Bringing Balance to the Future

ASSET MANAGEMENT PLAN 2025 UPDATE

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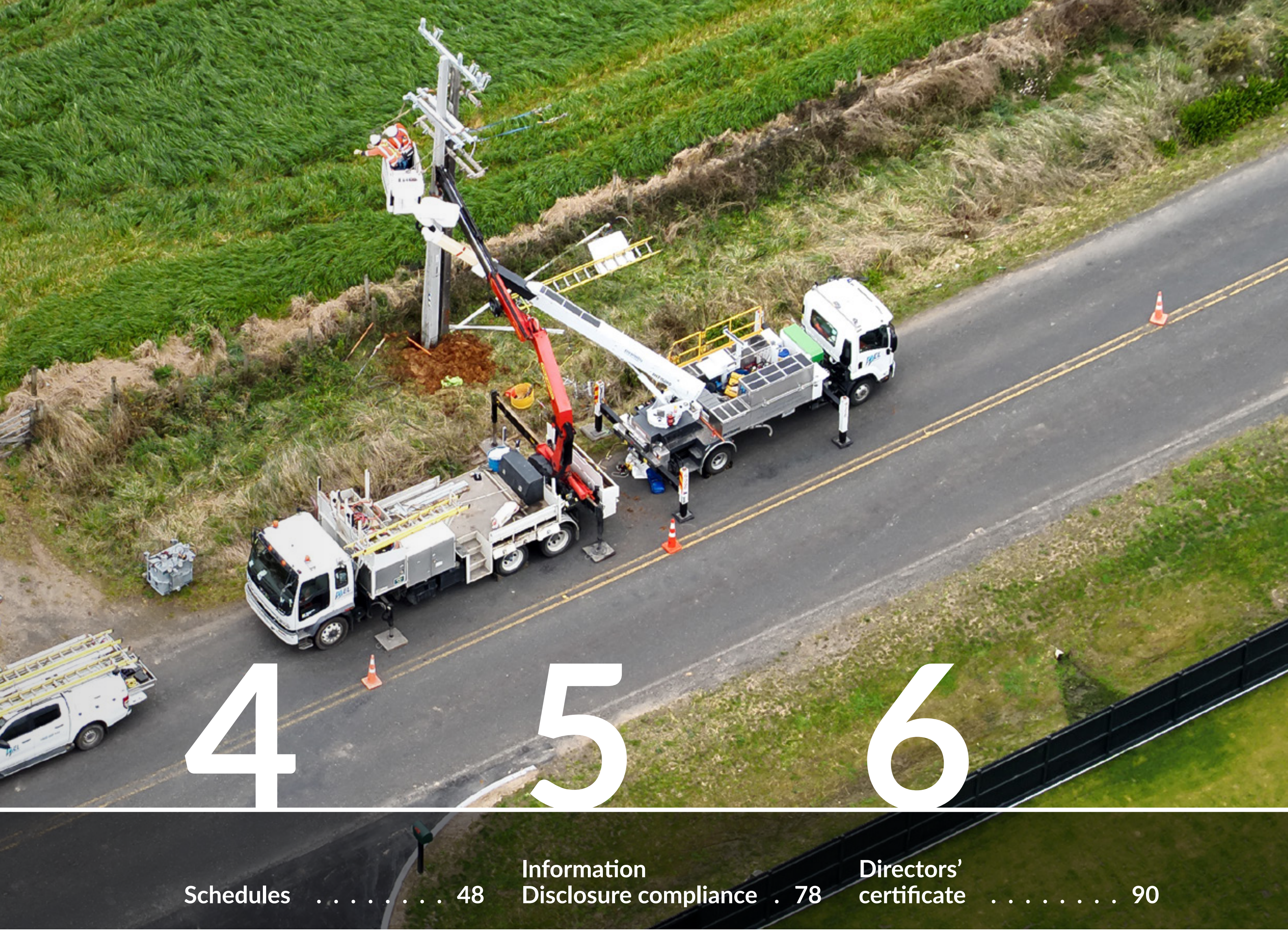
Ngā Rārangi Take



Executive Summary

Kōrero whakarāpopoto

Powering the future

Our 2025 Asset Management Plan Update (AMP Update) highlights the material changes in key investments for the next ten years. This includes meeting the requirements of continued growth and asset renewal, lifting the resilience of both the network and the organisation, keeping the cost of electricity affordable and supporting NZ's transition to a more sustainable energy future. This requires balance to ensure our customers and stakeholders receive the best service to meet their needs now and in the future.

There are many factors that affect forecasting demand, from emerging new technologies to evolving policy and changing markets. There continues to be uncertainty from the rate of change in technologies such as solar power, electric vehicle infrastructure and digitalisation. On top of this uncertainty there are significant trends that must be managed.

Despite these trends, we're still determined to make the right long-term investment decisions for customers, so our network remains safe, resilient, reliable, sustainable, and affordable. This balancing of objectives is often described as the energy trilemma where objectives such as energy security (resiliency and reliability), energy equity (accessibility and affordability), and environmental sustainability are kept in equilibrium. Being able to balance these objectives is an important goal for WEL now and into the future.

Seeing the road ahead

Our E^3 Strategy (see p.9) provides the framework for how we will navigate these challenges. You'll see it focuses on enhancing value from the core business, exploring alternative energy solutions, and expanding our capabilities to meet future needs. This AMP Update builds on the progress made during 2024 and should be read in conjunction with last year's 2024 AMP Update and the last full AMP published in 2023.

During the planning period of this AMP Update, we remained focused on providing a quality service to customers now and into the future.

We have analysed the trends that will impact our business and are responding with a number of key initiatives as discussed below. This includes the creation of our resilience strategy and four other key initiatives to ensure we can continue to provide a quality service in the future.

Structures to support our approach

Five key initiatives will help chart a path through the trends and help deliver the network of the future. These are listed below and are explained in section 2 in more detail:

1. In early 2025, we published a new resilience strategy. The strategy expands our work described in last year's AMP and provides a framework to deliver greater resilience outcomes for customers.

2. Our Distribution System Operator (DSO) transformation roadmap is underway and is providing enhanced visibility of our low voltage network. As new load connects then this visibility and support tools will allow access to the latent capacity on the network and at an affordable cost.

3. Our digital journey continues to develop, which ensures we have systems and processes that allow our staff and contractors to work efficiently and to make the best effective decisions based on up-to-date data.

4. We continue to deliver battery and solar solutions that will help deliver sustainable and affordable outcomes for customers.

5. Our strategy is to deliver greater flexibility within long term network architecture decisions. This is to ensure a least regrets approach when undertaking large network investment decisions which provide capacity when and where required but avoid stranded investments. This can be impacted by a small number of large or "lumpy" network connections. This also factors in an opportunity in FY26 to purchase 110kV assets from Transpower, which may have a major input into our long-term network architecture.

AT A GLANCE : IN OUR 2025 AMP UPDATE, THE MOST SIGNIFICANT CHANGES OVER THE PERIOD OF THE 2024 AMP ARE:

A DECREASE IN OUR CUSTOMER INITIATED WORKS FORECAST OF

$14.0M

There was a significant increase in this area from the 2023 to 2024 AMP by $95.1m. Demand and expenditure is still expected to rise significantly over the period from residential intensification of Hamilton, increased investment in decarbonisation of industrial processes, growing EV uptake, and increasing adoption of distributed generation and distributed energy resources. Our forecast has been reset based on current rates and updated forecast information. In the short-term, subdivision and relocation activity is lower than forecast last year, especially in the next 2-3 years and this is largely driving the overall reduction.

A MARGINAL DECREASE OF

$1.0M

IN INVESTMENT IN NON-NETWORK CAPEX.

The 2024 AMP included a $23.5M uplift in non-network CAPEX from the 2023 AMP. This was to support the significant enhancement of our asset management and DSO capabilities and covers LV works management, digital transformation, data management, acquisition and platform services. This year there is a minimal change as projects are being delivered largely to forecast.

AN INCREASE OF

$11.4M

FOR NETWORK DEVELOPMENT

Last year we raised the category by $6.4M to improve the resilience of the network from high impact, low probability (HILP) events and bring forward feeder reliability projects to enhance our network performance. These projects are now underway. The increase of $11.4M over last year's AMP period is primarily due to an increased focus on improving resilience for Te Uku and Raglan area customers as well as seismic upgrades for zone substations. The Fairfield, Exelby and Crosby substation builds have been deferred due to slower load growth while the Airport substation build has been brought forward due to local commercial growth.

AN UPLIFT OF

$2.9M

FOR ASSET REPLACEMENT AND RENEWAL

This year the forecast has increased by $2.9M in 2026 mainly to address a small backlog of corrective CAPEX work. Overall, our asset renewal philosophy remains aligned to our previous AMP. It's our strategy to balance cost, risk and performance drivers by maintaining a constant level of risk for our asset portfolio over the planning period to deliver a network that remains safe, resilient and reliable.

AN UPLIFT OF

$10.0M

FOR NETWORK OPEX

We have increased the vegetation and preventative maintenance budgets across the forecast period to place downward pressure on outage numbers and related impacts to end customers. There has been a reduction in the faults budget to partially counteract the increase.

A DECREASE OF

$6.9M

FOR NON-NETWORK OPEX

Last year the 2024 AMP included a $43.8M uplift in non-network OPEX from the 2023 AMP. This was to support the significant work required as part of our digital transformation. This year's reduction is due to expected process efficiency and savings in later years as the benefits from the programme take effect.

CHAPTER 1
BACKGROUND
KUPU WHAKATAKI

WEL GROUP IS
100%
OWNED BY THE COMMUNITY

WEL NETWORK CONNECTS MORE THAN
102,000
RESIDENTIAL PROPERTIES AND BUSINESSES INCLUDING
967
COMMERCIAL INDUSTRIAL

WEL GROUP HAS OVER
350
PEOPLE WHO DELIVER ELECTRICITY SERVICES TO OUR COMMUNITIES

70,860
HOMES AND BUSINESSES CURRENTLY HAVE ONE OF OUR SMART METERS

WEL NETWORK MAINTAINS
6,996
KILOMETRES OF LINES
46% ARE OVERHEAD

FROM APRIL ‘23 TO MARCH ‘24 ACROSS OUR 29 PUBLIC EV CHARGERS WE’VE SAVED
435,000kg of CO_2e

1 About us

1.1 GROWING THE WAIKATO

WEL's network stretches from Hamilton in the southeast, to Raglan in the west and to Maramarua in the north. WEL also owns and operates small, embedded networks in Cambridge and the Auckland Region.

Our electricity network consists of six main elements: Grid Exit Points, Distributed Generation, 33kV Subtransmission Zone Substations, 11kV Distribution and the Low Voltage Network.

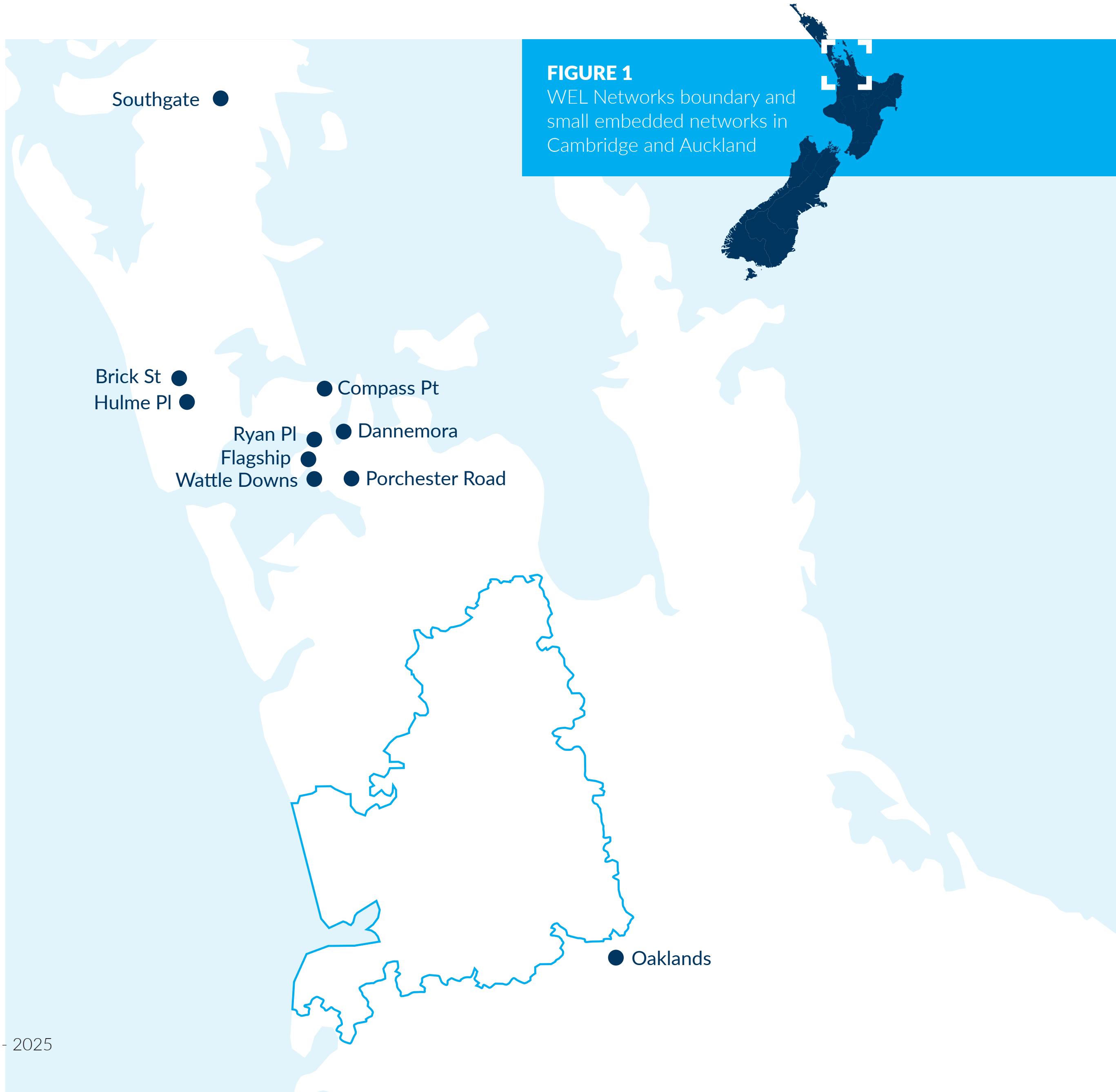


FIGURE 1
WEL Networks boundary and small embedded networks in Cambridge and Auckland

1.2

STATEMENT OF STRATEGIC INTENT

Leading Waikato's Energy Future

We deliver that through our

E3 STRATEGY

A strategy that unlocks our energy potential by enhancing value from our core services, exploring energy solutions, and expanding our thinking into the future.

ENHANCE
THE CORE VALUE

ENSURING WE GAIN THE GREATEST BENEFIT FROM THE INVESTMENTS MADE IN OUR CORE INFRASTRUCTURE.

EXPLORE
ENERGY SOLUTIONS

PROVIDING WHAT CUSTOMERS AND BUSINESSES NEED TODAY AND TOMORROW FOR A LOW CARBON, LOW PRICE, CHOICE-DRIVEN ENERGY FUTURE.

EXPAND
INTO OUR FUTURE STATE

INCUBATE NEW IDEAS WITH A VIEW TO INVEST IN SCALE-UPS AND START-UPS TO INCREASE OUR OFFERING AND OUR NON-REGULATED REVENUES.

1.3
GET TO KNOW OUR NETWORK

1.3.1 Why have we updated our AMP?

The 2025 AMP Update states material changes (greater than $500,000) to the 2024 AMP Update as required by the Electricity Distribution Information Disclosure Determination 2012. The last full published AMP was the 2023 AMP, and we have not repeated the more detailed explanations provided in that AMP here. Overall compliance against the Electricity Distribution Information Disclosure Determination is covered by several different documents. A full compliance checklist is included in section 5. You should read the 2023 AMP in conjunction with this update to gain a full picture.

All dollars presented in this AMP are indexed to FY 2026 dollars unless stated.

Section 1 provides an overview of this AMP, WEL Networks and uncertainty in our planning horizons. It provides our E3 Strategy which has been set to deliver our vision.

Section 2 outlines work that is underway to ensure that WEL adapts to our changing environment and ensures that we are well placed to meet the opportunities ahead.

Section 3 looks at material changes to our 2024 AMP network development plans, lifecycle asset management plans, and asset management practices – and explains our reasoning behind them.

Section 4 contains our updated Disclosure Schedules.

Section 5 contains a table of how we comply with the Electricity Distribution Information Disclosure Determination 2012.

Section 6 contains the Directors' Certificate.

1.3.2 What's the purpose of this AMP?

This AMP Update has been structured to meet disclosure requirements and is in a similar format to our previous AMP updates. It gives an overview of the changes we foresee in our operating environment – and how these affect our forecasts.

1.3.3 What's the duration of our new plan?

Our AMP period is 1 April 2025 to 31 March 2035, with the caveat that, naturally, there will be a higher level of accuracy in the earlier years than the later ones.

1.3.4 What is the Certificate Date?

This plan was approved and certified by the WEL Networks Limited Board of Directors on 4th March 2025.

1.3.5 Who is the plan intended for?

The plan is publicly available on our website for anyone to read. However, our primary audiences are our stakeholders including our wider community, our customers, the Commerce Commission, the Electricity Authority, and our staff and contractors.

1.3.6 What areas does the Information Disclosure cover?

This AMP Update covers* material changes to the last AMP in:

- Network development plans
- Lifecycle asset management plans
- Forecast capital and operational expenditure
- Asset management practices of WEL, and
- Drivers underlying those changes.

**Full disclosure requirements are set out in the Electricity Distribution Information Disclosures Determination 2012.*

1.4
FORECASTING IN A CHANGING WORLD

Forecasts allow us to plan and help us see any obstacles on the road ahead. But as the past few years have shown, there's always a degree of uncertainty, particularly over longer periods. There are a number of good reasons for this: technology moves quickly, policies change, markets shift, demand fluctuates, and customer trends happen quickly. Other factors, including large or "lumpy" short-notice commercial customer applications result in changes in demand that are difficult to predict and can lead to poor outcomes if each change is considered individually. From a procurement perspective, there has been significant uncertainty driven by the ongoing economic impact of global conflicts. One major trend is driven by New Zealand's commitment to achieve net zero greenhouse gas emissions by 2050. Electricity has a key role to play in achieving the country's climate ambitions. That said, the changes required – not least the speed at which these changes must be implemented – and potential investment requirement are unprecedented.

1.4.1 What can we do to mitigate change?

The size and timing of our distribution investment is based on net cost-benefit to customers over the lifecycle of customer demand and network assets. Adjusting our network investment ensures that network expansion meets our community's needs within finite financial and workforce capacity and minimises overall risks.

We are improving our forecasting models to better predict the loading on the network, with expected changes to the maximum demand and daily loading patterns. This means we need to better forecast the uptake and flexibility provided by DER such as EVs and distributed generation on top of more traditional loading changes.

To help mitigate load uncertainty, greater use of scenario planning is required. As well as load and DER forecast scenarios, this requires an accurate digital model of the network "a digital twin" to allow better scenario modelling of the network capacity, which is discussed further in section 2.5.

As well as total load uncertainty, greater uptake of DER may also impact power quality, by causing phase imbalances and voltage or harmonics issues. These issues will tend to get worse as loading (including DER) increases. We have updated processes to ensure new loads are equally balanced across phases and our DSO initiative, discussed in section 2.2, includes workstreams to identify and correct imbalance where these are causing loading and voltage issues.

