Asset Management Plan 2026 to 2036

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1. Executive summary

1.1 Introduction

We commenced a two-year programme to update our Asset Management Plan (**AMP**) at the beginning of 2024. The 2025 AMP represented a revised *baseline* view of the investments required in the network and the business. It was a significant revision over the 2023 AMP. Over the past 12 months, we have sought to optimise the investment requirements, and this 2026 AMP sets out the prudent asset investments to maintain safety, current service levels and prepare for demand growth; that is, it represents the results of the optimisation process to date.

This AMP communicates Electra's approach to operating a safe, reliable, and cost-effective electricity network. We are committed to the long-term stewardship of the network, which will allow us to meet the needs of customers and stakeholders and support the livelihoods of the people and businesses throughout Horowhenua and the Kāpiti Coast.

This AMP has been structured in three parts:

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

Whilst we have changed the structure, this AMP continues to provide all the information to assure our stakeholders that:

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

This executive summary highlights the key factors driving investment and performance, the strategies adopted to ensure the network responds to those factors, and the key programmes and projects supporting the strategy. This section overviews the six strategic themes driving the $300 million[1] investment in the network , systems, property, and plant over the next decade.

Over the next 12 months, we will continue to optimise the investments outlined in this AMP and implement the improvements outlined in the asset management improvement plan.

1.2 The network

Electra's network is spread over the Horowhenua and Kāpiti districts on the narrow strip of land between the Tasman Sea and the Tararua Ranges, stretching from Foxton and Tokomaru in the north to Paekākāriki in the south. The network covers approximately 1,628 km^2.

[1] This is total capital expenditure, before capital contribution are deducted.

The Horowhenua district has a population of approaching 38,400[2], with most people living in Foxton, Shannon, Levin, and several beach settlements. The northern (Horowhenua) network is tied to horticulture, dairy farming, and Levin's urban and commercial areas.

The Kāpiti Coast district has a population of around 58,000[3], with most people living in the towns Ōtaki, Waikanae, Paraparaumu, Raumati, Paekākāriki, and other beach settlements. The southern (Kāpiti Coast) network is predominantly urban and includes light commercial, rural lifestyle, and agricultural production. Many customers on the southern network commute to Wellington, so daytime demand is considerably less than evening demand. In both regions we have coastal/beach settlements with holiday and weekend homes.

Our network is electrically contiguous but generally operates as a northern and southern network, with the interconnection between the two being north of Ōtaki. We operate a very secure sub-transmission system, and all zone substations, except Paekākāriki, are afforded N-1 sub-transmission and zone substation transformer security. This is consistent with the semi-urban nature of our customer base.

The 11kV distribution network comprises interconnected radial feeders. This is primarily overhead construction in the northern region and mostly underground in the southern region. Our overhead network is exposed to adverse weather, vegetation, and vehicle damage (when located near the roadway). Our underground network, whilst reliable, has a very low switch density, which constrains our ability to restore faults quickly. This is an area for improvement.

1.3 Recent performance

We monitor our performance against various measures, including customer service, safety, environmental, asset performance, network efficiency and work delivery.

Our overall health and safety trend is positive. However, we recognise the need for ongoing focus to ensure the well-being of our employees, contractors, customers, and the public. We have increased our auditing and improvement efforts in recent years, and we expect these initiatives to improve safety outcomes. We have updated our critical risk framework, and focus groups are reviewing it to identify new areas for improvement.

Overall, our unplanned reliability performance has generally been good, and we perform well against our peers (Figure 1). We have exceeded our target in some years due to one-off events, which are not yet indicators of any current issues (Figure 2).

Recent unplanned reliability performance has been good, but it remains an area where risks are likely to increase. A few recent observations are:

- During FY2025, the network experienced no significant weather events or outages (such as loss of zone substation), resulting in better unplanned outage performance compared to previous years;
- Defective equipment continues to be the main cause of outages and the second-largest factor affecting SAIDI, with conductors, cables, pole-top hardware, and transformers being the main issues. Cable termination failures have significantly increased in FY2025 and are being tackled through targeted

[2] Estimated at 30 June 2025. Source: Infometrics.

[3] Estimated at 30 June 2025. Source: Infometrics.

strategies. Encouragingly, there has been a small decrease in the impact of defective equipment on the worst-performing feeders;

- We have observed a decrease in vegetation outages during periods when wind affects the network. This is a positive trend, indicating that vegetation management has been effective. However, we still notice a concentration of vegetation outages on a few feeders, and our operational plans are prioritised to ensure the worst-performing feeders (for vegetation) are attended to as much as tree regulations permit.

We raised our reliability targets in the 2025 AMP and effectively managed planned outages within the new goals. Our planned outages are significantly lower than those of our peers. As work on the underground network increases, we may need to increase the planned outage targets further.

Figure 1: Unplanned outage duration[4]

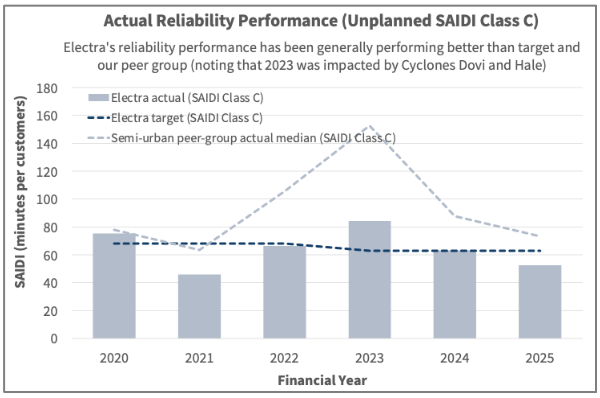
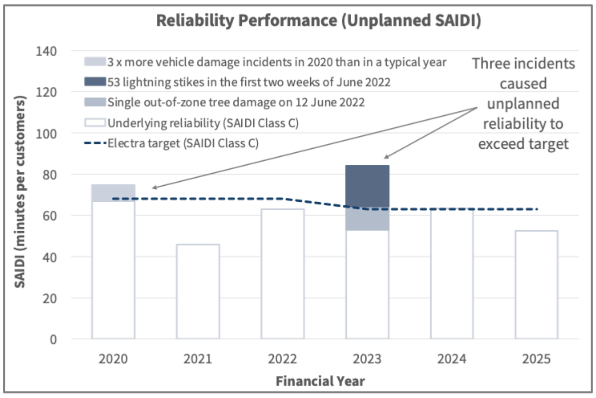


Figure 2: Unplanned outage, reasons for the target being exceeded



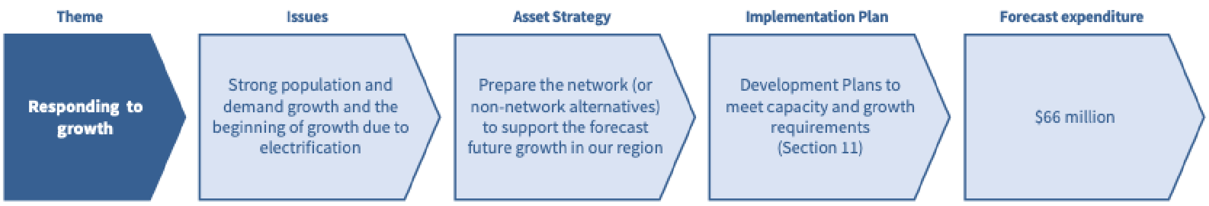
1.4 The strategic themes shaping this AMP

Six strategic themes are driving the investment and performance of the network:

- Responding to growth;
- Responding to the electrification of New Zealand;
- Responding to our aging assets;
- Reducing reliability risk;
- Preparing the business for the future;
- Balancing stakeholder needs.

We discuss the issues, strategy and implementation plans associated with these themes in the following Sections.

1.5 Responding to growth



[4] The semi-urban peer group was impacted by major weather events in 2022 and 2023 (Cyclones Dovi, Hale and Gabrielle).

Electra is experiencing a period of strong growth (refer to Section 5.2). Horowhenua District Council forecasts the population to grow to 62,000 by 2041. The District's population is projected to grow 1.8% annually over the next ten years[5]. This is much higher than in previous decades. The growth is partly driven by the Wellington Northern Motorway project, which improves access to the Wellington region. Plenty of flat land is available in Horowhenua, close to transport links. This land is cheaper than that available in Wellington and Palmerston North, which will likely drive commercial and light-industrial development in the region. Based on our projections, we expect approximately 9,000 new connections in the Horowhenua region by 2050 (slightly less than in the prior AMP).

On the Kāpiti Coast, we are seeing a slowdown in land development due to the current economic climate. The current view suggests land development will slow in FY2026 and FY2027, but longer term should be in the order of 600-700 sections per year, which equates to a growth rate of around 1.7%. Based on our projections, we expect approximately 13,800 new connections in the Kāpiti Coast region by 2050 (again, slightly less than in the prior AMP).

Our view on population growth will see the base demand (before the impact of electrification) grow by 13% by 2035 and 40% by 2050. This indicates an additional 26 MW of demand by 2050, before any effect from electrification.

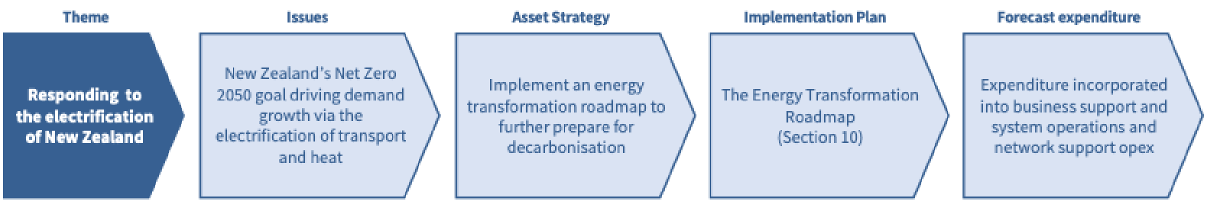
In response to this growth (and incorporating the early stages of electrification growth), we have identified a range of capacity constraints across the region that need to be addressed. The proposed work includes:

- Increasing the capacity of the Northern GXP. This project is discussed in Section 11.8. The capacity available from the existing Mangahao GXP will shortly become constrained, and we are analysing the potential options to increase capacity in the region. The project is not yet in the expenditure forecasts;
- Upgrading subtransmission line capacity in the Northern region and constructing two new zone substations (refer to Section 11.9);
- Construction of eleven new 11kV distribution feeders to supply new developments and additional capacity for growth. Our near-term plans include five specific feeders (most in the Southern region) and provision for a further six from FY2030 (refer to Section 11.10).

Our development plan has been prepared to meet controlled demand growth (see Section 10). Our current plans can efficiently accommodate high growth should it occur. Conversely, we can defer development should demand growth fall below the controlled demand forecasts.

We are also in the early stages of considering non-network alternatives. At this stage, there are no viable alternatives to the most of the proposed projects; however, we will continue to explore options as we move forward.

1.6 Responding to the electrification of New Zealand



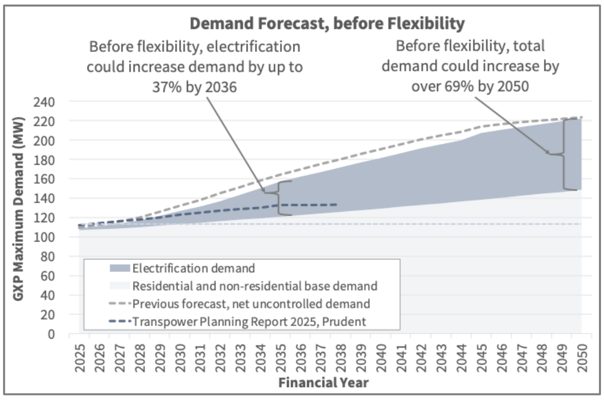
[5] Sense Partners, "Horowhenua Socio-Economic Projections Summary and Methods", May 2020

Reducing emissions through electrification and increasing renewable generation are critical to achieving net-zero 2050. In particular, the electrification of transport and heat (both process and general) and the use of distributed energy resources (**DERs**) are central to decarbonisation (refer to Section 5.3).

Our network provides the critical link between customers and energy markets and enables greater customer participation in decarbonisation. We prepared an energy transformation roadmap (**ETR**) in FY2022 and have been monitoring industry developments and progressing with the various actions on the roadmap since then. The ETR ensures we have a pathway to build the capability and capacity to support New Zealand's decarbonisation efforts (refer to Section 10).

We are forecasting a material increase in the connection of controllable DERs (like EVs and solar PVs in combination with batteries). These are expected to reach over 11,400 by 2050. These controllable DERs can provide flexibility (i.e. reducing electricity demand in response to a signal).

Figure 3: Demand Growth and the impact of flexibility

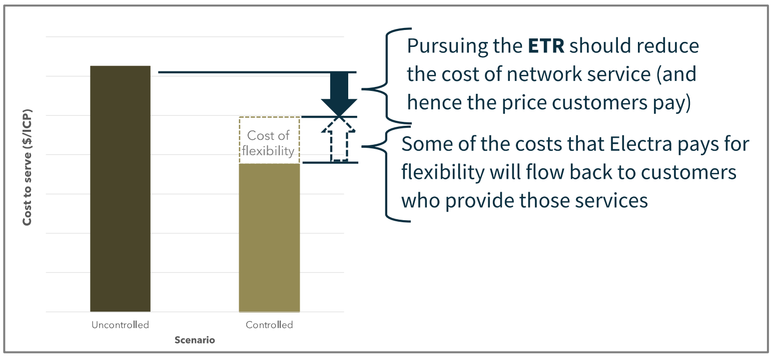


Utilising flexibility is an important aspect of our ETR. It can significantly reduce peak demand on the network and significantly reduce investment in new capacity. Our modelling indicates that flexibility could reduce demand by 63 MW by 2050, which is a 28% reduction (Figure 3).

Our modelling suggests three key benefits of pursuing the ETR (Figure 4). These include:

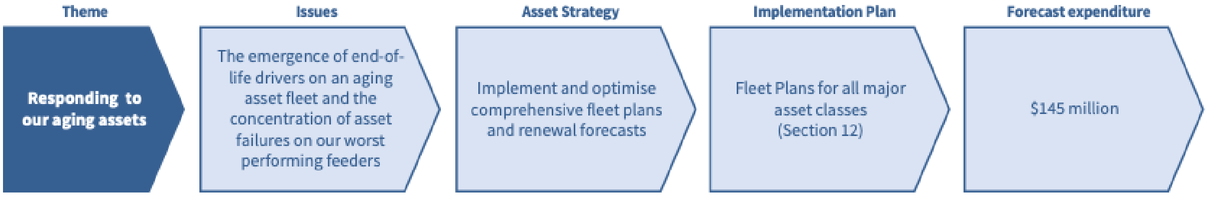
- Lowering the cost of network services—by utilising non-network alternatives, like flexibility to reduce investment in network capacity;
- Enabling customers to decarbonise through electrification;
- Lowering overall energy costs to customers through electrification and flexibility payments.

Figure 4: Benefits of the ETR



We have begun to increase the team's capabilities and we are forecasting that many of our operational technology systems will need to be upgraded in the future. The ETR is only the starting point for our transformation work. There will be further detailed network modelling and solution refinement over the next two years. We expect the roadmap to evolve (along the direction laid out) as technology evolves and customers and society adapt.

1.7 Responding to our aging assets



Many of our assets were installed in the 1950s, 1960s and 1970s, and many will reach end-of-life over the coming decades. We expect that end-of-life drivers for replacement could emerge in around 17% of the fleet over the next decade (refer to Section 5.4). How we manage asset-related risks will be a greater focus for the business.

We have defined asset fleet strategies that are aligned with the quality and availability of asset age, condition, and risk data. As condition data improves so will the quality of our renewal forecasting. We are targeting asset renewals where asset health is deteriorating, including prioritising pole-top hardware and conductors on the worst-performing feeders (refer to Sections 4.5.9, 12.12 and 12.13).

We use a Condition-Based Asset Risk Management Model (CBARMM) to forecast asset risk and renewals. The model is based on the DNO Methodology.[6] CBARMM models are used for all network assets. These models apply a risk-based, information-driven approach to asset renewal forecasting. The CBARMM models provide a systematic, data-driven methodology to identify asset renewal needs and enable us to evaluate overall asset fleet risks based on different renewal, refurbishment or maintenance scenarios (refer to Section 12.4).

Fleet risks are increasing most significantly for our zone substation assets, overhead distribution assets, and the low-voltage network. Fleet risks for the underground assets are challenging to forecast, but we expect them to emerge midway through the planning period.

Fleet risks for zone substation transformers, circuit breakers and protection systems are increasing. These are critical assets, and we have a lower risk tolerance for failure. Over the planning period, we have a $29 million renewal programme for these assets. We generally plan to replace zone substation assets before risk increases above medium (risk grade 3). However, we are replacing more assets than indicated by their risk grade alone as some safety-related factors, building resilience issues, and protection scheme vulnerability drivers are not fully reflected in CBARMM (refer to Section 12.6.2). The significant zone substation renewal programmes are power transformers ($14.9 million, due mainly to end-of-life risks) and protection relays ($7.0 million, due mainly to technological obsolescence).

The percentage of distribution assets with increasing risk varies. Our five-year forecast of assets with risk levels indicating replacement is required is <1.0% for concrete poles, 5.3% for crossarms, and below 9% for our small wood pole fleet.[7] We have a $47 million programme to address these risks over the next ten years

6 Ofgem, "DNO Common Network Asset Indices Methodology—Version 2.1", April 2021.
This is a common framework of definitions, principles and calculation methodologies published by Ofgem and adopted by all GB Distribution Network Operators for the assessment, forecasting and regulatory reporting of asset risk.

7 This is a risk based assessment (a combination of asset health and criticaility) for all asset classes expect wood poles, which is health based. The risk is lower for wood poles due to their low criticality. Hence, these percentages differ from Schedule 12a.

(refer to Section 12.6.3). Our expenditure on concrete poles and crossarms has reduced by $15 million (compared to the 2025 AMP) as a result of our fleet optimisation work and observed performance.

Our five-year forecast of high-risk assets varies for subtransmission, distribution and LV overhead conductor and cable. Most of these risks relate to overhead copper conductors, and there is a $34 million programme to address these assets over the next ten years (refer to Sections 12.13 and 12.14).

The $8 million renewal programme for distribution switches addresses type issues identified on our air-break switch and ring-main unit fleets. Given the lower consequences of failure for distribution transformers and pole-mounted dropout fuses, we are operating these assets at a higher risk rating whilst ensuring public safety. This approach is typical across the industry (refer to Sections 12.15 and 12.16).

We anticipate increasing end-of-life issues on our low-voltage pillar boxes, and a $17 million asset renewal and safety programme is planned over the coming decade. This programme focuses on steel pillar and link boxes, where we have identified potential safety issues being addressed (refer to Section 12.17).

Our CBARMM process predicts a growing number of high-risk 11kV and LV cables. Assessing the health of these assets is inherently challenging. Cable performance indicates that renewals are not yet required; however, we are seeing an increase in failures of cable terminations, and we have increased termination testing in this AMP. We are monitoring the fleet's performance to identify emerging health issues, and a programme of cable termination replacement (which will be an opex activity) may be included in future AMPs.

For all the assets being replaced, where possible, we will use the opportunity to incrementally address resilience (to physical conditions and the energy transformation).

1.8 Reducing reliability risk

Our planned and unplanned reliability performance has generally been good, but without change, there is an increasing risk of deteriorating reliability performance. The risks to reliability performance arise from climate change, population growth, our aging asset fleet and the limited switching points on the underground network (refer to Section 5.5).

Based on historical performance, we have a 45% probability of meeting our unplanned reliability (SAIDI) target in any given year (this has improved, given the recent good performance).

Managing reliability risk is increasingly important. Electrification will reduce energy diversity and increase New Zealand's dependence on a reliable electricity supply. Customers need confidence that electricity will be delivered where and when required, and maintaining the reliability of supply will provide this confidence.

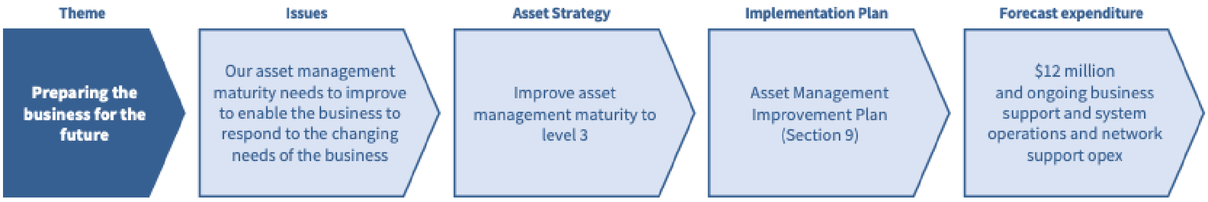
In the 2025 AMP, we outlined a security and reliability risk mitigation programme. In the context that we already operate a network that performs very well we need to ensure that we manage investment in a way that balances reliability and affordability meeting customer expectations. Therefore, some programmes that we included in the 2025 AMP are being reassessed and have been removed from expenditure forecasts whilst we complete our analysis.

Given these changes, security and reliability initiatives amount to $19 million over the planning period and include:

- Network security enhancements (Sections 11.9.3, 11.10.3 and 12.15);
- Network protection enhancements (Section 11.12.3);
- Improvements in resilience (Section 11.10.5[8]);
- SCADA replacement (Section 9.4.2).

Our overhead line and conductor renewal programme also targets the worst-performing feeders (Sections 4.5.9, 12.12 and 12.13). We also want to ensure that the vegetation management work focuses on the worst-performing feeders (Section 12.19.2).

1.9 Preparing the business for the future



Until recently, our maturity has been a good fit for the needs of the network. However, we are now improving our asset management maturity to ensure we can meet the changing needs of the network and the increasing complexity of our operating environment (refer to Section 5.6).

We have embarked on an asset management improvement plan to enhance asset management maturity (see Section 9). The improvement plan comprises three parts:

- Enhancing policies, processes and procedures;
- Enhancing IT/OT systems (Electra's Digital System Strategy Plan);
- Enhancing asset management data.

Regarding process improvements, our focus is on updating our policies and procedures across design, construction, commissioning, inspection and maintenance and contingency plans.

Over the past couple of years, we have implemented a new load flow modelling software, upgraded our core financial system, continued to refine CBARMM, and, at the time of writing, are implementing a new system to manage risks. We are progressing an update to our GIS and are in the planning phase to implement an enterprise asset management system (EAMS). This will allow us to align our core asset management processes to the best-practice processes, enable us to manage our assets more efficiently and effectively.

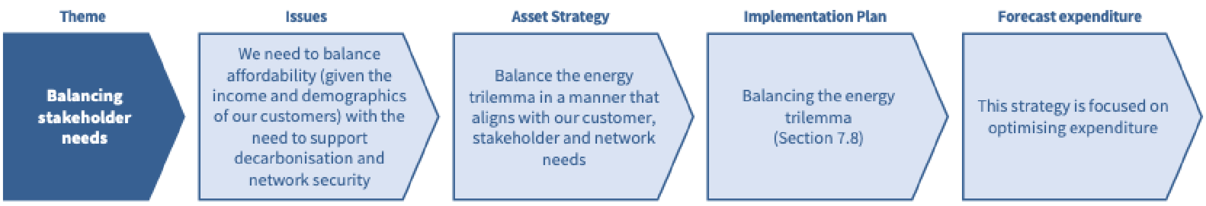
[8] We have a reliability improvement target for our resilience initiative. However, we have not yet specified the resilience projects. We have only recently finalised our resilience strategy, and the projects are being considered over the coming year.

The OT developments are focused on our core SCADA and ADMS operational systems. Our SCADA system is reaching end-of-life, and newer systems offer opportunities to increase resilience and cybersecurity. Our current SCADA and ADMS application layers are becoming outdated, with some areas of limited functionality, which we plan to upgrade or replace. These planned upgrades will ensure we keep pace with the evolving operating environment and prepare for the energy transformation.

The volume and use of data is increasing across all business areas, and our need to maintain data quality is growing as well. As a result, we have approved the implementation of a data transformation roadmap. This roadmap will guide the processes, policies, and technologies for data collection, storage, management, and analysis across the business. Our data transformation roadmap will enable us to make informed, data driven decisions.

This strategy impacts capex by $12 million over the forecast period, but most of the impacts are seen in opex, where there is an increase in personnel (as maturity improves and services increase) and in IT, as many of the new systems are now software-as-a-service. We are also actively engaging and collaborating with our peers seeking opportunities for shared services where it is both practical and efficient to do so.

1.10 Balancing stakeholder needs



Balancing the needs of stakeholders is essential in all aspects of our business. We have adopted the energy trilemma as a tool to consider this balance (from an asset management perspective). The energy trilemma is a well-recognised model for assessing the optimisation and balance across security of supply, affordability to customers, and sustainability (refer to Section 5.7).

In the energy context, the three limbs refer to:

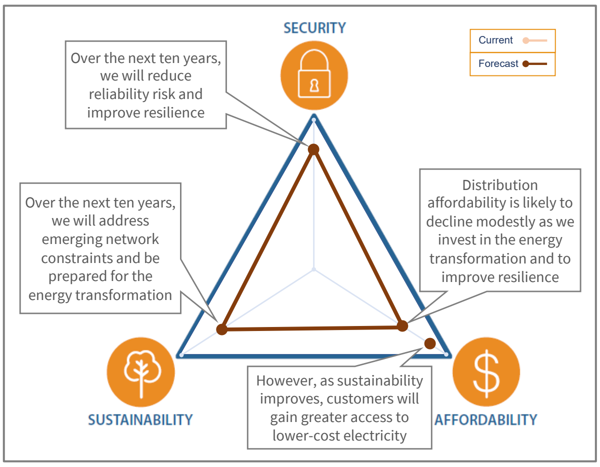
- **Security** means the ability to meet current and future energy demands reliably, as needed by our customers, including being resilient to external events (reliability is the measurable outturn of security for a distribution business);
- **Sustainability** means supporting New Zealand's energy transformation, minimising emissions, and adapting to climate change. In the AMP, we are principally concerned with supporting the energy transformation;
- **Affordability** means the cost of, and access to, energy (of which electricity is an increasingly important component).

Our current energy transformation balance (Figure 1) favours security and affordability, as we are only in the early stages of preparing for the energy transformation.

- **Security:** Electra's reliability has consistently ranked in the best-performing quartile over the past five years and has been less volatile than the industry and our semi-urban peers. However, we have further work to do to assess and improve resilience. The broader issue of energy security, including electricity generation and wholesale market activity, is outside the scope of our AMP.

- **Sustainability:** We developed an energy transformation roadmap in 2021 and have been progressing with its implementation, which remains in its early stages. We are not yet seeing material impacts from electrification, the uptake of DERs, and material changes in customer behaviour. However, our network analysis indicates that constraints will emerge on the network (depending on our ability to control demand through access to flexibility);
- **Affordability:** Since 2013, our distribution prices have declined in real terms.[9] Given the concentration of older people and the generally low income of our customers, affordability is a key strategic consideration for the business.

Figure 5: Electra's current and forecast energy trilemma balance



This AMP will affect the balance of the energy trilemma over the coming years (Figure 1). Our investment to address growth, prepare for the energy transformation, and renew our ageing asset fleet are increasing. The increase in capital expenditure will ensure that we continue to perform strongly on security and enhance sustainability. This will affect affordability. However, as sustainability improves, customers will gain greater access to lower-cost electricity (as a substitute for pricier fossil fuels), thereby enhancing their overall affordability (refer to Section 7.8).[10] Defining the impact on the energy trilemma balance is an ongoing area of work, and we will be including more information on this in future AMPs.

1.11 Future targets

We have comprehensive performance targets that are consistent with our asset strategies, stakeholder interests, and customer expectations (refer to Section 7).

We are committed to ensuring the health and safety of our employees, contractors, customers, and the public. We have a comprehensive health and safety system aimed at achieving zero LTIs (concerning critical risks), and we predominantly measure safety performance using leading indicators—which is the best way to ensure that we influence safety outcomes. We have commented on our prior performance in Section 4.2.

Figure 6 and Figure 7 show our primary reliability performance targets, including the planned risk mitigations (other targets are included in Section 7). We expect a 50% probability of achieving the unplanned SAIDI target in FY2036 (including the further reliability risk mitigations that are under consideration). Having forecast performance to at least achieve this probability strikes the right balance between investing more in reliability and accepting that, in some years (due mainly to weather), we will exceed the target.[11]

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[9] Based on the 2013 to 2023 Information Disclosures.

[10] Assessed by Sapere in their recent report for the Electricity Networks Association https://www.ena.org.nz/news-and-events/news/total-household-energy-cost-to-reduce-over-time/

[11] Based on our historical performance, a worst-case (1 in 10 years) reliability outturn will be a SAIDI of 84 minutes. This is 33% above target, but will occur once in every 10 years. Electra's actual and target performance is based on RAW SAIDI and SAIFI. That is, there is no normalisation for major events. This differs from regulated EDBs, which normalise for major events.

We are forecasting an increase in planned outages. This reflects the planned increase in work volume and an increase in work on the underground network. Even with this increase in planned outage, we will still perform significantly better than our peers. Planned outages are notified in advance and generally cause less inconvenience for customers.

Figure 6: Unplanned outage duration

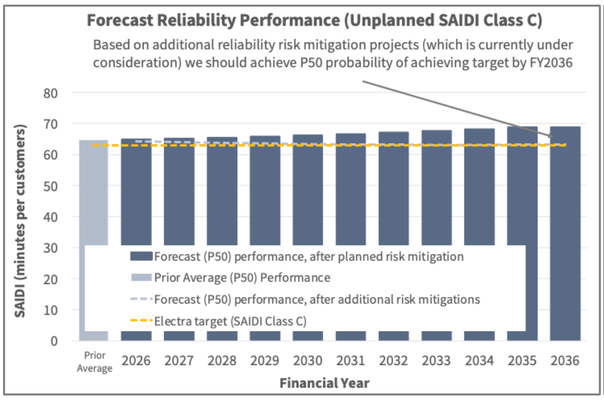
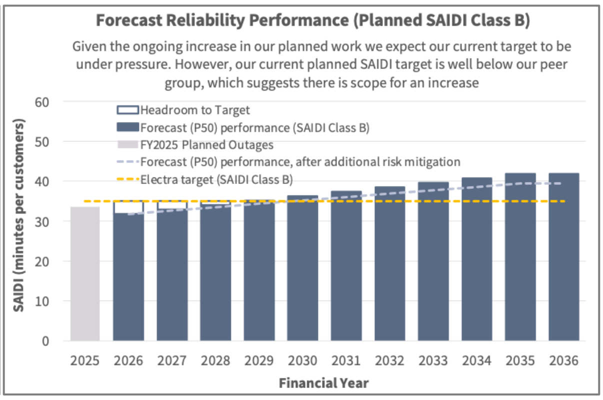


Figure 7: Planned outage duration



We also have a range of asset performance and work delivery targets. We are forecasting improvements in our performance in both these areas over the coming decades.

1.12 Delivery capability

Over the last decade, our resourcing strategy and Electra’s in-house resources have evolved to support the business's needs. Our strategy continues to evolve in response to our corporate and asset management strategies, recent delivery performance, national resource constraints, increasing work volumes, and our aging workforce (refer to Section 13).

Since our last AMP, we have responded to the various resource challenges through a range of initiatives, including:

- Establishing a new Design and Engineering team focused on engineering standards, design, and field assurance within the Asset Management Team. This will be supported by a group of preferred external designers for specialist work and to assist with peak workloads;
- Moving Network Control within the Asset Management Team to more closely align with the engineering teams;
- Within the Delivery Team, we have increased the project management capabilities;
- Building stronger relationships with a shortlist of approved contractors. This is to support an increase in core capex work and changes to our customer-initiated work process. Excluding major material purchases, external work will increase from around $6m p.a. in FY27 to F29 to around $10m p.a. from FY30;
- Enhancing the Digital Team's resources to support the data strategy.

1.13 Risk management

Electra faces a wide array of risks, not only those inherent in operating an electrical network but also external threats such as legislation, environmental changes, and stakeholder satisfaction. Beyond obvious physical dangers like cars hitting poles, vandalism, public safety issues, and storm damage, the network business is subject to a broader spectrum of risks that must be addressed. As a lifeline utility, we acknowledge our duty to keep the network safe, secure, and resilient.

We completed a revision of our risk management policy and framework over the past 12 months. Our approach to risk management is built on identifying the main challenges facing the network, developing strategies to address these issues, and setting out clear implementation plans to achieve the desired levels of performance.

Our policy and framework is based on the internationally recognised standard AS/NZS ISO 31000:2018. This system has identified significant business risks, including regulatory change, staff retention and recruitment, climate change and sustainability, decarbonisation, harm to workers and the public, and cyber security. We have developed a range of controls to manage these risks.

Operating and maintaining an electrical network involves hazardous situations with risks that cannot always be eliminated. For this reason, we operate a mature safety management system (refer to Section 13.6). This system includes a comprehensive range of controls, including hazard identification, certification, training and auditing (amongst many others).

Cyber-related attacks continue to increase globally and in New Zealand. We have carried out a series of assessments and undertaken a series of activities on cyber security controls. We continue to develop and enhance our cyber security controls, particularly concerning our operational technology.

1.14 Expenditure forecasts

Our forecast capital expenditure (capex) is higher than in the 2025 AMP due to the change in how we recognise customer connection capex. Operational expenditure (opex) is lower than the 2025 AMP, largely due to changes in emergency management and network support costs.

The capex forecast for the next five years is $162m (
Table 1), before deducting capital contributions. Compared to the 2025 AMP, this is an increase of $9.5m (6%).

The material drivers of the increase in capex over the first five years are:

- A $15.7m increase in customer connection capex, which reflects the change in our capital contribution policy;
- A $2.8m increase in system growth capex due to the change in timing of zone substation work planned for FY26, but now forecast for the FY2027 to FY2031 period and an increase in distribution transformer and switchgear upgrades due to the change in our capital contribution policy (refer to Sections 11.9 and 11.13);
- A $14.4m decrease in quality of supply capex, due to reclassification of the expenditure of some initiatives whilst the costs and benefits are reviewed and their impact on the energy trilemma is assessed;
- A $6.2m increase in non-network capex due to the change in timing for the development of a new Levin depot and higher vehicle replacement costs for the Service Delivery Team (refer to Section 13.7);
- Minor increase in asset renewals ($0.4m) and a minor reduction in asset relocations ($0.9m) and other reliability, safety and environment ($0.4m);

However, after deducting capital contributions, net capex drops to $144m for the first five years. Compared to the 2025 AMP, this represents a $3.3m (2%) reduction.[12]

The capex forecast for the 10-year planning period is $300m, which is $20m higher than the 2025 AMP.[13] Again, the driver for the increase is the change in our capital contribution policy and higher system growth capex. These increases are offset by a reduction in asset renewals, which reflects the optimisation work undertaken over the past 12 months.

Total opex forecast for the next five years is $130m (Table 2). Compared to the 2025 AMP, this is a decrease of $4.9m (4%).

The material drivers of changes in opex over the first five years are:

- A $1.2m decrease in business support costs. The reduction is primarily lower overall IT project and data strategy costs (refer to Section 9.8);
- A $3.4m decrease in system operations and network support costs, which reflects a reduction in our forecast of additional IT/OT costs. The forecasts include the project costs to implement the EAMS, but now exclude the costs for the replacement of the ADMS (refer to Section 9.9);
- A $1.9m reduction in service interruption and emergency management costs, which reflects our current review of these costs in a normal year (refer to Section 12.19.1);
- A $1.5m increase in our vegetation management programme in response to real cost increases an increase in vegetation work due to growth rates, climate change and a focus on our worst performing feeders (refer to Section 12.19.2);

For the 10-year planning period, network opex is $260m, which is $10m lower than the 2025 AMP.[14]

Figure 8: Capex Forecast (Real 2026$, before capital contributions)

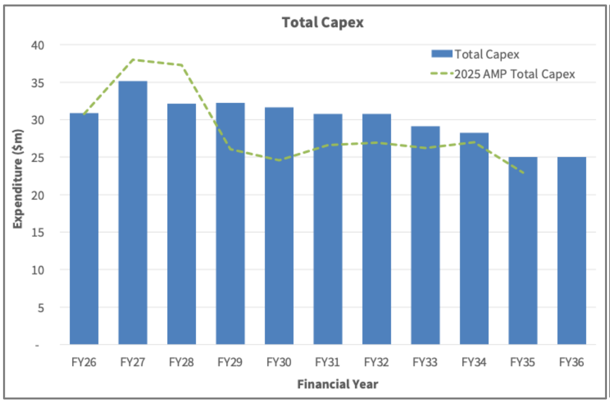


Figure 9: Opex Forecast (Real 2026$)

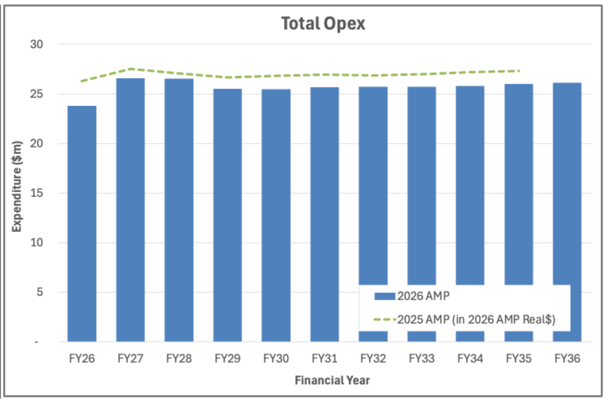


Table 1: Capex Forecast (Real 2026 $000, before capital contributions)

Forecast	FY27	FY28	FY29	FY30	FY31	FY32	FY33	FY34	FY35	FY36	FY27-31
Capex 2026 AMP	35,165	32,113	32,262	31,624	30,787	30,739	29,120	28,257	25,007	24,990	161,951
Capex 2025 AMP	37,964	37,292	26,051	24,579	26,619	26,924	26,195	26,995	22,951	-	152,505
Change	**(2,799)**	**(5,178)**	**6,211**	**7,044**	**4,167**	**3,815**	**2,926**	**1,262**	**2,055**	**-**	**9,446**

12 This is a like-for-like comparison. For FY2025 we have included Vested Assets and deducted Capital Contributions.

13 When comparing forecasts to the 2025 AMP, we can only compare the period FY2027 to FY2035 as this was the extent of the forecasts included in the 2025 AMP. Before deducting Capital Contributions.

14 When comparing forecasts to the 2025 AMP, we can only compare the period FY2027 to FY2035 as this was the extent of the forecasts included in the 2025 AMP.

Table 2: Opex Forecast (Real 2026 $000)

Forecast	FY27	FY28	FY29	FY30	FY31	FY32	FY33	FY34	FY35	FY36	FY27-31
Opex 2026 AMP	26,596	26,653	25,548	25,608	25,729	25,858	25,767	25,960	26,026	26,291	130,134
Opex 2025 AMP	27,502	27,070	26,653	26,816	26,949	26,884	26,998	27,173	27,335	-	134,990
Change	**(906)**	**(417)**	**(1,105)**	**(1,208)**	**(1,220)**	**(1,026)**	**(1,231)**	**(1,213)**	**(1,309)**	**-**	**(4,856)**

1.15 Concluding comments

This 2026 AMP is a continuation of our programme to update our AMP. Over the past 12 months, we have sought to optimise the investment requirements, and this 2026 AMP sets out the prudent asset investments to maintain safety, current service levels and prepare for demand growth.

After deducting capital contributions, our capex forecasts have reduced by $10m, and our opex have reduced by $10m compared to the 2025 AMP (over comparable AMP periods). This is a result of our ongoing work to optimise our asset management activities and to invest efficiently in the network.

This AMP describes our plans to develop and renew the network and build our business capabilities. It will ensure that the assets are managed for the long term and that the required level of performance can be delivered. We have defined improvement plans to close gaps where they exist.

This AMP defines our resilience strategy, which will ensure that high-impact asset-related risks are understood and managed.

The primary purpose of this AMP is to provide information to assure stakeholders that the assets are being managed for the long term, the required level of performance is being delivered, that the business is efficient, and asset-related risks are being managed. This AMP meets this purpose, and we have included a reconciliation of the AMP content to the Information Disclosure requirements in the appendices.

About this plan

2. Introduction, Purpose and Responsibilities

2.1 Introduction to this AMP

This AMP outlines how we intend to manage the network over the next ten years and beyond. It covers the current state of the network, our targets for network performance and customer service and our strategies and plans for the network.

We have been through a period of modest growth, with a network that has performed well and has not shown material signs of deteriorating asset health and risk. However, things are now changing. Connection growth across both the Kāpiti and Horowhenua regions has slowed over the past 12 months due to local and national economic factors. We expect connection growth to recover in the medium term. New Zealand's strategy to decarbonise through electrification could further boost demand. Our assets are ageing, and the presence of end-of-life drivers is increasing. The skills needed to manage the network are also evolving as we shift from a steady-state towards a future where our network plays a crucial role in New Zealand's decarbonisation efforts. Greater coordination between networks, customers, generators, retailers, aggregators, traders, and Transpower in its role as System Operator will be required.

In this AMP, we describe how we are responding to these changes.

The 2025 AMP represented a revised *baseline* view of the investments required in the network and the business. It was a significant revision over the 2023 AMP. Over the past 12 months, we have sought to optimise the investment requirements, and this 2026 AMP sets out the prudent asset investments to maintain safety, current service levels and prepare for demand growth; that is, it represents the results of the optimisation process to date.

This AMP is organised the AMP into three parts:

- Part 1: The key issues facing our network;
- Part 2: Strategies to address the key issues and performance;
- Part 3: How we are implementing our strategy.

The planning period for this AMP is from 1 April 2026 to 31 March 2036.

The Board approved this AMP on 26 March 2026, and the corresponding Director Certificate is included in the appendices.

2.2 Purpose of this AMP

The primary purpose of this AMP[15] is to provide information to assure stakeholders that:

- The assets are being managed for the long term;
- The required level of performance is being delivered (and where there are gaps, improvement plans are being implemented);
- Our business is efficient (so the distribution prices are no higher than they need to be) and that we consider affordability in our trade-off decisions;
- Asset-related risks, particularly high-impact asset-related risks, are understood and being managed.

[15] Commerce Commission, "Electricity Distribution Information Disclosure Determination", Section 2.6.2.

This AMP meets this purpose, and we have included a reconciliation of the AMP content to the Information Disclosure requirements in Appendix 1.

2.3 Key changes since our last full AMP

Much of the content in this AMP is an update to that included in the 2025 AMP. However, there are some key changes in this AMP, including:

- The review of performance includes the performance for FY2025 (Section 4);
- Our view on reliability risk has softened on the back of recent good reliability performance, although headwinds remain (Section 5);
- We have included an efficiency strategy and revised efficiency measures (Sections 6 and 7);
- Due to uncertainty in relation to the timing and drivers for some system growth projects and further work on justification for our reliability improvement initiatives, some of these projects and programmes have been reclassified as concept (Section 11);[16]
- Our view on forecast reliability performance has moderated, given the combination of a softening of risk and the change in reliability improvement initiatives (Section 7);
- We have optimised our fleet plans for overhead structures, distribution switchgear, distribution transformers and power transformers (Section 12).

There are no changes to our view of the key issues facing the network or the asset management strategies that address them.

2.4 Our stakeholders

Stakeholders are defined as any person or organisation that affects or is affected by Electra's business. These include customers, the Electra Trust, employees, contractors, suppliers, energy retailers, Transpower, Councils, Waka Kotahi, landowners, industry bodies, regulatory authorities, iwi, mana whenua, and the general public. We have identified the relevant interests of these stakeholders and how these link to the management of the network (as shown in Table 3).

Table 3: Stakeholder interests

Primary interest of stakeholders	Linkage to asset management
Safety	• Electra keeps the public safe by keeping all assets structurally sound, live conductors are well out of reach, all enclosures are secure, and all exposed metal is earthed • Our Safety Management System (SMS) and Public Safety Management System (PSMS) provide structured approaches to maintaining the safety of the public, contractors and staff • We provide staff all necessary equipment, safe work practices, and will stop work in unsafe conditions • Motoring safety is assisted by placing above-ground structures as far as practically possible from the carriageway within the constraints of private land and road reserve • We engage with stakeholders providing education, raising awareness about working and living safely near Electra's assets • We offer safety services such as asset location, stand-overs, isolations, and close approach permits
Reliability and supply quality	• Electra accommodates stakeholders' needs for supply quality through its security of supply, management of asset health, resilience strategy and operational practices • We pursue published security of supply standards

[16] These projects and programmes are still included in the AMP, but not included in the expenditure forecasts in Schedule 11a.

Primary interest of stakeholders	Linkage to asset management
	• We seek opportunities to increase system resilience and have developed a resilience strategy and planning standard. We have a dedicated engineering resource allocated to determine areas where resilience improvement is appropriate • We monitor the condition of our assets and direct our asset renewal and maintenance programmes to maintain asset health and minimise the risk of outages • Our operational practices ensure outages are minimised, and when they occur, they are restored quickly
Financial sustainability	• Electra satisfies stakeholders' needs by providing electricity distribution services at a level of quality that our customers are willing to pay for. Electra balances the cost of providing a more reliable or resilient service, with whether that level of service is affordable. • Electra aims to provide a satisfactory discount to Electra's consumers/owners, balancing the size of the discount with affordability and network investment requirements.
Affordability	• Affordability must be managed in line with regards to our regional demographic and our customers' ability to pay
Environmental sustainability	• Electra ensures it complies with all environmental regulations and requirements • We pursue a sustainability policy incorporating good industry practice • We consider sustainability and our impact on the environment in the choices we make about how we operate and invest in the network, the materials we purchase, and our installation methods from cradle to grave • We engage with energy users in our region to coordinate electrification requirements enabling the sustainability and energy transition of stakeholders in our regions
Compliance	• Electra ensures that all safety issues are adequately documented and available for inspection by authorised agencies as well as for learning by the staff and contractors • We operate a robust compliance process to ensure we comply with all regulatory, statutory and consenting requirements • We disclose performance information in a timely and compliant fashion.

Our planning standards, customer survey and performance targets provide the relevant standards for assessing compliance and performance against the primary interests. We report on the customer survey and performance in Section 5, define our targets for coming years in Section 7, and discuss our planning standards in Section 11.4.

Where we have conflicts in stakeholder interests, we prioritise safety above all else. This is followed by balancing supply quality (given its impact on customers and the region), environmental sustainability, and compliance, whilst ensuring financial sustainability.

2.5 Our strategy

Electra's business strategy is captured in our Statement of Corporate Intent (**SCI**), which defines our purpose, strategy, and values.[17]

Our purpose is:

> **To operate our region's electricity network safely and effectively, and support the growth and electrification of Kāpiti and Horowhenua**

Our strategy to deliver on this purpose is to:

Operate a safe, efficient, innovative and sustainable business which:

[17] https://electra.co.nz/wp-content/uploads/2025/07/SCI-2025-.pdf

- **Focuses on our core operations,**
- **Delivers the needs of our customers and communities in an affordable way,**
- **Supports the growth and electrification of our region,**
- **Invests for a clean energy future, and**
- **Demonstrates the clear value proposition from local trust ownership**

We have developed this AMP to support this strategy. In particular, this AMP demonstrates our focus on the network to ensure its performance meets the needs of customers and communities (Section 7.3). We have a strong focus in this AMP on supporting growth and electrification (Sections 10 and 11).

2.6 Asset management framework and improvements

We are implementing an asset management framework. This framework includes the key elements within ISO 55001 and guides our asset management activities. The framework provides a structure for the systems and processes to manage network assets effectively. It ensures that our asset management strategies, plans, and actions align with our vision, values, and corporate goals. It also ensures that services are delivered to meet the required standard.

Section 8 describes the asset management framework, and Section 9 describes the asset management improvement plan.

2.7 Accountabilities and responsibilities for asset management

Figure 10 shows our organisational structure. The responsibilities for asset management are shared across the executives and their respective teams; these include:

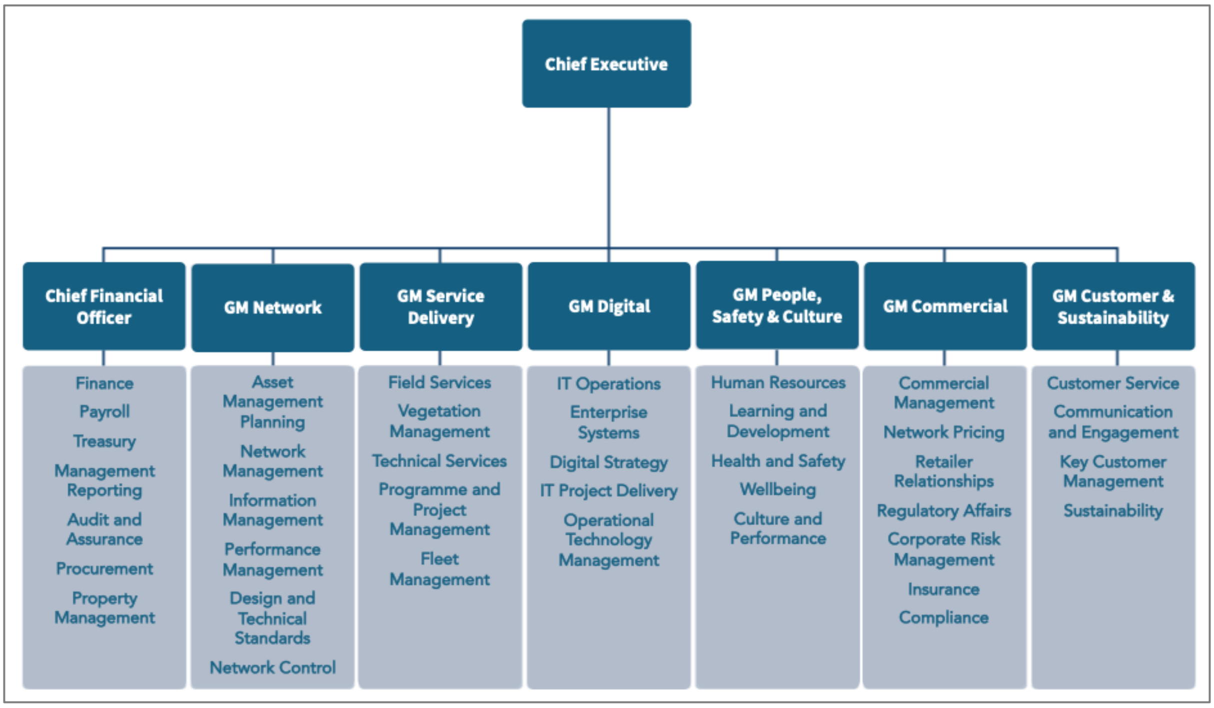
- Corporate strategy is the primary responsibility of the Board, Chief Executive and Senior Leadership Team;
- Strategic asset management is the primary responsibility of the Board's Asset Management Advisory Group, Chief Executive and General Manager Network;
- Health and safety is the responsibility of everyone in the business, and is the primary responsibility of the General Manager People, Safety and Culture;
- Asset management planning is the primary responsibility of the General Manager Network;
- Works programme management is the primary responsibility of the General Manager Service Delivery;
- Continuous improvement is shared across the Senior Leadership Team;
- Network control and managing the performance of the network is the primary responsibility of the General Manager Network;
- Risk management is overseen by everyone in the business, and is the primary responsibility of the General Manager Commercial;
- Human resource capability management is the primary responsibility of the General Manager People, Safety and Culture;
- Information management and the development of information systems is the primary responsibility of General Manager Digital;

Accountability and assurance that these activities are being undertaken to the required standards are achieved through:

- The Electra Trust have oversight of the company through the SCI, annual reporting, external auditing process, and regular reporting to the Electra Trust;
- The Board have oversight of the Chief Executive and the company through the company's management reporting, compliance programme, internal audit programme, asset management advisory group, audit and risk committee, health and safety committee, and approval of expenditure forecasts, annual budgets, asset management plans, and other tactical and operational plans;
- The Chief Executive and Senior Leadership Team oversee the company's asset management planning, delivery, and operational activities. This is supported by Electra's policies, procedures, standards, and management and operational reporting processes, which cover all aspects of the business's asset management and operational areas.

The delegated authority and position descriptions attached to all roles within the business support the accountability framework.

Figure 10: Organisational structure



2.8 Communication and participation in developing this AMP

This AMP is a key document for Electra and sets the direction for developing and maintaining the network. We communicate the key features of asset management planning and activities to the employees, contractors, and other stakeholders. Key features of our communication approach are:

- The Board conduct due diligence via their asset management advisory group. This covers the asset management policy, strategy, risks and other material matters;
- For those employees involved in the AMP development, we communicate the asset management policy, strategy and standards at the commencement of the AMP update process;
- For those employees and stakeholders involved in delivering capital projects, inspections and maintenance works, we communicate the plans and projects well ahead of the forthcoming financial year. Our construction, inspection and maintenance standards are available via Electra's contractors portal;

- For those employees involved with managing performance, we communicate the required standards ahead of the forthcoming financial year.

The AMP is communicated to our customers through publishing on our website.

2.9 Linkage to other documents

This AMP is the critical document to ensure that the assets deliver the required performance consistent with the needs of our stakeholders, the Statement of Corporate Intent, our strategy, and business plans. Within this document, the key link to stakeholders and strategy is through the asset management policy and asset management strategy (which are set out in Section 6). We achieve this through:

- Ensuring there is alignment between the strategies, plans and actions in this AMP and Electra's strategy, vision, values and corporate goals, where these goals are aligned with our stakeholder needs;
- Ensuring services are delivered to meet service levels and resilience to respond to high impact low probability events;
- Continuous improvement;

The linkage between the asset management plan and other corporate documents is shown in Section 8.3.

2.10 Significant assumptions

The significant assumptions used in this AMP are summarised in Appendix 2.

2.11 Forecast expenditure

Forecast expenditure included in this AMP is expressed in FY2026 real (i.e. constant price) dollars.

Part 1:

The key factors driving our asset management strategy

3. Network and Customer Overview

3.1 Introduction

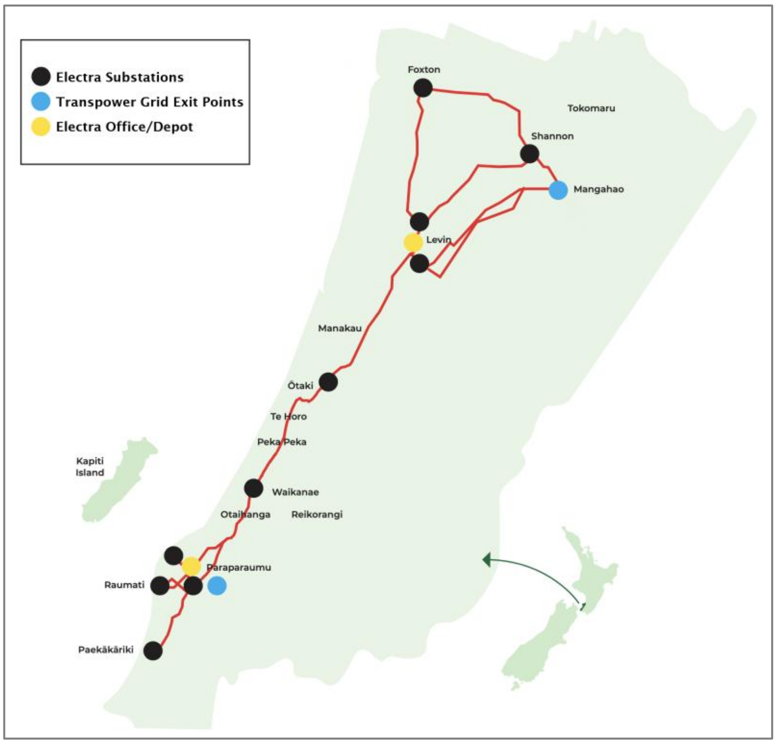
In this section we discuss the general characteristics of our customers and the network and consider the implications for our asset management strategies and plans. In summary, the implications are:

- Affordability is a key factor when we assess the energy trilemma balance given the age and income demographics of our customers (and beneficiaries);
- Customer behaviours are changing, which will have an impact on demand profile and control;
- Customers are currently afforded a high level of security at the sub-transmission and zone substation levels. This supports reliability and is consistent with the semi-urban customer base;
- Parts of our underground distribution network have a legacy architecture which features a very low number of switching points, which restricts the timely restoration of faults;
- Historical LV design standards have been conservative, which means we generally have good LV capacity headroom;
- Our demand profile has significant morning and evening peaks, which may present the opportunity to shift demand to daytime and overnight as electrification demand (particularly from EVs) increases;
- Firm capacity at the Mangahao GXP is exceeded, and we rely on Mangahao Generation to manage peak demand.

3.2 Network Area

As shown in Figure 11, Electra's network is spread over the Horowhenua and Kāpiti districts on the narrow strip of land between the Tasman Sea and the Tararua Ranges, stretching from Foxton and Tokomaru in the north to Paekākāriki in the south. The network covers approximately 1,628 km^2.

