing alternatives	<ul style="list-style-type: none"> In normal circumstances, no other options are assessed The exception is if historical data on vehicle accidents indicate the reclosers and sectionalisers are in a high-risk area, we will consider relocating the reclosers and sectionalisers
Defect repair and replacement	<ul style="list-style-type: none"> Defects are compiled in our defect management system, and a rating is applied based on urgency. The urgency rating considers the criticality of the asset

Table 155: Fleet renewal forecasting

13.17.9 Material spares

We hold stock sufficient to cover defect and damage replacements.

13.17.10 Population and age

The population and age of our reclosers and sectionalisers fleet is shown in figure 135. The graph indicates that five reclosers are above OOU, but none are at MPL¹⁴⁵. The age

profile reflects the large reliability improvement initiative utilising reclosers over the last twenty years. All of the older oil reclosers have now been replaced.

Around 30 controllers will reach MPL over the next five years.

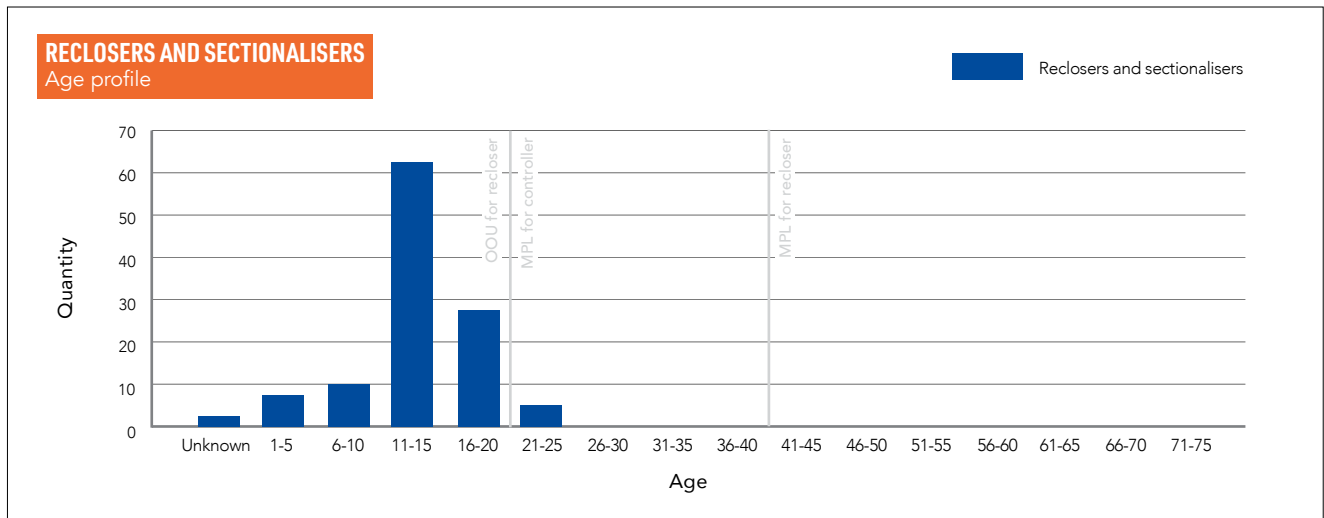


Figure 135: Age profile

13.17.11 Asset health

The health assessment for reclosers and sectionalisers is shown in figure 136 and is based on the EEA asset health

guide, including the health forecasting discussed in Section 13.5.3. All of the lower health assets are based on condition. Controller condition is the primary driver of lower asset health ratings, including reclosers fitted with RC-01 controllers.

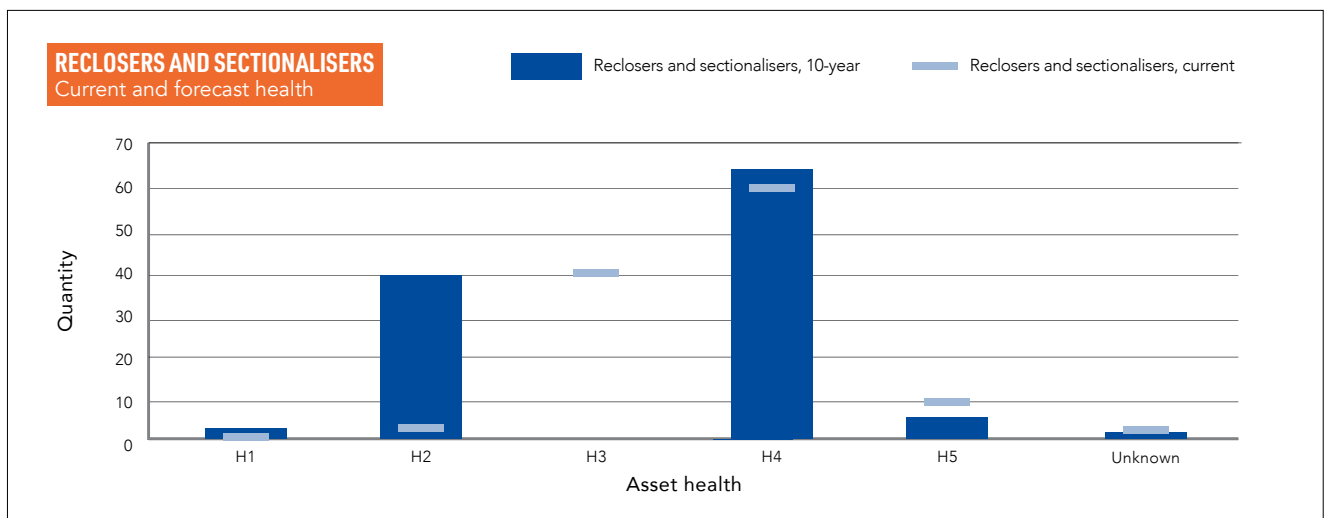


Figure 136: Current and forecast asset health

Table 156 shows the current and forecast for low-health reclosers and sectionalisers over the next 10 years. The controller condition is what is driving low health scores. However, there are also some recloser units currently at H3 that are forecast to transition to H2 from year five.

Type	Quantity	Grade H1 (Current)	Grade H1 (+10yrs)	% of fleet at grade H1 (+10yrs)
Reclosers and sectionalisers	115	3	40	37%

Table 156: Current and forecast asset health

¹⁴⁵ Reclosers and sectionalisers have a OOU of 20 years and an MPL of 45 years.

13.17.12 Asset replacements

Consistent with our renewal strategy, we are forecasting the remediation of all H1 and H2 reclosers and sectionalisers over the next 10 years (as shown in table 157). All older RC-01 controllers will be replaced by the end of FY34. The controller replacement programme will continue as technological obsolescence drives the need for ongoing replacements. We are forecasting the replacement of some recloser units from FY31; however, these will be inspected once more before FY31, which may alter their renewal timing in future AMPs.

Type	Grade H1 & H2 (+10yrs)	10yr forecast replacements
Reclosers and sectionalisers	12	12
Control boxes	40	40

Table 157: Asset renewal forecast

13.17.13 Expenditure forecast

Table 158 shows the forecast expenditure for this fleet. The number of reclosers forecast for renewal reflects our current view of the fleet's health.

The controller replacements have been phased over 10 to fit resourcing requirements and the increase in near-term maintenance requirements.

Description	Type	Category	FY27	FY28	FY29	FY30	FY31	FY32-36
Reclosers and sectionalisers, renewals	Planned	ARR	–	–	–	–	142	711
Control box replacements	Planned	AR	82	82	82	82	82	410
Total	–	–	82	82	82	82	224	1,122

Table 158: Forecast capital expenditure

FY26 real \$000

13.18 Distribution overhead switches fleet plan

13.18.1 Fleet overview

The purpose of overhead switches is to enable switching, segment isolation, and protection of the overhead distribution network. This fleet has four asset types, as shown in table 159.

Asset type	Quantity	Description
Enclosed load break switch (LBS)	154	An enclosed switch using vacuum or SF6 insulation can be operated under load to switch and isolate parts of the overhead network. Automation of the switch is also possible.
Air break switch (ABS)	445	Pole-top switches that can be operated under load to switch and isolate parts of the overhead network, either operated by handles or by a hot stick.
Links	282	These are dropout links that can be used to isolate line equipment. They must be switched under no-load conditions.
Dropout fuse (fuses)	3,652	These expulsion fuses protect a line section, usually a spur line, a pole-mounted distribution transformer, or a cable section. They can be used to isolate lines under small loads.
Total	4,533	

Table 159: Overhead switch asset types

We do not have good data on all the assets in this fleet. We have missing asset age data for 40% of the fleet; most of this concerns fuses, links, and some ABSs. Data quality on age for fuses and links will be difficult to improve. Therefore, we will rely on condition data for these asset types.

The failure modes for these assets are generally driven by corrosion, wear, component misalignment, and arc damage during operation. These failure modes can usually be observed during our inspection. Hence, for this fleet, condition-based health forecasting is appropriate.

13.18.2 Fleet performance

We do not have good data on faults by each asset type for this fleet (as all switchgear faults are combined) due to how historical outages were recorded. The number of unassisted faults for dropout fuses was approximately 17 faults per 10,000 units/year and 68 faults per 10,000 units/year for ABSs, LBSs and reclosers¹⁴⁶. The high fault rate for the latter was driven by issues with ABSs. Recent changes to the fault recording system will provide additional data to enable fault trends to be analysed in more detail from now on.

We are also finding a higher number of ABS with a seized operating mechanism and, therefore, inoperable during planned or unplanned switching. These failures are currently reported through our defect process.

13.18.3 Fleet risks

Table 160 highlights the material risks associated with the overhead switch fleet, their impact on stakeholders, and our response.

Risk	Stakeholder impact	Stakeholder linkage	Our response
Failure of the equipment to operate (either open or close) disrupts switching operations and causes risk to staff	An inability to isolate or live parts of the network. In these situations, the outage duration for some customers may be extended by the repair time. Failure of the switch can also endanger staff operating the switch.	Staff safety Network performance	Inspection and replacement of the switch. We have documented operational steps when a defective switch is found. When replacing switches or installing new ones, LBSs are preferred for feeder ties and major isolation points.
Certain ABS base mounting channels are prone to premature severe rusting at the bolting points. We are finding that certain types of ABS are prone to such issues	The switch becomes insecure and may endanger staff operating the switch or the public.	Staff safety Public safety Network performance	Inspection and replacement of the switch. LBSs are preferred for new and replacement switch installation.
Public gain access to the switch operating mechanism	Injury to members of the public.	Public safety	The operating handle is locked. Inspections of public safety measures. Upgrading the network access lock system. The new switch type will be hot stick-operated.
Failure of the earthing of the switch and handle	Injury to staff or members of the public.	Staff safety Public safety	Pre-operation checks. Use of insulating gloves. Inspections of public safety measures and earthing. The new switch type will be hot stick-operated.
Damage or failure of the structure supporting the switch	Damage or failure of the structure could result in a large outage and injury to members of the public.	Public safety Network performance	Refer to the Distribution Structures Fleet Plan.
Control and communication systems reach technological obsolescence and become incompatible with SCADA.	Controlled switches fail to operate, increasing the number of customers impacted by an outage.	Network performance	Scheduled maintenance to replace batteries. Upgrading the control and communication systems.

Table 160: Fleet risks

13.18.4 Fleet strategy

The objective for this fleet is to maintain high operational performance and address low-health assets to ensure reliable network switching and isolation and to ensure public and personnel safety.

To achieve the fleet objective and address fleet performance, manage risks, and address other issues discussed earlier, the 10-year fleet strategy is outlined in table 161. The strategy

varies depending on switch type. For ABSs and enclosed LBS, the approach involves proactively replacing these assets based on our health assessments and field inspection findings. For fuses and links, where health data is unreliable (and replacement is generally more straightforward), we will replace these assets when defects are identified, the asset is non-operational, or concurrently with other asset replacements (e.g., when pole-mount transformers or crossarms are replaced).

¹⁴⁶ This also includes sectionalisers.

Strategy	Description	Outcome
Common fleet strategies (refer to table 93 in Section 13.6)	<ul style="list-style-type: none"> Enhance inspection standards (complete) Enhance condition data through inspection Enhance asset health assessment and forecasting Implement risk-based renewal forecasting Enhance renewal project selection and prioritisation 	<ul style="list-style-type: none"> Increase in asset condition data accuracy score Increase in condition-based forecasting to >95% Improve the quality of our asset health, risk and renewal forecasting Improved optimisation of work plans and project timing
Eliminate all H1 ABSs and enclosed LBSs by the end of FY29	<ul style="list-style-type: none"> Ensure all H1 assets are replaced before failure Ensure all H2 assets are replaced before they become H1 	<ul style="list-style-type: none"> Zero H1 ABSs and Enclosed LBSs by the end of FY29
Timely replacement of defects	<ul style="list-style-type: none"> For ABSs and enclosed LBSs, defect replacements will be prioritised depending on operational criticality 	<ul style="list-style-type: none"> No high-consequence failures of assets with defect notices
Enhance operational performance (automated LBS only)	<ul style="list-style-type: none"> Inspect the controllers, carry out pest controls and replace defective batteries (complete) Catch-up on all 10-yearly maintenance 	<ul style="list-style-type: none"> Improve operational reliability
Improve the reliability of the worst-performing feeders	<ul style="list-style-type: none"> The initial focus of the planned switch renewal is on the worst-performing feeders 	<ul style="list-style-type: none"> Improve the reliability of the worst-performing feeders
Timely replacement of defects and failures for fuses and links	<ul style="list-style-type: none"> For fuses and links, given the generally low consequence of failure, our strategy is to replace them when defects are reported or when non-operational For delivery efficiency, these will also be renewed when undertaking renewal of associated assets (e.g., crossarms or transformers) 	<ul style="list-style-type: none"> Replacement occurs within mandated customer response and restoration times
Reduce the use of ABS and adopt enclosed LBS as the preferred switch	<ul style="list-style-type: none"> ABS is more prone to failure; hence, minimise the use of ABS and use enclosed LBS where possible 	<ul style="list-style-type: none"> Improve the performance reliability of the overall ABS/LBS asset types
Reduce the incidents of car vs. poles	<ul style="list-style-type: none"> Refer to the Distribution Structures (Poles and Crossarms) fleet plan for the switch support structure 	<ul style="list-style-type: none"> Refer to the Distribution Structures (Poles and Crossarms) fleet plan
Enhance fleet resilience		

Table 161: Fleet strategy

13.18.5 Design and construct

Waipā Network has standard designs prepared for all pole-mounted overhead switches. All equipment is purchased to the relevant industry standards. Refer to the Distribution Structures (Pole and Crossarm) fleet plan for structure design standards.

Due to the less reliable nature of ABSs, we intend to reduce their use. Our plan is to use ABSs:

- For bypass switches for reclosers and voltage regulators. We are also evaluating the need for a bypass switch for reclosers and the feasibility of using an enclosed LBS for the voltage regulator

- For ganged switches to mitigate ferro resonance risk when operating an expulsion dropout fuse (EDO) that supplies a long transformer cable
- For emergency like-for-like replacement
- Other situations where an enclosed LBS is not economical due to other extensive changes required, as judged and approved on a case-by-case basis.

We plan to use automated enclosed load-break switches (LBS) for critical switching points instead of ABS. LBSs offer a more reliable, lower-maintenance alternative to ABSs, but at a higher cost.

We have standardised the size and type of overhead switches to enable us to hold efficient spares for major events.

13.18.6 Monitoring

Table 162 describes our current fleet monitoring approach.

Monitoring type	Description	Frequency
Detailed inspection	<ul style="list-style-type: none"> Condition data is captured during the detailed line inspections or pole-mounted transformer inspections (refer to the Distribution Structures (Pole and Crossarm) fleet plan and the pole-mounted distribution transformer fleet plan) The detailed inspection captures the EOL condition drivers, which (under the new standard) will include the condition of the switch and operating mechanism Defect notices are raised where priority repair or replacement is required Thermal imaging scan of the switches to identify any high-resistance connections 	Every five years
Line patrol	<ul style="list-style-type: none"> A drive-by patrol of the line and visual inspection at sites of concern. Minor repairs may be performed, or defect notices are raised where priority repair or replacement is required 	As required in response to fault issues or reliability trends
Annual LBS inspection	<ul style="list-style-type: none"> Inspect and check the controller, battery, and site signal strength. Carry out pest control and battery replacement as required 	Annually
Operational monitoring (for automated LBS)	<ul style="list-style-type: none"> We monitor the operation of the controlled switches through SCADA. This alerts the operator to any operational issues. 	As required
Thermal imaging of contacts and connections	<ul style="list-style-type: none"> We undertake a thermal imaging scan of the switches to identify any high-resistance connections 	Every five years

Table 162: Fleet monitoring

13.18.7 Maintaining

There are no specific maintenance routines for links and dropout fuses. ABSs and enclosed LBSs are maintained as described in table 163.

Monitoring type	Description	Frequency
Routine inspection and earth testing	<ul style="list-style-type: none"> Visual inspections of a switch, including contacts and pantographs (for ABSs) Thermal scan to check the integrity of load-carrying components Visual inspection of the earthing system and measurement of the resistance of earthing connections 	Every five years
Routine maintenance (automated LBS)	<ul style="list-style-type: none"> Bug and pest control to prevent damage to controllers and electronics. Radio signal strength checks Battery condition checks 	Annually
Preventative maintenance (automated LBS)	<ul style="list-style-type: none"> Preventive maintenance on the operating mechanism is undertaken as per manufacturer recommendations Thermal scan to check the integrity of load-carrying components Calibration of CTs Battery replacement 	10 years

Table 163: Fleet maintenance

13.18.8 Renewal

Our fleet renewal approach is shown in table 164.

Decision	Description
Renewal forecasting	<ul style="list-style-type: none"> For ABSs and enclosed LBSs, this is as per the fleet strategy For fuses and links, the forecast of asset renewals is based on continuing historical replacement rates. This approach is adopted due to the unreliable health data and low consequence of failure for this fleet, as few customers are impacted, and replacement can be achieved quickly. Also, life expectancy is similar to that of crossarms, and the fuses and links are replaced when crossarms or transformers are due for renewal
Determining specific renewal projects (ABSs and enclosed LBSs)	<ul style="list-style-type: none"> Specific renewal projects are identified from the health assessment Site inspections are undertaken to confirm the scope and design for the renewal The renewal projects are prioritised by the criticality of the feeder
Assessing alternatives (ABSs and enclosed LBSs)	<ul style="list-style-type: none"> For ABS and enclosed LBS renewal, the team will assess whether the switch is needed at its current location (i.e., whether it is a duplicated device for removal or it would be better located elsewhere) and whether it should be upgraded to an automated enclosed LBS in conjunction with "11kV automation recloser/sectionaliser Additions" under Section 9.7.1 Exceptions include where the overhead switch replacement resulted from vehicle damage or operational safety issues. If historical data on vehicle crashes indicate the overhead switch is in a high-risk area, we will consider relocating the overhead switch as a planned project. Likewise, if it is identified via a safety-in-design workshop or improvement suggestion that a location presents a risk to the operator, the switch will be located to a new location
Determining specific renewal projects (fuses and links)	<ul style="list-style-type: none"> No specific renewal projects are defined for these asset types
Defect replacement	<ul style="list-style-type: none"> Defects are compiled in our defect management system, and a rating is applied based on urgency. The urgency rating considers the criticality of the asset

Table 164: Fleet renewal forecasting

13.18.9 Spares

Overhead switches are common assets exposed to adverse weather events and vehicle damage. We hold stock sufficient to cover any reasonable situation. We hold sufficient stock to support unplanned replacements for dropout fuses and links.

13.18.10 Population and age

The population and age of our overhead switch fleet are shown in figure 137 to figure 140. Enclosed LBSs are all below OOU, and 14% of ABSs are above OOU, and one is above MPL. The data for fuses and links is less reliable, as only 60% of fuses and 44% of links have age data. Hence, the age profiles for those assets are indicative only.

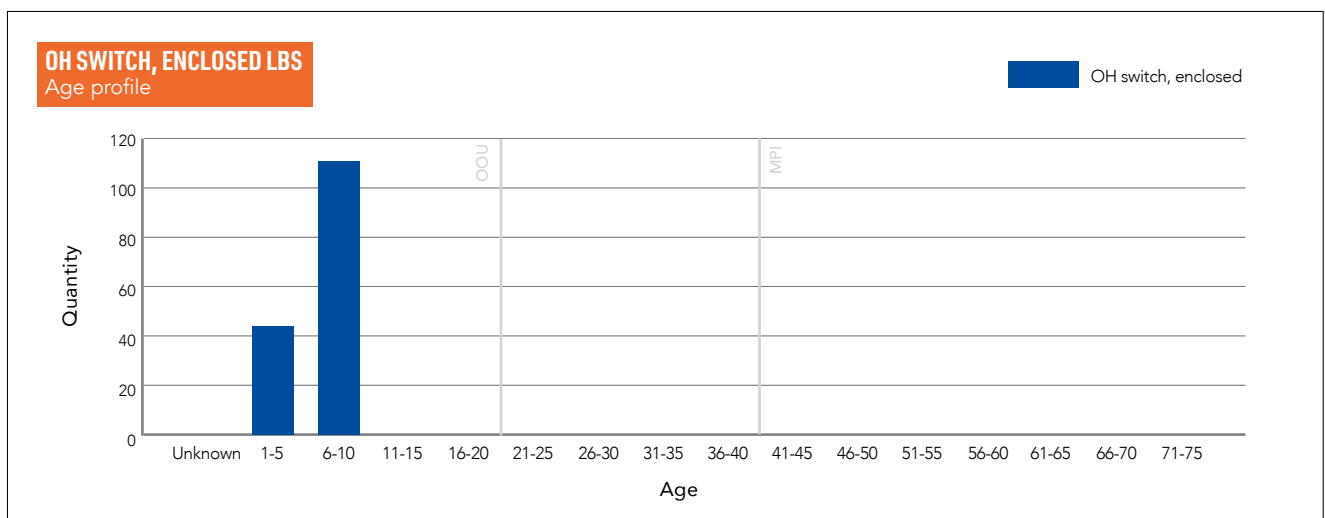


Figure 137: Age profile (enclosed LBSs)

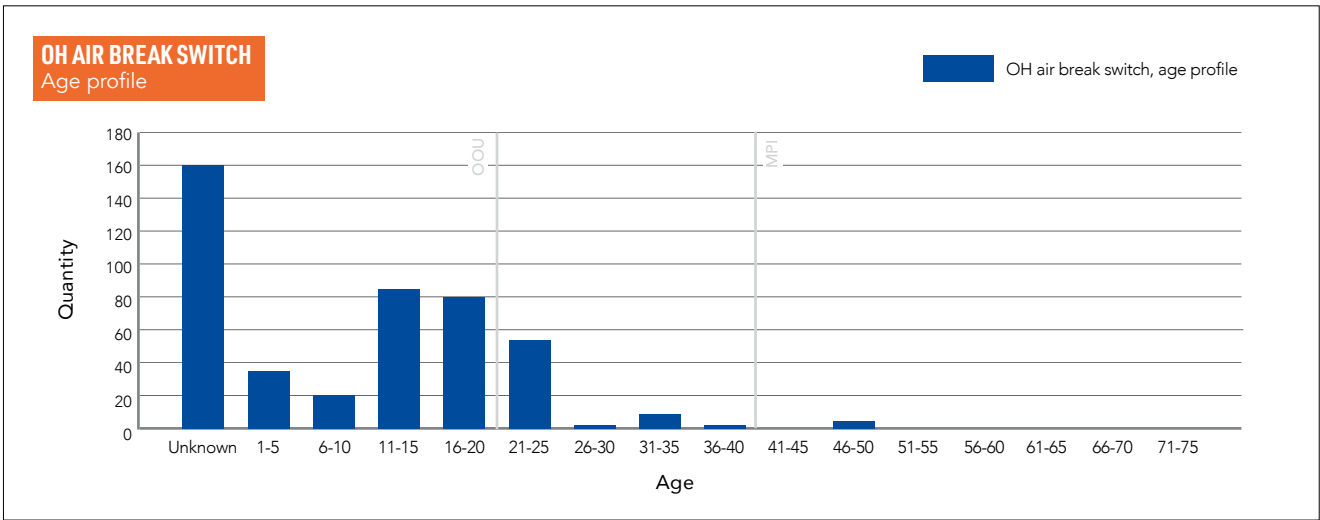


Figure 138: Age profile (ABSs)

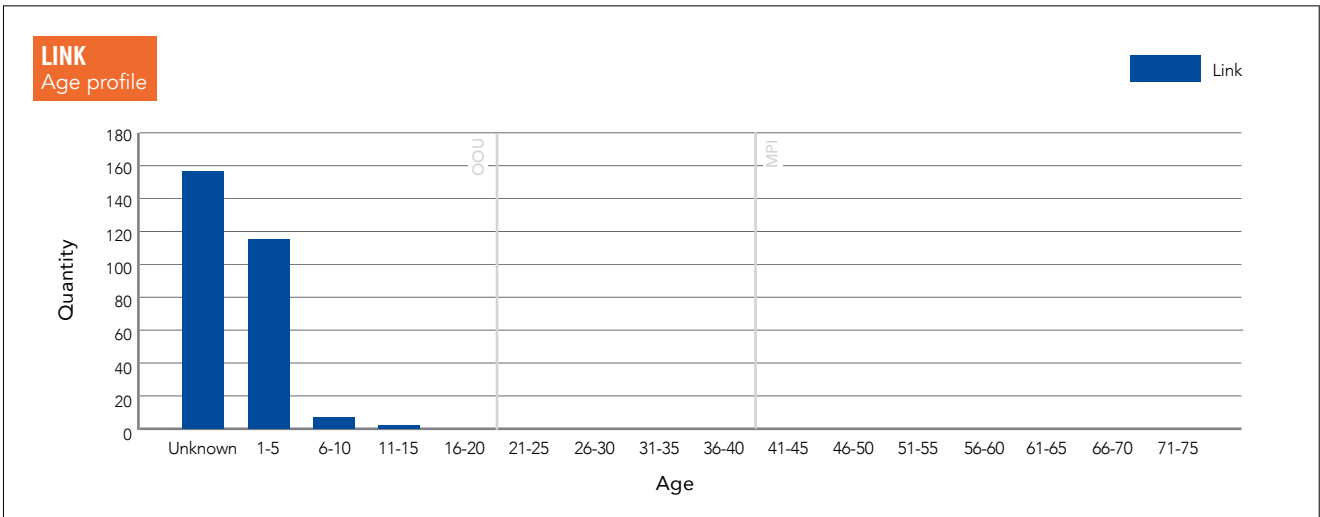


Figure 139: Age profile (links)

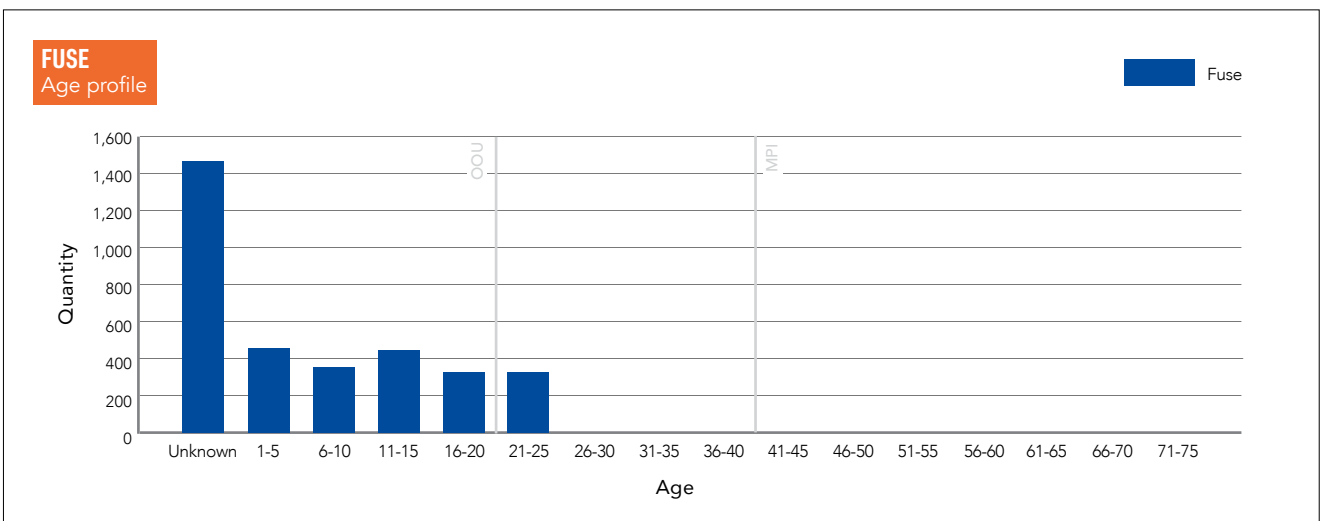


Figure 140: Age profile (dropout fuses and unknown)

13.18.11 Asset health

The health assessment for overhead switches is shown in figure 141 to figure 144. The assessment is based on the EEA asset health guide, including the health forecasting discussed in Section 13.5.3.

The health forecasting for enclosed LBSs and ABSs is predominantly age-based (38% of LBSs and 25% of ABSs have condition data). 100% of LBSs and 64% of ABSs have age data. Hence, for LBSs, health forecasting is good, and for ABSs, it is average (see Section 9.5.2 for definitions of data quality). We intend to use condition data for health forecasting for LBSs and ABSs, so the assessment accuracy for these assets will improve over the next few AMPs as condition data is captured through the inspection process.

We have no condition data for links and fuses, and the age data is 44% and 60%, respectively. Hence, current health forecasting is poor (i.e. unreliable). It is not practical to improve the age dataset (as this data cannot be obtained from our visual inspections); hence, our health and forecasting for these assets will only improve as we get condition data. Improvements can be expected over the next five years.

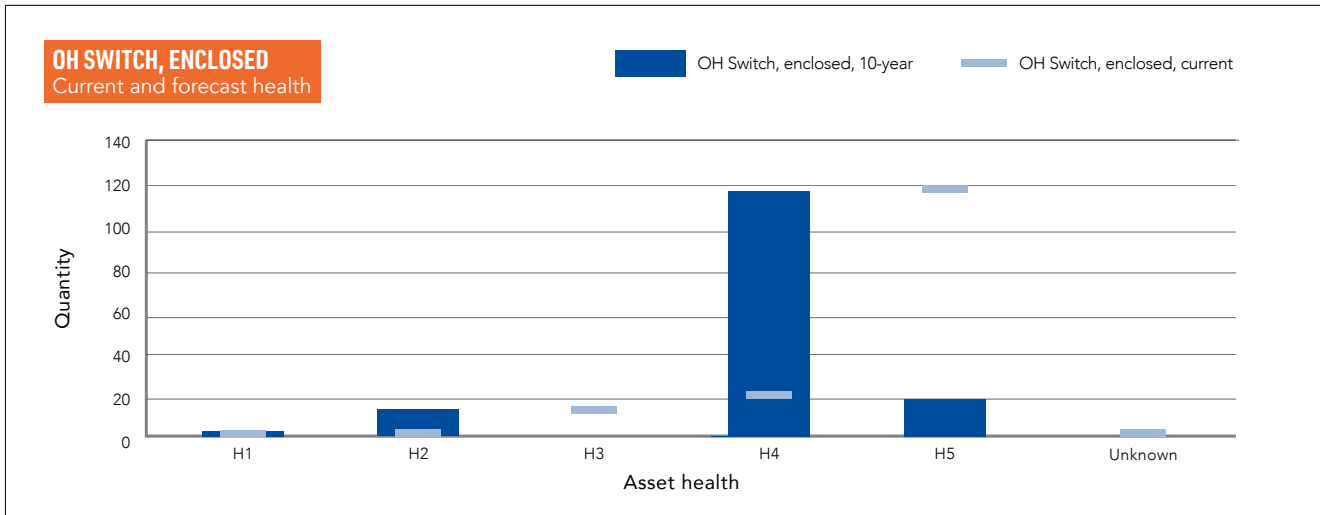
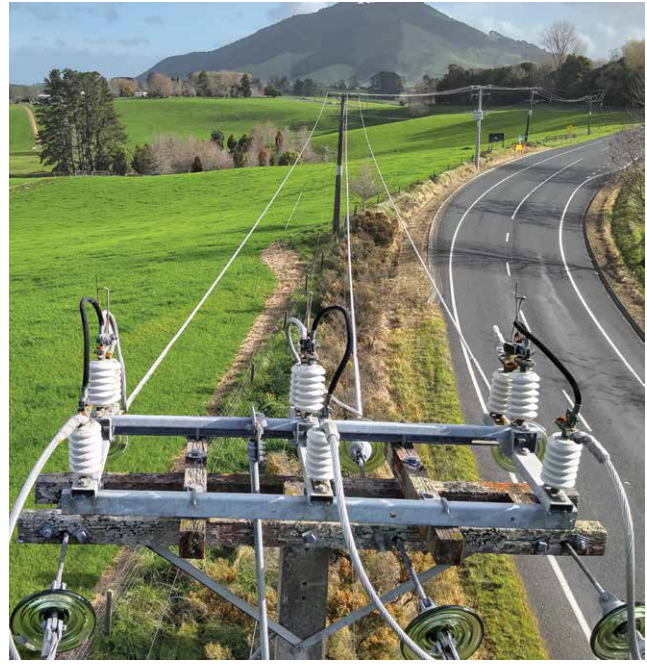


Figure 141: Current and forecast asset health (enclosed LBSs)

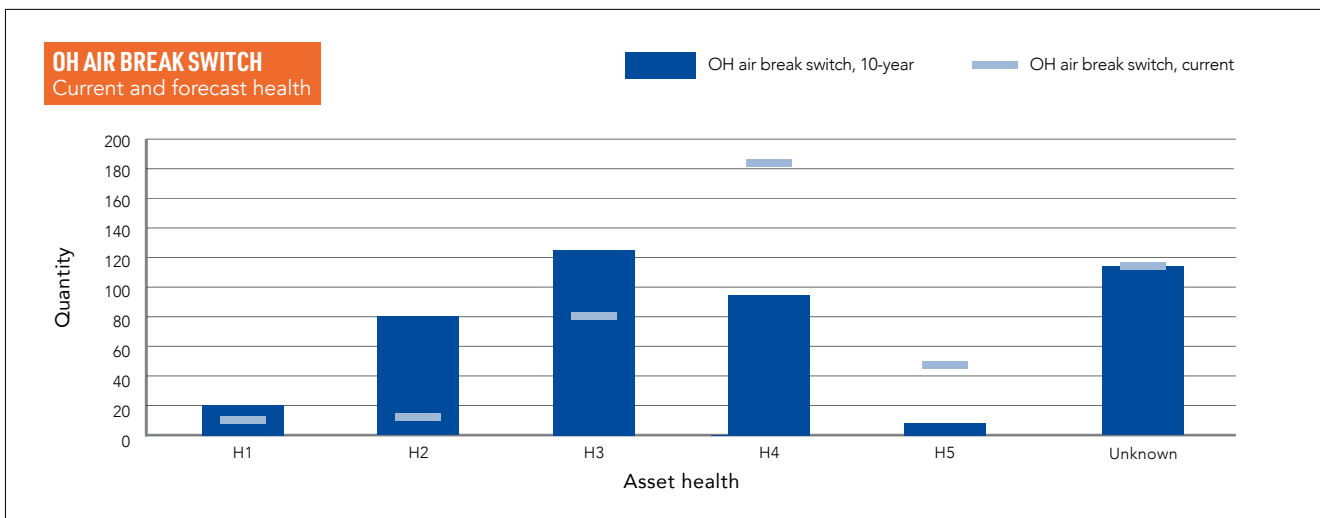


Figure 142: Current and forecast asset health (ABS)

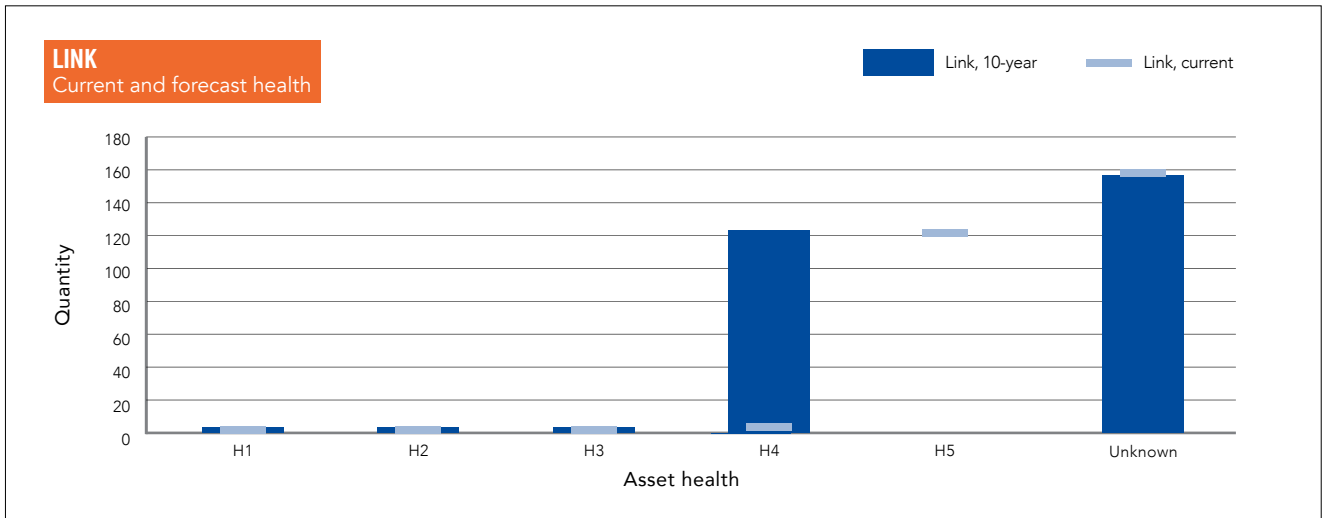


Figure 143: Current and forecast asset health (links)

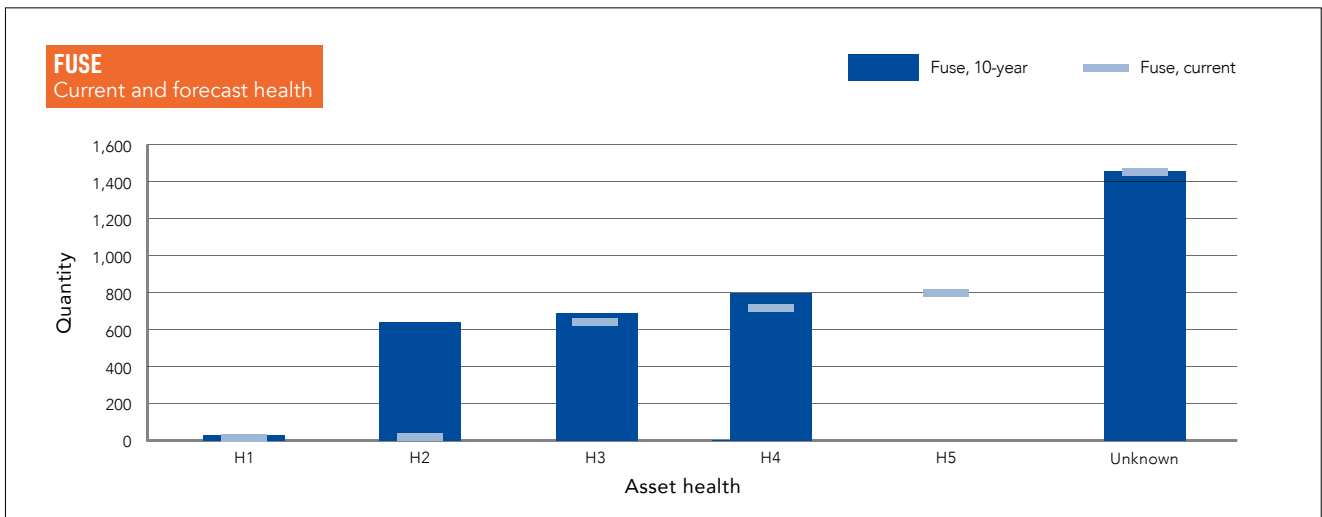


Figure 144: Current and forecast asset health (dropout fuses and unknown)

Table 165 shows the current and forecast for low-health overhead switches over the next 10 years. For enclosed LBS switches and ABSs, health forecasting is considered good

and average, respectively. For links and dropout fuses, the data is not regarded as accurate and is not used for renewal forecasting.