1.4.2 Can you expect to see any more changes?

Nobody can accurately predict the future, but we can prepare for it based on our best analyses. Consequently, we will need to make changes as time goes on, in line with our continual improvement philosophy for Asset Management. This means our development plans and corresponding investments will be amended in subsequent revisions of the AMP – reflecting the emerging needs of our customers, stakeholders and changing circumstances on the network.

We are already seeing changes in the way we model and operate the network. It is likely that the Asset Management delivery model may adapt away from our traditional model to reflect new ways of working with more accurate and timely information as well as better utilising new flexibility services as they become available.

CHAPTER 2
INVESTING IN OUR NETWORK
HAUMITANGI A-WHATUNGA

WE ARE DEALING WITH 8 SIGNIFICANT TRENDS

1 CLIMATE CHANGE	2 GEOPOLITICS & NATIONAL SECURITY	3 ECONOMIC FRAGMENTATION	4 NEW TECHNOLOGIES
5 ELECTRICAL SECTOR DYNAMICS	6 THE EMPLOYEE EFFECT	7 DOING BUSINESS IN THE WAIKATO	8 SUSTAINABILITY PRESSURES

We have expanded the 6 trends discussed in last year's AMP to the 8 above – the new inclusions are item 7. "Doing business in the Waikato" and item 8 "Sustainability Pressures". This ensures our position in the Waikato and our progress towards our carbon zero future in NZ is considered at this higher level and not embedded within the other trends, as it was in the 2024 AMP Update.

In addition to the list of four key initiatives that we published in 2024 we have added one more to manage significant load forecast uncertainty with potential large new connections. These connections have significant consequence on loads at GXP and zone sub level, so our planning process and network architecture needs to be flexible to manage these significant new connections. They are outlined below:

1) Development of a Resilience Strategy

In early 2025, we finalised a new resilience strategy. The strategy expands on our work described in the 2024 AMP Update and provides a framework to deliver greater resilience outcomes for stakeholders.

2) Our Distributed System Operator (DSO) Initiatives

A DSO transformation roadmap is underway and is providing enhanced visibility of our high and low voltage networks. As new load connects then this visibility and supporting technology allow us to achieve greater capacity on the network at an affordable cost.

3) Our Digital Journey

This ensures we have systems and processes that allow our staff and contractors to work efficiently and to make effective decisions based on up-to-date and accurate data.

4) Distributed Energy Resources

Continued development of battery and solar solutions contributes to the delivery of sustainable and affordable solutions for customers and our community.

5) A Flexible Network Architecture

Our strategy delivers greater flexibility in long term network architecture decisions. This is to ensure a least regrets approach when making large network investment decisions which provide capacity when and where required but avoid stranded investments. This can be impacted by a small number of large network connections.

2 Our Response

We are investing in the network of the future, so it's fit for purpose today – and tomorrow. From the resilience of our network assets and easier access to information, to the emerging demands of electrification and changing customer needs, we're focused on delivering a balanced and cost-effective service. Here, we describe our response to these drivers.

2.1 RESILIENCE STRATEGY

We view resilience in two ways. Firstly, in terms of our ability to prepare for and adapt to changing conditions and to withstand and recover rapidly from disruptions. This is assessed in terms of depth of the impact of the event, and the speed of recovery. Secondly, we monitor network reliability and our ability to maintain supply to our community. This is considered in terms of the frequency and duration of unplanned and planned power outages and is a standard regulatory measure used by EDBs to track customer service levels.

There is a renewed focus by the New Zealand Government on resilience of critical infrastructure. This is to ensure that critical infrastructure continues to support our communities in the face of changing environmental factors. Over the last year we have continued to build our resilience planning. This has resulted in the completion of a company-wide resilience strategy in February 2025. This strategy has advanced our thinking in the resilience field. The purpose of the resilience strategy is to deliver enhancements to the following areas:

- **Improved Insights:** Enhanced capacity to foresee and mitigate risks and vulnerabilities, as well as the readiness to exploit potential opportunities.
- **Reduced Financial Risk:** Operational disruptions can lead to financial losses. Improving operational resilience reduces the likelihood and impact of these losses.
- **Cost Savings:** Reducing disruptions helps organisations save money on downtime-related costs, such as lost productivity and revenue.
- **Improved Customer Satisfaction:** Customers are more likely to trust and do business with organisations that can reliably deliver services during disruptions.
- **Enhanced Competitive Advantage:** Resilient organisations are better positioned to compete in the marketplace.
- **Increased Worker Morale:** Workers (i.e. employees and contractors) are more motivated and engaged when working for resilient organisations.
- **Corporate Citizenship:** This involves considering the organisation's role in driving environmental and social change and its resilience to these changes.
- **Enhanced Reputation:** Resilient organisations are more likely to be trusted by stakeholders, which helps build, maintain, and measure trust, fostering trust equity.

We have taken an organisation wide approach in the Resilience Strategy. For each aspect, the Resilience Strategy is structured around the four sequential treatment phases known as the 4 Rs framework: Reduction, Readiness, Response, and Recovery. These are defined in the EEA Resilience Guide 2022 and by the National Emergency Management Agency. Each of these elements plays a crucial role in building a resilient organisation:

Ahead of an acute event or chronic change

- Reduction: Identifying and minimising vulnerability risks. This involves taking proactive steps to reduce the likelihood and impact of disruptions.
- Readiness: Preparing for potential challenges by having early warning systems, contingency plans, resources, training and exercising before an event. This ensures that individuals and teams can respond effectively.

After the acute event or chronic change has taken place

- Response: Taking immediate action after an event occurs. This includes post event assessment, implementing plans, mobilising resources, and coordinating efforts to address the situation and minimise further damage, as well as repair and restoration of services.
- Recovery: Long term reinstatement of the network to provide pre-event security of supply service standards. Rebuilding and restoring the organisation after a crisis. This involves repairing physical, emotional, and social impacts, as well as learning from the experience to improve future resilience.

By focusing on these four sequential requirements, and assessing significant trends and their organisational exposure, WEL is developing management plans that enable it to adapt, withstand, and thrive amidst the evolving challenges.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RAV4

2.1.1 Organisation Aspects Covered in the Strategy

Resilience traditionally focuses on operational (asset-based) resilience, and how megatrends specifically impact operational aspects of the organisation. WEL has recognised that a lack of preparedness in other areas of the business can destabilise or limit organisational resilience.

Accordingly, the following five aspects of resilience, and their subsets, are considered to provide a more comprehensive representation of the entire organisation:

Operational (Asset) Resilience

- Physical assets
- Physical premises & security
- Cyber & information systems
- Personal security (people risk)
- Supply chain
- Procurement security

How WEL uses non-financial resources to withstand, absorb, recover from, adapt to, or regenerate from the impacts of shocks that affect their operations and assets/facilities

People Resilience

- Organisation adaptability
- Diversity & inclusion
- Workforce
- Leadership
- Health & wellbeing
- Culture

How WEL supports their people and fosters creativity and growth by cultivating personal resilience, and instituting the right cultural norms, conduct, and behaviours

Environmental Resilience

- Sustainable operations
- Climate change
- Environmental risk

How WEL works to achieve homeostasis with the natural world, making strategic choices that are both good for the environment and sustainable for business

Financial Resilience

- Financial stress testing
- Cost management
- Management information
- Balance sheet flexibility
- Governance and controls

How WEL demonstrates the ability to withstand events that impact our liquidity, income, or assets

Reputational Resilience

- Vision and leadership
- Financial performance
- Quality of services
- Social responsibility
- Stakeholder perception

How WEL is being responsive to external perceptions, building brand capital and reserves, and maintaining a foundation of trust and dependability

2.2
NETWORK INNOVATION: LEVERAGING OUR DISTRIBUTED SYSTEM OPERATOR (DSO) FUNCTION

This is an exciting time for the network. Traditionally network devices and connection points are passive and have only needed to be lightly coordinated. We are expecting large increases in network demand and DER being connected, as customers move towards a decarbonised future.

The challenge is that traditional network solutions require time and cost to implement, and this could slow down or add cost to the change. Network flexibility and coordination will enable solutions to be implemented faster and help defer or reduce the large investment needed in infrastructure. This is an important transformational change for our business.

DSO Roadmap

The roadmap has been divided into three broad stages, as shown in Figure 2 and discussed below.

FIGURE 2 DSO Roadmap

1) Visibility

Analysis and Improved Network Decision Making

This stage is improving network visibility and analysis to provide insights and to support everyday decision making. Our smart meter systems provide near real time data at a 5 min sampling rate and this data is integrated with other data sources (such as GIS and SCADA).

Making better asset management decisions is part of a targeted improvement plan with 7 priority areas of focus, summarised to the right.

Several case studies were published during the 2024 EEA conference to share insights and opportunities that WEL is gaining from greater network visibility and analytics.

NETWORK ASPECT	AREA OF FOCUS	DEVELOPMENT PLAN
1 **Safety**	ICP mapping, connection failure	Engineering logic detects network connectivity issues and to confirm ICP to transformer relationship. Real time meter alarms to detect supply equipment failure like broken neutral.
2 **Capacity**	Overloading and balancing	Distribution asset loading study and phase mapping to highlight areas to improve asset utilisation.
3 **Supply Quality**	Voltage management	Voltage supply band management and coordination.
4 **Resiliency**	Outage detection, backfeed options	Real time network outage detection. Integrated system planning for backfeed scenarios. Major event fault response.
5 **Asset Condition**	Defect identification and data accuracy	Early detection of connection defects and proactive corrective maintenance. Use data science to pick up asset data error.
6 **Customer Connections**	Demand flexibility	Use metering data to improve customer solution design and work with customer to develop demand response options.
7 **DER Integration**	Device integration and operating envelope	Manage hosting capacity via DER integration.

2) Inter-Operability

Allow new DERs to meet network and customer energy needs via flexibility.

The next stage is to develop a control interface to enable inter-operability. During this phase, equipment connections and operation standards are being implemented and a database will be created for approved network owned and customer owned equipment that can be used for flexibility management. A commercial engagement model on DER services will also be implemented.

An example of recent work was the successful flexibility solution implemented for a local school to increase their energy usage via a real time control envelope. By monitoring the local transformer load we now provide the school with a variable limit in near real time that they are using to adjust their own flexible load. The alternative network solution required significantly higher costs and lead times. WEL is working with other schools in the region with similar loading patterns to use the same solution.

We continue to use the flexibility provided by our own water heating load control system as well as flexibility services provided by our own DER services discussed in section 2.4.

We also considered the use of a flexibility option to provide resiliency and support load growth in the Raglan area. In this case we chose a network solution as this could be implemented relatively quickly and provide the significant step change required. Nevertheless, this is an important step to understand when and where to implement flexibility solutions.

3) Optimise

Enable and coordinate with flexibility market. This aims to incentivise DER participation, drive performance, encourage competition and investment.

The third stage optimises the flexibility value by using a market approach, so the overall transaction costs to use flexibility is reduced. This needs engineering, operation and financial models to support a more open network trading solution. The model will assess the best value to utilise available flexibility services and then call the right support whether this is from generators, aggregators, customers or network owned equipment.

FY26 DSO Focus

In 2026 we will continue to progress along the DSO roadmap. Initiatives include:

- Leveraging the engineering and data platform we have built in FY25 to productionise the decision-making tools for network driven initiatives. The learnings from this work will also be used in a new scenario-based approach for integrated system planning, as discussed in section 2.5.
- Designing and building automated applications for embedded distributed generation and new CIW residential connections to improve and speed up our decision-making processes.
- Continuing to improve the accuracy of network models, which are required to support future stages in the roadmap.
- In terms of flexibility products, in 2026 we will continue work with non-network solution flexibility service providers to enable the use of innovative solutions, like the school example above, but to also expand the complexity of optimisation calculations into our near real time system. This work includes completing a prototype of our Distributed Energy Resources Management System (DERMS).

Over the next 3 years, we are forecasting expenditure to run non-network flexibility pilot programmes. Our forecast then gradually ramps up as solutions and use cases are proven. We monitor the use of flexibility services in NZ and overseas to help support our own work and forecasts. The overall forecast for this work is included separately in the schedules for transparency and to meet the information disclosure requirements.

2.3
PROGRESSING OUR DIGITAL TRANSFORMATION

From decarbonisation and DER disruption to changing customer needs and expectations, the drive for change in our industry is greater than ever. Traditional approaches to operating our business are neither efficient nor sustainable when we consider the quantum of change ahead of us.

To enable our business to thrive, we need to have digital systems and processes that allow our staff and contractors to work efficiently and to make effective decisions based on accurate and up-to-date data. We need to truly understand our customers and provide digital channels that support their needs and behaviours. We will build digital systems that enable productivity at scale while providing full transparency to enable good business governance.

Implementing our digital strategy

Last year we kicked off the first stage of a major digital transformation initiative. The Digital Foundations programme was established to ensure that we have the right digital capabilities in place to support the business and our customers in the years ahead.

Significant progress has been made with a number of key milestones delivered over the past year:

- A major lifecycle upgrade of SAP to S/4HANA and migration to the cloud.
- A scheduled upgrade of GE PowerOn our network management system.
- Establishment of an enterprise data platform to support digital business operations and analytics.
- Establishment of an enterprise integration platform to support systems integration and workflow automation between core systems.
- Implementation of Genesys PureCloud to support our customer service centre and serve as a foundation for future digital customer engagement initiatives.
- Implementation of EcoPortal as our digital Health and Safety Management System.

While last year was largely focused on enabling technologies and core system upgrades, the focus areas for the years ahead will broadly fit into one of three distinct transformation programmes.

1. The Digital Electricity Network

We need to leverage the vast amounts of network and asset data that we capture to make the best possible investment decisions as customer demands increase. Traditional design approaches that are based on assumptions and calculations will be augmented by digital models and actual usage data to optimise our network designs and the resulting capital expenditure. Realtime data from the electricity network will be used to identify operational issues and allow us to substitute reactive fault work for planned maintenance and upgrades.

Priority focus areas:

- Leverage new Asset Management capabilities of SAP S/4HANA to support industry best practice.
- Bringing a digital approach to asset investment planning with the implementation of Copperleaf.
- Developing a digital workflow approach to support our design through to as-build processes.
- Scheduled upgrade of the ESRI GIS platform.
- Embedding the Network Innovation and Performance (NIP) systems and practices into the core business. Continuing to find ways to leverage data driven approaches to enhance how we design, build and operate the electricity network.

2. The Digital Employee Experience

Ensuring that all business-critical processes are supported with the appropriate digital solutions. In many cases this will mean enabling our staff to leverage data and systems that we already have where and when they need it. We'll focus on digitally enabling time-consuming and error prone manual processes to improve efficiency, accuracy, safety and job satisfaction. We'll also provide better support to manage the flow of work through our organisation via digital workflow management and greater enablement of existing mobile devices to provide access to data, documents, and systems when and where it's required. By leveraging modern cloud and mobile technologies, we can deliver an employee experience that both supports and encourages digital collaboration across the whole company, leading to faster, more informed, decision making.

Priority focus areas:

- Providing smart mobile solutions to support our field workers and contractors. These solutions will deliver direct access to core systems and data to remove the need for paper-based process and forms that support our network development and fault management operations.
- Unleashing employee creativity through better use of digital productivity and collaboration tools. Modernising the way that we work in the office and when working remotely to ensure that we are harnessing the power of the digital collaboration tools that we have available to us.

3. The Digital Customer Experience

We will review our existing customer engagement channels to determine if they are fit for purpose and meeting our customers' expectations. Where we have digitally enabled our internal processes, we will seek to provide transparency of work requests to our customers to enable customer self-service via updated and/or new digital channels. We will seek new ways to become closer to our customers and to better understand their needs and support them through greater use of digital technology.

Priority focus areas:

- Explicit focus on the experience that we provide our customers during unplanned outages. The goal is to keep our customers informed via existing and/or new digital channels so that we can provide the best possible customer experience at what may be a difficult time.
- Develop a customer experience strategy and execution plan, by undertaking customer interviews and research to better understand our customers' needs and behaviours.

2.4
DISTRIBUTED ENERGY RESOURCES (DER)

Distributed Energy Resources (DER) are impacting the network, and WEL believes this will continue to grow. For NZ to realise its climate change goals, the successful integration of DER across networks will be critical. WEL is studying the wider impact on the network and directly investing to enable this future state.

Battery Energy Storage System (BESS)

The 35MWh Rotohiko BESS has operated in the wholesale electricity market and the instantaneous reserves market throughout 2024.

Rotohiko is aligned to our long-term strategy, primarily ensuring that the delivery of electricity to our customers remains affordable. It achieves this through generating revenue via energy arbitrage. It is also capable of providing fast reserve support for the North Island grid, maximising the benefits of solar power as our own and other party solar farm projects continue to develop within the WEL Networks footprint.

WEL is investigating further distributed BESS projects connected at 11kV and 400V to provide benefits to local consumers and support the network. WEL is also considering the combination of BESS and other DER such as solar generation and EV chargers to maximise the utilisation of network capacity.

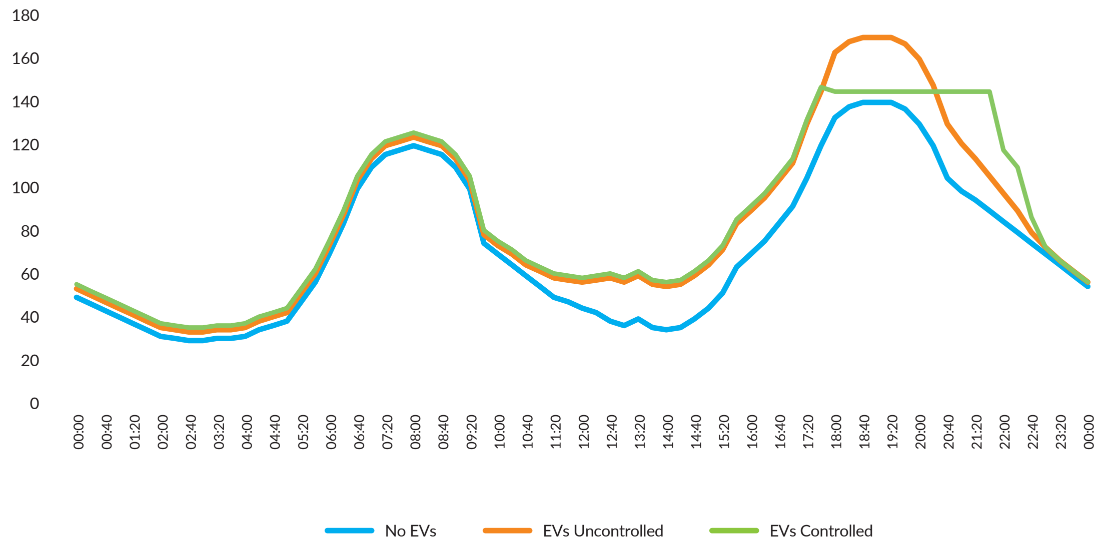
Solar Farm Development

WEL Group is focussed on supporting New Zealand's net carbon zero journey. The Taiohi 22.4 MW solar project near Rangiriri is now under construction and is planned for commissioning in the FY26 year. The site is embedded within WEL's 33kV network and will be operated by NewPower (which is part of the WEL Group).