Figure 11: Network supply area



The Horowhenua district has an estimated population of 38,400 in 2025[18], with most people living in Foxton, Shannon, Levin, and several beach settlements.

The Kāpiti Coast district has an estimated population of around 58,000[19] in 2025, with most people living in the towns Ōtaki, Waikanae, Paraparaumu, Raumati, Paekākāriki, and other beach settlements.

3.3 Customer overview

Our network supplies around 47,000 ICPs[20], of whom 79% are domestic customers with an average annual usage of less than 6,000 kWh.[21] We have a higher proportion of low users than most other networks[22]. The number of low users is higher in our region due to the low household occupancy, gas reticulation, the high proportion of people aged over 65 and the low average income.[23]

A further 20% are larger domestic and small commercial customers. These customers are also relatively low users and consume 12,650 kWh per year on average.[21]

A notable absence in our region is any single very large industrial user. Our 574 small industrial and larger commercial customers consume 27% of the electricity conveyed on the network. These customers are in food processing and production, manufacturing and retail trade.

Given the low concentration of industrial consumption, Electra faces a low revenue risk from its large industrial customers.

Given the concentration of older people and the generally low income of our customers (refer to Figure 12 and Figure 13), affordability is a key strategic consideration for the business. We discuss this further in Sections 5.7 and 7.8.

Since 2013, new connections have grown by around 0.8% p.a. Connection growth has increased in recent years, and we are now connecting over 400 customers p.a.[24] As mentioned in the introduction, we expect growth to accelerate further, and our forecasts are discussed further in Sections 5, 6 and 10.

Low fixed charge (LFC) tariffs are being phased out nationally over a 5-year period ending in 2027. Electra will continue working with retailers to ensure our customers are transferred to the correct tariff.

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[18] Estimated at 30 June 2025. Source: Infometrics.

[19] Estimated at 30 June 2025. Source: Infometrics.

[20] As at 31 March 2025.

[21] Source: 2025 IDs, Schedule 8b.

[22] Of the 40 network regions reported by the EA, we rank as the 8th lowest average consumption per residential customer. Source: https://www.emi.ea.govt.nz/ residential consumption league table report. For CY2024.

[23] Horowhenua and Kāpiti have 2.4 and 2.3 occupants per house, compared to the national average of 2.6. Source: Stats.nz
Horowhenua and Kāpiti have 26% and 27% of people over the age of 65, compared to the national average of 17%. Source: Stats.nz
Horowhenua and Kāpiti have average household income of 75% and 88% of the national average. Source: Infometrics

[24] This was 418 in FY25.

Figure 12: People over the age of 65 in our Region[25]

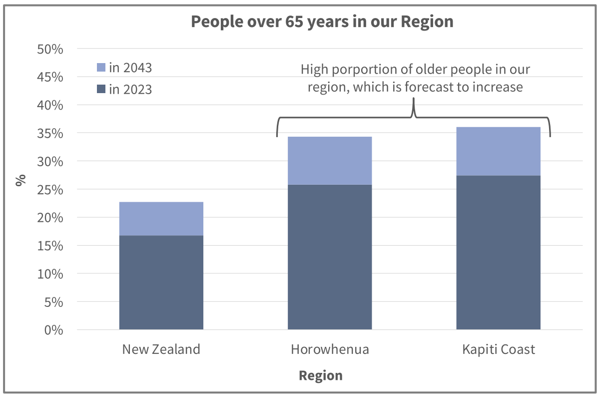
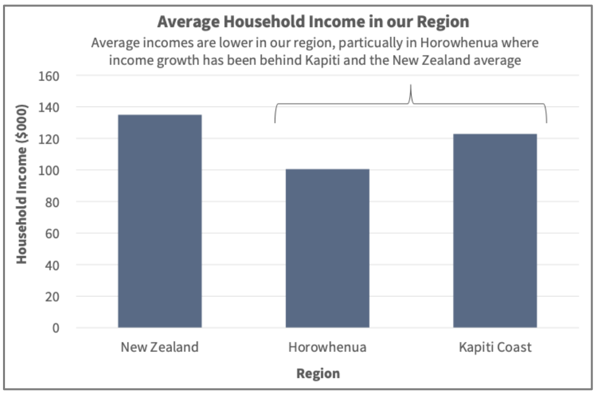


Figure 13: Average Household Income in our Region[26]



3.4 Network Demand Profile and Historical Growth

In FY2025, the network delivered 428.1 GWh of electricity and reached a peak demand of 102 MW (76 MW from the Mangahao and Paraparaumu GXPs and 26 MW from distributed generation). This was lower than the FY2022–FY2024 average peak of 110 MW because, on the system peak day, Paraparaumu's local peak did not occur at the same time, and Mangahao had significant load control in place. These timing and load-management effects were unusual, so the lower peak does not indicate a downward trend.

The northern (Horowhenua) network is tied to horticulture, dairy farming, and Levin's urban and commercial areas. The Horowhenua demand profile has a very slight morning peak and typically higher daytime demand (compared to the Kāpiti Coast), reflecting the greater number of commercial and light industrial customers in the region. For FY2025, the peak day coincided with cold temperatures, resulting in an increased peak demand compared to FY2024 (refer to Figure 14).

The southern (Kāpiti Coast) network is predominantly urban and includes light commercial, rural lifestyle, and agricultural production. Many customers on the southern network commute to Wellington, so daytime demand is considerably lower than evening demand, resulting in a low load factor. Working-from-home arrangements have reduced this impact in recent years. The southern region's demand profile reflects the high number of domestic consumers, resulting in strong evening winter peak demand (refer to Figure 15).

Since FY2013, our evening peak has been growing faster than total consumption, reflecting more energy consumed in the early evening. We expect this to relate to greater electricity use for heating, greater use of electrical appliances and devices, and a deterioration in the effectiveness of hot water load control.

The amount of control through ripple control of hot water load is slowly decreasing. We assume that customers will replace their resistively heated hot water cylinders with more efficient heat pump technology. Also, as the energy transformation evolves, we expect to see hot water control combined with electric vehicle charging and offered in flexibility markets (discussed further in Section 10).

Around 21% of our customers use reticulated gas or LPG bottles. The likely transition from gas to heat pumps will have a small impact on demand and profile over the planning period.

[25] Stats NZ. Subnational family and household projections, population by living arrangement type, and age, 2018(base)-2043

[26] https://www.infometrics.co.nz/product/regional-economic-profile

Both regional demand profiles are materially "peakier" than the national demand profile (and FY2025 being peakier than FY2024)[27]. This may present an opportunity to shift demand from the morning and evening peak to daytime and overnight, which could be used to reduce demand growth from electrification.

Figure 14: Horowhenua Load Profile

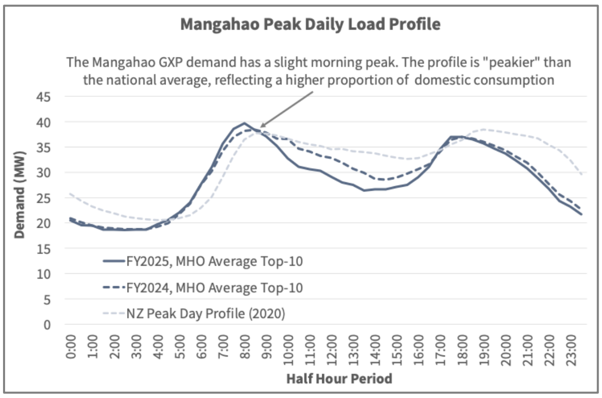
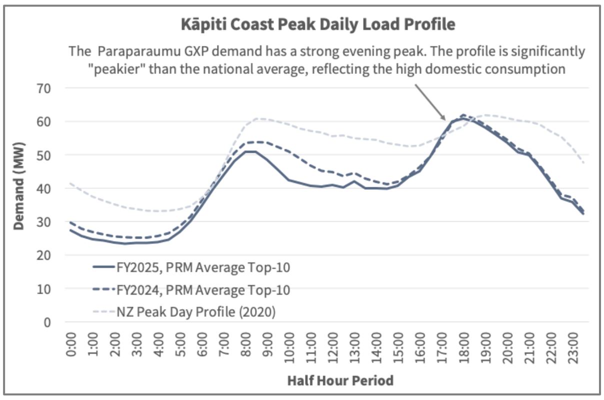


Figure 15: Kāpiti Coast Load Profile



We have begun to see the impacts of changing consumer behaviour on our load profile and expect this to increase over time. We are seeing the impact of retailers' price signals (e.g. the "free hour of power" and other incentives to shift usage), where our peak demand is shifting later in the evening on some days when these incentives are offered (this is known in the industry as consumer herding). Given our relatively low EV and solar PV penetration rates, we are not yet seeing any material impacts on our load profile. However, we expect this to change.

Presently, we still utilise hot water ripple control to reduce peak demand. The impact of hot water control is included in Figure 14 and Figure 15 and amounts to around 3.9 MW on the northern (Horowhenua) network and 6.1 MW on the southern (Kāpiti Coast) network. The impact of consumer herding on the peak demand is reducing the effectiveness of our hot water load control.

About 41% of energy is conveyed through the northern network and about 59% through the southern network.

The changing consumer behaviour will likely impact peak demand, and our asset management strategies and network planning need to incorporate this uncertainty. We discuss this further in Sections 6, 10 and 11.

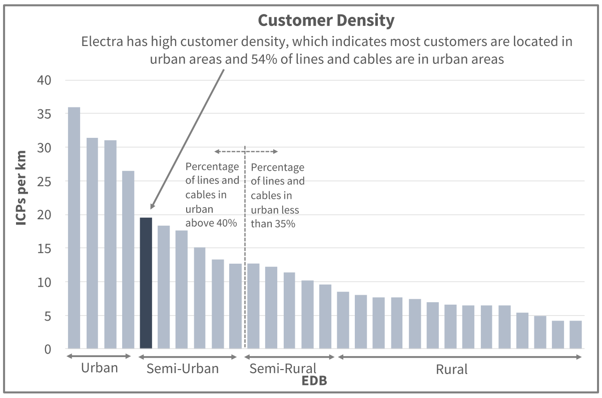
3.5 Network Configuration

3.5.1 Customer density

Figure 16 indicates that our customer density is higher than most EDBs and consistent with other semi-urban networks. Around 54% of our lines and cables are in urban areas. Most customers are in Paraparaumu, Waikanae, Raumati, Ōtaki, Levin, and Foxton.

[27] Our load profile in FY2025 was flatter

Figure 16: Customer Density Benchmark[28]



3.5.2 Sub-transmission network

Our network is electrically contiguous but generally operates as two separate networks:

- The northern network is supplied from the 110 kV Mangahao GXP and Mangahao generation and supplies Levin, Foxton and Shannon substations in a ring configuration (refer to Figure 17);
- The southern network is supplied from the 220 kV Valley Road Paraparaumu GXP and supplies Paekākāriki, Paraparaumu East and West, Raumati, Waikanae and Ōtaki substations in a double spur configuration (refer to Figure 18).

All zone substations, except Paekākāriki, are afforded N-1 sub-transmission and zone substation transformer security. This is consistent with the semi-urban nature of our customer base.

The northern sub-transmission network is predominantly overhead construction. It traverses rural areas and flood plains around Foxton and Shannon and is exposed to adverse weather and vegetation. Over 60% of the lines are located away from roadways, which reduces exposure to vehicle damage but can delay repairs due to ground conditions.

The southern sub-transmission network is 73% underground, reducing the exposure to vehicle and vegetation damage. For the overhead sub-transmission lines, over 55% are located away from the roadway, reducing exposure to vehicle damage.

[28] Electra is a semi-urban network. It has 54% of its lines and cables in urban areas and an ICP density of 19.5 ICP per km. This is consistent with other semi-urban EDBs (Aurora, Orion, WEL Networks, Unison and Counties) that have an average proportion of urban lines and cables of 55% and an ICP density of 16.1. Typically, urban networks have an ICP density above 25, semi-rural networks have an ICP density below 13, and rural networks below 8 ICP per km.

Figure 17: Northern 33/11kV network

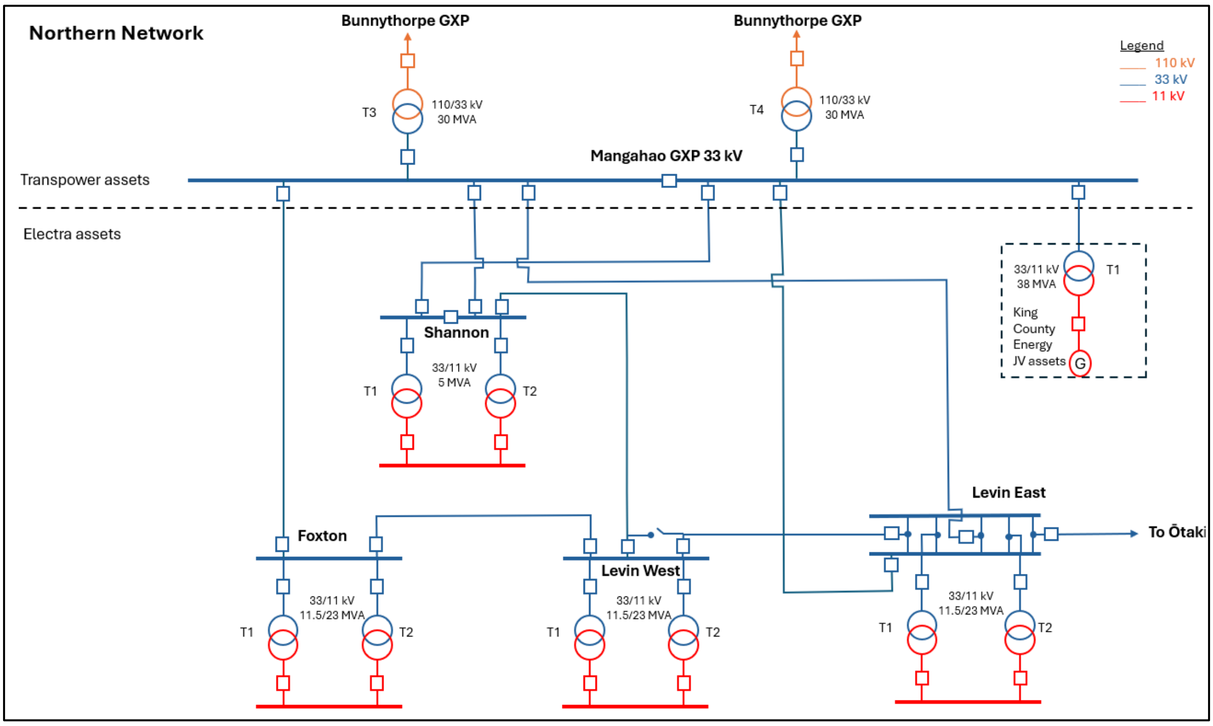
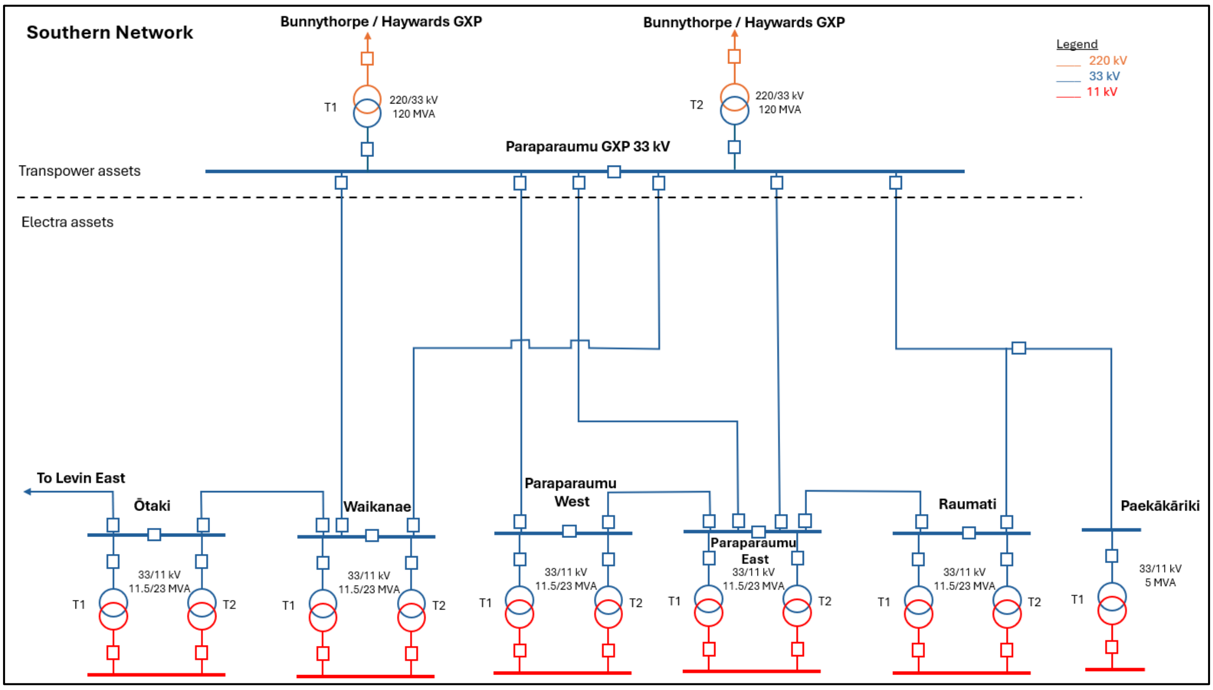


Figure 18: Southern 33/11kV network



3.5.3 Distribution network

The 11kV distribution network comprises interconnected radial feeders. It is overhead in older parts of the urban network, particularly in towns on the northern network and Ōtaki. As the southern region has grown, underground distribution has been installed, and that network is now 66% underground, twice that of the northern network.

Overhead lines are exposed to adverse weather, vegetation, and vehicle damage (when located near the roadway). This is why the fault rate on the northern network is 50% higher than the southern network.[29] Whilst the fault rate is higher on the northern network, the SAIDI contribution is around 45% of the total SAIDI. This is because faults in the southern region impact more customers, reflecting higher customers per feeder and less feeder sectionalisation.

Our overhead network has a reasonable level of recloser and sectionaliser density. Reclosers and sectionalisers allow the network to be segmented in the event of a fault and help improve reliability by reducing the area impacted by an outage.

Where a distribution feeder supplies both urban and rural customers, we have installed electrical protection (a line recloser) at the town boundary to maintain an appropriate level of service to our urban customers (as there are more outages in rural areas due to the length of the line exposed to hazards).

Our underground network has a legacy architecture that features very low ground-mounted switch density. While faults on the underground network are rare, having sufficient switching points allows for quicker network restoration and improves reliability when they do occur. This is an area for improvement, as outlined in Sections 6.3, 11.10.3 and 11.10.4.

Figure 19: Overhead Recloser and Sectionaliser Density

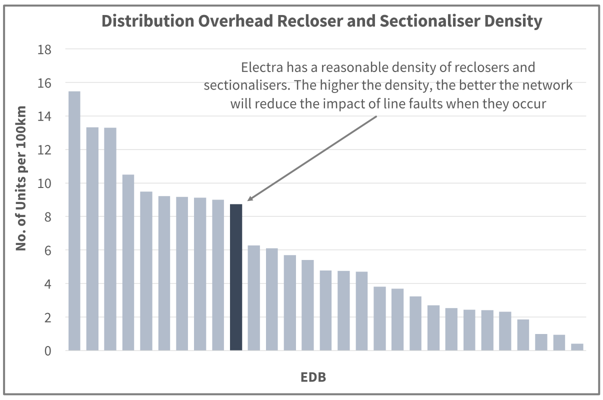
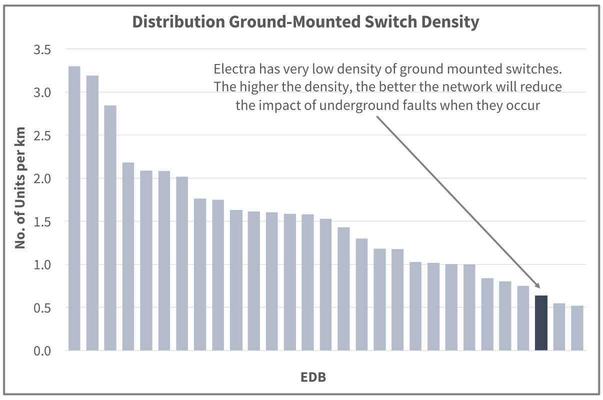


Figure 20: Underground RMU, Ground Mounted CB and Switch Density



Generally, the peak loading of feeders is within the 70% capacity limits to allow headroom for back-feeding during faults. However, there are some feeders where loadings are approaching the 70% capacity limits, and this is discussed further in Section 11.10.2.

3.5.4 Low voltage system

When designing the urban LV network, Electra adopted a standard design ADMD of 3.5 kVA per dwelling (which has been used for decades). This standard exceeds the current (GXP and feeder level) ADMD of around 2.6 kVA per customer and has helped minimise issues with the low-voltage network (e.g., low-voltage complaints). It provides a very good basis for accommodating the forthcoming growth in EVs and solar PV.

The low voltage network is 49% overhead and 51% underground. There is still a significant portion of overhead LV conductors in urban areas. Most of the underground LV cables are in urban areas.

[29] This is the number of faults per 100km.

3.5.5 Fixed and mobile generation

Electra has owned a 500kVA mobile diesel generator since 2008. It is primarily used to maintain supply during planned and unplanned outages. We have contracts to use a small fleet of generators ranging from small single-phase units to larger 880kVA units. The use of generation to minimise the impact of outages is based on an economic and customer assessment—that is, the cost of the generation needs to be less than the value of the loss load that is avoided.

We also have a backup generator installed at the Bristol Street corporate office. This supports our control room and other business functions.

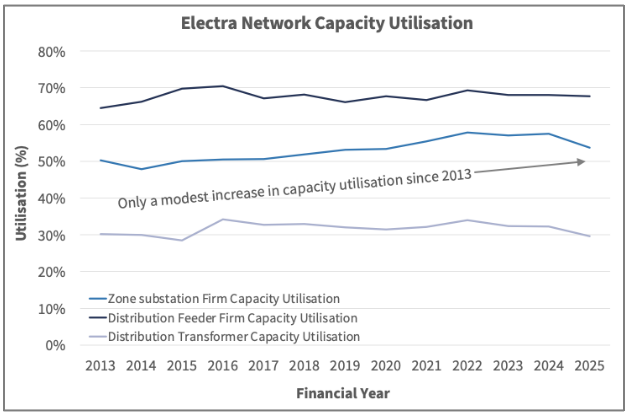
3.5.6 Standardisation

Over the preceding decades, Electra has adopted standardisation in the configuration and aspects of design. This standardisation means that the breadth of different technologies has been minimised, and the economics of spare holdings have been enhanced. This has improved our ability to maintain staff competency, reduced the risk associated with unfamiliar equipment, and reduced the cost of spares.

3.6 Network Utilisation

Over the past decade, Electra's network has had largely stable firm capacity, with modest demand growth, resulting in a modest increase in capacity utilisation (except for the reduction in demand for FY25, which, at this stage, we do not see as a trend). The capacity utilisation across zone substations, distribution feeders, and distribution transformers is generally within security limits. However, there are specific locations where growth is approaching capacity limits, as discussed in Section 11.

Figure 21: Network Capacity Utilisation



3.7 Grid Exit Points (GXPs)

As shown in Figure 17 and Figure 18, we obtain supply from Transpower's 110 kV Mangahao GXP for the northern network and from Transpower's 220 kV Valley Road Paraparaumu GXP for the southern network. We have metering and associated communication equipment installed at both GXPs.

Significant capacity is available at GXP supplying the southern network. However, current demand in the Horowhenua region at 42 MVA[30] is close to the capacity of the Mangahao GXP (at 44 MVA N-1-g firm, which

30 42 MVA is the peak ½ hour demand at the Mangahao GXP. The average of the top-10 peaks is 40.0 MVA. Data is for FY2025 (i.e. winter CY2024).

includes firm generation)[31]. The 38 MW Mangahao hydro generator supports supply security at peak times. This is discussed further in Section 11.8.

3.8 Distributed Generation

We have two large distributed generators embedded in the network: the 38 MW Mangahao hydro station and the two 0.96 MW diesel gensets at a customer site in Paraparaumu (although the site is not currently occupied). There are also 1,920 other small distributed generation sites with a combined capacity of about 10.6 MW[32]. We estimate that around 13% of these have batteries.[33]

We have been approached by several large solar and wind farm projects (over 1MW) for potential embedded connections. We are encouraging these start-ups and aiding them with their planning, equipment requirements, load flow studies, congestion determination, and alternative solutions for the customer to consider. The proximity of these proposed connections to our sub-transmission and substation assets has been advantageous in keeping connection costs down and reducing congestion of embedded generation on the distribution network.

The generation at Mangahao hydro station is currently required by Transpower System Operator to maintain GXP system security during peak demand periods. Its output currently supports the security of supply from the Mangahao GXP during peak demand. The current peak support arrangements are mutually beneficial for grid security and we have commenced discussions with the station owners to renew the Connection Contract. The Mangahao GXP transformers are reaching end-of-life[34], and the plans for replacing them are discussed in Section 11.8, including the impact on the embedded Mangahao station.

We discuss the future impacts of distributed generation, particularly solar PV, in Section 10.

31 The firm capacity of the GXP transformers is 30 MVA.

32 EA EMI, Installed distribution generation trend reports, as of 31 March 2025. Includes all solar sites.

33 Based on the New Zealand average: Source: EA EMI, Installed distribution generation trend reports, as of 31 March 2025. We used national data as our regional data looks to be under-reported.

34 Transpower have identified these for risk-based replacement between 2028 and 2030 in the 2025 Transmission Planning Report (Table 11.3, page 204).

4. Recent Customer Service and Network Performance

4.1 Introduction

This section reviews our customer and network performance. We monitor our performance against various measures, including customer service, safety, environmental, asset performance, network efficiency and work delivery. The systems described in Sections 9.4.1 and 9.4.2 are used to capture and maintain this data.

Overall, our unplanned reliability performance has generally been good, and we perform well against our peers. Most customers are satisfied with the reliability of supply they receive and are generally happy with our price-quality trade-off.

We have presented a comprehensive analysis of customer and network performance to assess the implications for our asset management strategy and detailed plans. In summary, the implications from the analysis that follows are:

- Although there are positive aspects to our health and safety trend, we recognise the need for ongoing focus to ensure the well-being of our employees, contractors, customers, and the public. We have increased our auditing and improvement efforts in recent years, and we expect these initiatives to support better safety outcomes in the future. We have updated our critical risk framework, and focus groups started reviewing these risks (7 in total), and this is due for completion by the end of CY2025;
- Our unplanned network reliability is consistently better than our semi-urban peers and has been favourable against the target for four of the past five years;
- Due to increased work volumes, we raised our planned reliability targets for FY2025. We complied with the new target in FY2025. Our planned reliability targets remain well below our peers; however, as work on the underground network increases (currently around 10-15%), we may need to increase the planned outage target further;
- Recent survey results show most customers prefer to keep current reliability levels. Notably, more people are willing to pay for improved service than to save money with reduced service. Although opinions vary based on personal circumstances and recent experiences, the survey consistently finds that most customers do not want a lower level of service;
- Defective equipment remains the leading source of outages and the second-largest contributor to SAIDI, with conductors, cables, pole-top hardware, and transformers being the primary causes. Cable termination failures have notably increased in FY2025 and are being addressed through targeted plans. Encouragingly, there has been a modest decline in defective equipment impacts on the worst-performing feeders.
- There were no material adverse weather outages in FY2025. Adverse weather mainly impacts overhead lines and is likely to increase due to climate change. To minimise the impact of high winds, we must ensure our overhead line designs meet site-specific wind speed requirements;
- We continue to experience a high incidence of vehicle damage outages, and further geographical analysis and assessment of options to reduce vehicle risks is required;
- A few feeders have experienced a high incidence of contractor damage to underground cables. Reducing the probability of further strikes is challenging; however, increasing the penetration of ground-mounted switches will reduce customers' outage duration should further contractor incidents occur;
- We have seen a decline in the number of vegetation outages during a period where wind has impacted the network. This is a positive trend and suggests that vegetation management has been effective. We

still see a concentration of vegetation outages on a few feeders, and our operational plans have been prioritised to ensure the worst-performing feeders (for vegetation) are addressed (to the extent that the tree regulations allow);

- The worst-performing feeder contribution to SAIDI varies year-to-year, and is not indicator of a deteriorating or improving trend. Resolving issues with our worst-performing feeders remains a focus for the business;
- Our opex efficiency measure has declined, which reflects our focus on capability building and is similar to our peer group. Capex efficiency continues to perform well and is well ahead of our peer group;
- We have gone through a period of increasing capex, and other than customer connections, we are now tracking close to plan (within 3%);
- Network opex continues to exceed plan, but the variance is now minor (within 5%) and reflects an increase in spend on zone substation maintenance;
- Lastly, prior inspection resource constraints have been resolved and all inspection (except for pillar boxes) were completed in FY2025. Pillar box inspections commenced in Q2 FY26.

4.2 Safety and environmental performance

Electra is committed to ensuring the health and safety of its customers, employees, contractors, and the public. Our people are our greatest assets, and Electra aims for them all to get home from work safely and well every day. Our customers and the public are just as important to us, and we strive to protect them from harm from our assets and work activity. We have three key pillars to achieve these goals: Health and Safety, Wellbeing, and Compliance.

Table 4 shows our safety and environmental performance for the past five years. We have seen positive improvements in some areas; however, there remain aspects where further progress is required to meet all of our health and safety objectives.

Understanding our most critical safety risks, including traffic (moving vehicles and plant), electricity (contact with), height (falls), lifting operations (suspended loads and falling objects), driving, and mental health and wellbeing (fatigue, work pressures), involves developing, reviewing and monitoring the key controls to reduce the likelihood of harm. Our auditing, preventative and proactive improvements, planned inspections and compliance with our public safety management system assist us in ensuring control effectiveness and ongoing improvement. Other than a recent delay in some inspections, these measures are tracking well. We discuss our critical risk, key controls and control effectiveness in Section 14.

Having an active internal safety observation and audit program based on our critical risks is vital. All people leaders have performance measures to ensure regular safety and wellbeing checks on their teams. This extends to our senior leaders and directors, who provide visible leadership and support through site visits. An external auditor comes in multiple times per year to audit our field team's safety and compliance, with positive findings to date and opportunities for improvement acted upon.

Our asset inspection program prioritises areas where the public is more likely to be present, especially around schools, shopping centres, and parks. Ad hoc safety audits are conducted more frequently in these locations. Engaging with third parties and contractors working around and on our network is an ongoing task, ensuring the risks of working near our assets are well known and appropriate controls and permissions are in place. We experienced a delay in some inspections in 2023 and 2024 (due to resource constraints).

Other than pillar boxes, all planned inspections were completed in FY2025. Additional resources commenced in Q1 and Q2 FY2026 and pillar box inspections have commenced (at the time of writing).

Whilst we recorded six employee lost-time injuries (LTIs) in FY2024 and FY2025. All were low severity, and importantly, none were caused by a critical risk. Our lost-time injury severity rate currently stands at 3.5, compared with an industry-wide rate of 11. All incidents are investigated, and lessons learned are shared and applied to our work procedures.

The wellbeing of our people is central to how we operate. We offer a range of supports, including health checks, funded health insurance and discounted benefits, an employee assistance programme for employees and their immediate families, peer support, and regular wellbeing checks. We also take care of the small but important things—like providing fresh fruit, cold water, and electrolytes for our crews working outdoors in the summer heat
No customers, members of the public, or other parties have been harmed by asset failure or our work activities. This result is supported by our public safety management system, which is audited annually by Telarc and certified to the NZS7901 standard. Our audits over the past three years have fully complied with the standard, with certification valid through to February 2027.

For environmental reporting, we are in final stages of implementing a Toitū certified Environmental Managements System (EMS). This ensures our compliance with RMA requirements, including regional and district council rules. The EMS will allow us to monitor all levels of environmental incidents across work carried out by us any by our contractors.

We have also recently completed our FY2025 Greenhouse Gas (GHG) emissions report. This means we have Toitū certification for GHG reports for FY2022 through to FY25, with FY2022 as our base year. We have decided to exclude emissions from network losses because the emissions aspect is controlled by the grid emissions factor, which Electra has no control over. Electra will endeavour to reduce our line losses to the extent practicable. Our FY2022 emissions, excluding line losses, were 2,809 $tCO_{2\text{-}e,}$ and in FY2025 they were 3,385 $tCO_{2\text{-}e.}$ Though absolute GHG emissions have increased, we have decreased our emissions intensity for work on the network.

As part of our circular economy journey, we conducted a waste audit across the business, which showed that Electra produces approximately 160 tonnes of waste annually. We currently divert around 60% of that waste from landfill, and we are exploring ways to continually improve this.

Table 4: Safety and Environmental Targets

Area	Indicator	Type	Target 2025	Average FY21-24	Actual FY25	Comments
Safety of staff, contractors, and the public	Staff Lost Time Injuries (LTIs)	Lagging	Zero (for critical risks)	2.0	0.0	The target of zero is for critical risks
	Number of incidents	Lagging	Reporting is encouraged	87	105	There was a positive increase in reporting for FY2025
	Public safety audits	Leading	60 per year	50	30	Total audits are ahead of plan. Our focus has been on contractor auditing
	Contractor safety audits	Leading	60 per year	183	285	

Area	Indicator	Type	Target 2025	Average FY21-24	Actual FY25	Comments
	Compliance with our public safety management system	Leading	Compliant	Compliant	Compliant	Fully compliant
	Completed preventative and proactive actions[35]	Leading	5% annual increase from 2020	1,042	1,293	Ahead of plan
Asset integrity	Completion of planned Inspections[36]	Leading	>95%	86%	88%	Only pillar box inspections were behind target. This was resolved by Q1 FY26
Environmental responsibility	Number of environmental incidents	Lagging	Zero	0	0	We had no reportable environmental incidents

4.3 Network reliability performance, customer perspective

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

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

Within these two measures, we assess unplanned and planned outages separately. Unplanned outages are particularly important because they inconvenience customers due to their unforeseen nature. Planned outages are notified in advance, and customers can alter their plans to accommodate them. We also use raw reliability data in our analysis, which is before any normalisation for major events (as is the case for regulated distribution businesses). We use raw data because this is the reliability that our customers experience.

Electra does not distinguish between customers in different geographical areas; however, the network configuration provides a higher level of reliability to urban customers than rural customers (refer to Section 3.5).

Unplanned reliability performance

Referring to Figure 22 and Figure 23, our unplanned network reliability is consistently better than our semi-urban peers[37] and has been favourable against target for four of the past five years. SAIFI performance has been particularly favourable against our target.

During FY2025, the network did not experience any significant weather events or network outages (e.g., loss of zone substation), and therefore unplanned outage performance was favourable compared to previous

[35] This measure captures all of our audits, incidents and all follow-up actions.

[36] This is a composite measure of the completion of planned inspections. Practical completion means the work is completed with the exception of minor omissions (of less than 5%), hence the target is >95%. We take a practical approach as some inspection require access to private property and can have weather restrictions.

[37] Electra is a semi-urban network. It has 54% of its lines and cables in urban areas and an ICP density of 19.5 ICP per km. This is consistent with other semi-urban EDBs (Aurora, Orion, WEL Networks, Unison and Counties) that have an average proportion of urban lines and cables of 55% and an ICP density of 16.1. Typically, urban networks have an ICP density above 25, semi-rural networks have an ICP density below 13, and rural networks below 8 ICP per km.

years. Unplanned SAIDI was 52.5 minutes per customer, 19% better than FY24 and 20% better than the target. Unplanned SAIFI followed a similar favourable trend.

However, one-off events can impact reliability performance. As shown in Figure 24, three factors led to the target being exceeded in FY2020 and FY2023. These were:

- A significant increase in vehicle damage to the network in FY2020. This was three times the normal rate, which has not occurred again;
- A significant weather event in early June 2022 which resulted in 53 lightning strikes in the first two weeks of June;
- During the same June 2022 storm, an out-of-zone tree fell causing significant damage. The Council closed the road due to safety concerns around the potential for a significant land slip meant that we were unable to access the damage and it took an extended period to restore supply.

Figure 22: Unplanned outage duration[38]

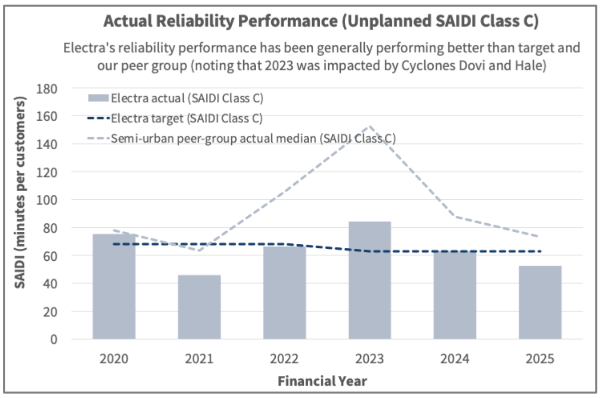


Figure 23: Unplanned outage frequency[38]

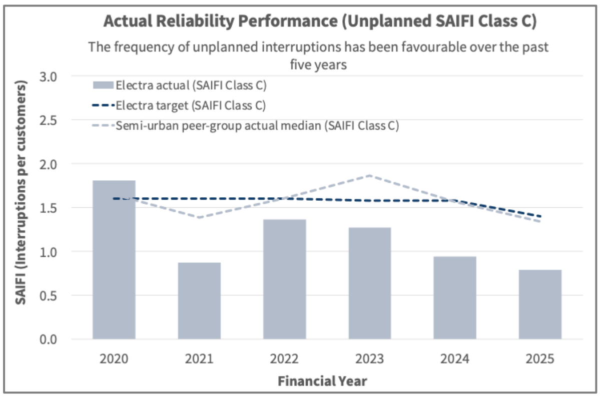
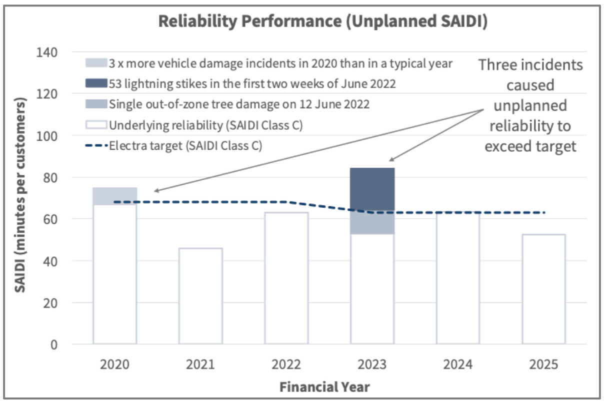


Figure 24: Unplanned outage, reasons for the target to be exceeded



Given the generally good performance, our focus is on mitigating reliability risk. This is important given the likely increase in adverse weather events due to climate change.

Planned reliability performance

Referring to Figure 25 and Figure 26, our planned network reliability has been unfavourable against the target in recent years. This is due to the increase in the work we have been undertaking on the network (requiring outages). However, our planned SAIDI is unusually low compared to the industry and our peer. This reflects our use of live-line techniques on the overhead network, the low work volumes on the

[38] The semi-urban peer group was impacted by major weather events in 2022 and 2023 (Cyclones Dovi, Hale and Gabrielle).

underground network (which currently account for 10% of planned outages and 13% of planned SAIDI), and our use of temporary generation. As work on the underground network increases, we may need to increase the planned outage target further.

Figure 25: Planned outage duration

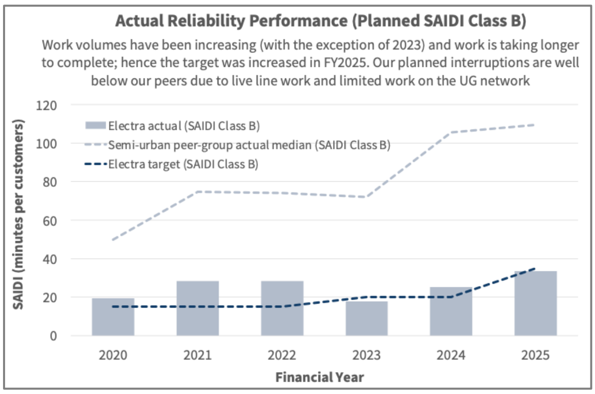
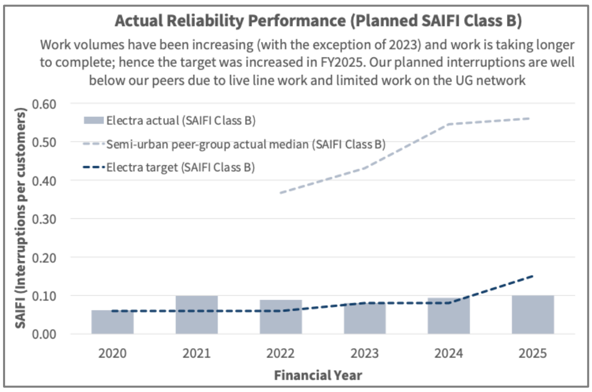


Figure 26: Planned outage frequency



4.4 Other areas of customer service performance

In addition to reliability, we also measure our performance in other areas important to customers. These include:

- Customers' views on our network reliability;
- Customers' views on our response to unplanned outages;
- Customers' views on the number of outages;
- Customers' views on notification of planned outages;
- Customers' views on price-quality trade-off.

Until 2023, we completed an annual customer survey to seek customers' views on our network reliability and service during faults. The survey was not conducted in 2024. A new survey tool was used in 2025, with results showing almost all customers are satisfied or neutral when asked to rate the reliability of the supply they receive from the network (refer to Figure 27). These views seem generally consistent with our prior survey (although they are not directly comparable).[39]

When faults occur, we want to be responsive and remedy them as soon as possible. Based on our most recent survey, customers are almost all satisfied or neutral with how quickly we restore power during outages (refer to Figure 28). Customers are almost all satisfied or neutral with how well we are doing at minimising the number of network outages (refer to Figure 29).

[39] Our customer survey tool changed in 2025 and used a a scale from 1-10. 8-10 was considered as satisfied, 5-7 was neutral. Our prior survey used a five point scale from very satisfied to very dissatisfied. Hence, the rating are not directly comparable between the two surveys. We have included the prior surveys for context only.

Figure 27: Customer views on network reliability[39]

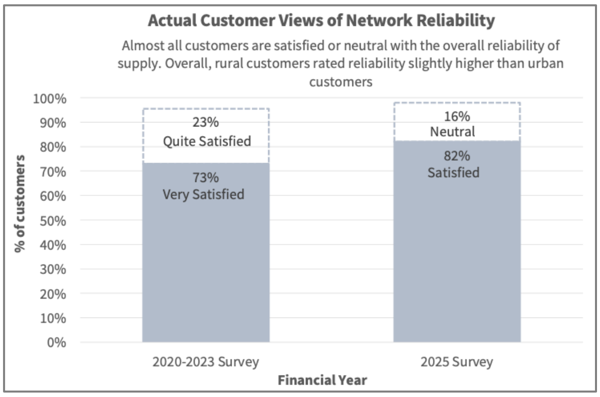
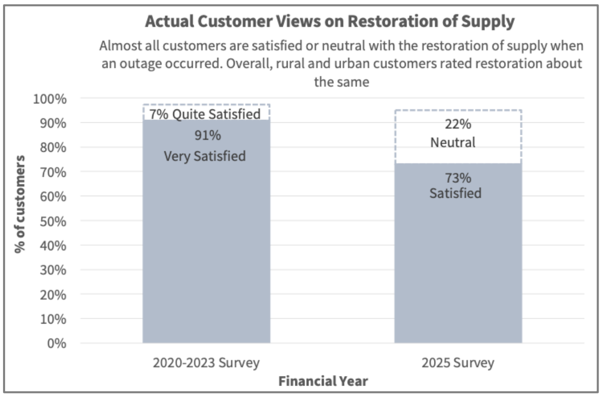


Figure 28: Customer views on service received during a fault[40]



A recent ENA study found that timely planned outage notification was important for customers. We have operational oversight in this area and asked customers for their views in our recent survey (refer to Figure 30). Customers were less satisfied with outage notification than they were with other reliability measures.

Figure 29: Customer views on the number of outages

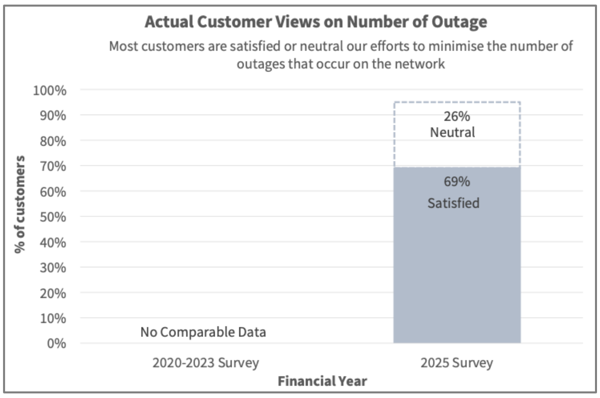
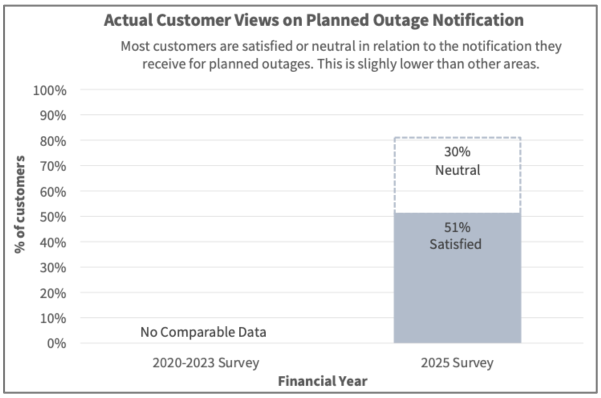


Figure 30: Customer views on notification of planned outages

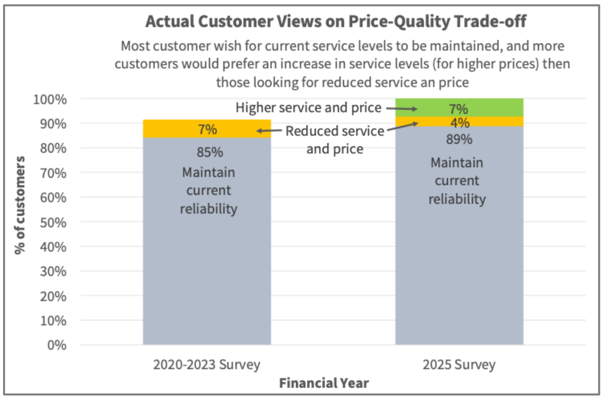


The same ENA study also identified that customers value ease of connection. This has been an area of focus for the Electricity Authority, and process changes will be introduced from April 2026. We intend to develop performance metrics as part of the process change.

While not a specific performance metric, it is important to understand whether customers are satisfied with our price-quality trade-off. This data helps determine whether our reliability targets are suitable and how much to invest to reduce reliability risk. The most recent survey results show that most customers want to maintain the current reliability performance, which is slightly higher than the average across our previous surveys (see Figure 31). A small number of customers are willing to accept more outages for a slightly lower price, but this has decreased compared to our prior survey. The most recent survey asked whether customers were willing to pay for a high level of service; interestingly, more customers were willing to pay for higher service than to receive savings for lower service. Customers' views on reliability depend on their particular circumstances and recent outage experiences; however, the survey consistently indicates that, overall, customers are generally unwilling to accept a lower level of service.

[40] For the prior survey, customers were asked to rate *the timeliness of our fault response*. The 2025 survey asked customers to rate *how quickly the electricity is restored when there is an outage.* Hence, these are not directly comparable.

Figure 31: Customers' views on Price-Quality Trade-off



4.5 Asset performance

4.5.1 Introduction

This section examines the causes of outages and their impact on overall reliability. We then assess the drivers of the material causes of outages. This assessment shapes our focus areas in the asset management strategies presented in Section 6. The analysis focuses on SAIDI and the number of outages, as the drivers (and resolutions) of these issues also affect SAIFI.

4.5.2 Material causes of outages

As shown in Figure 32 and Figure 33, defective equipment is the most significant cause of SAIDI, followed by third-party damage, vegetation and adverse weather. These causes contribute 80% of SAIDI and 70% of SAIFI.

Figure 32: Reliability Performance, Unplanned SAIDI

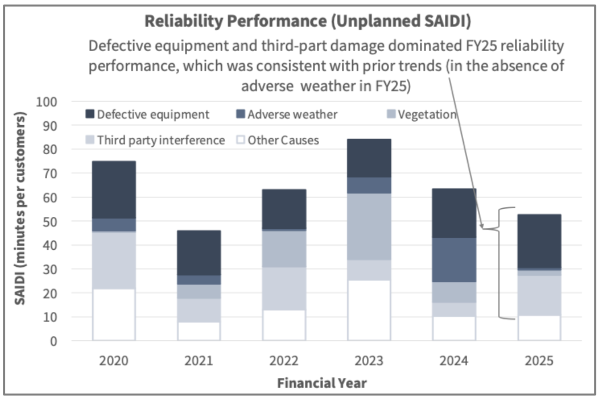
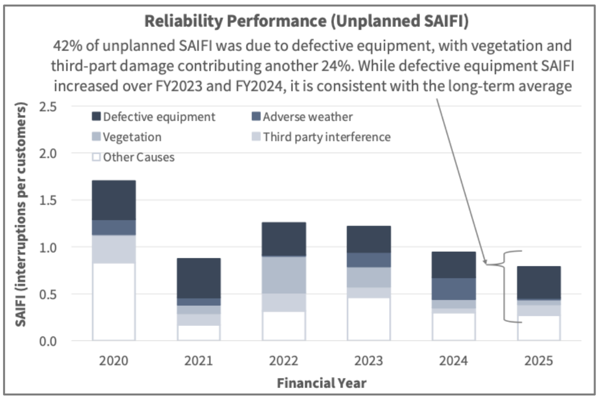


Figure 33: Reliability Performance, Unplanned SAIFI



In broad terms, over the past six years:

- Third-party damage was the most significant cause of SAIDI. This was a result of fewer outages (than most other causes), but when they occurred, they impacted a large number of customers and took longer to repair;
- Defective equipment was the second most significant cause of SAIDI, which was principally due to the high number of outages, but these typically impacted fewer customers and were of shorter duration;
- Vegetation SAIDI reflected a combination of outage numbers and the outages taking a long time to repair. Due to the settled weather, there were 60% fewer vegetation outages in FY2025;

- On average, adverse weather is not a material cause of outages but shows high volatility. That is, in the years when weather impacts the network, many outages typically affect many customers. These had an immaterial contribution in FY2025 due to the settled weather.

Almost all outages and SAIDI impacts occur on the distribution network. Over the past six years, the sub-transmission network and zone substations assets have contributed 2% to total unplanned SAIDI, lower than the industry median (8%) and the semi-urban peer group (4%). This reflects the high level of network security provided by the sub-transmission network and zone substations.

In the following sections, we assess the four material drivers of reliability. The analysis relates to the distribution network.

4.5.3 Defective equipment outages

Defective equipment is the largest source of outages and the second-highest for SAIDI. The extent of defective equipment outages on the network is consistent with our semi-urban peer group and close to the wider industry (refer to Figure 34).[41]

As shown in Figure 14 and Figure 36, five types of equipment are causing outages. The most significant are conductors and cables, pole-top hardware, overhead fuses and links, and ground-mounted transformers.

We are seeing year-to-year volatility in the types of equipment that cause outages (refer Figure 36), which suggests there isn't an underlying issue with a particular type of equipment. In FY2025, we experienced a significant increase in the number of 11kV cable termination failures (and their associated SAIDI impact) as shown in Figure 35). This is being addressed in the cable fleet plan (refer to Section 12.14). The impact of cable termination outages is exacerbated by the low security on many of our underground feeders (refer to Section 3.5.3).

Except for cables (and their associated joints and terminations), equipment failures are repaired promptly, or supply is restored through network backup. There are significantly fewer outages for cables, but the restoration times are materially longer. This reflects the time to locate and repair cable and joint faults and the limited switching on the underground distribution network. The impact the longer restoration times had on SAIDI can be seen in Figure 35 and Figure 36 (for FY2025).[42]

We have seen a modest decline in defective equipment impacts on the worst-performing feeders (refer to Figure 37). This is a positive trend and indicates that issues on the worst-performing feeders are being addressed.

[41] The percentage of defective equipment SAIDI looks higher than the comparators only because of a high percentage of defective equipment in 2021. This was a consequence of the low unplanned SAIDI in 2021, not because of an increase in defective equipment SAIDI in that year.

[42] The average outage time for cables is 206 minutes, compared to 77 to 117 minutes for other equipment.

Figure 34: Defective Equipment Benchmark

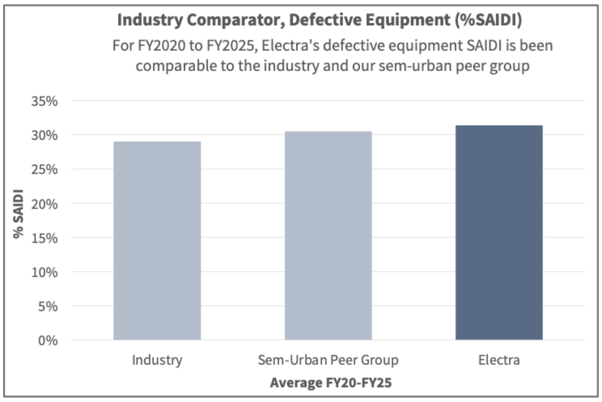


Figure 35: Defective Equipment, SAIDI

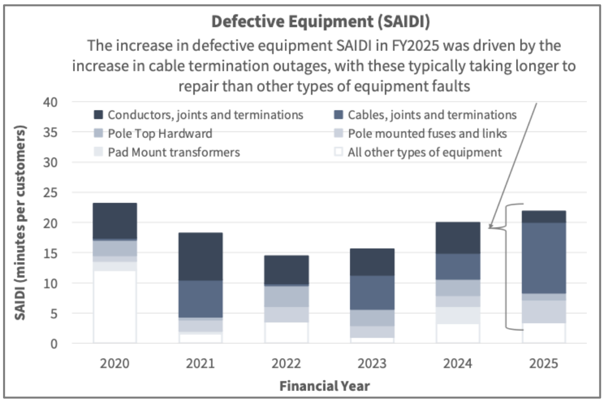


Figure 36: Defective Equipment, Outages

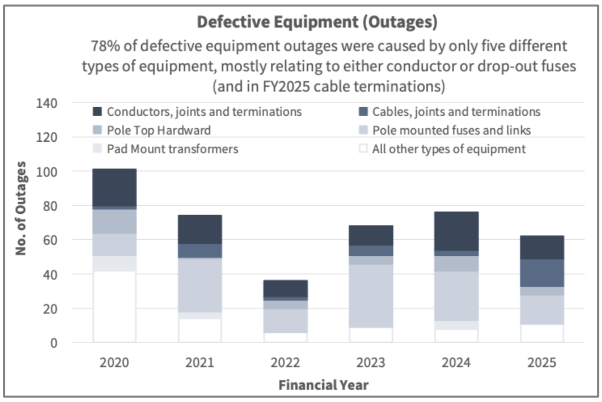
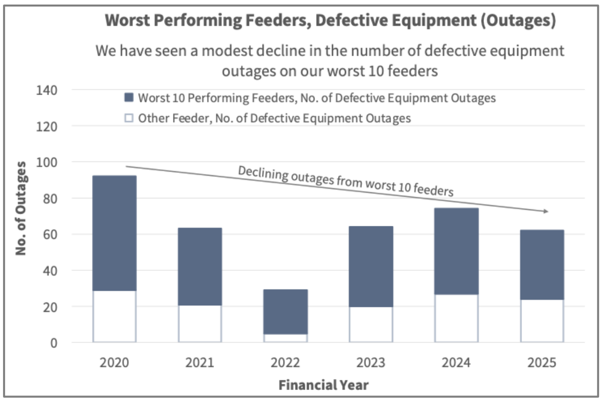


Figure 37: Worst Performing Feeders, Defective Equipment Outages[43]



This AMP focuses on improving the performance of the worst-performing feeders. In the development plan (Sections 11.10.3 and 11.10.4), we assess the worst-performing feeders for opportunities to reduce the risk of further poor performance. In the lifecycle plan (Sections 12.12 to 12.16), we assess whether there are any asset health drivers concerning the worst-performing feeders.

4.5.4 Adverse weather outages

Adverse weather outages generally result from asset failures that occur during such conditions. These typically occur when weather conditions exceed the design limits of the assets. In absolute SAIDI terms, except for FY2024, over the past six years, we have generally seen a lower impact from adverse weather than our peer group or the industry (refer Figure 39). However, in percentage terms, adverse weather has a larger impact on our network than our industry peers (Figure 38) yet this may be due to different classifications applied by our peers.