Type	Quantity	Grade H1 & H2 (Current)	Grade H1 & H2 (+10yrs)	% of fleet at grade H1 & H2 (+10yrs)
Enclosed LBS	154	2	16	10.4%
ABS	445	21	101	22.7%
282 Links	3,652	Not reliable	Not reliable	Not reliable
Dropout fuse	154	"	"	"

Table 165: Current and forecast asset health (ABSs and enclosed LBSs)

13.18.12 Asset replacements

For ABSs and enclosed LBSs, we forecast replacing all H1 and H2 assets over the next 10 years (as shown in table 166). The renewal rate is sufficient to eliminate all H1 enclosed LBSs by the end of FY29. However, we are forecasting a constant ABS replacement rate over the next 10 years (rather

than frontloading this to the FY27 to FY29 period), which means all H1 ABSs will be eliminated by FY31. A flattened replacement rate better fits our resourcing, and we do not consider that the two-year delay in eliminating H1 ABSs will create material risk, as we will be prioritising renewal in areas with high criticality.

Type	Grade H1 (+10yrs)	Grade H1 & H2 (+10yrs)	10yr forecast replacements
ABS	21	101	168
Enclosed LBS	2	16	16
Dropout fuse	Not reliable	Not reliable	453
Link	"	-	Defect only

Table 166: Asset renewal forecast

13.18.13 Expenditure forecast

Table 167 shows the forecast expenditure for this fleet. The forecast expenditure is consistent with that included in the 2025 AMP. The renewal provision for "other drivers" accounts for storm and vehicle damage.

Description	Type	Category	FY27	FY28	FY29	FY30	FY31	FY32-36
Enclosed LBS renewal	Planned	ARR	-	-	47	47	-	664
ABS renewal	Planned	ARR	662	662	662	662	688	3,441
Link replacements	Unplanned	ARR	-	-	-	-	-	-
Dropout fuse replacements	Unplanned	ARR	267	267	274	274	274	1,368
Unplanned replacements (all types), other drivers	Unplanned	ARR	79	79	79	79	79	395
Total	-	ARR	1,008	1,008	1,062	1,062	1,041	5,867

Table 167: Forecast expenditure

FY26 real \$000

13.19 Distribution and LV cable fleet plan

13.19.1 Fleet overview

Underground cables comprise 12% of Waipā Networks' distribution circuit length and 45% of the LV circuit length. This fleet plan includes 11kV and LV cables, as shown in table 168.

Asset type	Quantity
11kV cable	183 km
LV cable	408 km

Table 168: Cable fleet circuit length

Cables need to have good insulating properties (as they are buried in the ground and may contact other objects that must not become live), good conductivity (to minimise losses and associated heating), and resistance to deterioration of the insulation and conductor (as they are expensive to replace) – differences in insulation and cable construction result in different OOU and MPL.

Table 169 summarises the types of cables currently used on the network. We have gaps in our cable attribute and age data, and improving this data is part of our asset management improvement plan (see Section 9.6.3).

Cable and insulation type	Approximate % of the fleet	Attributes
11kV XLPE	100%	Cross-linked polyethylene is used as the insulation medium around the cable cores for these cables. PVC separates the cores and outer protection of aluminium sheaths or steel wire armour with a final sheath of PVC.
11kV PILC	0.01%	PILC uses oil-impregnated paper insulation. A lead sheath protects the cable cores and insulation. A lead sheath encases the cable, and a further outer sheath of tar-impregnated fibre material, PVC, or polyethylene. PILC cables have been used for over 100 years and typically have a long MPL. XLPE cables are favoured over PILC. The last of our PILC cables will be replaced in FY26 as part of the Te Awamutu GXP 11kV feeder cable upgrade project.
400V XLPE/PVC	100%	These cables use mostly XLPE insulation and an outer protective sheath of PVC. PVC insulation is sometimes used.

Table 169: Cable type

There is a range of failure modes for cables. These can be incremental, where health decays over time, or more acute, where failure is caused by foreign interference (e.g. digger excavation). Early generation XLPE cables were prone to insulation deterioration and premature failure due to water treeing. Other failure modes may be due to aluminium screening and the brittling of PVC sheaths (known as the 'red rubber sheathing' cable) associated with the older XLPE cables. These issues can cause water ingress, insulation deterioration, or other safety issues.

We believe we have many HV cables with 'red rubber sheathing' or early-generation XLPE, mainly in the Cambridge network. Our data improvement work will assist in assessing the extent of these cables on the network.

Note: This fleet plan excludes streetlight cables.

13.19.2 Fleet performance

We do not have detailed failure data for cables (which are currently grouped with conductors). However, based on operational observations, we experienced several failures over the years with the 'red rubber sheath' 11kV cable due to brittleness of the PVC sheath. Note: Recent changes to the fault recording system will provide additional data to enable better fault trend analysis in future AMPs.

13.19.3 Fleet risks

Table 170 highlights the predominant risk posed to the cable fleet, its impact, and our response.



Risk	Stakeholder impact	Stakeholder linkage	Our response
Excavation machinery coming into contact with live cables, risking electrocution and equipment damage	Electrocution or electric shock Damage to equipment Network outages	Public safety Network performance	Warning tape and protection are fitted above the cables. 11kV cables have steel protective screening. Electrical protection isolates the cable in the event of a fault. We have a public safety campaign to raise awareness of risks around digging in the road reserve. Provide a cable locate service to 3rd party, provide a mark-up, and issue a closed work permit.
The early generation 11kV XLPE cable, particularly the 'red rubber sheath' cable, has a high failure rate	Network outages	Network performance	Reactive renewal when such a cable is identified. Improve the quality of asset attribute and age data (see Section 9.7.3).

Table 170: Fleet risks

13.19.4 Fleet strategy

The objective of the cable fleet is to reliably and efficiently deliver electricity to consumers. Improving data quality is necessary to better understand asset health and address low-health assets.

To address the fleet performance, risks, and other issues mentioned in the preceding sections, the 10-year strategy for this fleet is shown in table 171.

Strategy	Description	Outcome
Improve asset attribute and age data	<ul style="list-style-type: none"> Refer to Sections 9.7.3 	<ul style="list-style-type: none"> Increase in data accuracy scores for asset register and age profile
Common fleet strategies (refer to table 93 in Section 13.6)	<ul style="list-style-type: none"> Enhance asset health assessment and forecasting (as we are currently relying on fault and reliability analysis to identify low health assets and drive the renewal projects) Implement risk-based renewal forecasting Enhance renewal project selection and prioritisation Understand and reduce fleet risk 	<ul style="list-style-type: none"> Increase in asset condition data accuracy score Increase in condition-based forecasting to >95% Improve the quality of our asset health and renewal forecasting Improved optimisation of work plans and project timing Reduce reliability and safety risks
Assess new condition assessment techniques.	<ul style="list-style-type: none"> We will monitor industry development concerning cable condition assessments. These will be adopted where practical to do so. 	<ul style="list-style-type: none"> Improved condition assessment, more accurate health forecasting, and more proactive health-based renewals
Public safety campaign to raise awareness for "Dial before you dig."	<ul style="list-style-type: none"> Newspaper adverts, social media campaigns, community events and target group (e.g., emergency services, excavators, etc.) presentations as part of our Public Safety Management System and its KPI 	<ul style="list-style-type: none"> Minimise public safety risks SFARP (So Far As Is Reasonably Practicable)
Replace early generation / 'red rubber sheath' 11kV XLPE cables	<ul style="list-style-type: none"> Reactive renewal when such a cable is identified through other projects or when asset data improves 	<ul style="list-style-type: none"> Progressively replace the older cable, improve overall fleet performance

Table 171: Fleet strategy

13.19.5 Design and construct

Cable selection and design are integrated into the line design process. We have a standard suite of cable sizes for each voltage.

As part of our network transformation roadmap, we will review cable sizes to ensure they remain appropriate for our future needs.

13.19.6 Monitoring

Proactive cable monitoring is limited to 11kV terminations. Cable testing is performed when fault and reliability trends indicate potential cable deterioration.

Monitoring type	Description	Frequency
Inspection and testing of 11kV cable terminations	<ul style="list-style-type: none"> Partial discharge and acoustic diagnostic testing of cable terminations in switchgear occurs as part of switchgear testing, Acoustic and visual inspection of the live termination in the distribution transformer HV compartment under a specific Standard Operating Procedure Overhead cable terminations are inspected as part of the detailed overhead line inspections 	<p>Every three years</p> <p>Every five years</p>
11kV Cable testing	<ul style="list-style-type: none"> We perform insulation testing on cable runs to assess the condition of a cable length where we have concerns about the cable's performance 	Ad hoc
400V cable	<ul style="list-style-type: none"> We do insulation testing on cable runs to assess the condition of a cable length where we have concerns about the cable's performance 	Ad hoc

Table 172: Fleet monitoring

13.19.7 Maintaining

There are no specific maintenance routines for cables. We will replace termination and joints if these show signs of deterioration after inspection or testing.

13.19.8 Renewal

Our fleet renewal approach is shown in table 173.

Decision	Description
Renewal forecasting	<ul style="list-style-type: none"> The forecast of asset renewals is to replace all current and forecast H1 and H2 assets over the next 10 years
Determining specific renewal projects	<ul style="list-style-type: none"> Renewal projects are determined from reliability trends and fault trends. These assessments direct more detailed testing to determine if renewal is required The assessments are prioritised by criticality and the worst-performing feeder
Assessing alternatives	<ul style="list-style-type: none"> For cables, the only alternative to like-for-like replacement relates to cable size. We may consider installing a larger cable size
Defect replacement	<ul style="list-style-type: none"> Defects are compiled in our defect management system, and a rating is applied based on urgency. The urgency rating considers the criticality of the asset. This mainly applied to 11kV terminations

Table 173: Fleet renewal forecasting

13.19.9 Spares

Cable is a common asset. We hold termination and joint spares and a reasonable amount of 11kV and 400V cables sufficient to support fault situations.

13.19.10 Population and age

The population and age of our cable fleet assets are shown in figure 145 and figure 146. Due to the high number of unknown assets, the data is not considered reliable. As mentioned earlier, improving cable age data is an important improvement project.

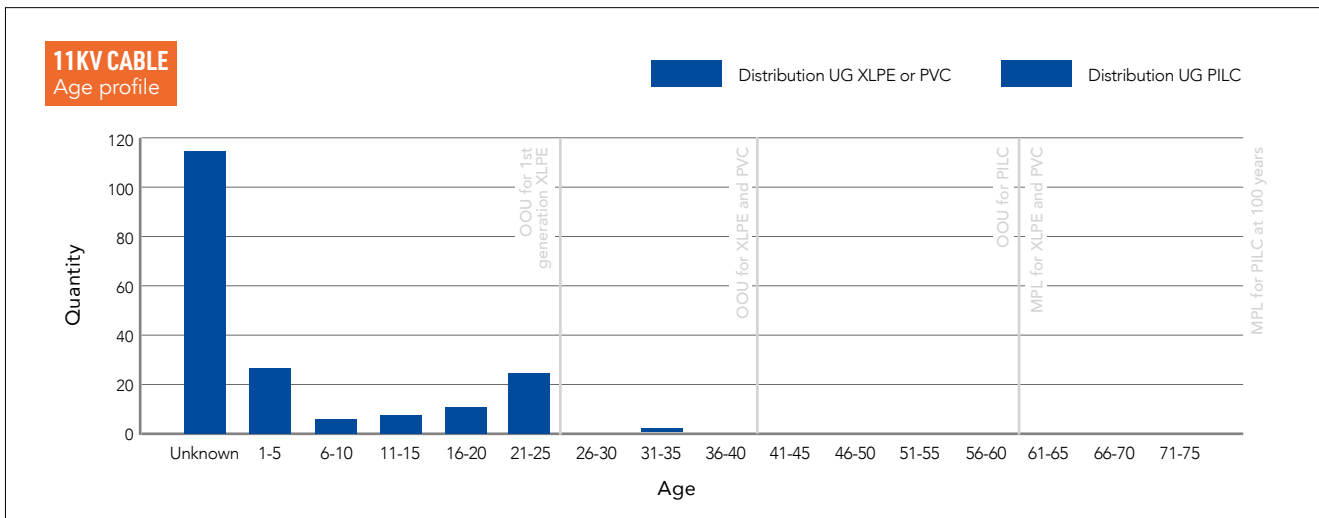


Figure 145: Age profile, 11kV cable

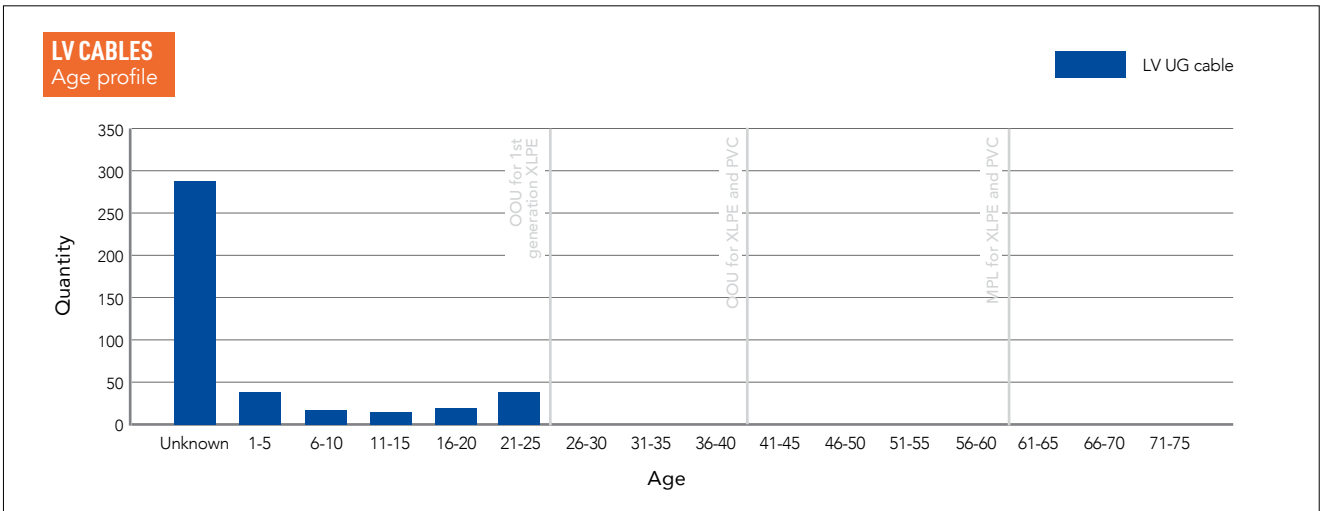


Figure 146: Age profile, LV cable

13.19.11 Asset health

The health assessment for 11kV and LV cables is shown in figure 147 to figure 149. The assessment is age-based using the EEA asset health guide, including the health

forecasting discussed in Section 13.5. As noted above, the age data is unreliable and should be treated only as a rough guide. Our health forecasting will improve following improvements to the data.

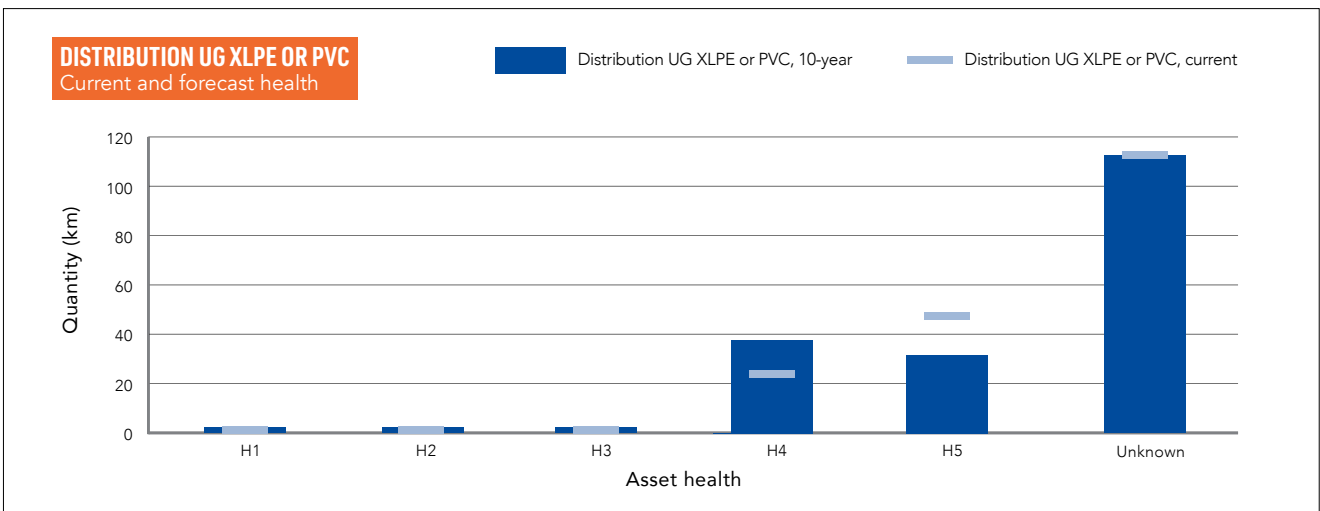


Figure 147: AHI, 11kV XLPE cables

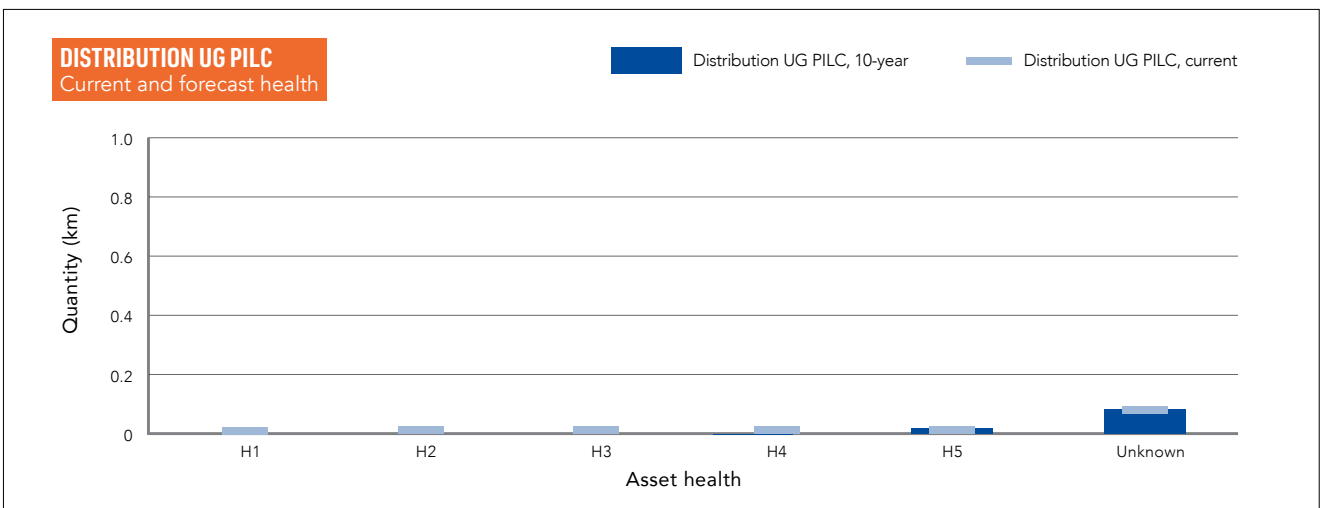


Figure 148: AHI, 11kV PILC cables

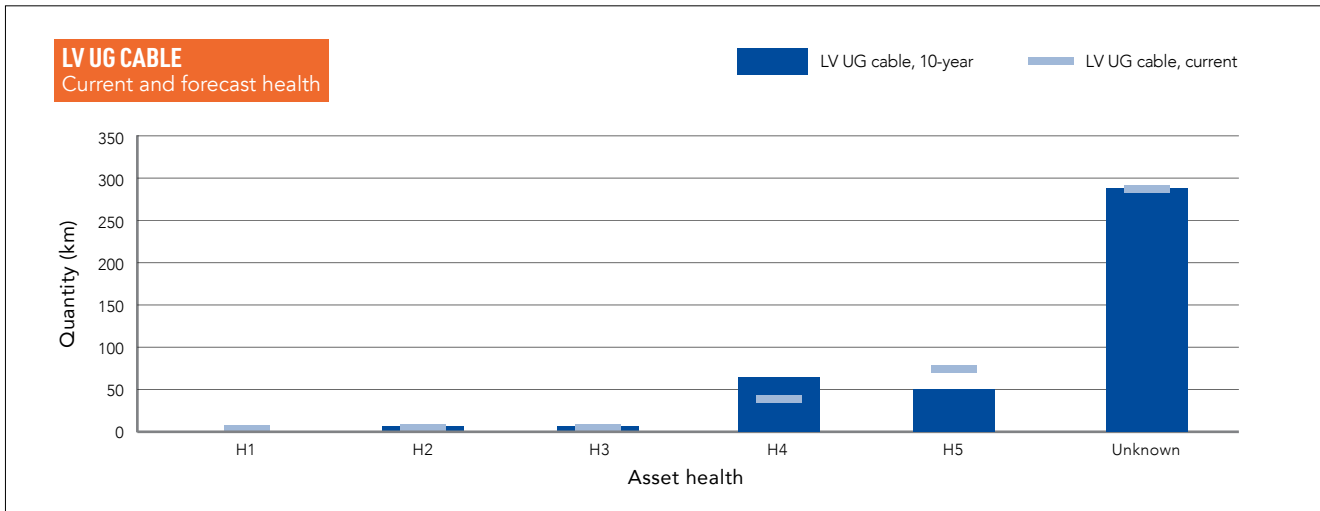


Figure 149: AHI, LV cables

Table 174 shows our current estimates of assets that will reach health grade H1 and H2 over the next 10 years. This assessment is not considered to be reliable.

Type	Quantity	Grade H1 & H2 (Current)	Grade H1 & H2 (+10yrs)	% of fleet at grade H1 & H2 (+10yrs)
11kV cable	183	Unreliable	Unreliable	Unreliable
LV cable	408	Unreliable	Unreliable	Unreliable

Table 174: Current and forecast asset health (circuit km)

Note: Quantities are in km.

13.19.12 Replacement programme

We have estimated the quantity of assets for renewal over the next 10 years (as shown in table 175). The forecast cable replacements are a provision only.

Type	Grade H1 & H2 (+10yrs)	10yr forecast replacements
11kV cable	Unreliable	3.5
LV cable	Unreliable	10

Table 175: Asset renewal forecast (circuit km)

Note: Quantities are in km.

Description	Type	Category	FY27	FY28	FY29	FY30	FY31	FY32-36
11kV cable reactive replacement	Planned	ARR	103	103	103	103	103	513
LV cable reactive replacement	Planned	ARR	184	184	184	184	184	920
Total	-	ARR	287	287	287	287	287	1,433

Table 176: Forecast capital expenditure

FY26 real \$000

13.19.13 Expenditure forecast

Forecast expenditure for this fleet amounts to \$2.9m over the next 10 years (table 176). The forecasts include a provision for replacing early-generation XLPE cables reactively when they are identified during other project work, and for unplanned renewal of LV cables. We have not included a provision for third-party damage repairs as these are difficult to forecast (and the net impact will be minimal as customer contributions are required for repairs).

13.20 Distribution ground-mounted transformers

13.20.1 Fleet overview

The purpose of distribution transformers is to convert the electricity supply from the distribution voltage (11kV) to low voltage (400V/230V) suitable for supply to residential, commercial and rural customers. A secondary purpose is to isolate the low-voltage network from common-mode voltage changes that can occur during asymmetrical earth faults on the 11kV network.

Ground-mounted distribution transformers have a capacity from 50kVA to over 1,500kVA. We hold spare transformers in stock for the standard sizes. These are generally located on the berm or on the customer premises. Transformers on industrial or commercial premises are covered by easement or existing use rights.

Table 177 summarises the population of ground-mounted distribution transformers by kVA rating.

Rating	Quantity	% of total	Typical usage
< 100kVA	137	14%	Mainly 50kVA supplying a few rural lifestyle customers in the urban fringe.
100kVA	228	24%	Supplying small urban areas or commercial customers
150 to 200 kVA	306	32%	Supplying urban areas or commercial customers
300 kVA	156	16%	Supplying commercial, industrial and urban areas
500kVA	72	8%	Supplying industrial customers
>500kVA	54	6%	Supplying industrial customers
Total	953	100%	

Table 177: Ground-mounted distribution transformer population by kVA rating

We have good-quality data on the age and attributes of this fleet. All but one asset has a date of manufacture. Asset condition data is available for 76% of the fleet. This should increase close to 100% over the next 2-3 years.

13.20.2 Fleet performance

Ground-mounted transformers are often located where the public can access them and, therefore, need to be designed and secured to ensure public safety. There are no recorded public safety events concerning these assets.

Apart from one known 1.5MVA transformer failure due to a tap changer, there have been very few incidents of ground-mounted transformer failures. There are presently no concerns with the fleet's performance.



13.20.3 Fleet risks

Table 178 highlights the material risks associated with the ground-mounted transformer fleet, their impact on stakeholders, and our response.

Risk	Stakeholder impact	Stakeholder linkage	Our response
Third-party interference (Car vs. Transformer) that damages the asset, causing outages and potential contact with live parts	Transformer damage could result in a large outage and injury to members of the public	Public safety Network performance	Our fleet strategy includes a mitigation plan.
Public gain access to live parts through poorly secured or damaged locks and doors	Injury to members of the public	Public safety	Doors are securely fixed and locked, and live parts are screened internally Large urban transformers are inspected annually to ensure that public safety measures are maintained An upgrade to the locking system is planned
Oil leaks that could cause environmental damage	Environmental damage	Environmental damage	The assets are inspected annually, and assets with oil leaks are replaced. We have oil spill kits, and our field crews are trained to handle oil spills should a leak occur
The earthing system is damaged, compromising electrical protection and risking fatal voltages	Proper earthing is critical to the multiple-earthed neutral (MEN) system in New Zealand	Public safety Regulatory breach	The earth is inspected and tested every five years
Unforeseen demand growth occurs, which causes overloading and damage to transformers	Transformer failure could result in a large outage	Network performance	Five-yearly monitoring of transformer load We are investigating an LV visibility solution
Sub-optimal transformer tap setting leading to high or low voltages at the LV network	Poor supplier voltage will affect customers' appliances and equipment and limit their ability to connect Distributed Energy Resources like electric vehicles and solar generators	Public safety Network performance Regulatory breach	Potential voltage issues due to network growth and backfeed are studied The low Voltage Complaint process addresses voltage issues We are investigating LV visibility solutions to enable proactive action

Table 178: Fleet risks



13.20.4 Fleet strategy

The objective for this fleet is to provide a reliable and compliant LV supply to customers and maintain public safety.

To achieve the fleet objective, address the fleet performance, risks, and other issues mentioned in the preceding sections, the 10-year fleet strategy is shown in table 179.

Strategy	Description	Outcome
Common fleet strategies (refer to table 93 in section 13.6)	<ul style="list-style-type: none"> Enhance inspection standards (complete) Enhance condition data through inspections Enhance asset health assessment and forecasting Implement risk-based renewal forecasting Enhance renewal project selection and prioritisation 	<ul style="list-style-type: none"> Increase in asset condition data accuracy score Increase in condition-based forecasting to >95% Improve the quality of our asset health, risk and renewal forecasting Improved optimisation of work plans and project timing Reduce reliability and safety risks
Eliminate all H1 transformers by the end of FY27	<ul style="list-style-type: none"> Ensure all H1 transformers are replaced before failure Ensure all H2 transformers are replaced before they become H1 	<ul style="list-style-type: none"> Zero H1 transformers
Ensure the security of the assets	<ul style="list-style-type: none"> Annual public safety inspection 	<ul style="list-style-type: none"> Zero public safety incidents
Maintain critical spare	<ul style="list-style-type: none"> Consider geotechnical and flooding hazards in the new site and structure design Stock critical spares. Review the spares required for industrial customers and include appropriate spares 	<ul style="list-style-type: none"> Critical spares of the right size and type are available for unplanned renewal
Timely replacement of defects	<ul style="list-style-type: none"> For ground-mounted transformers, given the potentially high consequence of failure, defect replacements shall occur promptly 	<ul style="list-style-type: none"> No failure of assets with defect notices
Assess third-party damage risk	<ul style="list-style-type: none"> Undertake a review of vehicle crashes to determine if there are any high-risk sites 	<ul style="list-style-type: none"> Consider protection or relocation for high-risk sites.
Enhance fleet resilience (refer to Section 9.4)	<ul style="list-style-type: none"> The design for new sites will take into consideration flooding and geotechnical hazards (seismic and wind are already covered in the design standards) 	<ul style="list-style-type: none"> Resilience to natural hazards

Table 179: Fleet strategy

13.20.5 Design and construct

The transformer foundations are designed to structural design standards (NZS 1170 series), and the transformers are designed to AS/NZS/IEC 60076 series. The transformer design standards include a capitalised loss calculation to ensure new transformers are efficient over their lifecycle. The design for these assets considers seismic in the structural design standards. Flooding and geotechnical hazards are considered during site selection.

Waipā Networks has standard designs prepared for general ground-mounted transformers, including its LV frame. Currently, we do not have any transformers with LV circuit breakers.

Special design requirements are in place for new transformer sites:

- In the circumstances of the overhead network supplying a ground mount transformer via a long cable (exceeding 200m), our design rules require a 3-phase switch to be installed in series with the drop-out fuse. Based on operating experience, there are no known ferro-resonance concerns for our network.
- For industrial or commercial sites with large, dedicated transformers supplying industrial or commercial consumers, our current design rules require a protection device on the transformer LV. We have standardised ganged fuse LV frame designs for transformers up to 1.5MVA. Special dispensation may be considered, and we would require the customer to meet the additional requirements under the NSZ3000 (e.g., mechanical protection) as an 'unprotected main'.

13.20.6 Monitoring

Ground-mounted transformers are inspected, and their earthing systems are tested separately from the detailed line inspection. Table 180 describes our current fleet monitoring approach.

Monitoring type	Description	Frequency
Safety inspection	<ul style="list-style-type: none"> Inspection of security, locks, doors and other public safety hazards for transformers located within urban areas 	Annually
Detailed inspection	<ul style="list-style-type: none"> The detailed inspection captures the EOL condition drivers, which (under the new standard) include the condition of the external tank, oil leaks, HV panel, LV panel, locks, doors, and earthing connections Reading of LV MDIs Defect notices are raised where priority repair or replacement is required 	Every five years
Earth testing	<ul style="list-style-type: none"> Measure the resistance of earthing connections Visual inspection of the earth connection 	Every five years
Special industrial site inspections	<p>Transformers supplying major industrial sites may be subjected to additional inspection and tests based on site-specific requirements and commercial arrangements with the owner, including but not limited to the following:</p> <ul style="list-style-type: none"> Detailed inspection as detailed above Dissolve gas analysis 	As agreed with the Customer

Table 180: Fleet monitoring

13.20.7 Maintaining

There are no specific maintenance routines for ground-mounted distribution transformers. However, earthing systems are maintained to achieve the same MPL as the transformer.

Distribution transformers removed due to capacity or surface corrosion are taken for painting and testing before being returned to our spares holding (for later use on the network). Large industrial units are sent for more detailed maintenance.

13.20.8 Renewal

Our fleet renewal approach is shown in table 181.

Decision	Description
Renewal forecasting	<ul style="list-style-type: none"> The forecast of asset renewals is to replace all current and forecast H1 and H2 assets over the next 10 years
Determining specific renewal projects	<ul style="list-style-type: none"> Renewal projects are determined from reliability trends and fault trends. These assessments direct more detailed testing to determine if renewal is required The assessments are prioritised by criticality and the worst-performing feeder
Assessing alternatives	<ul style="list-style-type: none"> For cables, the only alternative to like-for-like replacement relates to cable size. We may consider installing a larger cable size
Defect replacement	<ul style="list-style-type: none"> Defects are compiled in our defect management system, and a rating is applied based on urgency. The urgency rating considers the criticality of the asset. This mainly applied to 11kV terminations

Table 181: Fleet renewal forecasting

13.20.9 Spares

We hold sufficient stock of standard sizes for defect replacement. We increase our stockholding when supplier deliveries are constrained and lead times are extended. We are reviewing the need for spares of large sizes and non-standard configurations.

13.20.10 Population and age

The population and age of our ground-mounted transformer fleet are shown in figure 150. The graph indicates that 11% of the fleet is above a Waipā Networks-specific OOU, but no assets are at MPL¹⁴⁷. Our condition and asset replacement data suggest that the OOU for us is around 30 years, above the EEA standard for this asset type of OOU of 20 years.