Changing Load Patterns

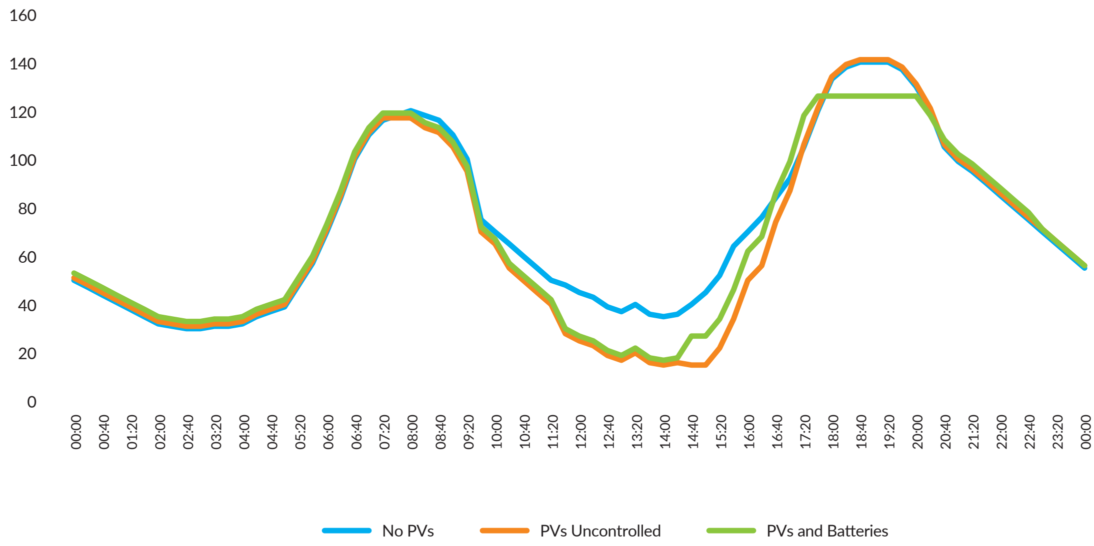
Over the past 12 months we have seen a continuing increase in DER connection requests, and in particular aggregators installing residential battery and solar systems. Managed DER can see a reduction in consumption during peak periods reducing costs to the end consumer. Below are two examples of pre-DER and post managed DER usage profiles.

FIGURE 3 Residential EV charger impact



Uncontrolled EV load will raise the loading on the network especially at peak times when EV charging coincides with standard evening peak (increase between the blue and red load curves). Controlling the EV load will flatten and reduce the overall load curve reducing network investment in the long term (green curve).

FIGURE 4 Residential PV Impact



Uncontrolled PV will reduce the loading on the network during daylight hours but not change the loading at winter peak times (impact between the blue and red load curves). Adding batteries and charging these before the peak for discharge during peak times will also flatten and reduce the overall load curve reducing network investment in the long term (green curve).

Historically residential usage patterns have followed the same profile however, as more DER comes on, we are seeing a shift in consumer usage patterns. We are working to understand the impact they will have on our network, and also what benefits or services they may provide. These network alternatives may provide greater cost benefit value to our consumers as opposed to traditional methods of network build as the nation electrifies.

ELECTRIFICATION AND DER MANAGEMENT

We.EV

We.EV is a business unit within WEL which has launched a charge point management platform that allows visibility and control of all EV chargers installed. This allows the development of third party applications to control charging load in the future. We.EV are developing software solutions to manage load across large DC charging stations so that the load of multiple EV chargers can be controlled to ensure it stays within a nominated capacity and can be reduced based on time of use (ToU) or other capacity constraints.

We.EV are installing home, commercial, and public smart chargers across the WEL network. They have load management installed to ensure that the additional EV charging load will not overload the network connection. We.EV has progressed to develop and deliver several EV charging stations outside of the WEL network, primarily across the North Island.

We.EV are developing a high-powered public DC charging site with the support of EECA funding. This will use a small network connection, backed up by a BESS that can charge off-peak to support fast charging. TradeWEL (interruptible load offering to market) are supporting this project and will integrate with the BESS to allow it to be offered into the reserves market. This solution will both reduce the size and capital cost of the required network connection and reduce the operating costs due to lower network fees and create additional revenue streams for both We.EV and TradeWEL.

Home Electrification

The increase in home electrification is the result of shifting away from natural gas solutions, electric appliance efficiency, electric vehicle adoption and increasing penetration of DER. WEL is exploring opportunities to support this electrification through smart meter analytics discussed in section 2.2.

School Heat Pumps

Over the past decade schools have been replacing traditional gas and coal heating systems with heat pumps. This is often done over multiple years adding incrementally to the school load over summer holidays. When these new heat pumps are in use at full load on cold winter mornings, it can create peak electricity usage in excess of the size of the site network capacity and potentially power outages if the fuse blows. A traditional solution would be to upgrade the schools network connection, which could also require costly capital upgrades and increased electricity costs for the school.

As discussed in section 2.2, WEL has implemented a trial solution at a school using live metering data to control the load of heat pump units. This will automatically reduce the power of the heat pumps at times where the school has a high load to ensure that the total site load stays within the network connection capacity. Once the site load drops off, power to the heat pumps is automatically increased. This solution has kept the school within its existing site capacity for a fraction of the cost of a traditional solution with no impact on the annual electricity cost. WEL is looking to roll this solution out to schools across the network.

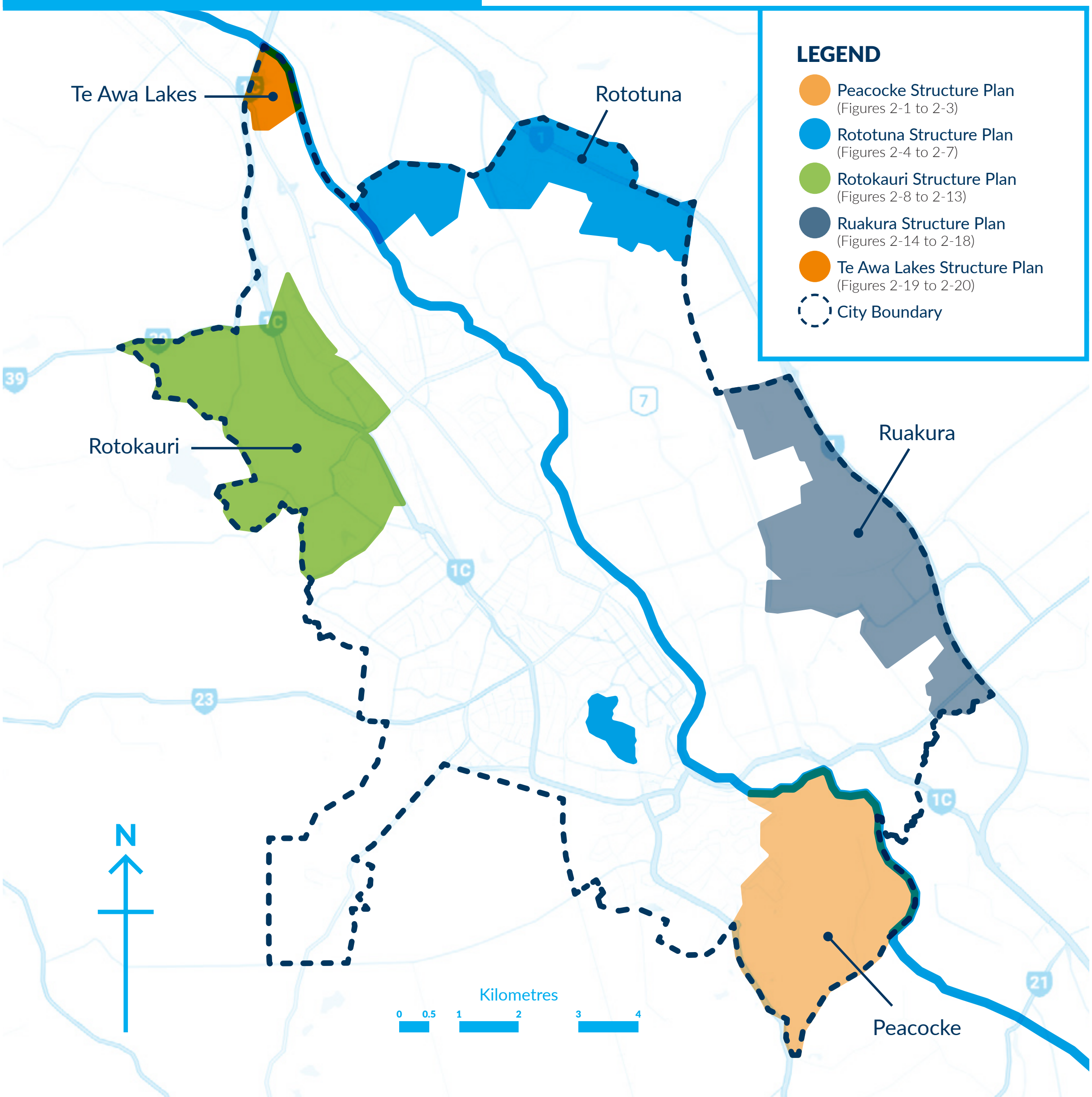
Commercial and Industrial Electrification

Commercial and industrial electrification in New Zealand is part of the country's broader strategy to reduce carbon emissions and transition to a low-carbon economy. Electrification in these sectors involves shifting away from fossil fuel-based energy sources to renewable electricity for heating, transport, and other operational processes. Electrification of process heat often goes hand-in-hand with efforts to improve energy efficiency. Businesses are adopting more energy-efficient electric technologies, such as LED lighting, electric ovens or furnaces, and smart building systems that optimize energy use.

The adoption of electric vehicles (EVs) in fleets has slowed through the removal of the clean car discount and introduction of Road User Chargers (RUC's) for electric vehicles. It is anticipated that as EV prices drop, demand will pick up again.

2.5
NETWORK ARCHITECTURE

FIGURE 5 Hamilton City Council Plan Excerpt



Network loading and the need for additional development is becoming more challenging to forecast.

As an example, the Hamilton 33kV grid exit point (GXP) is WEL Networks' largest connection point to the national grid managed by Transpower. This supplies over 50,000 connections in the southern and eastern side of the city. Over the next 10 years this area is forecast to see a high level of growth. Load growth will be driven by the Peacockes and Ruakura development areas as well as infill housing as shown in the figure to the left.

The Hamilton 33kV GXP is currently at its N-1 capacity. Forecast growth due to development at Peacockes and Ruakura in the South and East of the city will increase the peak load above capacity. Exceeding the N-1 capacity of the GXP places Hamilton at risk and clearly signals the need for investment at the GXP. The cost of this investment by Transpower would largely be passed to WEL Networks and our customers, through increased connection charges.

Over recent years we have managed to move some load from Hamilton to Te Kowhai and on to Huntly via tactical changes to our 33kV subtransmission network to defer a GXP upgrade. This can be completed in small stages that are lower cost, are quicker to implement than a GXP upgrade and avoid possible over investment that can occur in large one-off projects.

The approach has also delivered additional resilience as more load can be transferred between GXPs via our sub transmission network in the event of a major Transpower GXP outage.

Our last full AMP in 2023 summarised the Network Development investment plan including further steps in this staged approach.

We are now dealing with additional significant "single point" load increases across the network that could impact the strategy. As an example, there was a significant effective load increase at Te Kowhai in 2023 when the cogeneration plant at Te Rapa was decommissioned. These large changes can influence the benefit of the staged strategy, as it may be better to invest in the larger one-off step changes.

At Hamilton, Transpower is investigating replacement of a 220kV/33kV supply transformer and additional capacity at 110kV for the wider regional load including the 110kV circuits to Powerco and Waipa. Some potential solutions could impact the capacity available to WEL at Hamilton.

There is also an opportunity to purchase sections of Transpower's 110kV circuits between their Hamilton and Bombay substations. These circuits could help provide capacity north of Hamilton in corridors likely to experience high load growth.

The overall load to be supplied is also impacted by the uptake of DER technology, some of which will increase the energy transferred on the network (EVs) and some which will decrease the transfer (PV). The ultimate mix of uptake over time, coupled with various flexibility outcomes must be included in our planning.

After assessing the above factors, we will be reviewing our network strategy and development plan in 2025, to confirm it is the right approach for the future. Greater use of scenario planning will be required to understand risks and to chart the best path forward. Solution options to be considered will include:

- 33kV fast transfer solutions which allow GXPs to surpass their N-1 capacity but provide fast and reliable emergency transfer of load to adjacent GXPs in a network event. This would likely require 33kV switch automation and cable/line contingency re-rating and reinforcements.
- Capacity upgrades to GXPs, including recent opportunities from Transpower such as the sale of the 110kV line, upcoming renewal of the transformer T5 at the Hamilton GXP and a potential new 110kV interconnection near Hamilton.
- Non-network solutions such as load demand and energy storage options delivered by customers, aggregators and WEL directly.

A full update will be provided in the 2026 AMP.

CHAPTER 3
ASSET MANAGEMENT PLAN UPDATE 2025
TE WHAKAHOUTANGA MAHERE HUARAWA 2025

TOTAL NETWORK CAPEX

$895.8M

DELTA +$0.3M

TOTAL NETWORK OPEX

$139.6M

DELTA +$10.0M

TOTAL NON-NETWORK CAPEX

$89.0M

DELTA -$1.0M

TOTAL NON-NETWORK OPEX

$333.5M

DELTA -$6.9M

3 Where to from here?

3.1 A QUICK OVERVIEW

This section presents a high-level overview of the material changes to our forecasts and assumptions, and our related Network Development Plans, Asset Lifecycle Plans and Asset Management practices. For the expenditure plans discussed in this section, a material change is defined as > $500,000.

3.1.1 Managing Risk and Value across the Plan

In light of significant external factors that continue to impact the organisation, we are determined to make the right long-term investment decisions for customers, so our network remains safe, resilient, reliable, sustainable, and affordable. Being able to balance these strategic objectives is an important goal for WEL now and into the future.

As part of developing our longer-term asset management plans and approving projects for delivery each year, projects are evaluated and prioritised in terms of how they meet these strategic objectives.

The projects that deliver the greatest value or reduce the most risk are ranked the highest for delivery. The overall plan is then adjusted to consider constraints before being confirmed. Over time this approach helps ensure we are focusing on the right outcomes for stakeholders.

To help alignment, we run cross functional challenge sessions so the right projects are selected each year and all strategic objectives are considered.

In FY26 we are introducing the Copperleaf application as a decision support tool ensuring this overall process is efficient, is evidence based and allows for more alternative scenarios to be tested.

3.1.2 What material changes are there to our inflation forecast?

At the time of undertaking the analysis for this AMP Update the inflation forecast for FY26 was 2.2%, for the rest of the planning period we are forecasting CPI to return 2.0%.

3.1.3 What material changes are there to underlying growth factors?

Economic growth

Like most regions in NZ Hamilton's 2023 gross domestic product (GDP) growth rate fell to 0.6%, $14 billion, against a national GDP growth rate of 0.7%. GDP growth of 3.2% was experienced in the Waikato District in 2022 with the biggest contributors being manufacturing, construction, agriculture, forestry and fishing.

Population growth

In 2024 we again engaged the University of Waikato to provide insights into the future population growth for the WEL Networks region. Based on this work, we continue to forecast population growth of 1.5% per year over the next 10 years. From this, we estimate that around 1505-2635 new dwellings will be built each year over the medium to long-term.

Demand forecast

In our 2024 AMP Update we forecast a continued slowdown in new residential development over the short-term. We are now experiencing the effect of this slowdown with reduced applications. This slowdown will likely continue into FY26 before starting to improve at the back end of FY26. By contrast, in the medium to long-term, demand resulting from EV adoption and electrification of industry is expected to increase markedly. Responding to these drivers will require significant expenditure in reticulation upgrades.

We have detailed our input assumptions (used to formulate the various growth scenarios) in Figure 6.

Our demand forecast scenarios are graphically presented in Figure 7. The scenario (Med) represents a balanced view of the many factors influencing demand and is used as a fair indicator in our network development decision-making processes.

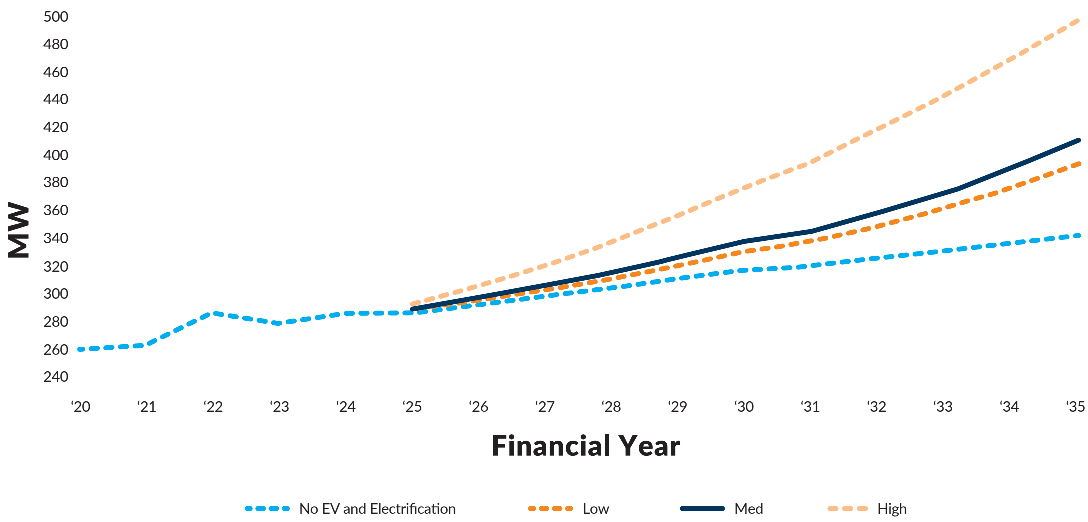
We are working on our forecasting models to better predict the loading on the network, with expected changes to the maximum demand and daily loading patterns. This means we need to better forecast the uptake and flexibility provided by DER such as EVs and distributed generation on top of more traditional loading changes. This is complicated by large or "lumpy" short-notice commercial customer applications such as new data centres, that result in changes in demand that are difficult to predict and can lead to poor outcomes if each change is considered individually.

As discussed in section 2.5, greater use of scenario planning will be used to help mitigate this uncertainty.

FIGURE 6 WEL Growth Scenarios

	LOW	MEDIUM	HIGH
Scenario Description	Short Recession, Slow Recovery	Short Recession, Medium Recovery	No Recession
Residential Growth (as provided by CIW)	1495-2440 dwellings p.a.	1505-2635 dwellings p.a.	1515-2850 dwellings p.a.
Industrial/Commercial Growth	1.5 MW p.a.-2027 onwards	2 MW p.a.-2027 onwards	3 MW p.a.-2027 onwards
Electrification	0.3 MW p.a.	0.5 MW p.a. + 9 MW of proposed projects	1.6 MW p.a. - +16 MW of proposed projects
EV Uptake contribution to Peak (as provided by We.EV)	43,395 EVs by 2035	51,050 EVs by 2035	113,100 EVs by 2035
Superhub Inland Port and Ruakura Structure Plan	Stage 1 supplied/Others Not Supplied by WEL	Stage 1 supplied/Others Not Supplied by WEL	Stage 1 supplied/Others Not Supplied by WEL
Sleepyhead Estate	Factory Only	Factory + Industrial	Factory + Industrial + Residential

FIGURE 7 WEL Demand Forecast (MW)



3.2
WHAT MATERIAL CHANGES ARE THERE TO FORECAST CAPITAL EXPENDITURE?

CUSTOMER INITIATED WORKS - CAPEX

FORECAST EXPENDITURE FROM FY26 THROUGH FY35

$375.6M

DELTA

-$14.0M

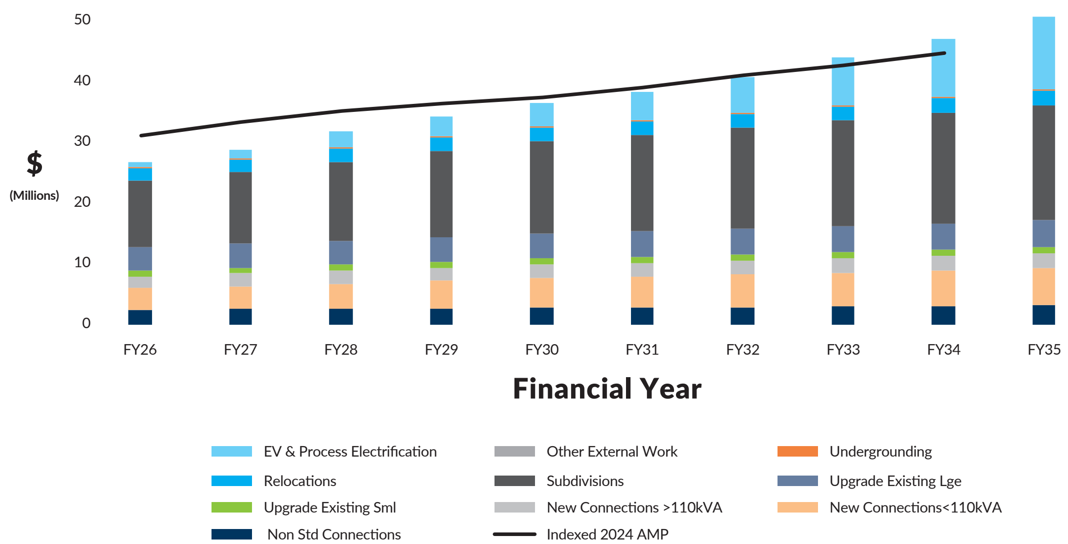
FORECAST EXPENDITURE VS THE PLAN

3.2.1 Customer Initiated Works (CIW) - CAPEX

The CIW forecast includes consumer connections, new subdivision reticulation, asset relocation expenditure, and a provision for electrification, including greater uptake of solar PV and electric vehicles. As noted earlier, a short-term slowdown in residential expansion is expected compared with FY24. The same underlying economic drivers and Government policy will like contribute to a similar short-term slowdown in EV adoption. While industrial and commercial enquiries remain strong, a slowdown in activity in these sectors is expected to continue into FY26.