43 These are the worst 10 feeders in any given year.

Figure 38: Adverse Weather Benchmark

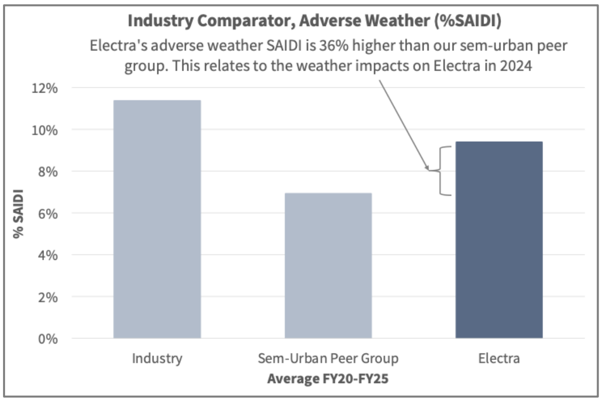
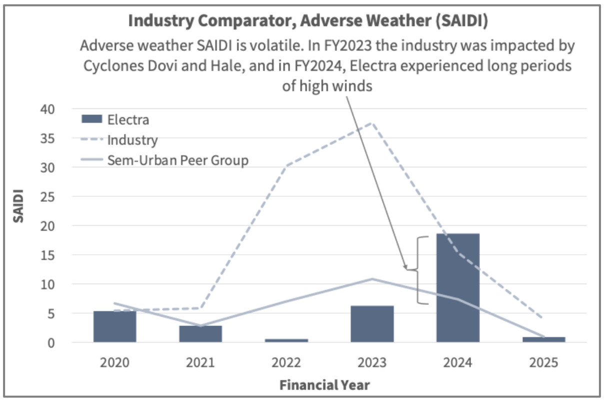


Figure 39: Adverse Weather Volatility



As shown in Figure 40, the impacts of adverse weather outages are volatile and can result in around 30% of total unplanned SAIDI in years when major weather events occur. In normal years, the impact is around 6%.

High winds cause around 80% of all adverse weather outages (refer to Figure 41). As expected, adverse weather mostly impacts overhead lines. Consistent with defective equipment, conductors and associated joints and terminations are mostly impacted (refer to Figure 42). Ensuring our overhead line designs meet site-specific wind speed requirements is important to minimise the impact of high winds.

When adverse weather events occur, their impact is often concentrated on only a few feeders. Often, the same feeders are affected, partly due to their location; this reinforces our need to focus on resolving issues with our worst-performing feeders (refer to Figure 43).

Figure 40: Adverse Weather, SAIDI

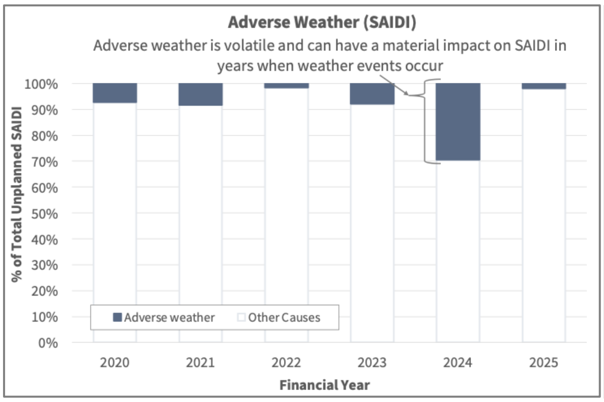


Figure 41: Adverse Weather, Conditions Outages (FY2024)

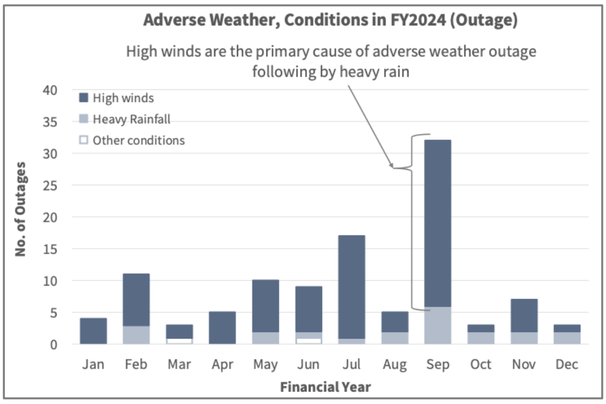


Figure 42: Adverse Weather, Equipment Type, Outages

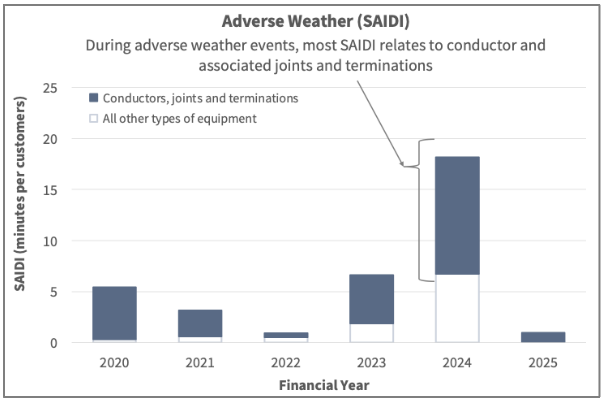
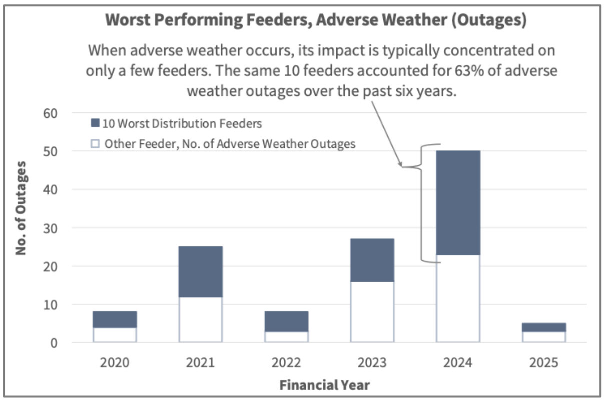


Figure 43: Worst Performing Feeders, Adverse Weather, Outages



4.5.5 Third-party damage outages

Third-party damage has materially impacted reliability over the past five years. For Electra, third-party damage SAIDI was around 39% more than our semi-urban peers. While much of this is related to the very high number of vehicle damage incidents in 2020, after normalising for 2020, it remains over 30% higher than our peers (refer to Figure 44).

Third-party damage is primarily caused by vehicle damage (typically to overhead lines) and contractor damage (typically to underground cables). Pleasingly, incidents have declined since the 2020 peak (refer to Figure 45).

Figure 44: Third-Party Damage Benchmark

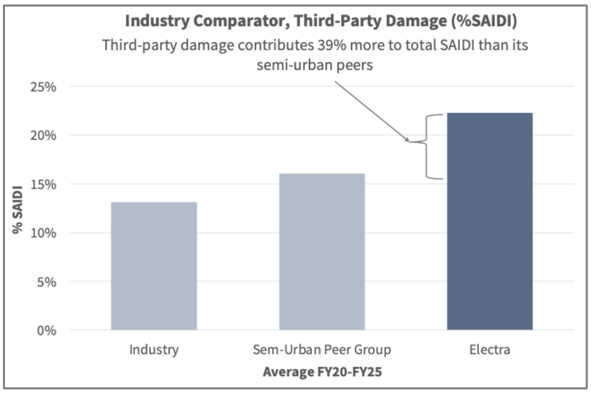
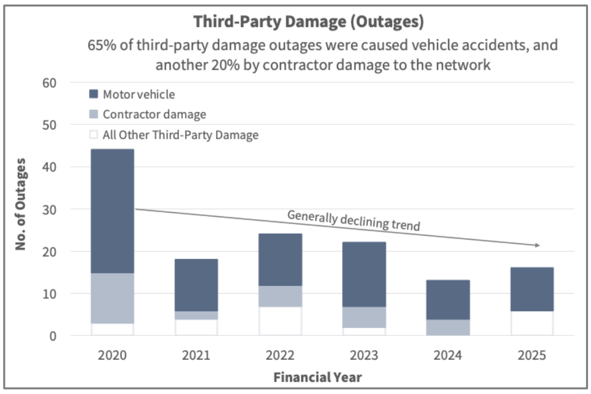


Figure 45: Key Causes of Third-Party Damage, Outages



As shown in Figure 46, vehicle damage is concentrated on a few feeders. Ten feeders account for 51% of vehicle damage outages.

As shown in Figure 47, third-party contractor damage is also concentrated on a few feeders. Since FY2021, three feeders have accounted for 62% of contractor damage incidents. We rely on process-based controls to mitigate damage caused by third-party contractors (i.e., the dial-before-you-dig process); hence, reducing the probability of incidents is difficult. However, increasing the underground network's security by adding ground-mounted switches will reduce the duration of customer outages. The prioritisation of installing new switches considers the locations of third-party contractor damage incidents and areas for significant building and civil work (refer to Sections 11.10.3 and 11.10.4).

Figure 46: Vehicle Damage, Outages

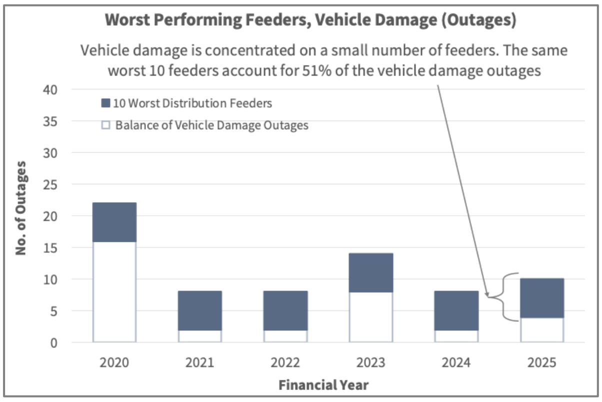
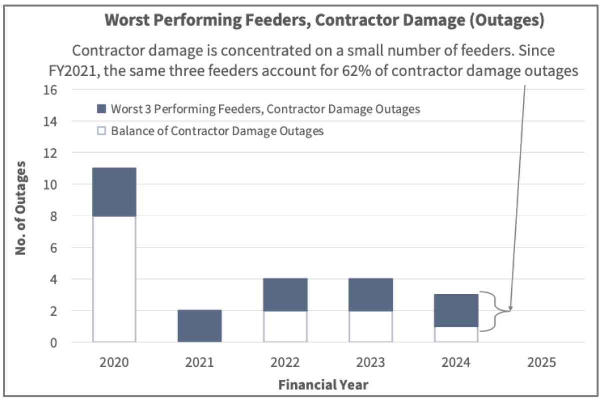


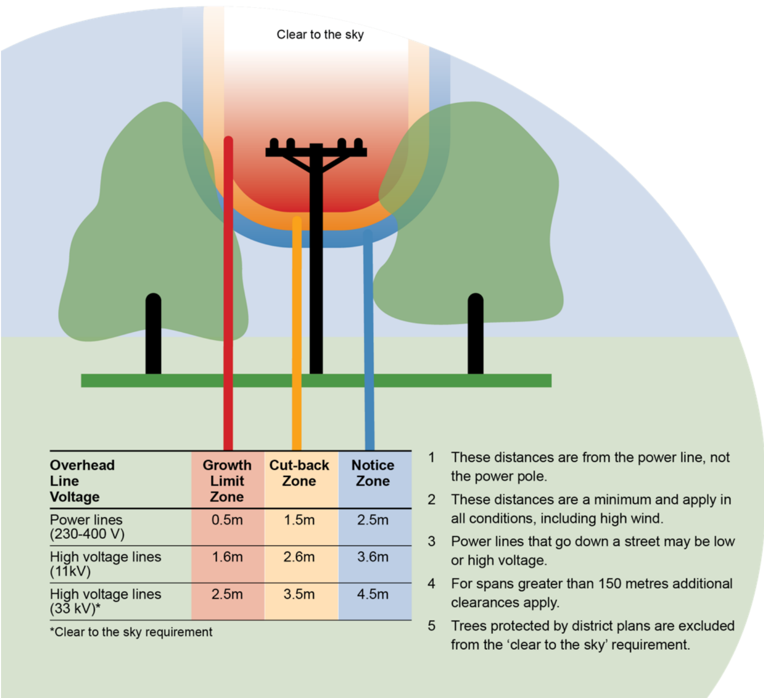
Figure 47: Third-Party Contractor, Outages



4.5.6 Vegetation outages

Our vegetation outage analysis considered the impact of vegetation contacts on the network from inside and outside of the growth limit zone (GLZ), as shown in Figure 48. Management of vegetation outside the notice zone is complex and is not supported by regulations. The Electricity (Hazards from Trees) Regulations were amended in 2024 to extend the notice zone by one metre. While these zones provide clearance from interference from branches (though greater clearance would be useful), they are inadequate to manage tree-fall risk and interference during storm events, where greater separation is needed. Further regulations are planned to increase our rights to address out-of-zone trees, but these have not yet been enacted.[44]

Figure 48: Vegetation zones



Overhead Line Voltage	Growth Limit Zone	Cut-back Zone	Notice Zone
Power lines (230-400 V)	0.5m	1.5m	2.5m
High voltage lines (11kV)	1.6m	2.6m	3.6m
High voltage lines (33 kV)*	2.5m	3.5m	4.5m

*Clear to the sky requirement

1. These distances are from the power line, not the power pole.
2. These distances are a minimum and apply in all conditions, including high wind.
3. Power lines that go down a street may be low or high voltage.
4. For spans greater than 150 metres additional clearances apply.
5. Trees protected by district plans are excluded from the ‘clear to the sky’ requirement.

[44] The Electricity (Hazards from Trees) Regulations specifies minimum distances from overhead power lines that vegetation must be clear from, with distances varying depending on voltage and conductor span length (the GLZ). These were updated in November 2024, extending the notice zone by one metre and making the zones clear to the sky. For 11kV lines, the GLZ is 1.6m, the cut-back zone is 2.6m and the notice zone at 3.6m from the line.

Over the past six years, we experienced a similar impact from vegetation damage as our semi-urban peers and the wider industry (refer to Figure 49). Vegetation originating from outside the GLZ is often the predominant source of outages (see Figure 50).

Not unexpectedly, the reliability impact from vegetation contact outside the GLZ occurs due to wind (see Figure 51). However, we have seen a decline in the number of vegetation outages during a period where wind has impacted the network. This is a positive trend and suggests that vegetation management has been effective

In recent years, vegetation-related outages have been concentrated on a few feeders. Since FY2020, the same ten feeders resulted in 63% of the vegetation outages (see Figure 52).

Vegetation outage management is an ongoing issue exacerbated by climate change, the difficulty of gaining access and approval to trim vegetation, and the narrow GLZ that reduces the effectiveness of trimming work. We have established a vegetation management strategy presented in Section 12.19.2. Our operational plans have been prioritised to ensure the worst-performing feeders are addressed.

Figure 49: Vegetation Benchmark

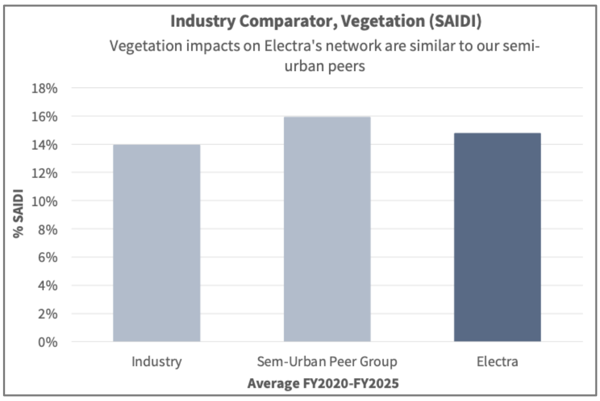


Figure 50: Vegetation Contribution to Unplanned SAIDI

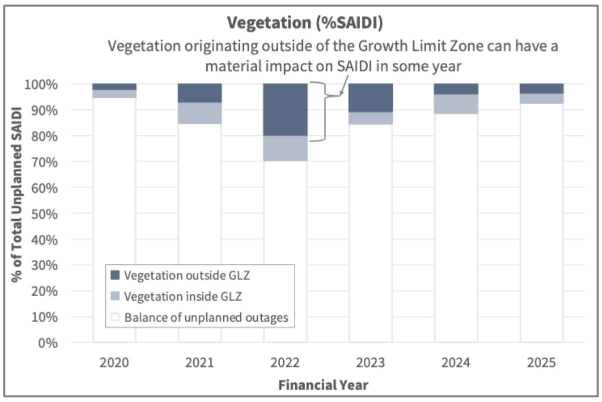


Figure 51: Underlying Vegetation Trend, Outages

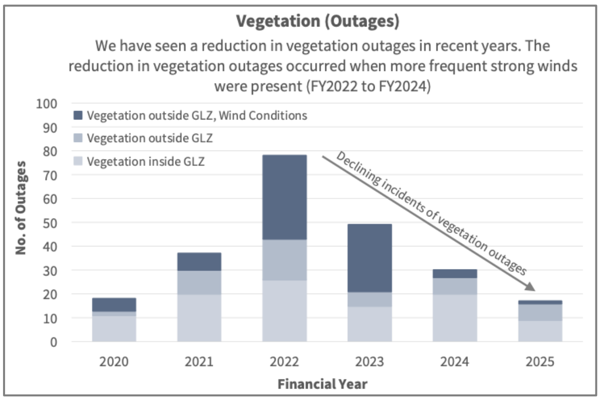
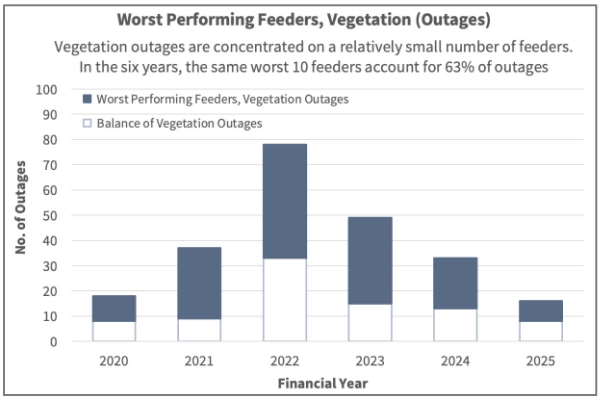


Figure 52: Vegetation, Worst Performing Feeders, Outages



4.5.7 Unknown interruptions

All EDBs experience unknown cause outages. These outages are where, after investigation, we could not determine the cause. These outages are typically of short duration and often occur due to the standdown period required before the control room can attempt to restore supply. Over the past six years, these have averaged around 7% of SAIDI, well below the industry average.[45] We have well-defined procedures for post-fault investigation, which has led to good results in this area.

4.5.8 Extended duration outages

Extended-duration outages take more than three hours to restore. Pleasingly, Electra's performance is better than our peer group and the industry (Figure 53). Other than FY2023, the trend in extended duration has been static. Extended-duration outages make the most significant contribution to third-party damage outages—where repair time influences the outage time—and this is most apparent on the underground network.[46]

Figure 53: Extended Duration Outage Benchmark

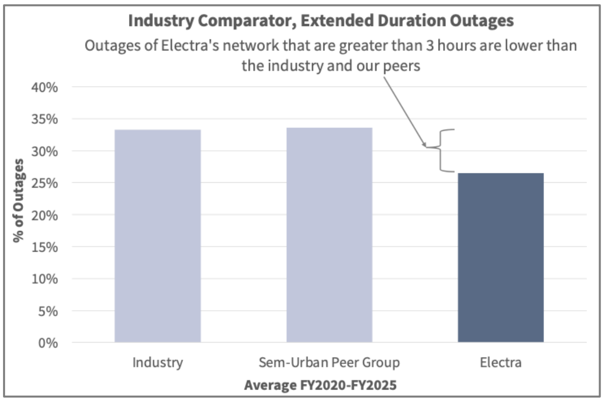
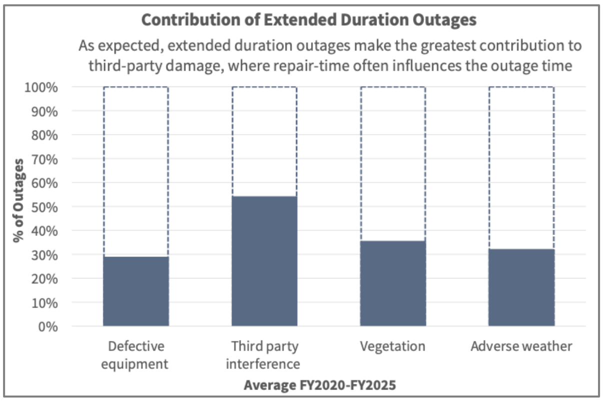


Figure 54: Extended Duration Outage Contribution to Top-4 Causes



4.5.9 Worst-performing feeders

The worst-performing feeder contribution to SAIDI varies year-to-year, and is not indicator of a deteriorating or improving trend (Figure 55). The 90th percentile worst-performing generally only comprises two to four feeders and averages around 23% of unplanned SAIDI.

Figure 55: Worst-Performing Feeders (90th Percentile)

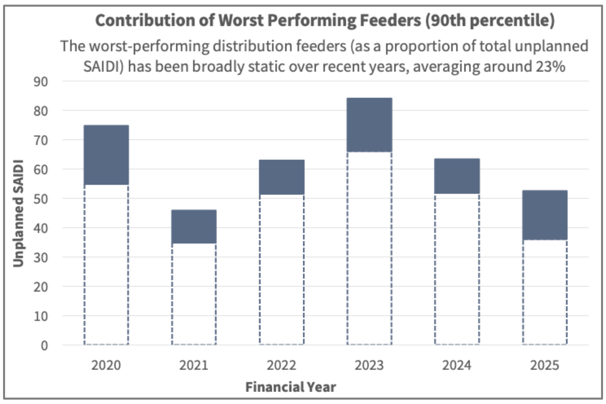


Table 5 identifies our top 10 worst-performing feeders by SAIDI (and these strongly overlap with the worst-performing by the number of outages). Six of these feeders are carried over from the 2025 AMP. Three of the list is in Ōtaki (down from five in the 2025 AMP)—which reflects high customer numbers per feeder, lower security on some feeders, and exposure to vehicle damage. Managing risks on these feeders is a focus of this AMP, and Table 5 provides our planned work on these feeders.

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45 For the FY2020 to FY2025 period, the industry average is 9% and the semi-urban peer group is 11%.

46 In FY2024, extended duration outages comprised 53% of faults on the underground network and 25% on the overhead network.

Table 5: Top-10 worst performing feeders FY23-25

Feeder	Substation	Average SAIDI FY23-25	Primary cause	Secondary cause	Plans to mitigation for reliability risk
L349*	Ōtaki	5.7	Lightning	Vegetation	• Potential security mitigation (Section 11.10.3, Project 12) • Potential switch automation** (Section 11.10.4)
C4*	Foxton	3.5	Defective Equipment	Third-party damage	• Being assessed for targeted asset renewal
E150	Levin West	3.4	Third-party damage	-	• Will be assessed for resilience work
119*	Shannon	3.2	Adverse Weather	-	• Potential switch automation** (Section 11.10.4) • Will be assessed for resilience work • Being assessed for targeted asset renewal
L352*	Ōtaki	2.2	Vegetation	Defective Equipment	• Included in the vegetation remediation plan • Potential switch automation** (Section 11.10.4) • Being assessed for targeted asset renewal
L350*	Ōtaki	2.1	Defective Equipment	-	• Security mitigations (Section 11.10.3, Projects 4 and 15) • Potential switch automation** (Section 11.10.4) • Being assessed for targeted asset renewal
G306	Levin East	1.7	Defective Equipment	Adverse weather	• Potential for security mitigation (Section 11.10.3, Project 25) • Being assessed for targeted asset renewal • Will be assessed for resilience work
G308*	Levin East	1.6	Third-party damage	Defective Equipment	• Potential security mitigation (Section 11.10.3, Project 23) • Potential switch automation** (Section 11.10.4) • Being assessed for targeted asset renewal
E153	Levin West	1.6	Adverse weather	-	• Will be assessed for resilience work
V318	Paraparaumu East	1.5	Defective Equipment	-	• Targeted for cable termination PD testing and follow-up maintenance • Being assessed for targeted asset renewal • Potential for security mitigation (Section 11.10.3, Project 16)
Total		**26.4**			

* On the prior list included in the 2025 AMP

**These programmes are in concept phase only, awaiting further work on our energy trilemma (i.e. affordability-quality) trade-off and business case development.

4.6 Network efficiency

We currently have two main measures of efficiency—opex and asset cost-to-serve. Increasing costs have led to a decline in real opex cost-to-serve in recent years. This is an industry-wide trend driven by:

- Capability-building in response to increasing capital works programmes that require an increase in resources to manage;
- An increase in asset management and network management practices;
- New capabilities, systems and processes that are now required in response to increasing business complexity and regulation;

- Many IT costs moving to software-as-a-service,[47] and,
- Some business-related costs are increasing faster than general inflation (e.g. insurance).

Between FY2020 and FY2024, our asset cost-to-serve has remained largely static, driven in part by strong growth in customer connections. This was because the incremental asset cost to connect a new customer is lower than the cost required to serve existing customers. However, our capex programme has increased in recent years, thereby increasing the asset cost-to-serve.

Figure 56: Opex Cost-to-Serve[48]

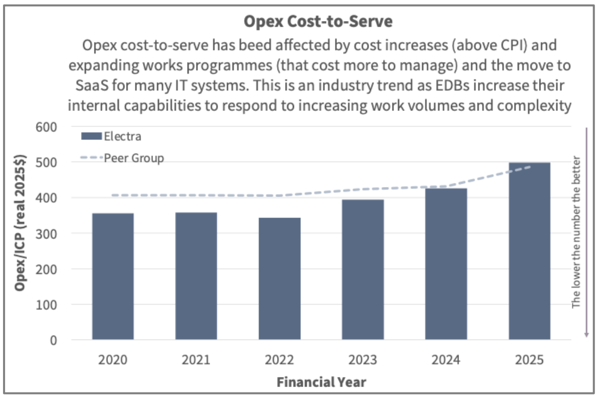
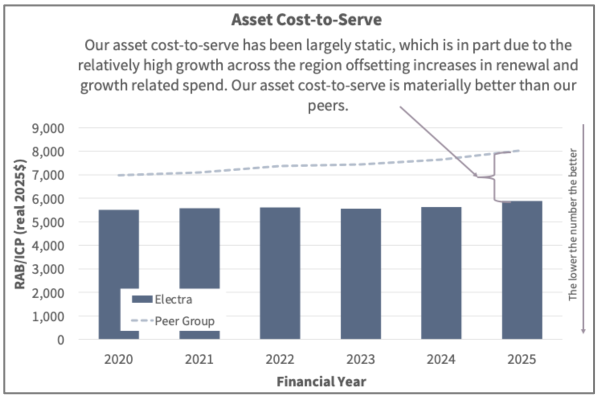


Figure 57: Asset Cost-to-Serve[48]



We have been working on how to better measure efficiency, and our new approach is outlined in Section 7.6. We will be reporting using the new measures in the 2027 AMP.

4.7 Work delivery performance

Delivering the capex works program relies on the work being designed, property rights procured, materials being supplied, and field resources being available. Figure 58 shows various external and internal factors that have impacted delivery in recent years.

We have gone through a period of increasing our capital work programme, and capex has increased by 80% since FY2022. In FY2023 and FY2024, we experienced delays in delivering system growth projects. Various external factors have impacted this work, including consultation on route selection, land acquisition and large project-based material requirements. The time taken to select new line and cable routes has been longer than anticipated, and the time taken to deliver materials has also increased.

Many of these delays are now behind us, and for FY2025, the capex variance was due to an underspend on customer connection capex. We changed our forecasts in the 2025 AMP to reflect a new customer connection process that would move from a vested asset process to a connection capex process. Due to the pending regulation of the connection process (by the Electricity Authority), implementation was delayed. Hence, excluding customer connections, we were only 3% behind the forecast for FY2025. We continue to work on improving delivery, which is discussed later in Sections 9 and 13.

Pleasingly, the delivery of asset replacement and renewal work over the last three years has been on plan.

---

[47] That were previously capital licencing and development costs

[48] We only benchmark versus our peers as they have similar network characteristic. Network characteristics can have a significant influence on business cost structure and the level of assets employed. Whilst the absolute difference is useful. It is the relative trend that is most important as this less influenced by network characteristics.

The opposite has occurred with network opex delivery, where we have consistently exceeded the budget (refer to Figure 59). For FY2022 to FY2024, the main driver for this has been higher system interruption and emergency costs (e.g., fault response and restoration). For FY2025, the system interruption and emergency budget was 27% higher than in FY2022, and costs were at that level for the year. Other than FY2023, the number of faults has been reasonably consistent; hence, the cost of undertaking the work has been the primary driver of the increase. This is due to various reasons, including materials, resources and traffic management costs. The rise in fault response costs is consistent with industry trends, where system interruption and emergency costs have increased by 20% between 2020 and 2025.

We experienced a resource constraint with our asset inspections, which led to some underspending between FY2023 and FY2025 (which is discussed further below).

Figure 58: Network Capex Works Delivery

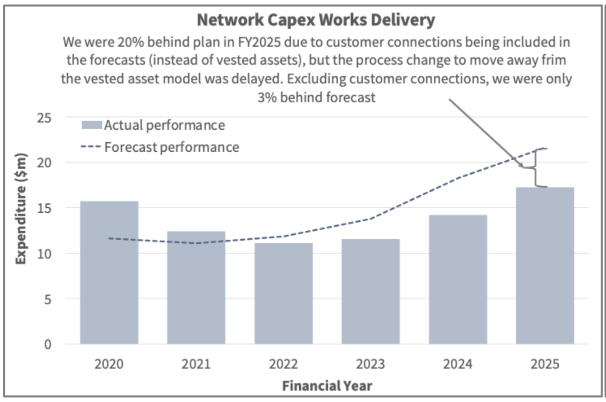


Figure 59: Network Opex Delivery

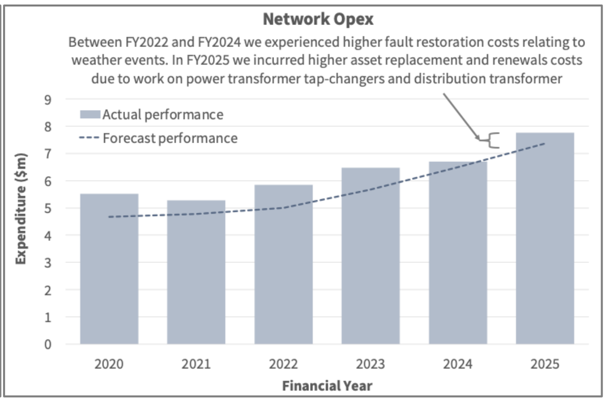


Table 6 summarises our planned inspection performance. Prior to FY2023, we consistently completed our planned inspections. A resource constraint in our inspection team impacted distribution and LV asset inspections in FY2023 and FY2024. These constraints have now been resolved. We also deferred our 33kV thermography inspections in FY2023 and FY2024. All inspections planned for FY2025 were completed, except for pillar boxes (which have completed at the time of writing).

Table 6: Completion of Planned Inspections

Assets	Target FY25[49]	Average FY21-24	Actual FY25	Comments
Sub-transmission assets (visual, thermography and acoustic)	>95%	60%	100%	Resource constraints delayed line inspections in FY2023. No thermography inspections undertaken in FY2023 and FY2024. All inspections completed in FY2025
Zone substation assets	>95%	100%	100%	All inspection completed
Distribution lines and switchgear assets	>95%	92%	95%	Resource constraints delayed line inspections in FY2023 and FY2024. This issue has now been resolved.
LV pillar boxes	>95%	80%	0%	Resource constraints delayed line inspections in FY2024 and FY2025. This issue has now been resolved and inspections commenced in Q2 FY26.

Table 7 summarises the major project delivery for FY2025. The slow economic climate has led developers to pull back on development staging, reducing the urgency for investment in new infrastructure to serve these

49 We are targeting to achieve practical completion of our inspection. Practical completion means the work is completed with the exception of minor omissions (of less than 5%), hence the target is >95%. We take a practical approach as some inspection require access to private property and can have weather restrictions.

subdivisions (e.g., the Waikanae Beach feeder). We experienced approval delays for Foxton switchgear. The other variances were due to delivery timing for multi-year projects.

Table 7: Major Capital Project Delivery (above $1m)

Project Title	Budget FY25	Actual FY25	Variance	Comments
New 11kV Waikanae Beach feeder for Ngarara Subdivision	2,263	0	(100%)	The project was removed from the worklist as one of the developments is being sold, and the capacity is not required. Minor design and scoping works were completed
Foxton 33kV New Bus and Switchgear	1,023	0	(100%)	The project has been delayed. However, long lead time equipment has been ordered (but is invoiced on receipt). Arriving Q2 Sep 2025
Pole replacements in conjunction with LV reconductoring	2,216	1,816	(18%)	Minor underspend reflecting a lower quantity of poles requiring replacement during reconductoring.
Levin East 11kV Switchboard Replacement	1,177	1,337	14%	Project occurring across FY2025 and FY2026. Variance due to construction and procurement timing.
New Depot - Roe St	3,551	8,866	150%	Variance due to project timing. The building and land costs paid in FY2025 rather than across 3 years as budgeted

4.8 Other aspects of performance

We monitor compliance with all our legislative and regulatory compliance using the ComplyWith system. As detailed in Section 14.5.4, the most recent certification process covered 44 pieces of legislation, with 415 responses completed. There were no non-compliances identified.

5. The Key Issues Driving Investment and Performance

5.1 Introduction

This Section considers other key issues that are driving investment and performance. It builds on the preceding two sections. The key issues discussed in this Section shape our asset management policy and strategy. The key issues are:

- Demand growth due to regional population growth;
- Demand growth due to electrification to meet New Zealand's net zero 2050 goal;
- The aging of the network assets which will see the emergence of end-of-life drivers;
- The increasing risk that future reliability targets won't be met;
- Increasing our asset management maturity to meet future requirements;
- The need to balance competing limbs of the energy trilemma, with a particular focus on efficiency and affordability.

We discuss each of these issues in the following sections.

5.2 Demand growth due to regional population growth

Horowhenua region

Until around 2017, the Horowhenua district saw relatively low growth. Given the recent high growth[50], the Horowhenua District Council forecasts the population to grow to 62,000 by 2041. The District's population is projected to grow 1.8% annually over the next ten years[51].

The growth is partly driven by the Wellington Northern Motorway project, which improves access to the Wellington region.[52] The Northern Motorway to Ōtaki is complete, and the Ōtaki to Levin section is currently underway and is due for completion by 2029.[53]

Sense Partners note:

> *"it appears that domestic migration into Horowhenua has been higher than we or other experts, such as Statistics New Zealand, would have predicted three or four years ago. This is likely to be due to a combination of factors, including:*
>
> - *Improved accessibility from the expressways that have been built to the south of the District;*
> - *Increased costs of living, especially house price inflation, in most urban centres including Palmerston North and Wellington."*

Horowhenua District Council's current view is that the population will continue to grow at the 95th percentile (consistent with the past six years). The most recent census indicates the region's population growth was 2.0% from 2013 to 2023. We have adopted the 75th percentile over the long term as this reflects a continuation of the ten-year trend (rather than the continuation of recent trends adopted by the

50 The population growth has been 2.1% per year for the last six years.

51 Sense Partners, "Horowhenua Socio-Economic Projections Summary and Methods", May 2020

52 https://www.horowhenua.govt.nz/Growth-Projects/Growth. This is based on the 95th percentile growth rate from the May 2020 projections.

53 https://www.nzta.govt.nz/projects/wellington-northern-corridor/otaki-to-north-of-levin

Horowhenua District Council). However, we recognise some upside risk of higher growth (refer to Figure 60 and Figure 61). Our current view implies growth of 1.4% for FY2026 and FY2027, then an annual growth rate of 2.1% over the remainder of the AMP forecast period. Our forecast has been rebased to the most recent population estimates for FY2025 (which is slightly below the 2025 AMP forecast for that year) and to lower growth for FY2026 and FY2027, reflecting the current economic climate, which will limit net migration into the region.

We expect population growth to drive increased demand from residential, commercial, and small industrial customers. Plenty of flat land is available in the Horowhenua close to transport links. This land is cheaper than that available in Wellington and Palmerston North, which will likely fuel commercial and light industrial development in the region. Based on our projections, we forecast around 9,000 new connections in the Horowhenua region from FY2026 to FY2050 (down from 9,300 in the prior AMP).

Population growth is expected to increase base demand (before the impact of electrification) by 14% by 2035 and 38% by FY2050. These are slightly below the 2025 AMP and indicate an additional 15 MW of demand before any impact from electrification (but not visible due to rounding to the nearest MW).

Figure 60: Horowhenua Population Forecasts

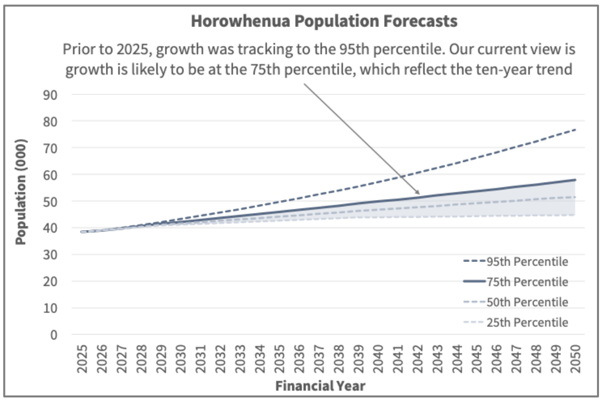
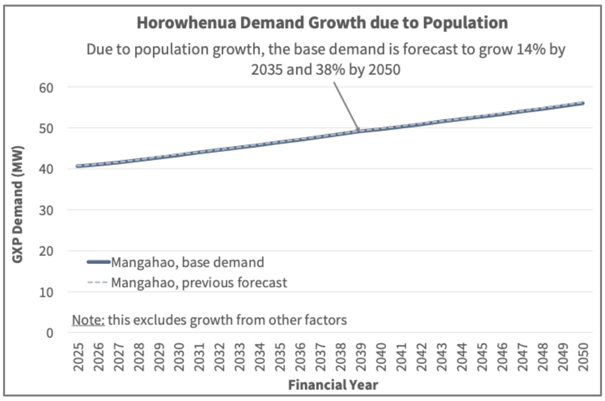


Figure 61: Horowhenua Demand Growth due to Population



Kāpiti Coast region

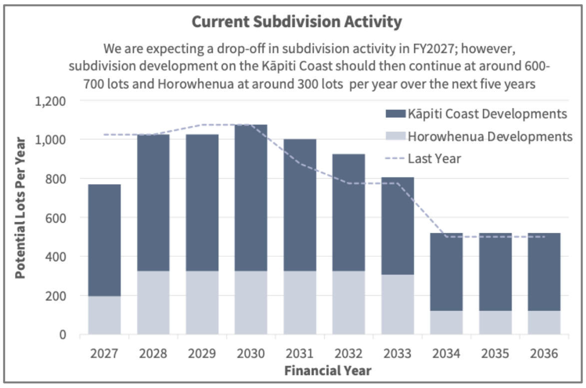
In 2021, Sense Partners forecast the Kāpiti Coast to grow by approximately 32,000 people to 90,000 by 2051, requiring close to 14,000 additional dwellings (based on the 50th percentile).[54] Recent growth (to 2023) has been below those prior forecasts, and the population growth forecasts have been reduced. The May 2023 update by the Kāpiti Coast District Council saw an easing of growth across the next 30 years, reflecting lower levels of migration into the region. The Council's view is that the population is now expected to grow to 78,000 by 2050, a growth rate of 1.2% p.a.[55]

We are seeing a slowdown in progress on land developments due to the current economic climate (refer to Figure 62). The current view suggests land development will slow in FY2026 and FY2027, but longer-term should be in the order of 600-700 sections per year, which equates to a growth rate of around 1.7% (which implies a population growth rate at the 75th percentile).

[54] This was prepared for the Greater Wellington Regional Council and the Kāpiti Coast District Council.

[55] https://www.kapiticoast.govt.nz/community/community-insights/population-and-demographics

Figure 62: Subdivision development



Despite the current slowdown (reflected in the FY2025 rebasing of our forecasts and lower growth for FY2026 and FY2026), we have continued with long-term population growth projections at the 75th percentile (as adopted in the 2025 AMP) for the Kāpiti Coast region. Based on our projections, we forecast around 13,800 new connections by 2050 in the Kāpiti Coast region (slightly below the figure included in the 2025 AMP).

Given our view on population growth, base demand (before the impact of electrification) will grow by 13% by 2035 and 40% by 2050. This equates to an additional 26 MW of demand by 2050, before any impact from electrification (slightly below the forecast in the 2025 AMP, but not visible due to rounding to the nearest MW).

Figure 63: Kapiti Coast Population Forecasts

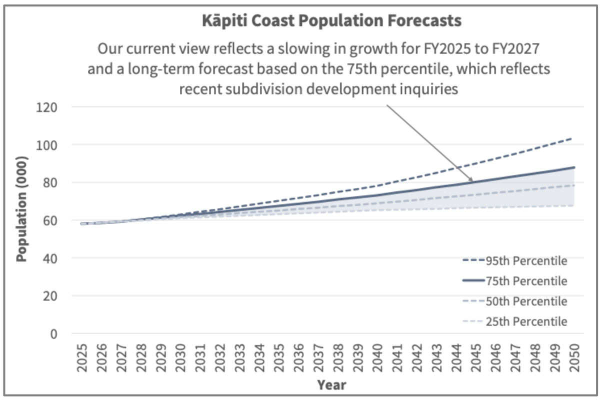
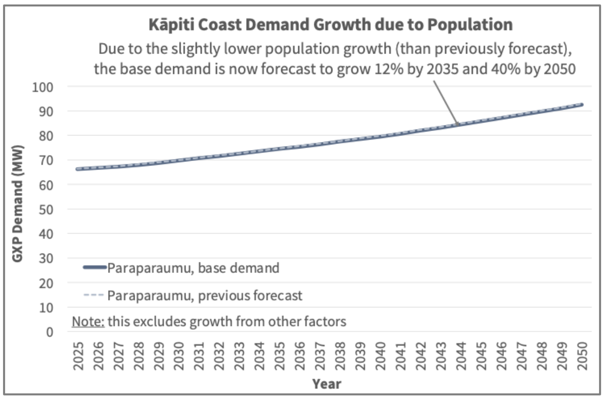


Figure 64: Kapiti Coast Demand Growth due to Population



5.3 Demand growth due to electrification to meet New Zealand's net zero 2050 goal

Reducing emissions through electrification and increasing renewable generation are critical for New Zealand's net-zero 2050 goal (refer to Figure 65). In particular, electrification of transport and heat (both process and general) is the central pillar to achieving decarbonisation. As a result of electrification, the industry forecasts consumption to increase by around 70% by 2050 (refer to Figure 66).

Figure 65: New Zealand's Net Zero Pathway

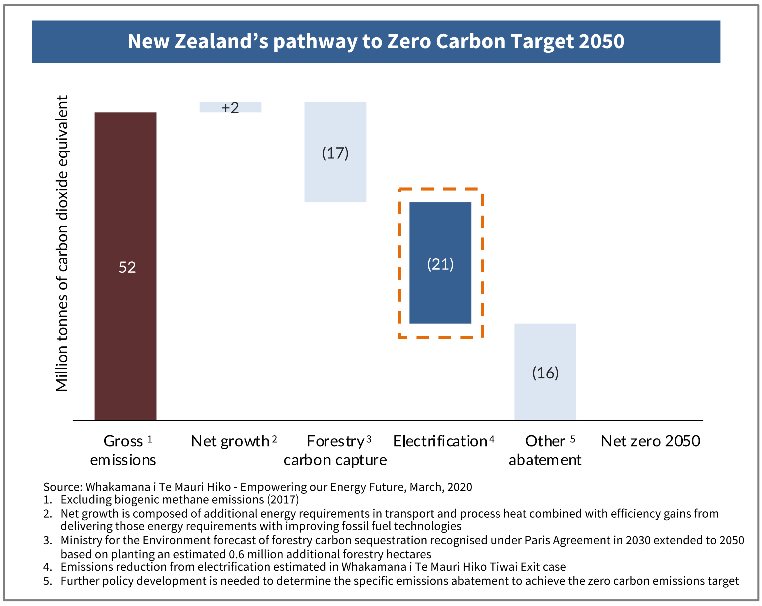
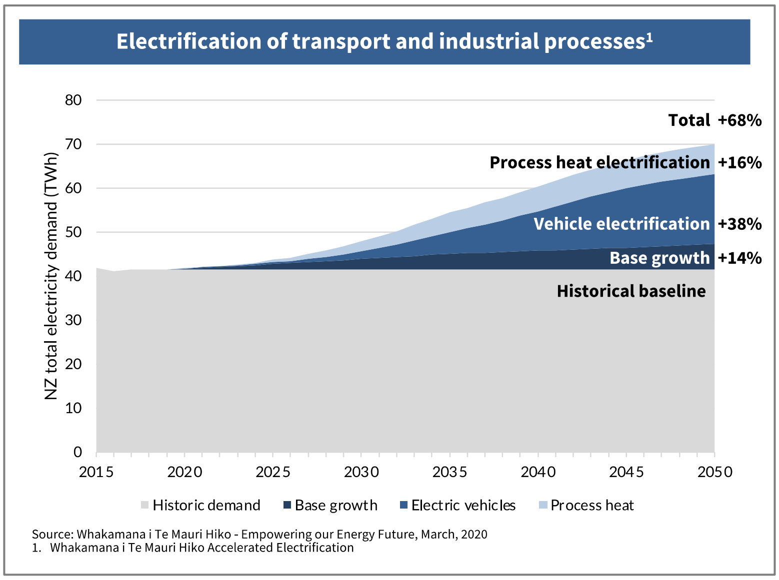


Figure 66: Industry Forecast of Consumption Growth Due to Electrification



We expect the pace of electrification to increase due to the improving economics of new technology and the increasing cost of carbon emissions. We expect to see an increase in electric vehicle (EV) charging, installing solar PV and batteries, and electrifying process and general heat. EVs (particularly second-hand EVs) have strong economics for commuting, and we expect to see strong uptake in the Kāpiti Coast and along the Wellington Northern motorway. Transpower's most recent energy transformation monitoring report notes, "*New Zealand continues to exhibit signs of a new period of electrification growth…indicators continue to point towards growth in electrification of transport and process heat*."[56]

We revised down our electrification demand forecasts to reflect the current economic situation (included in Section 10.8); however, they still indicate material growth due to the impact of electrification (refer to Figure 67). Albeit, the demand forecasts have reduced slightly over those included in the 2025 AMP due to the slightly lower population growth and its impact on electrification uptake.

[56] Transpower, Whakamana i Te Mauri Hiki, Monitoring Report, October 2023.

There is significant uncertainty regarding the extent of demand growth, and material reductions are possible using flexibility from EV smart charging and other sources of demand response (refer to Figure 68).

Figure 67: Demand Growth due to Electrification

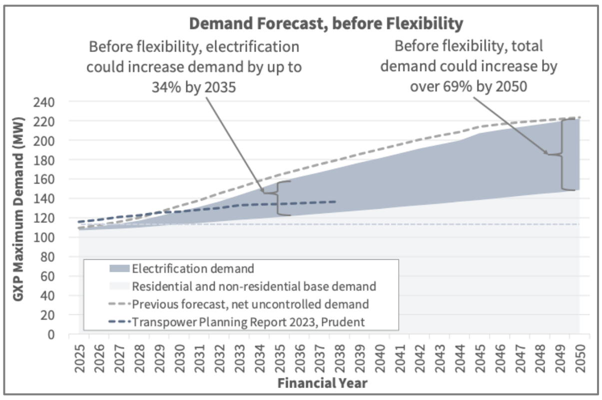
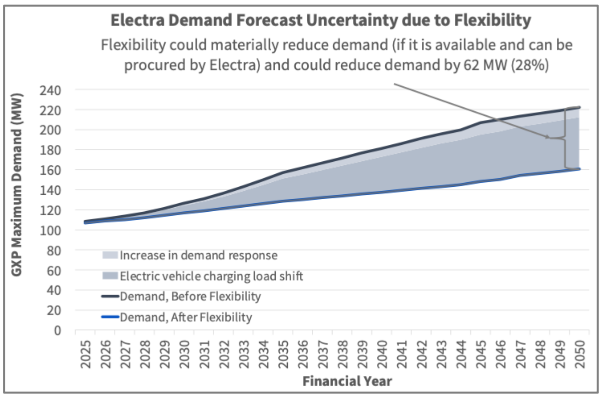


Figure 68: Uncertainty in Demand Growth



Combined with the impacts of population growth, we are forecasting that demand could increase between 22 and 49 MW by 2035 and between 54 and 114 MW by 2050. The range reflects the influence of flexibility in relation to EV charging load-shifting and additional demand response. Demand growth at the upper end of this range will have a material impact on the network.

Our forecast of uncontrolled demand growth equates to a 105%[57] increase in demand by 2050, before the contribution from flexibility. This demand growth is slightly higher than recent industry forecasts (before flexibility), which indicates that national peak demand could increase 93% by 2050.[58] The higher uncontrolled growth we are forecasting reflects higher connection growth present in our region. Our controlled demand growth forecasts (after flexibility) are below that forecast by Transpower in their most recent Transmission Planning Report[59]. Transpower's forecasts reflect electrification demand consistent with their Whakamana i te Mauri Hiko report, which assumes that EV charging load-shifting and additional demand response will occur.

5.4 The network assets are aging, and end-of-life drivers are emerging

Like most distribution businesses in New Zealand, many of our assets were installed in the 1950s, 1960s and 1970s, and many will reach end-of-life over the coming decades. Figure 69 through Figure 75 show the age profile of our primary asset categories and where we expect to see end-of-life drivers emerging. The actual driver for replacement (as set out in our fleet plans in Section 12) is based on a combination of asset health and criticality. However, these graphs indicate that we will see increased asset-related risks over the coming decade.

The onset of unreliability could affect around 17% of the fleet over the next decade, with 30-40% of these assets having asset-related risks that will drive their replacement. How we manage asset-related risks will be a greater focus for the business, including ensuring that we understand the health of the assets and can reasonably forecast the required maintenance or renewal of the assets. This AMP includes fleet plans for our

[57] Including the impact from population growth.

[58] BCG, "The Future is Electric", October 2022, Page 47.

[59] Transpower, "Transmission Planning Report, 2025", Page 200 and 262.

primary asset classes, which communicate the health, risk and expected asset renewals over the coming decade.

Figure 69: Concrete and Wood Pole

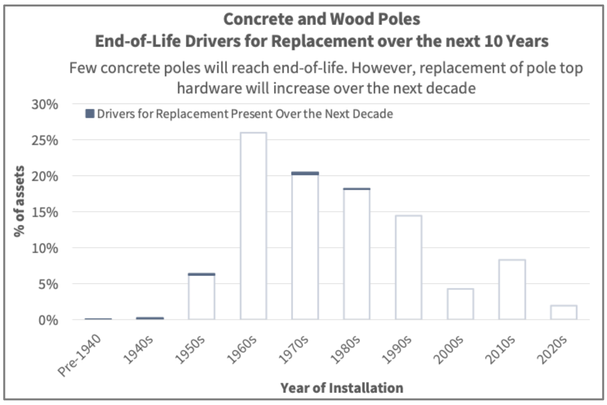


Figure 70: Conductor

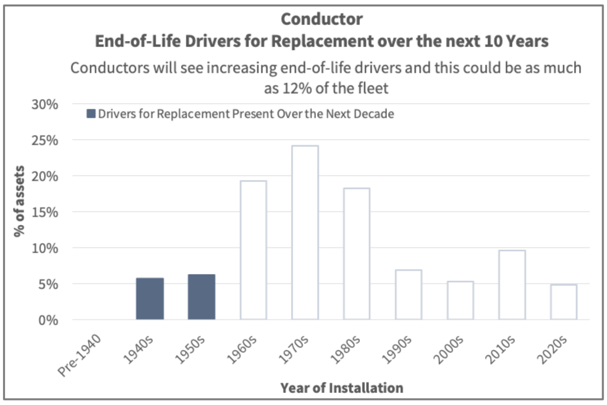


Figure 71: Cables

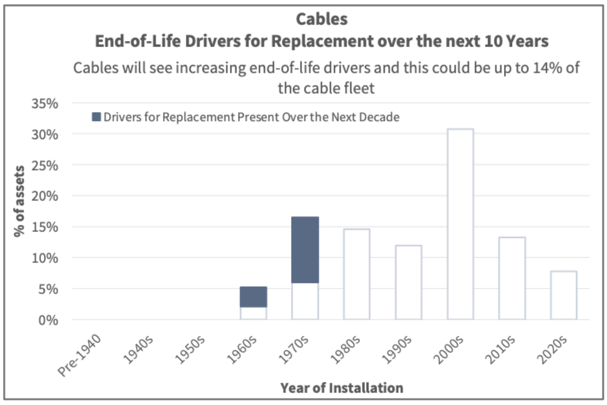


Figure 72: Zone Substation Switchgear

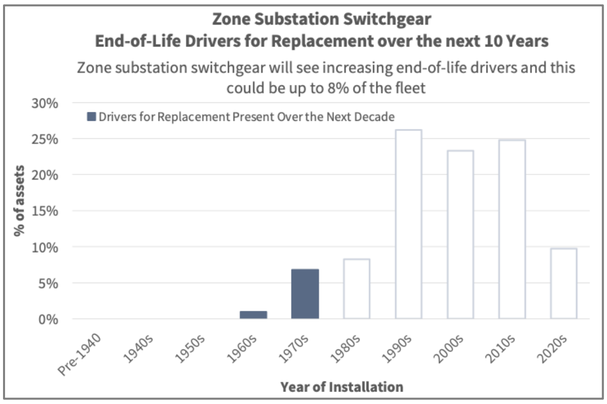


Figure 73: Zone Substation Transformers

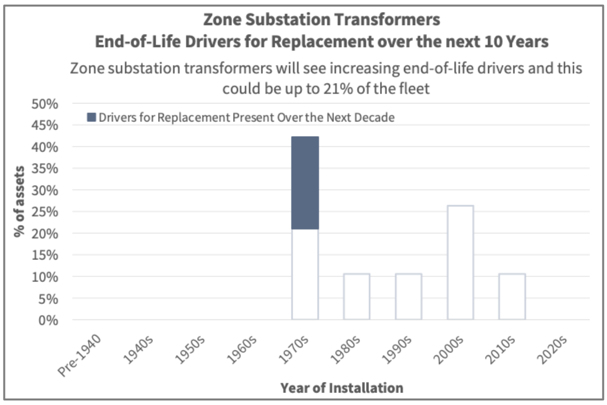


Figure 74: Distribution Switchgear

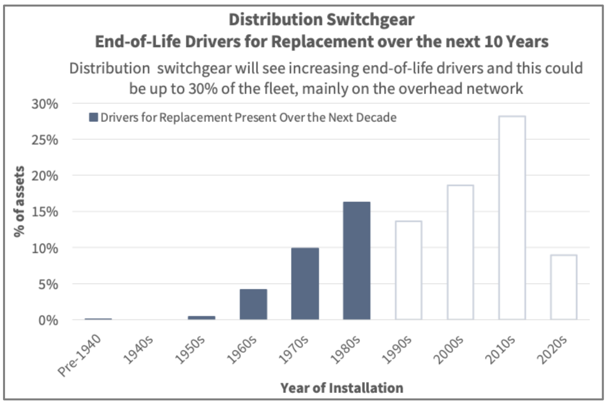
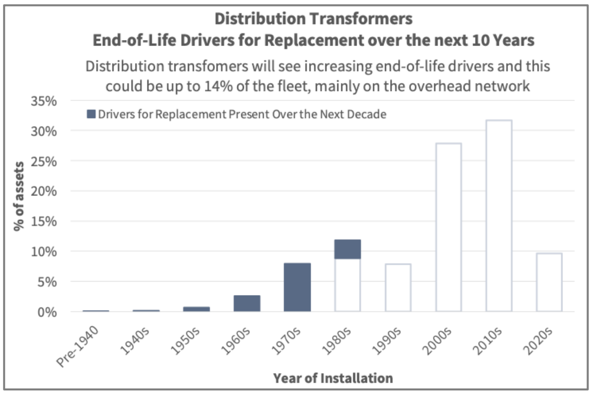


Figure 75: Distribution Transformers



5.5 There is an increasing risk that future reliability targets won't be met

Our planned and unplanned reliability performance has generally been good, but without mitigation, there is an increasing risk of deterioration in reliability (refer to Figure 76 and Figure 77). The risks to reliability performance arise from climate change, population growth, our aging asset fleet and the limited switching points on the underground network:

- We are seeing an increase in adverse weather events due to climate change. Increasing adverse weather events will increase the number of outages due to asset design limits being exceeded and increase the number of out-of-zone vegetation outages;
- Increasing population and economic activity increases vehicle-kms travelled and increases the risk of third-party damage to lines (from vehicles) and to cables (from contractors);
- Our assets are aging, and the risk of end-of-life drivers resulting in asset failures will increase;
- We are forecasting increasing maintenance and renewal work on the underground network, which will require very large outage areas due to the legacy network architecture which features a low number of switching points on the network.