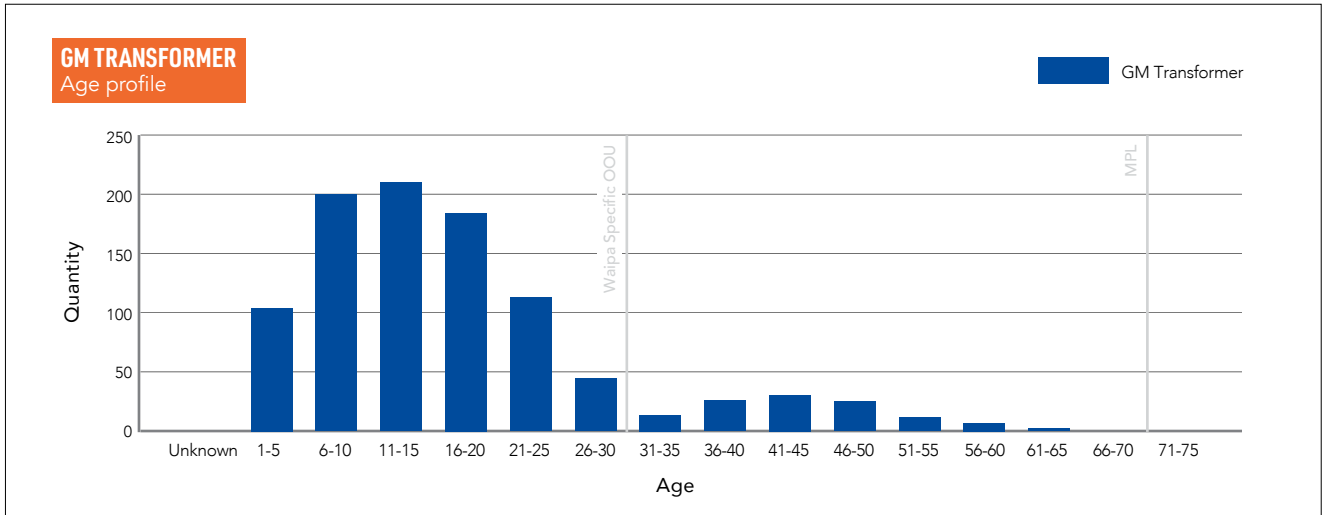


Figure 150: Age profile¹⁴⁸

13.20.11 Asset health

The health assessment for ground-mounted distribution transformers is shown in figure 151 and is based on the EEA asset health guide, including the health forecasting discussed in Section 11.5.3.

The data used for ground-mounted transformer health forecasting is robust, with 76% being condition-based. The remainder of the assets have good age data. The deterioration of ground-mounted transformers is relatively gradual, consistent with the long MPL for this fleet.

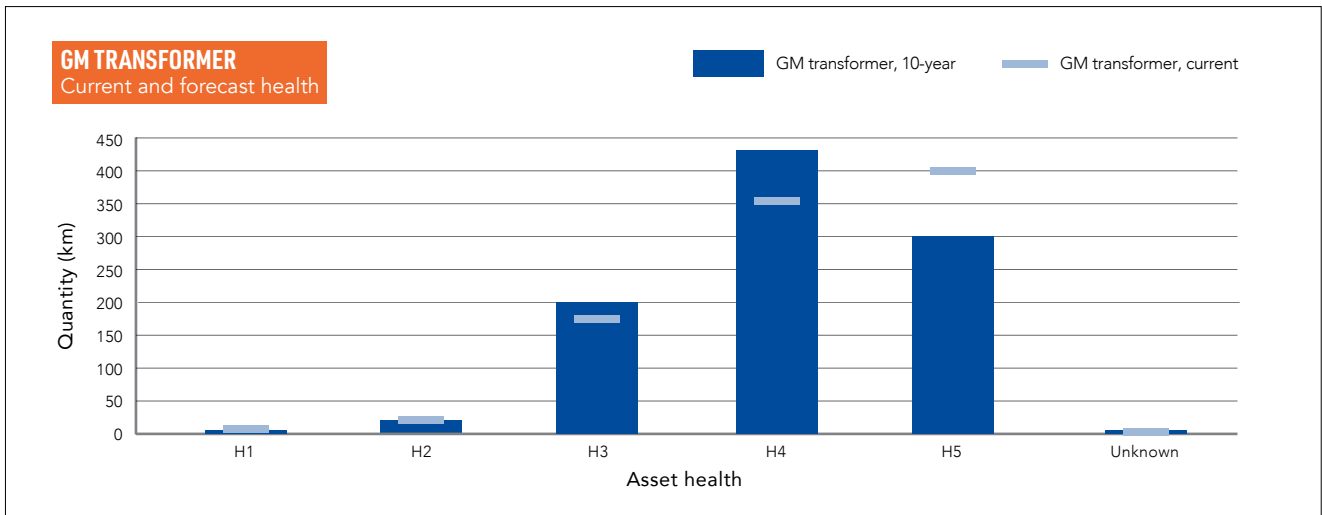


Figure 151: Current and forecast asset health

Table 182 shows the current forecast numbers of low-health ground-mounted transformers over the next 10 years. 100% of low-health transformers are forecast based on condition. The recent inspections revealed some H1 transformers that will need timely replacement.

¹⁴⁷ Ground-mounted transformers have a Waipā OOU of 30 years and an MPL of 70 years.

¹⁴⁸ The Waipā specific OOU was discussed in the 2024 AMP.

Type	Quantity	Grade H1 & H2 (Current)	Grade H1 & H2 (+10yrs)	% of fleet at grade H1 & H2 (+10yrs)
Ground-mounted transformers	953	27	27	2.8%

Table 182: Current and forecast asset health

13.20.12 Asset replacements

Consistent with our renewal strategy, we forecast replacing all H1 and H2 ground-mounted transformers over the next 10 years (as shown in table 183). Our 10-year forecast for renewals is slightly higher than that for H1+H2 assets. Based on new condition data, we reduced our forecast for renewal compared to the 2025 AMP (by ~12 transformers). Given that we are awaiting condition data for the remaining 24% of the fleet, we refrained from further reducing renewals. This will be updated in the next AMP when additional condition data will be available.

Type	Grade H1 & H2 (+10yrs)	10yr forecast replacements
Ground-mounted transformers	27	35

Table 183: Asset renewal forecast

13.20.13 Expenditure forecast

Table 184 shows the forecast expenditure for this fleet. The forecast expenditure is around \$1.0m below the 2025 AMP due to better fleet health (however, expenditure has increased in the first five years compared to the 2025 AMP).

The renewal provision for "other drivers" covers damage to the asset caused by other drivers (e.g., weather events or third-party damage). The provision for transformer replacements for load upgrades is included in the development plan.

Description	Type	Category	FY27	FY28	FY29	FY30	FY31	FY32-36
Ground-mounted transformer, renewals	Planned	ARR	333	333	333	333	333	666
Ground-mounted transformer, other drivers	Unplanned	ARR	68	68	68	68	68	341
Total	-	-	401	401	401	401	401	1,007

Table 184: Forecast capital expenditure

FY26 real \$000

13.21 Distribution ring main units (RMUs)

13.21.1 Fleet overview

Our fleet of ring main units (RMUs) provides switching points for the underground cable network. Almost all the RMUs are in the urban, commercial and industrial areas. They are primarily installed in the road reserve with significant public exposure.

We currently have 198 11kV RMUs in service. The fleet is relatively young, as all old oil-filled RMUs were replaced due to potential fire risk. Table 185 summarises the types of RMU installed in the network.

Manufacturer/Type	Insulation	Qty	% of Fleet
Schneider 11kV RingMaster RMU	Air/SF6 insulated	5	2.5%
Entec 11kV Halo RMU	Solid insulation	3	1.5%
ABB 11kV Safelink and Safelink2	SF6 insulated	21	10.5%
ABB 11kV SafeRing/SafePlus	SF6 insulated	152	77%
Siemens 11kV 8DJH RMU	SF6 insulated with insulated elbow termination	10	5.0%
Unrecorded	-	7	3.5%
Total	-	198	100%

Table 185: Asset types

We have good quality data on the age and attributes of this fleet. 98% of RMUs have a known date of manufacture. Asset condition data (to the new standard) is presently being captured and is available on 67% of the fleet. We conducted a network-wide RMU partial-discharge survey and proactively mitigated sites with high partial-discharge readings.

13.21.2 Fleet performance

Failures and operational issues are rare, but the impacts on customers can be significant when they do occur. In FY23, an RMU failure on the Cambridge East feeder caused 11.84 SAIDI minutes. We are also experiencing RMU damage due to cable termination failures, mainly triggered by moisture-induced partial discharges and flashovers within the cable compartment for certain types of RMU. Due to the RMU's intrinsic safety design, faults are well contained within the RMU.

13.21.3 Fleet risks

Table 186 highlights the material risks associated with the RMU fleet, their impact on stakeholders, and our response.

Risk	Stakeholder impact	Stakeholder linkage	Our response
Third-party interference (Car vs. RMU) that damages the asset, causing outages and potential contact with live parts	RMU damage could result in a large outage and injury to members of the public	Public safety Network performance	Refer to the fleet strategy
The public gain access to the switch controls through poorly secured or damaged locks and covers	Unauthorised operation of the switch results in switch damage, customer outages, and potential injury to members of the public	Network performance Public safety	The covers are securely fixed and locked. RMUs are inspected annually to ensure that public safety measures are maintained. An upgrade to the locking system is planned.
Cable termination for ABB RMU is susceptible to condensation-triggered partial discharge, hence failure	Cable termination failure could result in a large outage	Network performance Note: The RMU is arc containment rated for safety.	A partial discharge test has been included in the standard maintenance procedure.
ABB SafeLink RMUs manufactured in certain years are prone to have the switch over-travel when operating, phase making contact to earth, resulting in an internal fault	RMU switch over-travel could result in an internal fault and a large outage	Network performance Staff safety Note: The RMU is arc containment rated for safety	We follow the manufacturer's instructions and operate such RMU with the Manufacturer's proprietary overtravel arrest device.
According to the latest industry update, Entec Halo RMU has recorded internal failures, which typically occur during switching upon re-livening. We have three units in the network	RMU internal faults will result in a large outage and expose staff to hazards	Network performance Staff safety	Temporary operating restrictions on the earth switches have been imposed according to the manufacturer's recommendation.

Table 186: Fleet risks

13.21.4 Fleet strategy

The objective for this fleet is to maintain high operational performance for work isolation and network re-configuration, and to ensure public safety.

To achieve the fleet objective, address the fleet performance, risks, and other issues mentioned in the preceding sections, the 10-year fleet strategy is shown in table 187.

Strategy	Description	Outcome
Common fleet strategies (refer to table 93 in Section 13.6)	<ul style="list-style-type: none"> Enhance inspection standards and data Enhance asset health assessment and forecasting Implement risk-based renewal forecasting 	<ul style="list-style-type: none"> Increase in asset condition data accuracy score Increase in condition-based forecasting to >95% Improve the quality of our asset health and renewal forecasting
Avoid any H1 assets	<ul style="list-style-type: none"> Ensure all H2 RMUs are replaced before they become H1 	<ul style="list-style-type: none"> Zero H1 RMUs
Ensure the security of the assets	<ul style="list-style-type: none"> Annual public safety inspection 	<ul style="list-style-type: none"> Zero public safety incidents
Ensure operational performance	<ul style="list-style-type: none"> Complete the required inspections and maintenance on the assets For RMUs, given the potentially high consequence of failure, defect replacements shall occur promptly 	<ul style="list-style-type: none"> Inspection and maintenance completed as per schedule No failure of assets with defect notices
Assess third-party damage risk	<ul style="list-style-type: none"> Design and position RMU away from busy roadways and corners. Undertake a review of vehicle crashes to determine if there are any high-risk sites 	<ul style="list-style-type: none"> Consider protection or relocation for high-risk sites.
Enhance fleet resilience (refer to Section 11.4)	<ul style="list-style-type: none"> Consider geotechnical and flooding hazards in the new site and structure design 	<ul style="list-style-type: none"> Improved asset resilience

Table 187: Fleet strategy

13.21.5 Design and construct

The RMU foundations are designed to structural design standards (NZS 1170 series), and RMUs are designed to AS/NZS 60265. The design for these assets considers seismic performance in the structural design. Flooding and geotechnical hazards are considered during site selection.

Waipā Networks has standard designs prepared for RMU sites.

13.21.6 Monitoring

Table 188 describes our current fleet monitoring approach.

Monitoring type	Description	Frequency
Safety inspection	<ul style="list-style-type: none"> Inspection of security, locks, covers, doors and other public safety hazards for units located in towns or special locations Inspection of insulating gas levels 	Annually
Detailed inspection and testing	<ul style="list-style-type: none"> The detailed inspection captures the EOL condition drivers, which (under the new standard) include the condition of the external tank, operating mechanism, locks, doors, and earthing connections Partial discharge and acoustic diagnostic tests Measure the resistance of earthing connections Visual inspection of the earth connection Defect notices are raised where priority repair or replacement is required 	Every two years

Table 188: Fleet monitoring

13.21.7 Maintaining

The maintenance of RMUs is shown in table 189.

Monitoring type	Description	Frequency
Preventative maintenance	<ul style="list-style-type: none"> All units are SF6 insulated. All components within the SF6-insulated tank are maintenance-free for the unit's life expectancy Gas top-up is not expected during the lifecycle. Gas levels are readjusted in response to inspection if technically and economically acceptable. Unit is red tagged and operating temporarily ceased until maintenance is completed (May be replaced – dependent on leakage rate) 	As required
Condition-driven maintenance	<ul style="list-style-type: none"> Maintenance is carried out in response to the inspection and testing. This may include maintenance on the unit Damage to panels (or restrictions from opening panels) repaired or remedied as required 	As required

Table 189: Fleet maintenance

All maintenance activity is up to date, and there are no maintenance backlogs.

13.21.8 Renewal

Our fleet renewal forecasting approach is shown in table 190.

Decision	Description
Renewal forecasting	<p>The forecast of asset renewals is to:</p> <ul style="list-style-type: none"> Ensure there are no H1 assets Replace all H2 assets before they become H1 Replace all current and forecast H1 and H2 assets over the next 10 years
Determining specific renewal projects	<ul style="list-style-type: none"> Specific renewal projects are identified from the health assessment Site inspections are undertaken to confirm the scope and design for the renewal The renewal projects are prioritised by feeder criticality
Assessing alternatives	<ul style="list-style-type: none"> In normal circumstances, no other options are assessed. The exception is if historical data on vehicle crashes indicate the RMUs are in a high-risk area, we will consider relocating the RMUs or adding protection
Defect repair and replacement	<ul style="list-style-type: none"> Defects are compiled in our defect management system, and a rating is applied based on urgency. The urgency rating considers the criticality of the asset

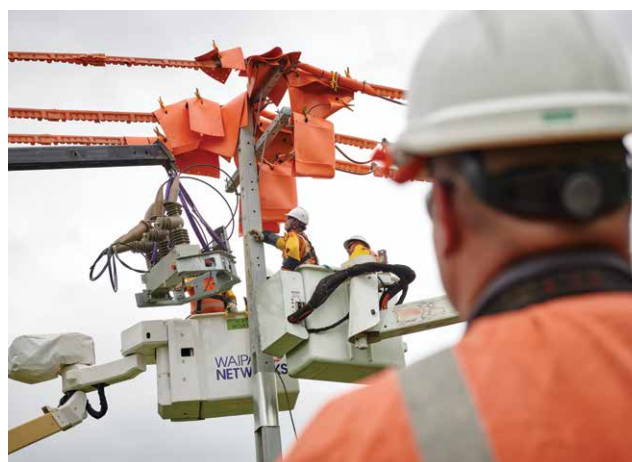
Table 190: Fleet renewal forecasting

13.21.9 Spares

We hold stock sufficient to cover defect and damage replacements. We are looking at rationalising the models and quantities we hold for emergency spares.

13.21.10 Population and age

Figure 152 shows the population and age of our Rmu fleet. 5% of the fleet is above OOU, but none are at MPL¹⁴⁹. The age profile reflects the initiative to replace oil-filled switchgear over the last twenty years. Age data for the four unknown age assets will be captured during the current inspection round.



¹⁴⁹ RMUs have a OOU of 20 years and an MPL of 40 years.

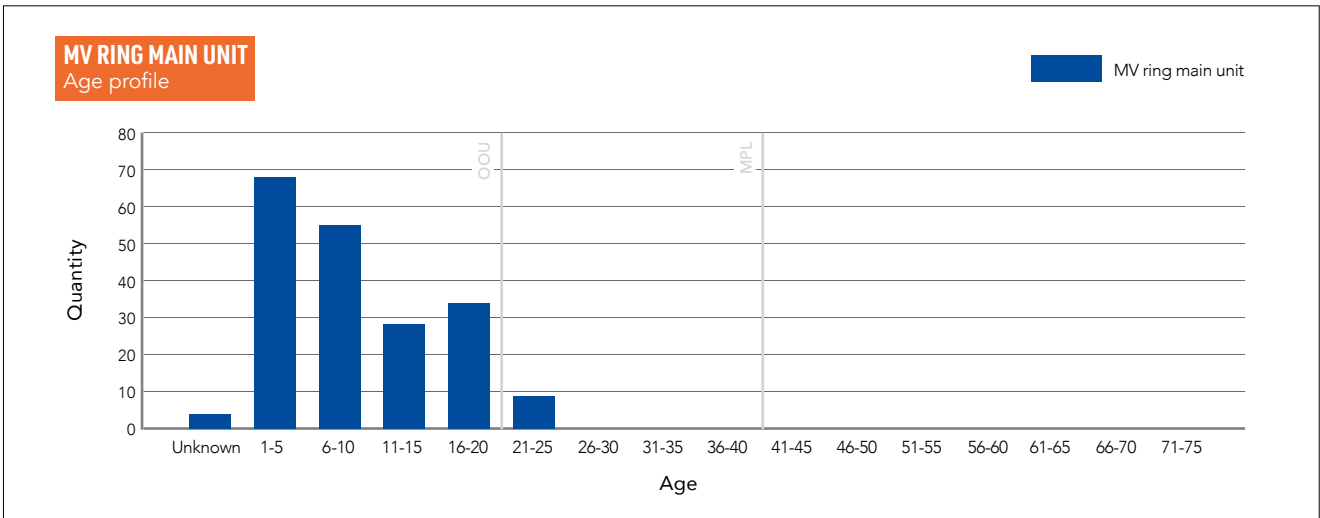


Figure 152: Age profile

13.21.11 Asset health

The health assessment for RMUs is shown in figure 153 and is based on the EEA asset health guide, including the health forecasting discussed in Section 13.5.3. For RMUs, 67% of

the assets have condition data, and 92% of the forecast H1 and H2 assets are condition-based. Tank condition and partial-discharge results were the drivers of the low health of the assets. The current H1 assets relate to tank issues.

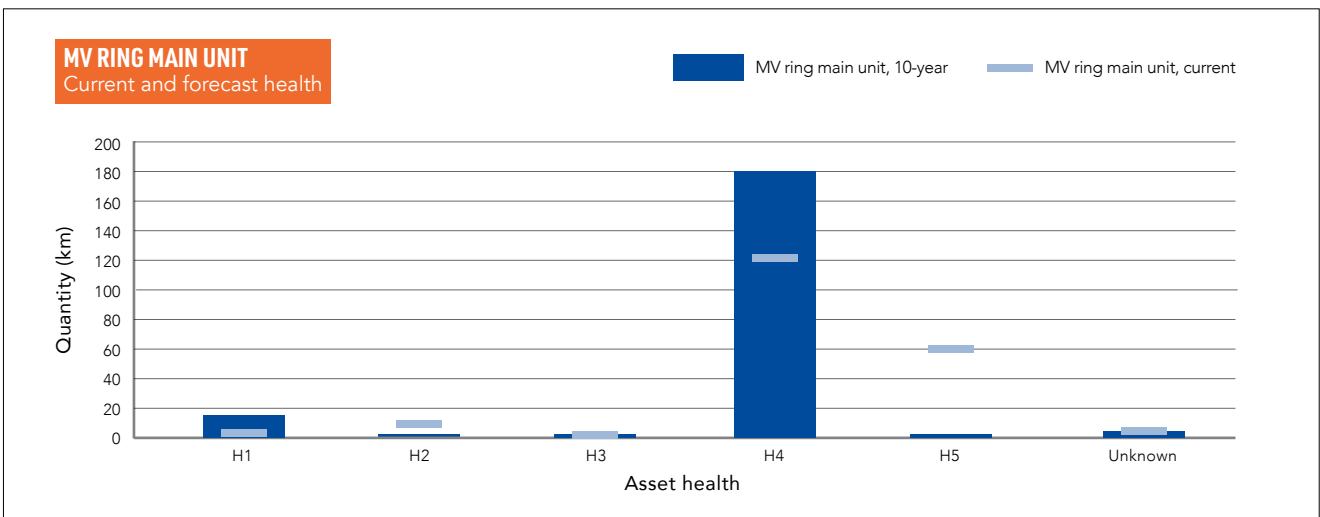


Figure 153: Current and forecast asset health

Table 191 shows the current and forecast for low-health RMUs over the next 10 years.

Type	Quantity	Grade H1 & H2 (Current)	Grade H1 & H2 (+10yrs)	% of fleet at grade H1 & H2 (+10yrs)
RMUs	198	12	13	6.6%

Table 191: Current and forecast asset health

13.21.12 Asset replacements

We forecast replacing all H1 and H2 assets over the next 10 years (see table 192). Replacement rates are higher in the first five years to address the recently identified H1 tank issues. Addressing the remaining partial discharge findings is scheduled from FY29, as urgent issues have already been addressed. We are taking a little more time to fully consider how to address the partial discharge findings, as some may be resolved through maintenance, which may change our future forecasts.

Type	Grade H1 & H2 (+10yrs)	10yr forecast replacements
Ground-mounted transformers	27	35

Table 192: Asset renewal forecast

Description	Type	Category	FY27	FY28	FY29	FY30	FY31	FY32-36
RMUs, renewals	Planned	ARR	144	144	144	72	72	144
RMUs, defect replacement	Unplanned	ARR	30	30	30	30	30	149
Total	-	-	174	174	174	102	102	293

Table 193: Forecast expenditure

13.22 Secondary systems and other assets

13.22.1 Secondary systems fleet overview

Secondary systems include protection, communication and control systems and are critical to operating a safe and reliable electricity network. The MPL of secondary systems is generally shorter than that of primary assets, as most are electronic and software-driven. Hence, technological obsolescence and performance-driven improvements drive the need to renew the fleet.

13.21.13 Expenditure forecast

Forecast expenditure for this fleet amounts to \$1.0m over the next 10 years. Expenditure is higher during FY27 to FY29 to address H1 assets. The defect replacement covers unplanned replacements due to other causes (e.g., failure or vehicle damage).

13.22.2 Secondary systems fleet strategy

The objectives for secondary systems are to:

- Effectively protect the network to ensure it operates in a fail-safe manner and minimises the potential for harm to people and damage to equipment
- Improve efficiency through the reliable remote operation of equipment

The 10-year strategy for secondary systems is shown in table 194.

Strategy	Description	Outcome
Common fleet strategies (refer to table 93 in Section 13.6)	<ul style="list-style-type: none"> • Enhance inspection standards and data • Enhance asset health assessment and forecasting (including incorporating technological obsolescence in the health assessments, as this is a key driver for replacement of the secondary fleet) • Implement risk-based renewal forecasting • Enhance renewal project selection and prioritisation 	<ul style="list-style-type: none"> • Increase in asset condition data accuracy score • Increase in condition-based forecasting to >95% • Improve the quality of our asset health and renewal forecasting
Eliminate all H1 assets	<ul style="list-style-type: none"> • Ensure all H1 assets are replaced before failure • Ensure all H2 assets are replaced before they become H1 	<ul style="list-style-type: none"> • The target will be set as data improves

Table 194: Fleet strategy

13.22.3 Load control system and relays

Fleet overview

We operate a ripple control system to manage peak demand (by controlling customers' hot water) and to control council street lighting. We have three ripple injection plants, one each at Cambridge and Te Awamutu GXP (connected at 11kV) and one at the new Forrest Road substation (connected at 33kV). We also own all the ripple relays installed at the customers' premises.

The ripple converters are seven years old at Te Awamutu and Cambridge, and the coupling cells (transformers, capacitors, and inductors) are 17 years old at Te Awamutu and 23 years at Cambridge. The equipment at Forrest Road is new.

Condition, performance and risks

The ripple plant and control system are in good condition because they are inspected, serviced, and tested annually.

Failure of the ripple plant could risk exceeding the GXP security level and the failure to meet the System Operator's load-shedding request under a Grid Emergency Situation. It would also require us to manually control street lighting. Customer service could be significantly impacted if the ripple plant failed when hot water was switched off.

Design and construct

Ripple injection plants are designed for each specific application.

Monitoring and maintaining

Our service agreement with Landis and Gyr (the ripple plant supplier) provides annual condition monitoring and access to a contingency spare replacement converter panel, capacity cell, and other strategic spares. We also hold spares for the converter controllers interfacing with the SCADA system. This supports the rectification of major faults within 48 hours (provided the failure is not catastrophic or involves the primary reactor or capacitor plant).

Regular inspection and testing of the ripple injection system assets ensure continued and reliable operation. The preventive maintenance schedule includes yearly onsite testing and physical inspection of the ripple plant. To comply with the Electricity Participation Code 2010, we conduct 10-year inspections and recertification of ripple relays.

We also offer the ripple to the reserve market through an external service provider.

Renewal

Currently, there are no plans to renew or change the ripple control within the period of this plan. However, the energy transition and the development of flexibility markets will likely lead to a shift from ripple control to consumer – and market-based control.

The future abandonment of the system requires further consideration as we approach end-of-life. We may need to replace the existing ripple plant coupling capacitors as soon as they reach the typical service life (per the manufacturer's advice). This project is under consideration.

Forecast expenditure

There is no forecast renewal capex associated with the ripple control plants. Replacement of relays is included in the System Emergency and Interruption forecasts, as these are only replaced upon failure.

13.22.4 Communication systems

Fleet overview

The communications network carries our SCADA data and voice systems. Data is used for the SCADA system to monitor and control automated devices. In contrast, voice channels are used for voice communication between the field staff and the control room to operate or switch network devices.

Our communications network consists of data systems and physical infrastructure, including fibre-optic circuits, UHF point-to-point digital radios, microwave point-to-point digital radios, point-to-multipoint UHF repeaters, and cellular/ADSL circuits.

Our current standard communications protocol comprises two main types:

- For HV distribution devices in the field, like reclosers and voltage regulators, ABBEY RTUs convert relay DNP protocol to proprietary ABBEY protocol over analogue UHF and VHF carriers, routing to the ABBEY SCADA hub and master station. Direct DNP use is limited; the system still relies on proprietary ABBEY RTUs or analogue radios with restricted bandwidth. This will be resolved as we complete the new digital communication backbone, commission the new ADMS system, and progressively replace field analogue radios with digital units.
- For the new Forrest Zone Substation, all IEDs communicate via local digital RTU and Ethernet switches/routers, then transmit through digital radios or fibre in native DNP protocol back to the ABBEY SCADA hub and master station, which have DNP licenses for processing.

Condition, performance, and risks

Some repeater channels have exceeded the maximum recommended RTUs per line, impacting overall SCADA system performance.

The existing SCADA cannot be expanded significantly because it is constrained by the bandwidth between our depot and the repeater sites, and also between repeater sites. In the interim, it may be possible to install additional SCADA repeaters to alleviate the constraint (by reducing the number of RTUs per line and enabling more devices to be connected). However, the SCADA system's speed will not improve with these measures.

There is an increasing number of automated devices on the network, and the requirements for voice and data are exceeding the capabilities of the older analogue channels. In FY26, we commenced a project to upgrade our communication system (see Section 11.19.4).

Design and construct

We are implementing a digital communication system, and design matters are discussed in the development section (refer to Section 11.19.4).

Monitoring and maintaining

We conduct an annual visual inspection of radios, switches, antennas and their alignment at automated devices and radio sites. Battery testing will also be carried out.

Renewal

In FY26, we started a project to upgrade our communication system (see Section 11.19.4).

Forecast expenditure

Refer to Section 11.19.4.

13.22.5 Pillar boxes

Fleet overview

Pillars are the ground-level connection points on the low-voltage underground network. Pillars contain fused connections that provide protection for the connected circuits/loads, and operational switching points. The pillars are mostly located in the road reserve and adjacent to the property boundaries.

There are two functional categories of pillars:

- The distribution pillar that provide connection between the network and the customer premises
- Link pillars that provide switching points along the distribution mains cables.

The physical types are (i) partially buried pillars with heads above ground level and (ii) pit pillars that are flush with ground level, installed where the above-ground type would impede access to premises.

Fleet risks and any performance issues

The most common source of risk for pillars comes from their location in areas accessible to the public, posing risk of unauthorised/public access to unsecured pillars, and damage due to impact from vehicles, lawn mowers (as most are in berms). The damage is mostly broken lids, broken fuse holders, broken base and burnt fuse holders. Impact damage tends to cause a loose connection that leaves the pillar prone to catching fire. Field trials of a new pillar are underway. This pillar has increased spacing of fuses, which proves greater heat dissipation. This reduces the risk of pillar fires.

Modern pillars have gel covered connections which reduces risk of water damage when the pillar cover is dislodged. Pit pillars are also sealed to prevent water damage.

Asset information

Our pillar asset information is not complete, 40% of the fleet has unknown material type. We have started collecting detailed information from inspections and as-built records. The average age information is based on a small subset of the population.

Type	Qty	Average Age*	% of Fleet
Fibreglass	57	3 years	1%
Plastic	5,266	7 years	59%
Unknown	3,526	6 years	40%

Table 195: Asset types

Monitoring

We have an ongoing pillar inspection programme, with five-year return cycle to match the feeder inspection programme. We have completed inspections on 31% of the pillars since last year when we started the structured inspection programme. A particular risk associated with pillars is loose or high resistance connections. A key component of the inspection is to identify any termination issues.

Asset health and replacements forecasts

The current inspection graded 2% of the pillars as having H1 or H2 condition grade. Forecasting condition is currently unreliable due to the limited asset data and the inspection coverage. This is expected to improve with wider inspection coverage.

Type	Quantity	Grade H1 & H2 (Current)	Grade H1 & H2 (+10yrs)
Pillar boxes	8,849	171	Not reliable

Table 196: Current and forecast asset health

Replacement has mainly been reactive based on field inspection findings, and where existing pillar does not have room to connect new customers. (Urban densification that requires new connection from existing pillar locations is the main driver for replacement of pillars.)

Forecast for asset renewals is based on continuing historical replacement rates. This approach is adopted due to the unreliable health data and low consequence of failure for this fleet as few customers are impacted, and replacement can be achieved quickly.

Description	Type	Category	FY27	FY28	FY29	FY30	FY31	FY32-36
Pillar, renewals	Planned	ARR	276	276	276	276	276	1,382

Table 197: Forecast expenditure

FY26 real \$000

13.22.6 Streetlighting

Fleet overview

We provide electricity supply for streetlights from the LV distribution network via either overhead or underground distribution. Our streetlighting asset fleet is made up of 90 km of underground cable and 64 km of overhead line.

We do not own any streetlighting luminaries, columns, lamps or outreach arms. Our streetlight management practice document guides our approach to streetlight management and the interface between the parties managing the streetlighting assets.

The age data for both the streetlighting conductor and the underground cable are largely unknown. We have complete location information, whether overhead or underground; however, the conductor type attributes are not reliable. Any replacement or repair is informed by on-site inspections.

Description	Type	Category	FY27	FY28	FY29	FY30	FY31	FY32-36
Streetlighting, defect replacement	Unplanned	ARR	11	11	11	11	11	55

Table 198: Forecast expenditure

FY26 real \$000

13.22.7 Generation

Fleet Overview

We maintain a small fleet of generators to support critical parts of the network during planned and unplanned outages and maintain support to our depot/office. We also have a fixed generator that provided supply security at Cambridge GXP (before the commissioning of the Hautapu GXP and Forrest Road substation).

The small generator fleet is deployed on demand as a short-term solution to maintain supply. Therefore, the generator sets need to be serviceable when required to run.

The existing generator sets are:

- Swayne Road: 3x 1 MVA. This generation supported Cambridge GXP. The generators only operate during network peak load hours, generally during winter cold snap days, to manage network demand within Cambridge GXP N-1 capacity of 47 MVA. Following the commissioning of the Hautapu GXP and Forrest Road substation, the loading at the Cambridge GXP has substantially reduced, and the generators are no

Monitoring

There are no specific inspections on the streetlighting conductors or cables. The assets will be inspected alongside low-voltage conductors or cables as our condition monitoring of those assets evolves.

Replacements forecasts

We do not presently have a specific renewal programme for streetlight conductors and cables. These are replaced as part of planned conductor and cable renewals. We have a minor provision for defect replacement, as shown in table 198.

longer needed. We have isolated the generator from the network and are preparing for full decommissioning. We are looking into redeploying them to other parts of the network to improve network reliability and resilience.

- 1x 275kVA (portable) located at Te Awamutu depot
- 1x 220kVA (fixed) at Te Awamutu depot/office providing backup support.

Monitoring and maintaining

The maintenance routine includes inspections and services according to manufacturer specifications, as well as routine operational tests to ensure the generators will run when needed. These assets are not part of the standard network assets, so their maintenance is outsourced, commonly as part of the supply contract.

Renewal

The need for generator renewal is reviewed when the asset is nearing the end of life.

Forecast expenditure

No renewal capex is forecast for this fleet.

13.23 Systems interruption and emergency management

13.23.1 Function overview

This function delivers field-switching operations and response and restoration of electricity following outages. Our in-house delivery team delivers these activities.

13.23.2 Forecast expenditure

Our forecasts are based on normal weather patterns and do not include provisions for major weather events of Cyclone Dovi or Gabrielle scale. We have reduced the base fault costs (compared to the 2026 AMP) as expenditure in recent years has been lower than forecast. We have also included some cost reductions to reflect the forecast reliability improvements outlined in Section 7.8. However, we are seeing higher costs due to unrecoverable third-party damage, copper theft, and the expected increase in network scale.

We currently do not forecast future real labour or material cost increases.

Description	Type	Category	FY27	FY28	FY29	FY30	FY31	FY32-36
Historical forecast ¹⁵⁰	1,783	1,783	1,783	1,783	1,783	8,915	17,830	

Table 199: Forecast expenditure

FY26 real \$,000

13.24 Vegetation management

13.24.1 Overview

Vegetation is one of the significant causes of outages on the network. Parts of our network pass through dense vegetation and forested areas, exposing the network to faults from branch contact and tree fall, particularly during storm events. Moreover, a faster vegetation growth rate due to summer/spring growth seasons getting warmer and wetter quickly erodes the established clearances. Overgrown trees and other vegetation near power lines can lead to outages, fires, and safety hazards.

Vegetation management is necessary to ensure supply reliability by preventing line interference and providing access to network assets and public safety by reducing the risk of fire or a broken conductor falling on the ground. We undertake routine inspections of our network to identify areas where vegetation has the potential to breach (or already has breached) the minimum specified legislative distances.

Inspections include frequent assessments of the network to identify where vegetation is encroaching (or is approaching) overhead lines. It also includes liaising with landowners regarding subsequent first-cut costs associated with physical trimming or felling of vegetation we bear.

Vegetation management is undertaken in-house by our delivery team.

13.24.2 Tree Regulations

The Electricity (Hazards from Trees) Regulations 2003 specifies minimum distances that vegetation must be clear from overhead power lines, "growth limit zone," with distances varying depending on voltage and conductor span length. The vegetation zones were updated in November

2024, extending the notice zone by one metre and making the zones clear to the sky. For 11kV lines, the growth limit zone is 1.6m, the cut-back zone is 2.6m and the notice zone at 3.6m from the line. While these zones provide clearance from interference from branches (although greater clearance would be useful), they are inadequate to manage tree fall risk and interference during storm events, where greater separation is needed.

We can request that the tree owner trim or remove vegetation once it infringes on the notice zone, and enforce trimming when it encroaches on the growth limit zone (using a prescribed process that can take some time to complete). However, in high-growth areas, the trees quickly exceed the limits after trimming, requiring frequent return visits. Under the regulations, we have no mandate to remove a small tree from under a line but must wait until it encroaches the notice zone before acting.

The regulations also require EDBs to advertise suitable safety information to tree owners in appropriate publications and contact owners whose vegetation reaches the notice zone. Tree owners can take ongoing responsibility for maintaining vegetation outside the minimum distance(s) or granting the network owner approval to keep the vegetation outside the minimum distance by appropriate trimming or removal. The notice and trim process must be repeated for every individual tree on a property.