In the longer term, increased demand is expected to be driven by residential intensification plans for Hamilton, increased investment in decarbonisation of industrial processes (electrification of process heat), EV uptake, and adoption of distributed generation and distributed energy resources. This short-term slowdown results in a $14.0M decrease in the CIW expenditure forecast from FY26 to FY34 compared to our 2024 AMP. This change has been factored into our demand forecasts and is illustrated in the graph below in terms of capital expenditure (CAPEX).

FIGURE 8 Customer Initiated Works (CIW) Expenditure



NETWORK DEVELOPMENT - CAPEX

FORECAST EXPENDITURE FROM FY26 THROUGH FY35

$262.8M

DELTA

+$11.4M

FORECAST EXPENDITURE VS THE PLAN

3.2.2 Network Development

Our Network Development Plan includes expenditure associated with system growth, assuring legislative and regulatory compliance, quality of supply and improvements to reliability, safety, and environmental performance shown in Figure 9. Network Development expenditure has been derived from the medium load growth scenario (base case), adjusted to reflect the economic slowdown, while also anticipating the electrical infrastructure upgrades that will be required in the medium to long term to support the changing demand of existing and future customers.

There are few material changes, increased focus on resilience of supply to Raglan and Te Uku areas, Weavers zone substation upgrade and seismic substation upgrades. The Fairfield, Exelby and Crosby substation builds have been deferred due to slower load growth while the Airport substation build has been brought forward due to local commercial growth.

Resilient come rain or shine

The recent cyclones highlighted the need for improved resilience of all critical infrastructure. Electrification to support the decarbonisation of the economy will increase the country's dependence on electrical infrastructure, further underscoring the importance of resilience in our sector. An investment of $12.3M from FY26 to FY35 has been allocated to bolster the network against high impact, low probability (HILP) events. These funds will kickstart initiatives we identify through resilience gap analyses and risk studies.

Material changes at-a-glance

Figure 10 summarises the material changes to Network Development projects presented in the 2024 AMP, along with our reasons for the changes. Material changes are over $500k.

The net effect of these changes and non-material adjustments is increased expenditure on Network Development of $11.4M from FY26 to FY34 compared to our 2024 AMP.

FIGURE 9 Network Development Expenditure

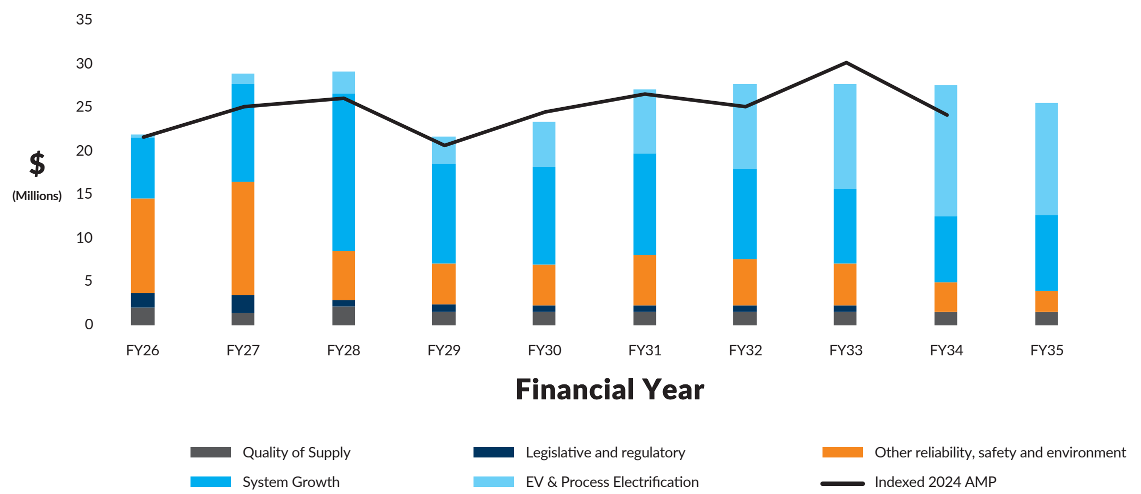


FIGURE 10 Network Development Project Material Changes

GXP	PROJECT NAME	2024 AMP		2025 AMP		REASON FOR CHANGE	OPTIONS CONSIDERED AND SELECTED (√)
		Timing	Cost (000's)	Timing	Cost (000's)		
ALL	**Network Resilience Initiatives**	FY26-FY34	$8,960	FY26-FY35	$12,346	Was an allowance in AMP24 whereas AMP25 has specific projects and detailed costing for the initial years (for Cogswell 33kV RMU replacement in FY26)	• Replace RMU with containerised switchgear at same site, (√) • Replace RMU with containerised switchgear at new site, • Replace RMU with new RMU
ALL	**Seismic upgrades of substations**	FY25-FY28	$4,243	FY25-FY33	$8,289	Program extended through to FY33	Covered in AMP 2023
ALL	**Lock replacement programme**	N/A	N/A	FY26-FY27	$570	New: Project to assess the solution to switchyard and substation locks that are becoming obsolete	• Do nothing • Recycle old locks • Adopt new lock system (√)
ALL	**Daisy Chain Transformer Unbundling**	FY24-FY34	$3,387	FY24-FY35	$4,296	Cost adjusted and program extended	Covered in AMP 2023
HAM33	**Crosby Distribution Network**	FY29-FY34	$2,212	FY31-FY34	$1,440	Program shortened to 4 years; any additional work will be completed as the area develops	Covered in AMP 2023
HAM33	**FAI Feeder to Offload HAMCB2722**	FY26	$1,280	FY26	$598	Scope reduced for FY26, remaining works to be scoped in conjunction with Fairfield substation build in FY29	Covered in AMP 2023
HAM33	**Peacockes new 33kV cable**	N/A	N/A	FY35	$7,120	New: Sub transmission to Peacockes substations is expected to be constrained by FY35, alleviated by 3rd 33kV cable from HAM33 GXP	• New sub transmission circuit from Hamilton GXP to Peacockes substation (√) • New sub transmission circuit from Hamilton GXP to Latham substation • Grid scale Battery
HLY33	**Weavers Zone Substation**	FY26-FY28	$4,024	FY26-FY28	$6,388	Detail design and scoping required a more complex solution.	Covered in AMP 2023
TWH33	**TEUCB1 reinforcement for Raglan 11kV backfeed support**	N/A	N/A	FY26-FY27	$4,993	New project to improve reliability and resilience to the Raglan area via new 11kV backfeed.	• Reinforce TEUCB1 (√) • Split TEUCB1 feeder • Grid scale Battery
TWH33	**Exelby Distribution Network**	FY26-FY31	$2,202	FY29-FY32	$1,420	Program shortened to 4 years; any additional work will be completed as the area develops	Covered in AMP 2023
TWH33	**Reconfiguration and Reinforcement between SAN feeders (SANCB6)**	FY26, FY28	$1,171	FY28	$549	FY26 objective achieved by reconfiguring existing feeders with switching	Covered in AMP 2023

ASSET RENEWAL - CAPEX

FORECAST EXPENDITURE FROM FY26 THROUGH FY35

$257.5M

DELTA

+$2.9M

FORECAST EXPENDITURE VS THE PLAN

3.2.3 Asset Replacement and Renewal

Overall, our asset renewal philosophy remains aligned to our previous AMP. It is our strategy to balance cost, risk, and performance drivers by maintaining a constant level of risk for our asset portfolio over the planning period. Most of the work is consistent with the 2024 AMP.

In the FY26 year we have raised the budget to address some specific items:

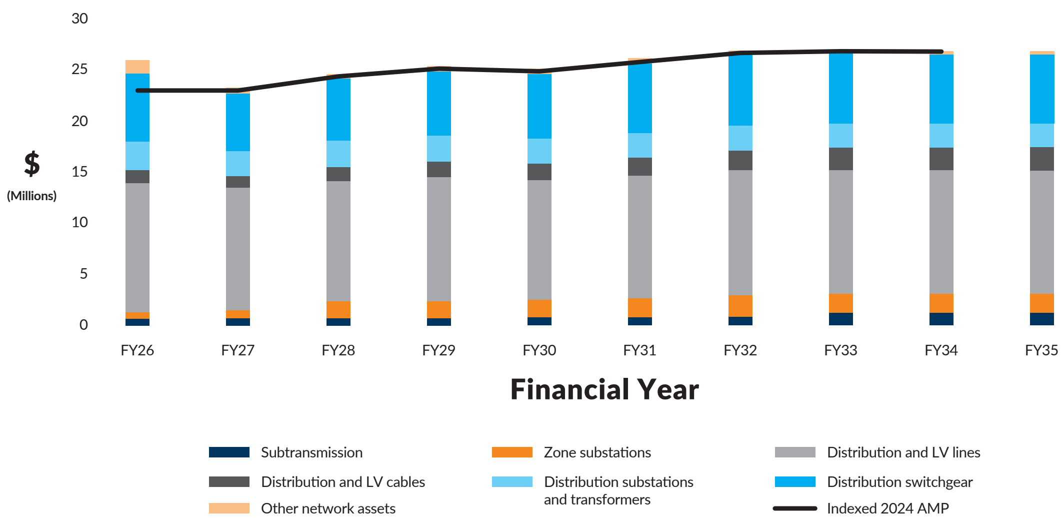
- Additional budget for protection and communications upgrade in Bryce Substation.
- One off project to address remedial replacements that were driven by external events such as storms in the FY25 financial year.
- Tactical increases of line recloser replacements to address an expected failure mode with some specific reclosers.

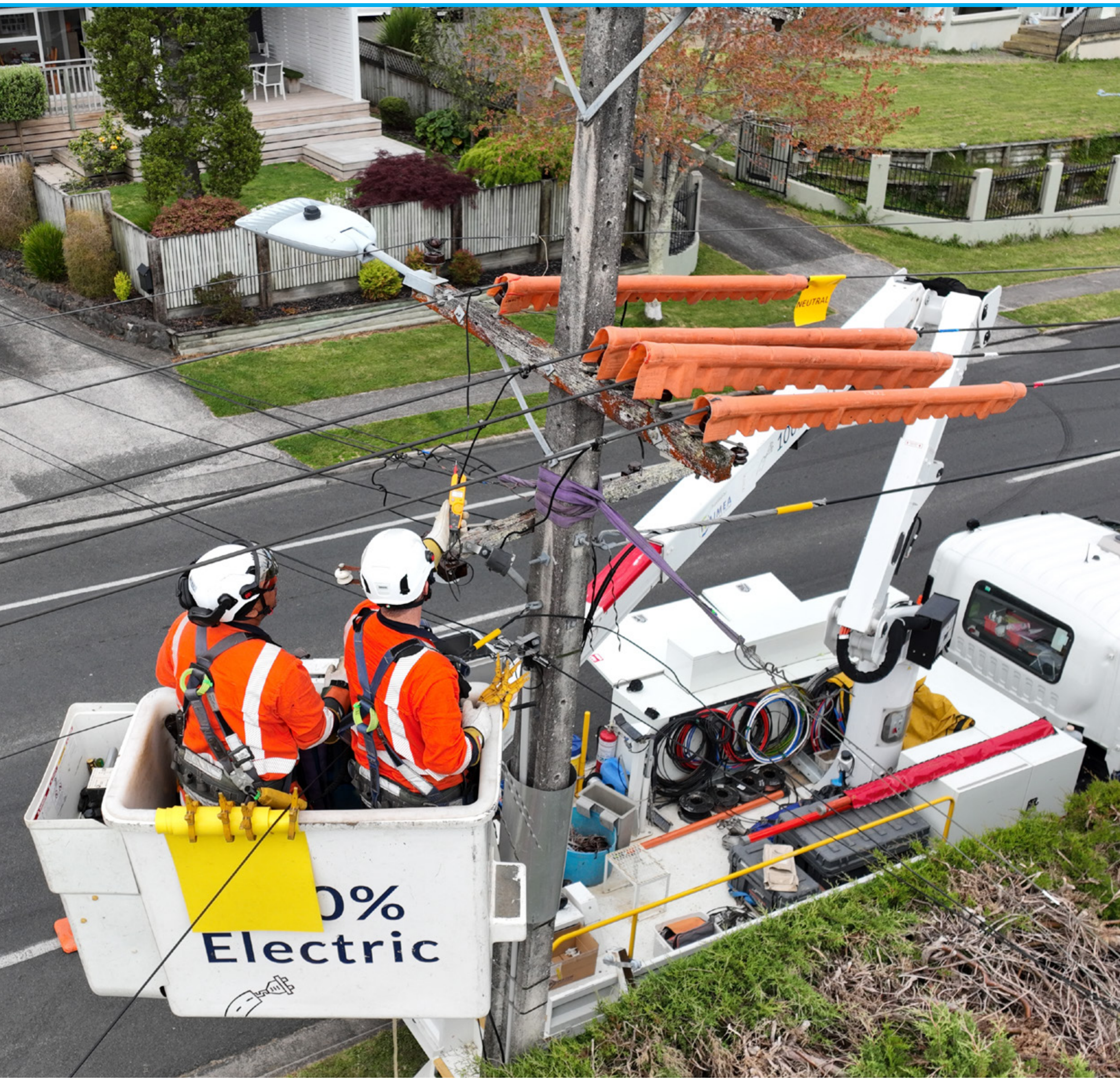
The Asset Renewal forecast expenditure is $2.9M more than the published 2024 AMP, moving from $228M to $231M over the FY26-FY34 period.

From FY28 and consistent with last year's AMP, there will be an increase in expenditure on ring main units, LV underground cables and substation equipment replacements to address the age-related condition of asset fleets.

In FY25, we commenced a review of the asset renewal strategies, and this work is ongoing through FY26 which also includes the implementation of the Copperleaf application. Indications from the work to date are that there may be additional increases in outer years as all asset categories are revalidated within the Copperleaf solution. A full update will be provided in next year's AMP.

FIGURE 11 Asset Renewal Capital Expenditure




NEUTRAL
0%
Electric

NON-NETWORK - CAPEX

FORECAST EXPENDITURE FROM FY26 THROUGH FY35

$89.0M

DELTA

-$1.0M

FORECAST EXPENDITURE VS THE PLAN

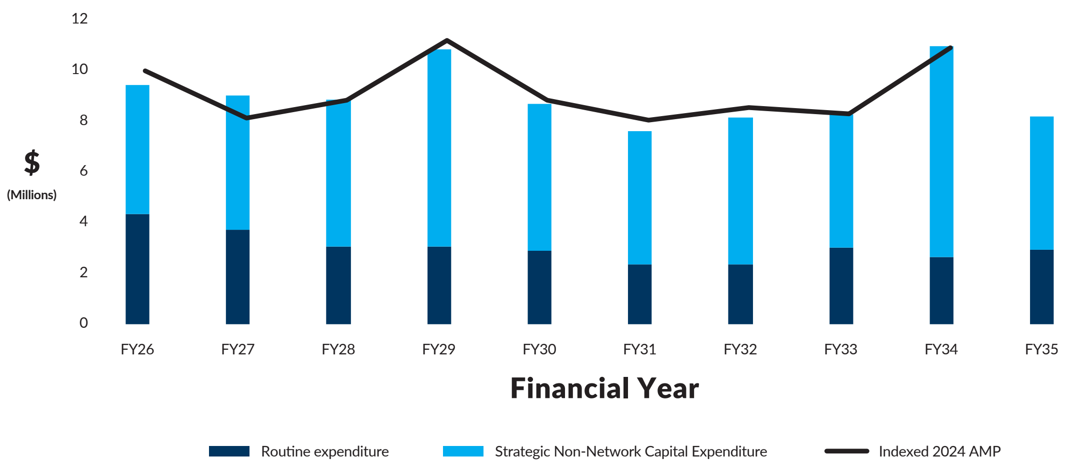
3.2.4 Non-Network - CAPEX

This is expected to reduce by $1.0M compared to the 2024 AMP, partly due to a saving/reduction of $500k in Itron metering costs in FY26. The FY25 programme was largely delivered to forecast including the SAP to S/4Hana upgrade.

There has been some reclassification of projects as follows:

- A digital programme of work has been separated out within the atypical expenditure category. This had been included within "other projects or programmes" category in the 2024 AMP.
- Work included as atypical Building/Facilities expenditure in FY24 has been reclassified in FY25 under the routine Property, Plant and Equipment/Facilities area.

FIGURE 12 Non-Network Capital Expenditure



TOTAL - CAPEX

FORECAST EXPENDITURE FROM FY26 THROUGH FY35

$984.8M

DELTA

-$0.7M

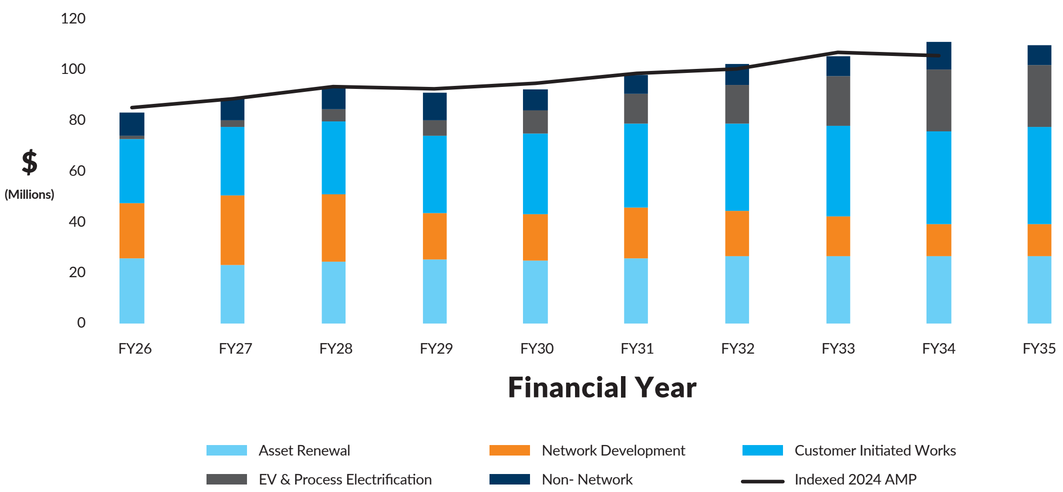
FORECAST EXPENDITURE VS THE PLAN

3.2.5 Total - CAPEX

The changes in capital expenditure, from the 2024 AMP (indexed to this year's costs), over the previous AMP period, can be summarised as a total decrease of $0.7M.