Based on recent historical performance, we have a 45% probability of achieving our unplanned reliability (SAIDI) target in any given year.[60] Given the risks mentioned above (if left unmitigated), this could reduce the probability of achieving the target to ~10% by the end of the decade. We have plans in this AMP to address this issue.[61]

Given the increase in planned work (and that the current configuration of the underground network is not meeting our planning standards), we won't be able to achieve the current planned reliability target over the long term. Planned work on the underground network will severely impact customers due to the large outage areas required. Whilst we may increase our planned outage target to account for increasing work volumes (as our current performance is significantly better than our peers), we believe that very large-scale outages may be unacceptable to our urban customer base.

Managing reliability is increasingly important. Electrification will reduce energy diversity and increase New Zealand's dependence on a reliable electricity supply. Customers need confidence that electricity will be delivered where and when required, and maintaining the reliability of supply will provide this confidence.

[60] FY2020 to FY2025. The probability of achieving target drops to 35% if we consider our performance over the FY2013 to FY2025 period; however, this ignores recent improvements, hence the short period is used.

[61] Our view on reliability risk has reduced compared to that communicated in the 2025 AMP. This reflects the good performance in FY2025, which has improved our view of average performance and reduced expected volitality.

Given the reliability risks, we must actively pursue projects to manage and maintain the network's security, reliability and resilience.

Figure 76: Risk to unplanned reliability performance

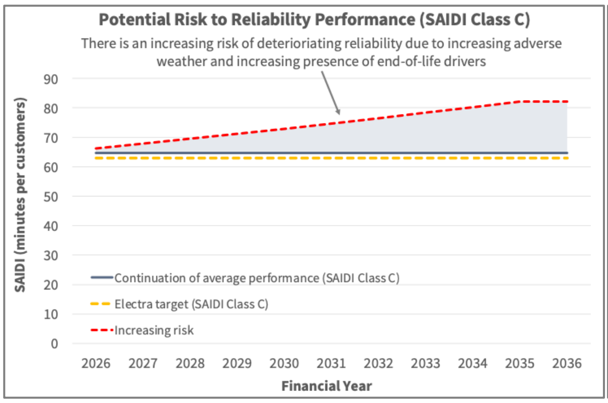
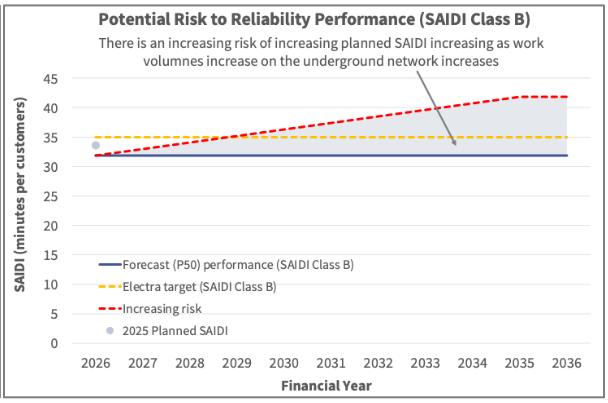


Figure 77: Risk to planned reliability performance[62]



5.6 Increasing our asset management maturity to meet future requirements

Figure 78 shows our current asset management maturity, which remains unchanged from the 2025 AMP. We have made incremental improvements in some areas and reassessed our maturity in others. This progress is behind what we had intended in the 2025 AMP due to our focus on our core asset management activities.

Until recently, our maturity has been a good fit for the needs of the network. Over the last decade, the network performance has generally been good, and our assets have been in good condition (commensurate with their age). While strong, growth has been manageable with the capacity and security limits of the network. However, as noted in the preceding sections, future growth will be greater, complexity will increase, asset end-of-life drivers will emerge, and network risks will increase.

We need to improve our asset management maturity assessment tool (**AMMAT**) from Level 2.5 (as of November 2025) to 3.0. Level 3 means that all elements of our asset management system are in place and are being applied and integrated, with only minor inconsistencies.[63] Our current level of 2.5 indicates that in some areas the system is fully developed, while in others, implementation is not yet fully completed and integrated.

The extent of the gaps in the AMMAT assessment indicates that a wide-ranging improvement programme is required. Our immediate focus will be on the following areas:

- Given the expected increase in demand, development planning (the early phase in an asset's lifecycle) needs to be more mature;
- The increasing use of DERs and the evolution of flexibility markets will increase the complexity of our business and will require new processes to dynamically manage demand and higher maturity in information management;

[62] We have reduced the impact of the increase in planned work on the underground network as some of these outages will be suitable for generator support.

[63] EEA, Guide to Commerce Commission Asset Management Maturity Assessment Tool (AMMAT), May 2014.

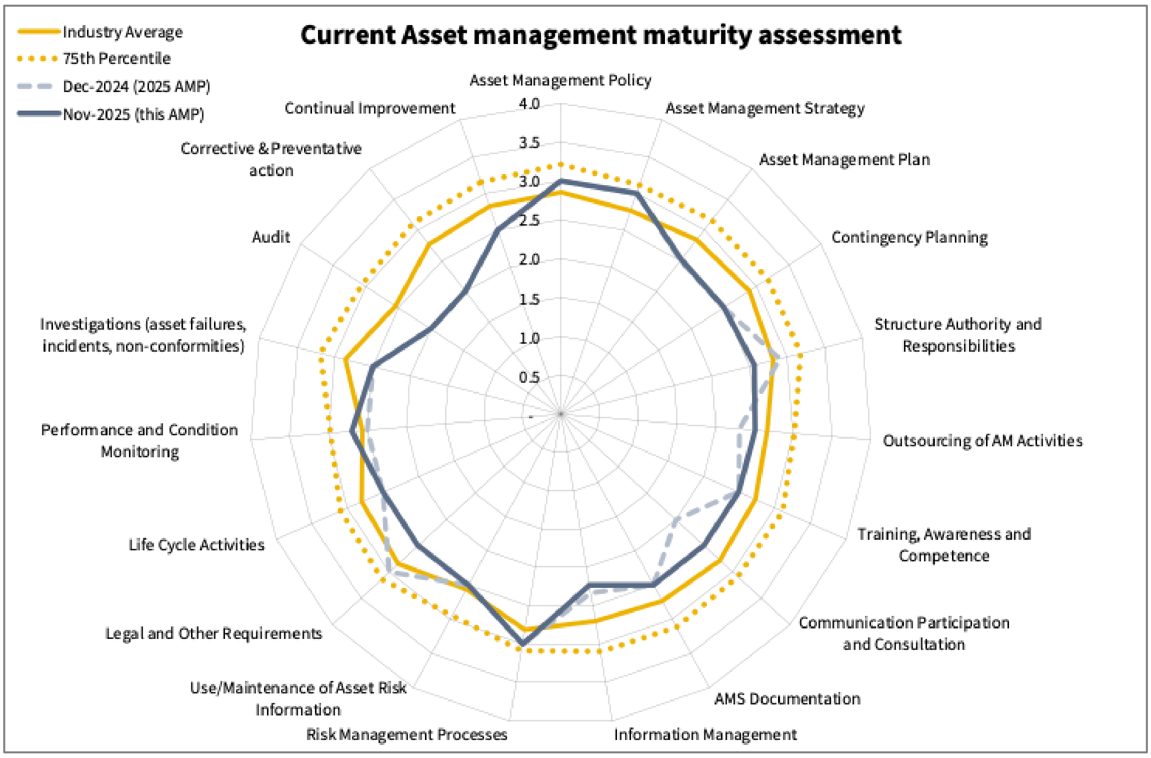
- Given that asset end-of-life drivers are emerging, a higher maturity in life cycle activities, information management, performance and condition monitoring, and asset management strategy will be required*;
- Asset condition assessment standards, condition data and age data have not kept pace with the evolution of the condition-based asset risk management model (CBARMM), which has impacted the quality of our forecasting for some asset classes*;
- Much of the asset information (and associated processes) is stored in different systems and spreadsheets, which makes analysis and forecasting difficult, which makes optimising asset risks and renewal more difficult;
- Capex work has seen delivery delays due to the time taken to select new line and cable routes and the delivery of materials. Improvement in our front-end engineering design (FEED) and outsourcing processes is required*.

* indicates areas where incremental improvement has been made.

Better information and process management will support many of these focus areas. This requires a step-up in our asset information systems.

Following the more immediate work, our focus will be on training, communication, documentation, audit, corrective actions, and continuous improvement.

Figure 78: Current Asset Management Maturity



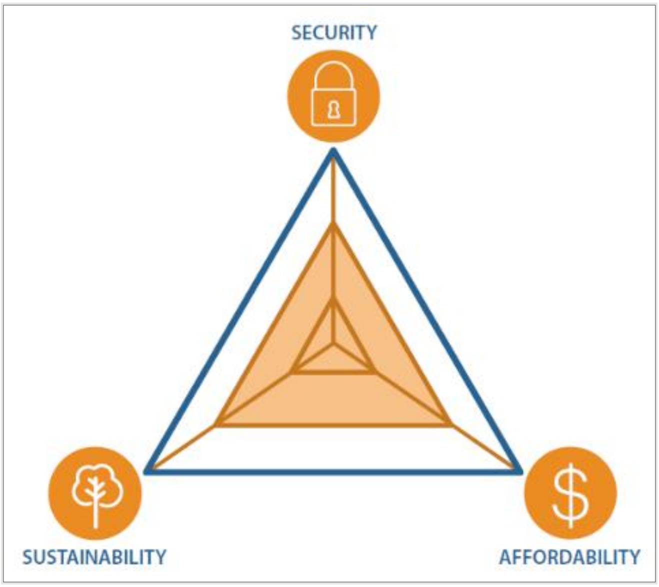
5.7 The need to balance competing limbs of the energy trilemma

The Energy Trilemma is a well-recognised framework (refer to Figure 79) for strategic optimisation in the energy sector. This framework has been adopted throughout the industry to communicate how these factors are balanced.

In the energy context, the three limbs of the trilemma refer to:

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

Figure 79: The energy trilemma



The importance of this balance has increased for Electra due to:

- The need for higher opex and capex to respond to our aging asset fleet;
- The need for higher opex and capex to support New Zealand's sustainability and decarbonisation goals through supporting the electrification of transport and process heat;
- The need for higher opex and capex to maintain a secure, resilient and reliable network as energy diversity reduces (due to electrification) and risk increases (due to climate change);
- The need to maintain a strong emphasis on affordability given the concentration of older people and the generally low income of our customers (refer to Section 3.3).

The energy trilemma balance needs to be a key consideration for major projects. We also need to communicate how we are balancing factors as a business. We believe that it is important to communicate with stakeholders about our thinking about balancing the energy trilemma and what this could mean for our customers.

Part 2:

Our asset management strategy

6. Asset Management Policy and Strategy

6.1 Introduction

This Section presents the asset management policy and strategy. The policy and strategy define the principles and objectives to guide the more detailed plans contained later in the AMP.

We have amended asset management strategy #4 to more accurately describe this as our initiative to manage ongoing reliability and resilience risks.

6.2 Asset Management Policy

The Asset Management Policy establishes the principles that guide the direction and approach to managing the electricity network. The policy describes Electra’s commitment to the responsible stewardship of the electricity network assets. It sits alongside our Health, Safety and Wellbeing Policy, Sustainability and Environmental Policy, Risk Management Policy, Procurement Policy and other key corporate policies.

Asset Management Policy

Electra is committed to responsible stewardship of the electricity network to meet the needs of our customers and stakeholders over the long term.

Effective asset management is the foundation for meeting this commitment. Asset management involves the entire organisation. We shall apply sound technical, social, and economic principles that consider customers' present and future needs and the services they require from the network assets.

We will:

- Maintain and manage the network assets to enable the safe, efficient and effective delivery of electricity to our customers
- Consider the economic, environmental and cultural impact of our business and find an appropriate balance between them
- Monitor service levels to ensure they support customers and our business goals and objectives
- Develop the network responsibly to meet current and future needs, and we will adopt new technology to ensure we keep pace with the requirements of customers and other stakeholder
- Establish asset operating, maintenance and replacement strategies to ensure our assets support the services required and minimise the total lifecycle costs, including through extending the useful life of assets
- Seek to provide stable long-term pricing to our customers and appropriate financial stewardship
- Implement good governance and management practices to ensure risk is appropriately managed, service levels are delivered, and actions are taken to improve performance when necessary
- Report to customers and other stakeholders on the status and performance of work related to implementing this asset management policy

6.3 Asset Management Strategy

Our asset management strategy

We have developed an asset management strategy to guide our asset management work over the next decade. We will review the strategy periodically to ensure it continues to respond to the needs of customers, stakeholders and the network.

Asset Management Strategy

Our asset management strategy comprises six initiatives:

1. Prepare the network (or non-network alternatives) to support the forecast future growth in our region.
2. Implement an energy transformation roadmap to further prepare for increased electrification.
3. Develop comprehensive fleet plans and renewal forecasts.
4. Continuously manage reliability risk and resilience.
5. Improve asset management maturity to level 3.
6. Balance the energy trilemma in a manner that aligns with our customer, stakeholder and network needs.

Work programmes (discussed in the implementation section) are aligned under each initiative.

The strategy is aligned with the asset management policy and:

- Is aligned with Electra's business strategy and the needs of our stakeholders contained in Section 2.4 and 2.5;
- Is consistent with the context of our network and the types of customers we have, as discussed in Section 3;
- Responds to any material gaps in performance described in Section 4;
- Responds to the key issues driving investment and performance as described in Section 5;
- Supports the achievement of our performance targets contained in Section 7.

Table 8 provides further detail on each of the initiatives.

Table 8: Our asset management strategy

Initiative	Description
1. Prepare the network (or non-network alternatives) to support future growth in our region	We need to ensure we properly plan for future demand growth in a manner that has the least cost and risk for our customers. We will do this by: • Preparing development plans to cater for forecast growth at the GXPs, sub-transmission, distribution and low voltage networks; • Developing a long-term solution for providing capacity and security at Mangahao GXP; • Ensuring the plans provide a staged development pathway that can be adjusted for non-network alternatives (i.e. flexibility) and advanced or deferred if growth differs from that forecast.
2. Implement an energy transformation roadmap to further prepare for increased electrification	In addition to planning for network demand growth, we must ensure all aspects of our business are ready for the energy transformation to support New Zealand and our region's decarbonisation goals. We will do this by: • Preparing monitoring reports and adjusting the roadmap steps to align with technology change and the pace of the energy transformation;

Initiative	Description
	• Continue implementing the roadmap (a comprehensive energy transformation roadmap was developed in 2021); • Being ready to utilise flexibility where this provides viable non-network alternatives to manage demand and reduced the extent of network augmentation.
3. Implement and optimise comprehensive fleet plans and renewal forecasts	As an increasing number of our assets approach end-of-life, we need to prepare comprehensive fleet plans. We will do this by: • Ensuring condition assessment standards and data align with our health assessment and renewal forecasting methodology; • Defining asset fleet strategies that are aligned to the quality and availability of asset age, condition and risk data; • Maintaining asset fleet plans and renewal forecasts for all material asset classes; • Accelerating asset condition inspections where data gaps exist, in particular overhead conductors and cable terminations; • Targeting asset renewals where asset health is deteriorating, including prioritising pole-top hardware and the worst-performing feeders.
4. Continuously manage reliability risk and resilience	Whilst our reliability is generally good, we need to manage reliability risk to ensure our future reliability targets can be met. We will do this by: • Assessing options to increase the automation and protection of rural feeders, targeting the worst-performing feeders; • Assessing options to increase the number of ground-mounted switches, targeting areas where asset health is deteriorating and where there is heightened third-party damage risk; • Reviewing our overhead line designs and practices to ensure they meet site-specific wind speed requirements to improve resilience; • Prioritise our operational vegetation management plans to ensure the worst-performing feeders (for vegetation) are addressed; • Undertake further analysis of vehicle damage incidents and high-traffic areas to assess options to reduce vehicle damage risks.
5. Improve asset management maturity to level 3	We need to ensure our capabilities keep pace with the changing needs of the business. We will do this by: • Developing an asset management improvement plan that closes the key maturity gaps, which will involve: • Updating our policies and procedures across design, construction, commissioning, inspection and maintenance; • Revising and developing business processes (the focus areas are outlined in Section 5.6); • Consolidating asset information and key processes within an new asset management system (included in Electra's Digital System Strategic Plan); • Implementing an asset management committee (AMC) to oversee various asset management actions required to lift maturity; • Improving the maturity of the AMP content, particularly in the area of asset lifecycle.
6. Balance the energy trilemma in a manner that aligns with our customer, stakeholder and network needs	We must carefully balance the influence of our capex, opex and sustainability programmes on affordability. We will do this by: • Modelling the impact of our expenditure on affordability (an initial view is provided in this AMP) and adjusting programmes where appropriate;

Initiative	Description
	• Ensure that the timing for our various programmes is optimal so that expenditure keeps pace with demand but does not lead to asset stranding if demand changes; • Ensure that our support for decarbonisation is consistent with industry standards and timing, and that it serves the needs of our customers.

Alignment of asset management strategy to issues

Table 9 describes how the asset management strategy aligns and responds to various issues described in Sections 3 to 6. The asset management strategy does not address all of the issues identified, as some issues are addressed directly by a programme or project specified in the implementation sections of the AMP.

Table 9: Alignment of our asset management strategy to the key drivers

Initiative	In response to…
1. Prepare the network (or non-network alternatives) to support the forecast future growth in our region 2. Implement an energy transformation roadmap to further prepare for increased electrification	• Demand growth due to regional population growth • Demand growth due to electrification to meet New Zealand's Net Zero 2025 • Changing customer behaviours, which will have an impact on our demand profile and the effectiveness of our hot water load control • The forecast breach of firm capacity at Mangahao GXP and the continued reliance on Mangahao Generation to manage peak demand
3. Develop comprehensive fleet plans and renewal forecasts	• Asset condition assessment standards, condition data and age data have not kept pace with the evolution of the CBARM model • The aging of the network assets which will see the emergence of end-of-life drivers • The concentration of defective equipment and adverse weather outages on our worst-performing (overhead) feeders
4. Continuously manage reliability risk and resilience	• The increasing risk that future reliability targets won't be met • The very low number of switching points on the underground network which restricts the timely restoration of faults • The concentration of defective equipment and adverse weather outages on our worst-performing (overhead) feeders • The high incidence of vehicle damage outages, which could increase as population and economic activity increases • The high concentration of vegetation-related outages on a few feeders and the likely increase due to climate change
5. Improve asset management maturity to level 3	• The need to increase development planning maturity in response to the expected increase in demand • The need to develop new processes to dynamically manage demand and increase maturity in information management in response to the increasing business complexity due to DERs and flexibility markets • The need to increase the maturity of lifecycle activities, information management, performance and condition monitoring, and asset management strategy in response to the emergence of asset end-of-life drivers • Asset condition assessment standards, condition data and age data have not kept pace with the evolution of the condition-based asset risk management model (CBARMM), which has reduced the quality of our forecasting for some asset classes • Our asset information is stored in different systems and spreadsheets, which makes analysis and forecasting difficult, which makes optimising asset risks and renewal more difficult • Capex work has seen delivery delays due to the time taken to select new line and cable routes and the delivery of materials. Improvement in our front-end

Initiative	In response to…
	engineering design (FEED) and outsourcing processes is required. Note: We also address the field resources in relation to works delivery in Section 13. • The areas for improvement need to be supported by better information and process management. This requires a step-up in our asset information systems
6. Balance the energy trilemma in a manner that aligns with our customer, stakeholder and network needs	• The importance of affordability given the age and income demographics of our customers (and beneficiaries) • The need to support New Zealand's sustainability goals through supporting the electrification of transport and process heat • The need for higher opex and capex to maintain a secure, resilient and reliable network as energy diversity reduces (due to electrification) and risk increases (due to climate change)

6.4 Customer Service

6.4.1 Customer service strategy

Traditionally, the nature of our services meant that we engage with customers infrequently and reactively, for example, in the event of an unplanned outage or when things go wrong, when we need to do planned works and these impact them, or when they want to do something that affects us like a new connection or change in capacity.

To support the growth and electrification in our region, we are proactively engaging with commercial organisations and developers to understand where and when the expected growth in our network is required.

This engagement will take the form of direct and regular meetings with our large energy consumers, identifying and meeting our emerging energy users to understand timing and demand characteristics, and working with KCDC and HDC to build a pipeline of future works within the developer community. Input for these activities will influence future AMPs.

Internally, we are building a set of service level targets for typical activities and dashboards to monitor progress on key performance indicators such as:

- Customer service (reliability) targets;
- Customer connections;
- Customer satisfaction targets.

Electra customers should expect quality service and support at all times. Customers are encouraged to advise us of problems or complaints, including land issues, so that we can fix them. Customers can access Electra via telephone or the Electra website.[64] All our staff are committed to treating complaints seriously and reaching resolutions as quickly and fairly as possible.

6.4.2 Customer communication

Electra received clear feedback through the results from the Customer Satisfaction survey that customers are seeking an increased level of communication with customers and the broader community is essential. Our approach is to:

[64] https://electra.co.nz/contact-us/complaints-process/

- Build strong relationships with customers through proactive communication, particularly during power outages. Our goal is to have consistent and timely communication via multiple media channels;
- Engage with the community across multiple media channels on areas of interest such as planned network developments, outages, public safety, energy efficiency and pricing changes;
- Having a clear and easily accessible portal that provides information on areas such as staying safe around our network, how to get connected, and how to connect new devices like solar PV, batteries and EV chargers;
- Communicate our service standards and performance (through this AMP, the summary AMP, the SCI, our website, social media channels and at community engagement sessions);
- Provides a platform to connect industry partners and stakeholders.

We use a multi-channel approach to customer communication, with our website as the primary interface for inbound customer communication. An update to the website is planned in FY26 to improve its structure, make it more mobile-friendly, and introduce an improved architecture to handle “storm event” scaling.

The website contains the current status of the network, information about connecting to the network, safety information, the services we provide, network prices, general company information and our compliance process.

We also use social media (Facebook and LinkedIn) to communicate with customers and stakeholders. This will be primarily used for informing, educating and providing links to enable community feedback.

We also operate an internal call centre during business hours, supported out of hours by an external service, which enables customers to report power outages in person, although this can also be done through our outage application as well as the website.

6.4.3 Notice of planned and unplanned interruptions

Notices for planned outages are issued to customers by their energy retailers and are also displayed on the network status page on the website and the Electra outage application. Electra also does a card drop for all planned outages and provides notification through social media.

For major projects that require multiple outages or could cause community disruption, we prepare specific comms plans that include a pamphlet, comms plans, and radio and social media updates. Refer to the Feeder 401 Project communication case study on the next page as an example.

For short-notice planned outages (which may be required for urgent work), the card-drop is provided and may also include outbound calling from our customer experience team, as there is normally no notification from retailers due to the short cycle time.

Case Study: Stakeholder Communication on the Feeder 401 Project

Community Engagement During Infrastructure Upgrades

The Feeder 401 project involved installing a new 11kV cable from our substation on Arko Place west along Kapiti Road to boost supply capacity for the Paraparaumu Beach community. The project team prioritised proactive, transparent, and inclusive communication to minimise disruption and foster positive relationships across the community.

Stakeholders were identified and engaged throughout the project. These included the Kāpiti Coast District Council (KCDC), businesses and residential properties impacted by the works, the general public using Kapiti Rd, Kapiti Airport, emergency services, and public transport operators.

The project's communication strategy was comprehensive and multifaceted, ensuring that each stakeholder group received tailored information and timely updates.

Various communication platforms were used, including direct engagement through KCDC channels and targeted updates for businesses and residents along the feeder route. The team shared information with Kapiti Airport, emergency services, Metlink, and other transport providers, and reached a wider audience through social media and council bulletins. Combining traditional methods like mail and newspaper inserts with digital tools ensured all affected parties received timely and relevant updates.

This approach enabled swift responses to concerns, facilitated collaboration, and maintained trust throughout the project, demonstrating the value of clear, consistent communication in infrastructure upgrades.

6.5 Efficiency Strategy

Ensuring the efficiency of our assets and operations is a key focus for Electra. Insofar as this relates to asset management, our strategy is to:

1. Ensure capital efficiency in the planning and delivery of network investments;
2. Lowering the cost of undertaking work on the network;
3. Increasing the use of demand response and non-network solutions;
4. Industry standardisation, adoption of common business processes and systems.

We discuss each of these strategies below.

1. Ensure capital efficiency in the planning and delivery of network investments

EDBs are capital-intensive businesses, and the return on and of capital is a significant component of our total costs (which drive line prices). We have a range of initiatives to ensure our investments in the network are efficient, including:

- Increasing the visibility of customer demand and consumption data to ensure that demand forecasting accurately reflects customer usage patterns and the utilisation of the network is maximised, in particular LV (see Sections 10.8 and 10.10);
- Using planning horizons that ensure assets are optimally sized and commissioned to meet expected demand. that is, balancing the risk of building too big and too early, that risk under-utilised assets vs. building too small and too late, that fails to serve customers or materially increases security-related risk, (our planning horizon is discussed in Section 11.5.4);
- Lowering asset replacement capex through a better understanding of asset failures and risk profiles, including through sharing asset knowledge across the industry (our asset risk profiles and our approach to risk are included in the fleet plan in Section 12);
- Active consideration of demand response and non-network solutions (including DERs) to defer network upgrades and improve the utilisation of the network (item 3 below);

2. Lowering the cost of undertaking work on the network

Maximising the value of our investments ensures they are efficient. We have a range of initiatives to ensure efficient design and delivery, including:

- Choosing the most efficient technical solution considering network and non-network solutions to minimise the whole of lifecycle costs (our consideration of alternatives are discussed throughout Section 11);
- Purchasing processes that seek to make efficient purchasing decisions;
- Working with the industry to seek ways to lower the cost of doing work (e.g. consenting, vegetation management processes, and traffic management costs);
- Optimising our use of outsourced service providers to efficiently manage peak and variable workloads (refer to Section 13.4.4).

3. Increasing the use of demand response and non-network solutions;

Lowering our system growth-related capex through maximising the use of demand response and non-network solutions (including DERs) to defer network upgrades and improve the utilisation of the network, where it is technologically and economically feasible to do so.

- We are actively considering non-network solutions in the development of solutions to meet demand growth (consideration of non-network solutions is discussed throughout Section11);
- Providing new large customers (who have flexibility) with the option of interruptible capacity, which improves the network load factor and avoids costly capacity upgrades;
- Implementing time-use-pricing that incentivises the use of energy at lower demand (off-peak) times to minimise peak demand and to improve our load factor (refer to our pricing methodology[65]);
- Using load control to minimise peak demand and to improve our load factor. We use our load control to minimise the maximum demand on our network, managing peak demand ahead of network upgrades and deferring capital investment (refer to Section 3.4);

4. Industry standardisation, adoption of common business processes and systems

Driving efficiency through industry-standardisation and the adoption of common business processes and systems is important for lowering operating and capital costs. We have a range of initiatives in this area, including:

- Standardisation of designs, equipment and materials. This reduces design and engineering costs, enables training, spares, and purchasing scale efficiencies (refer to Section 11.5.3). We currently outsource our procurement to Connetics to gain purchasing efficiencies (refer to Section 13.3);
- Increasing our outsourcing of IT solutions and support to ensure we achieve the necessary expertise and to ensure we receive efficient market prices for those services;
- Collaborating with our peers in relation to significant IT/OT initiatives and major system implementation.

[65] https://electra.co.nz/wp-content/uploads/2025/03/Pricing-Methodology-1-April-2025.pdf

7. Performance Targets

7.1 Introduction

This Section describes our performance targets. The targets are consistent with our asset strategies, stakeholder interests and customer expectations. Section 7.8 explains how this asset management plan influences the energy trilemma—that is, how it balances affordability, security of supply and supports New Zealand's decarbonisation efforts. This is the first time we have sought to measure ourselves against the trilemma, so we expect this to evolve over the coming AMPs.

7.2 Safety and environmental targets

Table 10 shows our safety and environmental targets. These targets remain unchanged from prior AMPs and reflect our commitment to safety and environmental performance.

Electra is committed to ensuring the health and safety of its customers, employees, contractors, and the public. We have a comprehensive health and safety system aimed at achieving zero LTIs summarised in Section 13.6. We predominantly measure safety performance using leading indicators—which is the best way to ensure that we have influencing safety outcomes. The integrity of our assets also impacts safety, and completing planned inspections (to understand risk) and remediating defects is important.

We have commented on our prior performance in Section 4.2. Our future targets are consistent with prior years, and we believe the targets are appropriate, consistent with stakeholder expectations, and achievable over the long term.

Table 10: Safety and Environmental Targets

Area	Indicator	Indicator type	Average of last 5 years	Target FY2026-31
Safety of staff, contractors, and the public	Staff Lost Time Injuries (LTIs)	Lagging	2.2	Zero LTIs (for critical risks)
	Number of incidents	Lagging	90	No target. Reporting of incidents is encouraged
	Public safety audits	Leading	34	60 per year total
	Contractor safety audits	Leading	198	
	Contractor training seminars	Leading	2.4	No target. Training is provided as required.
	Compliance with our public safety management system	Leading	Compliant	Compliant
	Completed preventative and proactive actions	Leading	1,107	5% annual increase from 2020. This averages 1,209 over FY2026-31.
Asset integrity	Completion of planned Inspections[66]	Leading	86%	>95%
	Remediation of defects in the required timeframe[67]	Leading	-	Future measurement following the implementation of the EAMS
Environmental responsibility	Number of environmental incidents	Lagging	0	Zero incidents

[66] This is a composite measure of the completion of planned inspections. Practical completion means the work is completed with the exception of minor omissions (of less than 5%), hence the target is >95%. We take a practical approach as some inspection require access to private property and can have weather restrictions.

[67] The target is det to achieve practical completion. That is, the work is completed with the exception of minor omissions (of less than 5%), hence the target is >95%. We take a practical approach as some as some defect repair work requires planed outages, access to private property and can have weather restrictions.

Electra has decided to adopt the Environmental, Social, and Governance (ESG) sustainability framework and is in the process of planning its implementation. The framework will provide guidance on managing environmental risks, meeting growing stakeholder expectations, complying with regulations, and enhancing community engagement. We are also finalising an Environmental Management System (EMS) that has been certified by Toitū Envirocare to ensure compliance with RMA requirements (refer also to Section 14.7).

7.3 Network reliability targets, customer perspective

The context for reliability targets

As mentioned in Section 4.3, our primary customer service metric is network reliability, measured by SAIDI (the average duration of outages) and SAIFI (the average number of outages per customer). Outages may be planned or unplanned; unplanned outages are particularly important because they inconvenience customers due to their unforeseen nature.

As mentioned in Section 4.4, customers are generally unwilling to accept a lower level of service and are satisfied with the current reliability. For these reasons, our unplanned reliability SAIDI and SAIFI targets remain unchanged.

Our planned and unplanned reliability performance has generally been good, but the risk of deterioration is increasing. The risks to reliability performance arise from climate change, population growth, our aging asset fleet, and the legacy network architecture of our underground distribution network, which features a very low number of switching points that restrict the timely restoration of faults (refer to Sections 3.5.3 and 5.5).

Managing reliability is becoming more crucial. Electrification will lessen energy diversity and increase New Zealand's reliance on a stable electricity supply. Customers require assurance that electricity will be delivered where and when needed.

Planned mitigation initiatives to offset the increasing risk to reliability performance

Given the increasing reliability risks and the importance of maintaining a reliable network, we are planning a range of risk-mitigation projects. We are working through the justification for these programmes (a change from what was presented in the 2025 AMP). The potential impact these projects are forecast to have on reducing reliability risk is shown in Figure 80 and Figure 81. The initiatives will reduce the risks associated with both unplanned and planned reliability performance.

The reliability risk mitigation initiatives are:

- Addressing asset health on the worst-performing feeders (Sections 12.12 and 12.13);
- Increasing vegetation management on the worst-performing feeders (Section 12.19.2);
- Enhancing resilience (Sections 14.6, 11.9.4 and 11.10.5[68]);

We are reviewing the justification for other reliability risk mitigations. These are discussed in concept in Sections 11.10.3, 11.10.4 and 11.12.3).

We have forecast our future reliability performance separately from our target to provide a view on reliability risk. The future performance is based on a continuation of an “average” year (with respect to the impact of

[68] We have a reliability risk mitigation target for our resilience initiative. However, we have not yet specified the resilience projects. We have only recently finalised our resilience strategy, and the projects are being considered over the coming year.

weather, third-party damage, and other factors). It incorporates our planned risk mitigations (that are included in the expenditure forecasts) and the potential for further reliability risk mitigations (that are currently in the concept phase, as mentioned above).

Figure 80: Unplanned reliability risk mitigations to offset increasing risk

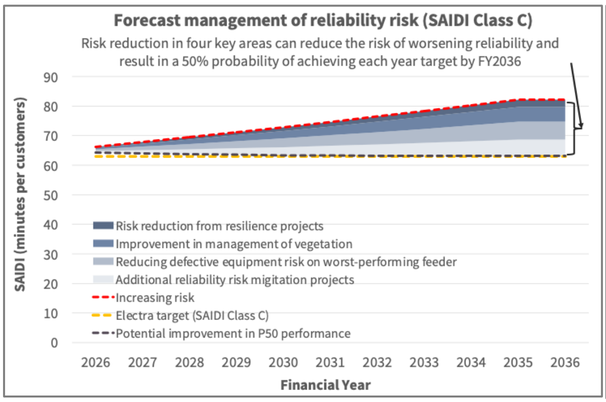


Figure 81: Unplanned reliability risk mitigations to offset increasing risk

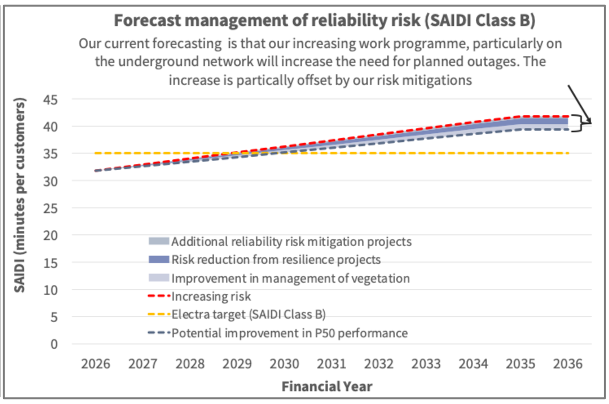


Figure 82 to Figure 85 show our reliability targets and the forecast performance, including the planned risk mitigations. The Figures also show the impact of further reliability risk mitigations currently under consideration. We expect a 50% probability of achieving the unplanned SAIDI target in FY2036 (including the further reliability risk mitigations that are under consideration). Having forecast performance to at least achieve P50 strikes the right balance between investing more in reliability and accepting that, in some years (due mainly to weather), we will exceed the target.[69]

We are forecasting an increase in planned outages. This reflects the planned increase in work volume and an increase in work on the underground network. Even with this increase in planned outage, we will still perform significantly better than our peers, suggesting there is scope to raise the target. Planned outages are notified in advance and generally cause less inconvenience for customers.

Figure 82: Unplanned outage duration

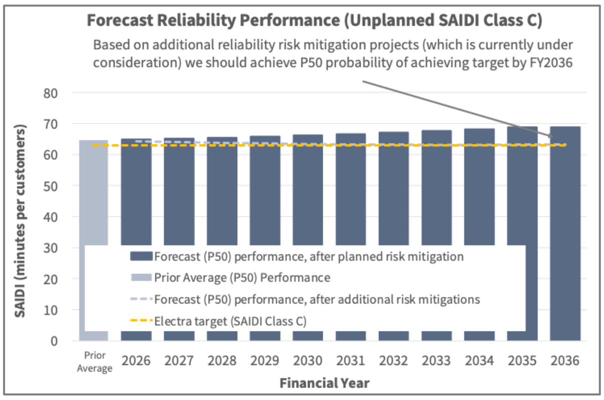
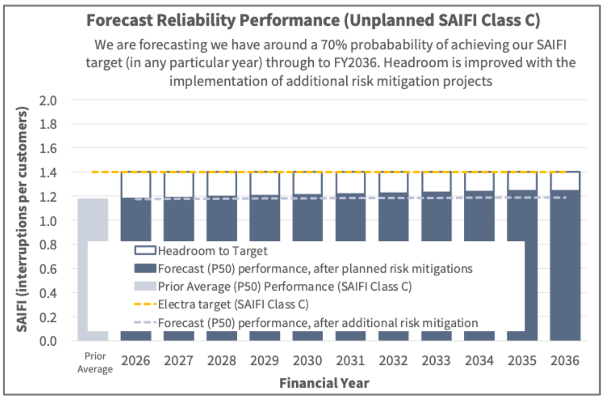


Figure 83: Unplanned outage frequency



69 Based on our historical performance, a worst-case (1 in 10 years) reliability outturn will be a SAIDI of 84 minutes. This is 33% above target, but will occur once in every 10 years. Electra's actual and target performance is based on RAW SAIDI and SAIFI. That is, there is no normalisation for major events. This differs from regulated EDBs, which normalise for major events.

Figure 84: Planned outage duration

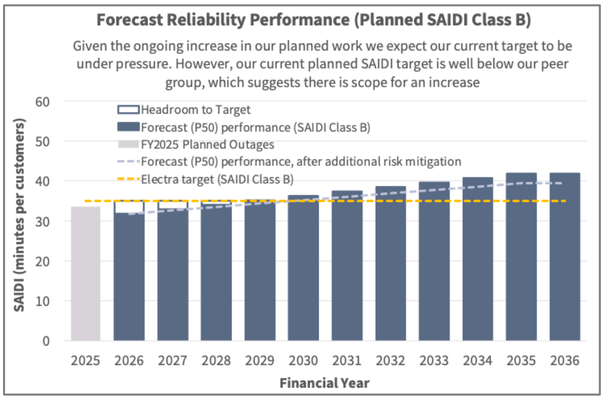
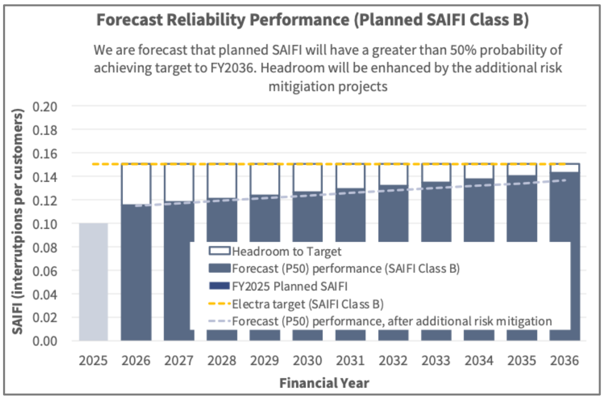


Figure 85: Planned outage frequency



7.4 Other customer service targets

During FY2026, we completed a customer survey with an external provider that offers services similar to those of other EDBs, allowing us to benchmark our relative performance across areas such as overall satisfaction, response to unplanned outages, and satisfaction with communication regarding planned outages. This will give us a customer perspective on network reliability and fault services and provide a benchmark for us to measure against in the coming years. Our target is to provide a reliable supply of electricity that meets customers' needs and, when faults occur, a fault service that also meets customers' needs.

Electricity Networks Aotearoa (ENA) collaborated with EDBs to produce a connection process guideline for distributed generation, and this is something Electra is working towards implementing and build out across other connection pathways as well.

7.5 Asset performance targets

Table 11 shows the asset performance targets. The table shows that our current average reliability performance is above target[70] and is forecast to deteriorate without intervention. We have set long-term targets to manage our asset performance (and unplanned SAIDI), consistent with the reliability risk mitigations outlined in Figure 80. These risk mitigations offset the forecast deterioration and should see our average (P50) performance achieving target by FY2036.

Sections 7.3 and 4.5.9 presented the linkages to the various reliability risk mitigation initiatives. Managing reliability risk through structural changes like security, automation, and protection takes time. We expect to see our reliability risk reduce over the next 10 years.

Table 11: Asset performance targets

Asset performance measure	Recent average unplanned SAIDI performance	Forecast increase in unplanned SAIDI without intervention by FY2036	Impact of current risk mitigations on unplanned SAIDI by FY2036	Impact of further risk mitigations on unplanned SAIDI by FY2036	P50 Unplanned SAIDI Performance by FY2035
Reliability performance on the distribution underground network	64.6	4.7	0.5[71]	2.9	~63.2

[70] Target is 63 SAIDI.

[71] Estimated share of resilience improvements.

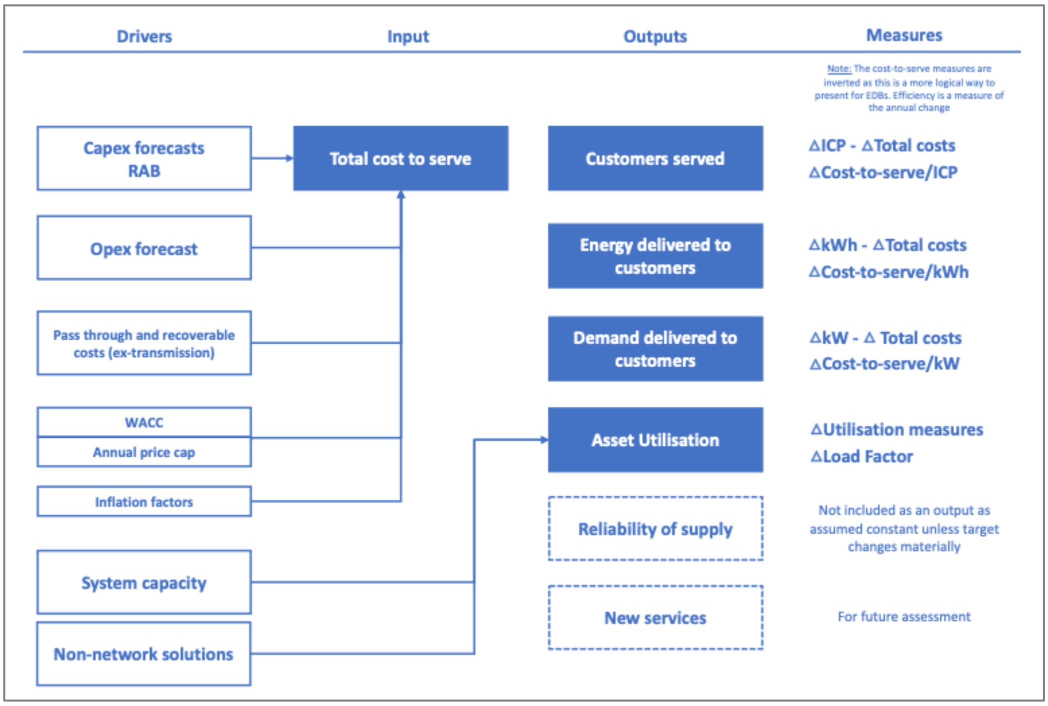
Asset performance measure	Recent average unplanned SAIDI performance	Forecast increase in unplanned SAIDI without intervention by FY2036	Impact of current risk mitigations on unplanned SAIDI by FY2036	Impact of further risk mitigations on unplanned SAIDI by FY2036	P50 Unplanned SAIDI Performance by FY2035
Reliability performance on the distribution overhead network		5.8	2.0[71]	2.6	
Defective equipment outages on the worst-performing distribution feeders		3.7	6.0		
Vegetation outages on worst-performing distribution feeders		3.5	5.0		
Subtransmission network		-	-		
Total	**64.6**	**~17.6**	**~13.5**	**~5.5**	**~63.2**

7.6 Network efficiency targets

We have been working on new efficiency measures. We believe that any new efficiency measures we introduce should measure factors that support our total cost-to-serve and reflect outputs relevant to customers. The measurement must be meaningful to our asset management planning. We believe that focusing on cost-to-serve is central to customer affordability. Figure 86 presents our current thinking and approach for future AMPs. The purpose of measuring efficiency is to assess how well resources (in our case, investment in assets and operating costs) are used to achieve a specific customer outcome.

We propose a range of measures to assess our use of capital and labour resources (i.e., our total costs) to produce output (i.e., connect customers, supply energy, and meet required demand), and how this changes over time. A single composite measure would be ideal, but it adds complexity and requires judgment on weightings, which will be difficult to determine.

Figure 86: Approach to efficiency measurement



Our approach differs from the Total Factor Productivity (TFP) and that used by the CEPA in their work for the Commerce Commission.[72] Our view is that TFP is not the appropriate measure for us due to its complexity and because it measures the productivity of an economy or a large system after controlling for labour and capital growth.

We are planning to use the total cost as input. This is the total cost of providing our services, incorporating total opex, depreciation, and return on capital. We believe this is a better approach than using opex and capex, as capex is volatile year to year and ignores our total asset base (which are a key driver of customer costs).

The output measures we plan to use are connected customers, energy supplied to customers, and customers' electrical demand on the network. Taken together, these are a good measure of the outputs of our business that are relevant to customers. Network reliability (a measure of output quality) is covered in our performance reporting in Section 4.3.

The measures outlined in Figure 86 are understandable and are an improvement over our current reporting in Section 4.6. The drivers can be influenced by the actions outlined in our efficiency strategy in Section 6.5 and by improvements in our asset management capabilities and maturity in Section 9.3 to 9.5 and 13.4.

We also monitor asset utilisation. How we utilise our assets influences efficiency, and it will be influenced by how we utilise non-network solutions. We report on utilisation in Section 3.6.

7.7 Work delivery targets

Our work delivery targets have two components: expenditure and asset inspections. For both these programmes, we aim to achieve practical completion. Practical completion means the work is completed except for minor omissions (less than 5%); hence, the target is >95%. We take a practical approach, as various external factors can influence delivery (e.g., weather conditions, coordination with other utilities, customers, and landowners).

We have had some gaps in delivery in recent years. Much of this was related to front-end engineering design (**FEED**) issues or resourcing (refer to Section 4.7). We have improvement plans for both aspects—FEED improvements are addressed in Section 9.3, and resourcing is addressed in Section 13.4.

Table 12: Work Delivery Targets

Indicator	Average of last 5 years	Target FY2026-31
Network capex (actual vs. forecast), excluding customer work	93%	>95%
Network opex (actual vs. forecast)	109%	>95%
Inspection of sub-transmission assets (visual and thermography)	68%	>95%
Inspection of zone substation assets	100%	>95%
Inspection of distribution lines and switchgear assets	93%	>95%
Inspection of LV pillar boxes	64%	>95%

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

7.8 Energy trilemma balance

A key strategy for this AMP is to *balance the energy trilemma in a manner that aligns with our customer, stakeholder and network needs* (asset management strategy #6). The importance of this balance has increased for Electra due to the forecast increase in opex and capex in response to demand growth, preparing for the energy transformation and our aging asset fleet.

Finding the right balance will allow us to support New Zealand's aim of decarbonising transport and process heat through electrification while still placing a strong emphasis on affordability.

The objective is to ensure that customers experience a lower overall energy cost (which will be achieved through lower cost electricity offsetting high-cost fossil fuels).

Figure 87: Forecast changes in the Energy Trilemma[73]

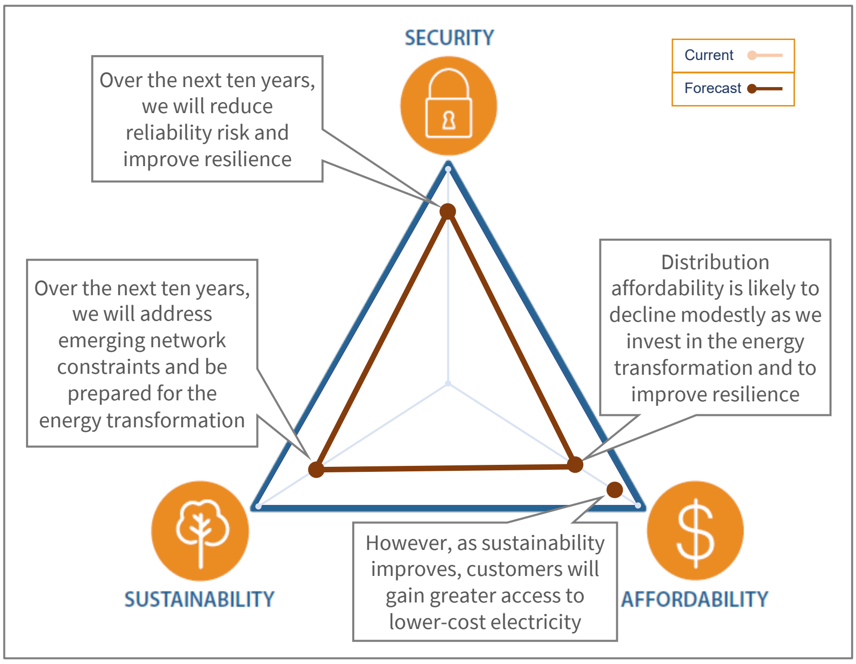


Figure 87 illustrates our assessment against the three limbs of the energy trilemma framework. This assessment indicates the direction of travel over the 10-year horizon of this AMP, which is:

- Sustainability is expected to improve as we *develop the network (or non-network alternatives) to support future growth in our region* (asset management strategy #1) and *implement an energy transformation roadmap to further prepare for increased electrification* (asset management strategy #2);
- Security and reliability risks are expected to decline as we *continuously manage reliability risk and resilience* (asset management strategy #4) and *implement comprehensive fleet plans* (asset management strategy #3);
- Due to the increase in capital expenditure, electricity distribution will become less affordable. However, as sustainability improves, customers will gain greater access to lower-cost electricity (as a substitute for pricier fossil fuels), thereby enhancing their overall affordability.

Our focus on sustainability is vital to ensure that customers can transition away from higher-cost fossil fuels without restrictions.

[73] An explanation of the three limbs is given in Section 5.7.

Our focus on security and reliability is crucial, especially as customer dependence on electricity increases (reducing energy diversity). Therefore, we anticipate that our customers will demand a more secure, reliable, and resilient supply.

Our focus on affordability is also essential, given our region's concentration of older people and our customers' generally low incomes. Balancing sustainability and security against affordability is a critical challenge for the business. We must ensure the energy transition is fair for all customers. In this and future AMPs, we must remain focused on prudent long-term investment, maintenance, and operating needs for the network.

In the 2027 AMP, we will provide greater visibility of the metrics that support this trilemma balance.

Part 3:

How we are implementing our strategy

8. Asset Management System

8.1 Introduction

This Section describes Electra's asset management framework and system, which guides the management of the network assets and the development of this AMP. We also describe our existing information and operational technology systems and data that support the asset management system. The improvements we intend to make to our asset management system are discussed in Section 9.

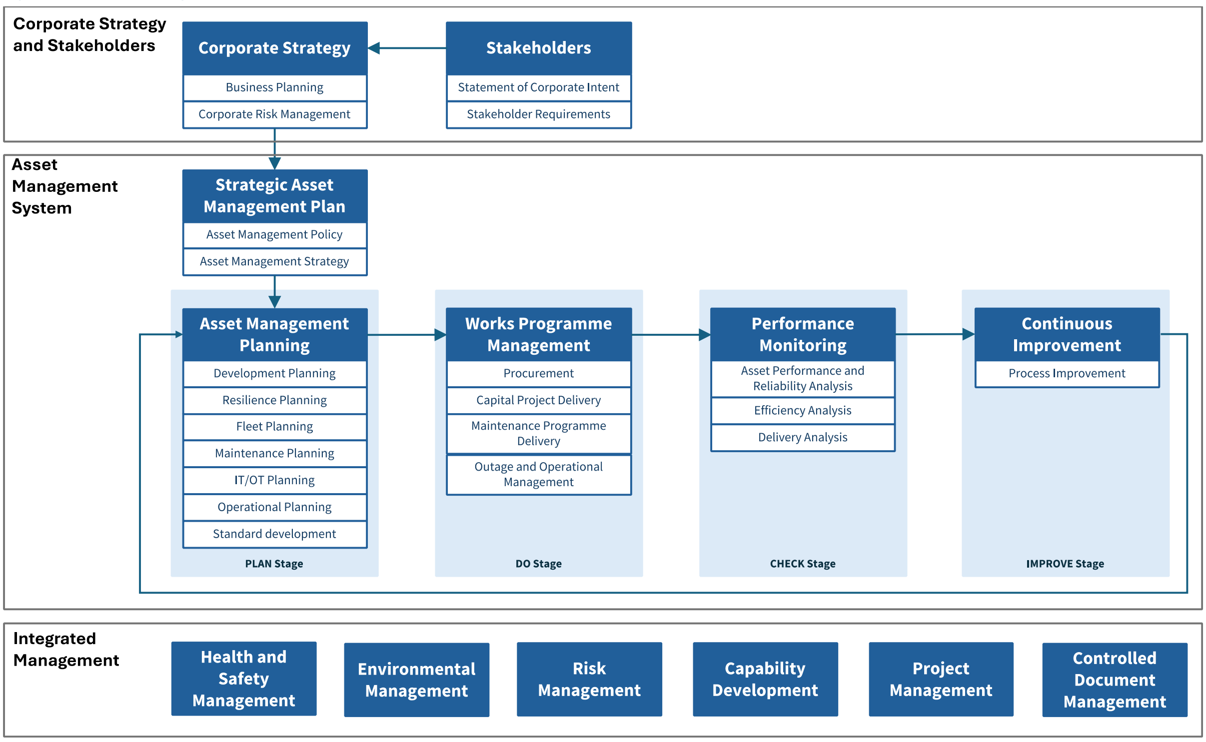
8.2 Asset management framework

We are implementing an asset management framework (refer to Figure 88). This framework guides our asset management activities and includes the key elements of ISO 55000[74]. The framework ensures that our asset management strategies, plans, and actions align with our vision, values, and corporate goals. It also ensures that services are delivered to meet the required standard and that high-impact, low-probability risks are appropriately considered and controlled.

The asset management system forms part of our integrated management framework to ensure risks are managed, capabilities are developed, and projects are delivered. It also ensures that we monitor performance and continually seek to improve performance.

Recent developments include developing our project governance processes, improving communication and outsourcing for the delivery of the AMP and the continued development of the AMP. The AM&PC (which was mentioned in the 2025 AMP) has evolved into a Board Advisory Group that provides increased oversight and governance over important asset management decisions.

Figure 88: Asset Management Framework

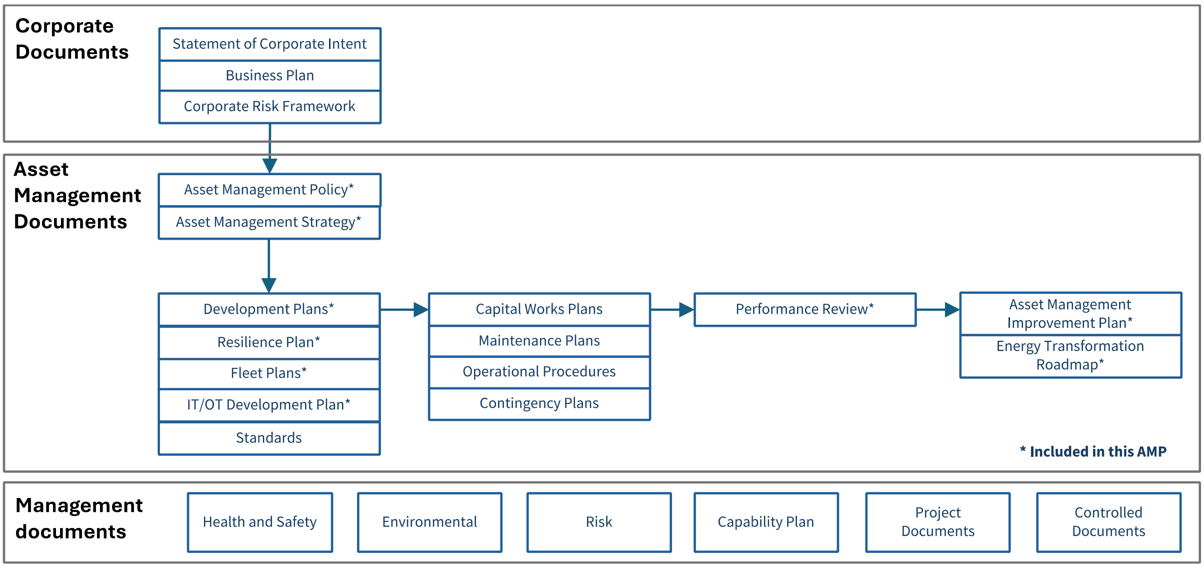


[74] The ISO 55000 suite of standards covers the asset management system's overview, definition and requirements.

8.3 Framework documents

Figure 89 depicts the relationship between Electra's key plans and documents. It shows the links between Electra's asset management documents.

Figure 89: Asset Management linkages



8.4 Asset management information technology and operational technology

By way of an introduction, operational technology (**OT**) systems control and monitor the physical equipment on the network. They focus on real-time management to ensure safe and efficient operations. Information technology (**IT**) systems collect, process, and store data, assisting in business decision-making and communication.