The tree legislation requires EDBs to offer tree owners a first free cut. The landowner must then meet the cost of resulting cuts, which has resulted in an increasing number of trees being declared "no interest" by landowners on the second cut. At that point, we prefer to completely remove the tree to avoid future issues rather than trimming the tree.

¹⁵⁰ Based on FY26 forecast in FY26\$.

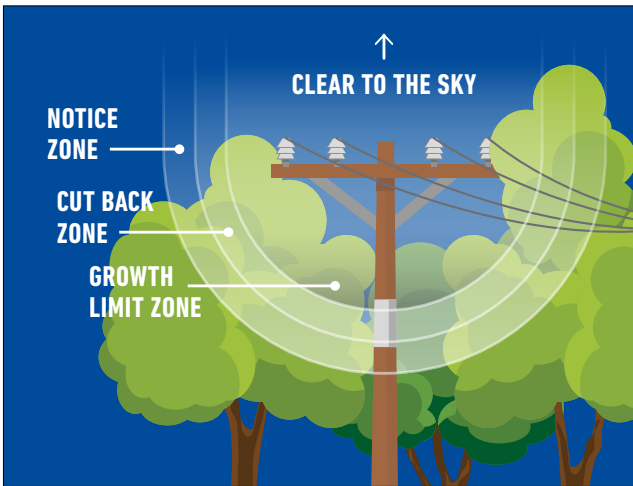


Figure 154: Vegetation management zones

13.24.3 Risks from vegetation

Vegetation presents two primary risks to us in achieving our business objectives. These are public safety risks and reliability risks.

- **Public safety risk:** Vegetation owners may put themselves at risk by carrying out the vegetation trimming or felling work themselves. This puts the vegetation owners at risk of electrocution or may elevate the fire risk due to arcing between live power lines and the trees being worked on.

Children who climb trees close to power lines are at risk of serious injury or death.

In severe weather, vegetation can become electrically 'live' and may pose an electrocution risk.

- **Reliability risk:** Vegetation-related outages made up 19% of our SAIDI over the past five years. If vegetation isn't properly managed, we're less likely to meet our reliability target. That would mean more outages and longer periods without power for our customers.

We sometimes encounter vegetation that impedes field staff access to our equipment. This can delay operations and power restoration, as the vegetation must be cleared first to enable access to the equipment. The issue is presently managed reactively.

13.24.4 Objective and strategy for vegetation management

Mitigating vegetation-related outages is one of our key strategies (asset management strategy #6)

Our vegetation management strategy aims to identify and address vegetation growth issues before they become safety hazards or impact network reliability, i.e.:

- Vegetation interference does not increase public safety risk
- Vegetation interference has minimal impact on the network performance, primarily focusing on normal weather condition
- Expenditure on vegetation management is efficient
- We comply with our regulatory obligations.

We currently do not proactively manage trees in the fall zones (apart from the 'well-known' critical spots in the network as observed from recent cyclone events – under Asset Management Strategy #3 – Resilience). Our future position and strategy will be established once the Tree Regulation review is complete.

In FY24, the team reviewed our vegetation management approach and strategy. The new strategy has four key initiatives, each responding to the drivers above.

Decision	Description
Establish regular baseline measurements of vegetation in the line corridor.	<ul style="list-style-type: none"> • Identify all trees in the line corridor that could present a risk and link these to the relevant tree owner through a combination of annual and 3-yearly inspection cycles, depending on the location of the network • Capture accurate data on vegetation outages and control activities • Implement a practical vegetation management system
Implement a practical risk-based vegetation control programme	<ul style="list-style-type: none"> • Determine the risk posed by all vegetation sites in the line corridors • Determine a risk-prioritised vegetation management work programme • Develop an inspection and cut programme based on criticality and reliability, targeting high-risk in-zone and fall-zone trees
Increase community engagement	<ul style="list-style-type: none"> • Use customer engagement to enhance full cuts, tree-owner payments, and vegetation control beyond the growth limit zone
Continuous improvement	<ul style="list-style-type: none"> • Develop an understanding of the long-term work and expenditure requirements • To progress our vegetation management to industry best practice • Increase vegetation management resources in the region

Table 200: Vegetation management initiatives

13.24.5 Risk-based vegetation management practices

Previously, the planned inspection and cut/trim for feeders were in the same cycle. Under our new approach starting in FY25, the two activities ('intelligence gathering' vs 'plan and act') are now decoupled, emphasising the importance of having an up-to-date view of the wider network first to better direct plan and act. Our vegetation management practices include the following four key elements:

Inspection

We undertake routine inspections of our network to identify areas where vegetation has the potential to breach (or already has breached) the minimum specified legislative distances. The inspections combine annual, rotational, and/or reactive surveys. The inspections are generally undertaken by vehicle and on foot, drone, or may use a helicopter in certain terrain.

Historically, we inspected feeders (and trim) every five years. However, given tree growth rates, that return period was too long to maintain clearance from the growth limit zone. We reduced the interval to three years for the whole network based on the team's experience.

We have adopted a practical risk-based¹⁵¹ inspection approach. This includes:

- Annual inspection for lines to the second reclosers from the GXP. These lines are close to the GXP and a vegetation event will result in a large SAIDI impact; hence, we inspect them more often. Most parts of the network will be inspected annually.
- 3-year inspection cycle for the remaining network (i.e., the tail-end of the rural feeders). The adequacy of this interval will be monitored to consider whether this interval should be further reduced.
- Targeted more frequent inspection for known problematic feeders, for example, Kāwhia feeder, where a fault (including vegetation) will require a longer duration to identify and clear due to its challenging terrain, resulting in a higher SAIDI. We also conduct reactive inspection post repetitive reclosing or feeder tripping.

Further opportunities under consideration include using satellite-based vegetation inspection, which will make it possible to shorten the inspection cycle for most of the network from three-year to one or two-year intervals.

Recording

Records of vegetation that present a risk to our network are managed similarly to an asset through a record with attribute data and specific location details assigned to it. Liaison with the vegetation owners then occurs as appropriate. Work packs are designed and compiled where applicable to allow our team or external contractors to undertake the corresponding vegetation control work.

Leveraging our GIS system, the team now adopted the Field Maps application as the digital survey platform for asset and vegetation inspection. This application lets the team record and collect vegetation issues digitally – removing all paper-based inspection forms and improving overall administration efficiency and backend work management.

Further opportunities the team is looking into include visualisation of inspection results and problematic sites on the maps; and continue refining the content of the inspection and record form to better support risk and time urgency-based works planning and enable a direct printout of the land-owner liaison form.

Vegetation control work plan and tactics

The subsequent cut/trim work will be planned based on inspection results. Work prioritisation is risk-based; primarily informed by observations, consideration of public safety risk and network performance (impact of outages), and urgency to act.

We aim for a high tree fall rate (rather than trim). Our recent review shows that our internal vegetation management team achieved a fall rate of 85%, and we will continue to maintain this high fall rate through good stakeholder engagement.

Resourcing and stakeholder engagement

We have directed our efforts to manage the risk of vegetation interference by, where possible, obtaining greater clearances (including full removal) than those provided by the legislation, with the cooperation of vegetation owners. Obtaining clearances exceeding the minimum values specified in legislation reduces the risk of network damage, reduces the frequency of return visits, and enhances landowners' safety.

We have a dedicated Scoping and Liaison officer to support the above inspection and stakeholder engagement activities.

A performance review will be conducted at the end of FY26 to guide our continuous improvement.

¹⁵¹ Currently considering network impact only.

13.24.6 Forecast expenditure

Our forecast for vegetation management expenditure is shown in table 201. Expenditure has reduced compared to our historical forecast due to changes to the Delivery

Team overhead allocation, which now reflects the vegetation team as if it were a standalone business. Hence, the forecast reduction has not altered the vegetation management programme.

Description	FY27	FY28	FY29	FY30	FY31	FY32-36	Total
Historical forecast ¹⁵²	2,155	2,155	2,155	2,155	2,155	10,777	21,554
Removal of one-off costs in historical forecast	-	-	-	-	-	-	-
Changes in overhead allocation	(97)	(97)	(97)	(97)	(97)	(483)	(966)
Impact of change in network scale	-	6	11	17	23	197	253
Real labour/material cost increase	-	-	-	-	-	-	-
Total	2,059	2,064	2,070	2,076	2,082	10,491	20,842

Table 201: Forecast expenditure

FY26 real \$000

13.25 Reactive and corrective maintenance and inspection

13.25.1 Activity overview

Reactive and Corrective Maintenance and Inspection (RCMI) covers our routine, detailed inspection and testing of network assets. The types of activities included in this expenditure category are discussed in the monitoring and maintenance sections of the fleet plan.

Other than certain specialised activities, this work is undertaken by our delivery team.

13.25.2 Forecast expenditure

Our forecast RCMI expenditure is shown in table 202. The historical RCMI forecasts (based on FY26) included one-off inspection and maintenance for RMU partial discharge testing and associated maintenance, earth testing, and Forrest Road substation post-commissioning testing. These are not expected to recur annually and have been removed. The new programmes added relate to Forrest Road substation and the inspection and maintenance of the 110kV line in FY27 and FY28. The net result of these changes is a reduction in RCMI relative to the FY26 forecast.

Description	FY27	FY28	FY29	FY30	FY31	FY32-36	Total
Historical forecast ¹³⁴	1,133	1,133	1,133	1,133	1,133	5,663	11,326
Removal of one-off and major maintenance in historical forecast	(505)	(447)	(447)	(447)	(447)	(2,233)	(4,524)
New one-off or major maintenance programmes	136	147	118	123	262	925	1,711
Impact of change in network scale	-	11	22	34	53	439	560
Real labour/material cost increase	-	-	-	-	-	-	-
Total	763	845	827	843	1,001	4,749	9,072

Table 202: Forecast expenditure

FY26 real \$000

¹⁵² Based on FY26 forecast in FY26\$.

13.26 Asset replacement and renewal (opex)

13.26.1 Activity overview

Asset Replacement and Renewal (ARR opex) covers asset refurbishment and subcomponent replacements that do not meet the threshold for capitalisation as an asset. This work includes refurbishment of our voltage regulator, transformers, RMUs and other assets that do not result in life extension. Most of the expenditure relates to work on voltage regulators and transformers.

The types of activities included in this expenditure category are discussed in the maintenance or renewal sections of the fleet plans.

Other than certain specialised activities, this work is undertaken by our delivery team.

13.26.2 Forecast expenditure

Our forecast ARR expenditure is shown in table 203. The historical ARR forecasts (based on FY26) included significant refurbishment of voltage regulators, which has been reduced. The increased programmes relate to the refurbishment and replacement of pillar boxes and transformers.

Description	FY27	FY28	FY29	FY30	FY31	FY32-36	Total
Historical forecast ¹⁵³	747	747	747	747	747	3,734	7,469
Reduction in programmes in historical forecast	(283)	(283)	(283)	(283)	(283)	(1,415)	(2,829)
Increase of periodic programmes	168	168	168	110	110	548	1,272
Impact of change in network scale	–	9	17	24	32	284	366
Real labour/material cost increase	–	–	–	–	–	–	–
Total	632	641	650	598	606	3,151	6,278

Table 203: Forecast expenditure

FY26 real \$000



¹⁵³ Based on FY26 forecast in FY26\$.

13.27 Voltage monitoring and management

Voltage is critical to our network as we have long 11kV distribution feeders. For the 11kV feeders, we have remotely controllable devices connected to our SCADA system, such as reclosers and voltage regulators, that provide real-time voltage measurements.

However, we have traditionally not had permanent voltage monitoring for low-voltage networks and instead rely on customer feedback, after which we install portable dataloggers to confirm any issues. We now have LV transformer monitoring devices installed on a few select distribution transformers. We initiated a project to provide visibility into the low-voltage network via the GridSight platform (refer to Section 10.11.4).

13.27.1 Addressing non-compliance

As network load increases, feeder loading can exceed the initial design limit, potentially resulting in voltage non-compliance. Regular feeder-quality performance reviews, through field monitoring and network modelling, confirm potential voltage issues. We address voltage non-compliance at both HV and LV levels.

For the HV network, we address potential voltage non-compliance issues through:

- Installing automatic voltage regulators
- Installing capacitor banks
- Upgrading conductor
- Reconfiguring the feeders.

For the LV network, we address potential voltage non-compliance issues through:

- Reconfiguration of the LV network
- Transformer upgrades
- Upgrading conductor
- Adjusting transformer tap changers.



13.27.2 Responding to low-voltage issues raised by stakeholders

When customers notify us of voltage issues, we follow these steps:

- Technical verification that includes engineering assessment of network layout for the affected stakeholder(s), field verification of the desktop assessment through data logging, transformer tap position check, verifying installed conductors and possible alternate LV arrangements.
- This step identifies possible reasons for the non-compliance and confirms whether the issue is on the network or the customer side.
- Where the issue is due to the network, our engineering teams determine an appropriate solution, and the field services team deploys the solution.
- Verifying the solution's effectiveness through onsite measurements and with the affected stakeholders.
- If there is a repeat notice from the same customer, we classify it as a complaint and raise the priority for resolution.

13.27.3 Communication with affected customers

We keep the customer informed of progress throughout the resolution process and aim to resolve customer complaints within 20 working days. Should there be a requirement to exceed this timeframe, we will communicate this and the reasons to the customer and work to resolve the complaint as soon as possible.

13.27.4 Improvement initiatives

Initiatives that will improve our practices and network voltage performance include:

- Network architecture changes, such as introducing subtransmission, driven mainly by capacity needs, improve network voltage performance by shortening distribution feeders and introducing another stage for voltage control.
- Our voltage management programme considers forecast load at the distribution feeder level and proactively deploys voltage management solutions, such as voltage regulators, capacitors, and conductor upgrades. Our current practice for the low-voltage network is to respond to issues as they arise.
- Updating our design standards to allow for the change in customer density and usage profiles.
- Extending the coverage of LV monitoring based on the smart meter data aggregation method will enable us to improve voltage performance at low voltage levels proactively.

13.28 Non-network assets

13.28.1 Vehicle fleet

Fleet overview

We own and manage a fleet of vehicles to support the business. Most of the fleet supports the delivery team by providing fault, vegetation management, inspection, and maintenance services (as per the preceding sections). In addition, we have a small fleet of pool vehicles that support the wider business.

Vehicles are essential assets that enable our activities to meet our asset management objectives. As of March 2025, the fleet comprised of:

Type	Number	Average age
Utility vehicles (utes)	35	4
Trucks (including crane, bucket and tipper trucks)	15	11
Light vehicles (cars and SUVs)	11	4
Forklifts	2	8
Diggers/trenchers	2	3
Other (chippers, trailers, etc.)	9	12
Cable jointing van	0	0

Table 204: Summary of vehicle fleet

Records of our vehicles are maintained in the financial management system, the Smartrak fleet management system, and spreadsheets. Vehicles are split into various classes and categories, and relevant attributes are recorded against each vehicle. The records allow visibility of maintenance activities against each vehicle.

Our vehicles are regularly maintained to ensure compliance,

operational effectiveness and to minimise component failure, which could contribute to poor performance and/or lower reliability.

Our utility vehicles travel the greatest distances. Utility vehicles are retained for 10 years or 200,000kms and SUVs for 6 years or 120,000kms, whichever is earlier. Trucks are now retained for 15 years.

A comprehensive fleet review was completed in FY24, resulting in prioritised recommendations for action from FY25. A four-year plan was developed to address the age and composition of the truck fleet and to reduce the high maintenance costs.

Future sourcing of the vehicle fleet incorporates the total cost of ownership and ensures vehicles and their designs are fit for purpose, cost-effective, standardised and sustainable.

13.28.2 Buildings and land

We own and maintain non-network property and buildings, including Te Awamutu's main office building and depot. This houses engineering, network, financial, commercial, and corporate services staff, as well as contracting business staff, including management, supervisors, engineers, design estimators, fault crews, and administrative support.

The depot includes an electrical workshop, store, warehouse, plant and vehicle sheds, hazardous goods store, and the yard housing materials and equipment.

Recent land purchases were for the Forrest Zone substation and land adjacent to Te Awamutu GXP for future network development.

13.28.3 Forecast expenditure

Table 205 summarises our non-network capex (excluding IT/OT, which is presented in Section 9).

Description	FY27	FY28	FY29	FY30	FY31	FY32-36	Total
Vehicle purchases	1,271	886	1,425	1,454	1,483	11,307	17,825
Plant purchase	403	311	317	323	330	1,748	3,433
Land and building	62	62	62	62	62	308	616
Office furniture and fitting	195	4	4	4	4	23	235
Total	1,931	1,262	1,808	1,843	1,878	13,386	22,108

Table 205: Forecast expenditure

FY26 real \$000

13.29 Asset lifecycle management expenditure forecasts

Table 206 and table 207 summarise the lifecycle capex and opex for the network assets.

Fleet	FY27	FY28	FY29	FY30	FY31	FY32-36	Total
Zone substation transformers	-	-	-	-	-	-	-
Zone substation circuit breakers	-	-	-	-	-	-	-
Zone substation protection relays	-	-	-	-	-	-	-
Concrete poles/steel structure	372	344	344	344	344	1,638	3,386
Wood poles	221	221	193	193	193	773	1,794
Crossarms	2,072	2,072	2,072	2,063	2,072	10,341	20,692
Distribution OH Conductor	101	186	186	186	186	929	1,773
LV OH Conductor	30	61	61	61	61	305	579
Pole Mounted Transformer	882	882	882	882	882	4,412	8,824
OH Switches (ABS, LBS, Fuse, Link)	1,008	1,008	1,062	1,062	1,041	5,867	11,047
Voltage regulators	108	108	108	284	284	862	1,754
Reclosers and sectionalisers	82	82	82	82	224	1,122	1,674
Distribution UG XLPE or PVC	103	103	103	103	103	513	1,026
Ground Mounted Transformer	401	401	401	401	401	1,007	3,013
RMU	174	174	174	102	102	293	1,018
LV UG Cable	184	184	184	184	184	920	1,842
LV OH/UG Streetlight circuit	11	11	11	11	11	55	110
OH/UG consumer service connections	276	276	276	276	276	1,382	2,764
Total	6,033	6,120	6,147	6,242	6,372	30,456	61,370

Table 206: Asset replacement and renewal expenditure

FY26 real \$000

Fleet	FY27	FY28	FY29	FY30	FY31	FY32-36	Total
System interruptions and emergencies	1,686	1,707	1,728	1,750	1,771	9,179	17,821
Vegetation management	2,059	2,064	2,070	2,076	2,082	10,491	20,842
Reactive and corrective maintenance and inspections	763	845	827	843	1,001	4,794	9,072
Asset replacement and renewals	632	641	650	598	606	3,151	6,278
Total	5,140	5,257	5,275	5,266	5,460	27,615	54,012

Table 207: Network opex

FY26 real \$000



14. CAPABILITY TO DELIVER

14.1 Introduction

In this section, we describe our capabilities to deliver the Asset Management Plan. This includes:

- Our resourcing strategy
- Use of external contractors and consultants
- Capability reviews
- Corporate and asset management delivery and resourcing
- Fieldwork delivery process
- Energised vs. de-energised fieldwork delivery
- Fieldwork resourcing.

14.2 Resourcing strategy

Our historical resourcing strategy was based on maintaining in-house corporate and asset management resources, as well as in-house construction, maintenance, and fault-handling capabilities to efficiently deliver most of our asset management, fieldwork programmes and customer work. We augmented our in-house resources with external expertise that could not be efficiently maintained in-house, where projects required specialised support, or to resource projects that could not be resourced internally. Engagement of consultants and contractors in compliance with our procurement policy.

The electricity distribution sector is experiencing increasing operational complexity, growing workloads, and rising regulatory, digital, and customer expectations. In this context, the conventional resourcing approach will risk adding organisational complexity and reducing efficiency, particularly given the ongoing shortage of experienced and specialist capability. Accordingly, our resourcing strategy is under review regarding corporate and asset management resources and capabilities.

As mentioned in our Efficiency Strategy in Section 7.5, Waipā Networks is actively evaluating options to lift efficiency and improve customer experience, while keeping decision rights and accountability close to our communities. Hence, we intend to participate in a structured evaluation of shared services. Currently, our network control is undertaken via WEL Networks as a mutually beneficial agreement that lowers the cost of both networks. We will assess further opportunities in finance, asset management, and digital functions to accelerate our access to capability and capacity.

14.3 Use of external contractors, consultants and partners

We presently use external consultants, contractors and partners to support our in-house team. This includes:

- Specialist engineering and asset management work. Areas include zone substation and protection design, communication systems, SCADA and asset management
- Control room and fault call centre services
- Civil work activities that can be well-defined and where a local competitive market exists, such as trenching, directional drilling and building/general construction
- Traffic management for most roadside lines and vegetation management works

- Specialist line inspection, investigation and commissioning work. Areas include major network surveys, third-party investigation of faulted equipment, and some testing and commissioning work
- Specialist IT support, including for our SCADA, ADMS and cybersecurity
- Augmenting our field resources for works programme delivery, specialist tasks and major weather events.

As discussed later in this section, we forecast an increase in fieldwork contracting over the next five years.

14.4 Capability reviews

14.4.1 Corporate

Our corporate resourcing has evolved over the past decade in response to our growing customer base and the increasing complexity of the business. Our continued focus on health and safety and cybersecurity and the need to refresh our IT systems has driven the increase in resourcing. The increased resourcing improves our capacity to manage asset data, enhance community and customer engagement, strengthen commercial capability, including contract and procurement. We've also increased our capacity for increasing demand in financial, compliance, and risk management.

14.4.2 Asset management

Asset management capability reviews are being undertaken in response to a fundamental shift in our operating context. The business is now moving to deliver a new hybrid network architecture, alongside a material increase in capital investment and a broader set of solutions to meet customer and system needs. This represents a step change from traditional distribution planning and delivery models and requires a corresponding shift in asset management capability to ensure investment decisions remain robust, targeted, and value for money.

To support this shift and address constraints, Waipā Networks is assessing requirements for network strategy and planning functions, complemented by a more customer-focused network solutions model. This approach incorporates long-term network strategy, investment sequencing, solution development and customer engagement. This approach will enable greater use of non-traditional solutions, staged investment, and co-designed outcomes for complex constraints. Distributed energy resources capability will be required to further support this model by improving the integration of generation, energy storage, and emerging technologies and services into network decision-making.

We have established the Network Intelligence function to expedite the identification, discovery and adoption of specialised digital systems for the network function and deliver asset management improvement initiatives in conjunction with the network team.

Together, these changes will provide the next level of capability required to deliver the new network architecture at scale. They strengthen our ability to actively manage risk,

confidently target investment to areas of greatest benefit, and adapt to changing customer, regulatory, and technology drivers, while continuing to deliver safe, reliable, and efficient outcomes for the community.

14.4.3 Works delivery

The Delivery team has identified the need to adjust its resource mix in response to the future of our fieldwork. Delivery team resourcing has historically been overhead line-centric. However, the network has transitioned from a predominantly rural setting to a semi-urban distribution network with a growing subtransmission network. This is increasing the fieldwork associated with underground and ground-mounted assets, as well as zone substation assets. Customer work and network projects are increasingly focused on ground-mounted assets and underground cables. The sophistication of protection schemes, new Intelligent Electronic Devices, and digital communication networks is increasing the level of technical expertise required to construct, inspect, and maintain the network.

The current Delivery team resource mix consists of multiskilled field staff, including Line Mechanics and Fault Technicians, who also perform Cable Jointing. This model has historically been very efficient but can no longer accommodate the changing work mix and the increasing need for technician-related skills.

The Delivery team is now building a dedicated team of cable jointers, electrical fitters and substation technicians. The transition is underway, and skill-building will continue over the next few years as our fleet of zone substations, underground assets and OT devices grows.

We have experienced delays in completing our inspection programme (see Section 5.7.1) due to changes within the newly established inspection team. This is now resolved, and the backlog of inspections is being addressed. We will continue monitoring the resourcing level and inspection progress.

Modelling of the future resource requirements (see Section 14.8.1) has identified a significant shortfall in in-house resources over the next three years, which will require a material increase in the use of external contractors. We discuss our approach to the external market in Section 14.8.2.

14.5 Corporate and asset management delivery

Our approach to increasing internal corporate and asset management capability is subject to our resource strategy review. We plan to assess greater use of partnering to enable increased capability and efficiency of delivery.

14.6 Field work delivery process

The key components of our workflow for delivering the fieldwork programme are the Annual Work Plan, Project Definition Documents, workflow delivery monitoring and control, and resource forecasting. We discuss these below and present the resource forecasting in Section 14.8.

14.6.1 Annual works plan and defects management

The Network Team publishes our Annual Work Plan before the start of each financial year. The purpose of this document is to provide an annual job list for the Works Planning and Field Delivery teams to ensure sufficient design and construction resources are secured to meet the year's forecast workload. In this plan, there are the major projects and allowances for defect management.

The Annual Work Plan process provides schedulers, project managers, and designers with sufficient visibility into upcoming projects and enables them to identify and order long-lead items. The process also allows projects to be allocated to external providers.

The process ensures there are enough resources to deliver the forecast workload for the forthcoming financial year.

Throughout the year, the Network team also issues active defects to the Delivery Team based on field inspection feedback. These are a significant contributor towards the annual works capital spend. The Delivery bundles the defects with the previously identified job list provided at the start of the year. This process requires ongoing triaging and prioritisation.

Project definition documents

Whilst the Annual Work Plan identifies all projects planned for the upcoming year, the project scope is captured in the Project Definition Document. This process supports the complexity of many of our projects.

The Project Definition Document contains a high-level description of the project, scope of work, current and proposed network configurations, high-level commissioning approach, key materials, resource requirements per craft type, and budget. It also documents the technical review and approval process, supporting the overall AMP financial approval process.

During the development of the Project Definition Document, consideration is also given to minimising network outages whilst maximising resource utilisation. Long-lead procurement items are also identified. Following approval of the PDD, associated budgets and resource plans for detailed design and project construction are developed to produce a high-level project delivery timeline.

14.6.2 Monitoring and control

The Annual Work Plan is developed and reviewed ahead of the forthcoming financial year. Once the plan is finalised, the work delivery is monitored and continuously managed through the monthly forward work planning meetings.

The monthly forward work planning process is used to ensure that:

- Work specified in the Annual Work Plan is delivered annually and on budget
- Work requested from customers is delivered on time and meets customer expectations
- Any conflicts in delivery timing are addressed (which can occur due to unforeseen customer work and major weather events)
- Plant and equipment, material and resourcing requirements are proactively managed and planned
- Workforce utilisation achieves the KPI targets.



14.7 Energised vs. de-energised fieldwork delivery

During work planning, a key consideration for fieldwork is whether the work is undertaken energised or de-energised, with safety being our overriding driver.

Work is sometimes carried out while still energised when large efficiencies can be gained or when it reduces outage impacts on a large number of customers, including those who are supply sensitive. However, safety is the primary consideration when deciding whether to proceed while still energised. In some cases, an outage is unavoidable.

To ensure safety is maintained in all cases, we use a risk assessment tool to determine whether work should be undertaken while still energised or on a de-energised system. This justification process follows EEA guidelines and industry best practice.

When work must be undertaken on a de-energised system, we endeavour to consolidate planned projects on a single feeder and complete them together to minimise the number of outages. This reduces SAIDI and customer inconvenience.

14.8 Fieldwork resourcing

14.8.1 Long-term resource forecast

We completed a 10-year resource forecast as part of the annual work planning process (see figure 155). Our analysis covered the 10-year planning period and uses broad assumptions for labour components for similar work types. The long-term projection provides a general indicator of workforce needs as there is design work required to determine the skills required to deliver the final solutions (e.g., if an overhead circuit or cable network will be used). It is estimated that the accuracy of these estimates is $\pm 25\%$

Our in-house field resources are sufficient to cover core network work, but forecasts indicate a shortfall for FY27 to FY31. When major customer work such as the Waikeria Prison upgrade, and NZTA projects are included, the resource shortfall is material. If these two projects are separated out and treated as one-off pieces of work, a resource shortfall remains, but at a level that will sustain an external service provider under a service-level agreement. We have shown the Waikeria Prison, and NZTA work separately in figure 155, as this work will be tendered, given the size of the works. Customer-initiated work and other external work can be volatile. However, we expect to rely on external contractors to deliver a mix of work, including customer-initiated work, asset relocations, asset renewals and several major projects.

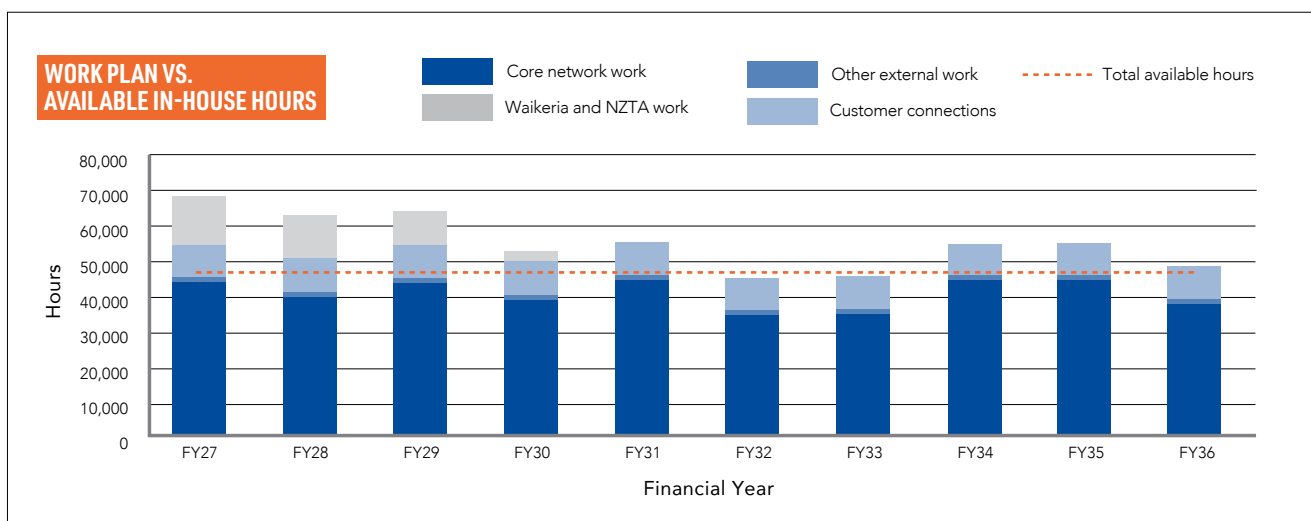


Figure 155: Work plan vs. available in-house hours¹⁵⁴

The shortfall in in-house resources is estimated at approximately 18,000 hours (each year) over the next three years, which will need to be sourced from the external market. This could require approximately \$27m worth of projects for outsourced field delivery over the next three years. Certain components of the \$27m, such as material procurement, are intended to be retained in-house to improve cost efficiency.

¹⁵⁴ Core network work is all network capex and opex, excluding vegetation management, customer works, Waikeria Prison upgrade and the SH1 Cambridge to Piarere project. Vegetation management is excluded from both the workplan and available resources as these are matched and include an allowance for external vegetation work.

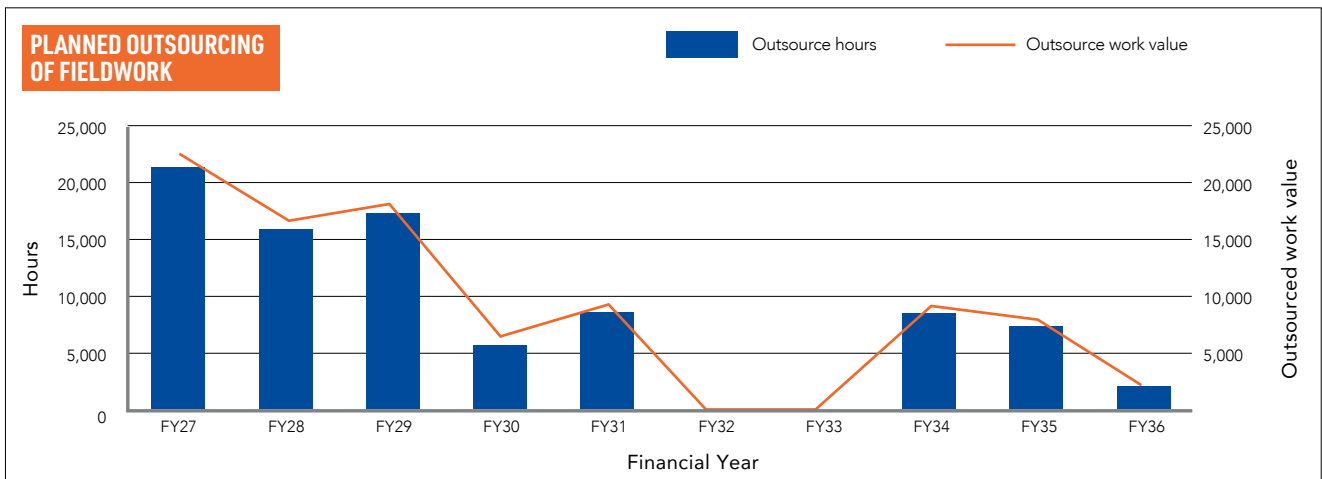


Figure 156: Planned outsourcing or fieldwork

14.8.1 External market capabilities and access

We are increasing our use of external fieldwork contractors to:

- Support delivery of core network and customer-initiated work
- Resource major projects that cannot be efficiently delivered with internal capacity (notably Waikeria Prison and NZTA SH1).

Base (non-major project) work

Following a delivery model review undertaken in FY25, we confirmed two key changes in our operating environment:

- Our network is transitioning from predominantly rural to more semi-urban, requiring greater depth in underground and substation capability
- While we do not have a material shortfall today, we expect a material resource shortfall to emerge within (FY27) if we rely on the current model.

To avoid building an internal workforce sized to intermittent peaks, we commenced a 12-month trial in FY26 with two delivery partners. The intent is to establish a long-term relationship with one partner, comprising an ongoing base work commitment and the ability to tender for major project work. This arrangement will provide scalable resourcing for our core network and customer work (excluding Waikeria Prison and NZTA SH1 projects).

The trial has been extended into FY27 to enable a robust performance assessment. When the trial started, we did not yet have the forecast shortfall, and, as a result, the volume of work allocated (particularly customer-initiated work, which is inherently volatile) has not provided a sufficiently large dataset to confidently assess capability, productivity, safety performance, and delivery outcomes across a representative workload. The extension provides time to complete a clean comparative assessment and select the long-term partner.

Major projects

For Waikeria Prison and the SH1 Cambridge to Piarere project, we intend to tender the work to the external market. We successfully used external delivery to construct the Forrest Road zone substation and intend to adopt a similar approach for other major projects where scale, specialist capability, or delivery timing makes external resourcing the most efficient option.

Confidence in external market capacity

We are confident the external market can support both our core programme and major projects. The Waikato, Bay of Plenty and upper North Island contractor market has sufficient capability across overhead, underground, and substation disciplines, and we have already secured active participation through the current partner trial. We will manage market capacity risk by providing forward visibility of the work programme, staging procurement to avoid peak-on-peak clashes, and maintaining contingency through dual-sourcing (where practicable) and clear escalation pathways should resourcing constraints emerge.

Delivering the \$27m external work is a material risk, and our risk and controls are discussed in Section 8.3.



15. EXPENDITURE FORECASTS

15.1 Assumptions on cost inflators

Since our last full AMP, cost pressures on opex and capex activities have eased. Our assessment of inflation in network capex activities for FY25 to FY26 was 2.59%. This was the capital goods price index for the electricity sector at the time we prepared our forecast model.

For Schedules 11a and 11b, where we escalated constant prices to nominal dollars, we applied 2.0% for FY26 real to FY27 nominal based on NZIER Consensus Forecasts

(September 2025). We used Westpac's CPI forecast for FY28, then applied a 2% p.a. increase from FY29, consistent with the middle of the Reserve Bank's inflation policy range.

Unless specified otherwise, all dollar amounts disclosed in this AMP are in constant dollars (thousands) as of September 2025 (i.e. 2026 real\$). Forecast data for capital goods, producer input prices, and the labour cost index are not readily available.