Customer Initiated Works	-$14.0M
Asset Renewal	+$2.9M
Network Development	+$11.4M
Non-Network - CAPEX	-$1.0M

FIGURE 13 Total Capital Expenditure



3.3
WHAT MATERIAL CHANGES ARE THERE TO FORECAST OPERATIONAL EXPENDITURE?

NETWORK - OPEX

FORECAST EXPENDITURE FROM FY26 THROUGH FY35

$139.6M

DELTA

+$10.0M

FORECAST EXPENDITURE VS THE PLAN

3.3.1 Network - OPEX

We have increased our Proactive Maintenance budget to support targeted inspections and investigation programmes. This includes increased costs for Dissolved Gas Analysis, increases in the number of Partial Discharge testing on HV cables and a higher number of 'cable location' requests. These have all been successful in reducing the risk of unplanned outages and potential costly repairs.

We have updated our vegetation management policy to help control the risk of network outages during high wind events. Overall, there is an increase in budget of $780k pa to reduce the number of high priority growth sites that are within the growth limits specified in the regulations. This budget increase also includes traffic management cost increases.

Within the Asset Replacement and Renewal area we have also made allowance for tapping of distribution transformers to address voltage issues that are visible from smart meter data analysis.

This has resulted in an increase of $10.0M from FY26 to FY34 compared to our 2024 AMP.

FIGURE 14 Network Operational Expenditure

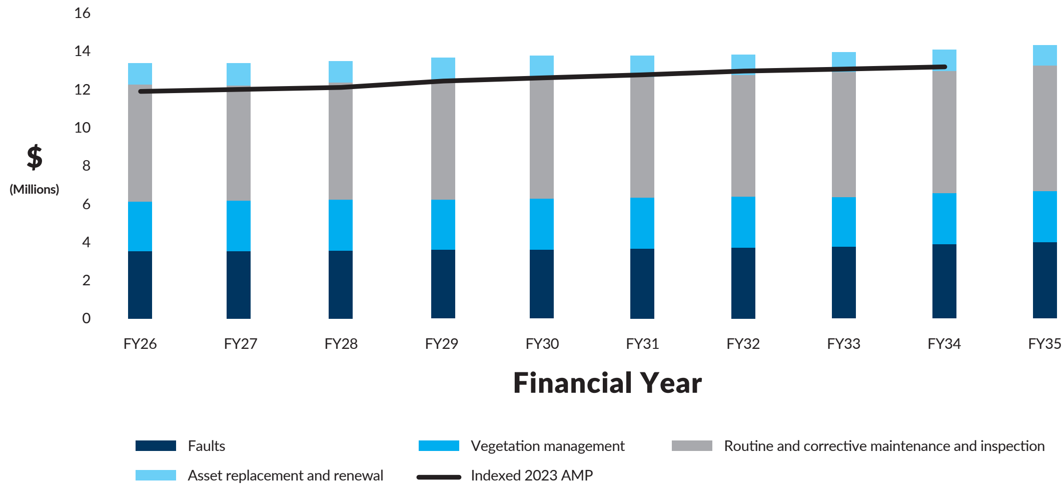
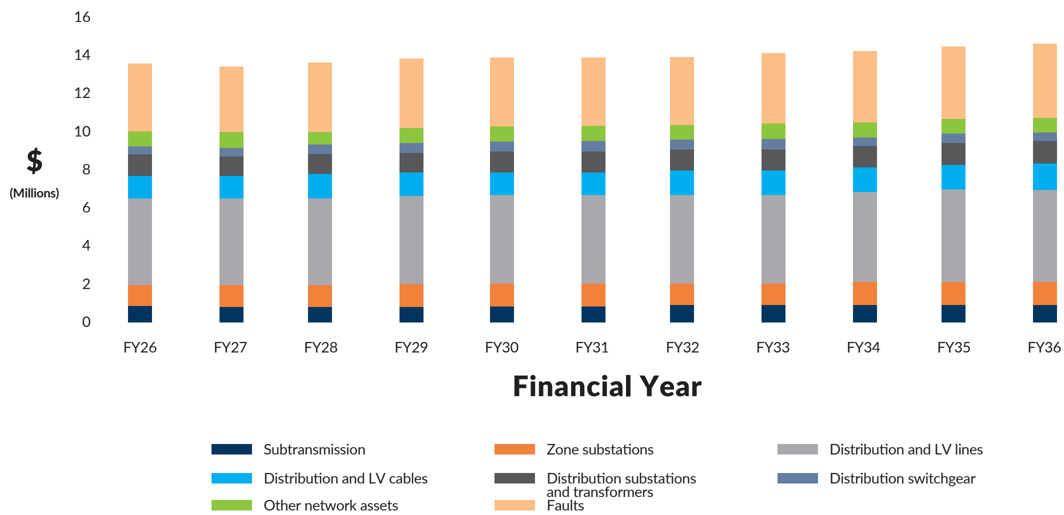


FIGURE 15 Network OPEX Broken Down By Asset Category



NON-NETWORK - OPEX

FORECAST EXPENDITURE FROM FY26 THROUGH FY35

$333.5M

DELTA

-$6.9M

FORECAST EXPENDITURE VS THE PLAN

3.3.2 Non-Network - OPEX

The changes in operational expenditure, from the 2024 AMP (indexed to this year's costs), over the previous AMP period, can be summarised as:

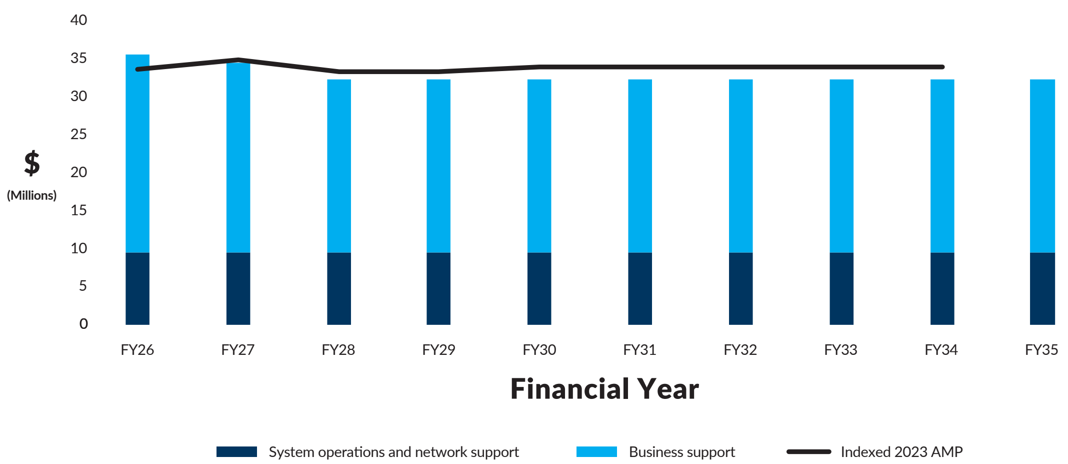
System Operations	-$2.7M
Business Support	-$4.2M

This has resulted in a total reduction of $6.9M, across the previous AMP period, as illustrated in Figure 16.

Last year the 2024 AMP included a $43.8M uplift in non-network OPEX from the 2023 AMP. This was to support the significant work required as part of our digital transformation. The activation of our digital strategy will ensure our business has systems and processes in place that allow our staff and contractors to make efficient decisions based on up-to-date data

This year's reduction is due to expected process efficiency and savings in outer years as the benefits from the program take effect.

FIGURE 16 Non-Network Operational Expenditure



TOTAL - OPEX

FORECAST EXPENDITURE FROM FY26 THROUGH FY35

$473.1M

DELTA

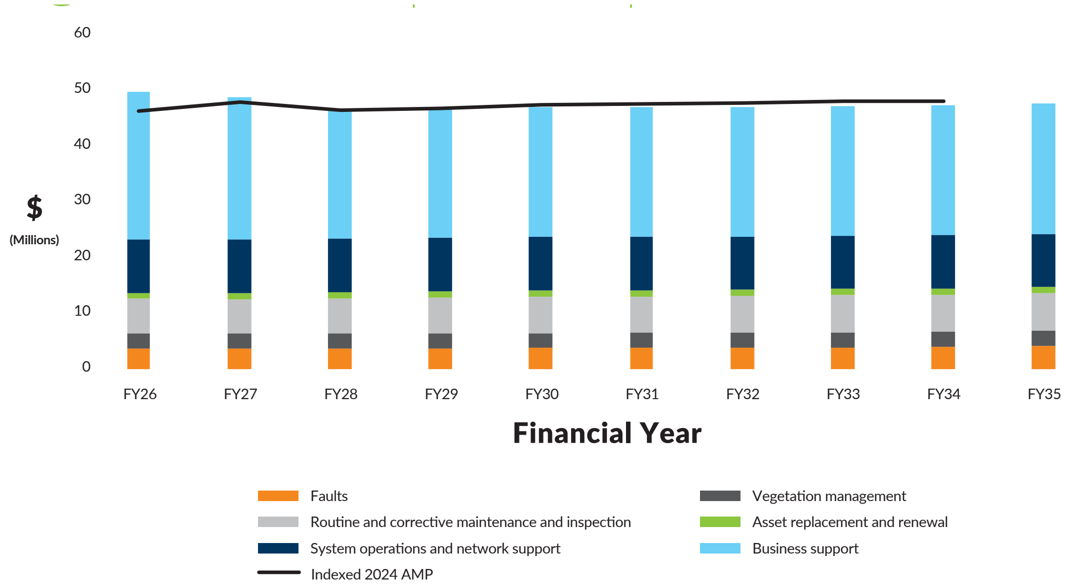
+$3.1M

FORECAST EXPENDITURE VS THE PLAN

3.3.3 Total - OPEX

The changes in operational expenditure, from the 2024 AMP (indexed to this year's costs), over the previous AMP period, can be summarised as a total increase of $3.1M, as illustrated below.

FIGURE 17 Total Operational Expenditure



3.4
MATERIAL CHANGES TO ASSET MANAGEMENT PRACTICE

In FY25 we successfully achieved certification to ISO55001:2014 the international standard for Asset Management. This Standard is recognised by the NZ Commerce Commission as evidence of best practice.

Our focus is continuing improvement across the business for the effective planning and delivery of asset management activities. This includes a robust schedule of internal audits to ensure our activities and processes are continually reviewed and improved.

We have internal stakeholder meetings held monthly, with the financials and delivery against the Annual Works Plan, reviewed in two separate meetings. One is at a granular level (project by project) including the delivery partners. The second is our monthly business performance meeting (BPM) which addresses the progress against the plan. At the programme level, the risk is assessed and mitigated by delivery to the forecast. The BPM reviews KPI's for our applicable Strategic Asset Management objectives, as defined in our Strategic Asset Management Plan (SAMP). These activities support the asset management system and our ISO55001:2014 certification.

Work continues to develop standard designs to maintain quality, standardisation and cost efficiency. Asset categories, which have standardised designs, include most overhead line assets, distribution transformers and switchgear, LV pillars and specific zone substation equipment.

Standard design development targets asset categories where there is a large number of similar assets and where standardisation has the greatest benefit. Standardised designs are typically identified during asset renewal processes and development of asset maintenance strategies.

3.5
MATERIAL CHANGES TO PLANNED NETWORK OUTAGES

In FY24 we saw a significant increase in the amount of planned SAIDI impacting our network as a result of additional planned work being delivered, especially with the introduction of Tier 1 service providers. The actual FY24 SAIDI was 58.9 minutes vs the target of 35.6 minutes.

Our performance has historically been very good when compared to the wider industry. However, we acknowledge that the reliance on electricity is increasing with a shift to a decarbonised economy. We actively investigate methods to reduce outages as much as possible, wherever it is cost effective. This includes reviewing our processes, changing our network standards, and investing in plant and equipment, including non-wire solutions.

In FY25, outage numbers have again increased but better overall outage advertising and consolidation of outages has controlled the planned SAIDI, and this is forecast to 52.0 minutes. This is the forecast level per annum for the remainder of the 10-year AMP forecast period.


WeEV

CHAPTER 4

Schedules

AMP PLANNING PERIOD
1 APRIL 2025 –
31 MARCH 2035

Te Whakamōhiohio

4.1 SCHEDULE 11A:
Report on forecast capital expenditure

11a(i): Expenditure on Assets Forecast	Current Year CY 31 Mar 25	CY+1 31 Mar 26	CY+2 31 Mar 27
	$000 (in nominal dollars)		
Consumer connection	27,130	24,433	27,166
System growth	11,097	7,456	12,719
Asset replacement and renewal	25,882	26,027	23,535
Asset relocations	1,456	2,021	2,145
Reliability, safety and environment:			
Quality of supply	2,985	2,060	1,520
Legislative and regulatory	2,148	1,848	2,111
Other reliability, safety and environment	10,392	10,770	13,352
Total reliability, safety and environment	15,525	14,677	16,983
EXPENDITURE ON NETWORK ASSETS	**81,090**	**74,614**	**82,548**
Expenditure on non-network assets	14,276	9,313	9,078
EXPENDITURE ON ASSETS	**95,366**	**83,927**	**91,626**
PLUS Cost of financing	-	-	-
LESS Value of capital contributions	12,459	5,389	6,018
PLUS Value of vested assets	-	-	-
CAPITAL EXPENDITURE FORECAST	**82,908**	**78,539**	**85,608**
Assets commissioned	87,907	78,757	85,255

CY+3 31 Mar 28	CY+4 31 Mar 29	CY+5 31 Mar 30	CY+6 31 Mar 31	CY+7 31 Mar 32	CY+8 31 Mar 33	CY+9 31 Mar 34	CY+10 31 Mar 35
30,538	33,580	36,628	39,514	42,854	47,316	51,873	57,189
21,599	15,557	17,871	21,187	22,974	23,939	26,714	25,993
25,580	26,828	27,051	28,704	30,183	30,896	31,514	32,145
2,276	2,353	2,435	2,523	2,614	2,706	2,803	2,904
2,237	1,709	1,721	1,733	1,768	1,803	1,840	1,876
770	807	812	817	833	850	-	-
5,930	5,104	5,142	6,437	5,935	5,514	3,948	2,856
8,937	7,619	7,674	8,987	8,536	8,167	5,788	4,733
88,929	**85,937**	**91,660**	**100,915**	**107,161**	**113,024**	**118,692**	**122,964**
9,098	11,376	9,282	8,336	9,066	9,425	12,683	9,680
98,028	**97,313**	**100,941**	**109,251**	**116,227**	**122,448**	**131,375**	**132,644**
-	-	-	-	-	-	-	-
6,775	7,402	8,044	8,679	9,418	10,420	11,440	12,636
-	-	-	-	-	-	-	-
91,253	**89,911**	**92,897**	**100,572**	**106,808**	**112,028**	**119,935**	**120,008**
90,970	89,979	92,748	100,188	106,497	111,767	119,539	120,004

4.1 SCHEDULE 11A:
Report on forecast capital expenditure - Continued

	Current Year CY 31 Mar 25	CY+1 31 Mar 26	CY+2 31 Mar 27
	$000 (in constant dollars)		
Consumer connection	27,130	24,433	26,633
System growth	11,097	7,456	12,470
Asset replacement and renewal	25,882	26,027	23,074
Asset relocations	1,456	2,021	2,103
Reliability, safety and environment:			
Quality of supply	2,985	2,060	1,490
Legislative and regulatory	2,148	1,848	2,070
Other reliability, safety and environment	10,392	10,770	13,090
Total reliability, safety and environment	**15,525**	**14,677**	**16,650**
EXPENDITURE ON NETWORK ASSETS	**81,090**	**74,614**	**80,930**
Expenditure on non-network assets	14,276	9,313	8,900
EXPENDITURE ON ASSETS	**95,366**	**83,927**	**89,830**

Subcomponents of expenditure on assets (where known)			
Energy efficiency and demand side management, reduction of energy losses	-	-	-
Overhead to underground conversion	26	30	30
Research and development	-	-	-

CY+3 31 Mar 28	CY+4 31 Mar 29	CY+5 31 Mar 30	CY+6 31 Mar 31	CY+7 31 Mar 32	CY+8 31 Mar 33	CY+9 31 Mar 34	CY+10 31 Mar 35
29,353	31,643	33,838	35,789	38,053	41,191	44,273	47,854
20,760	14,660	16,510	19,190	20,400	20,840	22,800	21,750
24,586	25,281	24,991	25,998	26,802	26,897	26,897	26,897
2,187	2,217	2,250	2,285	2,321	2,356	2,392	2,430
2,150	1,610	1,590	1,570	1,570	1,570	1,570	1,570
740	760	750	740	740	740	-	-
5,700	4,810	4,750	5,830	5,270	4,800	3,370	2,390
8,590	**7,180**	**7,090**	**8,140**	**7,580**	**7,110**	**4,940**	**3,960**
85,476	**80,981**	**84,679**	**91,402**	**95,156**	**98,394**	**101,302**	**102,891**
8,745	10,720	8,575	7,550	8,050	8,205	10,825	8,100
94,221	**91,701**	**93,254**	**98,952**	**103,206**	**106,599**	**112,127**	**110,991**
-	-	-	-	-	-	-	-
31	31	31	32	32	33	33	34
-	-	-	-	-	-	-	-

4.1 SCHEDULE 11A:
Report on forecast capital expenditure - Continued

	Current Year CY 31 Mar 25	CY+1 31 Mar 26	CY+2 31 Mar 27
Difference between nominal and constant price forecasts	**$000**		
Consumer connection	-	-	533
System growth	-	-	249
Asset replacement and renewal	-	-	461
Asset relocations	-	-	42
Reliability, safety and environment:			
Quality of supply	-	-	30
Legislative and regulatory	-	-	41
Other reliability, safety and environment	-	-	262
Total reliability, safety and environment	**-**	**-**	**333**
Expenditure on network assets	**-**	**-**	**1,619**
Expenditure on non-network assets	-	-	178
Expenditure on assets	**-**	**-**	**1,797**

CY+3 31 Mar 28	CY+4 31 Mar 29	CY+5 31 Mar 30	CY+6 31 Mar 31	CY+7 31 Mar 32	CY+8 31 Mar 33	CY+9 31 Mar 34	CY+10 31 Mar 35
1,186	1,937	2,789	3,725	4,801	6,125	7,600	9,336
839	897	1,361	1,997	2,574	3,099	3,914	4,243
993	1,547	2,060	2,706	3,381	3,999	4,617	5,247
88	136	185	238	293	350	411	474
87	99	131	163	198	233	270	306
30	47	62	77	93	110	-	-
230	294	392	607	665	714	578	466
347	**439**	**584**	**847**	**956**	**1,057**	**848**	**773**
3,453	**4,957**	**6,980**	**9,513**	**12,005**	**14,630**	**17,390**	**20,073**
353	656	707	786	1,016	1,220	1,858	1,580
3,807	**5,613**	**7,687**	**10,299**	**13,021**	**15,850**	**19,248**	**21,653**