Electra's strategy is to implement *fit for purpose* systems (not a business-wide ERP) for its OT and IT systems and seeks to integrate these where practical. We will align our systems with good industry practices and systems where possible.

Our current OT Systems

Electra has three core OT systems:

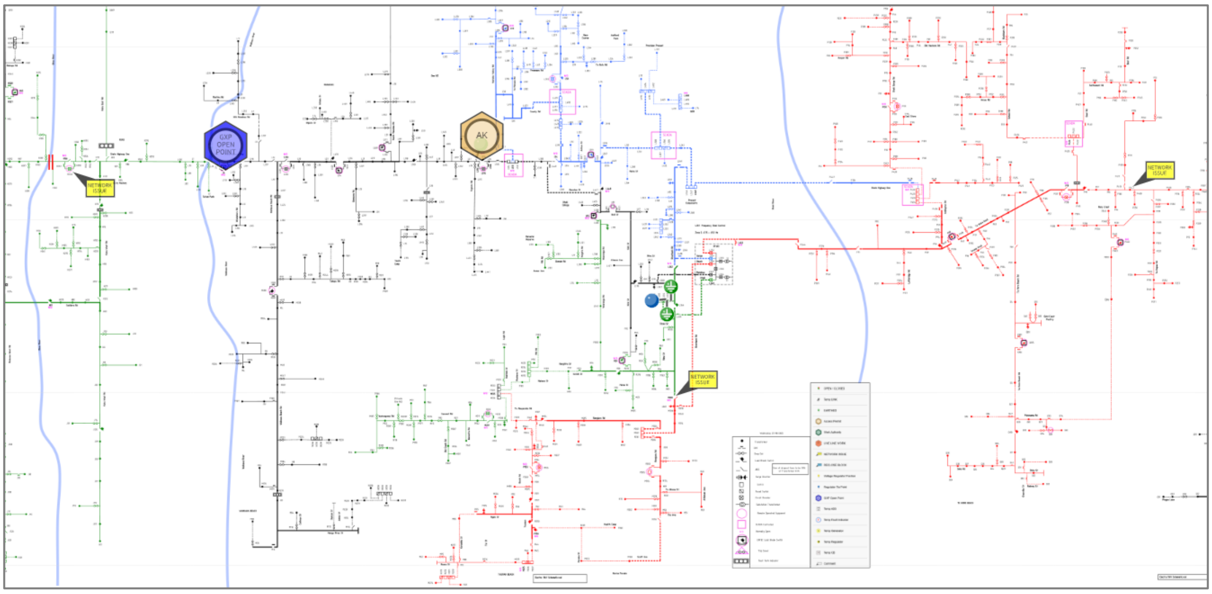
- System Control and Data Acquisition (**SCADA**);
- Advanced Distribution Management System (**ADMS**);
- IoT network status monitoring.

These integrated systems are the primary tools for monitoring and controlling access and switching operations on the network, managing the restoration of network outages and associated reporting. They enable monitoring IoT devices on network assets, power quality meters, and customer outage sensing devices.

Electra uses GE iFIX for general SCADA control and monitoring. This was installed in 2010. The master station has had progressive software and hardware upgrades and is located at Levin, Head Office, with a second instance on “hot” standby at Levin West Substation. This relays information via a point-to-point link to the network control centre at Electra’s offices in Levin.

Two other systems complement our Milsoft ADMS. EDNAR and Edvam. EDNAR enables the network access request process for planned work and associated switching. This system manages the workflow for planned work and initiates the customer notification process. Edvam is used to visualise open points and switching, and allows the Control Room to advise field staff know where there is current work on the network via a mobile app (refer to Figure 90).

Figure 90: Edvam system diagram



Our current IT Systems

Electra's core IT systems comprise:

- Business Central, which is Electra's financial system;
- Esri ArcGIS Enterprise Geographical Information System (**GIS**), which is the primary source of asset and geospatial information for all assets and currently includes tools for maintenance management;
- Condition-based asset risk management model (**CBARMM**), which is used to determine asset health, criticality and risk;
- DIgSILENT PowerFactory application is used for network load flow modelling, to determine network constraints and solutions;
- Vegetation management database, which is used for the management of vegetation around the network;
- ManageEngine is used as a service management platform to support customer requests related to our assets, customer relationship support and service delivery management;
- Damstra Technology Vault application is our safety management software, which is used to manage risks, incidents, injury, illness and near misses, plus associated injury management and rehabilitation;
- Quantate, which will manage risks, with Vault remaining as the health and safety system (the transfer of risk data from Vault to Quantate is occurring in FY2026);
- Axos is used for electricity billing and ICP and DG registry management (from July 2025);
- FME is used for data integration between systems.

We operate various other systems to support cybersecurity, document management, data storage, integration, and reporting. Some IT systems are integrated to share data where needed, particularly for asset information. The OT systems and the GIS are also integrated to provide asset information.

8.5 Asset management data

Accurate asset data is critical for operating the business and accurately forecasting asset renewals. Improving asset data is an ongoing focus for Electra. The data was initially populated from the original construction records and GPS site inspections. For new assets, data is obtained from construction drawings and documentation; for name-plated assets, it is verified during field inspections.

Our asset management data falls under our corporate data strategy. This is discussed in Section 9.5.

During FY2024 and FY2025, we completed a significant programme to improve asset age and attribute data for overhead structures, such as poles, crossarms, switches, and pillars. These assets are not nameplated, so determining accurate ages requires reviewing old construction drawings and nameplated assets installed at the same time as the line.

We have defined objective data quality measures, as shown in Table 13. These grades map to the data accuracy scoring used for information disclosure purposes. We use this grading for asset attributes (ID Schedule 9a), asset age (ID Schedule 9b), and asset condition (used in combination with asset age to determine asset health in ID Schedule 12a).

Table 13: Data Quality Grades

Electra Data Quality Grade	Measurable definition	Comparable Commerce Commission grading
4 – Very good	• Data is available for all assets • Data accuracy is greater than 99% (error rate less than 1/100)	4 –means good quality data is available for all assets
3 – Good	• Uncounted assets less than 1% • Data accuracy is greater than 90% but less than 99% (error rate between 10/100 and 1/100)	3 –Data is available for all assets but includes a level of estimate where there is some poor data
2 – Average	• Uncounted assets between 1% and 10% • Data accuracy is greater than 50% but less than 90% (error rate between 50/100 and 10/100)	2 –Good quality data is available for some assets and includes estimates for uncounted assets
1 - Poor	• Uncounted assets greater than 10% • Data accuracy is less than 50%	1 –Good quality data is not available for any assets, and estimates are likely to contain significant errors

As shown in Table 14, we have very good or good-quality data for most asset fleets. Where there are gaps in data quality, we adjusted our asset renewal forecasting process as needed, which we discuss in Section 12.5 and in the fleet plans.

Table 14: Quality of asset data

Asset fleet	Quality of attribute data	Quality of asset age data	Quality of asset condition data
Power transformers	Very good	Very good	Very good
Zone substation switchgear	Very good	Very good	Very good
Zone substation buildings and structures	Very good	Very good	Very good

Asset fleet	Quality of attribute data	Quality of asset age data	Quality of asset condition data
Overhead structures (poles and crossarms)	Good	Good. Some gaps in pre-1995 data.	Good
Conductor	Very Good – subtransmission Average – distribution and LV	Very good – subtransmission Good – distribution and LV	Average
Cables	Very good – subtransmission Good – distribution and LV	Very good – subtransmission Good – distribution and LV	Good quality (where partial discharge data is available, which is currently only subtransmission)
GM distribution switchgear	Good	Good	Good
GM distribution transformers	Good	Good	Good
PM reclosers	Good	Good	Good
PM air-break switches	Good	Average	Average
PM drop-out fuses	Average	Average	Poor. No reliable condition data
PM distribution transformers	Good	Good	Good
LV pillar boxes	Good	Average	Good
Secondary systems	Very Good	Very good	Good

Our SCADA and ADMS provide high-quality data on the HV networks, but there are some limitations for the LV networks. Improvements to this data are planned (refer to Section 9.5).

We have a very good working loadflow model for the 33kV system and over the past 12 months we have prepared a complete load flow model for the 11kV system (refer to Section 9.5).

We have a comprehensive demand forecast model. This model is reviewed annually, and assumptions are refined to reflect the most current data.

8.6 Cyber Security

We are committed to ensuring we have robust cybersecurity. We have chosen to safeguard our digital assets by adopting the NIST Cybersecurity Framework. The National Institute of Standards and Technology (**NIST**) provides a comprehensive approach to managing and mitigating cybersecurity risks. This framework encompasses a set of industry standards and best practices to help organisations identify, protect, detect, respond to, and recover from cyber threats. By integrating the NIST framework, we ensure a robust and systematic approach to cybersecurity, enhancing our resilience against potential cyber incidents.

Figure 91: NIST Cyber security framework

Over the past few years, we have delivered a cybersecurity improvement programme to elevate cybersecurity maturity and implement a range of controls and measures. This programme covered a range of initiatives, including deploying advanced threat detection systems, implementing enhanced access controls, conducting regular vulnerability assessments, biannual penetration testing (and when new systems are implemented), and continuously monitoring network activity. Electra's commitment to cybersecurity is a continuous process involving all staff. Regular training sessions, awareness campaigns, and simulated phishing exercises are conducted to educate employees about the latest threats and the best practices to counter them.

We completed our first maturity assessment last year. The benchmarking process indicates that our detection, response, and recovery processes were good, but we had a few areas where improvement was needed. We have developed a roadmap to close these gaps.

We aim to maintain a secure digital environment by focusing on these areas, effectively mitigating risks and safeguarding critical information assets. This addresses current security needs and builds a foundation for long-term cybersecurity resilience.

8.7 Expenditure Forecasts

The expenditure associated with the asset management system and existing IT/OT systems are incorporated with the Business Support and System Operations and Network Support opex forecasts in Sections 9.7 to 9.9.

9. Asset Management Improvement Plan

9.1 Introduction

We have embarked on a process to improve our asset management maturity from Level 2.4 (in March 2024) to 3.0.[75] Our maturity has been a reasonable fit for the network's needs. However, future needs are changing, and we need to lift our maturity to prepare for future changes.

In this Section, we describe our asset management improvement plan that will drive the improvement in asset management maturity. The improvement plan comprises three parts:

- Enhancing policies, processes and procedures;
- Enhancing IT/OT systems (Electra's digital system strategy);
- Enhancing asset management data.

Electra's Digital System Strategic Plan (**DSSP**), which we summarise in Section 9.4, drives the development of our IT/OT systems. Our internal people capabilities, discussed in Section 13.4, support these improvements.

The section includes details of the capex and opex required to support the improvement plan.

9.2 Asset management improvement—overall plan and target

9.2.1 Link to Asset Management Strategy

The improvement plan primarily supports asset management #5 *Improve asset management maturity to level 3* and #3 *developing comprehensive asset fleet plans*. The asset management strategies are outlined in Section 6.3.

Concerning asset management strategy #5, we need to ensure our capabilities keep pace with the changing needs of the business. We are developing an asset management improvement plan that will guide the:

- Updating our policies and procedures across design, construction, commissioning, inspection and maintenance;
- Revising and developing business processes, with a particular focus on our front-end engineering design (**FEED**), real-time information management and power flow management, performance and condition monitoring (refer to Section 5.6);
- Improving the maturity of the AMP content, particularly asset lifecycle management (which is now close to completion);
- Consolidating asset information and key processes within a new asset management system (included in Electra's DSSP);
- Implementing an asset management group (**AMG**) to oversee various asset management actions required to lift maturity.

Concerning asset management strategy #3, the improvement plan will ensure condition assessment standards and data align with our health assessment and renewal forecasting methodology.

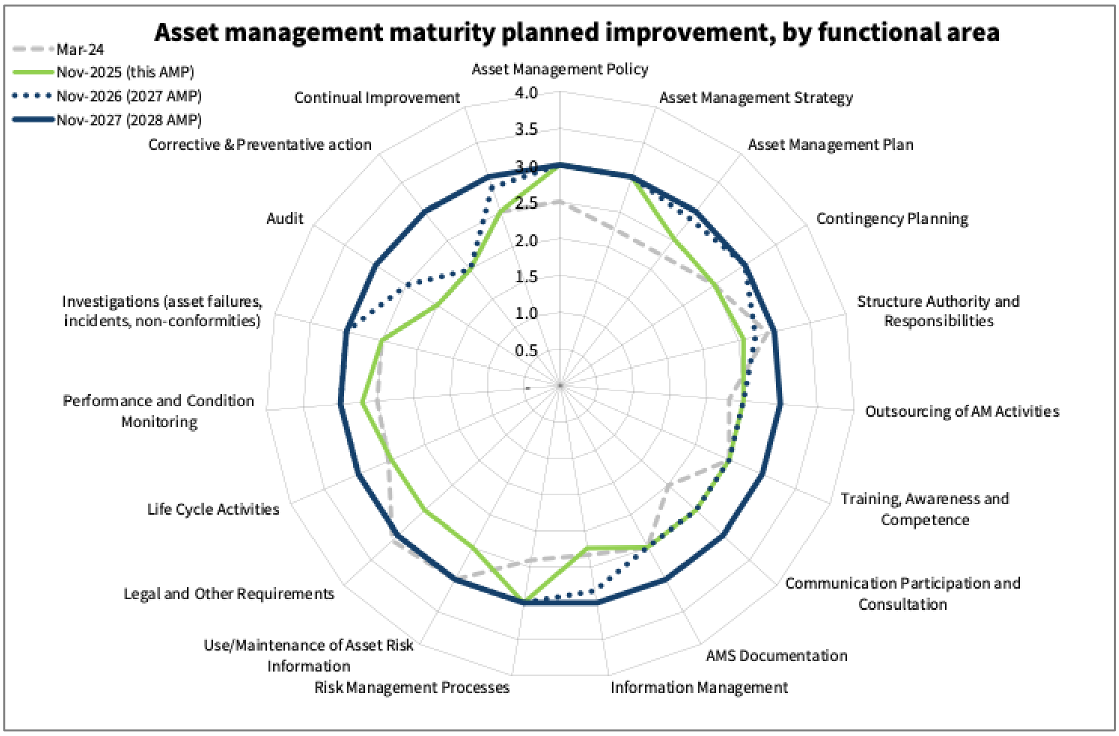
[75] Level 3 means that all elements of our asset management system are in place and are being applied and integrated, with only minor inconsistencies. EEA, Guide to Commerce Commission Asset Management Maturity Assessment Tool (AMMAT), May 2014.

9.2.2 Target improvement areas and timing

Since the 2024 AMP, we have improved our maturity from 2.4 to 2.5 (as reflected in the AMMAT assessment accompanying this AMP). The areas where our maturity has improved are in asset management strategy and planning, performance and condition monitoring, condition data and asset health modelling, and capex work delivery processes.

As shown in Figure 92, we target significant improvement during CY2026 (for inclusion in the 2027 AMP). Further improvements will be made during CY2027 (for inclusion in the 2028 AMP). The work completed in CY2027 should achieve an asset management maturity of 3.0 in the 2028 AMP. This timing is one year behind what we indicated in the 2025 AMP. The delay is due to a combination of resourcing constraints (which are being addressed in a team restructure) and the timing for system development (in particular, our new enterprise asset management system).

Figure 92: Target improvements in asset management maturity



9.3 Improvements to policies, processes and procedures

We have developed a detailed plan to address gaps in our asset management maturity. The planned improvements are summarised in Table 15. In FY2026, we made progress on our outsourcing model, development planning, and resourcing for engineering design. Our focus for FY2027 continues to be on condition assessment standards, embedding the design function within the network and contingency plans. We will also look to formally establish an asset management group (**AMG**) to oversee various asset management actions required to lift maturity (which was delayed in FY2026). These near-term actions will support the more pressing needs of the business.

Following the more immediate work, our focus will be on training, communication, documentation, audit, corrective actions, and continuous improvement.

Table 15: Policies, Processes and Procedures Improvement Plan

Improvement Plan	FY2026[76]	FY2027 and FY2028
Technical standards	• Inspectors manual substantially complete; • Minor progress on technical standards	• Preparation/updating of other inspection, testing, maintenance standards, and management of change standards. Note: The inspection and testing standards will be aligned with the requirements for CBARMM • Updating design, construction, maintenance and commissioning standards
Align core asset management processes to the best-practice processes in an enterprise asset management system (EAMS)	• Defect process has been updated; • Other work planned for FY2026 has been delayed to align with the implementation of the EAMS	• Align works delivery processes with best-practice processes within EAMS • Align inspection and maintenance processes with best-practice processes within an EAMS • Align remaining processes with best-practice processes within EAMS
Contingency plans	• Only minor progress was made on contingency planning in FY2026 due to resourcing constraints	• Update the emergency response plans • Determine and prepare contingency plans for all reasonable events Communicate plan requirements to the team • Test and improve plans
Outsourcing	• A new outsourcing model has been developed and is being rolled out (which delayed our planned auditing of our procurement policy)	• Audit compliance with the new procurement policy • Review and refine outsourcing requirements • Audit compliance with outsourcing requirements
Resourcing and competency	• We completed a restructure of the network team to better align to our work requirement. A number of roles are being recruited, which has delayed work in this area.	• Review competency requirements and delivery of training (via Our Hub) • Review external contractor competency requirements • Implement a common competency framework Review resourcing requirements given the future needs of the business and ETR.
Asset management framework (and associated documentation)	• The recent structure changes between the Network Team and Delivery team will support improvements in front-end engineering design as the design team now resides in the Network team • The maturity of our development planning process has improved with the completion of the full 11kV loadflow model in DIgSILENT. This will enhance our modelling work	• Review/prepare documentation supporting the asset management framework
Continuous improvement and corrective actions	• Review and implement improvements to the as-builts process • Improvement to business case processes (largely complete)	• Develop ICAM process for minor and major fault review • Implement a formal process to consider innovations • Develop additional models to support the business case processes • Oversight by AMG
Asset Management Group (AMG)	• This work was delayed due to internal resourcing constraints	Implementing an AMG, with a focus on: • Communicate delivery requirements for AM • Communicate objectives and responsibilities for AM • Six-monthly network and delivery performance reviews The focus for the AMG will be: • Managing cost-effectiveness and efficiency

[76] Progress to the time of writing.

Improvement Plan	FY2026[76]	FY2027 and FY2028
		• Review of major outages and proposed solutions • Develop an internal audit plan and implementation process

The Energy Transformation Roadmap has identified a range of other process requirements. Refer to Section 10 for details.

9.4 Improvements to IT/OT Systems (Electra's DSSP)

We have identified a significant IT/OT system enhancement programme. Our strategy of choosing right-sized, least-customised technology products and aligning with good industry practice.

Over the past couple of years, we have implemented a new load flow modelling software (DIgSILENT PowerFactory), and this now includes a full 11kV model, upgraded our core financial system from Microsoft NAV to Business Central, implemented registry management in Axos, implemented Edvam, continued to refine CBARMM, and at the time of writing, are implementing Quantate to manage risks.

We are now progressing with the implementation of an enterprise asset management system (EAMS). Modern EAMSs provide significant industry-standard processes to enhance maintenance and asset management delivery. We will also upgrade the GIS data model, as our current model was developed over a decade ago. This work was originally planned for FY2026, but has been delayed one-year to complete version upgrades on GIS, ADMS and FME. This will align us with industry standards and facilitate better integration with an EAMS.

The OT developments are focused on our core SCADA and ADMS operational systems. Our SCADA system is reaching end-of-life, and newer systems offer opportunities to increase resilience and cybersecurity. Our current SCADA and ADMS application layers are becoming outdated, with some areas of limited functionality, which we plan to upgrade or replace. These planned upgrades will ensure we keep pace with the evolving operating environment and prepare for the energy transformation.

The following sections provide details on each of our primary systems, the data they hold, what the data is used for, and any planned improvements. The systems cover OT, IT, and cyber security, and the proposed system needs to support the Energy Transformation Roadmap.

9.4.1 Information technology systems

Table 16: IT System Improvements

System	Data held	What the data is used for	Extent of integration	Planned Improvements
Financial system	All company financial information, including the asset registers, P&L and balance sheet	Financial and management reporting and information disclosure reporting	The financial system will be integrated with the EAMS (when implemented)	• None. Upgrading of the financial system from Microsoft NAV to Business Central was completed in FY2025.
Enterprise asset management system (**EAMS**)	A new system is being implemented. It will become the authoritative source of asset information	Primary asset management system and asset-related information disclosure reporting Used for all network inspection, maintenance	The new system will integrate with the financial system, GIS and CBARMM	• Undertaking a feasibility study for Maximo • FY2027, implementation of asset and work order management modules • FY2028+ other modules

System	Data held	What the data is used for	Extent of integration	Planned Improvements
	(attributes, age, condition, health, risk)[77]	and other asset management processes		
Geographical Information System (**GIS**)	The authoritative source for geospatial asset information (location and associated easements)	Used by field, real-time operators, planning and project management staff within the Network team to obtain information on asset location, attributes and connectivity	Requires at least some manual intervention to import or export data into recognised formats.	• FY2026 upgrade software version (completed) • FY2027, upgrade to the common information model, and the ESRI GIS utility networks model (delayed from FY2026) • See data improvements*
Condition-based Asset Risk Management Model (**CBARMM**)	Asset condition, health, criticality and risk	Used to determine the health and risk of assets to determine planned asset renewals	Integrates with GIS and will integrate with EAMS	• See data improvements*
Network modelling, loadflow, and contingency analysis system	Complete 33kV and 11kV network model	Modelling the capacity and voltage of the network	The system is not currently integrated	• None. 11kV data model was completed in mid-FY2026
Strategic Vegetation Management Database	Tree owners, requests, trimming works, proactive and reactive plans	Monitoring of requests, works, costs, proactive and reactive planning, reporting	The system is not currently integrated	• The intention is to integrate vegetation management into the EAMS/GIS. The project is not yet defined
Customer Relationship Management (**CRM**)	Customer Information, complaint information, 3rd party service requests and customer queries	Customer relations and service delivery management	The system is not currently integrated	• FY2027-30, Increase adoption and functionality for customer related business processes
Website and customer apps	Corporate and outage information	Communicate with customers and stakeholders	Outage data integrated with ADMS	• FY2027-35, Upgrade of corporate website and apps
Quantate	Risk register (organisation and network)	To quantify and manage risks, controls and treatments	Stand-alone system	• FY2026 implementation of new system and transfer of relevant data from Vault
Vault	H&S risk management system including incidents, injury, illness and near miss, plus associated injury management and rehabilitation	Used by H&S for managing risk register and incidents; used by employees to report H&S and public safety incidents; used to report to senior leaders and Board; automatically notifies the above for critical events; audit and checks through mobile apps	Stand-alone system	• None
AXOS Billing System	ICP connection details, electricity consumption, price option, retailers	Used to determine electricity consumption, losses, ICPs by price option, retailer billing and sales discounts	No automated integration with other systems	• None

[77] This information is currently in GIS and will be transferred to the EAMS

System	Data held	What the data is used for	Extent of integration	Planned Improvements
Reporting and analysis tools	Analytical tools that access data held in other systems	Various analytical tasks	Integrated with ADMS, IoT, SCADA business systems (Power BI)	• Ingest more information and commit resources to analyse and interpret data to identify additional value* • A data analytical platform is needed to analyse LV monitoring and/or meter data. This is not yet defined.

* No associated capex

We operate various other systems to support document management, data integration and reporting. These systems include Electra's electronic document management system (**EDMS**), safety management system (a library of safety documents held in the EDMS), information disclosure compilation tool, and Plexus gateway (legal document storage). These systems are in a steady-state or continuous improvement phase; no material capex is required.

9.4.2 Operational technology systems

Table 17: OT System Improvements

System	Data held	What the data is used for	Extent of integration	Planned Improvements
System Control and Data Acquisition (**SCADA**)	System Control and Data Acquisition System is the primary tool for monitoring and controlling access and switching operations for Electra's network; asset operational information, including loadings, voltages, temperatures and switch positions	Measuring voltages, currents and device statuses on various parts of the network. This is used for assessing security, load forecasts and feeder configurations	Integrated with ADMS	• FY2026: Upgrade the application layer to the latest version of GE iFix SCADA (on track for completion) • FY2026-27: End-of-life hardware upgrades (on track for completion) • FY2028+, provision for further hardware upgrades
Advanced Distribution Management System (**ADMS**)	An integrated system containing geospatial information of assets, customers, and engineering models. ADMS takes input from SCADA and displays load flows. The authoritative source for the network connectivity model.	Used by field, real-time operators, planning and project management staff to update customer outages, obtain asset information and carry out engineering studies	Integrated with GIS, SCADA, Field Service Management, IoT, customer outage mobile application, customer web outage viewer and business intelligence reporting and analytics	• FY2026-29, minor capex associated with: ○ EAMS integration ○ Automated customer notifications (social media and app) ○ Serve to distributed workforce and remote offices (completed FY2026) • Further upgrade of ADMS is under consideration in FY2029-30 to provide LV monitoring and optimisation and flexibility management to meet energy transformation needs
ADMS (incident tracking)	System outages, location, duration, cause, number of consumers affected	Used to identify assets that are causing outages and to report on SAIFI/SAIDI and CAIDI	Integrated with other ADMS applications	
IoT network status monitoring	The status information of specific network assets – RMU fault condition, DDO fuse status, voltage present indicators,	IoT communications can have significant latency and are not typically used for real-time decisions. The platform is primarily	Integrated with ADMS and SCADA. IoT devices can report to the control room in the same way as SCADA/ADMS	• We have currently paused work on further network sensors until the SCADA upgrade is completed.

System	Data held	What the data is used for	Extent of integration	Planned Improvements
	power quality meters, client outage sensing devices, plus other non-critical data used for post-analysis	used to gather small amounts of data from multiple sites at low cost and to confirm or locate real-time events reported by SCADA or other systems		• Integrate the data into our SCADA and ADMS when these systems have been upgraded. • Include data from 3rd party devices or services to increase sources of loss-of-power event reports. • Note: These projects are not yet defined.

9.4.3 Cybersecurity, planned improvement

We continue implementing cybersecurity controls to improve our maturity and cybersecurity posture. Central to this programme is the adoption of Secure Access Service Edge (SASE) and zero-trust architecture. Integrating SASE will streamline our network security into a single, cloud-delivered service model, enabling us to enforce comprehensive security policies seamlessly across all users and devices. The zero-trust model enhances our security posture and minimises the risk of unauthorised access to our networks and systems.

In addition to delivering SASE and zero-trust services, deploying a centralised vulnerability management system will identify, assess, and remediate vulnerabilities within our IT infrastructure. This system will maintain a comprehensive inventory of assets and ensure that all components are secure. By proactively managing vulnerabilities, we will mitigate potential threats before malicious actors can exploit them. Strong vulnerability management will be another control crucial in maintaining the integrity and security of our digital environment.

As mentioned in Section 8.6, we have adopted the NIST framework, undertaken benchmarking, prepared the NIST roadmap, and are in the process of implementing it. We have implemented Overcyte to manage the implementation activities. Roadmap activities include:

- Implementing zero-trust architecture (in FY2027);
- Developing a comprehensive suite of digital policies (in progress);
- Implementing additional tools to quantify and manage cyber risk and rolling out tools to manage third-party cybersecurity risk (in progress);
- Implementation of Microsoft Intune to manage our digital devices and enforce policies (completed).
- End-point protection for mobile devices;
- SaaS and AI security protection.

We will also further secure our OT and SCADA systems, which are integral to our operations and manage critical processes and infrastructure. Implementing robust cybersecurity controls for OT and SCADA systems ensures these essential systems are protected against cyber threats that could disrupt operations or cause significant harm. We are implementing the Claroty continuous threat detection (CTD) for our OT environment. CTD provides real-time monitoring and deep visibility into OT networks, enabling us to detect, analyse, and respond to threats as they emerge.

9.4.4 Potential IT/OT systems required to support the Energy Transformation Roadmap

Section 10 discusses the Energy Transformation Roadmap (**ETR**). The ETR has identified a range of system enhancements that will allow Electra to effectively and efficiently fulfil its role in the energy supply chain and provide the tools to manage the complexity associated with the increasing use of DERs and the evolution of flexibility markets.

The potential system requirements to support the Energy Transformation Roadmap:

- Meter Data Management System: To manage meter data and make it available for ADMS. Whether this is required will depend on Electra's approach to meter data management (as there are likely to be different procurement and hosting models);
- ADMS Upgrade—LV Monitoring and Optimisation: Real-time modelling of LV voltage & capacity to optimise loading and hosting capacity;
- ADMS Upgrade—Flexibility Management: Issuing market signals to procure flexibility services;
- Connection and consumer Data Management: Management of consumer connection data, including flexibility information, hosting capacity, installation standards, and auditing.

9.5 Improvement to asset management data

The quantity and use of data are increasing across all areas of the business, and our need to maintain data quality is growing as well. As a result, we signed off on a corporate data strategy during FY2026. The data strategy will enhance decision-making by providing clean, trusted, accessible data, improve efficiency by reducing data challenges faced by some employees and create opportunities to improve data sharing and innovation.

We developed a pragmatic data roadmap, prioritising actions needed to get started and deliver value quickly. The roadmap covers three phases:

- Core foundations: Establish a new data operating model (FY2026);
- Enable business outcomes: Modernise the data landscape (FY2026 to FY2028);
- Empower data: Deliver and enable strategic data products (FY2028+).

The first phase focuses on building core data capabilities and foundations to efficiently extract business value from data at scale. This is about preparation and ensuring Electra is set up for the next 5 years, enhanced by intelligence and AI,.

Our data strategy will deliver significant benefits by creating advanced data products. Business benefits that will be enabled include:

- Network intelligence: Real-time performance, fault analysis, forecasting;
- Asset health optimisation: Predictive maintenance and lifecycle modelling;
- Customer insights: Sentiment analysis and real-time service updates;
- Financial forecasting: Price-quality optimisation and long-term investment planning

We are progressing in a range of asset data improvements that, as shown in Table 18. There are two key themes for our data improvements:

- Enhancing the network connectivity models to enable accurate load flow modelling and enable real-time monitoring of the LV network;

- Enhancing the asset data (attributes, operations, duty and loadings) to enable more accurate asset health and renewal forecasting.

Work on some data improvements was delayed from FY2026 to FY2027 as we updated the GIS software platform.

Remediating and enhancing our asset data is a foundational activity. Table 18 outlines our asset data improvement plan.

Table 18: Asset Data Improvement Plan

Improvement Plan	FY2026	FY2027	FY2028+
Asset data issues register		• Prepare data and maintain	
High voltage connectivity (Loadflow, ADMS)	• HV schematic accuracy and 11kV loadflow model complete	-	-
Low voltage connectivity (ADMS)		• Improve LV schematic and loadflow model accuracy • Develop LV transformer schematic diagrams	• Undertake customer phase verification
Asset location (GIS)		• Implement processes to verify asset location • Capture the location of conductor joints • Capture the location of cable joints	
Asset attributes (GIS, EAMS, Loadflow, CBARMM)		• Improve distribution and LV conductor attributes (size) • Improve distribution and LV cable attributes (size) • Improve distribution OH fuses and ABSs attributes (type)	
Condition Data (GIS, EAMS, CBARMM)	• Condition data will be improved as condition assessment standards are revised		
Equipment operations (SCADA, EAMS, CBARMM)	-	• Capturing equipment operations and fault tripping and using it as input into CBARMM for health assessment	-
Equipment duty (SCADA, EAMS, CBARMM)	-	• Capturing equipment duty (i.e. loading) and using it as input into CBARMM for health assessment	-

9.6 Continuous improvement

Over the past decade, we have pursued continuous improvement, but it has been mainly ad hoc. Recent improvements include developing project governance processes and stakeholder consultation framework. We have also implemented weekly Kanban and monthly progress assessments to improve delivery performance.

As part of this improvement plan, we will enhance our approach and ensure appropriate oversight by the Network Team. Recent activity includes:

- Work on updating the distribution inspection process is largely complete (and is on track for completion by the end of FY2026), including enhancements to operational reporting and preparation of the Inspector's manual.

- Completion of improvements to the defect process. All staff can now report defective assets using mobile devices. Further work will be undertaken on reporting.
- Completion of phase one of improvements to the as-built process. This ensures that as-built information is accurate and readily available to stakeholders. A second phase in FY27 will focus on standardisation with industry and seeking automation and digitalisation of the processes.

9.7 Forecast expenditure on IT/OT systems

Table 19 and Table 20 summarise the developments of the proposed IT and OT systems. These projects and programmes were previously all capex. However, they are progressively moving to software-as-a-service (**SaaS**), and the associated costs are shifting from capex to opex. All projects and programmes align with the improvement work identified in the previous sections, except for the ongoing IT infrastructure hardware renewal and upgrading (which is routine expenditure on these assets). The GIS upgrade and the EAMS implementation include related data improvements.

Table 19: Proposed Major IT projects and programmes

Project	Driver	Cost/Year	Justification/options considered
IT Infrastructure and hardware renewal programme	An ongoing programme to replace and upgrade hardware (servers, switches, laptops, tablets, phones, etc.) and meet organic growth requirements	$3.1m FY27-36	• The programme is optimised to maintain IT hardware within support contract requirements, consistent with application layer requirements, performance and cybersecurity standards • There is higher spending planned for FY28 for core infrastructure replacement
Implementation of EAMS. This is a multi-year implementation that involves: • FY2027 implementation of asset and work order management modules • FY2028+ other modules	Consistent with our strategy of choosing right-sized and least customised technology products, and aligning to good industry practice, we are progressing with the implementation an EAMS and adopting the best-practice processes embedded within the system	$2.0m SONS Opex FY27-28+[78]	• We do not currently have an integrated asset management system. This is needed to support our process improvement and consolidation of business processes as outlined in Section 9.3. This system supports the processes required to improve asset management maturity
Upgrading the GIS to the common information model, and the ESRI GIS utility networks model	Align GIS asset data model with industry standards, facilitate the integration with EAMS and provide the foundation to adopt best-practice processes	$200k SONS Opex FY27	• Electra's GIS data model is decades old and will not support the implementation of best-practice processes available in the new EAMS

Table 20: Proposed Major OT projects

Project	Driver	Cost/Year	Justification/options considered
SCADA GE iFix version upgrade	The SCADA has reached end-of-life and needs to be upgraded to the latest product	$102k FY26	• Completed in FY26
ADMS replacement	Our current ADMS does not offer the development pathway we need for	$TBC	• We will be undertaking a RFI/RFP and business case process in FY27

Note: The SCADA Hardware and RTU replacements are now included in Section 12.18.5.

[78] Current assumed as SaaS. The budget and expenditure type will be confirmed during the the feasibility phase.

Table 21: IT System Projects and Programmes (Real $000)

Projects and Programmes	FY27	FY28	FY29	FY30	FY31	FY32	FY33	FY34	FY35	FY36	Total
IT Infrastructure and hardware	373	560	270	170	220	220	621	220	221	221	3,097
EAMS	$2.0m SONS opex										
GIS Common Information and Utility Data Model	$200k SONS opex										
GIS data improvements	$100k SONS opex										
Customer related systems	FY27-37 BS Opex										
Major project provisions	-	-	-	208	208	209	209	209	209	209	1,462
Total	**373**	**560**	**270**	**378**	**428**	**429**	**830**	**429**	**430**	**430**	**4,558**

Note: IT infrastructure and hardware and major project provision is non-network capex.

Table 22: OT System Projects and Programmes (Real $000)

Projects and Programmes	FY27	FY28	FY29	FY30	FY31	FY32	FY33	FY34	FY35	FY36	Total
SCADA hardware replacement	This is mainly related to field RTUs. Capex is now included in in Section 12.18.5.										
Total	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**

Note: ADMS is non-network capex. SCADA costs are asset replacement and renewal as SCADA is an other network asset.

Table 23 shows the range of possible future IT/OT projects under consideration. We are considering upgrading Milsoft ADMS and have identified potential systems associated with the Energy Transformation Roadmap (refer to Section 10). A decision on the ADMS upgrade project should be included in the 2027 AMP[79]. Decisions on the other systems will evolve over the next three to four years. The projects in Table 23 are not included in the expenditure forecasts.

Table 23: IT/OT System improvements in the concept phase (Real $000)

Concepts	FY27	FY28	FY29	FY30	FY31	FY32	FY33	FY34	FY35	FY36
CRM, connection and consumer data management	-	-	-	Currently estimated as an FY30 SaaS implementation						
ADMS Upgrade, including LV monitoring and optimisation	-	-	Currently estimated as an FY29 SaaS implementation							
ADMS Upgrade, flexibility management	-	-	-	Currently estimated as an FY30 SaaS implementation						
Meter data management system	TBA. This will depend on the approach to customer meter data									
IoT network status monitoring	**Not yet confirmed, awaiting completion of SCADA and ADMS upgrade**									

9.8 Business Support and associated expenditure forecasts

Business support covers all corporate activities, including governance, information technology, commercial, customer service, sustainability, people, safety, and culture (refer to the organisation structure in Section 2.7).

In real terms, business support costs in FY2027 have decreased by 2.0% over those included in the 2025 AMP (over the first five years). The primary drivers of the decrease is lower IT project and data strategy costs.

[79] One year later than we said in the 2025 AMP. Our focus this year has been working on the business case for the EAMS.

The additional personnel costs relate to new IT and OT data management roles[80]. The new roles will provide expertise across key areas, including data management, business analysis, project delivery, and IT and OT systems integration. The IT project costs mostly relate to implementing the data strategy (including external support, building data projects, corporate data remediations, and AI pilot projects), cybersecurity, and upgrading our payroll system. The OT project in FY28 relates to feasibility, due diligence, and business case work for the ADMS upgrade. (refer to Table 24). The IT/OT project costs taper-off from FY2029 which reflects a absence of defined projects, rather than indicating there will be no further project work.

Table 24: Business Support (Real $000)

Cost	FY27	FY28	FY29	FY30	FY31	FY32	FY33	FY34	FY35	FY36	Total
Base business support[81]	9,464	9,464	9,464	9,464	9,464	9,464	9,464	9,464	9,464	9,464	94,639
Insurance	1,340	1,340	1,340	1,340	1,340	1,340	1,340	1,340	1,340	1,340	13,405
Additional personnel costs	300	300	300	300	300	300	300	300	300	300	3,000
IT project costs	647	585	265	215	215	215	215	215	215	215	3,002
OT project costs	-	200	-	-	-	-	-	-	-	-	200
Total	**11,751**	**11,889**	**11,369**	**11,319**	**11,319**	**11,319**	**11,319**	**11,319**	**11,319**	**11,319**	**114,245**

9.9 System Operations and Network Support and associated expenditure forecasts

System Operations and Network Support (**SONS**) covers the network team (refer to the organisation structure in Section 2.7) and associated network IT systems and OT systems. We have spent the past three years focused on building the capability and capacity of our engineering and network support teams. During this period, we have made strategic investments in talent and development.

In real terms, SONS costs have decreased by 9% relative to those included in the 2025 AMP (over the first five years). Our current assessment of the additional IT project costs has been refined and is lower than we had expected in the 2025 AMP. We have also removed the OT project costs, as they are under review and not yet well-defined. We have not yet defined the project to replace the ADMS or to address future upgrades to that system. This will drive increases in SONS costs from FY2029. As we define these projects, we will include the costs in future AMPs.

The high network IT costs in FY2027 and FY2028 are due to the implementation of EAMS.

We are currently focused on improving the maturity of our systems. Over the coming years, we will focus on optimising and leveraging our workforce to drive efficiency.

Table 25: System Operations and Network Support (Real $000)

Cost	FY27	FY28	FY29	FY30	FY31	FY32	FY33	FY34	FY35	FY36	Total
Base SONS[82]	6,176	6,176	6,176	6,176	6,176	6,176	6,176	6,176	6,176	6,176	61,760
Additional personal costs	-	-	-	-	-		-	-	-	-	-
IT project costs	1,248	1,000	450	450	450	450	450	450	450	450	5,848
OT project costs	-	-	-	-	-	-	-	-	-	-	-
Total	**7,424**	**7,176**	**6,626**	**6,626**	**6,626**	**6,626**	**6,626**	**6,626**	**6,626**	**6,626**	**67,608**

80 These were included in the data transformation strategy in the 2025 AMP.

81 Based on the FY26 forecast, excluding insurance and project costs.

82 Based on the FY26 forecast, less one-off costs.

10. Energy Transformation Roadmap

10.1 Introduction

In this Section, we present our Energy Transformation Roadmap (**ETR**) and discuss the implications of the energy transformation for electricity demand on our network.

Reducing emissions through electrification and increasing renewable generation are critical to achieving net-zero 2050. In particular, the electrification of transport and heat (both process and general) and the use of distributed energy resources (**DERs**) are central to decarbonisation. This is the *energy transformation* from oil, coal, and gas to renewable and low-emission electricity.

There is general recognition of the importance that EDBs play in the energy supply chain. Distributors form the critical link between customers and energy markets and can enable greater participation by customers in decarbonisation (or constrain involvement if they are ill-prepared).

Enabling decarbonisation through electrification requires that EDBs:

- Have the capability and network capacity to allow customers to increase their use of electricity to replace fossil fuels;
- Can connect and integrate DERs into the network and allow the owners of DERs to participate in energy markets.

We prepared the ETR in FY2022 and have been monitoring industry developments and progressing with the various actions on the roadmap since then. The ETR ensures we have a pathway to build the capability and capacity to support New Zealand's decarbonisation efforts. We are confident that by following the roadmap, we will be ready for the energy transformation.

10.2 Alignment to asset management strategy

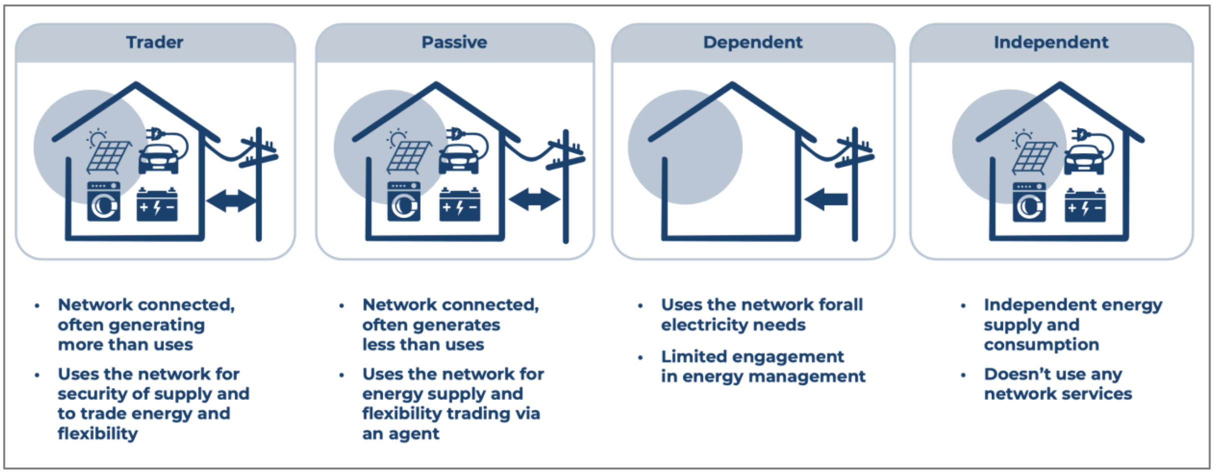
This section delivers on asset management strategy #2 to *implement an energy transformation roadmap to further prepare for increased electrification*. It sets out the plan and steps to achieve the activities under the strategy.

10.3 Evolution of customers and market structures to support the energy transformation

How customers will use the network

Customers are at the centre of the energy transformation. Much has been written about the evolution of energy customers. We have distilled this work into four types of customers (Figure 93). The difference between them relates to the adoption of technology and engagement with energy markets (except for independent customers who, as the name suggests, operate independently of the energy market). These definitions cover the range of customers from active to passive (the spectrum used by the ENA).

Figure 93: Customer types



Market structures

Understanding the industry operating model is essential to ensure Electra can fulfil its role in connecting and integrating DERs. Figure 94 illustrates the generally accepted industry view of the market model (consistent with the ENA view and the Electricity Authority's views in their recent regulatory settings paper). There is a reasonable consensus that distributors must evolve and the first stage of this we have termed being a distribution system integrator.

A distribution system integrator (**DSI**):

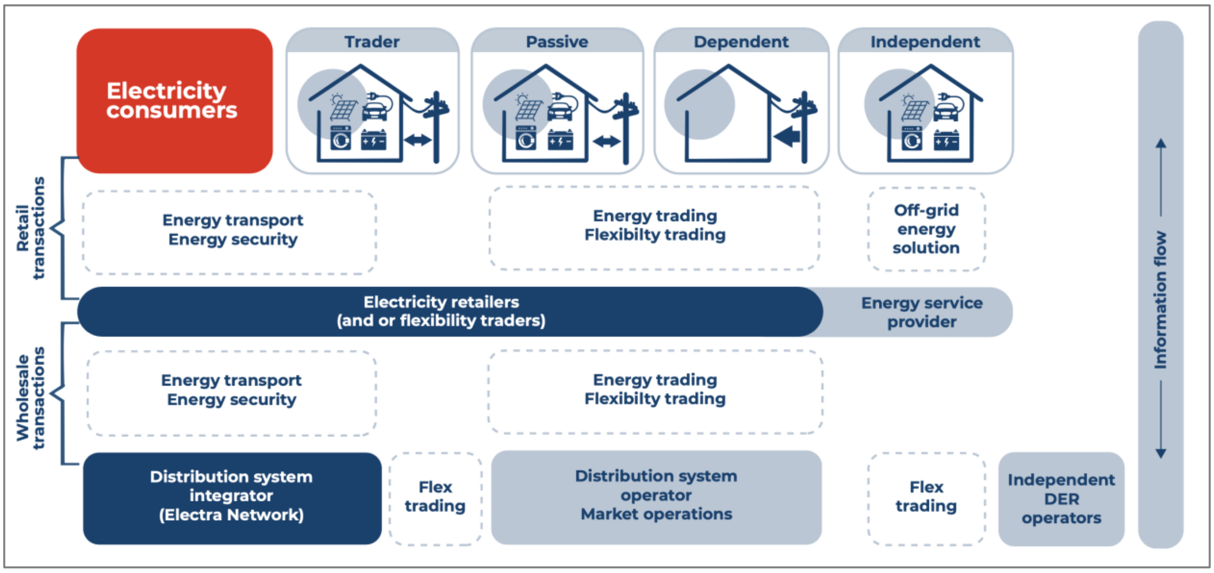
- Operates the distribution network to connect customers (with and without DERs) to energy and related markets;
- Develops the distribution network to integrate DERs and support bidirectional power flow;
- Invests in the systems required to support open access to the distribution network for a wide range of customers and DERs.

There is also the possibility that distributors could take on all or part of the role of a distribution system operator (**DSO**), where they monitor and control controllable DERs to maximise the value of the flexibility they offer. A range of DSO business models are evolving and being considered within the sector—from fully centralised markets and operators to fully decentralised markets and operators. This is a key area of work for the future network forum (part of the ENA). Their work outlines three main options:

- **Total Transmission System Operation (TSO) Model**. This is a centralised model where Transpower (TSO) manages all flexibility services, including local distribution constraints. Aggregators and retailers interact only with the TSO and EDBs provide visibility of local constraints, but do not operate local markets. While this provides a standarised approach, there is likely to be limited visibility and responsiveness to low-voltage (LV) network constraints and the model is best suited if HV-connected flexibility dominates and LV congestion is minimal.
- **Total Distribution System Operation (DSO) Model**. This is a decentralised model where each EDB acts as a DSO, managing local flexibility markets and dispatching DER. Aggregators interact only with the DSO, which aggregates bids and passes them to the TSO. DSO has full control over local constraints and dispatch. This model offers strong local network visibility and enables customer choice, and supports decarbonisation at LV level, but requires significant capability uplift for EDBs and requires complex regulatory changes. This model is suitable where LV congestion and DER proliferation are high.

- **Hybrid model**. There is shared responsibility between TSO and DSO. Aggregators can interact with both TSO and DSO depending on service type. The DSO manages local flexibility markets; TSO manages wholesale market, however, it requires strong coordination and data exchange between TSO and DSO. The model could balance central and local optimisation and supports customer choice and decarbonisation, but creates some complex coordination and potential for "duelling dispatch".[83]

Figure 94: Current view of the market operating model



We are closely monitoring these developments to ensure that we are best positioned to support our customers and the wider industry.

Flexibility

Flexibility is where customers (or merchant providers) change their usage patterns by either switching on generators or reducing consumption in response to a signal (e.g., hot water load control). *Flexibility resources* are delivered through controllable DERs. Distributed solar without a battery is not a flexible resource because it is uncontrollable. Hot water load control, EV charging, and charging /discharging of batteries are flexible resources. *Flexibility markets* are the mechanisms for matching and rewarding traders of controllable DERs, including providing dispatch instructions in response to prices.

The purchases of flexibility could be:

- Energy retailers or generators who buy flexibility as an alternative to energy on the spot market;
- The System Operator who buys flexibility for energy reserves or ancillary services;
- Transpower who buys flexibility as an alternative to upgrading transmission assets;
- EDBs who buy flexibility as an alternative to upgrading distribution assets.

We are forecasting a material increase in the connection of controllable DERs. These are expected to reach around 11,400 by 2050.

83 https://www.ena.org.nz/our-work/news/new-report/document/1544.

Recent regulatory changes

The Electricity Authority (EA) has a work program underway to support the transition to a decarbonised and more decentralised electricity system. The work will ensure the regulatory regime is fit for purpose and will help the adoption of new technologies to assist in transitioning to a low-emissions economy.

A key EA work programme is enabling the flexibility market and connection of DERs through rule changes, market initiatives, and innovation support. This work includes:

- Requiring large energy retailers to offer time-of-use pricing, allowing consumers to shift demand and potentially lower bills;
- Consulting on different models for DSOs to effectively coordinate consumer energy resources to provide flexibility;
- Examining ways to reward industrial consumers for providing demand flexibility, which can reduce the need for expensive peak-demand generation;
- Launching an initiative to give innovators better access to regulatory information and support, helping them bring new ideas to market faster;
- Working to co-design new flexibility products for the wholesale electricity market;
- Doubling the amount of electricity that residential solar can supply to local networks;
- Improve visibility of DERs;
- Developing rules that allow customers to have multiple retailers for different services at their property.

Interoperability and communication standards

The development of communication standards and operating protocols for dispatching flexibility or demand response in New Zealand's electricity market is progressing through collaborative industry efforts. The Electricity Authority has been actively involved in advancing interoperability and standardisation, focusing on enabling efficient participation of distributed energy resources and demand response providers.

Complementing this, industry bodies such as the Electricity Engineers' Association (EEA) and the Electricity Networks Association (ENA) are working to establish consistent technical protocols and best practice guidelines. These initiatives are designed to support secure, real-time communication between market participants and system operators, ensuring that flexibility services can be reliably dispatched and integrated while maintaining system security and customer value. The combined efforts aim to reduce integration costs, avoid technical fragmentation, and foster an open, competitive flexibility market aligned with New Zealand's decarbonisation and reliability goals.

10.4 The future is uncertain

It is unclear how the industry will deploy flexibility, as 66% of the benefits can be attributable to parties other than EDBs.[84] This creates significant uncertainty about how much EDBs can rely on demand response. Hence, how the transformation will unfold is not yet clear, and we developed the ETR anticipating two possible pathways—one where we can control demand effectively (using flexibility) and one where we are not able to control demand effectively (and therefore need to augment the network to support increasing demand and use of DERs).

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[84] Sapere Research Group, "Cost-benefit analysis of distributed energy resources in New Zealand, Report for Electricity Authority", September 2021

It will take some time for clarity to emerge on how flexibility services will evolve. However, the likelihood of distributors continuing to enjoy the sole benefits of demand control (via the ripple control system) is remote.

The ETR is only the starting point for our transformation work. There will be further detailed network modelling and refinement of solutions over the next 12-24 months. We expect the roadmap to evolve (along the direction laid out) as technology evolves and customers and society adapt.

10.5 Development of the Energy Transformation Roadmap

The ETR (coupled with ongoing monitoring and adjustments) will guide us through this uncertainty. It does this by defining two pathways—one where we continue to enjoy the benefits of demand control and one where we need to augment the network without relying on demand control.

Figure 95 shows the controlled pathway. This outlines the steps we need to take to enjoy the benefits of a controlled demand outcome and enable customers to enjoy the benefits of their investment in DERs. The network augmentation pathway is similar; however, it focuses on optimising network augmentations to support electrification while still enabling customers to enjoy the benefits of their investment in DERs.

Figure 95: Controlled Pathway Roadmap

In the medium term, the roadmap defines low-regret investments that build our capabilities while keeping both pathways open. These include:

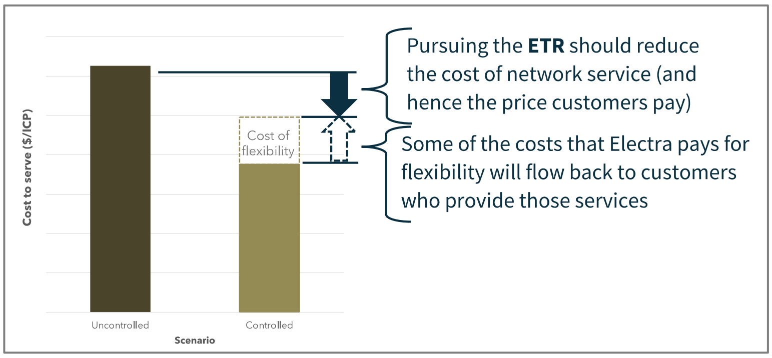
- Building people capabilities;
- Completing the constraint and solution modelling, including an assessment of available hosting capacity;
- Building LV monitoring capabilities;
- Preparing and implementing key system enhancements;
- Enhancing technical standards that reduce risks;
- Revising and progressing Electra's pricing strategy to better influence demand response;
- Monitoring the direction and pace of the transformation (and adjusting our plans accordingly).

10.6 Benefits of the ETR

Our modelling suggests there are three key benefits of pursuing the ETR to deliver the controlled demand outcome (Figure 96). These include:

- Lowering the cost of network services;
- Enabling customers to decarbonise through electrification;
- Lowering overall energy costs to customers through electrification and flexibility payments.

Figure 96: Benefits of the ETR



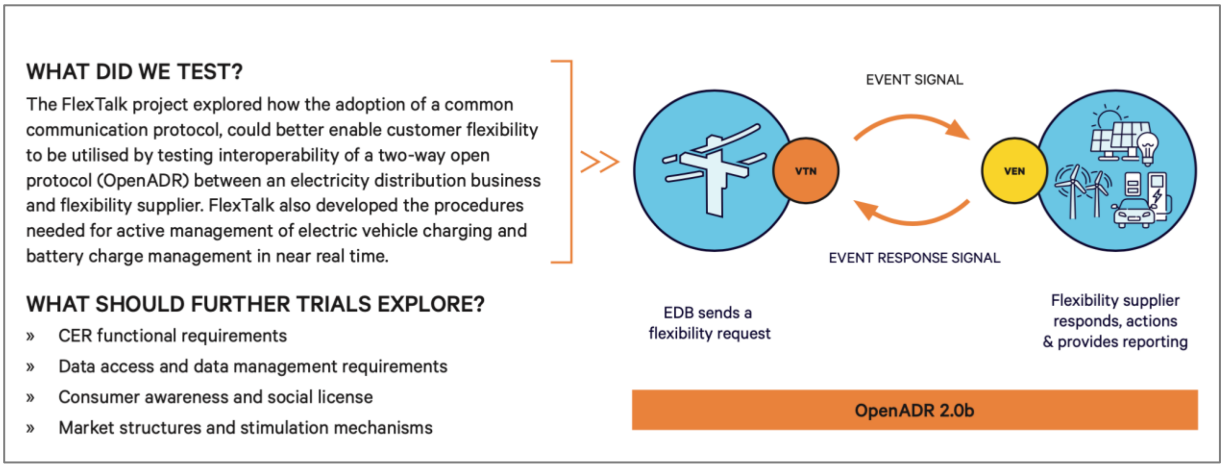
10.7 Collaborative approach

The energy transformation will only be efficient and effective if the industry standardises the market structure and communication protocols. Our approach is to support and adopt industry arrangements and protocols.

We are taking a collaborative approach to our energy transformation work. We are involved with the ENA Future Networks Forum. Electra is also part of the Northern Energy Group, a member of the Flex Forum, and participated in the EEA's Flex Talk project (Figure 97).

While we have shown our own ETR, this is consistent with the ENA's Network Transformation Roadmap (**NTR**). The NTR will be refreshed over the coming year, and we will adjust our plans to align with any changes.

Figure 97: Summary of FlexTalk



10.8 Demand forecasts

10.8.1 Methodology and demand drivers

We reviewed our demand forecasts during the early part of FY2026. This involved re-basing our forecasts to current customer numbers and demand, reflecting a slowing of net migration into our region, and reflecting the slowing economic growth its impact on customer purchasing decisions around EVs and other technology.