Year	FY27	FY28	FY29	FY30	FY31	FY32	FY33	FY34	FY35	FY36
Inflation	2.00%	2.28%	2.00%	2.00%	2.00%	2.00%	2.00%	2.00%	2.00%	2.00%

Table 208: Inflation forecasts used for capex and opex

15.2 Capex

15.2.1 Total capex

Figure 157 and table 209 summarise the 2026 AMP total capex compared to 2025 AMP (in comparable, 2026 AMP constant prices). The 10-year forecast table is available in Appendix H.

Total capex in the 2026 AMP is \$309.5m, which is a \$98.9m (52%) increase compared to the 2025 AMP¹⁵⁵. The material reasons for the change are:

- \$34.8m increase in customer connection capex in relation to the significant supply upgrade to the Waikeria Prison
- \$57.4m increase in system growth capex, mainly in relation to regional and distribution capacity-related projects in Te Awamutu. This work was anticipated in prior AMPs, but not included due to the level of uncertainty. Our Te Awamutu architecture review has progressed during FY26, and plans are now sufficient to include in this AMP

- \$8.3m increase in asset relocation due to widening of SH1
- \$1.8m increase in network security and reliability improvements
- \$2.1 million increase in non-network assets due to additional spend in FY27 on vehicles and office equipment
- \$6.4m reduction in asset replacement capex, mainly in relation to voltage regulator refurbishment (rather than replacements) and the transfer of the ADMS to non-network capex.

The reasons for the movements are discussed in more detail in the following sections.

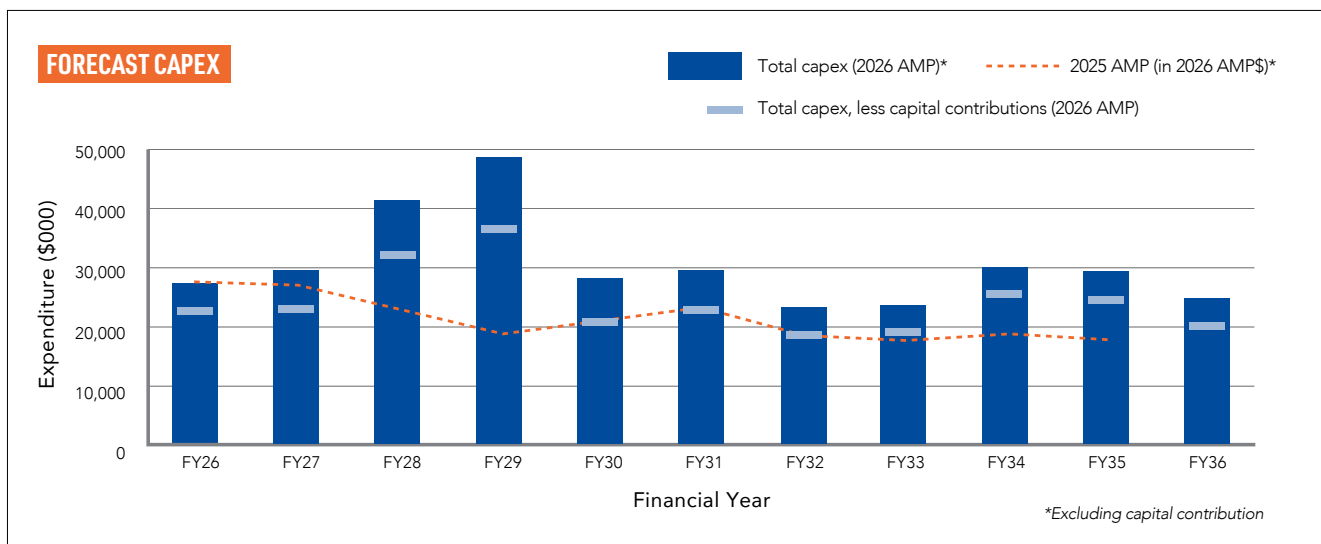


Figure 157: Forecast capex

FY26 real \$

Year	FY27	FY28	FY29	FY30	FY31	FY32	FY33	FY34	FY35	FY36
2026 AMP capex	29,611	41,521	49,155	28,355	29,787	23,259	23,645	30,087	29,453	24,637
2025 AMP capex	26,798	23,293	18,771	21,232	23,067	18,807	17,809	18,523	17,651	-
Change	2,812	18,228	30,384	7,124	6,720	4,452	5,836	11,564	11,802	-

Table 209: Capex forecast (before capital contributions), real 2026 \$000

FY26 real \$000

¹⁵⁵ The 2026 AMP period is FY27 to FY36 and the 2025 AM period is FY26 to FY35. Both in 2026 real\$. Hence, the periods are not directly comparable, but provide an indicator the scale of the change. The variances refer to the comparable FY27 to FY35 period.

15.2.2 Customer connections

Customer connection capex is forecast at \$107m for FY27 to FY36.

Customer connection capex has increased by \$34.8m (120%) over the FY27 to FY31 period, compared to the 2025 AMP (refer to figure 158). The increase relates to the new Waikeria substation and associated work to support the significant increase in demand from the Waikeria Prison (refer to Section 12.2.6). There is no material change in customer connection capex beyond FY32.

Customer connection capex is inherently volatile and depends largely on the progress of land development and population growth. We have experienced strong growth in connections over recent years and forecast this trend to continue. Other than the Waikeria Prison upgrade, the customer connection capex forecast reflects the five-year historical average connection capex. Our target capital contribution from customers and developers for this work is typically 78%; however, with the Waikeria Prison project, this is reduced to 57%.

The connection process is changing, and this may alter or customer connection capex and capital contribution forecasts in future AMPs (refer to Section 12.2.3).

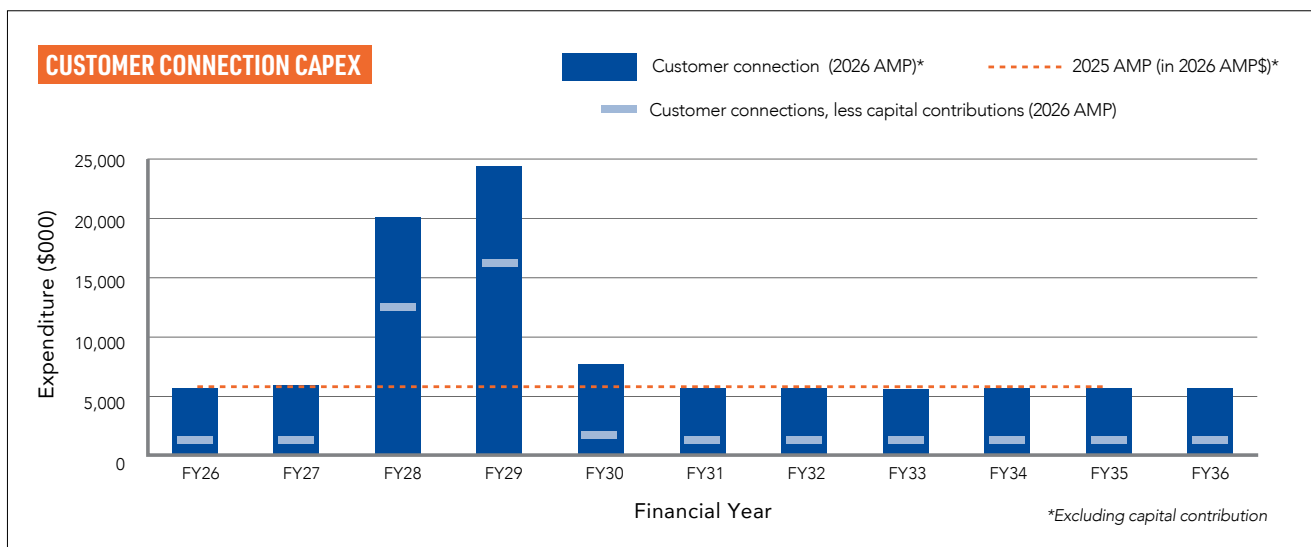


Figure 158: Customer connection capex

FY26 real \$

15.2.3 System growth

System growth capex covers work required to meet changes in demand (or generation) or to maintain existing security or reliability standards as demand increases. It is forecast at \$93m for FY27 to FY36.

System growth capex has increased by \$21m (60%) over the FY27 to FY31 period compared to the 2025 AMP (refer to figure 159). The increase was driven by the new capacity-related distribution programmes in the Te Awamutu area (see Section 11.12).

System growth capex has increased by \$36m from FY32 compared to the 2025 AMP. This reflects the inclusion of capex for meeting forecast demand increases in Te Awamutu. The major projects driving the increase from FY32 are:

- The commencement of construction of the new Leamington zone substation (see Section 11.7.1)

- The new Pirongia zone substation and associated work in the Te Awamutu area (see Section 11.11.1)
- A continuation of capacity-related distribution programmes in the Te Awamutu area (see Section 11.12).

As mentioned above, the increase in capacity-related capex in the Te Awamutu area was anticipated in prior AMPs but not included, due to the degree of uncertainty around the solutions required. Our Te Awamutu architecture review has progressed during FY26, and plans are sufficient to signal in this AMP.

Our system growth capex forecasts for Te Awamutu are mostly traditional network projects (except some non-network solutions included in Section 11.11.1). Assessing and implementing non-network alternatives is a focus for the next stage of the Te Awamutu architecture review and the Kāwhia project (see Sections 11.9). As noted in Section 11.12.1, we expect a shift from our current capex to opex as we implement non-network solutions.

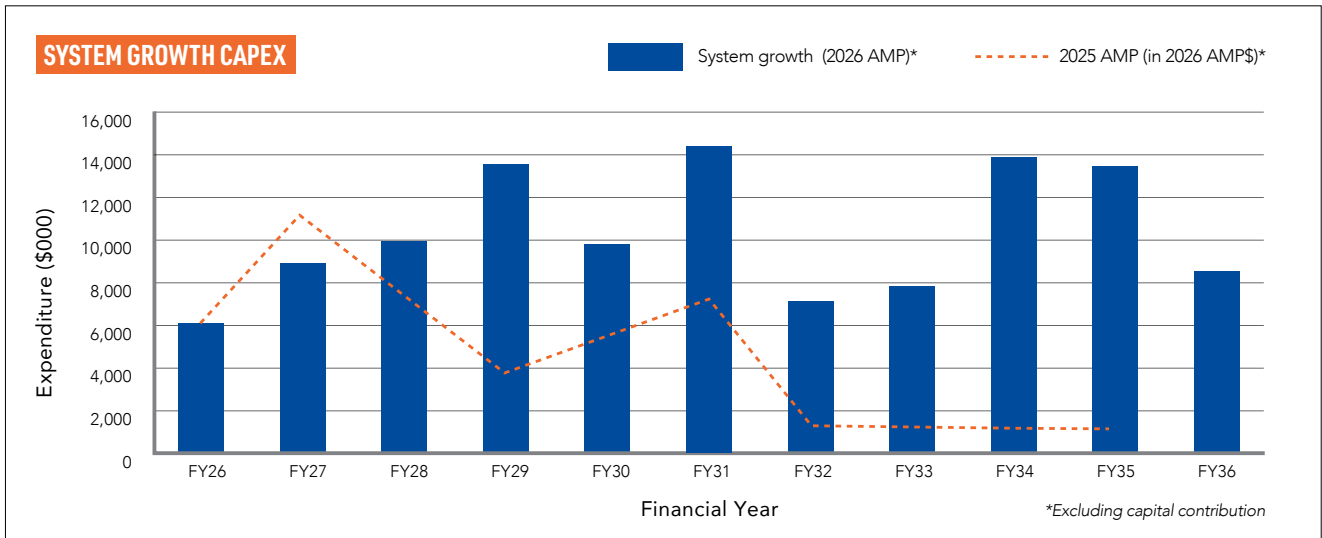


Figure 159: System growth capex

FY26 real \$

15.2.4 Asset replacement and renewal

Our asset replacement and renewal capex forecasts cover work to replace and refurbish the network. It continues to evolve as we incorporate new condition information in our health forecasting. Asset replacement and renewal capex is forecast at \$61m for FY27 to FY36.

Asset replacement and renewal capex has decreased by \$1.9m (6%) over the FY27 to FY31 period, compared to the 2025 AMP (refer to figure 160). The decrease was driven by:

- The transfer of the ADMS project from renewal to non-network opex (see Section 9.7.4)
- Reduction in voltage regulator refurbishment costs. These were previously based on full replacement (see Section 13.16).

There are a range of other minor movements in renewals capex. Refer to the Section 13.7 for a summary of these changes.

Asset replacement and renewal capex has decreased by \$4.4m from FY32 compared to the 2025 AMP. The same reasons as above, plus a reduction in GM transformer renewals (see Section 13.20).

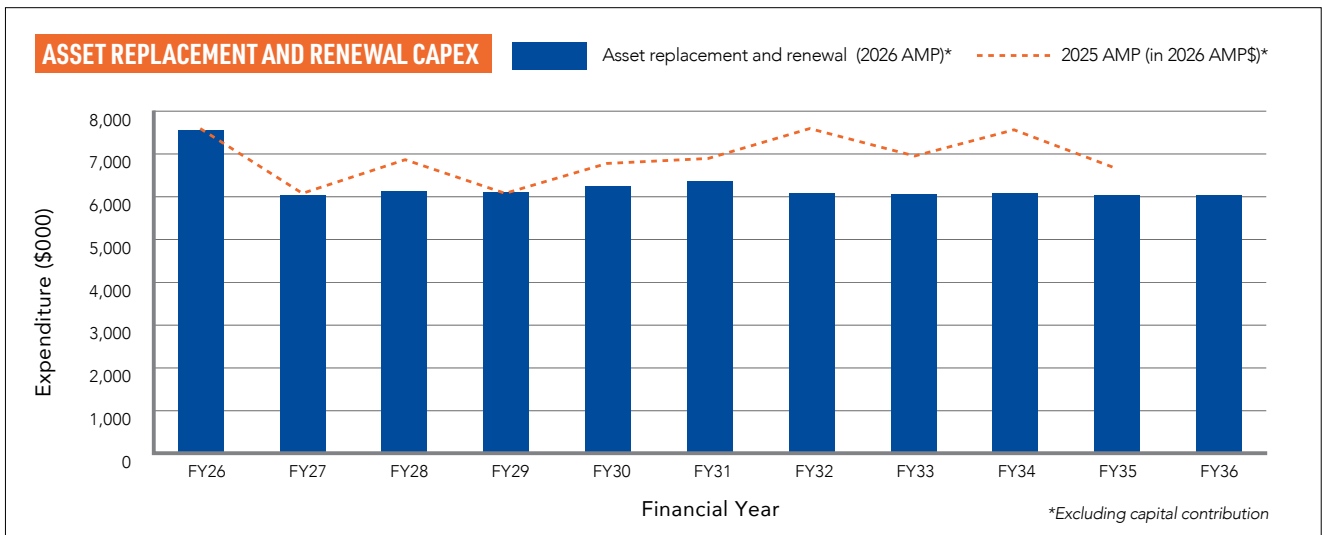


Figure 160: Asset replacement and renewal capex

FY26 real \$

15.2.5 Asset relocation

Asset relocation capex is for work to move or alter our assets due to requests from third parties, such as government agencies, local councils, or other external stakeholders. It is forecast at \$11m for FY27 to FY36.

Asset relocation capex has increased by \$8.3m over the FY27 to FY31 period compared to the 2025 AMP (refer to figure 161). Asset relocation capex is volatile and depends on the NZ Transport Agency and Council roading programmes. The increase is driven by the NZTA realignment of SH1 between

Cambridge and Piarere, and some additional costs to relocate our assets away from Transpower's lines (see Section 12.3.2). There is no material change in asset relocation capex beyond FY32.

Our base programme for asset relocation capex forecast reflects the five-year historical average. Capital contributions to this work have historically averaged 88%. Due to the nature of the SH1 Cambridge to Piarere project (where Waipā Networks typically funds material costs), this has reduced to 67%.

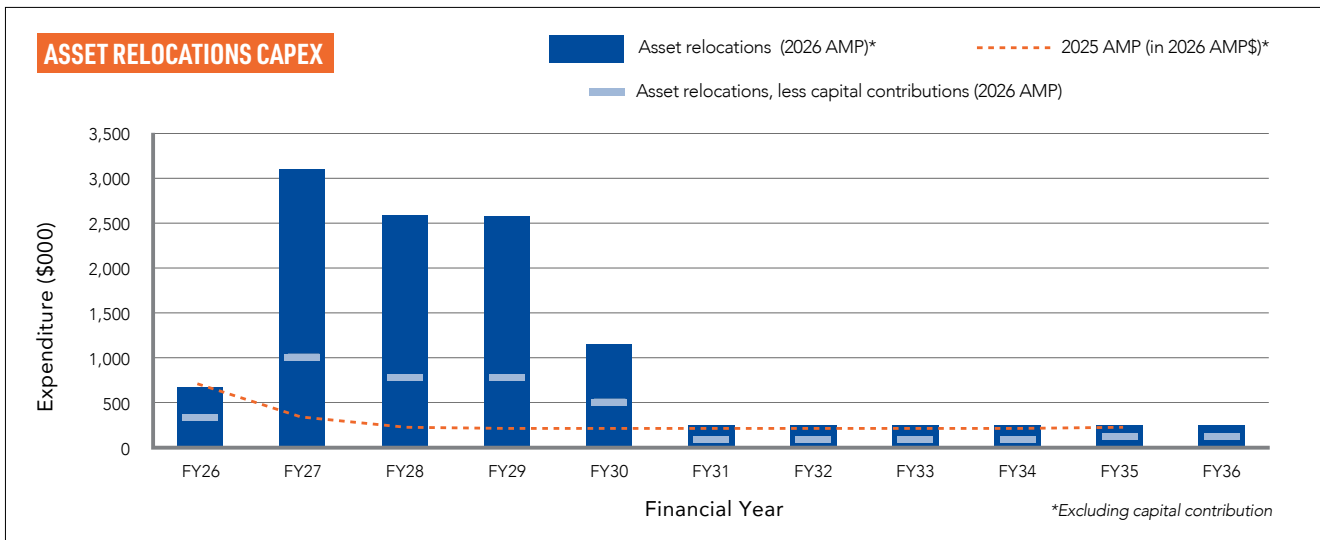


Figure 161: Asset relocation capex

FY26 real \$

15.2.6 Reliability, safety and environmental – the quality of supply

Quality of supply capex relates to projects required to meet improved security or reliability standards. It is forecast at \$10m for FY27 to FY36.

Quality of supply capex has increased by \$1.0m over FY27 to FY31 period compared to the 2025 AMP (refer to figure 162). The change is driven by an increase in our network automation programme (see Section 11.8.2 and 11.12.2) as part of our reliability improvement initiatives.

Quality of supply capex has increased by \$700k from FY32 compared to the 2025 AMP, again due to an increase in our network automation programme.

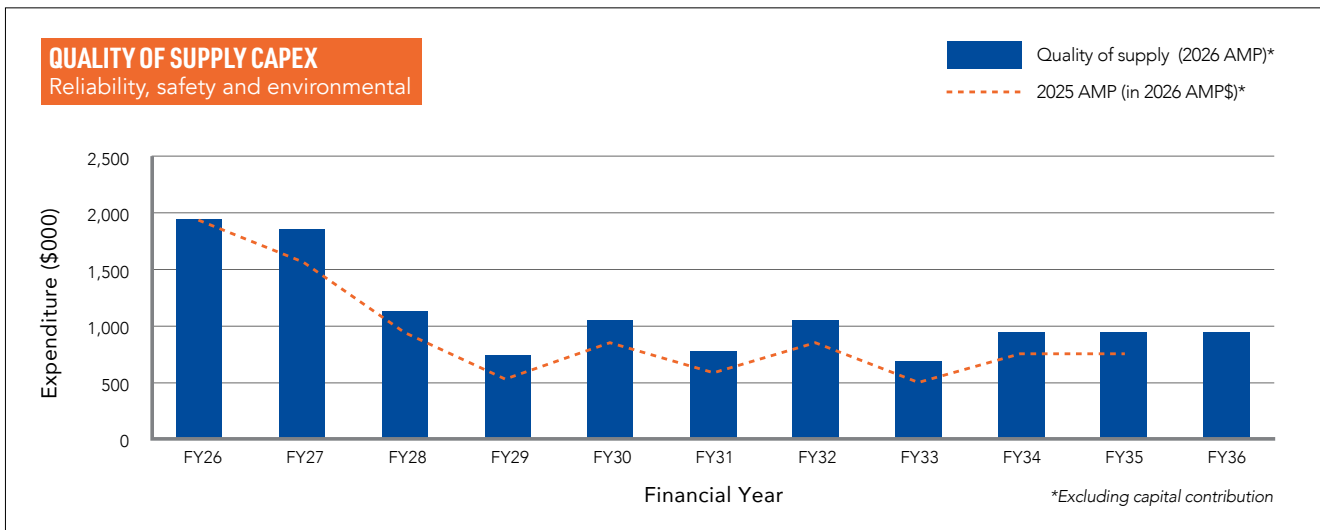


Figure 162: Reliability, safety and environmental – quality of supply capex

FY26 real \$

15.2.7 Reliability, safety and environmental – legislative and regulatory

Legislative and regulatory capex is driven by electricity code-compliance projects and remediation of line clearance issues. It is forecast at \$1.4m for FY27 to FY36.

Legislative and regulatory capex has increased by \$380k over FY27 to FY31 period compared to the 2025 AMP (refer to figure 163). This is due to delays in completing the Mutu St and the Te Rahu Road underground project (see Section 11.12.3). There is no material change to legislative and regulatory capex beyond FY32.

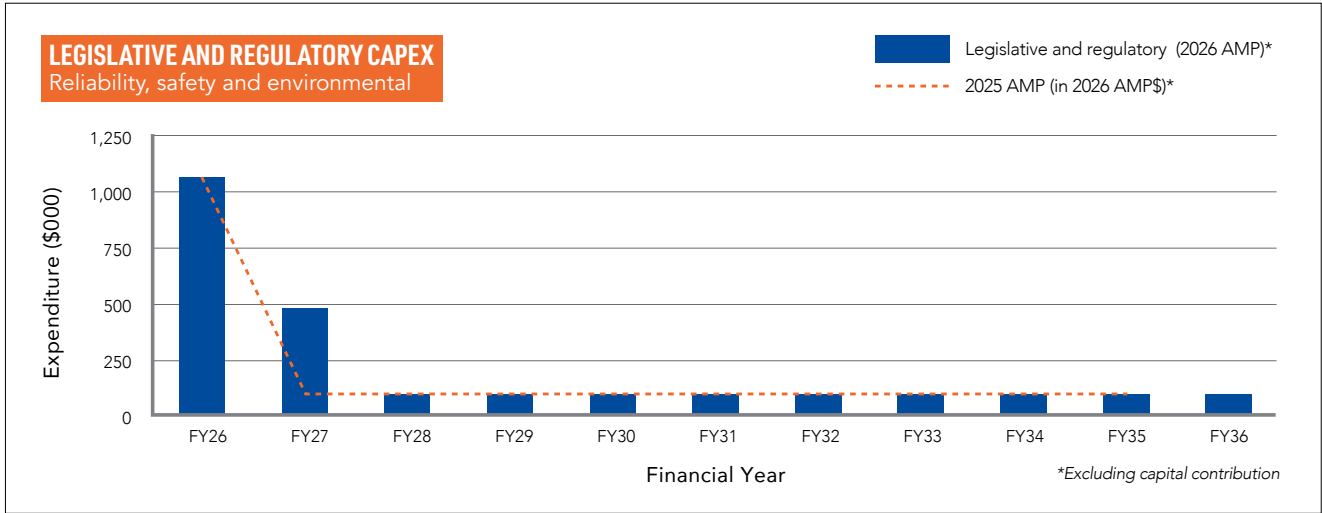


Figure 163: Reliability, safety and environmental – legislative and regulatory capex

FY26 real \$

15.2.8 Reliability, safety and environmental – other

The category includes replacing network access locks and seismic and environmental resilience work. It is forecast at \$2.2m for FY27 to FY36.

Other reliability, safety and environmental capex has increased by \$650k over FY27 to FY31 period compared to the 2025 AMP (refer to figure 164). The changes have been driven by delays to the Kāwhia line deviation project and the undergrounding of the Te Rahu Road and SH3 intersection (see Section 11.12.3).

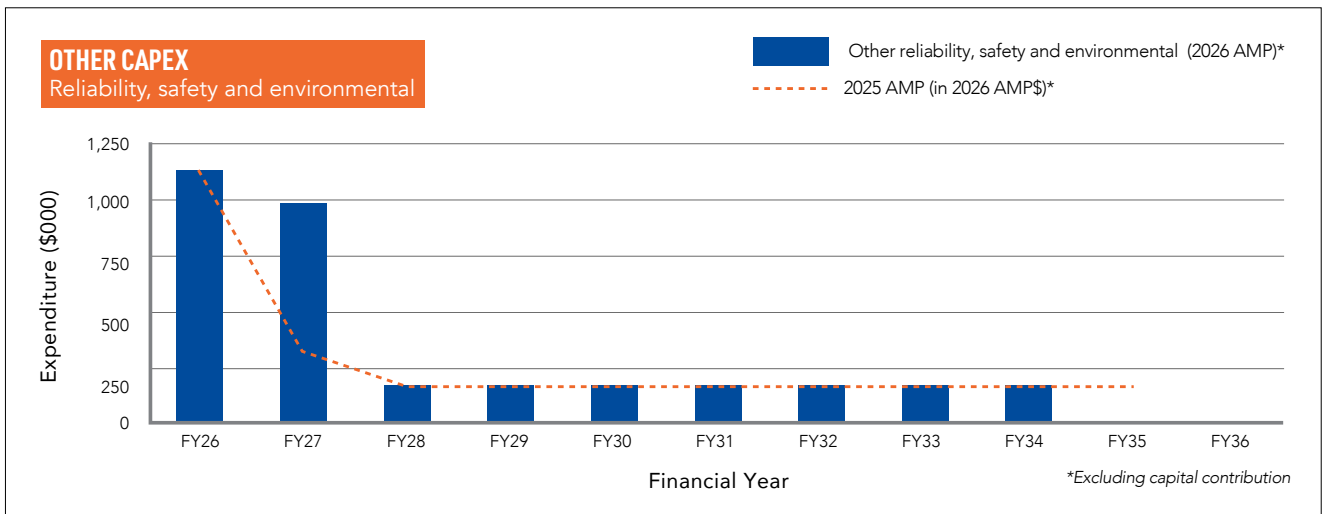


Figure 164: Reliability, safety and environmental – other capex

FY26 real \$

15.2.9 Non-network asset capex

Non-network expenditure covers:

- Office furniture and equipment purchases
- Computer software and equipment
- Land and buildings
- Motor vehicles, fleet and plant purchases
- Information network systems

- Asset data (including data generated from programmes like drone-based survey.

Capital expenditure on non-network assets has increased by \$940k over FY27 to FY31 period compared to the 2025 AMP (refer to figure 165). The changes have been driven by additional expenditure on motor vehicles and the office fitout (see Section 13.28).

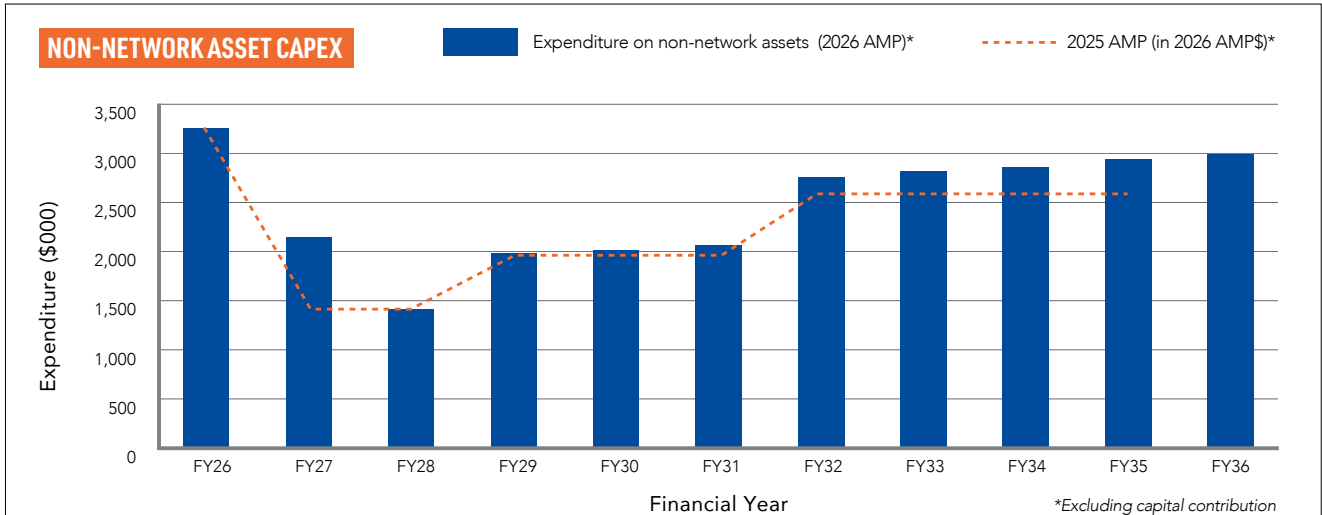
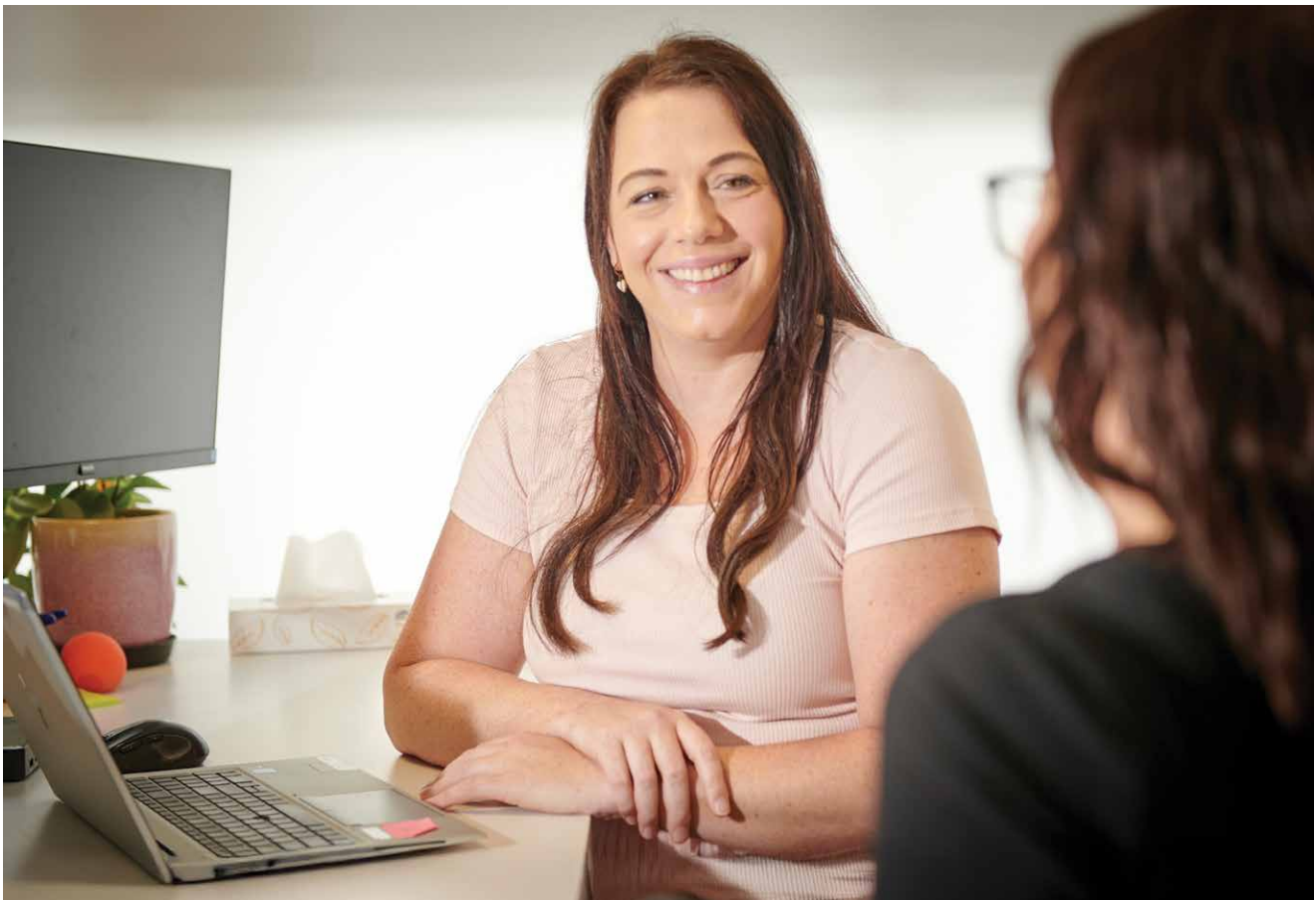


Figure 165: Non-network asset capex

FY26 real \$



15.3 Opex

15.3.1 Network opex

Figure 166 and table 210 summarise the 2026 AMP network opex compared to 2025 AMP (in comparable, 2026 AMP constant prices).

Network opex in the 2026 AMP totals \$54m, a \$4m (8%) decrease over the 2025 AMP¹⁵⁶. The reasons for the change are:

- A minor reduction in system interruption and emergency costs due to lower fault costs

- A reduction in overhead allocation for vegetation management work
- A reduction in expected major maintenance work
- A reduction in expected voltage regulatory refurbishment work.

The reasons for the movements are discussed in more detail in Sections 13.23 to 13.26.

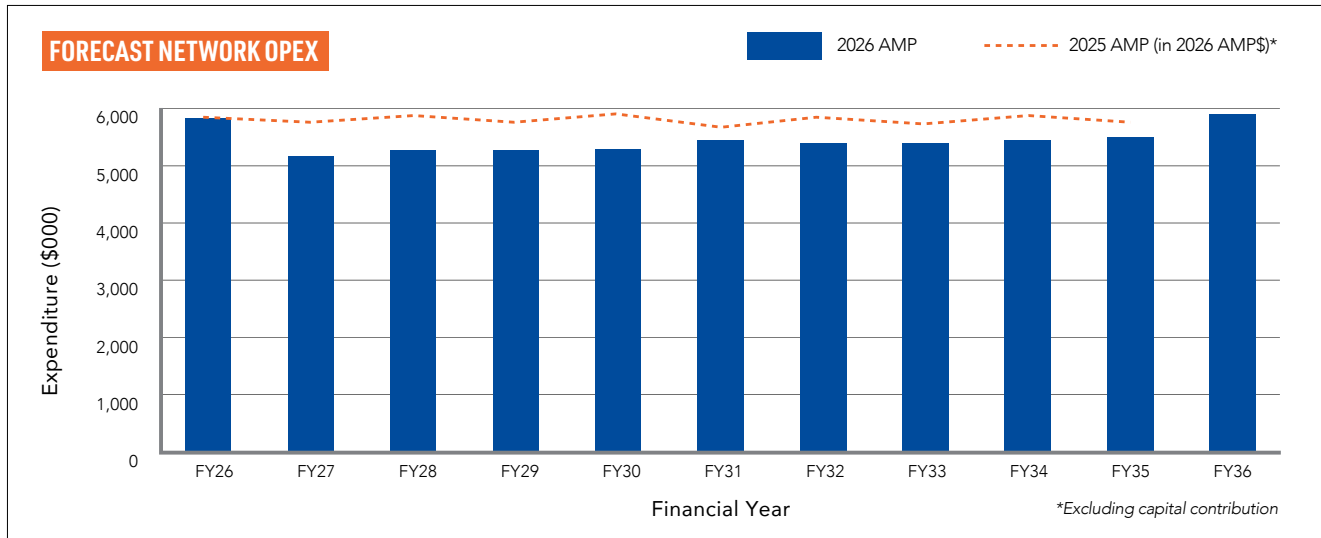


Figure 166: Forecast network opex

FY26 real \$

Year	FY27	FY28	FY29	FY30	FY31	FY32	FY33	FY34	FY35	FY36
2026 AMP network opex	5,140	5,257	5,275	5,266	5,460	5,382	5,394	5,453	5,495	5,891
2025 AMP network opex¹⁵⁷	5,775	5,843	5,754	5,886	5,689	5,859	5,735	5,834	5,730	-
Change	(635)	(585)	(480)	(620)	(229)	(477)	(341)	(381)	(235)	-

Table 210: Capex forecast (before capital contributions)

FY26 real \$000

¹⁵⁶ The 2026 AMP period is FY27 to FY35 and the 2025 AM period is FY26 to FY35. Both in 2026 real\$. Hence, the periods are not directly comparable, but provide an indicator the scale of the change. The variances refer to the comparable FY27 to FY35 period.