4.1 SCHEDULE 11A:
Report on forecast capital expenditure - Continued

11a(ii): Consumer Connection	Current Year CY 31 Mar 25	CY+1 31 Mar 26	CY+2 31 Mar 27	CY+3 31 Mar 28	CY+4 31 Mar 29	CY+5 31 Mar 30
	$000 (in constant prices)					
Consumer types defined by EDB*						
Residential Customers	20,603	16,038	17,342	18,757	20,353	21,754
Business Customers	1	1,191	1,404	1,986	2,463	2,975
Large Customers - Low Voltage 400V	6,526	7,092	7,393	7,621	7,837	8,118
Large Customers - Medium Voltage 11kV	-	111	494	989	990	991
Large Customers - High Voltage 33kV	-	-	-	-	-	-
CONSUMER CONNECTION EXPENDITURE	**27,130**	**24,433**	**26,633**	**29,353**	**31,643**	**33,838**
LESS Capital contributions funding consumer connection	8,155	3,626	4,050	4,569	4,994	5,411
CONSUMER CONNECTION LESS CAPITAL CONTRIBUTIONS	**18,975**	**20,806**	**22,583**	**24,783**	**26,649**	**28,428**

11a(iii): System Growth	Current Year CY 31 Mar 25	CY+1 31 Mar 26	CY+2 31 Mar 27	CY+3 31 Mar 28	CY+4 31 Mar 29	CY+5 31 Mar 30
	$000 (in constant prices)					
Subtransmission	1,135	917	2,050	1,540	450	670
Zone substations	3,424	-	4,570	12,410	7,510	6,490
Distribution and LV lines	-	-	-	-	-	-
Distribution and LV cables	6,378	6,334	5,250	5,520	5,100	6,740
Distribution substations and transformers	160	205	600	1,290	1,600	2,610
Distribution switchgear	-	-	-	-	-	-
Other network assets	-	-	-	-	-	-
SYSTEM GROWTH EXPENDITURE	**11,097**	**7,456**	**12,470**	**20,760**	**14,660**	**16,510**
LESS Capital contributions funding system growth	-	-	-	-	-	-
SYSTEM GROWTH LESS CAPITAL CONTRIBUTIONS	**11,097**	**7,456**	**12,470**	**20,760**	**14,660**	**16,510**

	Current Year CY 31 Mar 25	CY+1 31 Mar 26	CY+2 31 Mar 27	CY+3 31 Mar 28	CY+4 31 Mar 29	CY+5 31 Mar 30
11a(iv): Asset Replacement and Renewal	**$000 (in constant prices)**					
Subtransmission	906	772	742	723	740	847
Zone substations	207	606	776	1,747	1,713	1,727
Distribution and LV lines	13,451	12,716	12,091	11,767	12,179	11,667
Distribution and LV cables	1,575	1,189	1,115	1,354	1,427	1,628
Distribution substations and transformers	1,157	2,870	2,487	2,563	2,512	2,407
Distribution switchgear	5,962	6,564	5,548	6,124	6,406	6,419
Other network assets	2,624	1,311	315	309	303	297
ASSET REPLACEMENT AND RENEWAL EXPENDITURE	**25,882**	**26,027**	**23,074**	**24,586**	**25,281**	**24,991**
LESS Capital contributions funding asset replacement and renewal	-	-	-	-	-	-
ASSET REPLACEMENT AND RENEWAL LESS CAPITAL CONTRIBUTIONS	**25,882**	**26,027**	**23,074**	**24,586**	**25,281**	**24,991**

	Current Year CY 31 Mar 25	CY+1 31 Mar 26	CY+2 31 Mar 27	CY+3 31 Mar 28	CY+4 31 Mar 29	CY+5 31 Mar 30
11a(v): Asset Relocations	**$000 (in constant prices)**					
Project or programme*						
Undergrounding	26	30	30	31	31	31
All other project or programmes - asset relocations	1,430	1,991	2,072	2,157	2,186	2,218
ASSET RELOCATIONS EXPENDITURE	**1,456**	**2,021**	**2,103**	**2,187**	**2,217**	**2,250**
LESS Capital contributions funding asset relocations	4,303	1,762	1,850	1,943	1,981	2,021
ASSET RELOCATIONS LESS CAPITAL CONTRIBUTIONS	**(2,847)**	**259**	**252**	**245**	**236**	**229**

4.1 SCHEDULE 11A:
Report on forecast capital expenditure - Continued

	Current Year CY 31 Mar 25	CY+1 31 Mar 26	CY+2 31 Mar 27	CY+3 31 Mar 28	CY+4 31 Mar 29	CY+5 31 Mar 30
11a(vi): Quality of Supply	**$000 (in constant prices)**					
Project or programme*						
Distribution transformer and LV feeder upgrade projects identified via smart meters	688	838	860	860	890	880
Power Quality Analyser Installation	546	-	-	700	110	110
Smart Meter Distribution Transformer Monitoring	175	872	630	590	610	600
Power Quality Complaint Resolution-Reactive Capex			-	-	-	-
All other projects or programmes - quality of supply	1,576	350				
QUALITY OF SUPPLY EXPENDITURE	**2,985**	**2,060**	**1,490**	**2,150**	**1,610**	**1,590**
LESS Capital contributions funding quality of supply	-	-	-	-	-	-
QUALITY OF SUPPLY LESS CAPITAL CONTRIBUTIONS	**2,985**	**2,060**	**1,490**	**2,150**	**1,610**	**1,590**

	Current Year CY 31 Mar 25	CY+1 31 Mar 26	CY+2 31 Mar 27	CY+3 31 Mar 28	CY+4 31 Mar 29	CY+5 31 Mar 30
11a(vii): Legislative and Regulatory	**$000 (in constant prices)**					
Project or programme*						
Line clearance mitigation	56	329	340	-	-	-
NER protection changes through TWH Network	359	120	-	-	-	-
Seismic upgrades of substations	170	1,399	1,730	740	760	750
Transpower Lines Clearance Project	299	-	-	-	-	-
All other projects or programmes - legislative and regulatory	1,264	-	-	-	-	-
LEGISLATIVE AND REGULATORY EXPENDITURE	**2,148**	**1,848**	**2,070**	**740**	**760**	**750**
LESS Capital contributions funding legislative and regulatory	-	-	-	-	-	-
LEGISLATIVE AND REGULATORY LESS CAPITAL CONTRIBUTIONS	**2,148**	**1,848**	**2,070**	**740**	**760**	**750**

4.1 SCHEDULE 11A:
Report on forecast capital expenditure - Continued

11a(viii): Other Reliability, Safety and Environment	Current Year CY 31 Mar 25	CY+1 31 Mar 26	CY+2 31 Mar 27	CY+3 31 Mar 28	CY+4 31 Mar 29	CY+5 31 Mar 30
	$000 (in constant prices)					
Project or programme*						
Air-conditioning for substations	84	153	140	140	-	-
Daisy Chain Transformer Unbundling	686	778	290	290	300	290
Fibre installation (Discretionary)	4	72	70	70	80	80
Fibre routes	1,228	1,109	-	800	830	820
IoT Network Measurement	98	270	290	290	300	290
LV visibility and data insights	625	-	360	340	350	340
Massey 11kV Switchgear Replacement	133	-	-	-	-	-
Multi Circuit Rationalisation		-	-	-	340	340
Network Reliability Project	404	1,210	740	680	700	700
Raglan Area Resilience	3,902	1,398	-	-	-	-
Restricted Space Improvements	33	-	-	260	260	-
Serial radio	29	-	-	-	-	-
Te Uku Zone Substation Upgrade	2,238	-	-	-	-	-
WEACB6 Reliability Upgrade	637	-	-	-	-	-
Zone substation oil containment	-	-	-	-	-	360
Network Resilience Initiatives	-	2,596	2,880	1,070	1,650	1,530
SCADA WAN Visibility Upgrade	-	112	-	-	-	-
SCADA WAN route diversity	-	46	-	-	-	-
Protection comms improvement	26	23	-	-	-	-
Lock replacement programme	-	40	530	-	-	-
LV supply for PUK SS	-	225	-	-	-	-
TEUCB1 reinforcement for Raglan 11kV backfeed support	-	893	4,100	-	-	-
WEA CB6 resilience non- network solution	-	200	-	-	-	-
Sandwich Substation Protection and Comms Upgrade	-	328	-	-	-	-
Weavers Zone Substation Resilience	-	938	3,690	1,760	-	-
All other projects or programmes - other	265	380	-	-	-	-
OTHER RELIABILITY, SAFETY AND ENVIRONMENT EXPENDITURE	**10,392**	**10,770**	**13,090**	**5,700**	**4,810**	**4,750**
LESS Capital contributions funding other reliability, safety and environment	-	-	-	-	-	-
OTHER RELIABILITY, SAFETY AND ENVIRONMENT LESS CAPITAL CONTRIBUTIONS	**10,392**	**10,770**	**13,090**	**5,700**	**4,810**	**4,750**

11a(ix): Non-Network Assets	$000 (in constant prices) Current Year CY 31 Mar 25	CY+1 31 Mar 26	CY+2 31 Mar 27	CY+3 31 Mar 28	CY+4 31 Mar 29	CY+5 31 Mar 30
ROUTINE EXPENDITURE						
Project or programme*						
Computer Equipment	230	553	300	425	700	575
Computer Software	176	524	150	150	150	150
Property, Plant and Equipment / Facilities	2,498	1,743	2,000	1,000	800	800
Motor Vehicles	-	340	-	220	120	100
Smartmeters	774	903	1,000	1,000	1,000	1,000
Easements	245	250	250	250	250	250
All other projects or programmes - routine expenditure						
ROUTINE EXPENDITURE	**3,923**	**4,313**	**3,700**	**3,045**	**3,020**	**2,875**
ATYPICAL EXPENDITURE						
Project or programme*						
Land	-	-	-	-	-	-
Buildings	4,603	-	-	-	-	-
DSO/NIP Projects	1,154	1,000	1,200	1,200	1,200	1,200
Digital Program	3,118	3,000	3,000	3,000	3,000	3,000
ITRON	-	-	-	500	2,500	500
ALL OTHER PROJECTS OR PROGRAMMES - ATYPICAL EXPENDITURE	**1,479**	**1,000**	**1,000**	**1,000**	**1,000**	**1,000**
Atypical expenditure	10,354	5,000	5,200	5,700	7,700	5,700
EXPENDITURE ON NON-NETWORK ASSETS	**14,276**	**9,313**	**8,900**	**8,745**	**10,720**	**8,575**

4.1 SCHEDULE 11B:
Report on forecast operational expenditure

Operational Expenditure Forecast	Current Year CY 31 Mar 25	CY+1 31 Mar 26	CY+2 31 Mar 27
	$000 (in nominal dollars)		
Service interruptions and emergencies	3,937	3,533	3,639
Vegetation management	1,815	2,700	2,754
Routine and corrective maintenance and inspection	4,973	6,209	6,248
Asset replacement and renewal	973	1,112	1,134
NETWORK OPEX	**11,699**	**13,553**	**13,775**
System operations and network support	9,023	9,497	9,687
Business support	24,957	26,461	25,970
Non-network solutions provided by a related party or third party - Not Required before DY2025	-	50	51
NON-NETWORK OPEX	**33,980**	**36,007**	**35,708**
OPERATIONAL EXPENDITURE	**45,678**	**49,561**	**49,483**

	Current Year CY 31 Mar 25	CY+1 31 Mar 26	CY+2 31 Mar 27
	$000 (in constant prices)		
Service interruptions and emergencies	3,937	3,533	3,568
Vegetation management	1,815	2,700	2,700
Routine and corrective maintenance and inspection	4,973	6,209	6,126
Asset replacement and renewal	973	1,112	1,112
NETWORK OPEX	**11,699**	**13,553**	**13,505**
System operations and network support	9,023	9,497	9,497
Business support	24,957	26,461	25,461
Non-network solutions provided by a related party or third party - Not Required before DY2025	-	50	50
NON-NETWORK OPEX	**33,980**	**36,007**	**35,007**
OPERATIONAL EXPENDITURE	**45,678**	**49,561**	**48,513**

CY+3 31 Mar 28	CY+4 31 Mar 29	CY+5 31 Mar 30	CY+6 31 Mar 31	CY+7 31 Mar 32	CY+8 31 Mar 33	CY+9 31 Mar 34	CY+10 31 Mar 35
3,749	3,863	3,979	4,099	4,223	4,351	4,660	4,848
2,809	2,865	2,923	2,981	3,041	3,101	3,164	3,227
6,514	6,807	7,010	7,119	7,311	7,589	7,603	7,996
1,157	1,180	1,203	1,227	1,252	1,277	1,302	1,329
14,229	**14,715**	**15,115**	**15,427**	**15,827**	**16,318**	**16,729**	**17,399**
9,881	10,078	10,280	10,485	10,695	10,909	11,127	11,350
24,200	24,525	25,016	25,516	25,801	26,317	26,843	27,380
52	212	216	221	450	459	469	478
34,133	**34,816**	**35,512**	**36,222**	**36,946**	**37,685**	**38,439**	**39,208**
48,362	**49,530**	**50,627**	**51,649**	**52,773**	**54,003**	**55,168**	**56,607**

CY+3 31 Mar 28	CY+4 31 Mar 29	CY+5 31 Mar 30	CY+6 31 Mar 31	CY+7 31 Mar 32	CY+8 31 Mar 33	CY+9 31 Mar 34	CY+10 31 Mar 35
3,604	3,640	3,676	3,713	3,750	3,788	3,977	4,057
2,700	2,700	2,700	2,700	2,700	2,700	2,700	2,700
6,261	6,414	6,476	6,448	6,492	6,606	6,489	6,691
1,112	1,112	1,112	1,112	1,112	1,112	1,112	1,112
13,676	**13,866**	**13,964**	**13,973**	**14,054**	**14,206**	**14,278**	**14,559**
9,497	9,497	9,497	9,497	9,497	9,497	9,497	9,497
23,261	23,111	23,111	23,111	22,911	22,911	22,911	22,911
50	200	200	200	400	400	400	400
32,807	**32,807**	**32,807**	**32,807**	**32,807**	**32,807**	**32,807**	**32,807**
46,484	**46,673**	**46,771**	**46,780**	**46,861**	**47,013**	**47,085**	**47,366**

4.1 SCHEDULE 11B:
Report on forecast operational expenditure - Continued

Subcomponents of operational expenditure (where known)	Current Year CY 31 Mar 25	CY+1 31 Mar 26	CY+2 31 Mar 27
	$000 (in constant prices)		
Energy efficiency and demand side management, reduction of energy losses	285	291	291
Direct billing*	N/A	N/A	N/A
Research and Development	50	50	50
Insurance	951	1,046	1,194

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

Difference between nominal and real forecasts	Current Year CY 31 Mar 25	CY+1 31 Mar 26	CY+2 31 Mar 27
	$000		
Service interruptions and emergencies	-	-	71
Vegetation management	-	-	54
Routine and corrective maintenance and inspection	-	-	123
Asset replacement and renewal	-	-	22
NETWORK OPEX	-	**-**	**270**
System operations and network support	-	-	190
Business support	-	-	509
Non-network solutions provided by a related party or third party - Not Required before DY2025	-	-	1
Non-network opex	-	-	700
OPERATIONAL EXPENDITURE	**-**	**-**	**970**

CY+3 31 Mar 28	CY+4 31 Mar 29	CY+5 31 Mar 30	CY+6 31 Mar 31	CY+7 31 Mar 32	CY+8 31 Mar 33	CY+9 31 Mar 34	CY+10 31 Mar 35
291	291	291	291	291	291	291	291
N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
50	50	50	50	50	50	50	50
1,314	1,445	1,590	1,749	1,924	2,116	2,328	2,561

CY+3 31 Mar 28	CY+4 31 Mar 29	CY+5 31 Mar 30	CY+6 31 Mar 31	CY+7 31 Mar 32	CY+8 31 Mar 33	CY+9 31 Mar 34	CY+10 31 Mar 35
146	223	303	386	473	563	683	791
109	165	223	281	341	401	463	527
253	393	534	671	819	982	1,114	1,305
45	68	92	116	140	165	191	217
553	**849**	**1,151**	**1,454**	**1,773**	**2,112**	**2,451**	**2,840**
384	581	783	988	1,198	1,412	1,630	1,853
940	1,415	1,905	2,405	2,890	3,406	3,933	4,470
2	12	16	21	50	59	69	78
1,325	2,008	2,704	3,415	4,139	4,878	5,632	6,400
1,878	**2,857**	**3,855**	**4,869**	**5,912**	**6,990**	**8,083**	**9,241**

4.2 SCHEDULE 12A:
Report on asset condition

Voltage	Asset category	Asset class	Units
All	Overhead Line	Concrete poles / steel structure	No.
All	Overhead Line	Wood poles	No.
All	Overhead Line	Other pole types	No.
HV	Subtransmission Line	Subtransmission OH up to 66kV conductor	km
HV	Subtransmission Line	Subtransmission OH 110kV+ conductor	km
HV	Subtransmission Cable	Subtransmission UG up to 66kV (XLPE)	km
HV	Subtransmission Cable	Subtransmission UG up to 66kV (Oil pressurised)	km
HV	Subtransmission Cable	Subtransmission UG up to 66kV (Gas pressurised)	km
HV	Subtransmission Cable	Subtransmission UG up to 66kV (PILC)	km
HV	Subtransmission Cable	Subtransmission UG 110kV+ (XLPE)	km
HV	Subtransmission Cable	Subtransmission UG 110kV+ (Oil pressurised)	km
HV	Subtransmission Cable	Subtransmission UG 110kV+ (Gas Pressurised)	km
HV	Subtransmission Cable	Subtransmission UG 110kV+ (PILC)	km
HV	Subtransmission Cable	Subtransmission submarine cable	km
HV	Zone substation Buildings	Zone substations up to 66kV	No.
HV	Zone substation Buildings	Zone substations 110kV+	No.
HV	Zone substation switchgear	22/33kV CB (Indoor)	No.
HV	Zone substation switchgear	22/33kV CB (Outdoor)	No.
HV	Zone substation switchgear	33kV Switch (Ground Mounted)	No.
HV	Zone substation switchgear	33kV Switch (Pole Mounted)	No.
HV	Zone substation switchgear	33kV RMU	No.
HV	Zone substation switchgear	50/66/110kV CB (Indoor)	No.
HV	Zone substation switchgear	50/66/110kV CB (Outdoor)	No.
HV	Zone substation switchgear	3.3/6.6/11/22kV CB (ground mounted)	No.
HV	Zone substation switchgear	3.3/6.6/11/22kV CB (pole mounted)	No.