We have developed two demand forecast scenarios in relation to the energy transformation:

- In the uncontrolled scenario, we have little influence and control over demand behaviour. This could be a result of weak incentives to shift demand, or that demand response has a higher value in other parts of the system, and it is uneconomic for us to procure it;
- In the controlled scenario, consumers respond to incentives, and we can shift consumption and cause the dispatch of DERs to control demand at an economic cost.

We assessed five demand drivers to determine our demand forecasts. These are explained in Table 26.

Table 26: Demand drivers

Demand driver	Assumptions for controlled demand	Assumptions for uncontrolled demand	Influence on demand
Population growth	• This drives residential and commercial connection growth • Slower growth for FY2026 and FY2027, then based on Council population projections using the 75th percentile (which is consistent with historical trends) • 42 MW increase in demand by 2050; • Refer to Section 5.2	• The same as the controlled scenario	• High for controlled • High for uncontrolled
Future electricity intensity	• This factor accounts for future changes in the efficiency of electricity • Continued improvement in efficiency of 0.6% is assumed • Informed by Transpower's accelerated electrification scenario[85]	• The same as the controlled scenario	• Low for controlled • Low for uncontrolled
Uptake of electric vehicles	• 6 MW increase in demand by FY2050 • Penetration of LEVs is forecast to be 51% in the Northern region and 61% in the Southern region by FY2050 • The impact on ADMD is 0.13 kW per ICP with an EV. This accounts for the diversity of controlled charging • Informed by Transpower's accelerated electrification scenario[85], but moderated by average income levels across our two regions	• 56 MW increase in demand by FY2050 • The same penetration rate as the controlled scenario • Impact on ADMD increases to 1.3 kW per ICP with an EV. This accounts for the diversity of uncontrolled charging	• Low for controlled • High for uncontrolled
Electrification of gas	• 16 MW increase in demand by FY2050 • 5.6 MW relates to the electrification of boiler load[86] • ~22% of Electra's customers currently use natural gas or LPG, with an average annual consumption of 6,700 kWh for residential and 103 MWh for commercial customers • These customers are all assumed to use low and medium heat and switch to electricity by FY2050, consistent with Transpower's accelerated electrification scenario[85]	• The same as the controlled scenario	• Medium for controlled • Medium for uncontrolled
Demand control	• Electra's current demand control amounts to 10 MW (refer to Section 3.4).	• Existing ripple control is by-passed by new technology associated with the development of the flexibility market,	• Low for controlled • Medium for uncontrolled

85 Transpower, "Whakamana i Te Mauri Hiko", 2020

86 Based on a report of potential low temperature heat conversion. The report was prepared by DETA in 2024.

Demand driver	Assumptions for controlled demand	Assumptions for uncontrolled demand	Influence on demand
	• Existing ripple control is by-passed. The by-pass rate occurs at the rate that EV penetration increases. This assumes that future EV chargers integrate with the home demand control system • However, effective demand response is available through the flexibility market, which roughly maintains the level of demand response. • Net demand stays about the same by FY2050 (i.e. the loss of hotwater ripple control is replaced by a similar flexibility solution)	however is this is not reliability available to Electra • Demand increases by 10 MW by FY2050 as the next demand response is used for other purposes	
Uptake of distributed energy resources	• Controllable DERs reduce demand by 11 MW by 2050 • DERs uptake based on Transpower's accelerated electrification penetration rate for both controllable and non-controllable DERs[85], moderated for regional sunshine hours • External financing is assumed to overcome household income differences	• The same as the controlled scenario	• Medium for controlled • Medium for uncontrolled

10.8.2 Demand forecasts

Controlled demand forecast (used for planning purposes)

Figure 98 and Figure 99 show the controlled forecast to 2050. In this scenario:

- System electricity demand increases by 20% from 107 MW to 129 MW in FY2035 and by 50% to 160 MW in FY2050;
- Most of the demand growth is due to population growth. This adds 42 MW of demand growth by 2050. The next most significant driver is the electrification of gas;
- Due to the impact of flexibility and pricing incentives, only 17% of EV charging occurs during the morning and evening peak, which materially reduces peak demand over the uncontrolled scenario;
- Flexibility services from replacement hotwater (and other appliance) control offsets the loss of ripple control;
- Flexibility services from PV and battery installations provide 11 MW of demand reduction.

We use the controlled demand forecasts for planning purposes in this AMP.

These demand forecasts are lower (in the near term) than our prior forecasts, as we have included a reduction in near-term EV uptake given the recent changes in Government policy.

Figure 98: Northern region demand forecast (controlled)

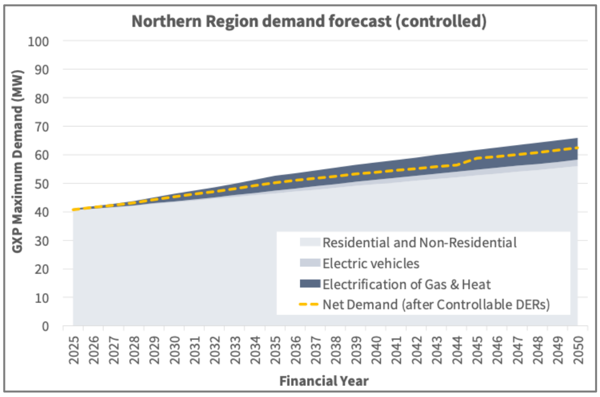
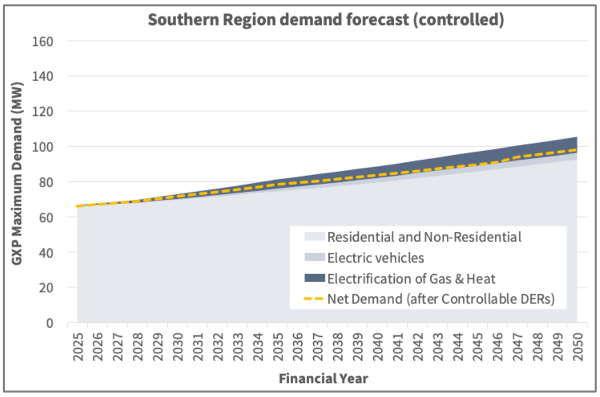


Figure 99: Southern Region demand forecast (controlled)



Uncontrolled scenario

Figure 100 and Figure 101 show the uncontrolled forecast to 2050. In this scenario:

- System electricity demand increases 104% from 107 MW to 222 MW;
- Population growth adds 42 MW of demand by 2050;
- 56% of EV charging occurs during the morning and evening peak, which accounts for 56 MW of demand growth by 2050;
- Electrification of gas & process heat adds 17 MW of demand by FY2050;
- Flexibility services from replacement hotwater (and other appliance) control is lost to other usages (or is unreliable), increasing demand by around 10 MW;
- Flexibility services from PV and battery installations provide 11 MW of demand reduction.

Figure 100: Northern region demand forecast (uncontrolled)

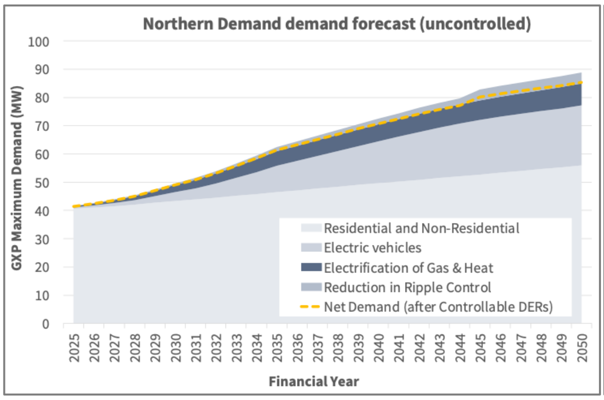
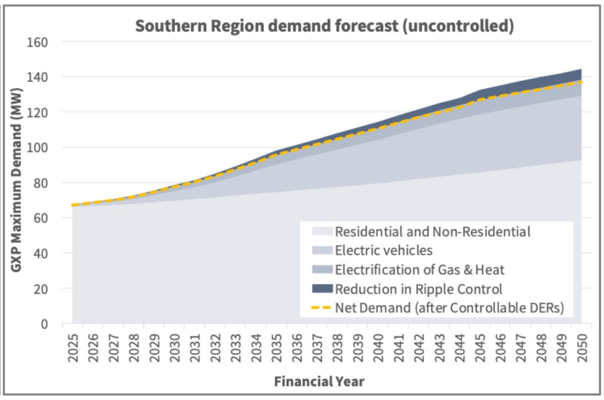


Figure 101: Southern Region demon forecast (uncontrolled)



Zone substation and feeder demand forecasts

We prepared zone substation and feeder demand forecasts using the same demand drivers. Demand drivers were assigned to each feeder (based on the feeder's customer mix). The feeder demand forecasts were then summed to provide zone substation forecasts (with appropriate adjustments for changes in demand diversity at the different network levels).

10.8.3 Managing the uncertainty

We have considered demand forecast uncertainty. This is discussed in the development sections that follow.

10.9 Impact on energy trilemma

Pursuing the ETR will have a positive impact on the energy trilemma balance:

- Overall energy affordability will improve as customers convert their energy usage to lower-cost electricity (compared to fossil fuel alternatives)[87]. For those customers that have DERs, they will also benefit from lower cost (or income) from using them to provide flexibility;
- Sustainability will improve as customers reduce their carbon output by converting their energy usage to renewable (and low-carbon) electricity;
- Security will improve for customers with DERs (as some DERs can provide electricity during a power outage).

We are mindful of the potential equity issues that may arise. That is, not all customers may benefit from lower overall energy costs (i.e. some customers may be unable to make the investments needed to convert from fossil fuels to electricity), and some customers may not be able to invest in DERs. We intend to monitor the distribution of benefits over time and will consider how these might be addressed.

10.10 Low voltage network monitoring

10.10.1 The importance of low voltage monitoring

Low voltage network monitoring is an essential step in our ETR. Visibility at the low voltage level will be important as electrification demand and DER uptake increases. These changes will likely result in complex multi-direction power flow on low-voltage networks.

To minimise the requirement to upgrade the network in the future, we will need to manage power flows on the low-voltage network to maintain power quality and thermal constraints (loading) in real time. This requires significant changes to the quality and granularity of our systems and data.

10.10.2 Current steps to improve the visibility of the LV network

In FY2026, we completed a programme to install power quality monitoring on 20% of ground-mounted transformers. These devices can provide real-time data on power flow and power quality, which our ADMS can use for future load management decisions. We plan to evaluate the data over the coming years to determine whether we continue the rollout.

We are also considering using real-time data from customer smart meters. This can assist in providing proactive and efficient customer service as we can be informed of power outages, power flows and power quality. Customer meter data could allow us to identify emerging trends and localised issues with power quality, constraints or emerging faults and defects on the low-voltage network. This will allow us to make a targeted response to low-voltage demand constraints or power quality issues. Most customers now have suitable smart meters.[88]

However, the cost and complexity of purchasing large quantities of smart meter data are presently constraints.

10.10.3 Using customer meter data

Current usages

In FY2024, we embarked on a project to obtain and process half-hourly customer consumption data (not in real time). The project aimed to leverage data collected from meters within our network to deliver improved

[87] Sapere, "Total household energy costs NZ, report for the ENA", November 2022.

[88] Around 93% of our customers have suitable smart meters as at October 2025.

outcomes across planning, asset management, and operations. We procured a single, three-year supply of historical half-hourly consumption data to improve our load forecasting and pricing models. We obtained a high level of coverage on our network.[89]

The current usages of customer meter data include:

- Distribution transformer loadings: We aggregated consumption data for each distribution transformer (making assumptions to fill data gaps) and compared the consumption profile with the transformer ratings. This identified distribution transformers that have or may soon exceed their ratings;
- We used the half-hourly consumption data in our existing network modelling application to assess selected LV networks. This analysis highlighted that the lack of customer phasing in our network model limits the analysis we can currently undertake. We will work to improve our network model, with field verification as required.

Challenges with customer meter data

We addressed the commercial and privacy issues associated with the half-hourly consumption data we purchased. During the process, there were real and perceived risks related to the data that needed to be addressed, which was time-consuming. The meter data was expensive, and we are still evaluating its value. We have not sought to obtain the more granular real-time data known as NODS (network operational data services), as the costs are significantly higher than half-hourly consumption data.

The benefit of historical half-hourly consumption data is limited to planning and asset management functions. It is purely consumption data and does not give insight into power quality issues experienced by that customer.

The volume of data, even just half-hourly consumption data, is considerable, as are the costs associated with storage and initial data processing. We have looked to service providers to store the data and proprietary analysis applications that are available and emerging on the market. While many of these applications offer potential, we have not yet been able to justify the costs based on our current network conditions.

We intend to continue testing the value proposition by obtaining additional half-hourly consumption data and real-time data, and by analysing the proprietary offerings in the market.

10.10.4 Low voltage network modelling challenges

Analysis using our existing network modelling application has been affected by network and connection information, requiring us to make assumptions about connectivity that will require verification. It may be possible to provide this verification through data analysis, or it may require on-site investigation. Both options will come with associated costs and will need to make the economic trade-off between value and accuracy.

We plan to focus on improving our network connectivity model. This will enable us to use and analyse half-hourly consumption data more confidently.

[89] Our agreements with retailers and MEPs have enabled us to obtain data from approximately 70% of smart meters, representing 63% of total ICPs on our network.

10.10.5 Alternatives to meter data

We commenced a programme in FY2020 to identify distribution transformers and sections of the low voltage network where we would benefit from high-quality real-time data for analysis in our network modelling systems. This programme has been completed and provides real-time visibility of our low-voltage network (down to each phase of the feeders) on 20% of our ground-mounted transformers. This data provides accurate, real-time information on LV circuits and transformer loadings.

10.10.6 How we respond to customer voltage complaints

Addressing non-compliance

As network load increases, feeder and LV network loading can exceed the initial design limit, potentially resulting in voltage non-compliance. Regular feeder-quality performance reviews, through field monitoring and network modelling, confirm potential voltage issues. Our current LV monitoring or customer complains identify LV voltage issues.

For the 11kV network, we typically address potential voltage non-compliance issues through reconfiguration of the feeder or upgrading conductors or cables.

For the LV network, we address potential voltage non-compliance issues through:

- Adjusting distribution transformer tap changers;
- Reconfiguration of the LV network;
- Upgrading the distribution transformer, conductor or cable.

Responding to low-voltage issues raised by stakeholders

When customers notify us of voltage issues, we respond as follows:

- Identify the reasons for the non-compliance and confirm whether the issue is on the network or the customer side. This typically includes an engineering assessment of the network layout, field verification using data logging, a check of transformer tap positions, verification of installed conductors, and possible alternate LV arrangements.
- When the issue is due to the network, we determine an appropriate solution, and the Service Delivery team undertakes the necessary work;
- We verify that the issue has been resolved through onsite measurements.

We keep the customer informed of progress throughout the resolution process and aim to resolve customer complaints within 20 working days. Should there be a requirement to exceed this timeframe, we will communicate this and the reasons to the customer and work to resolve the complaint as soon as possible.

11. Asset Lifecycle Management (Development Plans)

11.1 Introduction

In this section, we discuss the *development* and *design and construct* phase of our asset lifecycle management (refer to Figure 102). A description of the *operate and maintain* and *renew or retire* phase is provided in Section 12.3.

This section describes the material development plans for the network. These comprise:

- Our current thinking for the Northern GXP;
- The $20m subtransmission and zone substation development plan, which includes two new zone substations and two subtransmission line upgrades that are required in response to growing demand;
- The $26m distribution development plan, which includes 11 new feeders in response to growing demand and significant programmes to improve network security and manage reliability-related risks. This is a major reduction from the 2025 AMP as we are reviewing our reliability improvement programme;
- The $4m distribution transformer and LV development plan, which includes upgrading distribution transformers due to growth, interconnection projects to improve LV security, and a continuation of our LV monitoring programme;
- The $7m zone substation communication and protection upgrade programme (which is in addition to the end-of-life protection replacements included in the secondary system fleet plan in Section 12.11);
- Our current estimates for customer connections and asset relocations.

Our development plans typically include specific projects over the next three to five years and more general programmes to the end of the planning period (FY2036).

In this Section, we cover:

- How this section aligns with policy and strategy;
- Our approach to asset lifecycle management, as it relates to network development;
- The planning criteria used to guide network development;
- Design standards and other policies;
- Our approach to innovation;
- Network constraints and our development plans in response to those constraints;
- Customer connection and asset relocations.

11.2 Alignment to our asset management policy and strategy

Our development plans support the asset management policy in the areas of:

- Developing the network responsibly to meet current and future needs, and we will adopt new technology to ensure we keep pace with the requirements of customers and other stakeholder;
- Considering the economic, environmental and cultural impact of our business and finding an appropriate balance between them.

The asset management strategies in Section 6.3 include three initiatives concerning network development. These include:

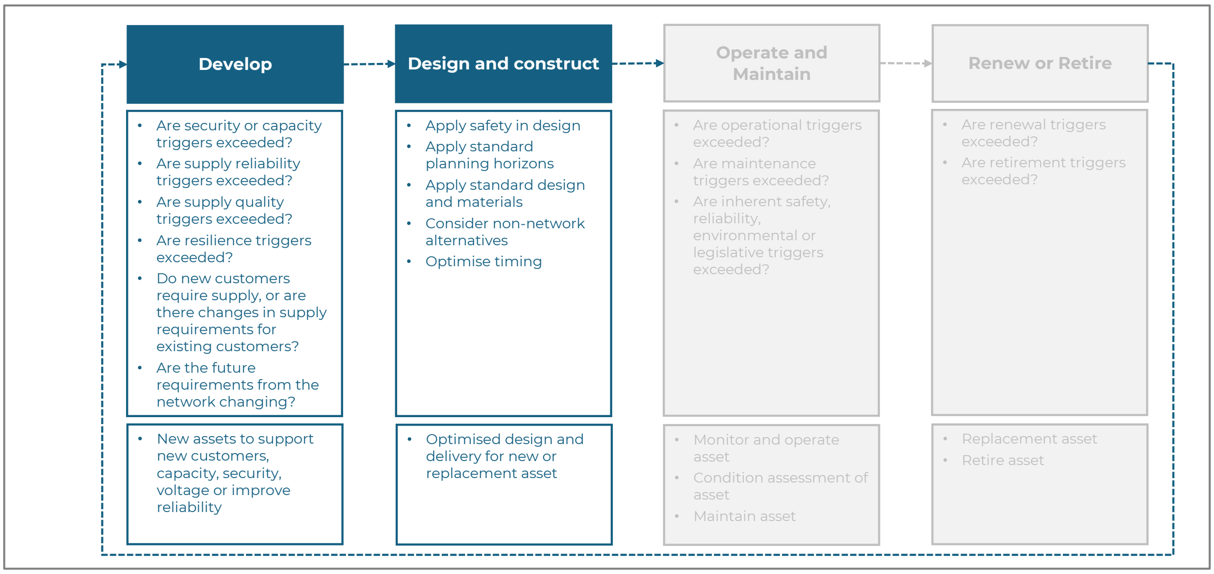
- **#1 Prepare the network (or non-network alternatives) to support the forecast future growth in our region:** The actions relate to preparing plans to cater for forecast growth, developing a long-term solution for Mangahao GXP, and ensuring our plans provide a staged development pathway that can be adjusted for non-network alternatives and changes in growth;
- **#2 Implement an energy transformation roadmap to further prepare for increased electrification:** The implementation of this initiative is mostly addressed in Section 10. However, in this Section, the action is being ready to utilise flexibility where this provides viable non-network alternatives to manage demand and reduce the extent of network augmentation;
- **#4 Continuously manage reliability risk and resilience:** The actions relate to increasing the automation and protection of our worst-performing rural feeders, increasing the number of ground-mounted switches, reviewing our overhead line designs to improve resilience, and reducing vehicle damage risks.

This Section gives effect to these policy aims, strategic initiatives and actions.

11.3 Asset lifecycle management (development)

We manage our assets throughout their lifecycle using the process shown in Figure 102. A description of the *development* and *design and construct* phase is provided below.

Figure 102: Asset Lifecycle



11.3.1 Development

The *development* phase involves creating an asset. It includes identifying the need, evaluating options, undertaking conceptual design work, and preparing the preliminary business case (if the project's scale warrants it). The purpose of this phase is to ensure the network is developed economically in response to customers' needs.

Typically, new assets are developed or acquired in response to one or more triggers (referred to as planning criteria):

- To support growth (security, capacity and customer numbers);
- New customer connections, changes in demand from existing customers and relocations of existing assets;

- Supply reliability;
- Supply quality;
- Resilience;
- Future network needs.

A network constraint occurs when a planning criteria is breached or forecast to be breached. When a constraint occurs or is forecast to occur, the planning team assesses possible solutions. This assessment may result in operational changes (e.g., reconfiguration of the network or implementation of an operational contingency), a network development project, or a non-network solution.

11.3.2 Design and Construction

The *design and construction* phase covers detailed design, procurement, business case and approval, project management, construction, and commissioning of the asset. This phase occurs in response to development or renewal needs. The design phase has taken on increasing importance as material risks in relation to safety, reliability, resilience, and serviceability can be removed through good design and selection of materials.

The outcome of this phase is the creation of an asset that is economically efficient (over its lifecycle), has appropriate inherent risks, and meets the business and customer needs.

11.4 Planning criteria used for network development

11.4.1 Planning criteria

Planning criteria define the standard across various network attributes that drive performance and enable the network to meet customers' current and future needs. The network is assessed against these standards to determine gaps (or constraints). Solutions are then developed to address the constraints, including network upgrades, operational changes, and non-network alternatives.

11.4.2 Network security, capacity and customer numbers

We assess the need to upgrade the network due to growth across three domains: security, capacity and customer numbers.

Electra's security of supply standards are shown in Table 27. For GXPs and zone substations, our security standards are above the traditional N-1 standard. The higher security standards apply to second-fault restoration. Security for second faults is provided by:

- Support for a loss of a GXPs through the subtransmission network;
- Support for a loss of a zone substations is provided through alternative sub-transmission assets or back-feeding on the 11kV network;
- For large 11kV feeders, additional security is provided by backfeeding from adjacent 11kV feeders.

Table 27: Network security criteria

Network level	Load type	Security level	First fault (Cable, Line, or Transformer Fault)	Second fault (Cable, Line, or Transformer Fault)	Bus-bar fault
GXP	Greater than 12 MVA or 6,000 consumers	N-1	No interruption	Restore as much load as technically	-

Network level	Load type	Security level	First fault (Cable, Line, or Transformer Fault)	Second fault (Cable, Line, or Transformer Fault)	Bus-bar fault
				possible, 100% in fault repair time	
Zone substation	Between 4 and 12 MVA or 2,000 to 6,000 consumers	N-1	No interruption	50% or more of load restored within 2 hours, 100% in fault repair time	No interruption for 50%, restore 75% within 2 hours and 100% in fault repair time.
	Less than 4 MVA	N-1 switched	100% restored within 30 minutes	100% in fault repair time	50% or more of load restored within 2 hours, 100% in fault repair time
Distribution feeder	Urban and large rural feeders typically between 2.0 and 4.0 MVA	N	50% or more of unaffected segment restored within 2 hours, 100% in fault repair time[90]	100% in fault repair time[90]	-
	Rural feeders between 0.5 and 2.0 MVA	N	50% or more of unaffected segment restored within 4 hours, 100% in fault repair time[90]	100% in fault repair time[90]	-
	Under 1 MVA Rural feeder, urban spur, distribution transformers, LV circuits	N	100% in fault repair time[90]	100% in fault repair time[90]	-

In addition to our security criteria, we have asset capacity planning criteria, as shown in Table 28. The security and capacity standards are related. The capacity standards provide a second layer of support to our security of supply standards.

Table 28: Network capacity criteria

Asset	Capacity criteria
Sub-transmission lines and cables	Conductor current should not exceed 66% of the thermal rating for more than 240 half-hours per year during normal operation[91]
	During contingency operation, conductor current should not exceed 100% of the thermal rating for more than 10 consecutive half-hours per year
Power transformers, zone substation switchgear and associated busbars conductor and cables	Maximum demand during normal operation should not exceed 50% of the full[92] nameplate rating (except for zone substations less than 4 MW and feeder circuit breakers)
	Load exceeds guidelines in IEC 354
Distribution lines and cables	Conductor and cable current should not exceed 70% of the thermal rating for more than 240 half-hours per year during normal operation
	Conductor and cable current should not exceed 100% of the thermal rating for more than 10 consecutive half-hours per year at any time
	HV and or LV fusing routinely exceeds ratings
	HV and or LV fuse operates

90 Generators to be used where feasible to enable restoration of power before fault is repaired.

91 Excluding contingency operation.

92 Full means at ADAF or AFAF ratings

Asset	Capacity criteria
Distribution substations	Where fitted with a maximum demand indicator the reading should not exceed 100% of the nameplate rating. During contingency operation, where fitted with a power quality monitor demand should not exceed 100% of the name plate rating for more than 240 half-hours per year during normal operation[93]
	HV and/or LV fuse operates repeatedly
	Short-term loading exceeds guidelines in IEC 354
LV lines and cables	Conductor current should not exceed 100% of the thermal rating for more than 10 consecutive half-hours per year. However, as limited on-line measurement is currently in place, this is criteria is monitored during GM transformer inspections. There is no active monitoring of overhead circuit demand.

The third area we assess to determine if the network needs to be upgraded is the customer number per feeder. The maximum customer number per feeder is shown in Table 1. In many cases, operational changes to the network (e.g., rebalancing customer numbers across adjacent feeders) can resolve most identified constraints.

Table 29: Network customer number, switch segment and interconnection criteria

Network level	Feeder type	Maximum numbers of ICPs	Maximum number of ICPs per switch segment	Minimum number of interconnection feeders
Distribution feeders	Urban	1500	300	3
	Rural	1000	200	2

11.4.3 New customer connections, changes in demand from existing customers and relocations of existing assets

The growth-related criteria in Section 11.4.2 define our response to organic growth. We also assess the network where a localised step-change in demand is foreseen. This assessment occurs when a new industrial or large commercial customer applies for a connection or an existing industrial or large commercial customer advises of a load upgrade. It also happens when a new subdivision development is planned. The criteria in Section 11.4.2 are applied to the localised change in demand and customer numbers to assess if a constraint will emerge; a solution is then developed accordingly.

There are no specific standards for asset relocations. They are initiated upon the request of NZ Transport Agency Waka Kotahi, Local Councils, or customers.

Our current connection standards are on our website[94] and in our network extension policy[95]. The network extension policy describes the responsibilities of Electra and developers when connecting new subdivisions and other large developments.

11.4.4 Supply reliability

We evaluate the need for an upgrade to the network should reliability be below the standards in Table 30. Reliability issues often indicate the presence of end-of-life drivers. The asset fleet plans included in Section 12 address the response to end-of-life drivers. However, in some situations, reliability issues are resolved through changes in protection settings, network configurations, or the addition of sectionalisers and

[93] Excluding contingency operation.
[94] https://electra.co.nz/getting-connected/
[95] https://electra.co.nz/our-company/disclosures/

reclosers. The development plan deals with managing reliability risk and resilience using network protection, changes in network configuration, or changes in asset type (e.g. undergrounding).

Table 30: Network reliability standards

Network level	Reliability criteria
Sub-transmission feeder	Achieve a fault rate better than industry average. For sub-transmission feeders, all faults are assessed for the root cause to determine whether improvements are required.
Zone substation	Achieve a fault rate better than industry average. For zone substations, all faults are assessed for the root cause to determine whether improvements are required.
Distribution feeder	Achieve a fault rate better than industry average Intervention will also be evaluated for all worst-performing feeder[96].
Distribution substation	Not applicable. A fault on a distribution substation typically occurs at end-of-life
Low voltage system	Intervention will also be evaluated where there are multiple faults within 12 months on an LV circuit

11.4.5 Supply quality (voltage)

Voltage is the primary supply quality parameter we assess. The standards in relation to network voltage are shown in Table 31.

Table 31: Network voltage standards

Network level	Voltage criteria
Sub-transmission feeders	33kV voltage below 31.5kV (0.95 pu) at the zone substation being supplied
Zone substations	Voltage drops below the level at which online tap changers can automatically raise taps
Distribution feeders	Voltage at HV terminals of transformer consistently drops below 10.5kV (0.95 pu) and cannot be compensated by local tap setting
Distribution substations	Voltage at LV terminals consistently drops below 100% of the nominal value
Low voltage system	Voltage below 90% of nominal voltage at the customer's point of supply Voltage above 110% of nominal voltage at the customer's point of supply

We also assess voltage and current harmonics when an issue is identified through our power quality monitors installed across 33kV, 11kV and LV in addition to any issues identified by customers. MBIE changed the LV voltage tolerances to 230V ±10% in 2025.

11.4.6 Resilience

Table 32 shows our draft resilience standard. This will be refined over the next 12 months.[97] We take a pragmatic approach to applying this standard to existing structures as site restrictions can impact remediation work—in which case we seek the highest practical performance or alternative supply arrangements in the event of a natural disaster.

Table 32: Draft resilience standard

Hazard	Draft Standard
Seismic	• All new zone substations, 11kV switching stations, control room and 11kV structures supplying critical infrastructure shall meet Importance Level 4 (**IL4**) defined in the National Building Standard. IL4 requires buildings to remain operational after a natural disaster (concerning earthquake, wind and snow structural loading). • All existing zone substations, 11kV switching stations, control room and 11kV structures supplying critical infrastructure shall meet IL4 where it practical and economic to do so;

[96] **Worst-performing feeder** means the feeder lines on an **EDB's network** that, in respect of the most recent **disclosure year**, are in the 90th percentile or higher for one or both of the following: (a) **feeder SAIDI**; and (b) **feeder SAIFI.**

[97] We had planned to review this standard in FY26, but this work was not completed at the time of writing.

Hazard	Draft Standard
	• 11kV buildings and fixings for ground mounted assets shall meet IL3. These buildings have increased performance requirements as they fulfil a role of increased importance to the local community.
Wind, snow and ice	• All new zone substations, 11kV switching stations, control room and 11kV structures supplying critical infrastructure shall meet IL4; • All existing zone substations, 11kV switching stations, control room and 11kV structures supplying critical infrastructure shall meet IL4 where it practical and economic to do so; • 11kV buildings and fixings for ground mounted assets shall meet IL3; • All new overhead lines shall meet security level 3 (under AS/NZS7000). Level 3 applies to lines where failure would cause increased risk to life or economic lost or where post disaster function is required.
Flooding and coastal inundation	• We have reviewed the network based on Council data. This data is based on a 1% annual exceedance probability (**AEP**) with significant climate change impacts[98] (which is a 1:100 year return period). • This return period (or AEP) is below that applied for other hazards. We are aware that some other distribution businesses apply 1:350 (0.35% AEP) or 1:500 (0.2% AEP). We are currently reviewing what standard is appropriate for Electra.
Landslips and subsidence	• This is yet to be defined. We currently assess this during site selection.
Vehicle damage to the overhead network and ground-mounted assets	• This is yet to be defined. However, we review all vehicle damage incidents and will assess whether there is an ongoing vulnerability. • We have commenced work with a roading consultancy to provide us with guidance regarding asset locations.
Third-party contractor damage to the underground network	• This is yet to be defined. However, we review all third-party contractor damage incidents and will assess whether there is an ongoing vulnerability.

This standard excludes cyber security, which is discussed in Sections 8.6, 9.4.3 and 14.5.3.

11.4.7 Environmental

Electra's policy is to prevent pollution, comply with all applicable environmental regulatory requirements and continually improve our environmental performance. Table 33 summarises our current environmental standard.

Table 33: Environmental standard

Environmental hazard	Standard
Oil contained in transformers	• Maintain bunding equivalent to 110% of the oil contained in power transformers. Incorporate oil/water separation units on power transformer bunding. • Respond rapidly to any identified oil leaks in distribution transformers and switchgear. All soils contaminated with oil shall be removed and disposed appropriately.
SF_6	• Regular monitoring of all switchgear containing SF_6. • Respond rapidly to any identified leaks and follow industry guidelines for repairs, removal and disposal.
Site waste	• Our Sustainability and Environmental Policy details Electra's overall priorities to reduce, reuse and recycle where possible. We use the Resource Management Act to guide our waste disposal activities. • Detailed environmental standard being created next year.
Discharge of liquids to another water body	• The quality is same or better as the water body it is being discharged to • The discharge does not cause a temperature increase >2 degrees Celsius after reasonable mixing • The discharge does not cause any erosion of channel or bank
Discharge of liquids to land	• Ensure compliance with GWRC Rule 91 and HRC RP-LF-LW-R34, R35 and R36
Cleanfill material	• Ensure compliance with GWRC Rule 80 and HRC RP-LF-LW-R29

[98] The climate change impacts are based on RCP 8.5 as defined by NIWA. This applies a range of mean annual temperature increases of 0.9–1.1 degrees Celsius by 2031–2050 and 2.8–3.1 degrees Celsius by 2081–2100.

Environmental hazard	Standard
Structures in Lakes and Rivers	• Ensure compliance with GWRC Rule 122 and HRC RP-LF-AWBD-R62

11.4.8 Non-network solutions

Non-network solutions are alternatives to traditional network solutions. They include demand response, distributed generation, and distributed storage. They are also referred to as controllable DERs or flexibility resources, and can provide flexibility to EDBs or other market participants.

Distributed generation (including batteries)

Electra's policies for embedded generation and batteries are on its website.[99] Key features of those policies include the following requirements:

- Compliance with the requirements of Part 6 of the Electricity Industry Participation Code 2010;
- Identification of the requirement for exported electricity to be sold to a retailer;
- Setting out the application process for both PV and batteries;
- Setting out the safety, technical, operational, commercial and regulatory requirements;
- A list of approved inverters.

Market flexibility options

Flexibility markets remain in a development phase. Where market-provided flexibility (provided through non-network solutions) is available, we intend to signal opportunities with sufficient lead time and adopt transparent evaluation criteria. Where in-house non-network solutions are implemented, we will assess and document why this approach provides greater value to customers than available market alternatives.

We support the standardisation of communication and operating standards for controllable DERs. This will lower integration costs and enable greater scalability. The development of communication standards and operating protocols for dispatching flexibility or demand response in New Zealand's electricity market is progressing, and we intend to adopt industry protocols.

11.4.9 Project evaluation and selection

We have recently updated our project governance process and have introduced a series of stage gates. The process covers:

- Project Justification Phase: Where we identify the issue (e.g. the breach of planning criteria or requirement from a new development or major customer), undertake optioneering, and create a project brief. This phase includes the consideration of network and non-network solutions;
- Stage Gate 1: The project is escalated based on the delegated authorities. Gate 1 decides if a project goes from concept to live project;
- Front End Engineering Design: Preparation of concept design and high-level costings are created;
- Stage Gate 2: Design and costing review to determine if the project will progress to the detailed design;
- Detailed Design Phase: Preparation of the detailed design (using internal service delivery or contractors). This phase includes the detailed design, bill of materials, construction methodology, and detailed project costs.
- Stage Gate 3: Detailed design review and approval to proceed to construction.

[99] https://electra.co.nz/services/distributed-generation/

Following Stage Gate 3, the project proceeds to procurement, construction and commissioning. Once complete, there is a final inspection, defect remediation (if needed) and as-builting. The as-builts are used to update the GIS and asset records.

The project may be presented to the Board for approval, if required by the delegated authorities due to financial value, at Stage Gates 2 and 3. Presenting at Stage Gate 2 provides the Board with oversight of the options considered, as well as the recommended option. Stage Gate 3 presents the accurate costings available at this time to the Board.

11.5 Design standards and other policies

11.5.1 Introduction

We have a range of other standards and policies that influence the design of any new project. These policies and standards drive safety, efficiency (via standardisation and modular concepts), and the amount of future capacity built into the design.

11.5.2 Safety in design

Safety in Design (SID) integrates hazard identification and risk assessment methods early in the design process. The project team participates in SID risk reviews to ensure a safe and smooth project delivery. SID development and assurance stages occur throughout the project delivery lifecycle. Safety is Electra's paramount consideration, and SID workshops provide traceability of its application of best-practice safety standards.

11.5.3 Standardisation

In September 2022, we created the Standards Review Forum, a cross-functional group within Electra that meets frequently to govern the approval and performance review of engineering standards, equipment approvals, and procedures. Using a RACI matrix, the group seeks to build consensus around standards and equipment approvals. This includes reviewing systemic issues identified through audit, observation, and event investigations and incorporating these into amended standards or procedures.

Electra uses NZ and international standards, codes, and guidelines to standardise design and materials. The areas where we have adopted a high level of standardisation (with minor site-specific alterations) are:

- Zone substation design and configuration, including conductor and cable types, switchgear, power transformers and protection systems;
- Distribution design and configuration, including conductor and cable types, ground-mounted distribution switchgear and transformers;
- LV design and configuration, including conductor and cable types, LV pillar and link boxes.

Our design and materials evolve as new standards offer improvements in safety, performance, inventory, or costs. Table 34 describes how standardisation across our supply chain supports asset management.

Table 34: Benefits of standardisation

Types of standardisation	Support construction and operational safety	Support asset performance	Minimise inventory costs	Minimise operating costs	Minimise design and construction costs
Standard design concepts				●	●
Technical design standards	●	●		●	
Standard asset capacity and configuration			●	●	●
Preferred purchasing arrangements	●	●	●		●
In-house field staff	●	●			●

11.5.4 Standard asset capacities and planning horizon

We have defined planning horizons so that upgrading the network takes a suitably long view of future demand to maximise fixed construction costs (e.g., trenching or building work) and avoid the need for uneconomic near-term reinforcements. Electricity is an essential service, and reliance on electricity will increase as electrification increases. For this reason, we see the risk of under-investment that compromises security and capacity (and limits decarbonisation) as higher than the risk of short-term over-investment.

We have defined standard capacities for network elements to guide material and equipment selection and to achieve standardisation, purchasing, and construction efficiencies. The standard capacities and planning horizons outlined in Table 35 reflect the standard cable, conductor, switchgear, and transformers typically available.

Table 35: Asset Capacity and Planning Horizon

Network level	Standard Capacity	Planning Horizon	Description
GXP	n/a	30+ years[1]	We apply a long planning horizon as development can take up to ten years, and the incremental cost of higher capacity at the time of construction is generally low. There is no standard capacity; however, capacity typically follows Transpower's standard transformer sizes.
Sub-transmission feeders	To support the required contingent capacity	20-30 years	We apply a long planning horizon due to the time and complexity of route selection and procurement of property rights.
Zone substations	Typical nominal rating is 23 MVA (N-1) for urban substations	20 years	We apply a long planning horizon due to the time required to consent and develop a zone substation. The standard substation capacity reflects Electra's historical practices.
Distribution feeders	4/6 MVA for urban feeders 3/4 MVA for rural feeders	Ten years	We apply a medium planning horizon, and distribution work can typically be completed in 1-2 years. The standard feeder capacity relates to normal/backfeeding and reflects Electra's historical practices.
Distribution substation, industrial	Customer-specific	Ten years	A ten-year view of capacity is generally appropriate for industrial customers. Distribution transformers can be incrementally upgraded in most cases.
Distribution substation, commercial	500-1,000 kVA	Ten years	A ten-year view of capacity is generally appropriate for commercial areas—the selected capacity needs to have suitable spare capacity for back-feeding adjacent loads.
Distribution substation, urban	200-300 kVA	n/a	Distribution transformer capacity is sized based on the standard residential customer number (3.5 kVA ADMD) and the expected number of connections.

Network level	Standard Capacity	Planning Horizon	Description
Low voltage	Standard cable and conductor sizing	n/a	Capacity is based on standard cable and conductor size. LV runs are limited to maintaining voltage and capacity compliance based on the standard residential customer number (3.5 kVA ADMD) and the expected number of connections
Residential customer demand	3.5 kVA ADMD (distribution TX level)	n/a	This is the maximum demand of a residential customer used for planning purposes. The diversity is measured at the urban distribution transformer. We are reviewing the ADMD we use for planning as part of our energy transformation work.

11.5.5 Energy efficiency

We seek to minimise network losses where it is economic to do so. We recognise that total network losses are significant (about 7% of energy entering the network); hence, the following approaches are used to minimise losses:

- Upgrading of overloaded conductors to reduce the I^2R losses;
- Consideration of losses when purchasing equipment;
- Identify and improve poor power factor installations to a minimum of 0.95;
- Optimisation of open points to ensure the load is balanced across feeders and LV circuits.

11.6 Innovation practices

At Electra, we do not directly innovate new products, materials, or systems. Instead, our strategy involves being a fast follower in adopting new products, systems, or processes. We aim to be an early adopter of new technology that has reached the commercialisation stage (by others) when significant benefits are available. The one exception to this approach has been our involvement in Flex Talk (refer to Section 10.7), which involved pre-commercialisation work (that was led by others).

Proposed innovations require a business case that considers the benefits of change, including safety, maintainability, longevity, customer service, and the impact on capex and opex. Innovations could involve changes to processes, systems, designs, or materials.

Due to our relatively small scale, we generally operate a conservative approach to design innovation—that is, when balancing standardisation vs. innovation, we place weight on standardisation, ensuring we can maintain competency (in operating and maintaining) assets. However, we will innovate on design with material performance or lifecycle cost advantages (the new modular outdoor zone substation circuit breakers are a good example). New products that can reduce future maintenance costs and perform well in coastal conditions are areas where we actively seek innovation.

Proposed innovations that could impact design or materials standards are reviewed by our Standards Review Forum (refer to Section 11.5.3). The forum ensures that there is a cross-business view on the impacts on safety, maintainability, longevity (in particular) and cost.

Recent innovations include our involvement in Flex Talk (refer to Section 10.7), the modular 33kV switchgear (Section 11.9.4), trip saver (Section 11.12.3), and the power transformer moisture probes (Section 12.8.4).

11.7 Demand forecasts for planning purposes

Our demand forecasts in Section 10.8 forecast demand at the GXP, substation, and feeder levels. They use two scenarios: one in which we have access to flexibility, which results in controlled demand forecasts, and one in which we do not have reliable access to flexibility, which results in *uncontrolled* demand forecasts.

The development plans have been prepared using the **controlled demand** forecasts, but we discuss our approach to managing demand uncertainty where necessary.

Figure 103: Mangahao GXP demand forecast

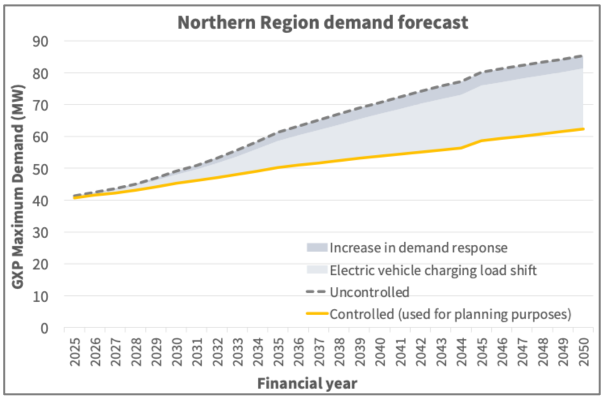
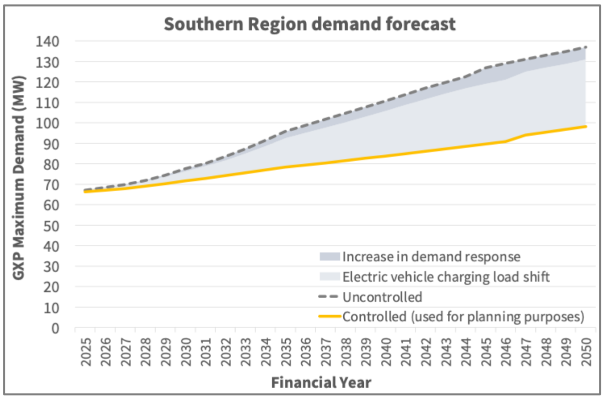


Figure 104: Paraparaumu GXP demand forecast



11.8 Development plan—grid exit points

11.8.1 GXP developments to meet security and capacity requirements

Background

Electra's network consists of two regions:

- The northern network, which is supplied from the 110 kV Mangahao GXP and Mangahao generation and supplies Levin East and West, Foxton and Shannon substations in a ring configuration;
- The southern network, which is supplied from the 220 kV Valley Road Paraparaumu GXP and supplies Paekākāriki, Paraparaumu East and West, Raumati, Waikanae and Ōtaki substations in a double spur configuration

There is significant capacity available at GXP supplying the southern network. However, current demand in the Horowhenua region at 42 MVA[100] is close to the capacity of the Mangahao GXP (44 MVA N-1-G firm, including firm generation)[101]. The 38 MW Mangahao hydro generator supports supply security at peak times. The output from this station currently supports the security of supply from the Mangahao GXP during peak demand, typically operating at ~26 MW.

The Mangahao GXP transformers (owned and operated by Transpower) are reaching end-of-life. Transpower are planning their replacement with higher rated transformers with on-load tap changers in around 2028-2030[102].

[100] 42 MVA is the peak ½ hour demand at the Mangahao GXP. The average of the top-10 peaks is 40.0 MVA. Data is for FY2025 (i.e. winter CY2024).

[101] The firm capacity of the GXP transformers is 30 MVA.

[102] Transpower's 2025 Transmission Planning Report

Planning standards drivers

Four relevant planning standards are guiding the development of options:

- Security of supply;
- Consideration and use of non-network alternatives;
- Planning horizon;
- Resilience.

Table 36 shows Electra's current security standards (as they relate to GXPs). The first fault requirement reflects a typical N-1 standard, and the second fault requirement requires a higher level of redundancy or alternatives. The network doesn't meet the second fault requirement in most situations; hence, it is under review. Hence, our principal focus is presently on the first fault requirement.

Table 36: Network security criteria

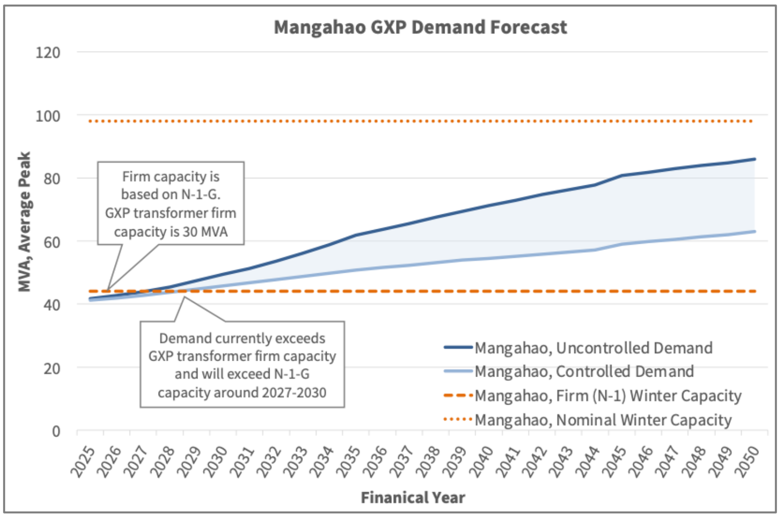
Network level	Load type	Security level	First fault	Second fault
GXP	Greater than 12MVA or 6,000 consumers	N-1	No interruption	Restore as much load as technically possible, 100% in fault repair time

Current constraints

Demand forecasts indicate a shortfall in capacity and a breach of GXP firm capacity in FY2027-FY2030 (Figure 105). We have assessed GXP firm capacity including Mangahao, based on the N-1-G industry standard (where G is the largest turbine at Mangahao).

Demand is currently exceeding the GXP transformer firm capacity but is supported by Mangahao generation at peak times, with Transpower System Operator constraining on the Mangahao generation as required

Figure 105: Mangahao GXP Demand Forecast



Our approach is to plan for controlled demand, but to have contingencies or an upgrade path to cater for uncontrolled demand, should this occur.

Network solution, preferred option

In previous AMPs we discussed that we were studying options for the supply of our Northern region. Purely from an engineering perspective a GXP on the 220kV transmission circuit west of Levin would ensure that the physical distance between supply and demand are minimised. We have heavily engaged in consultation with Transpower during this assessment and analysis.

The result of this assessment is that our preferred network solution is to allow Transpower to complete the end-of-life renewal of the Mangahao 110/33kV transformers with modern equivalent assets, which will include an increase in transformer capacity. The upstream grid constraint is the Bunnythorpe-Mangahao

110kV line, at 48/59MVA (summer/winter). We are currently in discussion with Transpower regarding forecast demand which will determine Transpower's selection of the modern equivalent asset and capacity. However, a 60 MVA firm capacity GXP would provide suitable capacity (based on controlled demand) for the next 20 years (reducing to 10 years for uncontrolled demand growth). Hence, whilst the preferred 30-year planning horizon is not achieved, this option will support medium-term planning at a materially lower cost than a new GXP. Higher capacity may be possible if the grid constraint can be mitigated.

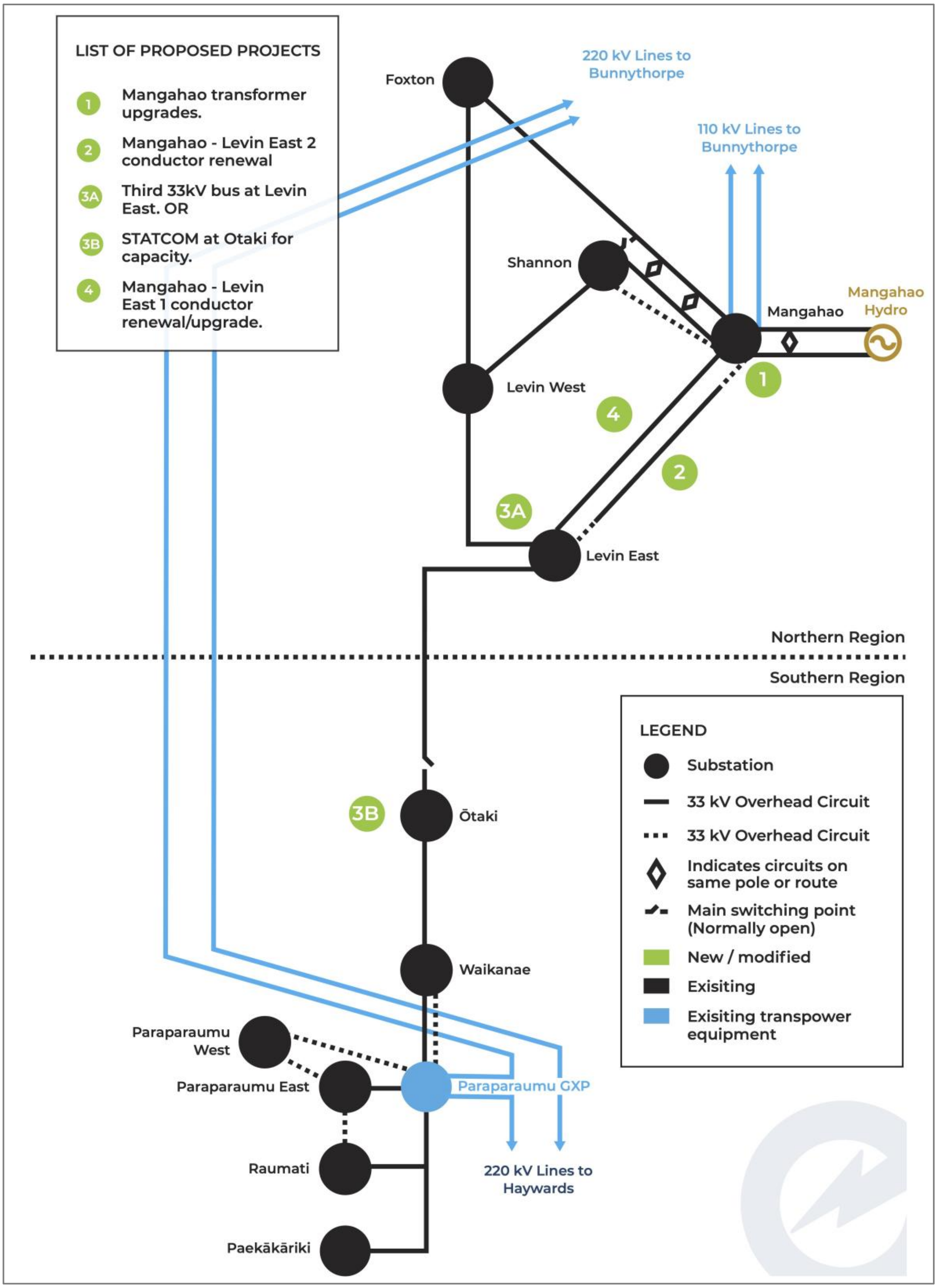
Proceeding with Transpower's renewal of the Mangahao GXP transformers is the lowest-cost option for Electra. It will increase capacity in the Horowhenua region and install on-load tap changers (OLTC) at the site, which should improve voltage at Ōtaki when supplied from the north.

Due to the forecast capacity constraints and the Mangahao GXP transformer's end-of-life status, there is no realistic do-nothing option.

Table 37: Projects under consideration

Solution under consideration	Driver	Estimate/Year	Options considered
1. Renewal of existing 110/33kV transformers at Mangahao with modern equivalent assets	Asset health	Transpower costs for the transformers. There may be some associated Electra costs $TBC FY27-29	• A new Mangahao 220/33 kV GXP; • A new Levin Southeast 220/33 kV GXP; • A new Levin Southwest 220/33 kV GXP; • An expanded Paraparaumu 220/33 kV GXP as a single point of supply to feed both Northern and Southern networks; • A new shared Electra/Genesis 220/33 kV GXP/GIP connecting both Electra and a proposed Genesis 200 MW solar farm northeast of Foxton. • A new Levin Northwest 220/33 kV GXP (North of Lake)
2. 33kV subtransmission line conductor renewal (MHO-LVE 2)	Asset health	Project in concept stage, subject to justification. ~$8.2m FY28-30	
3. Third 33kV bus at Levin East or STATCOM at Ōtaki for capacity and voltage support during northern transfer	Security of supply	~$1.5m FY32-33	
4. 33kV subtransmission line upgrade/renewal MHO-LVE 1 ex Transpower 110kV line	Capacity Asset health	$TBC FY37	• This is currently beyond the AMP planning horizon
Total (not in expenditure forecasts)		**~$9.7m**	• **FY27-36, System growth and Asset replacement and renewal capex**

Figure 106: Northern GXP, preferred network solution (proposed)



11.8.2 GXP developments to meet other drivers

No GXP developments are currently required to meet other drivers.

11.8.3 Managing demand growth uncertainty

The GXP development plan has been prepared to support controlled demand growth.

11.8.4 Consideration of non-network alternatives

Under our energy transformation roadmap, we will develop a non-network procurement policy, standards, and evaluation criteria. These will define performance standards for non-network alternatives. Where non-network alternatives are deployed or procured, we need to develop processes for monitoring their performance to ensure the benefits procured are delivered. Work on these policies and standards has not yet commenced.

Non-network alternatives cannot fully substitute the Mangahao transformer renewal as a new grid connection or upgrade to the existing GXP is required (given the end-of-life of the existing GXP transformers). However, non-network alternatives may reduce the capacity needed at the GXP and downstream network augmentation (e.g. the number and capacity of circuits and the requirement for capacitor support) or increase the capacity (to achieve the 30+ year planning horizon). Given the peakiness of the Mangahao GXP demand profile, there could be options for market flexibility solutions to soften the peak and extend the horizon over which the capacity can support. Non-network alternatives will be considered in the detailed study to finalise the transformer renewal and consideration of grid upgrade options.

Using the controlled demand growth graph in Figure 102, Mangahao GXP is anticipated to reach the winter-rated line capacity of 59MVA around 2046.

In the next 20 years, we expect more non-network alternatives and DERs to emerge, which may enable peak load shifting, voltage and capacity support, and the deferral of investment in additional southern region capacity upgrades.

11.8.5 How we are thinking about the energy trilemma balance

The renewal of the Mangahao transformers and associated work could have a marginal impact on line charges. During FY27 we will engage further with Transpower so we can more accurately understand the financial impact. Currently we consider that the impact will be a marginal increase and considerably less than half that of the options discussed in the 2025 AMP.

Greater GXP capacity is required to meet the northern region's future population and electrification needs—this is essential for the region. Greater GXP capacity is necessary to maintain GXP security as demand grows (at N-1, the standard currently afforded to the region)—security is essential to meeting our ongoing reliability performance targets.

We are mindful of the affordability impacts. Our approach to managing affordability is:

- To stage the development to the maximum extent possible, commensurate with the risk (which is discussed below);
- To provide capacity to service the controlled maximum demand and have an upgrade path to service the uncontrolled demand (should this be necessary);
- Utilise non-network alternatives (if viable) to minimise the initial development's capacity requirements, delay planned upgrades or deliver full capacity at the planning horizon.

Proceeding with the preferred option will increase security and sustainability with a modest impact on affordability. This is an appropriate balance.