¹⁵⁷ In 2026 real\$.

15.3.2 Non-network opex

The category includes expenditure for:

- Business support
- System operation and network support, and
- Non-network solutions provided by a third party of which Waipā Networks does not currently have any.

Non-network opex in the 2026 AMP totals \$142m, a \$9.8m (8%) increase over the 2025 AMP¹⁵⁸. The reasons for the change are primarily the refinement in the methodology

used to forecast and allocate non-network opex to better reflect projected costs and planning assumptions:

- \$6.0m increase in non-network opex due to the ADMS project being transferred from capex to opex and additional support, maintenance and hosting costs
- \$0.5m, increase in costs for digital communications, the LV visibility project, and decommissioning of the Swayne Road generator station
- A \$3.3m net increase in business support due to a refinement in the allocation of overhead costs across the business.

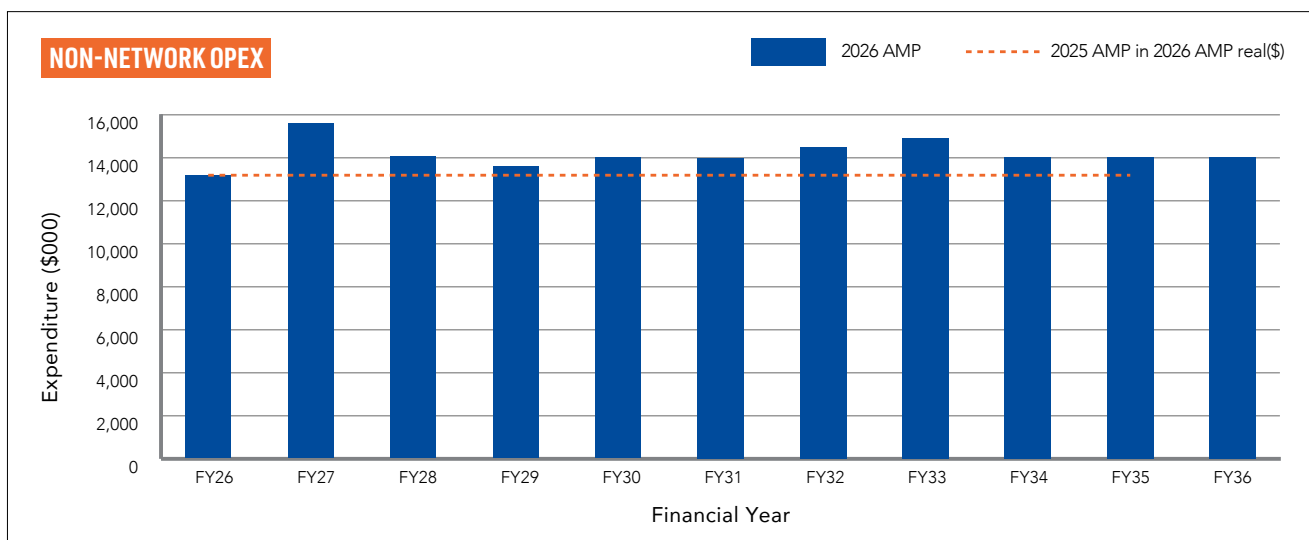


Figure 167: Forecast non-network opex

Year	FY27	FY28	FY29	FY30	FY31	FY32	FY33	FY34	FY35	FY36
2026 AMP non-network opex	15,568	13,966	13,785	14,125	14,042	14,263	14,472	13,976	13,968	14,087
2025 AMP non-network opex¹⁵⁹	13,154	13,154	13,154	13,154	13,154	13,154	13,154	13,154	13,154	-
Change	2,414	813	631	971	889	1,109	1,319	822	814	-

Table 211: Forecast non-network expenditure)

FY26 real \$000

15.4 Capex/opex trade-off

Capex/opex trade-offs are part of our development and lifecycle (renewal) planning processes. With development planning, the option analysis assesses viable alternatives, some of which may be opex-related. We have incorporated non-network alternatives in our regional supply solution for Te Awamutu (see Section 11.11.1). We expect the viability of opex options to increase as the flexibility market evolves, and we expect the use of non-network alternatives to rise. Assessing and implementing non-network alternatives is

a focus for the next stage of the Te Awamutu architecture review and the Kāwhia project (see Sections 11.9 and 11.12.2). As noted in Section 11.12.1, we expect a shift from our current capex to opex as we implement non-network solutions.

With lifecycle planning, the option to maintain an asset (rather than replace it) is considered when developing our fleet plans. In principle, we generally seek to maintain assets for as long as it is economical while continuing to deliver the same level of service from the asset.

¹⁵⁸ The 2026 AMP period is FY27 to FY35 and the 2025 AM period is FY26 to FY35. Both in 2026 real\$. Hence, the periods are not directly comparable, but provide an indicator the scale of the change. The variances refer to the comparable FY27 to FY35 period.

¹⁵⁹ In 2026 real\$.



APPENDICES

APPENDIX A – ASSUMPTIONS

Area	Assumption	Sources of uncertainty	The possible impact of uncertainty
Major weather and natural hazard events	There are no major weather or natural disasters in the context of annual operational planning and budgeting. (Note: there are projects planned to improve resilience)	While major weather events are becoming more prevalent, it is still unclear when and to what extent major events will impact the network in any given year. This is an area that needs further review in the coming years.	Extensive damage to a significant proportion of our network requires significant expenditure (both opex and capex) in a relatively short timeframe.
Demand forecasts	These are set out in Appendix D	Many factors could alter the demand forecasts. A range of these factors are considered in our low and high scenarios outlined in Appendix D.	Should actual demand be closer to the low scenario, there will be opportunities to defer some system growth or customer connection capex. This will reduce capex above that forecast in this AMP. Should actual demand be closer to the high scenario, we may need to advance some system growth or customer connection capex. This will increase capex above that forecast in this AMP.
Technology development	The uptake rate of new technologies (e.g., EVs, PV and battery storage) are discussed in Section 10 and Appendix D	The rate of uptake of new technologies remains uncertain.	Changes in technology uptake could change our demand forecasts as discussed above.
Inflation	These are set out in Section 15.1	Inflation in New Zealand is generally driven by a mix of domestic demand, supply-side constraints, and international factors. The Reserve Bank of New Zealand (RBNZ) aims to keep annual inflation between 1% and 3%, with the Consumer Price Index (CPI) acting as the main measure.	Should inflation vary from the assumed value, forecast nominal\$ amounts may increase or decrease.
Constant price escalation to nominal dollars	For Schedules 11a and 11b, where we escalated constant prices to nominal dollars, we applied 2.0% for FY26 real to FY27 nominal based on NZIER Consensus Forecasts (September 2025). We used Westpac's CPI forecast for FY28, then applied a 2% p.a. increase from FY29, consistent with the middle of the Reserve Bank's inflation policy range.	The forecasts are based on NZIER and Westpac observations of price movements, which could vary due to unseen factors.	Variations in the forecast value may increase or decrease, causing inaccuracies in forecast expenditure amounts. Further details are presented in the expenditure forecasts section.
Regulatory environment	No significant changes to the regulatory regime and requirements.	The shift in Government changes the regulatory nature/requirements of EDBs.	Plan revision may be required to adhere to any changes in regulatory requirements.
Customer connection capex	These are discussed in Section 12	Actual net migration into the region, subdivision activity or major industrial connection may differ from our forecast.	Customer connection capex may increase or decrease in response to net migration, subdivision activity or major industrial connection.
System growth capex	These are discussed in Section 11	Demand forecasts may differ from our forecast.	System growth capex may increase or decrease in response to changes in demand growth.
Asset relocation capex	These are discussed in Section 12	NZTA, councils or land developers may require relocation of our assets.	Asset relocation capex may increase or decrease in response to requests to relocate our assets.

Area	Assumption	Sources of uncertainty	The possible impact of uncertainty
Asset replacement and renewal capex	Our renewal assumptions are based on our assessment of asset health as described in Section 13. These assumptions assume no major asset failure.	The overall condition and rate of ageing of network assets may differ from our current assessment, or an equipment type defect might be discovered.	Asset replacement and renewal capex may increase or decrease in response to changes in known asset conditions and major asset failure.
System interruption and emergency opex	We have assumed that normal weather patterns will prevail and there is no allowance for major disaster events. Refer to Section 13.23.	There could be significant weather events or natural disasters.	System interruption and emergency opex will increase if a significant weather event or natural disaster occurs.
Availability of field resources	Field resources are available to complete the planned work.	The work will be delivered as per this AMP.	Additional external resources will be engaged to complete the work programme. This may result in some short-term delays.
Material costs	The cost of materials increases at the forecast rate of inflation.	Material costs can be influenced by international factors, including the demand for certain metals.	Higher material costs will lead to higher capex and opex, which will lead to higher prices. Lower material costs will lead to lower capex and opex, which will lead to higher prices.

Table 212: General assumptions



APPENDIX B – NETWORK INVESTMENT SELECTION AND APPROVAL PROCESS

Overview

We follow a structured investment selection and approval process that ensures investments selected for implementation meet our asset management goals and support delivery efficiency. Figure 168 shows the stages of our investment approval process. The level of analysis of issues and opportunities is commensurate with their complexity, level of expenditure, and timing. Complex, expensive, and imminent needs receive more rigour than those that are simple, inexpensive, or more distant in the future.

Various drivers determine the need for network investment, including customer requests, load growth, examination of existing constraints or limitations within our network, and asset condition.

This process enables consistent decisions that balance risk, service levels, and expenditure. It is used to determine and justify expenditures on network development, asset replacements and refurbishments, maintenance activities, and customer-initiated work.

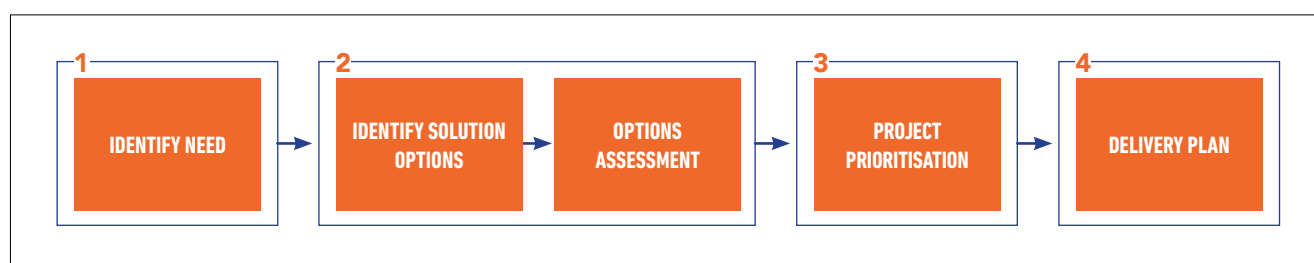


Figure 168: Investment selection and approval process

Need identification

A need is a clearly defined problem and/or opportunity that impacts how we operate the network. Identifying the need includes establishing a need date (i.e., the date at which a solution must be in place) and the planning lead time (i.e., the time required to complete the investment selection and approval and complete the delivery).

A need can include problems with a common set of solutions. The need is recognised when:

- One or more planning criteria are breached
- Request for new load connection or asset relocation from a customer
- Asset condition meets criteria for replacement or renewal
- Safety non-compliance
- Projects are identified under other business strategies or programmes.

Solution options identification

This stage explores a range of options to meet the need. Engineers typically develop network options using various tools, such as load flow modelling software, local knowledge (and experience), and sourcing information from others. For long-term issues, an incremental scope buildup would be usual as more knowledge on the issues and solution options is developed. When the project scope has been updated, the solution must pass through the assessment, prioritisation, and approval stages.

Options to address typically include:

- Consideration of non-network solutions (discussed in Appendix C)
- Operational activities that could be used to manage risk and delay the project
- New approaches for delivery and operation
- Other innovative ideas
- A do-nothing option representing the status quo is always considered.

In respect of asset renewal projects, there are often limited alternatives. Hence, the options considered include:

- Managing risk and delaying renewal
- Maintenance vs. replacement.

Options assessment

The outcome of this step is the selection of a preferred solution. The various solution options are assessed based on multiple criteria. The level of analysis depends on the size and risk of the projects. The solution or combination of options that best meet the needs is selected.

An option assessment accounts for the following:

- Total lifecycle costs to deliver, maintain, operate, and dispose of the relevant assets
- Cost of residual risk associated with the option
- Benefit, including risk mitigation or opportunity value, provided by the option
- Maximum net benefit that the option and the associated need date can provide

- Changes in the net benefit (including any changes in risk) when the need date is delayed or advanced (e.g., growth appears faster or load decommissioned earlier than forecast)
- Sensitivity analysis where two options have the same net benefit.

Some of the options may not be technically feasible or economical. Where possible, options are analysed and pre-determined and then documented in the relevant asset class lifecycle strategy.

The option with the highest net benefit, subject to sensitivity analysis, is selected as the solution. Solutions to security issues will be economically tested where the cost is high or the security benefit provided is modest. The cost/benefit assessment also provides a framework for managing conflicting stakeholder expectations and interests.

Prioritisation and approval

This step ranks projects and presents them for approval. We prioritise projects on:

- Need dates to ensure assets are commissioned on time
- Alignment with long-term network development plan
- Risk reduction—the extent to which the project eliminates or minimises network, health and safety, and business risks
- Ease of coordination with other projects, which supports work integration
- Service level improvement.

Where solutions are based on a risk assessment (other than asset capacity or condition), further prioritisation is undertaken based on the magnitude of the net benefits, with the solutions with the highest net benefit being prioritised first. Where available, criticality is also utilised to prioritise solutions.

Approval to proceed with the project is sought via the delegated authority process. For large projects, a business case is required.

Delivery

A works delivery plan is developed to ensure efficient solution delivery. This plan includes accounting for funding and deliverability constraints.

Nearer to the time, a concept design report is prepared in which implementation options are considered and selected, and revised expenditure estimates are presented for approval. Following this, the detailed design and material purchases are made.

We periodically review how we manage work activities to maximise efficiency and determine which spare inventories we need. Progress on the works programme is continuously tracked (both in the active implementation phase and in planned projects) to ensure expenditure remains within budget limits and that planned projects remain relevant.

We do monthly reviews to manage the status of capital projects and capitalise or expense costs when and where appropriate.

Stakeholder engagement to support the delivery is planned and coordinated following our stakeholder engagement strategy. After identifying options, plans for stakeholder engagement—customers, landowners, councils, and iwi, specific project communications can be enacted. When the preferred option is chosen, further engagement may be undertaken with landowners and the community on the proposed works.



APPENDIX C – DISTRIBUTED GENERATION, NON-NETWORK ALTERNATIVES, AND INNOVATION PRACTICES

Introduction

Historically, network reinforcement has been the primary response to forecast constraints. Waipā Networks is transitioning from traditional reinforcement-led planning to a more integrated, diverse framework that incorporates network and non-network solutions. In this shift, traditional reinforcement and non-network solutions are assessed systematically and early in the planning cycle. This transition will occur progressively over multiple AMP cycles and will require improvements in data capabilities, economic evaluation tools, market engagement, and customer insights.

We do not assume that these capabilities or markets exist today. The role of non-network solutions, pricing reform and distributed energy integration will be tested through customer engagement during this period, and outcomes will inform future AMPs.

This AMP therefore establishes direction and governance for staged improvement rather than assuming a fully mature flexibility framework today.

Strategic position on non-network solutions

Non-network solutions are alternatives and supplements to traditional network reinforcement, addressing identified network needs. They may include demand response, distributed generation, distributed storage, energy efficiency, and Remote Area Power Supplies (RAPS). We are also investigating less traditional network solutions such as connection to neighbouring networks, improved use of inherent capacity and regional capacity solutions.

Our objective is to meet required service levels at the least long-term cost and risk to customers. In a context of uncertain electrification uptake and variable demand growth, non-network solutions provide staging value. Less traditional solutions can sometimes release additional capacity at lower cost. Both can defer irreversible capital expenditure and improve utilisation of existing assets.

We do not assume that non-network and less traditional solutions will replace traditional reinforcement in all cases. Rather, we are moving toward a balanced model in which

all options are considered credible and are assessed using consistent economic and technical criteria. This was the process we followed when considering options to address capacity in the Te Awamutu area. We found that this hybrid solution, which incorporated non-network, less traditional and traditional solutions, provided a significant cost reduction compared to what could be delivered by the individual methods alone. It also ensures that investment can be staged depending on the maturity of the solution, and to better match demand growth.

Our goal is to now extend this thinking into the distribution network. With the development of a solution for Kāwhia identified as the initial trial. We are also aiming to co-develop solutions with customers and the community. We will use the output of this trial to further develop our evaluation methodologies. This work will also look to determine how we ensure all solutions are evaluated on an equal footing.

Pricing and the role of flexibility

Pricing is an important mechanism for encouraging efficient use of network capacity. We currently provide time-of-use price signals and controlled-load tariffs that encourage demand to shift away from peak periods.

Hot-water load has historically been the dominant source of flexibility within our network. We have transitioned toward pricing structures that increasingly enable price-responsive flexibility. This needs to ensure system stability and fairness to all customers, as our pricing options evolve.

Over time, we will continue aligning variable pricing components with our long-run marginal cost to ensure we maintain efficient prices and monitor emerging peak boundary risks. We recognise that transition risk exists, including uncertainty in demand response and the potential for new peaks forming at peak/off-peak boundaries. Pricing structures will therefore evolve progressively rather than through abrupt change.

The development of pricing and flexibility will be tested through customer engagement during this AMP period to ensure affordability, reliability and equity considerations remain central.

Market engagement and procurement

The New Zealand flexibility services market remains in a development phase. Procurement and engagement approaches must therefore balance transparency, practicality and cost.

Where non-network solutions are available and market-provided services are feasible, we intend to signal opportunities with sufficient lead time, adopt transparent evaluation criteria and seek competitive responses where practicable. Where in-house non-network solutions are

implemented, we will assess and document why this approach provides greater value to customers than available market alternatives.

We support interoperable and open communication standards to reduce integration costs and avoid fragmented solutions that limit scalability. During this AMP period, we expect to move from exploratory engagement and limited pilots toward more structured market testing where justified by identified constraints.

Distributed generation

We welcome enquiries regarding distributed generation, including photovoltaic and other embedded technologies. Our connection policy requires generators to operate safely, comply with technical standards and avoid adverse impacts on voltage, harmonics, protection systems and other customers.

Where distributed generation necessitates network reinforcement, cost contribution applies in accordance with our connection policy.

Most installations within our network are currently downstream of the metering point and at relatively low penetration levels. However, localised LV voltage issues have emerged on some feeders. In response, we are improving LV visibility, strengthening hosting capacity assessment processes and enhancing data integration. As penetration increases, we expect to move progressively from reactive issue management toward more proactive identification of hosting limits.

Innovation practice

Innovation strategy

Waipā Networks applies an evidence-led approach to innovation. We generally adopt a fast-follower strategy, prioritising proven solutions that deliver clear customer value while managing risk and cost. Given the uncertainty around the pace of technology uptake and market development, we closely monitor industry trends and progress and conduct our own assessment before committing to large-scale deployment.

Innovation activities and improvement since the last AMP disclosure

Our innovation priorities are aligned with our asset management strategy and our approach to non-network solutions:

- Evaluating non-network solutions as potential alternatives to traditional reinforcement
- Monitoring and assessing flexibility services and implications to pricing
- Enhancing network visibility, particularly at the low-voltage level, to assist in expanding the effective use of data in asset planning and operations.

These focus areas support reliable supply, prudent investment, and long-term network resilience.

Since the last AMP disclosure cycle, we have undertaken or progressed exploratory assessments and proof-of-concept activities related to:

- Assessment of the 'hybrid-network' solution for the future Te Awamutu network at both regional and area level (refer to C2 and Section 11.11).

- Load Data Dashboard – A centralised, interactive dashboard that consolidates historical SCADA load data across the network. This enables engineers to rapidly identify representative study periods, compare multiple feeders simultaneously, and export data for modelling.
- PowerFactory Calibration and Accuracy Improvements – A systematic review and calibration of the PowerFactory model to better reflect real-world network behaviour. This included conductor and cable library standardisation, feeder-specific power factor calibration using SCADA data, and statistically derived representative GXP and voltage regulator settings.
- LV visibility data and analytics – we put the initiative on hold since 2024 due to limited access to full network metering data (~52% available). The situation is improving as MEPs start offering data-provisioning services and alternate sources of data are becoming viable. We look to recommencing this initiative again in FY27 Q3. (Refer to Section 10.11.3).

Collaboration, dependencies and information

Innovation at Waipā is influenced by broader industry developments. We actively participate in national forums and peer collaboration, and we monitor emerging practices in flexibility procurement and non-network solutions. We will consider and participate in credible shared-services and collaboration initiatives where the business case shows net customer benefit and reflects recognised best practice.

APPENDIX D – DEMAND FORECAST ASSUMPTIONS

Demand driver	Low	Predicted	High
<p>Residential connection growth</p> <p>This is principally driven by population growth. Our view is that the Waipā district will remain a desired place to live and is well situated for business, but growth will soften slightly compared to the past 10 years.</p>	Residential connection growth of around 1.2% p.a., equating to around 9,400 lots.	Residential connection growth of 1.6% p.a. equates to over 12,000 new lots by 2050. This is consistent with Waipā District Council view and equates to 38 MW of demand growth between FY25 and FY50.	Residential connection growth of 1.7% p.a., equating to over 13,000 new lots by 2050.
<p>Industrial step-change growth</p> <p>Base growth will be driven by new customers and plant expansions (before decarbonisation). Our general view is that industrial expansions will remain strong and supported by the primary industry within the Waipā district and improved transport links to the “golden triangle” of Auckland, Hamilton, Tauranga (albeit slightly below historical levels). All scenarios include the decommissioning of Fonterra’s cogeneration plant in Te Awamutu.</p>	Lower growth occurs and many of the possible expansions do not occur.	Base commercial and industrial growth continues. This equates to 24 MW of new demand between FY25 and FY50 ¹⁶⁰ .	Modestly stronger growth based on possible expansions.
<p>Residential and commercial gas conversions</p> <p>Approximately 35% of our residential and commercial customers use fossil gas. Our general view is that most residential customers and small commercial customers will convert their energy use to electricity due to the higher efficiency available for heating applications.</p>	Some customers choose different forms of energy, and around 80% of residential and commercial natural gas customers convert to electricity by FY50.	Most residential and commercial natural gas customers convert to electricity by FY50. This equates to 8.5 MW of new demand between FY25 and FY50.	Electricity dominates fuel conversion, and close to 100% of residential and commercial natural gas customers convert to electricity by FY50.
<p>Light electric vehicles</p> <p>Reducing emissions by electrifying the vehicle fleet is a focus area in New Zealand, and our general view is that electrification of the light transport fleet will occur due to ongoing price decreases, the expansion of regional charging infrastructure, and the development of smart charging options at home. The scenario differences are the rate of uptake and whether the charging will be controllable, and to what extent this will occur during off-peak times.</p>	Uptake is slower for LEVs; most LEVs are being controlled, minimising the impact on peak demand.	We reach high penetration for LEVs in the early 2040s, with most LEVs charging being controlled, minimising the impact on peak demand. This equates to 6 MW of new demand between FY25 and FY50.	We reach close to 100% penetration in the early 2040s, with a large proportion of charging being uncontrolled, causing a more significant impact on peak demand.
<p>Heavy electric vehicles</p> <p>Conversion of the heavy vehicle fleet occurs, but is more limited to short haulage. Long-haul fleets use alternative fuels.</p>	Uptake of HEVs is slow, or does not occur for some applications.	Significant uptake of HEVs, with charging occurring mostly after hours, which does impact peak demand. This equates to 14 MW of new demand between FY25 and FY50.	Significant uptake of HEVs, with more charging occurring during peak times.
<p>Industrial gas/coal conversion</p> <p>Conversion of industrial gas/coal usage to electricity occurs to a varying degree due to the efficiency improvement available from heat-pump technology.</p>	Few industrial usage converts to electricity.	Significant volumes of industrial usage converts to electricity. This equates to 14 MW of new demand between FY25 and FY50 ¹⁶¹ .	A high percentage of industrial usage converts to electricity.

¹⁶⁰ Including Waikeria Prison expansion that includes some gas conversion.

¹⁶¹ This excludes the Waikeria Prison gas conversion, which is included in step-change growth as it is a known project.

Demand driver	Low	Predicted	High
<p>Distributed energy resources</p> <p>DERs, such as residential solar PV and battery, distribution-connected solar or wind farms. We expect a material increase in customers installing small-scale solar PV generation and battery installations. The falling cost and increasing efficiency of solar panels and batteries will enable higher DER uptake. We have estimated that around 24 MW of new DERs will be available to offset peak demand; however, their application to reduce peak demand may vary.</p>	Uptake and application of DERs is high, leading to 25 MW of new demand reduction at peak times.	Uptake and/or application of DERs is not maximised, resulting in around 12 MW of new demand reduction at peak times between FY25 and FY50.	Same as the predicted scenario.
<p>Merchant or industrial demand response</p> <p>No additional merchant or industrial demand response has been included.</p>	–	–	–
<p>Energy efficiency improvements</p> <p>Our view is that efficiency improvements will continue, but will be offset by increased use of electrical devices.</p>	–	–	–
Total system demand in FY50	148 MW	185 MW	244 MW

Table 213: Demand driver assumptions



APPENDIX E – KEY TERMS AND DEFINITIONS

Term	Description
ABS	Air break switch
ADMS	Advanced distribution management system
Adverse environment cause outages	All unplanned interruptions where the primary cause is an adverse environment, such as slips or seismic events.
Adverse weather cause outages	All unplanned interruptions where the primary cause is adverse weather, other than those caused directly by lightning, vegetation contact or adverse environment.
AMMAT	Asset management maturity assessment tool
AMP	Asset management plan
ARR	Asset replacement and renewal
AUFLS	Automatic underfrequency load shedding
BCP	Business continuity plan
CAIDI	Customer average interruption duration index is the average total duration of interruptions per interrupted customer.
Capacity utilisation	A ratio which measures the utilisation of transformers in the system. It is calculated as the maximum demand experienced on an electricity network in a year divided by the transformer capacity on that network.
Capex	Capital expenditure is used to buy, improve, or maintain fixed assets, i.e., vehicles, buildings, and equipment.
CB	Circuit breaker
CBD	Central business district
CO₂e	Represents an amount of a greenhouse gas (GHG) whose atmospheric impact has been standardised to that of one unit mass of carbon dioxide (CO ₂), based on the global warming potential (GWP) of the gas.
Conductor	Includes overhead lines, which can be covered (insulated) or bare (not insulated), and underground cables, which are insulated.
Continuous rating	The constant load which a device can carry at rated primary voltage and frequency without damaging and/or adversely affecting its characteristics.
CT	Current transformer
Current	The movement of electricity through a conductor, measured in amperes.
DDO	Drop-out fuse
Defective equipment cause outages	All unplanned customer interruptions resulting from equipment failure, either mechanical or electrical.
DER	Distributed energy resource
DERMS	Distributed energy resource management system
DG	Distributed generation
DGA	Dissolved gas analysis
DNO	Distribution network operators
DPP	Default price path (commerce commission)
DSO	Distribution system operator. Entities responsible for managing energy and other services (like flexibility services) across the distribution network.
Distribution substation	A kiosk, outdoor ground-mounted substation or pole-mounted substation taking its supply at 11kV and distributing at 400V.

Term	Description
ECP	Electrical code of practice
EDB	Electricity distribution business
EOL	End of Life
EV	Electric vehicle
Feeder	A physical grouping of conductors that originates from a district substation circuit breaker.
Flexibility	Customers (or merchant providers) are changing their usage patterns by either switching on generators or reducing consumption in response to a signal.
Flexibility purchaser	These are buyers of flexibility services and could be: <ul style="list-style-type: none"> • Energy retailers or generators who buy alternatives to energy on the spot market • System operator who buys reserve energy alternatives or ancillary services alternatives • Transpower, which buys alternatives to transmission assets • Distributors, who buy alternatives to distribution assets.
Flexibility markets	Mechanisms for matching and rewarding traders of controllable DERs, including providing dispatch instructions in response to prices.
Flexibility resources	Flexibility resources are delivered through DERs that are controllable. Distributed solar without a battery is not a flexible resource because it is not controllable.
Flexibility traders	Owners of DER portfolios who manage their DERs portfolio to allocate it to its highest value usage. Flexibility traders interact with flexibility buyers to provide the flexibility that they require. Importantly, flexibility traders maximise the value of DERs by allocating them to their highest value use (“value stacking”) rather than dedicating individual DERs to one use.
Frequency	On AC circuits, the designated number of times per second that polarity alternates from positive to negative and back again, expressed in Hertz (Hz).
FLISR	Fault location, isolation and service restoration
FY	Financial Year, e.g., FY2021, is Financial Year 2021, which covers 1st April 2020 to 31st March 2021.
GWh	Gigawatt hours
GXP or grid exit point	The point at which Transpower’s grid is connected to Waipā’s equipment.
H1	A measure of asset health. End of serviceable life. Immediate intervention is required. ¹⁶²
H2	A measure of asset health. Material deterioration but condition still within serviceable life parameters. Intervention likely within three years. ¹⁶²
H3	A measure of asset health. Normal deterioration requiring regular monitoring, but with an increasing risk of failure. ¹⁶²
H4	A measure of asset health. Normal deterioration requiring regular monitoring. ¹⁶²
H5	A measure of asset health. As new condition. ¹⁶²
H&S	Health and safety
Harmonics (wave for distortion)	A distortion to the supply voltage, which can be caused by network equipment and equipment owned by consumers, including electric motors or even computer equipment.
High voltage	Voltage exceeding 1,000 volts, generally 11,000 volts (known as 11kV)
HILP	High impact low probability
Hosting capacity	The amount of new production or consumption that can be connected to the network without endangering the reliability or voltage quality for other customers.
HR	Human resources
Human error cause outages	All unplanned customer interruptions resulting from contractors or staff, commissioning errors, incorrect protection settings, SCADA problems, switching errors, dig-in and overhead contact.

¹⁶² EEA Asset Health Indicator definition.

Term	Description
HV	High voltage. Voltages are typically above 1,000 Volts.
ICP	Installation connection point. The point of connection for an electricity consumer.
IP	Internet protocol
IT	Information technology
IoT	Internet of things
Interruption	An electricity supply outage caused by either an unplanned event (e.g., weather, trees) or a planned even (e.g., planned maintenance).
kV	Kilovolt
kW	Kilowatt
kWh	Kilowatt hour
kVA	Kilovolt amp output rating designates the output which a transformer can deliver for a specified time at rated secondary voltage and rated frequency.
LCP	Load control plant
LED	Light-emitting diode
Lightning cause outages	All unplanned customer interruptions where the primary cause is a lightning strike, resulting in insulation breakdown and or flashovers. Typically, protection is the only observable operation.
Load factor	The measure of annual load factor is calculated as the average load that passes through a network divided by the maximum load experienced in a given year.
Low voltage (LV)	Voltage not exceeding 1,000 volts, generally 230 or 400 volts
Maximum demand (peak demand)	The maximum demand for electricity during the course of the year
m	Million
MD	Maximum demand. The peak demand (measured in MW or MVA) for the network, element of the network, or load.
MDI	Maximum demand indicator
MED	Major event day
MPL	Maximum practical life. The age at which the majority of assets can be expected to have been removed from service. Approximately defined as the age at which nominally 95% of the population would be retired for end-of-life reasons.
MVA	Megavolt amp
MW	Megawatt
MWh	Megawatt hour (onem watt hour)
N-1 security	A load is said to have N-1 security if, for the loss of any one item of equipment supply to that load, it is not interrupted or can be restored in the time taken to switch to alternate supplies.
ONAF	Oil natural air forced
ONAN	Oil natural air natural
Opex	Operational expenditure is an ongoing expense for running a business, e.g., rent, power, wages.
OT	Operations technology, which means digital technology used for process control, protection of machinery and assurance of product quality.
PILC	Paper-insulated, lead-covered – a type of cable insulation.
PV or photovoltaic	The conversion of light into electricity using solar panels.

Term	Description
Ripple control system	A system used to control the electrical load on the network by, for example, switching domestic water heaters and street lighting.
RMU	Ring Main Unit
RTU	Remote Terminal Unit
SAIDI	System average interruption duration index is the average total duration of interruptions per connected customer.
SAIFI	System average interruption frequency index is the average number of interruptions per connected customers.
SCADA	Waipā's computerised system control and data acquisition system is the primary tool for monitoring and controlling access and switching operations for Waipā's Network.
SCI	Statement of corporate intent
Subtransmission	The lines and cables that connect the zone substation and the GXP.
SWER	Single wire earth return
Transformer	A device that changes voltage up to a higher voltage or down to a lower voltage.
Transpower	The state-owned enterprise that operates New Zealand's transmission network. Transpower delivers electricity from generators to various networks around the country.
TPD	Third party damage. Damage that has resulted from third party interference.
Third party interference cause outages	All unplanned customer interruptions resulting from external contractors or members of the public including dig-in, overhead contact, vandalism, and vehicle damage.
UG	Underground
UHF	Ultra-high frequency
Unknown cause outages	All unplanned interruptions where the cause is not known.
Vegetation cause outages	All unplanned customer interruptions resulting from vegetation contact, including debris, grass and tree contact
VHF	Very high frequency
VT	Voltage transformer
Voltage	Electric pressure. The force which causes current to flow through an electrical conductor.
Voltage regulator	An electrical device that keeps the voltage at which electricity is supplied to consumers at a constant level, regardless of load fluctuations.
WACC	Weighted average cost of capital
Wildlife cause outages	All unplanned customer interruptions resulting from wildlife contact – includes birds, possums, vermin, cats, etc.
XLPE	Cross linked polyethylene. Type of insulation for cables.
Zone substation	A major building substation and/or switchyard with associated high voltage structure where voltage is transformed from 33kV to 11kV.