Asset condition at start of planning period (percentage of units by grade)

H1	H2	H3	H4	H5	Grade unknown	Data accuracy (1–4)	% of asset forecast to be replaced in next 5 years
-	0.29%	11.43%	53.46%	34.48%	0.34%	3	3.49%
-	0.94%	30.09%	38.97%	29.63%	0.36%	3	9.76%
-	1.67%	-	25.00%	73.33%	-	3	-
-	0.35%	6.38%	28.20%	65.08%	-	2	-
-	-	-	-	-	-	N/A	-
-	-	2.11%	2.85%	95.04%	-	2	0.67%
-	-	-	-	-	-	N/A	-
-	-	-	-	-	-	N/A	-
-	-	-	97.07%	2.93%	-	2	-
-	-	-	-	-	-	N/A	-
-	-	-	-	-	-	N/A	-
-	-	-	-	-	-	N/A	-
-	-	-	-	-	-	N/A	-
-	-	-	-	-	-	N/A	-
-	-	7.69%	92.31%	-	-	4	-
-	-	-	-	-	-	N/A	-
-	-	-	25.00%	75.00%	-	4	-
-	-	50.00%	-	50.00%	-	4	-
-	-	-	-	-	-	N/A	-
-	6.67%	19.05%	30.95%	43.33%	-	4	-
-	-	9.52%	71.43%	19.05%	-	4	-
-	-	-	-	-	-	N/A	-
-	-	-	-	-	-	N/A	-
-	-	-	-	-	-	N/A	-
-	-	-	-	-	-	N/A	-

4.2 SCHEDULE 12A:
Report on asset condition - Continued

Voltage	Asset category	Asset class	Units
HV	Zone Substation Transformer	Zone Substation Transformers	No.
HV	Distribution Line	Distribution OH Open Wire Conductor	km
HV	Distribution Line	Distribution OH Aerial Cable Conductor	km
HV	Distribution Line	SWER conductor	km
HV	Distribution Cable	Distribution UG XLPE or PVC	km
HV	Distribution Cable	Distribution UG PILC	km
HV	Distribution Cable	Distribution Submarine Cable	km
HV	Distribution switchgear	3.3/6.6/11/22kV CB (pole mounted) - reclosers and sectionalisers	No.
HV	Distribution switchgear	3.3/6.6/11/22kV CB (Indoor)	No.
HV	Distribution switchgear	3.3/6.6/11/22kV Switches and fuses (pole mounted)	No.
HV	Distribution switchgear	3.3/6.6/11/22kV Switch (ground mounted) - except RMU	No.
HV	Distribution switchgear	3.3/6.6/11/22kV RMU	No.
HV	Distribution Transformer	Pole Mounted Transformer	No.
HV	Distribution Transformer	Ground Mounted Transformer	No.
HV	Distribution Transformer	Voltage regulators	No.
HV	Distribution Substations	Ground Mounted Substation Housing	No.
LV	LV Line	LV OH Conductor	km
LV	LV Cable	LV UG Cable	km
LV	LV Streetlighting	LV OH/UG Streetlight circuit	km
LV	Connections	OH/UG consumer service connections	No.
All	Protection	Protection relays (electromechanical, solid state and numeric)	No.
All	SCADA and communications	SCADA and communications equipment operating as a single system	Lot
All	Capacitor Banks	Capacitors including controls	No.
All	Load Control	Centralised plant	Lot
All	Load Control	Relays	No.
All	Civils	Cable Tunnels	km

Asset condition at start of planning period (percentage of units by grade)

H1	H2	H3	H4	H5	Grade unknown	Data accuracy (1–4)	% of asset forecast to be replaced in next 5 years
-	-	4.08%	26.53%	69.39%	-	4	8.16%
-	0.38%	19.72%	36.87%	43.04%	-	3	2.36%
-	-	-	-	-	-	N/A	-
-	-	-	-	-	-	N/A	-
-	1.55%	7.13%	3.58%	87.75%	-	1	0.11%
-	2.85%	22.50%	23.10%	51.56%	-	1	0.43%
-	-	-	-	-	-	N/A	-
-	-	7.80%	9.17%	72.02%	11.01%	4	6.58%
-	2.59%	18.03%	21.13%	58.25%	-	4	18.97%
-	0.28%	10.45%	21.43%	62.54%	5.30%	4	3.47%
-	-	-	-	-	-	N/A	-
-	0.20%	12.65%	35.43%	50.13%	1.59%	4	14.81%
-	0.61%	9.01%	24.11%	65.44%	0.83%	3	5.64%
-	0.09%	6.63%	57.67%	34.62%	0.99%	4	4.67%
-	-	13.33%	10.00%	43.33%	33.33%	4	6.67%
-	-	-	-	-	-	N/A	-
-	0.30%	16.39%	31.74%	51.57%	-	1	-
-	-	16.26%	25.51%	58.23%	-	1	0.26%
-	0.23%	8.38%	9.27%	82.12%	-	1	-
-	-	-	-	-	-	N/A	-
-	6.90%	36.78%	19.54%	34.10%	2.68%	3	17.03%
-	0.50%	14.72%	40.94%	43.85%	-	3	3.59%
-	-	100.00%	-	-	-	4	-
-	-	-	-	-	100.00%	4	-
-	-	-	-	-	-	N/A	-
-	-	-	-	-	-	N/A	-

4.3 SCHEDULE 12B:
Report on forecast capacity

12b(i): System Growth - Zone Substations

Existing Zone Substations	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
AVALON	16.3	24	N-1	No constraint	7.52	Winter
BORMAN	20.1	21	N-1	No constraint	0.46	Winter
BRYCE	13.5	23	N-1 switched	No constraint	9.42	Spring
CHARTWELL	16.6	26	N-1	No constraint	9.32	Winter
CLAUDELANDS	20.4	23	N-1	No constraint	2.46	Winter
COBHAM	15.9	26	N-1	No constraint	10.02	Summer
FINLAYSON	4.3	8	N	No constraint	3.18	Winter
GLASGOW ST	8.1	10	N	No constraint	1.92	Winter
GORDONTON	7.7	5	N-1	Capacity	-2.68	Winter
HAMPTON DOWNS	1.8	10	N	No constraint	8.17	Autumn
HOROTIU	13.3	18	N-1	No constraint	4.65	Winter
KENT	16.4	23	N-1 switched	No constraint	6.49	Winter
LATHAM COURT	17.3	23	N-1	No constraint	5.59	Winter
HOEKA	7.5	23	N	No constraint	15.53	Winter
NGARUAWAHIA	5.7	9	N-1	No constraint	3.33	Winter
PEACOCKES	15.5	26	N-1	No constraint	10.36	Winter
PUKETE	26.7	30	N-1	No constraint	3.34	Spring
RAGLAN	5.0	23	N	No constraint	18.00	Winter
SANDWICH	20.6	24	N-1	No constraint	3.19	Winter
TASMAN	22.8	26	N-1	No constraint	3.12	Summer
TE KAUWHATA	6.5	10	N-1	No constraint	3.52	Autumn
TE UKU	2.1	5	N-1	No constraint	2.90	Winter
WALLACE	10.4	15	N-1	No constraint	4.96	Winter
WEAVERS	9.1	9	N-1	Capacity	-0.11	Winter
WHATAWHATA	4.4	23	N	No constraint	18.57	Winter

Available capacity +5 yrs (MVA)	Security of supply classification +5 yrs	Peak load period +10 yrs	Min. available capacity +10 yrs (MVA)	Max. available capacity +10 yrs (MVA)	Security of supply classification +10 yrs (type)	Forecast constraint type	Year of any forecast constraint
4.02	N-1	Winter	-8.59	-0.62	N-1	Capacity	9
0.33	N-1	Summer	-14.89	-4.76	N-1	Capacity	6
3.92	N-1 switched	Spring	-3.63	1.72	N-1 switched	No constraint	None
7.19	N-1	Winter	-4.41	3.20	N-1	No constraint	None
0.45	N-1	Winter	-17.47	-7.01	N-1	Capacity	6
5.82	N-1	Summer	-1.37	2.44	N-1	No constraint	None
-0.74	N	Winter	-1.75	-1.05	N	Capacity	1
0.22	N	Winter	-4.49	-1.03	N	Capacity	6
12.84	N-1	Winter	11.03	12.30	N-1	No constraint	None
7.91	N	Autumn	6.87	7.68	N	No constraint	None
-3.90	N-1	Winter	-11.91	-8.52	N-1	Capacity	2
3.28	N-1 switched	Winter	-10.16	-1.34	N-1 switched	Capacity	9
1.84	N-1	Winter	-11.69	-0.50	N-1	Capacity	8
15.15	N	Winter	11.91	14.17	N	No constraint	None
2.74	N-1	Winter	-0.98	1.70	N-1	No constraint	None
5.27	N-1	Winter	-7.70	-1.65	N-1	Capacity	9
-4.31	N-1	Spring	-13.79	-10.22	N-1	Capacity	2
15.50	N	Winter	9.33	13.04	N	Security	10+
1.41	N-1	Autumn	-8.71	-1.96	N-1	Capacity	8
-4.14	N-1	Summer	-8.20	-5.90	N-1	Capacity	1
-3.32	N-1	Autumn	-7.65	-2.52	N-1	Capacity	2
2.76	N-1	Winter	19.54	20.38	N-1	No constraint	None
3.08	N-1	Winter	-4.11	0.72	N-1	No constraint	None
-0.85	N-1	Winter	9.70	12.11	N-1	No constraint	None
18.32	N	Winter	16.17	17.66	N	No constraint	None

4.3 SCHEDULE 12B:
Report on forecast capacity - Continued

12b(i): System Growth - Zone Substations

Existing Zone Substations	Constraint primary cause	Constraint solution type	Constraint solution progress
AVALON	Zone substation transformer	Divert load to alternative substation	Planning stage
BORMAN	Zone substation transformer	Divert load to alternative substation	Implementation stage
BRYCE	Not applicable	Not applicable	Not applicable
CHARTWELL	Not applicable	Not applicable	Not applicable
CLAUDELANDS	Zone substation transformer	Divert load to alternative substation	Solution confirmed
COBHAM	Not applicable	Not applicable	Not applicable
FINLAYSON	Zone substation transformer	Divert load to alternative substation	Planning stage
GLASGOW ST	Zone substation transformer	Divert load to alternative substation	Planning stage
GORDONTON	Zone substation transformer	Network upgrade	Solution confirmed
HAMPTON DOWNS	Not applicable	Not applicable	Not applicable
HOROTIU	Zone substation transformer	Divert load to alternative substation	Implementation stage
KENT	Zone substation transformer	Divert load to alternative substation	Planning stage
LATHAM COURT	Zone substation transformer	Divert load to alternative substation	Planning stage
HOEKA	Not applicable	Not applicable	Not applicable
NGARUAWAHIA	Not applicable	Not applicable	Not applicable
PEACOCKES	Zone substation transformer	Divert load to alternative substation	Solution confirmed
PUKETE	Zone substation transformer	Divert load to alternative substation	Implementation stage
RAGLAN	Zone substation transformer	Divert load to alternative substation	Planning stage
SANDWICH	Zone substation transformer	Divert load to alternative substation	Planning stage
TASMAN	Zone substation transformer	Divert load to alternative substation	Solution confirmed
TE KAUWHATA	Zone substation transformer	Divert load to alternative substation	Planning stage
TE UKU	Not applicable	Not applicable	Not applicable
WALLACE	Zone substation transformer	Not applicable	Not applicable
WEAVERS	Zone substation transformer	Network upgrade	Solution confirmed
WHATAWHATA	Not applicable	Not applicable	Not applicable

[1] Extend forecast capacity table as necessary to disclose all capacity by each zone substation

Temporary constraint solution remaining lifespan	Explanation
Not applicable	Planned offload to new Exelby zone substation
Not applicable	33kV OH conductor uprating project underway FY25-26. Load will be transferred to Chartwell zone substation FY27-29 and further to new zone substations Fairfield and Crosby are built.
Not applicable	Planned offload to nearby substations if high load scenario eventuates
Not applicable	Planned offload to nearby substations if high load scenario eventuates
Not applicable	Planned offload to new Fairfield zone substation and Chartwell zone substation FY27-29
Not applicable	Planned offload to nearby substations if high load scenario eventuates
Not applicable	Options to offload Finlayson under investigation (minor exceedance)
Not applicable	Planned offload to nearby substations
Not applicable	Transformer upgrade in FY28-29
Not applicable	
Not applicable	New Kohia zone substation completed, 11kV distribution feeders being built to pickup Horotiu and Pukete and new development load FY26-27
Not applicable	Planned offload to nearby substations
Not applicable	Planned offload to nearby substations
Not applicable	
Not applicable	Planned offload to nearby substations if high load scenario eventuates
Not applicable	Planned offload to new Airport zone substation
Not applicable	New Kohia zone substation completed, 11kV distribution feeders being built to pickup Horotiu and Pukete and new development load FY26-27
Not applicable	Subtransmission circuit security constraint being resolved by planned Raglan resilience project, FY25-FY27.
Not applicable	Planned offload to nearby substations
Not applicable	Offload to Pukete substaion and later to new Exelby substation planned to support Industrial and residential development FY29-FY32
Not applicable	Industrial and residential customer dependent growth.
Not applicable	Transformers coming up for renewal will be replaced with 23 MVA transformers FY30-31
Not applicable	Planned offload to nearby substations if high load scenario eventuates
Not applicable	Transformer upgrade in FY32-33
Not applicable	

4.4 SCHEDULE 12C:
Report on forecast network demand

12c(i): Consumer Connections

Number of ICPs connected during year by consumer type	Number of connections					
	Current Year CY 31 Mar 25	CY+1 31 Mar 26	CY+2 31 Mar 27	CY+3 31 Mar 28	CY+4 31 Mar 29	CY+5 31 Mar 30
Consumer types defined by EDB*						
Residential Customers	1,520	1,387	1,539	1,847	1,995	2,075
Business Customers	132	120	133	160	173	180
Large Customers - Low Voltage 400V	12	11	12	14	15	16
Large Customers - Medium Voltage 11kV	1	1	1	1	1	1
Large Customers - High Voltage 33kV	1	1	1	1	1	1
CONNECTIONS TOTAL	**1,665**	**1,519**	**1,686**	**2,023**	**2,185**	**2,273**
Distributed generation						
Number of connections made in year	369	563	602	641	679	718
Capacity of distributed generation installed in year (MVA)	4	28	16	6	7	7

12c(ii) System Demand

	Number of connections					
	Current Year CY 31 Mar 25	**CY+1** 31 Mar 26	**CY+2** 31 Mar 27	**CY+3** 31 Mar 28	**CY+4** 31 Mar 29	**CY+5** 31 Mar 30
Maximum coincident system demand (MW)						
GXP demand	309	297	304	312	319	327
PLUS Distributed generation output at HV and above	(0)	31	31	31	31	31
MAXIMUM COINCIDENT SYSTEM DEMAND	**309**	**328**	**335**	**343**	**350**	**358**
LESS Net transfers to (from) other EDBs at HV and above						
DEMAND ON SYSTEM FOR SUPPLY TO CONSUMERS' CONNECTION POINTS	**309**	**328**	**335**	**343**	**350**	**358**
Electricity volumes carried (GWh)						
Electricity supplied from GXPs	1,264	1,282	1,300	1,318	1,336	1,355
LESS Electricity exports to GXPs	13	13	13	13	13	13
PLUS Electricity supplied from distributed generation	260	263	267	271	274	278
LESS Net electricity supplied to (from) other EDBs	(15)	(15)	(15)	(15)	(15)	(15)
ELECTRICITY ENTERING SYSTEM FOR SUPPLY TO ICPS	**1,526**	**1,547**	**1,569**	**1,590**	**1,613**	**1,635**
LESS Total energy delivered to ICPs	1,454	1,474	1,495	1,516	1,537	1,559
LOSSES	**71**	**72**	**73**	**74**	**75**	**76**
LOAD FACTOR	**56%**	**54%**	**53%**	**53%**	**53%**	**52%**
LOSS RATIO	**4.7%**	**4.7%**	**4.7%**	**4.7%**	**4.7%**	**4.7%**

4.5 SCHEDULE 12D:
Report forecast interruptions and duration

SAIDI	Current Year CY 31 Mar 25	CY+1 31 Mar 26	CY+2 31 Mar 27	CY+3 31 Mar 28	CY+4 31 Mar 29	CY+5 31 Mar 30
Class B (planned interruptions on the network)	52.0	52.0	52.0	52.0	52.0	52.0
Class C (unplanned interruptions on the network)	69.5	69.5	69.5	69.5	69.5	69.5

SAIFI	Current Year CY 31 Mar 25	CY+1 31 Mar 26	CY+2 31 Mar 27	CY+3 31 Mar 28	CY+4 31 Mar 29	CY+5 31 Mar 30
Class B (planned interruptions on the network)	0.45	0.45	0.45	0.45	0.45	0.45
Class C (unplanned interruptions on the network)	1.02	1.02	1.02	1.02	1.02	1.02

CHAPTER 5

INFORMATION DISCLOSURE COMPLIANCE

TAUTUKUNGA WHAKAPUAKANGA PĀRONGO

CLAUSE	DESCRIPTION	REFERENCE
Summary		
3.1	The AMP must include a summary that provides a brief overview of the AMP contents and highlights information that the EDB considers significant.	2025 AMP 1, 2 2023 AMP Executive Summary 6.1-6.9
Background and Objectives		
3.2	The AMP must include details of the background and objectives of the EDB's asset management and planning processes	2023 AMP 1.1.2, 1.1.3, 3.2
Purpose Statement		
3.3	The AMP must include a purpose statement that:	
3.3.1	Makes clear the purpose and status of the AMP in the EDB's asset management practices. The purpose statement must also include a statement of the objectives of the asset management and planning processes.	2025 AMP 1,2 2023 AMP Executive Summary 1, 1.1.2, 3.2,
3.3.2	States the corporate mission or vision as it relates to asset management.	2025 AMP 1.2, 2023 AMP 1.1.2, 3.2, 4.1
3.3.3	Identifies the documented plans produced as outputs of the annual business planning process.	2023. AMP 3.2
3.3.4	States how the different documented plans relate to one another with specific reference to any plans specifically dealing with asset management.	2023 AMP 3.2, 4.1
3.3.5	Includes a description of the interaction between the objectives of the AMP and other corporate goals, business planning processes and plans.	2023 AMP 3.2, 4.1
AMP Period		
3.4	The AMP must state that the period covered by the plan is 10 years or more from the commencement of the financial year.	AMP 2025 1.3.3
3.5	Must state the date on which the AMP was approved by the Board of Directors.	AMP 2025 1.3.4
Stakeholder Interests		
3.6	A description of stakeholder interests (owners, consumers etc.) which identifies important stakeholders and indicates:	2023 AMP 3.1
3.6.1	How the interests of stakeholders are identified.	2023 AMP 3.1
3.6.2	What these interests are.	2023 AMP 3.1
3.6.3	How these interests are accommodated in asset management practices.	2023 AMP 3.1
3.6.4	How conflicting interests are managed.	2023 AMP 3.1.3
Accountabilities and Responsibilities		
3.7	The AMP must include a description of the accountabilities and responsibilities for asset management on at least three levels, including:	2023 AMP 1.1.3
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.	2023 AMP 1.1.3, 4.3
3.7.2	Executive—an indication of how the in-house asset management and planning organisation is structured.	2023 AMP 1.1.3, 4.3
3.7.3	Field operations—an overview of how field operations are managed, including a description of the extent to which field work is undertaken in-house and the areas where outsourced contractors are used.	2023 AMP 1.1.3, 4.3

CLAUSE	DESCRIPTION	REFERENCE
Assumptions		
3.8	The AMP must include all significant assumptions.	2023 AMP 6.1.2, 8.2.1, 8.3.2, 9.1.2
3.8.1	Must be quantified where possible.	2023 AMP 6.1.2, 8.2.1, 8.3.2, 9.1.2
3.8.2	Must be clearly identified in a manner that makes their significance understandable to interested persons.	2023 AMP 6.1.2, 6.4, 8.2.1 8.3.2, 9.1.2
3.8.3	A description of changes proposed where the information is not based on the EDB's existing business.	2023 AMP 6.1.2, 8.2.1, 8.3.2, 9.1.2
3.8.4	The sources of uncertainty and the potential effect of the uncertainty on the prospective information.	2023. AMP 6.2.1, 6.3, 9.1.2
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.	2023 AMP 9.1.2
Material Difference in Information		
3.9	The AMP must include a description of the factors that may lead to a material difference between the prospective information disclosed and the corresponding actual information recorded in future disclosures.	2023 AMP 6.1.3, 9.1.2
Asset Management Strategy and Delivery		
3.10	The AMP must include an overview of asset management strategy and delivery.	2023 AMP 3.2.2, 4.1
Systems and Information Management Data		
3.11	The AMP must include an overview of systems and information management data.	2023 AMP 7.1
3.12	The AMP must include a statement covering any limitations in the availability or completeness of asset management data and disclose any initiatives intended to improve the quality of this data.	2023 AMP 8.2.6, 8.3.2, 8.4
Asset Management Processes		
3.13	The AMP must include a description of the processes used within the EDB for:	
3.13.1	Managing routine asset inspections and network maintenance.	2023 AMP 8.1, 8.2, 8.4
3.13.2	Planning and implementing network development projects.	2023 AMP 4.2, 4.3, 4.4
3.13.3	Measuring network performance.	2023 AMP 5.3
3.14	The AMP must include an overview of asset management documentation, controls, and review processes.	2023. AMP 3.2, 4.1, 4.2, 4.5
Communication Processes		
3.15	The AMP must include an overview of communication and participation processes.	2023 AMP 3.1
Financial Values		
3.16	The AMP must present all financial values in constant price New Zealand dollars except where specified otherwise.	2023 AMP 9.1.2,