11.8.6 Managing demand until the Mangahao GXP is upgraded

Until the transformers are replaced, we are managing the risk of the maximum demand exceeding firm capacity and the end-of-life failure of one of the Mangahao GXP transformers. Our demand forecasts indicate that peak demand could exceed firm capacity at the Mangahao GXP between FY2027 and FY2030. Given the peakiness of the seasonal demand profile, any exceedance of the peak will be in a small number of half-hour periods over the next 5-8 years. We have options to manage peak demand through the existing Mangahao generator, more aggressive load control, or utilising the transformer's emergency/overload rating. Transpower as System Operator also have the ability to apply special protection schemes and constrained on generation as required.

We recently signed a new service-level agreement with Transpower to extend the overload capacity of the Mangahao transformers. This increases the ratings to a 60-minute pre-contingency of 44.1/40.8 MVA (winter/summer) for both transformers, after which the load must be reduced to the 24-hour post-contingency of T3 36.6/38.7 MVA (summer/winter) & T4 37.2/39.6 MVA (summer/winter). This assists our ability to manage our network post a contingent event.

Concerning the end-of-life failure risk of the Mangahao transformers, Transpower forecasts the replacement for FY2028-FY2030. We expect that new transformers can be commissioned in FY2029. Transpower has not escalated any concerns regarding transformer health and is managing the transformers appropriately.

11.8.7 Summary of justification for the GXP development projects

The capacity-driven projects in this section are required to meet demand from new customers and support future demand growth from existing customers. This is an essential requirement for Electra.

11.8.8 Expenditure forecasts

The replacement of the Mangahao GXP transformer are still in the concept/negotiation phases. Hence, the expenditure forecasts do not include our estimate of project costs (nor are the project costs fully developed). Over the next 12 months, we will be firming up any expenditure impact.

11.9 Development plan—subtransmission and zone substation

11.9.1 Overview

During the planning period (to the end of FY2036), subtransmission and zone substation developments are required to meet demand growth. The forecast demand growth is driving:

- Subtransmission constraints during contingency (N-1) operations on the Northern network;
- Voltage support for the Ōtaki substation;
- The development of new zone substations to support demand growth on the 11kV system, which cannot be met by augmenting the 11kV system.

The developments are primarily needed to maintain firm capacity as demand grows. Electra operates a very secure and reliable subtransmission system, and maintaining security is crucial to operating a reliable network. The subtransmission developments in this section are consistent with the Mangahao GXP upgrade, as discussed in Section 11.8. Note: the subtransmission projects that are contingent on the GXP upgrade are currently included in Section 11.8.

The subtransmission and zone substation developments are forecast to cost $20.1m. The significant projects are two zone substations (at Peka Peka and Taraika) and the upgrading of two subtransmission circuits in the Northern region. Development at several zone substations is also required to meet resilience and environmental needs. This is a continuation of existing programmes.

11.9.2 Zone substation demand growth

The demand growth drivers identified in Section 10.8 have been applied to each feeder based on customer mix to determine the zone substation demand (Table 38). Zone substation demand is forecast to grow significantly by 2050, with Northern region substations' demand growth between 27% and 75%. Zone substation demand growth in the Southern region is lower, at between 32% and 58%. Growth in Paekākāriki and Raumati is constrained by land availability.

Despite the strong demand growth, zone substation capacity is suitable to meet the controlled demand growth at all zone substations, except Shannon, Waikanae, and Levin East, to 2050. Constraints will occur at seven of the ten zone substations by 2050 if uncontrolled demand growth occurs.

Table 38: Zone substation customer type and demand growth

Zone substation	Current security level	Customer type	Controlled Peak Demand 2026 (MVA)	Controlled Peak Demand 2031 (MVA)	Controlled Peak Demand 2036 (MVA)	Controlled Peak Demand 2050 (MVA)	Total Controlled growth to 2050
Shannon	N-1	Mix of urban load in Shannon and rural load toward Tokomaru and Opiki	4.6	4.8	5.1	5.8	27%
Foxton	N-1	Predominantly urban load in Foxton with some rural load in all directions	7.4	8.3	9.2	10.6	43%
Levin West	N-1	Predominantly the rural areas to the north and west of Levin, Waitārere Beach, and some urban load in the western parts of Levin	14.3	16.3	18.1	20.9	46%
Levin East	N-1	Predominantly urban, although with some rural load to the south and east of Levin	15.9	18.1	20.4	27.9	75%
Ōtaki	N-1	Predominantly urban load in Ōtaki with some rural load in Ōtaki Gorge, Manakau, Te Horo and Waikawa Beach	12.7	13.8	14.9	18.5	45%
Waikanae	N-1	Dense urban load in and around Waikanae, some rural load to the north in Peka Peka and the east in Reikorangi	15.5	17.1	18.8	24.5	58%
Paraparaumu East[103]	N-1	Dense urban load in the eastern and central parts of Paraparaumu, some rural load on the immediate outskirts of Paraparaumu	13.2	14.7	16.3	20.5	56%
Paraparaumu West	N-1	Dense urban load in central and western parts of Paraparaumu	11.3	12.4	13.5	16.4	46%
Raumati	N-1	Dense urban load in and around Raumati	10.9	11.5	12.2	14.4	32%
Paekākāriki	N-1 switched	Mix of light urban and semi-rural load around Paekākāriki.	4.1	4.7	5.3	5.7	39%

[103] Paraparaumu renamed Paraparaumu East.

11.9.3 Subtransmission and zone substation developments to meet security and capacity requirements

We have undertaken extensive studies into the options for the subtransmission and zone substation development to meet controlled and uncontrolled demand growth. The constraints and proposed solutions presented meet the requirements for controlled demand growth. We discuss the impact of uncontrolled demand growth later in this section.

Constraints—on the subtransmission system and at zone substations

Besides firm transformer capacity at Shannon and voltage constraints limiting available capacity at Ōtaki (when supplied from the North during contingency situations), the zone substations have sufficient firm (i.e., post-contingency) capacity to supply the controlled demand for the next ten years (Table 39). Within the planning period, all substations other than Shannon and Waikanae can support uncontrolled demand growth.

Table 39: Zone substation capacity constraint

Existing Zone Substations	Current security level	Current Firm Capacity (MVA)	Current spare capacity (MVA)	FY31 spare capacity Controlled (MVA)	FY36 spare capacity Controlled (MVA)	Forecast constraint
Shannon	N-1	5.0	0.4	0.2	(0.1)	Power transformer security/capacity constraint from FY34
Foxton	N-1	23.0	15.6	14.7	13.8	No constraint
Levin West	N-1	23.0	8.7	6.7	4.9	No constraint
Levin East	N-1	23.0	7.1	4.9	2.6	No constraint
Ōtaki	N-1	23.0	(0.2)	(1.3)	(2.4)	There is a potential capacity constraint when supplied from the South under contingency conditions. There is a voltage constraint from FY26 when fed from the North. When supplied from the south, Ōtaki is forecast to exceed its minimum voltage limit in FY31 in the event of a Paraparaumu to Waikanae circuit 2 contingency. The Paraparaumu GXP to Waikanae circuit 2 is forecast to exceed its normal operation capacity limit in FY30. Additionally, Paraparaumu GXP to Waikanae circuits 1 & 2 are forecast to exceed their contingency operation capacity limits in FY32.
Waikanae	N-1	23.0	7.5	5.9	4.2	No constraint. The constraint on the cables between the GXP and Waikanae are shown at Ōtaki (i.e. Waikanae is suppled first)
Paraparaumu East	N-1	23.0	9.8	8.3	6.7	No constraint
Paraparaumu West	N-1	23.0	11.7	10.6	9.5	No constraint
Raumati	N-1	23.0	12.1	11.5	10.8	No constraint
Paekākāriki	N-1 switched	5*	0.9	0.3	(0.3)	Marginal constraint for controlled demand in FY36. However, constraint will emerge if Kiwi Rail demand growth occurs The Paekākāriki back-up supply (Z211) is forecast to exceed its contingency operation capacity limit in FY30, should KiwiRail increase demand.

* The 5 MW N transformer is supported by ~5MW of 11kV transfer capacity.

The voltage at Ōtaki will drop below 0.95 pu (33kV) when supplied from the North from FY2026 and below 0.90 pu around FY2035. The current breach in voltage (compared to our planning standard) is minor and can be addressed with more aggressive load control over the next few years. However, voltage support is required within 3-5 years. Longer term, voltage support is required at Ōtaki to maintain voltage at Ōtaki and Peka Peka zone substations in the event of a 33 kV outage from either the northern GXP or from Waikanae in the south.

There are multiple drivers for upgrading sections of low-capacity conductors on the Foxton to Levin West 33kV line and the Levin West to Levin East 33kV line. Capacity on these lines is presently restricted to around 20 MVA, below our standard of 30 MVA. The sections of smaller conductors are in poorer condition than the rest of the line, and risk-based renewal is expected within the planning period.

Table 40: Subtransmission and zone substation constraints

Constraints	Proposed network solutions
Demand at Shannon substation exceed power transformers firm capacity sometime around FY34	Project 1: Transfer demand to Levin West and Foxton using the 11kV network
Foxton to Levin West 33kV line is below standard capacity and the low-capacity sections are of low health. Full capacity from this line will be required within the planning period	Project 2: Capacity upgrade on the last remaining section of Foxton to Levin West 33kV line
Levin East to Levin West 33kV line is below standard capacity and the low-capacity sections are of low health. Full capacity from this line will be required within the planning period	Project 3: Capacity upgrade on the last remaining section of Levin West to Levin East 33kV line
Low 33kV voltage occurs at Ōtaki when supplied from Levin from FY26. It is also forecast that Otaki will exceed its minimum voltage limit in FY31 following the Paraparaumu – Waikanae line 2 contingency when supplied from the North.	Project 4: O2NL 33kV ducting in anticipation of future circuit capacity upgrades between Levin East and Ōtaki Project 10: Voltage compensation at Ōtaki substation using 3 x 5 MVAe static synchronous compensators
Both Paraparaumu GXP to Waikanae 33kV circuits are forecast to exceed their capacity limit criteria in FY30 and FY32.	Project 12: We are assessing potential solutions (in concept).

Constraints—on the distribution system that require subtransmission or zone substation solutions

There are five areas where localised demand growth cannot be serviced through augmentation of the 11kV network. These are:

Figure 107: Tara Ika proposed development

- The Tara Ika residential and commercial development. Tara Ika is a 420ha block of land to the east of Levin. It is privately owned by several parties and has been identified as a key growth area for the Horowhenua District. The development will comprise approximately 2,500 houses (at a range of different section sizes), a small commercial area, new parks and reserves, and education opportunities. Development of the site is expected to commence in CY2025 and be completed by in the mid to late 2030's;
- The O2NL highway development will significantly reduce travel times to Wellington, and land usage near the highway is expected to change. We have recently received significant connection inquiries and applications in the Manakau, Kuku and Ōhau areas. These comprise commercial developments and two residential developments comprising over 300 lots. The extent of these inquiries and applications

indicates that the load growth in the area will exceed the 11kV network capacity. We are expecting constraints to emerge around FY30 (depending on the actual pace of development);

- We continue to see extensive growth in the Peka Peka area and have received significant connection inquiries and applications for the area. Over the next three years, around 400 residential lots will be developed, and a further 1,200 over the long term. The extent of these inquiries and applications indicates that the load growth in the area will exceed the 11kV network capacity. We are expecting constraints to emerge around FY2027.
- A developer has purchased the 28-hectare greenfield block of land on Kāpiti Road between the Kāpiti Expressway and Coastlands Aquatic Centre. Designated as “New Central Park” in the fast-track consent application, the site will likely include over 100 lots of mixed-density residential, commercial, retirement village and retail and will need capacity greater than is available in nearby 11kV feeders;
- KiwiRail has requested an additional 2.4MVA connection for a new traction substation at The Escarpment, south of Paekākāriki. This new connection will require reconfiguration at the substation due to constraints with the existing 11kV bus and headroom of the power transformer.

Table 41: Subtransmission and zone substation constraints

Constraints	Proposed network solutions
New >2,500 Tara Ika residential and commercial development. The development commenced in 2025, with civil work already underway for stormwater ponds and roading.	Project 5: Installation of ducting during site development And Project 6: Tara Ika development new zone substation
The existing 11kV network is forecast to become constrained in Manakau, Kuku and Ōhau around FY30 due to developments following the opening of the O2NL highway.	Project 7: Manakau new zone substation (in concept)
The existing 11kV network supplying Peka Peka is forecast to become constrained by around FY27 due to continued residential growth in the area.	Project 8: Peka Peka new zone substation & 11kV augmentation
The existing 11kV network around Waikanae is forecast to become constrained by FY28 due to continuing residential growth in the region. The 11kV constraints are further discussed in Section 11.10.2.	Project 8: Peka Peka new zone substation & 11kV augmentation will resolve many of the constraints Note: The new feeders from Waikanae zone substation proposed in the 2025 AMP will not proceed as easements could not be obtained. The new feeders will now come from the new Peka Peka zone substation
77 Kāpiti Road development - large proposed mixed-use development	Project 11: Kāpiti Road -new substation (in concept)
The Paekākāriki back-up supply (Z211) is forecast to exceed its capacity limit criteria in FY30, when the KiwiRail load comes online.	This project is defined as a customer connection as the upgrade is for the connection of a new load. Refer to Section 11.13.4.

Proposed network solutions

Figure 108 and Table 42 show our proposed network solutions. We considered a range of development options, and the suite of proposed projects has a low cost to achieve controlled demand growth, and the lowest incremental costs should demand increase above this level (compared to other options). Given the uncertainty associated with future demand, having a low incremental cost to account for demand growth is important.

Figure 108: Subtransmission and zone substation proposed projects

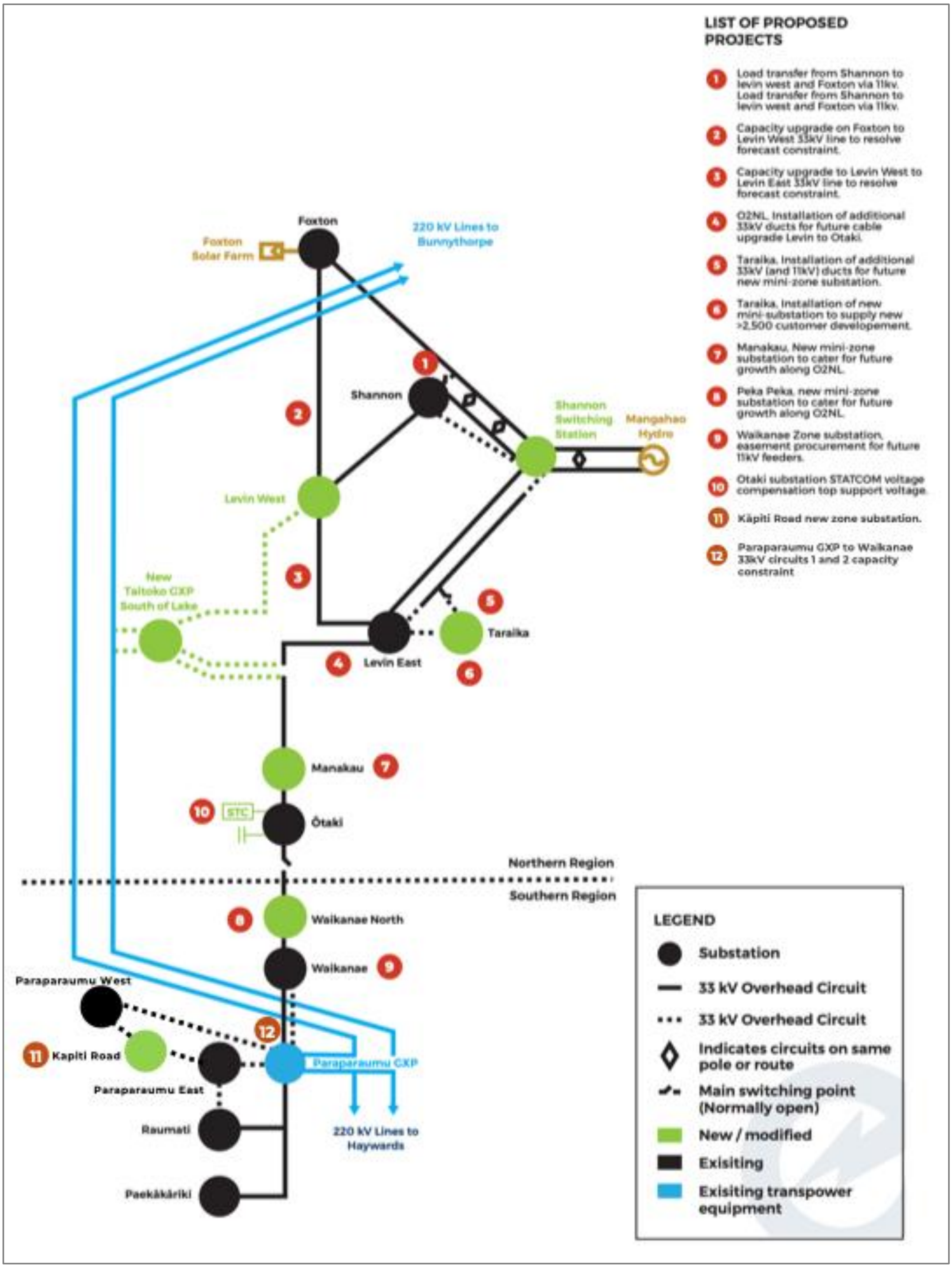


Table 42: Proposed Projects

Project	Driver	Cost/Year	Justification and options considered
1. Transfer demand to Levin West and Foxton using the 11kV network	Capacity	Nil	• This was completed in FY26.

Project	Driver	Cost/Year	Justification and options considered
2. Foxton to Levin West 33kV line • Upgrade 11km of line from Bee to butterfly conductor to achieve full line capacity	Capacity	$3.9m FY31-34	• A section of the existing line has not been upgraded to butterfly conductor. Completing the conductor upgrade is the least cost option to achieve full line capacity, which will be required during the planning period • The timing of the capacity upgrade balances the need for the additional capacity and when the sections of conductor will fall due for risk-based replacement.[104]
3. Levin West to Levin East 33kV line • Upgrade 3.2km of line from Bee to butterfly conductor to achieve full line capacity	Capacity	$2.2m FY30-33	• As above
5. Tara Ika development 33kV (and 11kV) ducting for a new zone substation • Installation of spare ducting in anticipation of future capacity required at Tara Ika	Capacity	$102k[105] FY27-28	• This project is making future provisions for 33kV and 11kV cable installation. Ducting installation during site construction is ~50% cheaper than installation when the development is completed.
6. Tara Ika development new zone substation • New 11.5/23 MVA N-1 switched substation	Capacity	$4.6m FY29-31	• This project will provide new capacity to new customers (>2,500). The current network has insufficient capacity, and a new zone substation is required • To optimise the development, an 11.5/23 MVA ONAN/ONAF transformer will be installed that can later be upgraded to N-1 with the addition of a second transformer and HV bus. Contingent support will use the 11kV network • Different configurations of substation were considered, and an N-1 switched (single transformer) substation is proposed to minimise overall cost
8. Peka Peka new zone substation • New 11.5/23 MVA N-1 switched substation • Rebalancing of feeder currently supplied from Ōtaki	Capacity	$5.8m FY27-29	• Supply using the 11kV network. The 11kV network will not be able to supply the required load over the long term cost-effectively • To optimise the development, a 16/23 MVA ONAN/ONAF transformer will be installed that can later be upgraded to N-1 with the addition of a second transformer and HV bus. Contingent support will use the 11kV network • Different configurations of substation were considered, and an N-1 switched (single transformer) substation is proposed to minimise overall cost
10.Voltage compensation at Ōtaki substation: • 3 x 5 MVAe static synchronous compensators (STATCOM) and switchgear • Enhancing the special protection scheme[106]	Security (To provide voltage support at Ōtaki during contingency situations)	$2.2m FY28-30	The proposed solution has a lower lifecycle cost than the other options considered: • Using 33 kV voltage regulators • Construction of a second 33 kV line in parallel to the existing Levin – Manakau – Ōtaki – Waikanae North – Waikanae line
Total		**$18.9m**	• **FY27-36, System growth capex**

[104] We have defined these projects and system growth, rather than renewal, as the need for standardisation and additional capacity is likely to be in advance of their risk-based renewal.

[105] $156k is planned to be spent in FY26, should this be delayed, it will be spend in FY27.

[106] Extending the existing Special Protection Scheme (SPS) at Ōtaki, used to automatically changeover supply between North and South, to cover automatic changeover for Manakau, Ōtaki, and Peka Peka.

Table 43: Projects under consideration, not yet included in the expenditure forecasts

Project	Driver	Cost/Year	Justification and options considered
4. O2NL 33kV ducting for future use • Installation of spare ducting in anticipation of future capacity and protection upgrades between Levin East and Ōtaki (Infrastructure corridor procurement)	Capacity	$TBC	• Concept discussions underway with NZTA.
7. Manakau new zone substation • Stage 1: Land procurement • Stage 2: Substation build is not yet defined	Capacity	$TBC FY36+	• Supply using the 11kV network. The 11kV network will not be able to supply the required load over the long term cost-effectively • Outside of the AMP planning period
11. Kāpiti Road new zone substation	Capacity	$4.5m FY31-FY33	• Options analysis will be required when more data is available. The developer has not approached Electra regarding their requirements. • Note: a capital contribution will be sought for this project from the developers
12.Project to resolve forecast capacity constraints on Paraparaumu GXP to Waikanae 33kV circuits 1 and 2	Capacity	$TBC FY30-FY32	• The solution to the capacity constraints in under investigation
Total		**~$TBC**	• **FY27-36, not yet included in expenditure forecasts**

Note: There are potential subtransmission projects that are contingent on the Northern GXP. These are discussed in Section 11.8.

11.9.4 Developments to improve resilience

Electra's resilience standard requires all zone substations to meet importance level 4 (**IL4**) under the NZ building code, where it practical and economic to do so. IL4 requires buildings to remain operational after a natural disaster (concerning earthquake, wind and snow structural loading). All zone substations have been assessed against the IL4 standards for seismic, wind and snow. Any site below IL4 has been scheduled for strengthening or demolition. Of the ten zone substations, seven have been strengthened to IL4. These are Ōtaki, Paraparaumu West, Raumati, Shannon, Waikanae, Levin East and Paekākāriki.

In respect to the three remaining substations:

- Foxton substation is due for completion by the end of FY26;
- Paraparaumu East is due for completion by the end of FY26;
- Remediation plans for Levin West have yet to be defined. The draft design has proved to be impractical and uneconomic. We are currently reviewing our options which could include strengthening or establishing a new structure.

We are moving to modular outdoor 33kV switchgear at substations with space for outdoor switchgear (see case study below). The modular outdoor switchgear increases the separation between the two bus sections and enables one bus section to be replaced within approximately one week in the event of a failure. This approach has been adopted following a circuit breaker failure at Shannon substation, which necessitated the replacement of one bus section and breaker, taking several months. To achieve a one-week repair time, a spare circuit breaker module is needed.

Table 44: Proposed projects

Project	Driver	Cost/Year	Justification and options considered
13.Seismic strengthening of Foxton and Paraparaumu East zone substation buildings to IL4	Resilience	$104k[107] FY27	• Strengthening was the least cost option. A complete rebuild was not a viable option.
14.Critical spares. Purchase of 1 x 5 way S&C Vista 33kV circuit breaker to support the outdoor modular switchgear approach	Resilience	$488k FY27	• The purchase of the critical spare supports the move to modular 33kV switchgear at zone substations. • Purchased FY26. delivery likely in FY27
Total		**$592k**	• **FY27, Other reliability, safety, environmental capex**

11.9.5 Developments to meet other drivers

Electra's environmental policy and requirements necessitate that all zone substations be bunded to capture transformer oil in the event of a leak and that the bunding be fitted with oil/water separators. Oil bunding has been installed around all power transformers in service for some time—however, a programme to install oil/water separation units is ongoing. Two of our zone substation bunds use a replaceable oil barrier arrangement. Oil separation units provide a more robust environmental long-term solution and we will replace oil barriers with oil separator units to ensure compliance with our environmental policy.

Table 45: Proposed projects

Project	Driver	Cost/Year	Justification and options considered
15.Foxton substation, oil/water separation unit	Environmental	Completion in FY26[108]	• The project is required to meet environmental requirements. There were no viable alternatives.
16. Shannon substation, upgrade oil bunding for existing critical spare transformer	Environmental	$156k FY27	• The project is required to meet environmental requirements. There were no viable alternatives
17.Peka Peka substation, pad and bunding for critical spare transformer	Resilience Environmental	$300k FY27-28	• Extra bund to store critical spare transformer in more strategic location. The project is required to meet environmental requirements. There were no viable alternatives
18.Obtain designation for all zone substations in the Southern region	Environmental	$112k FY27	• Completion of a programme to obtain designations on our zone substations
Total		**$568k**	• **FY27, Other reliability, safety, environmental capex**

11.9.6 Impact of distributed generation

Two large distributed generators are connected to the network—Mangahao hydro generation (37MW) and at a customer site in Paraparaumu (0.96MW x 2). We have been approached by several large solar and wind farm projects (over 1MW) for potential embedded connections. We encourage these initiatives, aiding them with planning, equipment requirements, load flow studies, congestion determination, and alternative solutions. The proximity of the proposed connections to our subtransmission and zone substation assets has been advantageous in keeping connection costs down and reducing congestion of embedded generation on the distribution network. We have also reviewed our connection and pricing policies and formalised the treatment of transmission rebates for large generators fairly and equitably.

[107] Total project cost is $890k, which is currently $785k in FY26 and $105k in FY27. This spend profile over FY26 and FY27 may change depending on progress in FY26.

[108] The project budget is $120k and due for completion in FY26. Project delays could see some capex incurred in FY27.

11.9.7 Managing demand growth uncertainty

The subtransmission and zone substation development plan has been prepared to meet controlled demand growth. The development plan can be adjusted to accommodate uncontrolled demand growth (should this occur) by bringing forward developments from the FY2037 to FY2050 period into the current planning period. We previously estimated an additional $11.5m of capex for this further planning period (in addition to the concept projects already mentioned in this section). These additional planned developments are primarily on the southern subtransmission network.

11.9.8 Consideration of non-network alternatives

As noted, this development plan was prepared based on controlled demand growth. It incorporates flexibility to shift EV charging and heating of hot water cylinders, and to utilise DERs to support peak demand. We have a programme (the ETR) to build capabilities to access the flexibility market.

We have considered using merchant flexibility (e.g., larger-scale network batteries or other forms of flexibility) to address the identified constraints. At this stage, there are no viable alternatives to the subtransmission solutions proposed for projects 1 to 3 and 10, given the timing and nature of those constraints. Projects 5, 6 and 8 all relate to supplying new developments requiring electricity connection and capacity; hence, there are no viable non-network alternatives.

11.9.9 How we are thinking about the energy trilemma balance

Proceeding with projects 1 to 3 and 10 will increase security and sustainability and have a minor impact on affordability. Although the impacts are minor, we have staged the work to the maximum extent possible to minimise the impacts.

Proceeding with projects 5, 6 and 8 will not impact affordability over the long term, as their incremental cost (per connection) is below the average cost of supplying customers.

11.9.10 Summary of justification for the subtransmission development projects

The capacity-driven projects in this section are required to meet demand from new customers and support future growth in demand from existing customers. This is an essential requirement for Electra.

The resilience and environmentally driven projects in this section are required to ensure that the network meets the relevant standards. Again, this is an essential requirement for Electra.

11.10 Development plan—Distribution

11.10.1 Overview

During the planning period (until the end of FY36), distribution developments are required to meet demand growth and manage reliability risk through selected security-of-supply enhancements, automation, and protection measures. These programmes align with our asset management strategies (as noted in Section 11.2).

This is the most significant development area, costing $26m[109] over the planning period.

[109] Before deducting capital contributions. This includes System Growth, Quality of Supply, and Other Reliability, Safety and Environmental capex.

Most of the development work is focused on capacity augmentation to support growth, reflecting the continued strong connections and inquiries, many of which are now reaching into the Northern region as the O2NL expressway development progresses. The plan includes the development of 11 new distribution feeders.

In the 2025 AMP, we outlined a comprehensive security and reliability risk mitigation programme. We are currently reviewing these programmes and assessing the business case to ensure they balance reliability and affordability consistent with customer expectations. Hence, many of the programmes included in the 2025 AMP are now categorised as "concept" and do not form part of our expenditure forecast. We expect to confirm some additional reliability risk mitigation projects in the 2027 AMP (which will achieve the targets set out in Section 7.3. But the scope of this work will be materially reduced from that included in the 2025 AMP.

11.10.2 Developments to meet capacity and customer requirements

Distribution demand growth and forecast feeder constraints

Significant residential, commercial and industrial developments are occurring across the region. We are also seeing increased connection requests and early-stage inquiries for large developments.

Figure 109 and Figure 110 illustrates the areas of known growth. We are seeing very strong residential development in the Southern region. The increase in residential development has begun in Ōtaki and is now commencing in Manakau, Ōhau and Levin. The increase in residential developments in the Northern region aligns with the progression of the O2NL expressway development . We are also seeing an increase in industrial development in the Northern region, which again is aligned with the O2NL development. This demand growth is consistent with the regional and zone substation demand forecasts in Section 11.7 and Section 11.9.2.

Figure 109: Areas forecast for significant development and load growth, Northern region

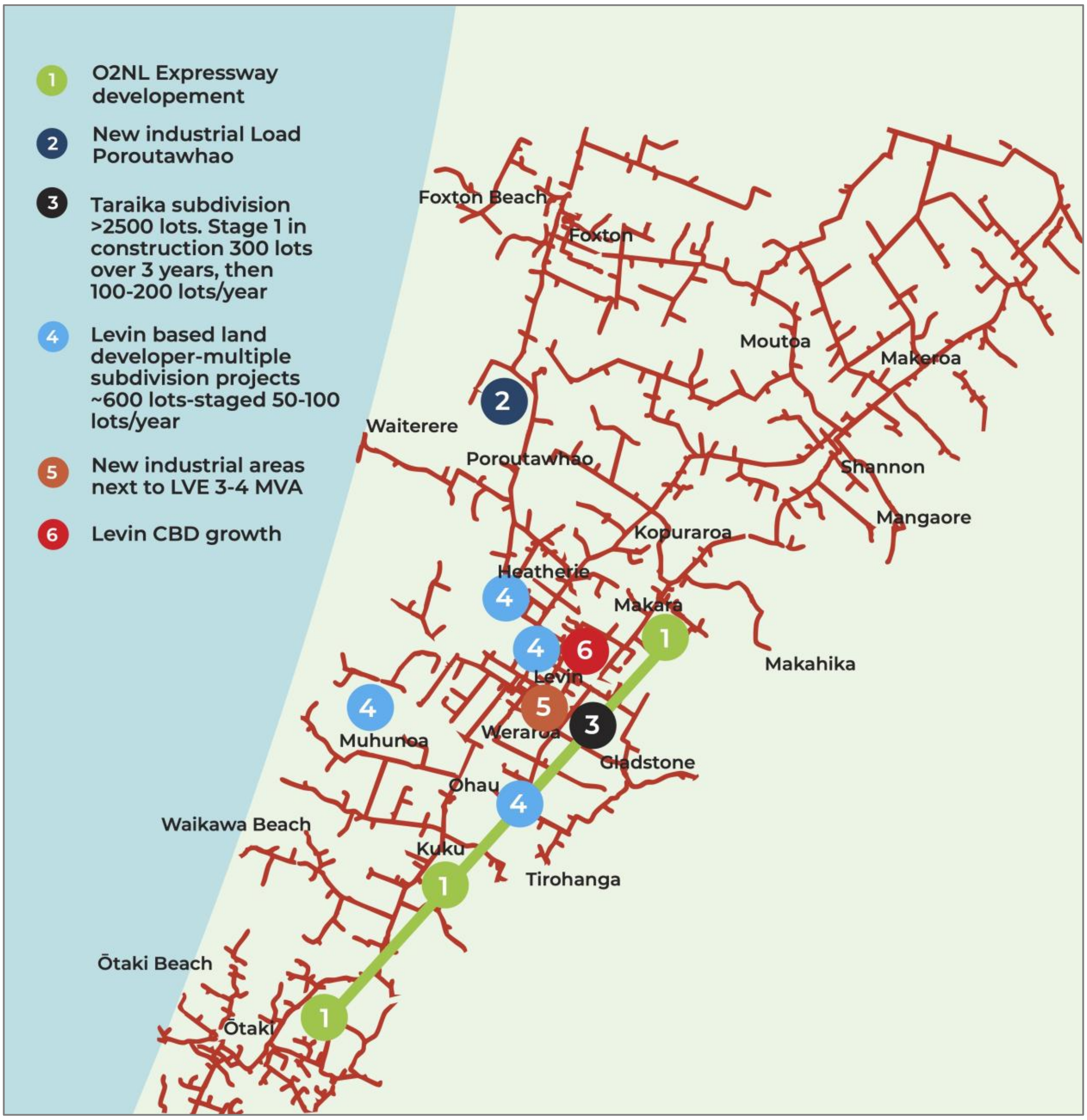


Figure 110: Areas forecast for significant development and load growth, Southern region

Table 46 summarises current and forecast feeder constraints given the known growth areas. We have identified various projects to resolve these constraints.

The demand forecast model indicates that constraints will occur on six feeders between FY26 and FY31 and four between FY32 and FY36. More than 10 feeders are listed in Table 1 as demand growth is more concentrated than our demand forecast model allows (which is an area for improvement in our modelling). Projects are linked to areas where specific constraints have been identified.

Demand growth at Tara Ika, Manakau/Kuku/Ōhau, and Peka Peka/Waikanae North exceeds the firm 11kV network capacity in the area (that is, we do not have sufficient capacity in the network to meet our 11kV security requirements). The sub-transmission and substation development section includes projects catering to this growth (Section 11.9.3).

Table 46: Forecast feeders constraints

Zone substation	Feeder	Constraint	Solution
Levin West	E148	Capacity constraints could emerge due to large industrial load growth at Poroutawhao, North of Levin. Timing is customer dependent.	No specific project as a constraint not yet certain
Levin East	G309, G313	Capacity constraints are forecast due to the Tara Ika development. This is expected to add 2,500 residential and commercial connections and around 8-10 MVA over 10 years from FY26	Resolved via substation development. Refer to Section 11.9.3.
Levin East	G311	Capacity constraint is forecast due to the Tararua Industrial Development Zone. This could add around 4-5MVA over a 3-5 year period from FY27	Project 1
Levin East	G306 G310	There is an emerging constraint in the Levin CBD due to growth in the area	No specific project as constraints are beyond FY30. Refer Project 9.
Levin East Ōtaki	G313, G308 L349	Capacity constraints are forecast due to the growth in Manakau, Kuku, and Ōhau. This includes around 600 residential sections in Manakau and Ōhau and the proposed Muhunoa East golf course	Resolved via substation development. Refer to Section 11.9.3.
Ōtaki	L351	Capacity constraints are forecast due to Ōtaki-Māori racecourse development. The development is expected to add 700+ residential connections and around 2 MVA	Project 3
Ōtaki	L350	Growth is strong in Ōtaki. Feeder L350 has significant customer connections and is forecast to reach planning limits in the next few years. L348 will also likely reach planning limits at the end of the planning period. Demand on both feeders is likely to reach planning limits by the end of the planning period	Project 4
Waikanae	622, 632	This is an area for significant future growth. Capacity constraints are forecast due to the following: • 600+ residential development in Peka Peka • 400+ development in Waikanae North • 400+ development at Manu Park These developments could add 5 MVA of demand.	Resolved via substation development. Refer to Section 11.9.3.
Waikanae	672, 682	There are current constraints in Waikanae North and Waikanae Beach areas and additional developments in the area will increase demand further (in particular, the supply to the 200-300 lot Harakeke development). Feeder 672 already exceeds firm capacity limits.	Project 5
Paraparaumu West	405	A section of lower capacity cable (70mm^2) between transformer W97 and W98 is limiting capacity. KCDC is adding a pumping station on the feeder that will increase demand above firm capacity.	Project 6
Paraparaumu East Waikanae	V311, V318 662	Capacity constraints are forecast towards the end of the planning period due to the 2,000+ lot residential development (Tini farm) at Otaihanga to North Paraparaumu. This could add 8-10 MVA	No specific project as constraints are beyond FY30. Refer Project 9.
Paraparaumu East	V312	Demand growth from the Kāpiti Lights commercial development will result in feeder constraints. The constraints could emerge in FY28.	No specific project as constraints are beyond FY30. Refer Project 10.
Paraparaumu East	V312	Demand growth from 77 Kāpiti Road development, which is a large proposed mixed-use development	Refer to Project 11 (concept) and also the long-term zone substation solution in Section 11.9.3.
Paraparaumu East Paraparaumu West	V311 403	Capacity constraints are forecast to emerge at the end of the planning period. They are driven by a 400+ lot residential development in the area	No specific project as constraints are beyond FY30. Refer Project 9.

Zone substation	Feeder	Constraint	Solution
Paraparaumu West	405	The 405 feeder supplies a large portion of Paraparaumu Beach. This feeder has a mix of residential and commercial customers, including medium-density apartments. It has 1990 ICPs (above the planning criteria), and demand is above firm capacity.	Project 7
Raumati	Z209	The demand on Z209 is above firm capacity, and customer numbers are above the customer number limits.	Project 8
Paekākāriki	Z166	Kiwirail demand growth	Resolved via customer connection (Refer to Section 11.13.4) and zone substation development (refer to Section 11.9.3).

New feeders, feeder augmentations and interconnections to meet capacity requirements

Table 47 describes the distribution developments required to meet capacity requirements. These projects address the constraints identified in the preceding section. These projects comprise six new feeders, one under-rated cable upgrade and ducting installation in anticipation of growth. Based on our demand forecasts, we expect additional feeders will be required over the six specified, and an allowance has been included for this future work. We will identify these additional feeder developments in subsequent AMPs.

Table 47: Proposed projects

Project	Driver	Cost/Year	Justification and options considered
1. New Levin East Feeder G314 to supply Tararua Industrial Development Zone to resolve constraint on G311	Capacity	$1.1m FY27-28	• Existing Levin East feeders G309 and G313 will not have the capacity to cater for the forecast growth from the industrial development zone • G309 and G313 are rated at our standard feeder capacity and cannot be practically upgraded to the extent required. There are no viable alternatives to supply the industrial development zone
2. O2NL 11kV ducting for future use • Installation of spare ducting in anticipation of future capacity south of Levin East substation	Capacity	$208k[110] FY27	• Ducting installation during site construction is around 50% cheaper than installation when the expressway is completed • Significant demand growth is forecast to the south of Levin (Ōhau, Kuku. Manakau), and this project makes a low-cost provision for future growth
3. Additional feeder to offload Ōtaki L351 feeder to enable the supply to the Ōtaki racecourse development	Capacity	$2.2m FY31-32	• L351 will be used to supply the Ōtaki-Māori racecourse development, which will increase demand above its firm capacity. L351 is rated at our standard feeder capacity and cannot be practically upgraded to the extent required • There are no viable alternatives to supply the Ōtaki racecourse development; hence, demand needs to be transferred to make way for supply to the racecourse • The Ōtaki-Māori project is consented; hence, options to delay the new feeder construction are unlikely to be viable.
4. Additional feeder to offload Ōtaki feeders L348 and L350 (some of the route will be shared with Project 3 to reduce costs)	Capacity	$1.0m FY30-33	• Demand forecasts indicate constraints occurring on both L348 and L350. Given the high growth forecasts in the region (to 2050), a new feeder is required to maintain L348 and L350 within firm capacity and customer connection limits. • The project is forecast beyond the next five years; there may be an opportunity to delay this feeder construction by 1-2 years if growth is slower than anticipated.

[110] Commeced in FY26, with a total budget of $312k.

Project	Driver	Cost/Year	Justification and options considered
6. Cable replacement between W97 & W98 on Paraparaumu West feeder 405	Capacity	$374k FY28-29	• There is an increase in load due to a new pump station. There are no viable alternatives to upgrading the cable to ensure firm capacity is maintained.
7. New 11kV 401 feeder to supply central Paraparaumu to offload feeder 405, which has demand above current capacity	Capacity	Due for completion in FY26[111]	• Due to the strong growth across the region, there are no options to transfer load to other feeders • Feeder 405 is currently above firm capacity and customer number limits; hence, there are no options to defer the project.
8. New 11kV feeder to offload Raumati feeder Z210. Z210 will then be used to offload feeder Z209	Capacity	$871k FY28-29	• We have modelled a range of solutions, and the least cost option was to transfer the load from Z210 to a new feeder and then transfer the load from Z209 to Z210. Building a new feeder to directly support Z209 was more expensive.
9.Augmentation of an additional seven feeders, FY30-FY35	Capacity	$17.4m FY31-36	• Our demand forecast indicated constraints will occur on 12 feeders over the planning period. Specific projects exist for six feeders (above). We have included an estimate for augmenting a further six feeders over FY31-36. The cost is based on the average feeder cost in this table.
Total		**$23.2m**	• **FY27-36, System growth capex**

Table 48: Proposed under consideration

Project	Driver	Cost/Year	Justification and options considered
5. New 11kV Waikanae Beach feeder to supply the Harakeke Heights development and to balance load on adjacent feeders	Capacity	~$5.6m FY28-29	• Feeder 672 is already above firm capacity, and an additional feeder is required to enable the supply to the Harakeke Heights development • Options to rebalance demand across adjacent feeders are not available, and options to delay the construction of the new feeder further are not possible • Note: A customer contribution is being proposed for this project, which will materially reduce the cost to Electra.
10.Additional 11kV feeder from Paraparaumu East for capacity augmentation to the Kāpiti Lights commercial area on Kāpiti Road.	Capacity	$TBC FY28	• Our modelling suggests that this is the least cost project to meet the demand requirements. • We considered using capacity in existing feeders, offloading onto adjacent circuits, an additional 11kV feeder from Paraparaumu West Zone Substation; however, these options had technical or cost issues. • Note: a capital contribution will be requested for this project.
11. 77 Kapiti Road development, 11kV connection for the first 1 MW	Capacity	~$521k FY28	• The remaining development will be supplied by a new mini-zone substation. • Note: A customer contribution is being proposed for this project, which will materially reduce the cost to Electra.
Total		**$TBC**	• **Not currently included in our expenditure forecasts**

11.10.3 Developments to meet security requirements

Distribution feeder security and reliability constraints

We have been analysing the network to determine areas where it does not meet our security and reliability standards (i.e. where a constraint exists). The areas where we currently (or are forecast to) breach our planning criteria are shown in Table 49. These mainly relate to:

- Breaches of the maximum number of ICPs between switching points or a on feeder;
- Feeders with asset performance issues where security can be improved through interconnections to adjacent feeders;

[111] This project has a budget of $2.2m planned for FY26. Due to some delays there will be some carryover into FY27.

- Customer numbers being about feeder limits.

By way of background, in the early stages of the residential developments in the Southern region, 11kV switches and interconnections were only installed in key locations. At the time, demand for the feeders was low, so the absence of switches and interconnection points was not a material breach of the planning standards. As demand and customer numbers have grown, the load between switching points has increased, and a program of interconnections and switch installations is now required.

Table 49: Forecast feeder constraints

Zone substation	Feeder	Constraint	Solution
Foxton	C4	This feeder is approaching customer number security limit	Project 19
Levin East	G308 G313	Feeder G308 supplies the Hokio area and ranks in the top 10 worst-performing feeders. Feeder G313 supplies the adjacent Kimberly areas and ranks just outside the top 10 worst-performing.	Project 23 (Concept)
Levin East	G305	This feeder is approaching customer number security limit	Project 19
Levin East	G306	This feeder is approaching customer number security limit	Project 25 (Concept)
Levin West	E150	Security of supply to Waitārere Beach is below network requirements. This spur has >1.5MVA of demand and 1074 ICPs, which is well in excess of the security limit	Project 24 (Concept)
Levin West	E151	This feeder is at the customer number security limit	Project 25 (Concept)
Ōtaki	L349	Feeder L349 supplies the Manakau area and ranks as the worst performing feeder. There is a single supply into Manakau village This feeder is also approaching customer number security limit (>300 customers on a switched segment)	Project 12
Ōtaki	L348 L351	L351 is the 9th and L348 is the 7th ranked worst performing feeder. The Mill Rd area includes OH & UG network that are below security requirements These feeders are also approaching customer number security limit (>300 customers on a switched segment)	Project 14 Project 15
Ōtaki	L350	Feeder L350 is the 3rd worst performing feeder. Te Rauparaha St includes network that are below security requirements This feeder is also approaching customer number security limit (>300 customers on a switched segment)	
Ōtaki	L352	This feeder is above the customer number security limit (>300 customers on a switched segment)	Project 25 (Concept)
Waikanae	670	This feeder is above the customer number security limit (>300 customers on a switched segment)	Project 25 (Concept)
Waikanae	662	This feeder is approaching the customer number security limit (>300 customers on a switched segment)	Project 25 (Concept)
Paraparaumu East	V317	There is a residential spur (Milne Rd) on the feeder that is below security requirements (>300 customers on a switched segment)	Project 16
Paraparaumu East	V318	This feeder is above the customer number security limit (>300 customers on a switched segment)	Project 25 (Concept)
Paraparaumu West	404	There are two residential spurs (Regent Drive) on the feeder that are below security requirements (>300 customers on a switched segment)	Project 22 (Concept)
Paraparaumu West	402	This feeder is above the customer number security limit (>300 customers on a switched segment)	Project 25 (Concept)
Paraparaumu West	405	This feeder is significantly above the customer number security limit (>300 customers on a switched segment)	Project 25 (Concept)
Raumati	Z211	The area around QE Park (Jeep Rd) includes OH and UG network that is below security requirements (>300 customers on a switched segment)	Project 21 (Concept)

Zone substation	Feeder	Constraint	Solution
Raumati	Z209	This feeder is above the customer number security limit	Project 19
Paekākāriki Paraparaumu East	Z167 V313	The Waterfall Rd to Valley Rd area includes OH & UG network that falls below security requirements (>300 customers on a switched segment)	Project 18

Interconnections to meet the security of supply requirements

The projects in Table 50 resolve the constraints mentioned in Table 49. Projects 12, 14 and 15 will mitigate reliability risk on several feeders in the Levin and Ōtaki areas that are currently performing poorly. Projects 16 and 18-22 will enhance the security of supply of the distribution network, which is necessary to ensure network reliability over the long term.

We are assessing several other security-related projects listed in Table 51.

Table 50: Proposed projects

Project	Driver	Cost/Year	Justification and options considered
12. Ōtaki feeder L349: improve security into Manakau Village 11kV Note: this project has been delayed from FY28 to FY30 due to delays in the O2NL project	Reliability	$630k FY30	• Improve the security to Manakau village by creating an OH ring (L470-L332) on feeder L349. The NZTA expressway will require some reconfiguration at the south-east of the village and enable interconnection via underground cable to Manakau Heights Drive (which reduces the overall cost of this project) • L349 is a poor performing feeder and improving security is necessary to enhance reliability. There are no other viable options available to improve security to the 120 customers in the village.
14. Ōtaki: installation of additional circuits to connect feeders L351 and L348	Security	$349k FY32	• The project requires two connections between Anzac Road to Carkeek Drive and Haruātai Park to Millhaven Place • Both L351 and L348 are poor performing feeders and reliability riks needs to be reduced. This project offers a low-cost security improvement. There are no alternative projects that can improve security (and reliability) at lower cost.
15. Ōtaki, feeder L350: installation of switchgear and an interconnection to feeder L348	Security	$491k FY33	• This project involves installation of switchgear at M139, M143, M194, M149 and to reconfigure the open points to feeder L348 to improve security • L350 is a poor performing feeder and improving security is necessary to enhance reliability. There are no other options available to improve security.
16. New interconnection between Raumati feeder Z209 and Paraparaumu West feeder V317 to resolve security issues on Milne Rd spur and increase interconnection between Raumati and Paraparaumu	Security	$363k FY27[112]	• The project involves cable connection and switchgear between transformers W468 and Z50. • The proposed interconnection is the least cost option to resolve security issues on feeder V317.
18. Interconnection between feeder Z167 and V313 to connect spurs between Waterfall Rd to Valley Rd	Security	Planned completion in FY26	• There are 3 sections of 11kV line required to interconnect feeder Z167 (Paekākāriki) and V313 (Raumati South) to resolve security issues • The proposed interconnection is the least cost option to resolve security issue to >470 customers

[112] Project is underway. Total project cost is $1.1m. $365k is the estimate for work in FY27.

Project	Driver	Cost/Year	Justification and options considered
19. Feeder customer number rebalancing with adjacent feeders	Security	Nil	• This relates to Feeders C4, G305, Z209
20. Unspecified interconnections to support the security of supply	Security	$1.5m FY29-36	• Funding for a continuation of the programme to provide interconnections between feeders to meet security of supply requirements in future years.
Total		**$3.3m**	• **FY26-35, Quality of supply capex**

Table 51: Projects under consideration (these projects are not currently in the expenditure forecasts)

Project	Driver	Cost/Year	Justification and options considered
21. Raumati South feeder Z211 QE park interconnect project: Jeep Rd to transformer Z9, Raumati South 11kV underground ring	Security	$572k FY28	• Project to interconnect Raumati South feeder Z211. GWRC have request us to move our lines in the park so the timing of this project will depend/align with negotiations and requirements of GWRC • The proposed interconnection is the least cost option to resolve security issue to >340 customers. • Project justification is being assessed.
22. Paraparaumu West feeder 404 interconnection to resolve a security issue. Cable installation between W494 and W502	Security	$365k FY28	• This project involves installation of 200m cable and switchgear between transformer W494 and W502 to enhance security (and remove the two spurs). • The proposed interconnection is the least cost option to resolve security issues on feeder 404. • Project justification is being assessed.
23. Levin East: install an interconnection between feeders G308 and E153 to mitigate reliability risk	Security	$448k FY28-29	• An interconnection between these feeders will enhance security and provide additional backfeeding options to assist in fault restoration. The gap between the feeders is ~200m • G308 and E153 are poor performing feeders and risk mitigation is required. This project offers a low-cost security improvement. There are no alternative projects that can improve security (and reliability) at lower cost. • Offloading L349onto Manakau mini-sub • Project justification is being assessed.
24. Security/resilience improvements to the Waitārere Beach line from SH1	Security	$TBC	• Resolving the security is a complex issue. We are currently considering two options: (a) Increasing the resilience of the existing line, which has sections built close to the road carriageway; (b) Non-network solutions. • The resilience option has a high cost and while it will materially reduce vehicle damage risk it does not resolve the security issues. Non-network solutions are yet to be fully assessed. • Project justification is being reviewed.
25. Consideration of options to resolve customer number limit on feeders	Security	$TBC	• This relates to feeders G306, E151, L352, 670, 662, V318, 402, and 404
Total		**~$TBC**	• **Not yet included in the expenditure forecasts**

New ground-mounted switches to meet the security of supply requirements

Currently, the distribution network has one of the lowest ground-mounted switch densities in New Zealand (refer to Section 3.5.3). The current situation reflects how the original network was rolled out in the Southern region. Consequently, the network does not meet our security of supply standard (having no more 300 ICPs on a switched segment) in many areas. While faults on the underground network are rare, when they do occur, having sufficient switching points allows for quicker network restoration and avoids lengthy repair-time outages. As the network ages (refer to Sections 5.4 and 5.5), the risk of cable faults increases.

Hence, it is now timely to undertake a switching point installation programme on the underground network. Table 52 outlines the two programmes that address the issue.

In the 2025 AMP, we included a $11.2m ground-mounted switch programme. As mentioned in the introduction to this section, we are presently reviewing the scope and justification for our switching enhancement programme. A revised and cost-benefit justified programme is being considered for the 2027 AMP.

Table 52: Projects under consideration (these projects are not currently in the expenditure forecasts)

Project	Driver	Cost/Year	Justification and options considered
30. RMU installation to split daisy-chain transformers between switching points	Security	$TBC	• The current network configuration breaches the planning criteria in may areas of the Southern region. The intention of this programme is to splits the daisy-chained transformers between switching points. Priority will be given to older network areas with three or more transformers between switching points • The justification for this programme is being reviewed and a revised programme is being considered for the 2027 AMP
31. RMU installation during GM transformer renewals	Security	$TBC	• The current network configuration breaches the planning criteria in may areas of the Southern region. The intention of this programme is to install RMU when ground- formers are renewed. continuously. • The justification for this programme is being reviewed and a revised programme is being considered for the 2027 AMP
Total		**$TBC**	• **Not yet included in the expenditure forecasts**

11.10.4 Developments to mitigate reliability risk

In the 2025 AMP, we outlined our strategy to manage reliability risk. The reliability risk mitigation programmes encompassed increasing automation on rural and urban feeders and improving lightning protection. We are reviewing these programmes and assessing the cost-benefit justification, and we may include a programme of additional reliability risk mitigation projects in the 2027 AMP.

Network automation and sectionalisation enhancements

As feeder customer density increases, the number of customers at risk of interruption from any single fault increases. To mitigate this risk, we are considering network automation to:

- Reduce the number of customers exposed to any single fault (by increasing the use of feeder sectionalisation)
- Increase interconnection points between feeders to enable greater restoration by switching (and few customers on the faulted section of line).

In the 2025 AMP, we included a $4.7m programme for overhead network automation and a $3.7m programme for underground network automation. We have retained these programmes in this AMP, but in the concept phase (so they are excluded from our expenditure forecasts). We are in the process of reviewing the justification for the automation programmes to ensure that they provide the appropriate reliability vs. cost (i.e. affordability) benefit. We intend to ensure these programmes are consistent with the reliability risk management being considered in Section 7.3. The revised programmes will focus on our worst-performing feeders or those that exceed our planning criteria (either >1,500 domestic customers or 5 MVA of commercial load). In relation to the overhead network (projects , our focus is likely to on Ōtaki feeders, and others in the Northern region. In relation to the underground network, the focus is on larger feeders in the Southern network.

Table 53: Projects under consideration (these projects are not currently in the expenditure forecasts)

Project	Driver	Cost/Year	Justification and options considered
1. Overhead network switch automation (new and existing sites)	Reliability	$TBC	• This programme would consist of new enclosed and automated switches to replace existing air-break switches and for new sites. The sites selected would be based on the worst-performing feeder but also consider the expected number of operations and travel times • The justification for this programme is being reviewed and a revised programme is being considered for the 2027 AMP
2. Underground network automation (new and existing sites)	Reliability	$TBC	• This programme consists of the automation of new and existing sites where automation can materially reduce outage times and reduce operating costs • The justification for this programme is being reviewed and a revised programme is being considered for the 2027 AMP
Total		**$TBC**	• **Not yet included in the expenditure forecasts**

Network protection enhancements

The reliability vs. cost benefit of the lightning protection programme (that was included in the 2025 AMP) has been reviewed. Our assessment indicates that the risks are infrequent and do not justify a mitigation programme. Hence, we have removed this programme for the AMP.

11.10.5 Developments to meet resilience and other requirements

Work on our resilience strategy has only recently been completed. We have not defined any resilience-related projects on the distribution network in this AMP. Further work is being undertaken over the next year, including additional analysis of vehicle damage incidents and high-traffic areas to assess options to reduce vehicle damage risks. We are expecting an increase in resilience-related projects in future AMPs.

11.10.6 Developments to meet future needs

This is an area for future work. Additional modelling work is suggested in our Energy Transformation Roadmap, which may lead to additional work to enhance hosting capacity, manage voltage variance (from bi-directional power flows), manage harmonics or enable flexibility services on the distribution network.

11.10.7 Justification for the development projects

Capacity projects

The capacity development projects in Table 47 amount to $23.3m. This is a significant programme due to the extent of the demand growth we are seeing on the network. The capacity-driven projects are required to meet demand from new customers and support future demand growth from existing customers. This is an essential requirement for Electra, for which no feasible alternatives exist.

Reliability risk mitigation projects (via security, reliability and automation)

We are currently reviewing the justification for our reliability and automation projects. Our previous analysis (in the 2025 AMP) indicated that resolving security issues in Ōtaki and Levin (listed in Table 50) could mitigate unplanned reliability by around 1.5 SAIDI minutes. Our initial assessments suggest that additional reliability risk projects could mitigate an additional 5 to 7 SAIDI minutes. We have yet to evaluate whether the reliability-versus-affordability trade-off is acceptable. Nevertheless, these benefits align with the forecasted reliability risk mitigations shown in Section 7.3.

11.10.8 Managing demand growth uncertainty

The distribution development plan has been prepared to meet controlled demand growth. Distribution developments have a relatively short planning horizon and are generally easier to plan and execute. Hence, there is no need to accommodate uncontrolled demand growth. Should the uncontrolled demand occur, additional capacity-related distribution development projects will be required.