APPENDIX F – ELECTRICITY DISTRIBUTION INFORMATION

DISCLOSURE DETERMINATION 2012 RECONCILIATION

Information disclosure requirements 2012 clause	AMP section
CONTENTS OF THE AMP	
3.1 A summary that provides a brief overview of the contents and highlights information that the EDB considers significant.	Section 1
3.2 Details of the background and objectives of the EDB's asset management and planning processes.	Section 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	2.2, 2.3
3.3.2 states the corporate mission or vision as it relates to asset management	2.3.1, 2.3.2
3.3.3 identifies the documented plans produced as outputs of the annual business planning process adopted by the EDB	2.3, 2.8, 2.9
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	2.9, 7.4
3.3.5 includes a description of the interaction between the objectives of the AMP and other corporate goals, business planning processes, and plans.	2.3
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.	2.5
3.5 The date that it was approved by the directors .	2.5
3.6 A description of stakeholder interests (owners, consumers etc) which identifies important stakeholders and indicates:	
3.6.1 how the interests of stakeholders are identified	3.5
3.6.2 what these interests are	3.5.3
3.6.3 how these interests are accommodated in asset management practices and	3.5.3
3.6.4 how conflicting interests are managed.	3.5.4
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	2.7, 2.9
3.7.2 executive – an indication of how the in-house asset management and planning organisation is structured and	2.7, 2.8
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.	14.2 – 14.6, 14.8
3.8 All significant assumptions	Appendix A Appendix D
3.8.1 quantified where possible	
3.8.2 clearly identified in a manner that makes their significance understandable to interested persons, including:	
3.8.3 a description of changes proposed where the information is not based on the EDB's existing business	
3.8.4 the sources of uncertainty and the potential effect of the uncertainty on the prospective information and	
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.	15.1
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.	Appendix A
3.10 An overview of asset management strategy and delivery.	7.3, 14.2

Information disclosure requirements 2012 clause	AMP section
<p>3.11 An overview of systems and information management data</p> <p>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:</p> <ul style="list-style-type: none"> a. the processes used to identify asset management data requirements that cover the whole of life cycle of the assets b. the systems used to manage asset data and where the data is used, including an overview of the systems to record asset conditions and operation capacity and to monitor the performance of assets c. the systems and controls to ensure the quality and accuracy of asset management information d. the extent to which these systems, processes and controls are integrated e. how asset management data informs the models that an EDB develops and uses to assess asset health and f. how the outputs of these models are used in developing capital expenditure projections. 	9.3, 9.4, 9.5
<p>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.</p>	9.5.4, 9.6, 9.7
<p>3.13 A description of the processes used within the EDB for:</p> <ul style="list-style-type: none"> 3.13.1 managing routine asset inspections and network maintenance 3.13.2 planning and implementing network development projects 3.13.3 measuring network performance. 	5.7.3, 13.3 14.6, 11.4, Appendix B Chapter 5, 7.8
<p>3.14 An overview of asset management documentation, controls and review processes.</p>	9.3.2
<p>3.15 An overview of communication and participation processes.</p>	2.8
<p>3.16 The AMP must present all financial values in constant price New Zealand dollars except where specified otherwise.</p>	All financials are represented in real FY26 dollar terms
<p>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.</p>	1.3, 2.4

ASSETS COVERED

4. The **AMP** must provide details of the assets covered, including:

<p>4.1 a high-level description of the service areas covered by the EDB and the degree to which these are interlinked, including:</p> <ul style="list-style-type: none"> 4.1.1 the region(s) covered 4.1.2 identification of large consumers that have a significant impact on network operations or asset management priorities 4.1.3 description of the load characteristics for different parts of the network 4.1.4 peak demand and total energy delivered in the previous year, broken down by sub-network, if any. 	4.2 3.6.3 3.7.1, 3.7.2 3.7.1, 4.5, 11.5.1
<p>4.2 a description of the network configuration, including:</p> <ul style="list-style-type: none"> 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 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 4.2.3 a description of the distribution system, including the extent to which it is underground 4.2.4 a brief description of the network's distribution substation arrangements 4.2.5 a description of the low voltage network including the extent to which it is underground 4.2.6 an overview of secondary assets such as protection relays, ripple injection systems, SCADA and telecommunications systems and 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. 	3.7.4, 4.5 4.6 4.7 4.6 4.8 4.9, 4.10, 13.10, 13.11, 13.22.3, 13.22.4 11.7.5, 11.8.6, 11.11.1, 11.11.5, 11.12.6

Information disclosure requirements 2012 clause	AMP section
4.3 If sub-networks exist, the network configuration information referred to in subclause 4.2 above must be disclosed for each sub-network .	N/A
NETWORK ASSETS BY CATEGORY	
4.4 The AMP must describe the network assets by providing the following information for each asset category:	
4.4.1 voltage levels	4.5 to 4.8
4.4.2 description and quantity of assets	4.3, 13.8 – 13.22
4.4.3 age profiles and	13.9 – 13.22
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.	6.4, 13.1 – 13.22
4.5 The asset categories discussed in subclause 4.4 above should include at least the following:	
4.5.1 the categories listed in the Report on Forecast Capital Expenditure in Schedule 11a(iii)	13.9 – 13.22
• Sub transmission	
• Zone substations	
• Distribution and LV lines	
• Distribution and LV cables	
• Distribution substations and transformers	
• Distribution switchgear	
• Other system fixed assets	
• Other assets.	
4.5.2 assets owned by the EDB but installed at bulk electricity supply points owned by others	4.10
4.5.3 EDB owned mobile substations and generators whose function is to increase supply reliability or reduce peak demand and	13.22.7
4.5.4 other generation plant owned by the EDB .	13.22.7
SERVICE LEVELS	
5. The AMP must clearly identify or define a set of performance indicators for which annual performance targets have been defined. The annual performance targets must be consistent with business strategies and asset management objectives and be provided for each year of the AMP planning period . The targets should reflect what is practically achievable given the current network configuration, condition and planned expenditure levels. The targets should be disclosed for each year of the AMP planning period .	7.6 – 7.12 5.3 – 5.8
6. Performance indicators for which targets have been defined in clause 5 above must include SAIDI and SAIFI values for the next 5 disclosure years .	7.6 – 7.12
7. Performance indicators for which targets have been defined in clause 5 above should also include:	
7.1 Consumer oriented indicators that preferably differentiate between different consumer types and	3.10, 5.4
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.	5.6, 5.7, 7.10, 7.11
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.	5.4, 5.5, 7.6 – 7.12
9. Targets should be compared to historic values where available to provide context and scale to the reader.	5.3 – 5.7
10. Where forecast expenditure is expected to materially affect performance against a target defined in clause 5 above, the target should be consistent with the expected change in the level of performance.	5.7.1
NETWORK DEVELOPMENT PLANNING	
11. AMPs must provide a detailed description of network development plans, including:	
11.1 A description of the planning criteria and assumptions for network development.	11.4
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.	11.4

Information disclosure requirements 2012 clause	AMP section
<p>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.</p>	<p>11.4.2, 11.4.3, 11.4.4, 7.5, 9.6.2</p>
<p>11.4 The use of standardised designs may lead to improved cost efficiencies. This section should discuss:</p> <p>11.4.1 the categories of assets and designs that are standardised</p> <p>11.4.2 the approach used to identify standard designs.</p>	<p>11.4.3</p>
<p>11.5 A description of strategies or processes (if any) used by the EDB that promote the energy efficient operation of the network.</p>	<p>Section 11, Appendix C2</p>
<p>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.</p>	<p>11.4.2</p>
<p>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.</p>	<p>11.4, Appendix B</p>
<p>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:</p> <p>11.8.1 explain the load forecasting methodology and indicate all the factors used in preparing the load estimates</p> <p>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</p> <p>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</p> <p>11.8.4 discuss the impact on the load forecasts of any anticipated levels of distributed generation in a network, and the projected impact of any demand management initiatives.</p>	<p>10.5, Appendix D</p> <p>11.5, 11.6, 11.10</p> <p>11.7.1, 11.8.1 to 11.8.3, 11.11.1, 11.12.1 to 11.12.3, 11.13</p>
<p>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:</p> <p>11.9.1 the reasons for choosing a selected option for projects where decisions have been made</p> <p>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</p> <p>11.9.3 consideration of planned innovations that improve efficiencies within the network, such as improved utilisation, extended asset lives, and deferred investment.</p>	<p>11.7.1, 11.7.3, 11.8.1, 11.8.4, 11.11.1, 11.11.3, 11.12.1, 11.12.4</p> <p>11.7.5, 11.8.6, 11.11.5, 11.12.6</p> <p>Appendix C6</p>
<p>11.10 A description and identification of the network development programme including distributed generation and non-network solutions and actions to be taken, including associated expenditure projections. The network development plan must include:</p> <p>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</p> <p>11.10.2 a summary description of the programmes and projects planned for the following four years (where known) and</p> <p>11.10.3 an overview of the material projects being considered for the remainder of the AMP planning period.</p>	<p>Section 11</p>
<p>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</p>	<p>Appendix C5</p>
<p>11.12 A description of the EDB's policies on non-network solutions, including:</p> <p>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</p> <p>11.12.2 the potential for non-network solutions to address network problems or constraints and</p> <p>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.</p>	<p>Appendix C2</p>

LIFECYCLE ASSET MANAGEMENT PLANNING (MAINTENANCE AND RENEWAL)

12. The AMP must provide a detailed description of the lifecycle asset management processes, including:	Section 13
12.1 The key drivers for maintenance planning and assumptions.	13.3, 13.4
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:	13.3 – 13.22
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	
12.2.2 any systemic problems identified with any particular asset types and the proposed actions to address these problems and	
12.2.3 budgets for maintenance activities broken down by asset category for the AMP planning period .	
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:	13.1 – 13.22
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	
12.3.2 a description of innovations made that have deferred asset replacement	
12.3.3 a description of the projects currently underway or planned for the next 12 months	
12.3.4 a summary of the projects planned for the following four years (where known) and	
12.3.5 an overview of other work being considered for the remainder of the AMP planning period .	
12.4 The asset categories discussed in clauses 12.2 and 12.3 above should include at least the categories in clause 4.5.	13.9 – 13.22
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	13.3, 13.5
12.5.2 the rationale for using the approach for each asset category.	13.3 – 13.5
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.	5.5.7, 13.24
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.	Section 11, Appendix C

NON-NETWORK DEVELOPMENT, MAINTENANCE AND RENEWAL

13. AMPs must provide a summary description of material non-**network** development, maintenance and renewal plans, including:

13.1 a description of non- network assets	13.28
13.2 development, maintenance and renewal policies that cover them	13.28.1, 13.28.2
13.3 a description of material capital expenditure projects (where known) planned for the next five years and	13.28.3
13.4 a description of material maintenance and renewal projects (where known) planned for the next five years.	13.28.3

RISK MANAGEMENT

14. AMPs must provide details of risk policies, assessment, and mitigation, including:

14.1 Methods, details and conclusions of risk analysis	Section 8
14.2 Strategies used to identify areas of the network that are vulnerable to high impact low probability events and a description of the resilience of the network and asset management systems to such events	8.2 8.3
14.3 A description of the policies to mitigate or manage the risks of events identified in subclause 14.2 and	8.2, 8.4
14.4 Details of emergency response and contingency plans.	8.5

EVALUATION OF PERFORMANCE

15. AMPs must provide details of performance measurement, evaluation, and improvement, including:

15.1	A review of progress against plan, both physical and financial	5.2
15.2	An evaluation and comparison of actual service level performance against targeted performance	5.3 – 5.8
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 and	6.6
15.4	An analysis of gaps identified in subclauses 15.2 and 15.3 above. Where significant gaps exist (not caused by one-off factors), the AMP must describe any planned initiatives to address the situation.	Section 5, Section 6

CAPABILITY TO DELIVER

16. AMPs must describe the processes used by the EDB to ensure that:

16.1	The AMP is realistic and the objectives set out in the plan can be achieved	2.3, Section 14
16.2	The organisation structure and the processes for authorisation and business capabilities will support the implementation of the AMP.	2.7, 2.8

REQUIREMENTS TO PROVIDE QUALITATIVE INFORMATION IN NARRATIVE FORM

17. AMPs must include qualitative information in narrative form, as prescribed in clauses 17.1-17.7 below:

Notice of planned and unplanned interruptions

17.1	a description of how the EDB provides notice to and communicates with consumers regarding planned interruptions and unplanned interruptions, including any changes to the EDB's processes and communications in respect of planned interruptions and unplanned interruptions	3.12.3
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Voltage quality and constraints

17.2 a description of the EDB's practices for:

17.2.1	monitoring voltage, including: <ul style="list-style-type: none"> a. the EDB's practices for monitoring voltage quality on its low voltage network 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 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 d. how the EDB communicates with affected consumers regarding the voltage quality work it is carrying out on its low voltage network and e. any plans for improvements to any of the practices outlined at clauses 17.2.1-17.2.4 above. 	10.11, 13.27
17.2.2	monitoring load and injection constraints, including: <ul style="list-style-type: none"> 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). 	10.11, 13.27

Customer service practices

17.3 a description of the EDB's customer service practices, including:

17.3.1	the EDB's customer engagement protocols and customer service measures – including customer satisfaction with the EDB's supply of electricity distribution services	3.3, 3.4, 3.5, 3.8, 3.9, 3.10
17.3.2	the EDB's approach to planning and managing customer complaint resolution.	3.12

Practices for connecting new consumers and altering existing connections

- | | |
|--|---------------------|
| 17.4 a description of the EDB's practices for connecting consumers, including: | |
| 17.4.1 the EDB's approach to planning and management of: | 12.2, 12.2.2 |
| 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 | 12.2.4 |
| 17.4.3 the EDB's approach to planning and managing communication with consumers about new or altered connections and | 12.2.5 |
| 17.4.4 commonly encountered delays and potential timeframes for different connections and | |
| 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. | 10.11 |

New connections likely to have a significant impact on network operations or asset management priorities

- | | |
|--|-------------------|
| 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: | 12.2 |
| a. how the EDB measures the scale and impact of new demand, generation, or storage capacity | |
| b. how the EDB takes the timing and uncertainty of new demand, generation, or storage capacity into account | |
| c. how the EDB takes other factors into account, e.g., the network location of new demand, generation, or storage capacity and | |
| 17.5.2 how the EDB assesses and manages the risk to the network posed by uncertainty regarding new demand, generation, or storage capacity. | 8.2, 8.3.3 |

Innovation practices

- | | |
|---|--------------------|
| 17.6 a description of the following: | Appendix C6 |
| 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 | |
| 17.6.2 the EDB's desired outcomes of any innovation practices , and how they may improve outcomes for consumers | |
| 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 | |
| 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 | |
| 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. | |
| 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. | N/A |

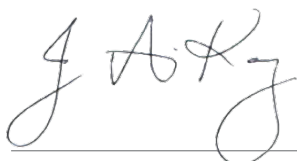
APPENDIX G – CERTIFICATION FOR YEAR-BEGINNING DISCLOSURES

Schedule 17: certification for year-beginning disclosures

As per Clause 2.9.1 of the Electricity Distribution Information Disclosure Determination.

We, Jonathan Anthony Kay and Shane Raniera Ellison, being directors of Waipā Networks Limited, certify that, having made all reasonable enquiry, to the best of our knowledge:

- a. The following attached information of Waipā Networks Limited prepared for the purposes of clause 2.4.1, clause 2.6.1, 2.6.3, 2.6.6 and 2.7.2 of the Electricity Distribution Information Disclosure Determination 2012 in all material respects complies with that determination.
- b. The prospective financial or non-financial information included in the attached information has been measured on a basis consistent with regulatory requirements or recognised industry standards.
- c. The forecasts in Schedules 11a, 11b, 12a, 12b, 12c and 12d are based on objective and reasonable assumptions which both align with Waipā Networks' corporate vision and strategy and are documented in retained records.



Jonathan Anthony KAY

30 March 2026



Shane Raniera ELLISON

30 March 2026



APPENDIX H – SCHEDULES

Schedule	Schedule name
11a	Report on forecast capital expenditure
11b	Report on forecast operational expenditure
12a	Report on asset condition
12b	Report on forecast capacity
12c	Report on forecast network demand
12d	Report forecast interruptions and duration
13	Report on asset management maturity
14a	Mandatory explanatory notes on forecast information

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.

schref

Difference between nominal and constant price forecasts

Current Year CY	CY+1	CY+2	CY+3	CY+4	CY+5	CY+6	CY+7	CY+8	CY+9	CY+10
31 Mar 26	31 Mar 27	31 Mar 28	31 Mar 29	31 Mar 30	31 Mar 31	31 Mar 32	31 Mar 33	31 Mar 34	31 Mar 35	31 Mar 36
\$000										
-	124	867	1,536	667	622	751	882	1,015	1,152	1,291
-	177	429	865	838	1,529	911	1,180	2,424	2,651	1,898
-	121	265	394	533	683	790	924	1,071	1,210	1,345
-	62	112	166	100	26	31	37	43	48	54
-	37	49	47	89	83	135	103	164	186	209
-	10	5	7	9	11	14	16	18	21	23
-	20	7	11	14	18	22	26	29	-	-
-	66	61	112	112	113	170	144	212	207	232
-	550	1,733	3,025	2,251	2,973	2,653	3,167	4,765	5,268	4,820
-	42	61	126	171	219	355	425	499	577	660
-	592	1,794	3,151	2,422	3,192	3,008	3,592	5,264	5,845	5,480

Commentary on options and considerations made in the assessment of forecast expenditure

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

11a(ii): Consumer Connection

Consumer types defined by EDB*

Residential and commercial connections
Industrial connections

*include additional rows if needed

Consumer connection expenditure
less Capital contributions funding consumer connection
Consumer connection less capital contributions

\$000 (in constant prices)

Current Year CY	CY+1	CY+2	CY+3	CY+4	CY+5	CY+6	CY+7	CY+8	CY+9	CY+10
5,803	5,803	5,803	5,803	5,803	5,803	5,803	5,803	5,803	5,803	5,803
-	400	14,250	18,150	2,000	-	-	-	-	-	-
5,803	6,203	20,053	23,953	7,803	5,803	5,803	5,803	5,803	5,803	5,803
4,526	4,677	7,527	7,777	5,527	4,527	4,527	4,527	4,527	4,527	4,527
1,277	1,527	12,527	16,177	2,277	1,277	1,277	1,277	1,277	1,277	1,277

11a(iii): System Growth

Subtransmission
Zone substations
Distribution and LV lines
Distribution and LV cables
Distribution substations and transformers
Distribution switchgear
Other network assets
System growth expenditure
less Capital contributions funding system growth
System growth less capital contributions

205	4,104	3,278	4,700	-	-	-	400	7,000	6,500	-
818	154	-	2,041	3,847	5,771	-	200	3,500	5,100	6,650
462	337	2,085	2,053	3,091	3,538	3,264	3,727	1,421	821	421
3,383	2,661	3,714	4,180	2,363	4,149	2,264	2,527	421	421	948
616	776	513	513	513	513	513	513	513	513	513
547	800	340	300	-	1,000	1,000	400	1,000	-	-
6,020	8,832	9,929	13,487	9,814	14,270	7,041	7,767	13,855	13,355	8,532
103	-	82	2,760	1,539	2,308	-	-	-	-	-
5,927	8,832	9,847	10,727	8,275	11,962	7,041	7,767	13,855	13,355	8,532

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 PAB 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.

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11a(iv): Asset Replacement and Renewal

Current Year CY 31 Mar 26	CY+1 31 Mar 27	CY+2 31 Mar 28	CY+3 31 Mar 29	CY+4 31 Mar 30	CY+5 31 Mar 31	CY+6 31 Mar 32	CY+7 31 Mar 33	CY+8 31 Mar 34	CY+9 31 Mar 35	CY+10 31 Mar 36
\$000 (in constant prices)										
-	-	-	-	-	-	-	-	-	-	-
-	-	-	-	-	-	-	-	-	-	-
2,552	2,807	2,895	2,867	2,858	2,867	2,840	2,812	2,812	2,789	2,789
580	571	571	571	571	571	571	571	571	571	569
1,689	1,391	1,391	1,391	1,568	1,568	1,192	1,192	1,299	1,299	1,299
1,402	1,264	1,264	1,317	1,245	1,367	1,509	1,509	1,437	1,437	1,390
1,368	-	-	-	-	-	-	-	-	-	-
7,590	6,033	6,120	6,147	6,242	6,372	6,111	6,083	6,119	6,095	6,047
-	-	-	-	-	-	-	-	-	-	-
7,590	6,033	6,120	6,147	6,242	6,372	6,111	6,083	6,119	6,095	6,047

Asset replacement and renewal expenditure
less
Capital contributions funding asset replacement and renewal
Asset replacement and renewal less capital contributions

11a(v): Asset Relocations

Current Year CY 31 Mar 26	CY+1 31 Mar 27	CY+2 31 Mar 28	CY+3 31 Mar 29	CY+4 31 Mar 30	CY+5 31 Mar 31	CY+6 31 Mar 32	CY+7 31 Mar 33	CY+8 31 Mar 34	CY+9 31 Mar 35	CY+10 31 Mar 36
\$000 (in constant prices)										
243	2,593	2,593	2,593	1,173	243	243	243	243	244	244
-	-	-	-	-	-	-	-	-	-	-
-	-	-	-	-	-	-	-	-	-	-
-	-	-	-	-	-	-	-	-	-	-
462	513	-	-	-	-	-	-	-	-	-
705	3,106	2,593	2,593	1,173	243	243	243	243	244	244
359	2,052	1,788	1,788	622	122	122	122	122	122	122
346	1,055	805	805	552	122	122	122	122	122	122

Project or programme*
NZA and Council asset relocations

*Include additional rows if needed
All other project or programmes - asset relocations
Asset relocations expenditure
less
Capital contributions funding asset relocations
Asset relocations less capital contributions

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.

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11a(vi): Quality of Supply

Current Year/CY	CY+1	CY+2	CY+3	CY+4	CY+5	CY+6	CY+7	CY+8	CY+9	CY+10
128	-	624	470	470	470	470	470	368	368	368
129	334	-	-	-	-	-	-	-	-	-
130	11	11	11	11	11	11	11	11	11	11
131	467	657	-	-	-	-	-	-	-	-
132	995	421	513	114	424	161	424	161	424	424
133	-	-	-	-	-	-	-	-	-	-
134	137	137	137	137	137	137	137	137	137	137
135	-	-	-	-	-	-	-	-	-	-
136	1,943	1,850	1,131	732	1,042	779	1,042	676	939	939
137	-	-	-	-	-	-	-	-	-	-
138	1,943	1,850	1,131	732	1,042	779	1,042	676	939	939
139	-	-	-	-	-	-	-	-	-	-
140	-	-	-	-	-	-	-	-	-	-
141	-	-	-	-	-	-	-	-	-	-
142	-	-	-	-	-	-	-	-	-	-

*include additional rows if needed

All other projects or programmes - quality of supply

Quality of supply expenditure

Capital contributions funding quality of supply

less

Quality of supply less capital contributions

11a(vii): Legislative and Regulatory

Current Year/CY	CY+1	CY+2	CY+3	CY+4	CY+5	CY+6	CY+7	CY+8	CY+9	CY+10
143	298	-	-	-	-	-	-	-	-	-
144	772	485	105	105	105	105	105	105	105	105
145	-	-	-	-	-	-	-	-	-	-
146	-	-	-	-	-	-	-	-	-	-
147	-	-	-	-	-	-	-	-	-	-
148	-	-	-	-	-	-	-	-	-	-
149	-	-	-	-	-	-	-	-	-	-
150	-	-	-	-	-	-	-	-	-	-
151	-	-	-	-	-	-	-	-	-	-
152	1,070	485	105	105	105	105	105	105	105	105
153	-	-	-	-	-	-	-	-	-	-
154	1,070	485	105	105	105	105	105	105	105	105
155	-	-	-	-	-	-	-	-	-	-
156	-	-	-	-	-	-	-	-	-	-

*include additional rows if needed

All other projects or programmes - legislative and regulatory

Legislative and regulatory expenditure

Capital contributions funding legislative and regulatory

less

Legislative and regulatory less capital contributions

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

Current Year/CY	CY+1	CY+2	CY+3	CY+4	CY+5	CY+6	CY+7	CY+8	CY+9	CY+10
157	168	168	168	168	168	168	168	168	168	168
158	209	594	-	-	-	-	-	-	-	-
159	349	217	-	-	-	-	-	-	-	-
160	-	-	-	-	-	-	-	-	-	-
161	-	-	-	-	-	-	-	-	-	-
162	-	-	-	-	-	-	-	-	-	-
163	-	-	-	-	-	-	-	-	-	-
164	403	-	-	-	-	-	-	-	-	-
165	1,130	980	168	168	168	168	168	168	168	168
166	-	-	-	-	-	-	-	-	-	-
167	1,130	980	168	168	168	168	168	168	168	168
168	-	-	-	-	-	-	-	-	-	-
169	-	-	-	-	-	-	-	-	-	-

*include additional rows if needed

All other projects or programmes - other reliability, safety and environment

Other reliability, safety and environment expenditure

Capital contributions funding other reliability, safety and environment

less

Other reliability, safety and environment less capital contributions

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 PAB 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.

Current Year CY 31 Mar 26	CY+1 31 Mar 27	CY+2 31 Mar 28	CY+3 31 Mar 29	CY+4 31 Mar 30	CY+5 31 Mar 31	CY+5 31 Mar 32	CY+5 31 Mar 33	CY+5 31 Mar 34	CY+5 31 Mar 35	CY+5 31 Mar 36
11a(ix): Non-Network Assets										
Routine expenditure										
<i>Project or programme*</i>										
170	559	195	4	4	4	4	4	5	5	5
171	-	62	62	62	62	62	62	62	62	62
172	2,445	1,674	1,197	1,742	1,777	1,813	2,559	2,610	2,662	2,716
173	-	-	-	-	-	-	-	-	-	-
174	245	191	158	161	164	167	174	177	181	184
175	-	-	-	-	-	-	-	-	-	-
176	-	-	-	-	-	-	-	-	-	-
177	-	-	-	-	-	-	-	-	-	-
178	-	-	-	-	-	-	-	-	-	-
179	-	-	-	-	-	-	-	-	-	-
180	-	-	-	-	-	-	-	-	-	-
181	-	-	-	-	-	-	-	-	-	-
182	3,249	2,121	1,420	1,969	2,007	2,046	2,745	2,853	2,909	2,966
183	-	-	-	-	-	-	-	-	-	-
184	-	-	-	-	-	-	-	-	-	-
185	-	-	-	-	-	-	-	-	-	-
186	-	-	-	-	-	-	-	-	-	-
187	-	-	-	-	-	-	-	-	-	-
188	-	-	-	-	-	-	-	-	-	-
189	-	-	-	-	-	-	-	-	-	-
190	-	-	-	-	-	-	-	-	-	-
191	-	-	-	-	-	-	-	-	-	-
192	-	-	-	-	-	-	-	-	-	-
193	-	-	-	-	-	-	-	-	-	-
194	3,249	2,121	1,420	1,969	2,007	2,046	2,745	2,853	2,909	2,966
Expenditure on non-network assets										
<i>Project or programme*</i>										
185	-	-	-	-	-	-	-	-	-	-
186	-	-	-	-	-	-	-	-	-	-
187	-	-	-	-	-	-	-	-	-	-
188	-	-	-	-	-	-	-	-	-	-
189	-	-	-	-	-	-	-	-	-	-
190	-	-	-	-	-	-	-	-	-	-
191	-	-	-	-	-	-	-	-	-	-
192	-	-	-	-	-	-	-	-	-	-
193	-	-	-	-	-	-	-	-	-	-
194	3,249	2,121	1,420	1,969	2,007	2,046	2,745	2,853	2,909	2,966

*include additional rows if needed

All other projects or programmes - routine expenditure

Routine expenditure

Atypical expenditure

*Project or programme**

*include additional rows if needed

All other projects or programmes - atypical expenditure

Atypical expenditure

Expenditure on non-network assets

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.

Current Year CY	CY+1	CY+2	CY+3	CY+4	CY+5	CY+6	CY+7	CY+8	CY+9	CY+10
Operational Expenditure Forecast										
Service interruptions and emergencies	1,783	1,720	1,781	1,839	1,899	1,961	2,025	2,090	2,157	2,226
Vegetation management	2,155	2,100	2,154	2,203	2,253	2,305	2,357	2,411	2,465	2,521
Routine and corrective maintenance and inspection	1,133	778	881	880	915	1,109	996	1,044	1,073	1,537
Asset replacement and renewal	747	645	669	691	649	671	699	717	741	780
Network Opex	5,818	5,243	5,484	5,613	5,716	6,045	6,078	6,213	6,401	7,202
System operations and network support	6,431	7,588	6,167	6,269	6,252	6,326	6,516	6,896	6,623	6,777
Business support	6,723	8,291	8,402	8,400	9,079	9,221	9,592	9,775	9,799	10,337
Non-network solutions provided by a related party or third party										
Non-network opex	13,154	15,879	14,570	14,668	15,332	16,108	16,671	16,422	16,740	17,220
Operational expenditure	18,972	21,122	20,054	20,281	21,047	22,186	22,884	22,829	23,325	24,422

Current Year CY	CY+1	CY+2	CY+3	CY+4	CY+5	CY+6	CY+7	CY+8	CY+9	CY+10
\$000 (in constant prices)										
Service interruptions and emergencies	1,783	1,686	1,707	1,728	1,750	1,793	1,814	1,836	1,857	1,879
Vegetation management	2,155	2,059	2,064	2,070	2,076	2,082	2,087	2,093	2,104	2,109
Routine and corrective maintenance and inspection	1,133	763	845	827	843	888	865	889	895	895
Asset replacement and renewal	747	632	641	650	598	614	622	630	638	647
Network Opex	5,818	5,140	5,257	5,275	5,266	5,460	5,382	5,394	5,453	5,891
System operations and network support	6,431	7,439	5,912	5,891	5,760	5,714	5,987	5,636	5,613	5,631
Business support	6,723	8,128	8,054	7,893	8,365	8,493	8,486	8,340	8,355	8,456
Non-network solutions provided by a related party or third party										
Non-network opex	13,154	15,568	13,966	13,785	14,125	14,263	14,472	13,976	13,968	14,087
Operational expenditure	18,972	20,708	19,223	19,059	19,391	19,645	19,866	19,429	19,462	19,978

Energy efficiency and demand side management, reduction of energy losses										
Direct billing*										
Research and Development										
Insurance										

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

Current Year CY	CY+1	CY+2	CY+3	CY+4	CY+5	CY+6	CY+7	CY+8	CY+9	CY+10
Difference between nominal and real forecasts										
Service interruptions and emergencies	34	149	111	149	190	232	276	321	369	418
Vegetation management	41	223	177	177	223	270	318	367	418	469
Routine and corrective maintenance and inspection	15	37	53	53	107	115	131	156	178	280
Asset replacement and renewal	13	28	42	42	65	66	79	110	127	144
Network Opex	103	338	227	338	585	696	819	954	1,091	1,310
System operations and network support	149	255	378	492	612	746	910	986	1,114	1,252
Business support	163	893	348	715	893	1,099	1,289	1,459	1,658	1,881
Non-network solutions provided by a related party or third party										
Non-network opex	311	604	884	1,207	1,505	1,845	2,199	2,445	2,772	3,133
Operational expenditure	414	831	1,222	1,656	2,090	2,541	3,018	3,400	3,863	4,444

Commentary on options and considerations made in the assessment of forecast expenditure

EDBs may provide a 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.

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.

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Asset condition at start of planning period (percentage of units by grade)

	Units	H1	H2	H3	H4	H5	Grade unknown	Data accuracy (1-4)	% of asset forecast to be replaced in next 5 years
36	No.	-	-	-	-	100.00%	-	-	4
37	km	-	0.03%	1.51%	33.23%	40.86%	24.37%	-	2
	km	-	-	-	-	-	-	-	N/A
	km	-	-	-	-	-	-	-	N/A
38	km	-	0.10%	0.10%	12.87%	25.89%	61.03%	-	1
	km	-	-	-	-	2.70%	97.30%	-	1
	km	-	-	-	-	-	-	-	N/A
	No.	-	2.61%	34.78%	52.17%	8.70%	1.74%	-	4
	No.	0.46%	0.62%	16.44%	20.21%	24.09%	38.19%	-	N/A
	No.	-	-	-	-	-	-	-	1
	No.	2.02%	4.04%	0.51%	61.11%	30.30%	2.02%	-	4
	No.	1.59%	11.38%	21.31%	33.64%	31.94%	0.14%	-	3
	No.	1.05%	1.78%	18.26%	36.94%	41.87%	0.10%	-	3
	No.	5.00%	20.00%	13.33%	28.33%	33.33%	-	-	4
	No.	-	-	-	-	-	-	-	N/A
	km	-	-	-	0.02%	74.49%	25.49%	-	2
	km	-	0.20%	0.67%	10.49%	18.30%	70.34%	-	1
	km	-	-	-	0.43%	36.13%	63.44%	-	1
	No.	19.00%	18.60%	18.90%	17.20%	26.30%	-	-	1
	No.	-	-	-	-	100.00%	-	-	4
	Lot	-	-	100.00%	-	-	-	-	3
	No.	-	-	-	-	100.00%	-	-	4
	Lot	-	-	100.00%	-	-	-	-	4
	No.	0.30%	1.60%	46.80%	39.60%	11.70%	-	-	1
	km	-	-	-	-	-	-	-	N/A

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.

12b(i): System Growth - Zone Substations

Existing Zone Substations	Current peak load (MVA)	Current peak load period	Installed operating capacity (MVA)	Current security of supply classification (type)	Current constraint type	Current available capacity (MVA)	Peak load period -5 yrs	Available capacity -5 yrs (MVA)	Security of supply classification -5 yrs (type)	Peak load period +5 yrs	Min. available capacity +5 yrs (MVA)	Max. available capacity +10 yrs (MVA)	Security of supply classification +10 yrs (type)	Forecast constraint type	Year of any forecast constraint	Constraint primary cause	Constraint solution type	Constraint solution progress	Temporary constraint solution remaining lifespan	Explanation
Transpower GWP Cambridge	43.5	Winter	47.4	N-1	Capacity	(2.7)	Winter	(8.7)	N-1	Winter	(34.5)	1.2	N-1	Capacity	4	Transpower	Network upgrade	Planning stage	<1 year	As at 31 March 2025 the firm capacity is being exceeded for short durations during the winter periods. Transpower's transformers have a short term overload rating of 45/7MVA (Summer/Winter). A special protection scheme installed in May 2020 avoids cascade tripping of supply transformers. Waipa Networks has installed 2.7MVA of peak load generation to manage peak demand. A new Forest Road Substation was commissioned in FY2026. Forecast capacities assume the commissioning of the Forest Road substation, further submission and zone substation projects are planned to resolve the forecast constraints (refer to Section 11.7.1).
Transpower GWP Te Awamutu	51.2	Winter	54.0	N-1	No constraint	11.7	Winter	4.7	N-1	Winter	(26.5)	4.3	N-1	Capacity	7	Transpower	Network upgrade	Planning stage	Not applicable	The GWP supply transformer firm capacity now 52/24 MVA (Summer/Winter) following protection upgrade in FY24. We are forecasting a constraint until FY33 due to large industrial customer growth and a mix of network and non-network solutions are proposed (refer to Section 11.11.4).
Forest Road (Commissioned in FY26)	16.6	Winter	28.0	N-1	No constraint	n/a	Winter	3.4	N-1	Winter	1.0	1	N-1	No constraint	None	Not applicable	Not applicable	Not applicable	Not applicable	This is a new substation that was commissioned in FY26 and will load will be progressively transferred from Cambridge GWP.

¹ Extended table as necessary to disclose all capacity and constraint information by each zone substation

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.

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12c(i): Consumer Connections

Number of ICs connected during year by consumer type

Consumer types defined by EDB*	CY+1	CY+2	CY+3	CY+4	CY+5
Residential	450	450	450	450	450
General	60	60	60	60	60
Unmetered	-	-	-	-	-
11kV	-	-	-	-	-
Connections total	510	510	510	510	510

* include additional rows if needed

Number of connections

Current Year CY	CY+1	CY+2	CY+3	CY+4	CY+5
450	450	450	450	450	450
60	60	60	60	60	60
-	-	-	-	-	-
-	-	-	-	-	-
510	510	510	510	510	510

Distributed generation

Number of connections made in year
 Capacity of distributed generation installed in year (MVA)

Current Year CY	CY+1	CY+2	CY+3	CY+4	CY+5
228	245	261	278	295	313
2	2	2	2	3	3

12c(ii): System Demand

Maximum coincident system demand (MW)

plus GXP demand
 Distributed generation output at HV and above
 Maximum coincident system demand
 less Net transfers to (from) other EDBs at HV and above
 Demand on system for supply to consumers' connection points

Current Year CY	CY+1	CY+2	CY+3	CY+4	CY+5
103	105	108	113	120	124
-	-	-	-	-	-
103	105	108	113	120	124
-	-	-	-	-	-
103	105	108	113	120	124

Electricity volumes carried (GWh)

Electricity supplied from GXPs
 less Electricity exports to GXPs
 plus Electricity supplied from distributed generation
 less Net electricity supplied to (from) other EDBs
 Electricity entering system for supply to ICs
 less Total energy delivered to ICs
 Losses

467	493	518	550	564	578
-	-	-	-	-	-
6	6	7	7	8	8
-	-	-	-	-	-
473	499	525	557	572	587
450	474	498	530	544	557
24	25	26	28	29	29
56%	56%	56%	56%	54%	54%
5.0%	5.0%	5.0%	5.0%	5.0%	5.0%

Company Name
Waipa Networks Limited

AMP Planning Period
1 April 2026 – 31 March 2036

Network / Sub-network Name
All

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						
11	126.2	126.2	126.2	126.2	126.2	126.2
12	109.3	109.3	109.3	109.3	109.3	109.3
SAIDI						
Class B (planned interruptions on the network)						
Class C (unplanned interruptions on the network)						
SAIFI						
Class B (planned interruptions on the network)	0.48	0.48	0.48	0.48	0.48	0.48
Class C (unplanned interruptions on the network)	1.73	1.73	1.73	1.73	1.73	1.73

SCHEDULE 13: REPORT ON ASSET MANAGEMENT MATURITY
 This schedule requires information on the EDBS self-assessment of the maturity of its asset management practices.