CLAUSE	DESCRIPTION	REFERENCE
Disclosure Requirements		
3.17	The AMP must be structured and presented in a way that the EDB considers will support the purposes of AMP disclosure set out in clause 2.6.2 of the determination.	Throughout the document
Assets covered		
4	The AMP must provide details of the assets covered and non-network solutions, including:	
4.1	A high-level description of the service areas covered by the EDB and the degree to which these are interlinked, including:	2023 AMP 1.2
4.1.1	The region(s) covered.	2023 AMP 1.2
4.1.2	Identification of large consumers that have a significant impact on network operations or asset management priorities.	2023 AMP 1.6.1
4.1.3	A description of the load characteristics for different parts of the network.	2023 AMP 1.2, 6.9
4.1.4	Peak demand and total energy delivered in the previous year, broken down by sub-network, if any.	2023 AMP 1.4, 6.9
Network Configuration		
4.2	The AMP must provide a description of the network configuration, including:	
4.2.1	Identifying bulk electricity supply points and any distributed generation with a capacity greater than 1 MW. State the existing firm supply capacity and current peak load of each bulk electricity supply point.	2023 AMP 1.2, 6.3
4.2.2	A description of the subtransmission system fed from the bulk electricity supply points, including the capacity of zone substations and the voltage(s) of the subtransmission network(s). The AMP must identify the supply security provided at individual zone substations, by describing the extent to which each has n-x subtransmission security or by providing alternative security class ratings.	2023 AMP 1.2, 6.1.1, 6.5, 6.5.1, 6.5.2, 6.5.3, 6.9
4.2.3	A description of the distribution system, including the extent to which it is underground.	2023 AMP 1.2, 2.5
4.2.4	A brief description of the network's distribution substation arrangements.	2023 AMP 1.2, 2.6
4.2.5	A description of the low voltage network including the extent to which it is underground.	2023 AMP 1.2, 2.4, 2.5
4.2.6	An overview of secondary assets such as protection relays, ripple injection systems, SCADA, and telecommunications systems.	2023 AMP 2.8
4.2.7	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	AMP 2023 6.6 AMP 2025 2.2
Sub-networks		
4.3	If sub-networks exist, the network configuration information referred to in subclause 4.2 above must be disclosed for each sub-network.	No sub-networks exist that meet disclosure threshold in definitions
Network Asset Information		
4.4	The AMP must describe the network assets by providing the following information for each asset category by:	
4.4.1	Voltage levels.	2023 AMP 2.2–2.9
4.4.2	Description and quantity of assets.	2023 AMP 2.2–2.9
4.4.3	Age profile.	2023 AMP 2.2–2.9
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.	2023 AMP 2.2–2.9

CLAUSE	DESCRIPTION	REFERENCE
Network Asset Information by Asset Category		
4.5	The asset categories discussed in subclause 4.4 should include at least the following:	
4.5.1	The categories listed in the Report on Forecast Capital Expenditure in Schedule 11a (iii)	2023 AMP 2.2–2.10
4.5.2	Assets owned by the EDB but installed at bulk electricity supply points owned by others.	2023 AMP 2.10
4.5.3	EDB owned mobile substations and generators whose function is to increase supply reliability or reduce peak demand.	2023 AMP 2.9.1
4.5.4	Other generation owned by the EDB.	2023 AMP 2.9.1
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.	2023 AMP 5
6	Performance indicators for which targets have been defined in clause 5 above must include SAIDI and SAIFI values for the next five disclosure years.	2023 AMP 5.3.3 2025 AMP 3.5
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.	2023 AMP 5.3
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.	2023 AMP 5.3.3, 5.4, 5.5
8	The AMP must describe the basis on which the target level for each performance indicator was determined. Justification for target levels of service includes consumer expectations or demands, legislative, regulatory, and other stakeholders' requirements or considerations. The AMP should demonstrate how stakeholder needs were ascertained and translated into service level targets.	2023 AMP 3.1, 5
9	Targets should be compared to historic values where available to provide context and scale to the reader.	2023 AMP 5
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.	2023 AMP 5.3.3
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.	2023 AMP 6.1.2, 6.5
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.	2023 AMP 6.1.1, 6.5
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.	2023 AMP 4.2.2, 4.3.1
11.4	The use of standardised designs	2023 AMP 4.3.1
11.4.1	the categories of assets and designs that are standardised; and	2025 AMP 3.8
11.4.2	the approach used to identify standard designs	2023 AMP 4.3 2025 AMP 3.8

CLAUSE	DESCRIPTION	REFERENCE
Network Energy Efficient Operation		
11.5	A description of strategies or processes (if any) used by the EDB that promote the energy efficient operation of the network.	2023 AMP 6.5.5, 6.6, 6.7.1, 6.7.2
Equipment Capacity		
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.	2023 AMP 6.5, 6.5.1
Project Prioritisation		
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.	2023 AMP 4.1, 4.2, 4.2.5
Demand Forecasts		
11.8	The AMP must provide details of demand forecasts, the basis on which they are derived, and the specific network locations where constraints are expected due to forecast increases in demand.	2023 AMP 6.4, 6.7, 6.9
11.8.1	Explain the load forecasting methodology and indicate all the factors used in preparing the load estimates.	2023 AMP 6.2
11.8.2	Provide separate forecasts to at least the zone substation level covering at least a minimum five-year forecast period. Discuss how uncertain but substantial individual projects/ developments that affect load are taken into account in the forecasts, making clear the extent to which these uncertain increases in demand are reflected in the forecasts.	2023 AMP 6.4.6, 6.7. 6.9
11.8.3	Identify any network or equipment constraints that may arise due to the anticipated growth in demand during the AMP planning period.	2023 AMP 6.4, 6.9
11.8.4	Discuss the impact on the load forecasts of any anticipated levels of non-network solutions in a network.	2023 AMP 6.3
Network Development Options		
11.9	The AMP must provide analysis of the significant network level development options identified and details of the decisions made to satisfy and meet target levels of service, including:	2023 AMP 6.6, 6.9
11.9.1	The reasons for choosing a selected option for projects where decisions have been made.	2023 AMP 6.6, 6.9
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;	2023 AMP 6.4–6.7, 6.9
11.9.3	The consideration of planned innovations that improve efficiencies within the network, such as improved utilisation, extended asset lives, and deferred investment.	2023 AMP 4.2, 5.3.2, 5.4.2, 5.5.2, 6.6.2-6.7.4, 8.2.6
Network Development Programme		
11.10	The AMP must include a description and identification of the network development programme including non-network solutions and actions to be taken, including associated expenditure projections. The network development plan must include:	2023 AMP 6.4–6.5, 6.7
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.	2023 AMP 6.4–6.5, 6.7
11.10.2	A summary description of the programmes and projects planned for the following four years (where known).	2023 AMP 6.4–6.5, 6.7, 6.9
11.10.3	An overview of the material projects being considered for the remainder of the AMP planning period.	2023 AMP 6.4–6.5, 6.7, 6.9

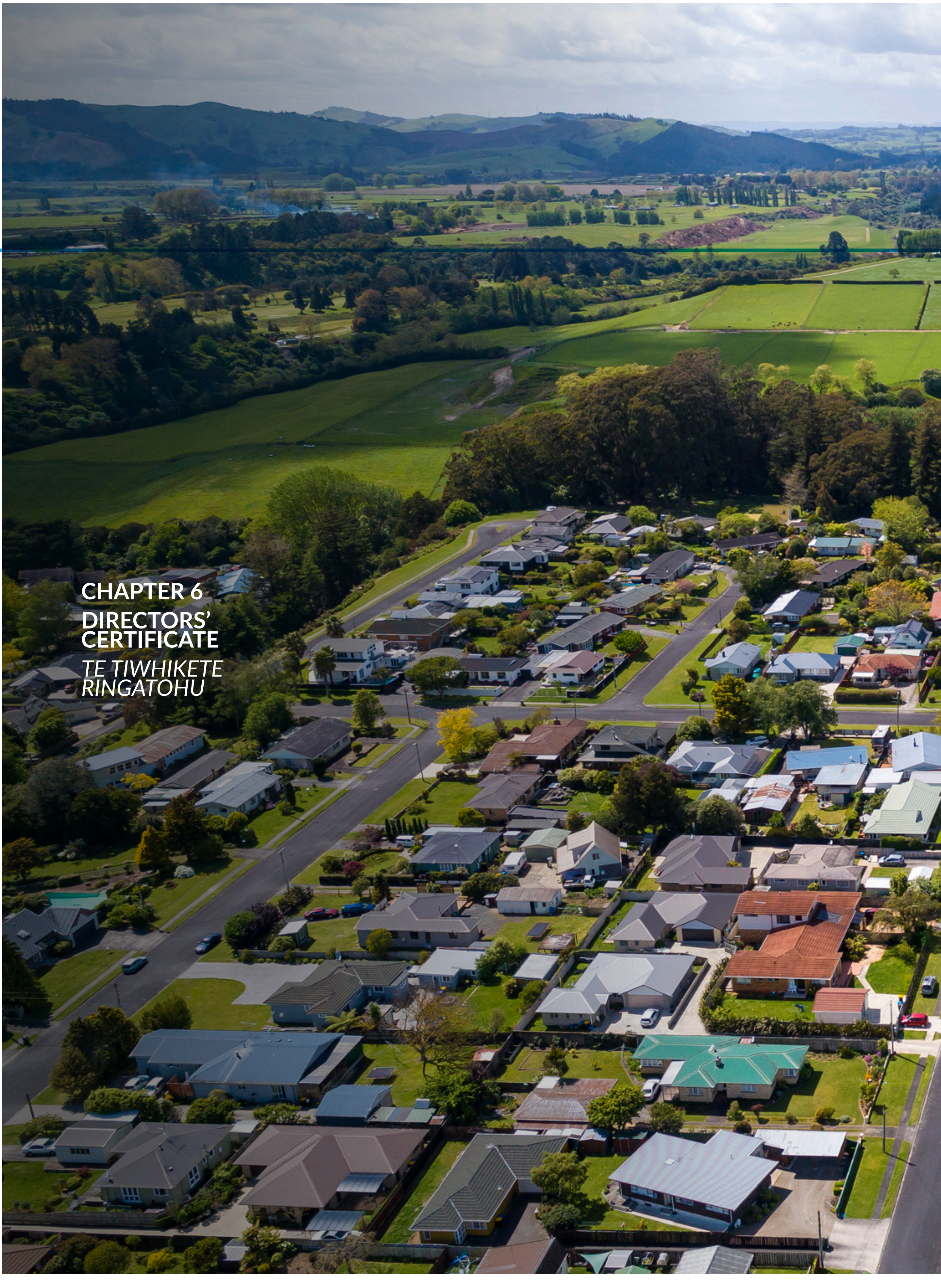
CLAUSE	DESCRIPTION	REFERENCE
Distributed Generation		
11.11	The AMP must include a description of the EDB's policies on distributed generation, including the policies for connecting distributed generation. The impact of such generation on network development plans must also be stated.	2023 AMP 6.3
Non-network solutions		
11.12	A description of the EDB's policies on non-network solutions, including	
11.12.1	Economically feasible and practical alternatives to conventional network augmentation. These are typically approaches that would reduce network demand and/or improve asset utilisation.	2023 AMP 6.6.2
11.12.2	The potential for non-network solutions to address network problems or constraints.	2023 AMP 6.6.2, 6.7
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.	2023 AMP 6.7.2, 6.9 2024 AMP 2.4 Found on our website here: LV Information Disclosure
Lifecycle Asset Management Planning (Maintenance and Renewals)		
12	The AMP must provide a detailed description of the lifecycle asset management processes, including:	
12.1	The key drivers for maintenance planning and assumptions.	2023 AMP 8.2
Maintenance Programme		
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:	2023 AMP 8.4
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.	2023 AMP 8.4
12.2.2	Any systemic problems identified with any particular asset types and the proposed actions to address these problems.	2023 AMP 8.4
12.2.3	Budgets for maintenance activities broken down by asset category for the AMP planning period;	2025 AMP 3.3.1

CLAUSE	DESCRIPTION	REFERENCE
Renewal Programme		
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:	2023 AMP 8
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.	2023 AMP 4.2, 8
12.3.2	A description of innovations made that have deferred asset replacement.	2023 AMP 4.2, 8
12.3.3	A description of the projects currently underway or planned for the next 12 months.	2023 AMP 8.4
12.3.4	A summary of the projects planned for the following four years (where known).	2023 AMP 8.4
12.3.5	An overview of other work being considered for the remainder of the AMP planning period.	2023 AMP 8.4
12.4	The asset categories discussed in subclauses 12.2 and 12.3 above should include at least the categories in subclause 4.5.	2023 AMP 8.4
12.5	The AMP must include identification of the approach used for developing capital expenditure projections for lifecycle asset management. This must include an explanation of:	2023 AMP 8.1-8.4
12.5.1	the approach that the EDB uses to inform its capital expenditure projections for lifecycle asset management	2023 AMP 8.1-8.4
12.5.2	the rationale for using the approach for each asset category	2023 AMP 8.1, 8.2, 8.3, 8.4
Vegetation Management		
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	2023 AMP 8.2.3, 2025 AMP 3.3.1
Non-Network Solutions		
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	2023 AMP 6.6 - 6.7 2024 AMP Section 2 2025 AMP Section 2.2
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.	2023 AMP 2.9, 7.1, 7.2
13.2	Development, maintenance and renewal policies that cover them.	2023 AMP 7.3
13.3	A description of material capital expenditure projects (where known) planned for the next five years.	2023 AMP 7.3.1
13.4	A description of material maintenance and renewal projects (where known) planned for the next five years.	2023 AMP 7.3.2

CLAUSE	DESCRIPTION	REFERENCE
Risk Management		
14	AMPs must provide details of risk policies, assessment, and mitigation, including:	
14.1	Methods, details, and conclusions of risk analysis.	2023 AMP 3.3
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.	2023 AMP 3.3.5
14.3	A description of the policies to mitigate or manage the risks of events identified in subclause 14.2.	2023 AMP 3.3.5
14.4	Details of emergency response and contingency plans.	2023 AMP 3.3.5
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.	2023 AMP 4.3, 5.4.4, 5.4.5, 5.5.4
15.2	An evaluation and comparison of actual service level performance against targeted performance.	2023 AMP 5.2-5.5
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.	2023 AMP 3.4
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.	2023 AMP 3.4.3, 5.2-5.5
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.	Throughout the document
16.2	The organisation structure and the processes for authorisation and business capabilities will support the implementation of the AMP plans.	2023 AMP 1.1.3, 1.1.4
Qualitative information		
17	AMPs must include qualitative information in narrative form, as prescribed in clauses 17.1-17.7	
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.	2023 AMP 5.3.3

CLAUSE	DESCRIPTION	REFERENCE
Voltage Quality and Constraints		
17.2	The AMP must include a description of the EDB's practices for	
17.2.1	Monitoring voltage, including (a) the EDB's practices for monitoring voltage quality on its low voltage network. (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 (a)-(d) above;	2023 AMP 6.7.2, 6.9, 5.3.3 2024 AMP 2.3 and 2.4 2025 AMP 2.2 and 2.4
17.2.2	Monitoring load and injection constraints, including: (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).	2023 AMP 6.7.2, 2024 AMP 2.4 2025 AMP 2.2 Found on our website here: LV Information Disclosure
Customer Service Practises		
17.3	The AMP must include 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	2023 AMP 5.3.2, 5.3.3
17.3.2	the EDB's approach to planning and managing customer complaint resolution	2023 AMP 5.3.2, 5.3.3
Customer Connections		
17.4	The AMP must include a description of the EDB's practices for connecting consumers, including	
17.4.1	the EDB's approach to planning and management of (a) connecting new consumers (offtake and injection connections), and overcoming commonly encountered issues; and (b) alterations to existing connections (offtake and injection connections)	2023 AMP 3.1, 4.1, 5.3.3
17.4.2	how the EDB is seeking to minimise the cost to consumers of new or altered connections	2023 AMP 3.1, 4.1, 4.2.1, 5.3.3
17.4.3	the EDB's approach to planning and managing communication with consumers about new or altered connections;	2023 AMP 3.1, 5.3.3
17.4.4	commonly encountered delays and potential timeframes for different connections	2023 AMP 5.3.3
17.4.5	the EDB's approach to sharing information on current and forecast constraints (both load and injection) with potential new consumers. This must include any information on low voltage network constraints, including the constraint information the EDB derives from the data specified under clause 17.2.2(a of attachment A).	2023 AMP 6.9 2024 AMP 2.4 Found on our website here: LV Information Disclosure

CLAUSE	DESCRIPTION	REFERENCE
New Large Customer Connections		
17.5	The AMP must include a description of the practises for New connections likely to have a significant impact on network operations or asset management priorities: including,	
17.5.1	how the EDB assesses the impact that new demand, generation, or storage capacity will have on the EDB's network, including (a) how the EDB measures the scale and impact of new demand, generation, or storage capacity. (b) how the EDB takes the timing and uncertainty of new demand, generation, or storage capacity into account. (c) how the EDB takes other factors into account, e.g., the network location of new demand, generation, or storage capacity	2023 AMP 6.2, 6.3 6.4, 6.9.1
17.5.2	how the EDB assesses and manages the risk to the network posed by uncertainty regarding new demand, generation, or storage capacity;	2023 AMP 6.2, 6.3, 6.4
Innovation Practises		
17.6	The AMP must include a description of description of the following:	
17.6.1	any innovation practices the EDB has planned or undertaken since the last AMP or AMP update was publicly disclosed, including case studies and trials	2023 AMP 6.6, 6.7, 8.2.6 2024 AMP Section 2 2025 AMP Section 2
17.6.2	the EDB's desired outcomes of any innovation practices, and how they may improve outcomes for consumers	2023 AMP 6.6, 6.7 2024 AMP Section 2 2025 AMP Section 2
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	2023 AMP 6.6, 6.7 2024 AMP Section 2 2025 AMP Section 2
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	2023 AMP 6.7, 6.7 2024 AMP Section 2 2025 AMP Section 2
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.	2023 AMP 6.7, 6.7 2024 AMP Section 2 2025 AMP Section 2
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.	



CHAPTER 6

DIRECTORS' CERTIFICATE

TE TIWHIKETE RINGATOHU

6 Directors' certificate

Electricity Distribution Information Disclosure
(Targeted Review 2024) Amendment Determination 2024 4909465

Schedule 17
Certification for year-beginning disclosures

Clause 2.9.1

We, Barry Spence Harris and Carolyn Mary Steele being directors of WEL Networks Limited certify that, having made all reasonable enquiry, to the best of our knowledge:

a) The following attached information of WEL Networks Limited prepared for the purposes of clauses 2.4.1, 2.6.1; 2.6.3, 2.6.6 and 2.7.2 of the Electricity Distribution Information Disclosure Determination 2012 in all material respects complies with that determination.

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

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

Director  Date 4th March 2025

Director  Date 4th March 2025

WEL Networks

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