Question No.	Function	Question	Score	Evidence—Summary	User Guidance	Why	Who	Record/document information
3	Asset management policy	To what extent has an asset management policy been documented, authorised and communicated?	3	The AM Policy is documented in Waipa's DMS and in the AMP. A copy of this policy is available for visitors, on the Company intranet, and on the company website for other stakeholders, interested parties and Commerce Commission. The policy is communicated within the Network team and at Executive, Board Asset Management Committee and Board level via the AMP and scheduled policy review processes. It is also communicated to the Network Intelligence team and Delivery Team. The AM Policy is prepared by the GM Network, reviewed by the CE and Board AM Committee and approved by the Board. The AM Policy defines the key principles and approach to asset management at Waipa.		Widely used AM practice standards require an organisation to document, authorise and communicate its asset management policy (eg as required in PAS 55 para 4.2.1). 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 sources 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	The AM Strategy is presented in Section 7 of the AMP. Sections 2, 3 and 6 discuss the drivers for the AM strategy, and Section 7 discussed how the AM Strategy aligns to the drivers, including the AMP policy, company strategies and stakeholder needs.		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 policies, strategies and stakeholder requirements as covered in drafting the asset management policy but at a greater level of detail.	Top management. The organisation's strategic planning team. The management team that has overall responsibility for asset management.	The organisation's asset management strategy document and other related organisational policies and strategies. Other than the organisation's strategic plan, these could include those relating to health and safety, environmental, etc. Results of stakeholder consultation.
11	Asset management strategy	In what way does the organisation's asset management strategy take account of the lifecycle of the assets, asset types and asset systems over which the organisation has stewardship?	3	The AM Strategy responds to the lifecycle needs of the assets as set out in Section 7. The key areas being responding to growth, the aging fleet, and managing reliability. We also have asset strategies for each asset fleet in Section 13. These align with the overarching AM strategy. Assets are categorised in classes that consider type and function with asset class specific lifecycle mgmt. strategies and plans.		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	The AMP includes lifecycle plans for each asset in Section 11 (development) and Section 13 (lifecycle management). There are asset fleet (lifecycle) plans for all material asset classes. The asset fleet strategies and fleet plans are focused on optimising costs, risk and performance for the assets.		The asset management strategy need to be translated into practical plan(s) so that all parties know how the objectives will be achieved. The development of plan(s) will need to identify the specific tasks and activities required to optimize costs, risks and performance of the assets and/or asset system(s), when they are to be carried out and the resources required.	The management team with overall responsibility for the asset management system. Operations, maintenance and engineering managers.	The organisation's asset management plan(s).

Company Name Waipa Networks Limited 1 A pril 2026 – 31 March 2036 Based on PAS 55							
Company Name AMP Planning Period Asset Management Standard Applied							
SCHEDULE 13: REPORT ON ASSET MANAGEMENT MATURITY (cont)							
Question No.	Function	Question	Maturity Level 0	Maturity Level 1	Maturity Level 2	Maturity Level 3	Maturity Level 4
3	Asset management policy	To what extent has an asset management policy been documented, authorised and communicated?	The organisation does not have a documented asset management policy.	The organisation has an asset management policy, but it has not been authorised by top management, or it is not influencing the management of the assets.	The organisation has an asset management policy, which has been authorised by top management, but it has had limited circulation. It may be in use to influence development of strategy and planning but its effect is limited.	The asset management policy is authorised by top management, is widely and effectively communicated to all relevant employees and stakeholders, and used to make these persons aware of their asset related obligations.	The organisation's process(es) surpass the standard required to comply with requirements set out in a recognised standard. The assessor is advised to note in the Evidence section why this is the case and the evidence seen.
10	Asset management strategy	What has the organisation done to ensure that its asset management strategy is consistent with other appropriate organisational policies and strategies, and the needs of stakeholders?	The organisation has not considered the need to ensure that its asset management strategy is appropriately aligned with the organisation's other organisational policies and strategies or with stakeholder requirements. OR The organisation does not have an asset management strategy.	The need to align the asset management strategy with other organisational policies and strategies as well as stakeholder requirements is understood and work has started to identify the linkages or to incorporate them in the drafting of asset management strategy.	Some of the linkages between the long-term asset management strategy and other organisational policies, strategies and stakeholder requirements are defined but the work is fairly well advanced but still incomplete.	All linkages are in place and evidence is available to demonstrate that where appropriate, the organisation's asset management strategy is consistent with its other organisational policies and strategies. The organisation has also identified and considered the requirements of relevant stakeholders.	The organisation's process(es) surpass the standard required to comply with requirements set out in a recognised standard. The assessor is advised to note in the Evidence section why this is the case and the evidence seen.
11	Asset management strategy	In what way does the organisation's asset management strategy take account of the lifecycle of the assets, asset types and asset systems over which the organisation has stewardship?	The organisation has not considered the need to ensure that its asset management strategy is produced with due regard to the lifecycle of the assets, asset types or asset systems that it manages. OR The organisation does not have an asset management strategy.	The need is understood, and the organisation is drafting its asset management strategy to address the lifecycle of its assets, asset types and asset systems.	The long-term asset management strategy takes account of the lifecycle of some, but not all, of its assets, asset types and asset systems.	The asset management strategy takes account of the lifecycle of all of its assets, asset types and asset systems. The organisation has also identified and considered the requirements of relevant stakeholders.	The organisation's process(es) surpass the standard required to comply with requirements set out in a recognised standard. The assessor is advised to note in the Evidence section why this is the case and the evidence seen.
26	Asset management plan(s)	How does the organisation establish and document its asset management plan(s) across the life cycle activities of its assets and asset systems?	The organisation does not have an identifiable asset management plan(s) covering asset systems and critical assets.	The organisation has asset management plan(s) but they are not aligned with the asset management strategy and objectives and do not take into consideration the full asset life cycle (including asset creation, acquisition, enhancement, utilisation, maintenance decommissioning and disposal).	The organisation is in the process of putting in place comprehensive, documented asset management plan(s) that cover all life cycle activities, clearly aligned to the asset management objectives and the asset management strategy.	Asset management plan(s) are established, documented, implemented and maintained for asset systems and critical assets to achieve the asset management strategy and asset management objectives across all life cycle phases.	The organisation's process(es) surpass the standard required to comply with requirements set out in a recognised standard. The assessor is advised to note in the Evidence section why this is the case and the evidence seen.

SCHEDULE 13: REPORT ON ASSET MANAGEMENT MATURITY (cont)

Question No.	Function	Question	Score	Evidence—Summary	User Guidance	Why	Who	Record/document 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?	2.5	Relevant aspects of the AMP to the delivery team for the delivery of the plan. The GM Network delegates appropriate sections of the AMP works program to appropriate planning and engineering staff and supervisors for implementation of the AMP. The GM Network reports to the CEO and Board on progress on delivery against the AMP. The level of detail appropriate to their participation or business interests in the delivery of the plan. Section 2.8 of the AMP outlines how the AMP is communicated.		Plans will be ineffective unless they are communicated to all those, including contracted suppliers, and those who undertake enabling functions(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?	2.5	The asset management plan documents responsibilities for the communication and delivery of the AMP (section 2.8), and appropriate detail is provided to enable delivery of these actions. The responsibilities for delivery of the AMP are also documented in Section 2.7 of the AMP.		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)	2.5	The AMP consider availability of resources (Section 14), which uses a mix of in-house Delivery and external service providers. The Delivery team undertakes most of the maintenance, vegetation management and replacement and minor upgrades on our network. Waipa utilises external resources as necessary to manage the peak workload and major network development projects. We manage the cost-effective delivery using a range of techniques. These are defined in our efficiency strategy (refer Section 7). There are a range of delivery monitoring processes at a supervisor, manager, GM and Board level.		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. Where appropriate the procurement team and service providers working on the organisation's asset-related activities.	The organisation's asset management plan(s). Documented processes and procedures for the delivery of the asset management plan.
33	Contingency planning	What plan(s) and procedure(s) does the organisation have for identifying and responding to incidents and ensuring situations and ensuring continuity of critical asset management activities?	2.5	We have considered contingency events in the configuration of our key systems. We have also developed a range of BCPs in the event of a major incident and emergency. These cover weather events and other events that could cause major business disruption. While our operation has been guided by the BCPs, we are at the start of the journey of operationally embedding the new BCP approach for the business. During emergencies, where control room and call centre functions may be disrupted or overloaded, network operations and fault dispatch functions can be performed by the administrative staff and field crews.		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.

<p style="text-align: center;"> Company Name Waipa Networks Limited AMP Planning Period 1 April 2026 – 31 March 2036 Asset Management Standard Applied Based on PAS 55 </p>							
SCHEDULE 13: REPORT ON ASSET MANAGEMENT MATURITY (cont)							
Question No.	Function	Question	Maturity Level 0	Maturity Level 1	Maturity Level 2	Maturity Level 3	
27	Asset management plan(s)	How has the organisation communicated its plan(s) to all relevant parties to a level of detail appropriate to the receiver's role in their delivery?	The organisation does not have plan(s) or their distribution is limited to the authors.	The plan(s) are communicated to some of those responsible for delivery of the plan(s). OR Communicated to those responsible for delivery is either irregular or ad-hoc.	The plan(s) are communicated to most of those responsible for delivery but there are weaknesses in identifying relevant parties, resulting in incomplete or inappropriate communication. The organisation recognises improvement is needed as is working towards resolution.	The plan(s) are communicated to all relevant employees, stakeholders and contracted service providers to a level of detail appropriate to their participation or business interests in the delivery of the plan(s) and there is confirmation that they are being used effectively.	The organisation's process(es) surpass the standard required to comply with requirements set out in a recognised standard. The assessor is advised to note in the Evidence section why this is the case and the evidence seen.
29	Asset management plan(s)	How are designated responsibilities for delivery of asset plan actions documented?	The organisation has not documented responsibilities for delivery of asset plan actions.	Asset management plan(s) inconsistently document responsibilities for delivery of plan actions and activities and/or responsibilities and authorities for implementation inadequate and/or delegation level inadequate to ensure effective delivery and/or contain misalignments with organisational accountability.	Asset management plan(s) consistently document responsibilities for the delivery of actions but responsibility/authority levels are inappropriate/ inadequate, and/or there are misalignments within the organisation.	Asset management plan(s) consistently document responsibilities for the delivery actions and there is adequate detail to enable delivery of actions. Designated responsibility and authority for achievement of asset plan actions is appropriate.	The organisation's process(es) surpass the standard required to comply with requirements set out in a recognised standard. The assessor is advised to note in the Evidence section why this is the case and the evidence seen.
31	Asset management plan(s)	What has the organisation done to ensure that appropriate arrangements are made available for the efficient and cost effective implementation of the plan(s)? (Note: this is about resources and enabling support)	The organisation has not considered the arrangements needed for the effective implementation of plan(s).	The organisation recognises the need to ensure appropriate arrangements are in place for implementation of asset management plan(s) and is in the process of determining an appropriate approach for achieving this.	The organisation has arrangements in place for the implementation of asset management plan(s) but the arrangements are not yet adequately efficient and/or effective. The organisation is working to resolve existing weaknesses.	The organisation's arrangements fully cover all the requirements for the efficient and cost effective implementation of asset management plan(s) and realistically address the resources and timescales required, and any changes needed to functional policies, standards, processes and the asset management information system.	The organisation's process(es) surpass the standard required to comply with requirements set out in a recognised standard. The assessor is advised to note in the Evidence section why this is the case and the evidence seen.
33	Contingency planning	What plan(s) and procedure(s) does the organisation have for identifying and responding to incidents and ensuring continuity of critical asset management activities?	The organisation has not considered the need to establish plan(s) and procedure(s) to identify and respond to incidents and emergency situations.	The organisation has some ad-hoc arrangements to deal with incidents and emergency situations, but these have been developed on a reactive basis in response to specific events that have occurred in the past.	Most credible incidents and emergency situations are identified. Either appropriate plan(s) and procedure(s) are incomplete for critical activities or they are inadequate. Training/ external alignment may be incomplete.	Appropriate emergency plan(s) and procedure(s) are in place to respond to credible incidents and manage continuity of critical asset management activities consistent with policies and asset management objectives. Training and external agency alignment is in place.	The organisation's process(es) surpass the standard required to comply with requirements set out in a recognised standard. The assessor is advised to note in the Evidence section why this is the case and the evidence seen.

SCHEDULE 13: REPORT ON ASSET MANAGEMENT MATURITY (cont)

Question No.	Function	Question	Score	Evidence—Summary	User Guidance	Why	Who	Record/document information
37	Structure, authority and responsibilities	What has the organisation done to appoint member(s) of its management team to be responsible for ensuring that the organisation's assets deliver the requirements of the asset management strategy, objectives and plan(s)?	3	Management has appointed appropriate people to ensure the assets deliver the requirements of the asset management strategy, objectives and plan(s). These include the GM Network (for asset management planning), GM Network Intelligence (for new operational technology), and the GM Delivery (for delivering the AMP). The GM Customer and Community, GM Technology, GM People and Safety, and GM Finance also contribute. Their responsibilities are communicated and understood.		In order to ensure that the organisation's assets and asset systems deliver the requirements of the asset management policy, strategy and objectives responsibilities need to be allocated to appropriate people who have the necessary authority to fulfil their responsibilities. (This question relates to the organisation's assets eg, para b), s 4.4.1 of PAS 55, making it therefore distinct from the requirement contained in para a), s 4.4.1 of PAS 55).	Top management. People with management responsibility for the delivery of asset management policy, strategy, objectives and plan(s). People working on asset-related activities.	Evidence that managers with responsibility for the delivery of asset management policy, strategy, objectives and plan(s) have been appointed and have assumed their responsibilities. Evidence may include the organisation's documents relating to its asset management system: organisational charts, job descriptions of post-holders, annual targets/objectives and personal development plan(s) of post-holders as appropriate.
40	Structure, authority and responsibilities	What evidence can the organisation's top management provide to demonstrate that sufficient resources are available for asset management?	2.5	A process exists for determining what resources are required for asset management activities across the business. There is a particular focus on resourcing in the Customer and Community, Network and Delivery teams. Our resourcing strategy is presented in Section 14. We undertake detailed assessments of field work delivery (which is a high resource area) and this is presented in Section 14.		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 changehands as appropriate.	Evidence demonstrating that asset management plan(s) and/or the process(es) for asset management plan implementation consider the provision of adequate resources in both the short and long term. Resources include funding, materials, equipment, services provided by third parties and personnel (internal and service providers) with appropriate skills, competencies and knowledge.
42	Structure, authority and responsibilities	To what degree does the organisation's top management communicate the importance of meeting its asset management requirements?	2.5	Communication of the asset management requirements is through annual AMP disclosures, and Network team leads monthly works, planning and delivery meetings for key internal stakeholders to monitor and coordinate delivery of the Asset Management Plan. The Network team prepares a monthly Operational report for operational and asset management staff to review progress against network KPIs and programmes of work.		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 b).	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-arounds would assist an organisation to demonstrate it is meeting this requirement of PAS 55.
45	Outsourcing of asset management activities	Where the organisation has outsourced some of its asset management activities, how has it ensured that appropriate controls are in place to ensure the compliant delivery of its organisational strategic plan, and its asset management policy and strategy?	2.5	Waipa outsources a number of asset management activities, such as Control Room Services, Call Care for customer enquiry and dispatch services and some field service delivery. This is discussed in Section 14. The delivery of outsourced activities is controlled through our procurement policy, contracts, and standards (see Section 9.3.2). All outsourced services have contracts which include performance KPI's to ensure efficient and cost-effective delivery of these activities. Construction Manual and network standards used to ensure contracted works are constructed to appropriate standard.		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 organisation 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 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.

SCHEDULE 13: REPORT ON ASSET MANAGEMENT MATURITY (cont)

Question No.	Function	Question	Maturity Level 0	Maturity Level 1	Maturity Level 2	Maturity Level 3	Maturity Level 4
37	Structure, authority and responsibilities	What has the organisation done to appoint member(s) of its management team to be responsible for ensuring that the organisation's assets deliver the requirements of the management strategy, objectives and plan(s)?	Top management has not considered the need to appoint a person or persons to ensure that the organisation's assets deliver the requirements of the management strategy, objectives and plan(s).	Top management understands the need to appoint a person or persons to ensure that the organisation's assets deliver the requirements of the management strategy, objectives and plan(s).	Top management has appointed an appropriate person to ensure the assets deliver the requirements of the asset management strategy, objectives and plan(s) but their areas of responsibility are not fully defined and/or they have insufficient delegated authority to fully execute their responsibilities.	The appointed person or persons have full responsibility for ensuring that the organisation's assets deliver the requirements of the asset management strategy, objectives and plan(s). They have been given the necessary authority to achieve this.	The organisation's process(es) surpass the standard required to comply with requirements set out in a recognised standard. The assessor is advised to note in the Evidence section why this is the case and the evidence seen.
40	Structure, authority and responsibilities	What evidence can the organisation's top management provide to demonstrate that sufficient resources are available for asset management?	The organisation's top management has not considered the resources required to deliver asset management.	The organisation's top management understands the need for sufficient resource, but there are no effective mechanisms in place to ensure this is the case.	A process exists for determining what resources are required for its asset management activities and in most cases these are available but in some instances resources remain insufficient.	An effective process exists for determining the resources needed for asset management and sufficient resources are available. It can be demonstrated that resources are matched to asset management requirements.	The organisation's process(es) surpass the standard required to comply with requirements set out in a recognised standard. The assessor is advised to note in the Evidence section why this is the case and the evidence seen.
42	Structure, authority and responsibilities	To what degree does the organisation's top management communicate the importance of meeting its asset management requirements?	The organisation's top management has not considered the need to communicate the importance of meeting asset management requirements.	The organisation's top management understands the need to communicate the importance of meeting its asset management requirements but does not do so.	Top management communicates the importance of meeting its asset management requirements but only to parts of the organisation.	Top management communicates the importance of meeting its asset management requirements to all relevant parts of the organisation.	The organisation's process(es) surpass the standard required to comply with requirements set out in a recognised standard. The assessor is advised to note in the Evidence section why this is the case and the evidence seen.
45	Outsourcing of asset management activities	Where the organisation has outsourced some of its asset management activities, how has it ensured that appropriate controls are in place to ensure the compliant delivery of its organisational strategic plan, and its asset management policy and strategy?	The organisation has not considered the need to put controls in place.	The organisation controls its outsourced activities on an ad-hoc basis, with little regard for ensuring the compliant delivery of the organisational strategic plan and/or its asset management policy and strategy.	Controls systematically considered but currently only provide for the compliant delivery of some, but not all, aspects of the organisational strategic plan and/or its asset management policy and strategy. Gaps exist.	Evidence exists to demonstrate that outsourced activities are appropriately controlled to provide for the compliant delivery of the organisational strategic plan, asset management policy and strategy, and that these controls are integrated into the asset management system.	The organisation's process(es) surpass the standard required to comply with requirements set out in a recognised standard. The assessor is advised to note in the Evidence section why this is the case and the evidence seen.

SCHEDULE 13: REPORT ON ASSET MANAGEMENT MATURITY (cont)

Question No.	Function	Question	Score	Evidence – Summary	User Guidance	Why	Who	Record/document information
48	Training, awareness and competence	How does the organisation develop plan(s) for the human resources required to undertake asset management activities – including the development and delivery of asset management strategy, process(es), objectives and plan(s)?	2.5	Role descriptions are in place for all staff required to conduct asset management functions, and these roles are filled with appropriately qualified personnel. Driven by the recently completed TA network architecture plan, we recognised our capability gaps to deliver this future plan, and are in the process of reassessing AM capability and engaging additional staff for long-term needs or contractors for short-term.		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), contract and service level agreements.
49	Training, awareness and competence	How does the organisation identify competency requirements and then plan, provide and record the training necessary to achieve the competencies?	2	The Company Training Matrix and Individual Personal Development Plans are used to identify maintain and increase skills of current staff. However, an Asset Management competency framework has not been developed to guide training requirements.		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, coordinated 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 education, training or experience?	2	Waipa monitors and ensures that contractors and staff have, and maintain their competencies. Well trained staff are engaged as Design Planners to prepare and manage job packs, review quality, and conduct inspections. As per our Health, Safety and Environmental requirements all contractors are inducted to work on our network. The Company assesses the competence of service providers under its direct control by observing the quality of the work performed and checking if any industry competencies that are required for the work are held by the staff doing the work. Competencies for fault staff to operate on the network are defined and new fault staff are assessed and signed off.		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.

<p style="text-align: center;">SCHEDULE 13: REPORT ON ASSET MANAGEMENT MATURITY (cont)</p>							
<p><i>Company Name</i> Waipa Networks Limited</p>							
<p><i>AMP Planning Period</i> 1 April 2026 – 31 March 2036</p>							
<p><i>Asset Management Standard Applied</i> Based on PAS 55</p>							
Question No.	Function	Question	Maturity Level 0	Maturity Level 1	Maturity Level 2	Maturity Level 3	Maturity Level 4
48	Training, awareness and competence	How does the organisation develop plan(s) for the human resources required to undertake asset management activities - including the development and delivery of asset management strategy, process(es), objectives and plan(s)?	The organisation has not recognised the need for assessing human resources requirements to develop and implement its asset management system.	The organisation has recognised the need to assess its human resources plan(s). There is limited recognition of the need to align these with the development and implementation of its asset management system.	The organisation has developed a strategic approach to aligning competencies and human resources to the asset management system including the asset management plan but the work is incomplete or has not been consistently implemented.	The organisation can demonstrate that plan(s) are in place and effective in matching competencies and capabilities to the asset management system including the plan for both internal and contracted activities. Plans are reviewed integral to asset management system process(es).	The organisation's process(es) surpass the standard required to comply with requirements set out in a recognised standard. The assessor is advised to note in the Evidence section why this is the case and the evidence seen.
49	Training, awareness and competence	How does the organisation identify competency requirements and then plan, provide and record the training necessary to achieve the competencies?	The organisation does not have any means in place to identify competency requirements.	The organisation has recognised the need to identify competency requirements and then plan, provide and record the training necessary to achieve the competencies.	The organisation is the process of identifying competency requirements aligned to the asset management plan(s) and then plan, provide and record appropriate training. It is incomplete or inconsistently applied.	Competency requirements are in place and aligned with asset management plan(s). Plans are in place and effective in providing the training necessary to achieve the competencies. A structured means of recording the competencies achieved is in place.	The organisation's process(es) surpass the standard required to comply with requirements set out in a recognised standard. The assessor is advised to note in the Evidence section why this is the case and the evidence seen.
50	Training, awareness and competence	How does the organization ensure that persons under its direct control undertaking asset management related activities have an appropriate level of competence in terms of education, training or experience?	The organization has not recognised the need to assess the competence of person(s) undertaking asset management related activities.	Competency of staff undertaking asset management related activities is not managed or assessed in a structured way, other than formal requirements for legal compliance and safety management.	The organization is in the process of putting in place a means for assessing the competence of person(s) involved in asset management activities including contractors. There are gaps and inconsistencies.	Competency requirements are identified and assessed for all persons carrying out asset management related activities - internal and contracted. Requirements are reviewed and staff reassessed at appropriate intervals aligned to asset management requirements.	The organisation's process(es) surpass the standard required to comply with requirements set out in a recognised standard. The assessor is advised to note in the Evidence section why this is the case and the evidence seen.

SCHEDULE 13: REPORT ON ASSET MANAGEMENT MATURITY (cont)

Question No.	Function	Question	Score	Evidence—Summary	User Guidance	Why	Who	Record/document information
53	Communication, participation and consultation	How does the organisation ensure that pertinent asset management information is effectively communicated to and from employees and other stakeholders, including contracted service providers?	3	Waipa has processes to communicate asset management information (refer to Section 2.8). These describe how we involve stakeholders in the processes. We also have detailed work delivery processes (refer to Section 14.6), which defines the work plan process, project documentation and our monitoring and control processes. These apply in the in-house Delivery Team and external service providers.		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/plans and objectives. This will include for example the communication of the asset management policy, asset performance information, and planning information as appropriate to contractors.	Top management and senior management representative(s), employee's representative(s), employee's trade union representative(s); contracted service provider management and employee representative(s); representative(s) from the organisation's Health, Safety and Environmental team. Key stakeholder representative(s).	Asset management policy statement prominently displayed on notice boards, intranet and internet; use of organisation's website for displaying asset performance data; evidence of formal briefings to employees, stakeholders and contracted service providers; evidence of inclusion of asset management issues in team meetings and contracted service provider contract meetings; newsletters, etc.
59	Asset Management System documentation	What documentation has the organisation established to describe the main elements of its asset management system and interactions between them?	2.2	We have defined the main elements of our asset management system in Section 9.3. Our system documentation is defined in Section 9.3.2. We have most elements of the system documented. The system documentation (i.e. policy, procedures, and standards) are contained in the DMS. Section 2.9 describes the linkages between our plans. Where gaps exist or improvement is needed in documentation, we have defined these and have an improvement plan to resolve them (see Section 9.6)		Widely used AM practice standards require an organisation maintain up to date documentation that ensures that its asset management systems (i.e. 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?	2.8	We have undertaken significant work to define our information requirements. These are shown in Section 9.4 (in relation to systems) and Section 9.5 (in relation to information). Where gaps exist or improvement is needed, we have defined these and have an improvement plan to resolve them (see Section 9.6). We have got an Asset Data Improvement Plan in place. We are in the process of defining future AM system needs as part of the BSP process.		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?	2.8	The Engineering, Network Information and administrative staff manage the asset information. Our asset inspections are the main process by which we maintain the accuracy of asset information. Field crews record changes or corrections to asset information (and some asset components) during the inspection process. We have also undertaken specific audits of particular asset types. We have assessed the quality of our asset management information (Section 9.5.4) and have plans to improve the quality when needed (see Section 9.6). The next step is to conduct a review of our asset building process for data collection integrity and robustness.		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 (e), (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.

SCHEDULE 13: REPORT ON ASSET MANAGEMENT MATURITY (cont)

Question No.	Function	Question	Maturity Level 10	Maturity Level 1	Maturity Level 2	Maturity Level 3	Maturity Level 4
53	Communication, participation and consultation	How does the organisation ensure that pertinent asset management information is effectively communicated to stakeholders, including employees and other contracted service providers?	The organisation has not recognised the need to formally communicate any asset management information.	There is evidence that the pertinent asset management information to be shared along with those to share it with is being determined.	The organisation has determined pertinent information and relevant communication is in place but as yet not all relevant parties are clear on their roles and responsibilities with respect to asset management information.	Two way communication is in place between all relevant parties, ensuring that information is effectively communicated to match the requirements of asset management strategy, plan(s) and process(es). Pertinent asset information requirements are regularly reviewed.	The organisation's process(es) surpass the standard required to comply with requirements set out in a recognised standard. The assessor is advised to note in the Evidence section why this is the case and the evidence seen.
59	Asset Management System documentation	What documentation has the organisation established to describe the main elements of its asset management system and interactions between them?	The organisation has not established documentation that describes the main elements of the asset management system.	The organisation is aware of the need to put documentation in place and is in the process of determining how to document the main elements of its asset management system.	The organisation in the process of documenting its asset management system and has documentation in place that describes some, but not all, of the main elements of its asset management system and their interaction.	The organisation has established documentation that comprehensively describes all the main elements of its asset management system and the interactions between them. The documentation is kept up to date.	The organisation's process(es) comply with requirements set out in a recognised standard. The assessor is advised to note in the Evidence section why this is the case and the evidence seen.
62	Information management	What has the organisation done to determine what its asset management information system(s) should contain in order to support its asset management system?	The organisation has not considered what asset management information is required.	The organisation is aware of the need to determine in a structured manner what its asset information system should contain in order to support its asset management system and is in the process of deciding how to do this.	The organisation has developed a structured process to determine what its asset information system should contain in order to support its asset management system and has commenced implementation of the process.	The organisation has determined what its asset information system should contain in order to support its asset management system. The requirements relate to the whole life cycle and cover information originating from both internal and external sources.	The organisation's process(es) surpass the standard required to comply with requirements set out in a recognised standard. The assessor is advised to note in the Evidence section why this is the case and the evidence seen.
63	Information management	How does the organisation maintain its asset management information system(s) and ensure that the data held within it (them) is of the requisite quality and accuracy and is consistent?	There are no formal controls in place or controls are extremely limited in scope and/or effectiveness.	The organisation is aware of the need for effective controls and is in the process of developing an appropriate control process(es).	The organisation has developed a controls that will ensure the data held is of the requisite quality and accuracy and is consistent and is in the process of implementing them.	The organisation has effective controls in place that ensure the data accuracy and is consistent. The controls are regularly reviewed and improved where necessary.	The organisation's process(es) surpass the standard required to comply with requirements set out in a recognised standard. The assessor is advised to note in the Evidence section why this is the case and the evidence seen.

SCHEDULE 13: REPORT ON ASSET MANAGEMENT MATURITY (cont)

Question No.	Function	Question	Score	Evidence—Summary	User Guidance	Why	Who	Record/document information
64	Information management	How has the organisation's ensured its asset management information system is relevant to its needs?	2.2	Asset Management information system requirements were initially reviewed during development of the business case to implement GIS, ensuring that they meet Asset Management needs. The Asset Strategy Manager and Network Information Specialist recommend improvements that are designed and implemented by the Network Information team and IT, and the operational staff provides feedback. We are undertaking further work at the corporate level on business information needs and reviewing the ISSP. Further AM information system needs will be identified through this process.		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) for the identification and assessment of asset and asset management related risks throughout the asset life cycle?	3	The organisation has an overarching risk management system compliant with ISO31000 documented in Risk Management Policy, Framework and Appetite, and uses the Company Risk Register to track and communicate corporate risks. Risk processes are discussed in Section 8. We have identified specific asset-related risks in the asset fleet plans (refer to Section 13).		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	Outputs from operational risk assessments are fed back into standards, procedures and training through the actions resulting from various meetings and other communications. The linkages from the risk management system to key plans are evolving, and the organisation is in the process of ensuring that outputs of risk assessment are consistently included in developing requirements for resources and training. The Company Training Matrix and Individual Personal Development Plans are used to increase the skills of current staff.		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 organisation's risk management framework. The organisation's resourcing plan(s) and training and competency plan(s). The organisation should be able to demonstrate appropriate linkages between the content of resource plan(s) and training and competency plan(s) to the risk assessments and risk control measures that have been developed.
82	Legal and other requirements	What procedure does the organisation have to identify and provide access to its legal, regulatory, statutory and other asset management requirements, and how is requirements incorporated into the asset management system?	3	The organisation has procedure(s) to identify its legal, regulatory, statutory and other asset management requirements. Waipa Networks uses ComplyWith web enabled software to assess compliance with legislative and regulatory requirements. This produces a six monthly declaration of compliance that is reported to the Board. The AMP communicates how the organisation translates its legal and other requirements into asset management programmes, and performance targets.		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 organisation's 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

<p style="text-align: center;">Company Name AMP Planning Period Asset Management Standard Applied</p> <p style="text-align: center;">Waipa Networks Limited 1 April 2026 – 31 March 2036 Based on PAS 55</p>						
SCHEDULE 13: REPORT ON ASSET MANAGEMENT MATURITY (cont)						
Question No.	Function	Question	Maturity Level 0	Maturity Level 1	Maturity Level 2	Maturity Level 3
64	Information management	How has the organisation's information system ensured its asset management information system is relevant to its needs?	The organisation has not considered the need to determine the relevance of its management information system. At present there are major gaps between what the information system provides and the organisations needs.	The organisation understands the need to ensure its asset management information system is relevant to its needs and is determining an appropriate means by which it will achieve this. At present there are significant gaps between what the information system provides and the organisations needs.	The organisation has developed and is implementing a process to ensure its asset management information system is relevant to its needs. Gaps between what the information system provides and the organisations needs have been identified and action is being taken to close them.	The organisation's asset management information system aligns with its asset management requirements. Users can confirm that it is relevant to their needs.
69	Risk management process(es)	How has the organisation documented process(es) and/or procedure(s) for the identification and assessment of asset and asset management related risks throughout the asset life cycle?	The organisation has not considered the need to document process(es) and/or procedure(s) for the identification and assessment of asset and asset management related risks throughout the asset life cycle.	The organisation is aware of the need to document the management of asset related risk across the asset lifecycle. The organisation has plan(s) to formally document all relevant process(es) and procedure(s) or has already commenced this activity.	The organisation is in the process of documenting the identification and assessment of asset related risk across the asset lifecycle but it is incomplete or there are inconsistencies between approaches and a lack of integration.	Identification and assessment of asset related risk across the asset lifecycle is fully documented. The organisation can demonstrate that appropriate documented mechanisms are integrated across life cycle phases and are being consistently applied.
79	Use and maintenance of asset risk information	How does the organisation ensure that the results of risk assessments provide input into the identification of adequate resources and training and competency needs?	The organisation has not considered the need to conduct risk assessments.	The organisation is aware of the need to consider the results of risk assessments and effects of risk control measures to provide input into reviews of resources, training and competency needs. Current input is typically ad-hoc and reactive.	The organisation is in the process ensuring that outputs of risk assessment are included in developing requirements for resources and training. The implementation is incomplete and there are gaps and inconsistencies.	Outputs from risk assessments are consistently and systematically used as inputs to develop resources, training and competency requirements. Examples and evidence is available.
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 asset management requirements incorporated into the asset management system?	The organisation has not considered the need to identify its legal, regulatory, statutory and other asset management requirements.	The organisation identifies some its legal, regulatory, statutory and other asset management requirements, but this is done in an ad-hoc manner in the absence of a procedure.	The organisation has procedure(s) to identify its legal, regulatory, statutory and other asset management requirements, but the information is not kept up to date, inadequate or inconsistently managed.	Evidence exists to demonstrate that the organisation's legal, regulatory, statutory and other asset management requirements are identified and kept up to date. Systematic mechanisms for identifying relevant legal and statutory requirements.
						<p>Maturity Level 4</p> <p>The organisation's processes(es) surpass the standard required to comply with requirements set out in a recognised standard.</p> <p>The assessor is advised to note in the Evidence section why this is the case and the evidence seen.</p>

SCHEDULE 13: REPORT ON ASSET MANAGEMENT MATURITY (cont)

Question No.	Function	Question	Score	Evidence—Summary	User Guidance	Why	Who	Record/document information
88	Life Cycle Activities	How does the organisation establish implement and maintain process(es) for the implementation of its asset management plan(s) and control of activities across the creation, acquisition or enhancement of assets. This includes design, modification, procurement, construction and commissioning activities?	2.7	We have developed a Procurement Policy, Design Manual, Construction Manual, Maintenance and Inspection Standards, and a Safety Management System for the control of asset creation including design, modification, procurement, construction and commissioning. We have some areas for improvement, and these are being addressed in our AM Improvement Plan (Section 9.6). Our Engineers and Project Management review and monitor the delivery against the standards.	Life cycle activities are about the implementation of asset management plan(s) i.e. they are the 'doing' phase. They need to be done effectively and well in order for asset management to have any practical meaning. As a consequence, widely used standards (eg, PAS 55 s.4.5.1) require organisations to have in place appropriate process(es) and procedure(s) for the implementation of asset management plan(s) and control of lifecycle activities. This question explores those aspects relevant to asset creation.	Asset managers, design staff, construction staff and project managers from other impacted areas of the business, e.g. Procurement	Documented process(es) and procedure(s) which are relevant to demonstrating the effective management and control of life cycle activities during asset creation, acquisition, enhancement including design, modification, procurement, construction and commissioning.	
91	Life Cycle Activities	How does the organisation ensure that process(es) and/or procedure(s) for the implementation of asset management plan(s) and control of activities during maintenance (and inspection) of assets are sufficient to ensure activities are carried out under specified conditions, are consistent with asset management strategy and control cost, risk and performance?	2.5	There are inspection and maintenance programmes for underground assets, overhead assets and Substation assets. We have documented the maintenance and inspection standards for substation assets. We are progressing with the formalisation and documentation of maintenance and inspection standards for distribution assets.	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.	

Schedule 14a Mandatory explanatory notes on forecast information

Electricity distribution information disclosure determination 2012

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

This Schedule is mandatory – EDBs must provide the explanatory comment specified below, in accordance with clause 2.7.2. This information is not part of the audited disclosure information, and so is not subject to the assurance requirements specified in Section 2.8.

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

2. In the box below, comment on the difference between nominal and constant price capital expenditure for the current disclosure year and 10 year planning period, as disclosed in Schedule 11a.

Box 1: Commentary on difference between nominal and constant price capital expenditure forecasts

Waipā Networks reviews and refines the capital forecasts of expenditure on network assets each year. For the price escalation between constant and nominal prices, we applied 2.0% from FY26 Constant to FY27 Nominal, based on the NZIER Consensus Forecasts (September 2025). We used Westpac's CPI forecast for FY28 (at 2.28%), then applied a 2.0% p.a. increase from FY29, consistent with the middle of the Reserve Bank's inflation policy range.

Commentary on difference between nominal and constant price operational expenditure forecasts (Schedule 11b)

1. 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

Waipā Networks reviews and refines the operational expenditure on networks assets each year. For the price escalation between constant and nominal prices, we applied 2.0% from FY26 Constant to FY27 Nominal, based on the NZIER Consensus Forecasts (September 2025). We used Westpac's CPI forecast for FY28 (at 2.28%), then applied a 2.0% p.a. increase from FY29, consistent with the middle of the Reserve Bank's inflation policy range.

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