11.10.9 Consideration of non-network alternatives

As noted, this development plan was prepared based on controlled demand growth. It incorporates flexibility to shift EV charging and heating of hot water cylinders, and to utilise DERs to support peak demand. Given the pressing need to meet new demand and resolve security issues, we are not proposing to use merchant flexibility as a non-network alternative for the projects proposed for FY27 and FY28, as the market and our ability to call on this flexibility are not yet sufficiently mature. However, the use of merchant flexibility will be explored for projects beyond FY28 in subsequent AMPs.

11.10.10 How we are thinking about the energy trilemma balance

The capacity-related projects enhance affordability as the LRMC[113] to serve new demand is lower than the current average cost to serve existing customer demand. That is, in real terms, the average cost to serve a MW of demand (or customer) is lower when new demand and system growth capex is included (compared to new demand and system growth capex being excluded).

However, this affordability improvement will be offset by the impact of costs associated with security- and reliability-related risk mitigation projects. However, the security- and reliability-related capex will reduce reliability risk. Hence, the net impact is likely to be modestly favourable on affordability with an increase in reliability. This balance will shift more towards reliability when the additional reliability risk initiatives are included.

11.11 Distribution transformer and LV developments

11.11.1 Overview

This section describes the distribution transformer and LV development plan. The development plan is consistent with prior years and includes programmes to:

- Upgrade distribution transformers capacity due to growth;
- Install links, interconnections and extensions on the LV cable to resolve capacity, voltage and security issues

11.11.2 Distribution transformer developments to meet capacity and customer requirements

We have an ongoing programme to upgrade distribution transformer capacity in response to localised growth. We monitor the demand on our ground-mounted distribution transformers using the MDIs installed

[113] LRMC stands for Long-Run Marginal Cost. In the context of electricity networks, LRMC refers to the additional cost incurred to supply one more unit of demand over the long term, taking into account the investment in new infrastructure and ongoing operational expenses. It is used to assess the economic viability of capacity expansion and helps determine whether serving new demand is more cost-effective compared to existing average costs. Essentially, LRMC provides an estimate of the future costs associated with system growth and is important for planning network investments and maintaining affordability for customers.

in the LV cabinet or our online power quality monitors (see 11.11.4). Where we identify that demand is reaching the name-plate capacity, we will schedule an upgrade of the transformer.

The programme is based on the historical upgrade rate. In 2021, we undertook some initial studies on the performance of distribution transformers in response to the energy transformation (for both controlled and uncontrolled demand growth). In either scenario, we are unlikely to see a wholesale need to upgrade our distribution transformer fleet, as the transformers are sized for an ADMD of 3.5 kVA (well above our current ADMD). Hence, future upgrades will continue to be driven by localised issues.

Table 54: Proposed projects

Project	Driver	Cost/Year	Justification and options considered
Ground-mounted transformer upgrades due to growth	Capacity	$1.7m FY27-36	• This programme allows the upgrade of three ground-mounted distribution transformers annually.
Total		**$1.7m**	• **FY27-36, System growth capex**

11.11.3 LV developments to meet capacity, security and voltage requirements

We have ongoing programmes to install new LV links and extend or modify the low-voltage cable network. We have identified a programme to add LV links to enable load transfers to meet voltage, capacity, or fault-restoration needs. We also have a reactive programme to extend or modify the LV cable network in response to voltage or capacity issues, or to enhance security through interconnections with other LV circuits.

These programmes are based on historical upgrade rates; however, we may see the number of LV cable extensions or modifications increase towards the back end of the planning period. In 2021, we undertook some initial studies on the performance of the LV network in response to the energy transformation (for both controlled and uncontrolled demand growth). If uncontrolled demand growth is observed, we could see constraints on 30-40% of our LV circuits at the end of the planning period. If controlled demand growth occurs (which is our current planning case), these constraints will likely emerge from around FY39, beyond the end of the current planning period.

Table 55: Proposed projects

Project	Driver	Cost/Year	Justification and options considered
Installation of LV links to connect LV cable circuits	Security Voltage Capacity	$1.1m FY27-36	• This is a planned programme to add LV links to better load transfers to meet voltage, capacity or fault restoration needs
Extensions or modifications of the LV cable network	Voltage Capacity Security	$1.5m FY26-35	• This is a reactive programme to extend or modify the LV cable network to address voltage, capacity or reliability needs
Total		**$2.5m**	• **FY27-36, Quality of supply capex**

11.11.4 Developments to meet resilience needs

Work on our resilience strategy was completed only recently. We have not defined any resilience-related projects on the LV network in this AMP. Further work is being undertaken over the next year, including additional analysis of vehicle damage incidents and high-traffic areas to assess options to reduce vehicle damage risks. We are expecting an increase in resilience-related projects in future AMPs.

11.11.5 Developments to meet future network needs

In FY2026, we completed our programme to install power quality meters on 20% of our distribution transformer fleet. We have no other work planned in this area. Additional modelling work is suggested in our Energy Transformation Roadmap, which may lead to additional work to enhance hosting capacity, manage voltage variance (from bi-directional power flows), manage harmonics or enable flexibility services on the LV network.

11.11.6 Justification for the development projects

The distribution transformer and LV development capex are driven by capacity or voltage constraints. We must maintain voltage within regulatory limits.

11.11.7 Managing demand growth uncertainty

The distribution transformer and LV development plan have been prepared to meet controlled demand growth. Distribution transformer and LV developments have a short planning horizon and are generally easier to plan and execute. Hence, there is no need to accommodate uncontrolled demand growth. Should the uncontrolled demand occur, additional capacity-related distribution development projects will be required.

11.11.8 Consideration of non-network alternatives

As noted, this development plan was prepared based on controlled demand growth. Our controlled demand forecasts incorporate flexibility to shift EV charging and heating of hot water cylinders, and to utilise DERs to support peak demand. We have a programme (the ETR) to build capabilities to access the flexibility market.

At this stage, we have not considered merchant flexibility (e.g., larger-scale network batteries or other forms of flexibility) to offset the augmentation of distribution transformers or LV capacity. However, this will be explored further in subsequent AMPs.

11.11.9 How we are thinking about the energy trilemma balance

The capacity-related projects enhance affordability as the LRMC to serve new demand is lower than the current average cost to serve existing customer demand. That is, in real terms, the average cost to serve a MW of demand (or customer) is lower when new demand and system growth capex is included (compared to new demand and system growth capex being excluded).

11.12 Other network assets

11.12.1 Overview

Other network assets include protection, communication, ripple control plants and SCADA. This section deals with the first three. SCADA is covered in operational technology in Sections 8 and 9.

11.12.2 Communication system

The communication link upgrades increase the resilience of our SCADA communication network as these new routes provide an alternative path for SCADA communication and protection system operations. Upgrading of communication links between substations is required to allow line differential functions and associated advanced protection strategies to be implemented.

Integrating optical fibre into our communication infrastructure offers significant benefits, particularly in terms of resilience, reliability and speed of operation enabling advanced protection functionality. Unlike traditional copper or wireless systems, fibre optic cables are immune to electromagnetic interference, power surges, and lightning strikes, which are common threats in power distribution environments. This inherent immunity drastically reduces the risk of communication outages during adverse weather or electrical faults, ensuring continuous data flow for grid management.

Furthermore, the physical robustness of fibre cables makes them highly resistant to environmental degradation and physical tampering. Their large bandwidth capacity also means that the communication network can handle vast amounts of data without degradation, providing stable and high-speed connectivity crucial for real-time monitoring, smart grid applications, and fault detection systems (high speed differential protection schemes). This enhanced reliability translates directly into more efficient operations, reduced downtime, and improved service delivery to customers.

Table 56: Proposed projects, communication systems

Project	Driver	Cost/Year	Justification and options considered
1. Fibre installation between Waikanae ZS to Paraparaumu East	Resilience	$623k[114] FY27	• See Section 11.12.6 • Electra considered both leased fibre and installing our own, which utilises existing assets to run fibre across our network. Installing our own fibre was chosen as leased fibre is third party managed and utilises shared infrastructure which results in application limitations and no long-term guarantee of access. Microwave radio is already in use across Electra's communications network and was not considered for the purposes of protection improvements as fibre has a much larger bandwidth.
2. Fibre installation between Waikanae and Waikanae North	Resilience	$938k FY28-29	
3. Fibre installation between Waikanae North and Ōtaki	Resilience	$656k FY28-29	
4. Fibre installation between Ōtaki and Levin East	Resilience	$2.2m FY29-32	
Total		**$4.4m**	• **FY27-36, Quality of supply capex**

11.12.3 Protection system

Recent technical review of protection

In 2021, we undertook a comprehensive study of our subtransmission protection system. The study followed several spurious protection trippings caused by mutual coupling. Mutual coupling occurs when two or more power lines are close together and can affect the power system's selectivity, reliability and safety. The issues exist where we have 33kV and 11kV circuits on the same poles, which often occurs around zone substations. The report indicated that the potential risks to the network are high, including the possibility of widespread network loss of supply. While many risks have a lower probability of occurring, in some cases, the outcomes should such risks occur can be severe. For example, a network fault that isn't cleared has obvious safety risks due to a permanently energised primary equipment fault but may also result in severe and widespread equipment damage, such as damage to long lengths of overhead lines.

The report also noted that the existing 33 kV line protection schemes have become increasingly unfit for purpose as Electra has interconnected the network. In addition to having significant known protection performance limitations, the existing schemes limit the network's operational capabilities. Upgrading the protection system is considered a high priority.

[114] Project commenced in FY26. Total project cost is $700k

The report proposed a roadmap to improve the primary and backup protection schemes for various asset classes based on cost, risk and performance. Electra agreed with the recommendation and is proceeding with the roadmap.

Developments to manage reliability risk (subtransmission)

Table 57 shows the projects associated with the protection roadmap (projects 5 to 7). The upgrading of the relays (that deliver broadly the same functionality) is covered in the *balance of plant* fleet plan as the relays assets are also at end-of-life. The protection roadmap involves:

- Line protection replacement on all Electra 33 kV lines (covered in the fleet plans);
- Adding 33 kV busbar protection (in Table 57).

Upgrading communication links between substations is required to enable the implementation of line differential functions and associated advanced protection strategies (Table 56).

Table 57: Proposed projects, protection

Project	Driver	Cost/Year	Justification and options considered
5. Levin West substation protection upgrade, including new bus-zone protection	Reliability	$1.1m FY30-31	• See Section 11.12.7 • No other option available except for risk acceptance
6. Levin East substation bus-zone and Line differential protection upgrade Note: This project include the replacement of the 33kV line project relays and introduction of a bus zone scheme (refer Table 98)	Reliability	$1.3K FY28-29	• See Section 11.12.7 • No other option available except for risk acceptance
7. Bus zone projection optimisation at Paraparaumu East and Raumati	Reliability	Completion in FY26	
Total		**$2.3m**	• **FY27-36, Quality of supply capex**

Developments to manage reliability risk (distribution)

The case study below describes our distribution protection enhancements. Tripsaver units have been installed on several feeders that have experienced repeated faults. We are currently reviewing the justification to continue the programme (refer to Table 58), balancing managing reliability and the impact on affordability.

CASE STUDY ON TRIP SAVERS

The protection programme also includes the installation of Tripsavers on spur lines with repetitive nuisance faults. Three units have been installed at sites that had issues with nuisance faults in 2022. The three sites averaged 16 outages a year together; since the installation of Tripsavers, the number of faults has dropped to three in FY23.

Tripsaver in closed and open position

The majority of overhead faults are transient from either storms, vegetation or wildlife. Older protection schemes used traditional fuses with the resulting time to restoration for crews attending site and replacing the fuse. Tripsavers have the operational characteristic of a fuse but reclose up to 3 times before dropping open. Using this we can restore remote spurs faster reducing outage times for customers.

Table 58: Projects under consideration (these projects are not currently in the expenditure forecasts)

Project	Driver	Cost/Year	Justification and options considered
8. Install trip-saver on the worst-performing feeders	Reliability	$TBC	• This project is part of our integrated approach to addressing the performance of our worst-performing feeders
Total		**$TBC**	• **Not yet included in the expenditure forecasts**

11.12.4 Ripple Control

The existing ripple injection plants cannot cover the entire network in the event of a plant failure. Installing a third in the centre of the existing network will allow for continued ripple control during faults. Being able to control demand is necessary as this is the basis for our demand forecasts used throughout this development. However, alternatives to traditional ripple control are evolving in the market. Market flexibility solutions will likely become available to supersede traditional load control. For this reason, we have not yet committed to this project. It will remain in the concept phase until we can be more confident that the plants will not be stranded by other technology or that other technology will become viable.

In the 2025 AMP, we were planning to enhance our spares holdings for the ripple plant. We have since had further discussion with our supplier and are now comfortable that we can rely on our support contract with them. No additional spares will be purchased.

Table 59: Projects under consideration (these projects are not currently in the expenditure forecasts)

Project	Driver	Cost/Year	Justification and options considered
10. Additional ripple control plant	Security	$TBC	• Alternatives to traditional ripple control are evolving in the market. Market flexibility solutions will likely become available that will mitigate the need for an additional ripple plant
Total		**$TBC**	• **Not yet included in the expenditure forecasts**

11.12.5 Developments to meet future needs

We have no other work planned in this area.

11.12.6 Justification for the communication projects

The expansion of the fibre network is a strategic initiative aimed at managing network resilience and reliability, and enabling advanced protection functionality. This programme upgrade will provide the necessary communication medium to implement line differential protection (an advanced scheme for fault detection and isolation), enhancing the security of our subtransmission network. Furthermore, the new fibre optic routes will establish a crucial diversity of communication mediums, mitigating the risk of widespread communication failure and ensuring operational continuity during major network events. In particular, this enhanced resilience and reduces the reliance on our microwave links for SCADA communications. This investment is integral to future-proofing the network and maintaining safety and service levels.

11.12.7 Justification for the protection projects

The 33kV protection programme is being undertaken to mitigate High Impact Low Probability (**HILP**) events associated with a material protection failure. Due to the low probability of these failures, we have not evaluated the programme from an economic standpoint (as the economic cost of low-probability events is low when considered on an annualised basis). The annualised cost of the programme is $370k, which is low compared to the economic cost of a significant subtransmission outage, which could quickly run into the millions.

The trip-saver programme justification is currently under review.

11.12.8 How we are thinking about the energy trilemma balance

Refer to Section 7.8.

11.12.9 Development plan expenditure forecasts

Table 60 to Table 63 summarise the development plan capex by expenditure category.

Table 60: Subtransmission and zone substation development plan capex (Real $000)

Item	FY27	FY28	FY29	FY30	FY31	FY32	FY33	FY34	FY35	FY36	Total
System Growth	2,141	2,659	2,621	3,286	2,821	2,294	2,298	731	-	-	18,851
RSE (environmental)	889	270	-	-	-	-	-	-	-	-	1,160
Total	**3,031**	**2,929**	**2,621**	**3,286**	**2,821**	**2,294**	**2,298**	**731**	**-**	**-**	**20,010**

Table 61: Distribution development plan capex (Real $000)

Item	FY27	FY28	FY29	FY30	FY31	FY32	FY33	FY34	FY35	FY36	Total
System Growth	208	316	2,075	104	3,161	5,183	3,416	2,892	2,899	2,899	23,153
RSE (quality of supply)	363	-	208	833	208	557	491	209	209	209	3,289
Total	**571**	**316**	**2,284**	**937**	**3,370**	**5,740**	**3,908**	**3,100**	**3,109**	**3,109**	**26,443**

Table 62: Distribution transformer and LV development plan capex (Real $000)

Item	FY27	FY28	FY29	FY30	FY31	FY32	FY33	FY34	FY35	FY36	Total
System Growth	167	168	168	168	168	168	169	168	169	169	1,683
RSE (quality of supply)	42	42	329	329	329	329	121	330	331	331	2,511
Total	**209**	**210**	**497**	**497**	**497**	**498**	**290**	**498**	**499**	**499**	**4,194**

Table 63: Other network asset development plan capex (Real $000)

Item	FY27	FY28	FY29	FY30	FY31	FY32	FY33	FY34	FY35	FY36	Total
RSE (quality of supply)	623	1,192	1,888	1,417	947	640	-	-	-	-	6,706

There is currently no forecast capex for GXP developments. These projects are in the concept phase.

11.13 Customer connections

11.13.1 New connections forecasts

We connected 500 new residential, commercial, and industrial electricity customers in FY2025. We forecast that the number of new connections will increase over the coming decade, which aligns with the Council's population growth predictions (see Figure 111 below and Section 5.2).

We also expect to see an increase in DER connections (Figure 112), with more of these containing batteries and thus able to offer flexibility services. The proportion of DERs with batteries is expected to grow from 25% in FY2024 to nearly 50% in FY2035. Many of these DERs are being connected to existing customers.

Figure 111: Forecast new connections

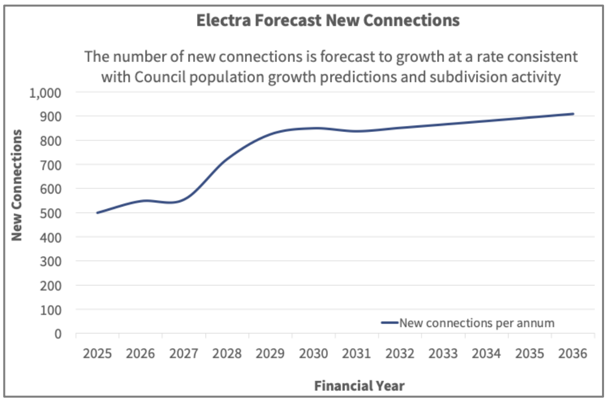
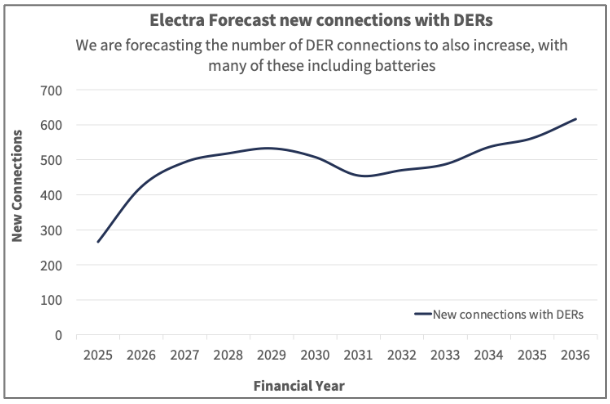


Figure 112: Forecast new connections with DERs



11.13.2 Connection process

Current connection process

Electra's connection process is shown in Figure 113 and is contained on our website.[115] The connection process is arranged between the customer and various approved contractors and applies to new connections, alterations and distributed generation.[116]

Figure 113: Electra's current connection process

• The customer makes a connection request to one or more pre-approved contractor	• The contractor prepares a design for the connection and submits to Electra for approval	• Electra reviews the design and assesses the network for constraints • Where additional upstream work is required, this is advised to the contractor • Electra approves the design when all issues are resolved	• The contractor updates the design and re-submits to Electra as required • When the design is approved, a quote is provided to the customer	• The customer accepts the quote • Electra may provide a contribution to the cost of the project based on its Network Extension Policy	• The contractor builds the new connection and advises Electra when it is ready to connect	• The connection process is arranged with the contractor • New ICPs are created vis the standard registry process • The Network Purchase Agreement is signed between Electra and the Customer, then • payment of any contribution is made to the customer

Note: The process is simplified, and no design approval is required, where a standard new connection is made to an existing service pillar within a new subdivision.

For residential and commercial customers, the connection is arranged via an approved contractor, and any associated connection costs are payable by the customer (hence, we have no forecast customer connection capex).

For connection of new subdivision developments, network upgrades to connect large customers, or line extensions required to connect rural properties, these are undertaken by an approved contractor. The customer pays the entire cost of the developments, upgrades, and extensions, and then vests the network assets to Electra. We have a legacy contribution model that is used to determine the payments made to customers for new connection assets. This calculates the net present value of the new connection (of the new revenue and new costs, including the return on, and of capital). We have determined standard payments for subdivisions based on the number of new lots being developed.

Electra's payments to customers are recognised as vested asset payments. We anticipate that they will increase in line with the growth in new connections. This process is outlined in the Electra Network Extension Policy.[117]

This connection process is also applied to distributed generation. However, there are some other connection requirements and the connection costs are applied consistent with the Electricity Code requirements.[118] The additional requirements for distributed generation is provided on our website.[119] Also, refer to Section 11.4.8.

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[115] https://electra.co.nz/getting-connected/

[116] Electra has three primary approved contractors (Electra service delivery, Connetics, Scanpower) for large-scale connection work. There are another two approved contractor who undertake small standard connections to existing LV assets (where no changes to the network are required.

[117] https://electra.co.nz/our-company/disclosures/

[118] Part 6 of the Electricity Industry Participation Code 2010.

[119] https://electra.co.nz/services/distributed-generation/

We operate a competitive process (primarily between the customer and our approved contractors) for new connections. This ensures that customers pay the efficient cost of connecting to the network (less the payment made by Electra).

New connection process from April 2026

During FY26 we have been preparing to make changes to our customer connections policy, processes, capital contribution calculation, and methodology. We recognised that an update to connections process would provide us with closer understanding of connections projects at the initiation stages, feeding into our long term planning. It would also allow us to make an equitable calculation and sharing of the costs and benefits with our customers when the connect to our network.

These changes are also timely as from 1 April 2026, the Electricity Authority is mandating changes to the new connection process. Under these changes, we will be required to adopt standardised connection procedures and report on connections timelines.

The significant change for us will be that we now become the primary contact for customers (rather than approved contractors). This process will also change how we recognise and calculate capital contribution costs, moving away from the vested assets model.

From 1 April 2026, we will recognise customer connection capex and capital contributions (refer to Table 65).

The revised connection process introduces defined service levels for processing connection applications, with set timeframes for each stage—such as initial response, design approval, and final connection. There will also be a requirement to make information about load and injection constraints more accessible, ensuring that stakeholders have the necessary details to plan their projects effectively.

The Electricity Authority's guidelines are intended to support a more competitive and customer-focused connection environment, aligning with broader industry objectives for improved network access and efficient infrastructure development. These changes will be reflected in Electra's updated policies and procedures from April 2026 onwards, with further details available on our website and through direct communication with the network development team.

11.13.3 How we assess the impact of new demand, generation or storage capacity on the network

We presently assess the impact of new demand, generation, or storage capacity on a case-by-case basis using load flow modelling. In our energy transformation roadmap, we have a work activity to better understand network constraints and hosting capacity (refer to Section 10.5). The process involves:

- Initial communication to ascertain the requirements of the site;
- Application submitted to Electra. This may be an application under Part 6 of The Code for distributed generation and/or storage, or a new connection application alongside an electrical network design;
- Application considered by the network planning team for compliance & safety, and approved or declined;

The exception to the above is for single residential customer connections that meet specific criteria, e.g. no network extension, construction or additional assets are required to connect the customer.

During the design approval process, we evaluate the network for constraints and inform the approved contractor of any additional upstream work needed. The approved contractor will then update the customer about the constraints and required upstream work. Depending on the scale of the new connection, we may conduct load flow studies to examine constraints and possible solutions. Our target turnaround for design approval is ten working days. For larger and more complex connections where network constraints are present, this process may take longer as we discuss the constraints and potential solutions with the contractor. These solutions could involve flexibility (i.e. customer demand response to limit coincident demand to avoid network constraints).

We do not actively publish details on load or injection constraints in the network (at sub-transmission, distribution, or LV levels). This information is provided to contractors (who then pass it on to customers) as needed. For large, complex connections, we usually meet with both the customer and the contractor to discuss the constraints and potential solutions.

For new loads arising from developments of any size, we use a standard ADMD of 3.5kVA for residential and 10kVA for commercial sites, unless a higher ADMD is requested or indicated by the developer. Large capacity new connections are advised by the customer, and assessed using engineering software to ascertain potential impacts of the connection on the existing network infrastructure, including thermal, voltage, location/distance to the site and available network capacity at all levels.

For large distributed generation enquiries, we operates a capacity queue. Although we are not currently constrained for generation, a large connection enquiry may exceed the available capacity in either our northern or southern regions.

Timing and uncertainty play a part in any new connection or development, and we rely on the connecting party to advise on any delays on their side that may affect the timing of the new connection. We ask for site staging plans to informing when and where capacity is required throughout the life of the project. Our design approvals give one year to begin site works (with extension possible) before they expire, to prevent stalled developments from blocking newcomers.

11.13.4 New large demand connections

We are currently working with KiwiRail to secure a new connection for a traction substation south of Paekākāriki . This will enable larger, more frequent trains on the electrified Metlink Kāpiti line (Wellington to Waikanae). An additional 2.4 MVA of capacity is needed, requiring upgrades at the Paekākāriki Zone Substation. This is a conceptual phase project being scoped and designed in FY26.

Table 64: Projects under consideration, not yet included in the expenditure forecasts

Project	Driver	Cost/Year	Justification and options considered
Paekākāriki capacity upgrade of 2.4 MVA	Capacity	$TBC FY27-FY28	• We are presently considering options for a 33kV solution at $3-4m, or a 2nd transformer and 11kV supply at $4-5m • Note: A capital contribution will apply to the project
Total		**$TBC**	• **FY27-36, not yet included in expenditure forecasts**

11.13.5 Expenditure forecasts

Our expenditure forecasts for new connections are shown in Table 65. These forecasts reflect the change from vested asset to customer connection capex, with an offsetting capital contribution.

Table 65: Customer connections (Real $000)

Cost	FY27	FY28	FY29	FY30	FY31	FY32	FY33	FY34	FY35	FY36	Total
Customer connections	2,294	2,987	3,410	3,514	3,463	3,521	3,578	3,638	3,698	3,759	33,861
System growth associated with customer connections	1,530	1,991	2,274	2,342	2,309	2,347	2,386	2,425	2,465	2,506	22,574
Less: Capital contributions	(2,294)	(2,986)	(3,411)	(3,514)	(3,464)	(3,521)	(3,579)	(3,639)	(3,699)	(3,760)	(33,866)
Total	**1,530**	**1,991**	**2,273**	**2,342**	**2,309**	**2,347**	**2,385**	**2,424**	**2,464**	**2,504**	**22,570**

11.14 Asset relocations

Electricity network assets often require relocation due to impacts from land or other infrastructure development. We fund the relocation work and receive a capital contribution equal to the cost of the work. We often use this opportunity to augment the network or install a spare duct, which we pay for (this explains the difference between the capex and capital contributions in Figure 112).

We typically are only aware of asset relocations a year or two in advance. The known projects are:

- Asset relocations associated with the O2NL expressway project. There is currently a pipeline of 20 areas where our assets will be impacted (some of which have yet to be fully scoped and included in the forecasts below);
- GWRC requested relocation of 11kV overhead lines through QE park;
- Asset relocations related to a subdivision in Waikanae North.

Table 66: Asset relocations (Real $000)

Cost	FY27	FY28	FY29	FY30	FY31	FY32	FY33	FY34	FY35	FY36	Total
Asset relocation capex	1,944	1,136	521	-	-	-	-	-	-	-	3,601
Less: capital contributions	(1,916)	(1,011)	(511)	-	-	-	-	-	-	-	(3,439)
Total	**28**	**125**	**10**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**163**

12. Asset Lifecycle Management (Fleet Plans)

12.1 Introduction

This Section describes our asset lifecycle management. It deals with the asset lifecycle beyond its development (which is described in Section 11).

Fleet plans outline the steps throughout an asset's lifespan to ensure it delivers the required performance at the lowest overall lifecycle cost.

As more of our assets approach end-of-life, we have increased our focus on asset lifecycle management and made a number of improvements aligned with our asset management strategy.

In this Section, we cover:

- How this section aligns to policy and strategy;
- Our approach to asset lifecycle management, as it relates to fleet plans;
- Planning approach and standards used for fleet planning;
- The approach to assessing asset health;
- Detailed fleet plans for our material asset classes;
- High-level fleet plans for other asset classes;
- Our vegetation management plan.

The comprehensive fleet plans are the key improvement visible in this Section. We have also continued to improve our asset data and condition data and better target renewals. The incorporation of the latest condition data and adjustments to asset nominal expected lives (to reflect Electra's specific asset performance) are the main drivers for the changes in our asset health assessments and renewal forecasts.

12.2 Alignment to our asset management policy and strategy

Our fleet plans support the asset management policy in the areas of:

- Maintaining and managing our network assets at defined levels to enable the safe, efficient and effective delivery of electricity to our customers
- Establishing asset operating, maintenance and replacement strategies to ensure our assets support the services required and minimise the total lifecycle costs, including through extending the useful life of assets
- Considering the economic, environmental and cultural impact of our business and finding an appropriate balance between them.

The asset management strategies in Section 6.3 include two initiatives concerning our asset lifecycle plans. This included:

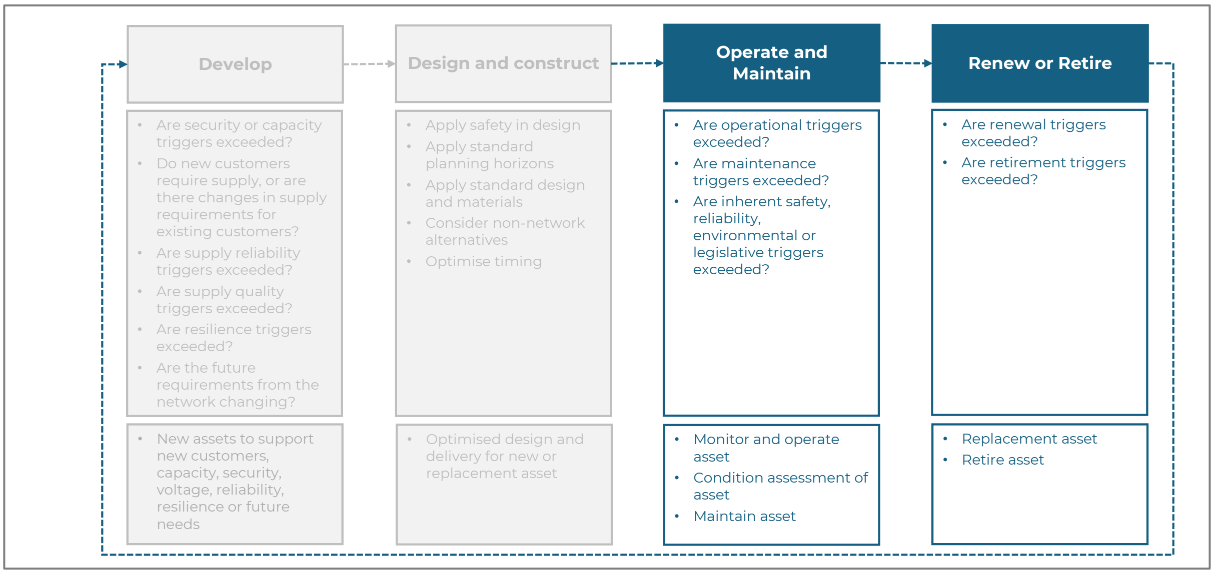
- **#3 Implement comprehensive fleet plans and renewal forecasts:** The actions relate to defining fleet plans and strategies, condition assessments, health and renewal forecasting, and targeting renewals in areas where health is deteriorating. We have incorporated the actions from this initiative within the fleet plans;
- **#4 Continuously manage reliability risk and resilience:** The actions relate to better targeting our vegetation management activities. The other actions from this initiative are covered in Section 11.

This Section gives effect to these policy aims, strategic initiatives and actions.

12.3 Asset lifecycle management (fleet management)

We manage our assets throughout their lifecycle using the process shown Figure 114. In this section, we discuss the *operate and maintain* and *renew or retire* phase. A description of the *development* and *design and construct* phase is provided in Section 11.3.

Figure 114: Asset Lifecycle



12.3.1 Operate and maintain

The *operate and maintain* phase covers the operation of the assets, ongoing condition assessment, corrective and preventative maintenance, and any emergency response in relation to the assets. The purpose of this phase is to ensure the safe and reliable performance of an asset over its expected life.

12.3.2 Renew or Retire

The *renew or retire* phase covers deciding when to renew or retire assets. Typically, the decision to renew an asset is made in response to:

- Increasing asset risk (which is a combination of asset health and criticality). The actual replacement of the assets is subject to a detailed assessment of the asset condition and criticality;
- Deteriorating reliability performance;
- Safety and integrity concerns;
- Technical or operational obsolescence;
- The economics of ongoing maintenance (compared to replacing with a modern equivalent asset).

Disposal of the asset occurs when the asset is removed from service and cannot be redeployed or reused.

12.4 Planning approach and standards used for fleet planning

12.4.1 Condition-based asset risk management modelling

We utilise a Condition-Based Asset Risk Management Model (CBARMM) to forecast asset risk and renewals. The model is based on the DNO Methodology.[120] CBARMM models have been developed for all network assets. These models apply a risk-based, information-driven approach to asset renewal forecasting.

The DNO Methodology provides industry-specific guidance for quantifying individual asset risk by evaluating an asset's health and criticality. An asset's health is calculated as its probability of failure, and its criticality is calculated as its consequence of failure. Thus, asset risk is calculated as the product of probability and consequence of failure.

Whilst the principles and the key calculations of the DNO Methodology were adopted in developing CBARMM, the inputs and calibration parameters were customised to align with our environmental and operating conditions.

The CBARMM models provide a systematic, data-driven methodology to identify asset renewal needs and enable us to evaluate overall asset fleet risks based on different renewal, refurbishment or maintenance scenarios.

An overview of the CBARMM process is shown in Figure 115. It consists of three main elements:

- **Health assessment:** This process involves determining the health of an asset based on various inputs. Under the DNO Methodology, asset health is defined using a health index and health index bands (HIB1 to HIB5). The probability of failure (**PoF**) is determined for the individual assets based on the individual health indices and the performance of the asset class. The PoF calculation forms an important relationship in the methodology between the health indices of individual assets and the performance of the asset class. This relationship between an asset's health and PoF is shown in Figure 116. The CBARMM model allows the future health of an asset to be calculated, given the aging of the asset.
- **Criticality assessment:** This involves assessing the consequences of failure (**CoF**) for each asset class across four categories: safety, network performance, financial, and environmental. Each of these is quantified in monetary terms on an asset class basis and then specified for each asset by considering the importance of the asset in its location. CoF remains static over time.
- **Risk assessment:** The probability and consequences of failure of an individual asset are combined to quantify risk. This is the product of the asset's PoF and CoF.

The health assessment inputs include nominal expected life, location, duty, asset age, operations, reliability, and condition inputs. Location factors are principally used to assess the impact of the coastal environment on an asset's expected life. Duty factors are used where equipment loading can impact an asset's expected life. The number of operations (typically under fault conditions) is used where this has an impact on the condition of the assets over time.

[120] Ofgem, "DNO Common Network Asset Indices Methodology—Version 2.1", April 2021.
This is a common framework of definitions, principles and calculation methodologies published by Ofgem and adopted by all GB Distribution Network Operators for the assessment, forecasting and regulatory reporting of asset risk.

The reliability factor is applied to an asset class based on the asset's performance history and experience in managing and operating the asset. It is used to identify if there are any generic issues that affect health associated with the make and type or construction of the asset.

Condition inputs include those that are observed (through inspections) and those that are measured (through standardised testing). The health score is modified depending on the condition based on the approach defined in the DNO Methodology. In Table 70, we have provided our view on how reliable the condition data is in determining the health of an asset.

Figure 115: CBARMM[121]

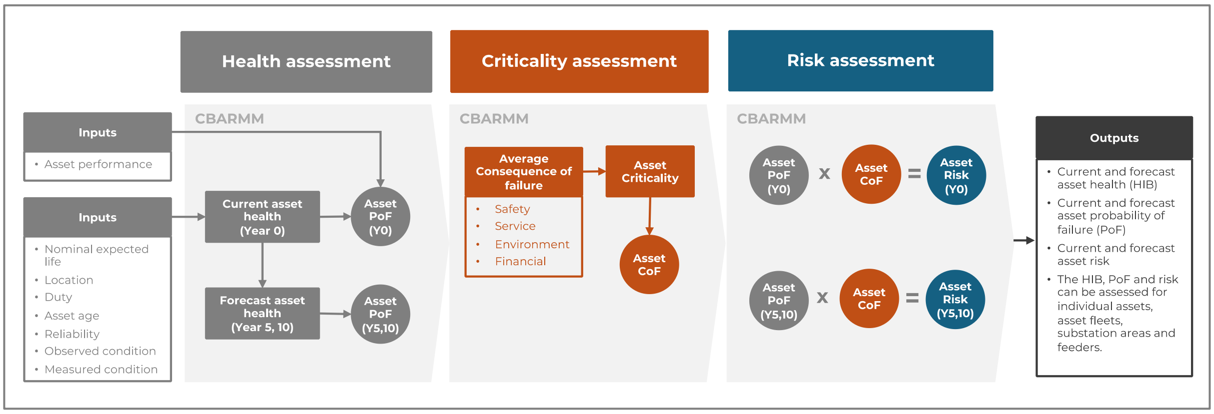
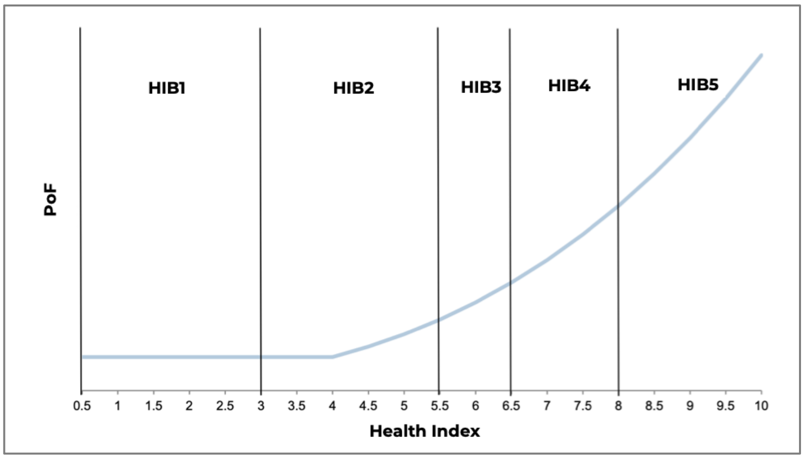


Figure 116: Relationship between asset health and PoF[122]



12.4.2 Asset health standards

CBARMM uses a combination of a nominal (or average) expected life and operational factors to determine the expected life for the asset. The relationship between the asset's age and the expected life determines the initial health index, which is then modified using the asset condition inputs.

An asset's age forms the underlying basis for determining its health (which is modified based on its condition); hence, ensuring quality asset age data is important and has been a key focus for the business.

In this AMP, we describe asset health using the CBARMM health index bands, which are mapped to the EEA and Information Disclosure asset health scores (refer to Table 67).

121 This is a simplified version of various figures included in the DNO Common Network Asset Indices Methodology.

122 Ofgem, "DNO Common Network Asset Indices Methodology—Version 2.1", April 2021. Figure 3.

Table 67: CBARMM Asset Health Index Bands to EEA and Information Disclosure Asset Health Scores

CBARMM health Index band	CBARMM health index	Description	EEA and ID health score
HIB1	≥0.5 to <4.0	**As new condition:** no drivers for replacement	H5
HIB2	≥4 to <5.5	**Serviceable condition:** no drivers for replacement, normal in-service deterioration	H4
HIB3	≥5.5 to <6.5	**Emerging health risks:** End-of-life drivers for replacement emerging, asset-related risks are increasing above serviceable condition	H3
HIB4	≥6.5 to <8	**Increasing health risks:** End-of-life drivers for replacement present – high asset-related risk	H2
HIB5	≥8	**End of life:** End-of-life is imminent, replacement recommended	H1

12.4.3 Asset criticality standards

In this AMP, we describe asset criticality using the CBARMM criticality index bands (which are the same as the DNO Methodology), which can be mapped to the EEA criticality scores (refer to Table 68).

CBARMM uses a combination of nominal (or average) expected life and operational factors to determine the asset's expected life. The relationship between the asset's age and expected life determines the initial health index, which is then modified using the asset condition inputs. An asset's age forms the underlying basis for determining its health (which is modified based on its condition); hence, ensuring quality asset age data is important and has been a key focus for the business.

Table 68: CBARMM Asset Criticality Bands to EEA Asset Criticality Scores

CBARMM criticality index band	Description	EEA criticality scores
C1	**Low criticality:** Credible consequences of failure are broadly tolerable, and run to failure may be a valid strategy	C4
C2	**Average criticality:** Asset failure would cause some disruption and inconvenience, but systems are already in place to anticipate and manage the outcomes	C3
C3	**High criticality:** Asset failure would cause significant harm to people, assets, the business or the environment. The consequences are tolerable but should be avoided or mitigated if it is practicable to do so	C2
C4	**Very high criticality:** The credible consequences of failure would generally be unacceptable	C1

12.4.4 Asset risk standards

Risk gradings are not explicitly defined in the DNO methodology. We have also adopted the risk grading and definitions from the EEA (refer to Figure 117 and Table 69). The EEA grades reflect how we manage asset risk. The risk grades include a tolerable risk rating where run-to-fail may be acceptable (which is common practice for small distribution transformers and fuses where asset health is difficult to determine).

Figure 117: Asset risk matrix

	HIB1	HIB2	HIB3	HIB4	HIB5
C4	RG3	RG3	RG5	RG5	RG5
C3	RG2	RG2	RG4	RG4	RG5
C2	RG2	RG2	RG2	RG4	RG5
C1	RG1	RG1	RG1	RG1	RG1

Table 69: CBARMM Asset Risk Ratings

CBARMM risk grades	Description	EEA risk grades
RG1	**Acceptable risk:** Low consequences of failure and increased failure rates or running assets to failure are tolerable, depending on the asset class. Proactive interventions are based on efficiency considerations.	RG5
RG2	**Low risk:** Typical asset in the useful life phase. Asset to be monitored and maintained	RG4
RG3	**Medium risk:** Healthy but very high critical assets. Appropriate monitoring of the assets is required, and interventions are required to minimise health deterioration.	RG3
RG4	**High risk:** A combination of criticality and health indicates elevated risk. Appropriate intervention is required within a reasonable timeframe, provided current risks can be prudently managed in the interim.	RG2
RG5	**Intolerable risk**. Deteriorating asset health. Immediate intervention is required.	RG1

12.4.5 Operational, maintenance, inherent safety, reliability and environmental legislative triggers

Operational, maintenance, inherent safety, reliability, environmental, and legislative triggers are defined for each asset class within the fleet plans. Safety, reliability, environmental, and legislative triggers relate to issues inherent in the asset class, not network related issues. Network related issues are discussed in the development section (refer to Section 11).

12.4.6 Renewal and refurbishment triggers

Specific renewal and refurbishment triggers are discussed in each fleet plan.

In general terms, Electra classifies work as renewal if there is no change (usually an increase) in functionality (i.e., the output of any asset does not change). The key criteria for triggering a renewal or refurbishment are:

- Asset health and asset risk;
- Technological obsolescence;
- When operating and maintenance costs exceed the renewal cost.

Safety, reliability, environmental, and legislative triggers may also result in renewal.

12.4.7 Retirement triggers

The general criteria for retiring an asset include:

- Its physical presence is no longer required usually because a consumer has ceased demand;
- It creates unacceptable risk exposure, either because its inherent risks have increased over time or because safe exposure levels have reduced. Assets retired for safety reasons are not re-deployed or sold for re-use;
- Where better options exist to deliver similar outcomes, and there are no suitable opportunities for re-deployment;
- Where an asset has been upsized, and no suitable opportunities exist for re-deployment;

Safety, reliability, environmental, and legislative triggers may also result in retirement.

Our group policy on “Asset Lifecycle and Waste Disposal” identifies the following principles when disposing of waste materials and end-of-life assets:

- Consider the all-of-life impact in the design, procurement and implementation of the asset:
- Support central, regional and local government environmental commitments;
- Encourage suppliers to minimise waste and take responsibility for the waste that is generated;
- Protect the company and employees from accusations or acts of fraudulent behaviour associated with disposal;
- Seek to maximise the usable life of the asset and encourage re-purposing before disposal by recycling, with treatment as waste as a last resort.

12.4.8 Planned improvements

During FY2024 and FY2025, we completed a program of work to improve asset attributes and age data. These are key inputs in determining the asset's initial health score.

We are currently undertaking a program to review our condition assessment standards to ensure that we capture the necessary observed and measured condition inputs to enable an accurate asset health assessment (this is an action under asset management strategy #3). This work is included in the asset management improvement roadmap (refer to Section 9.3).

We are progressively improving the data inputs used in CBARMM. Our future work includes:

- Using duty (e.g. loading) as input for power transformer and circuit breaker health assessment;
- Using joint data as input for conductor and cable health assessment;
- Using the number of fault operations as input for ABSs, reclosers and circuit breaker health assessment;
- Using observed condition as input for recloser health assessment.

We are also constantly reviewing survival statistics to ensure that the nominal expected life for the assets is consistent with the materials and equipment used by Electra and its operating and environmental conditions.

12.5 Summary of our approach to determining asset health, renewal forecasts and renewal projects

Table 70 summarises how we determine asset health and asset renewals and define specific renewal projects. Additional details are included in the fleet plans. Our approach to assessing health and forecasting renewals varies based on the quality of our data and the ability to obtain reliable condition data that can be used to predict asset health. Presently, for some assets, it is difficult to obtain condition data (e.g. for buried assets, where significant outages are required to inspect the equipment or where material samples need to be removed) or where condition data can only provide a broad indicator of asset health.

Table 70: How we are determining asset health, asset renewals and specific renewal projects

Asset fleet	Quality[123] of asset age data	Quality of asset condition data and reliability[124] to predict health	How we determine asset health	How we forecast asset renewals	How we determine renewal projects
Power transformers	Very good	Very good quality and a reliable health predictor	CBARMM, using age, location, condition, duty and operations	CBARMM risk grade	Projects are defined following detailed assessment (initiated based on risk grade)
Zone substation switchgear	Very good	Very good quality and a reliable health predictor	CBARMM, using age, location, duty and operations	CBARMM risk grade	Projects are defined following detailed assessment (initiated based on risk grade)
Zone substation buildings and structures	Very good	Very good quality and a reliable health predictor	Interpretation of building assessment report and structure condition data	Projects identified in building assessment report and structure condition data	Projects identified in building assessment report and structure condition data
Secondary systems	Very good	Good quality and an indicative health predictor	We apply a nominal expected life to avoid technological obsolescence.	CBARMM risk grade	Health (technological obsolescence)
Overhead structures (poles and crossarms)	Good. Some gaps in pre-1995 data. Projects have been completed to improve data.	Good quality and a reasonable health predictor	CBARMM, using age, location, condition and reliability data	CBARMM risk grade, adjusted for the most recent condition assessments	Most recent condition data and risk grade
Conductor	Very good for subtransmission and good for distribution and LV	Average quality and an indicative health predictor	CBARMM, based on age, location and reliability Condition and joints are not current used	CBARMM risk grade, adjusted for recent asset reliability	Subtransmission conductor projects are based on health and risk assessment. Distribution conductor projects are based on reliability or defects
Cables	Good	Partial discharge condition data is only available for subtransmission. Other condition data relates to terminations, which is not a reliable indicator of asset health	CBARMM, based on age and reliability Condition and joints are not current used	CBARMM risk grade, adjusted for known asset reliability issues	For subtransmission we initiate projects based on asset condition For distribution and LV cables we initiate projects based on reliability or defects
GM distribution switchgear	Good	Good quality and a reasonable health predictor (where partial discharge and SG6	CBARMM, based on age, location, reliability and condition	CBARMM risk grade	Projects are defined based on asset condition and risk grade

123 Data quality grading is consistent with the data accuracy definitions included in Section 8.5. These are: **Very good**, which means a data accuracy score of 4; **Good**, means a score of 3; **Average**, means a score of 2; **Poor**, means a score of 1.

124 We have applied a grading in respect of how reliable condition data is at predicting asset health. This assessment is based on the condition assessments applied at Electra. These are: **Reliable**, which means that there is a strong body of evidence to support the relationship between asset condition and health; **Reasonable,** which means there is reasonable evidence to support the relationship between asset condition and health; **Indicative**, which means the relationship between asset condition is either difficult to assess (using the standards currently applied by Electra), or only provides a broad indicator of health

Asset fleet	Quality[123] of asset age data	Quality of asset condition data and reliability[124] to predict health	How we determine asset health	How we forecast asset renewals	How we determine renewal projects
		leak tests are available)			
GM distribution transformers	Good	Good quality and a reasonable health predictor	CBARMM, based on age, location, reliability, condition	CBARMM risk grade	Projects are defined based on asset condition and risk grade
PM reclosers	Good	Good quality and a reasonable health predictor (where partial discharge is available)	CBARMM, based on age, location, reliability Operations and condition are not currently used	Current renewal forecasts are based on recent inspection and operational data. This approach is being reviewed	The replacement programme is being revised
PM air-break switches	Good	Average quality and an indictive health predictor	CBARMM, based on age, location, condition and reliability Operations are not currently used	CBARMM risk grade	Current projects are based on asset-type issues and asset condition
PM drop-out fuses and links	Average	No reliable condition data. The current line inspections drive the defect process	CBARMM, based on age and location	Based on historical replacement rates	No specific projects identified. Renewal coordinated with other projects or initiated from defects or fault
PM distribution transformers	Good	Good quality and a reasonable health predictor	CBARMM, based on age, location, reliability and condition	CBARMM risk grade	For large PM transformers projects are defined based on asset condition and risk grade No specific projects identified for small PM transformers where renewal coordinated with other projects or initiated from defects of fault
Underground connections (LV pillar and link boxes)	Good	Good quality and an indicative health predictor	CBARMM, based on age, location and condition	CBARMM risk grade, adjusted for known condition	Specific projects are defined from the most recent inspections. Assets in high-risk areas are prioritised.
Overhead connections	Data is no maintained for these assets. No renewal forecasts or projects are prepared. These assets are replaced in conjunction with other projects or on failure				

12.6 Summary of risk and renewal plan for our asset fleets

12.6.1 Movement in Schedule 12a asset health

There has been movement in the asset condition scores in Schedule 12a as shown in Figure 118 and Figure 119. The material changes in relate to:

- Power Transformers, where we have adopted a transformer age index model (TAIM) to assess the biological age of our fleet, which provides a more accurate reflection of the fleet health;

- A reduction in wood pole and recloser health based on the most recent condition data;
- An increase in the crossarm health, reflecting current data and the aging of the fleet;
- A reduction in pole-mount transformer fleet, where we have increased the nominal expected life of this fleet to reflect how the fleet is performing.

Figure 118: Movement subtransmission asset current health

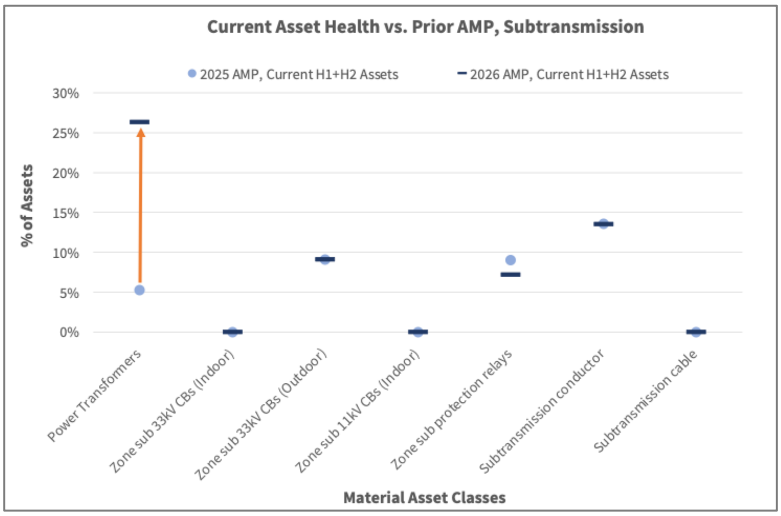
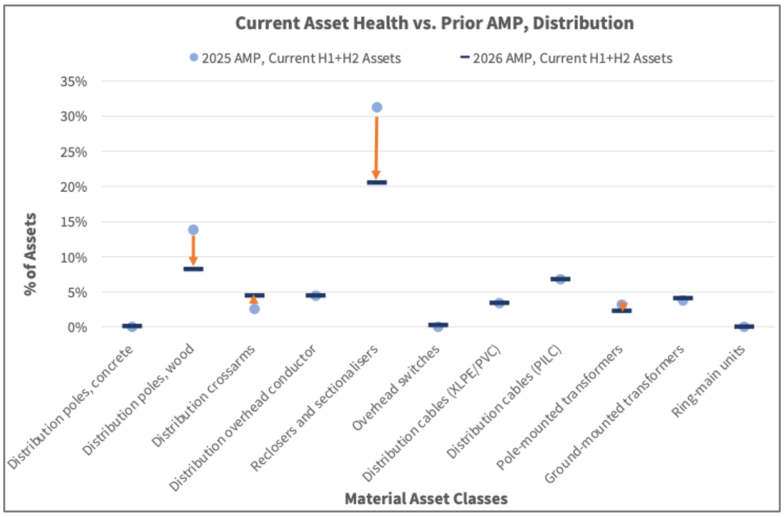


Figure 119: Movement distribution asset current health



12.6.2 Zone substation asset fleets

Due to their generally higher criticality, the zone substation asset fleets are managed more conservatively than distribution assets (that is, we have a lower risk tolerance for these assets). For zone substation assets, we generally plan to replace or refurbish the assets before the risk increases above medium (above risk grade 3). As shown in Table 71, we are replacing more assets than indicated by CBARMM. This reflects some replacement drivers that are not fully recognised in CBARMM (i.e. some safety-related factors, building resilience issues and protection scheme vulnerabilities).

Table 71: Zone substation fleet risk and renewal summary

Asset fleet plans	10 Year forecast assets with high risk and above[125]	10 Year forecast renewals and refurbishment	10-year forecast capex	Comments
Power transformers	8	7[126]	$14.9m	Forecast renewals will maintain the fleet at medium or lower risk
Zone substation 33kV circuit breakers	4	16	$5.5m	These renewals are driven by factors not included in CBARMM (working clearances and technical obsolescence)
Zone substation 11kV circuit breakers	Nil	9	$1.6m	These renewals are driven by factors not included in CBARMM (building seismic issues)
Zone substation secondary systems	95	99	$7.0m	Forecast renewals are higher than forecast risk for protection relays as some relays are being replaced to remove known protection vulnerabilities.

12.6.3 Other subtransmission, distribution and LV asset fleets

For non-zone substation assets, we generally plan to replace the assets when they reach risk grade 4 (where the risks can be managed) and before they transition to risk grade 5. However, our views on risk tolerance and the drivers for renewals varies for each asset fleet and asset type.

The material renewal programmes are the replacement of poles and crossarms ($46.8m), conductors ($34.1m), and pillar boxes ($16.0m). These programmes address high-risk assets: older concrete and wood poles, overhead copper conductors, and steel pillar boxes.

Table 72: Distribution fleet risk and renewal summary (5-year fleet plans)

Asset fleet plans	5 Year forecast assets with high risk and above[127]	5 Year forecast renewals and refurbishment	10-year forecast capex	Reason for differences
Overhead structures (poles and crossarms)	Concrete 0.6% Wood 2.0% Crossarms 5.3%	2.5% 9.9% 10.7%	$46.6m	Renewals are greater than forecast risk for poles and crossarms due to additional replacements during the reconductoring programme. Wood poles are also being replaced due to asset health (the 5-year forecast for low health wood poles is 8.4%).
Conductor	33kV 11.8% 11kV 1.5% LV 50.1%	<0.1% 7.3% 15.4%	$34.1m	The forecast risk for 33kV overhead conductors relates to two circuits from Mangahao where the future use of the is unclear, hence renewal is not yet forecast. The 11kV conductor renewals are higher than forecast risk due to the copper conductor renewal programme, which is health (rather than risk based). LV overhead conductor renewals are below forecast health and risk—the current forecast addresses assets with observed condition issues.
Cable	33kV 0% 11kV XLPE 3.4% 11kV PILC 10.7% LV 21.2%	2.2% 0.3% 0.2% <0.1%	All cables Renewal $0.3m Safety $2.2m	There are no planned cable renewals (other than some 33kV cables relocations associated with O2NL, which has been included).

[125] Before renewal or refurbishment intervention. This is a measurement of asset risk, so may differ from the asset health in Schedule 12a.

[126] The current replacement programme comprises 8 transformers. The last transformer is forecast for replacement in FY2037.

[127] Before renewal or refurbishment intervention. This is a measurement of asset risk, so may differ from the asset health in Schedule 12a.

Asset fleet plans	5 Year forecast assets with high risk and above[127]	5 Year forecast renewals and refurbishment	10-year forecast capex	Reason for differences
				11kV and LV cable replacements are presently driven by reliability and defect issues. Most expenditure relates to shows the safety-related replacement of pitch-filled potheads and in-line joints on poles.
Distribution switchgear	PM reclosers 30% PM switches 3.5% RMUs 4.1%	21.9% 5.1% 4.2%	$8.3m	Forecast renewals for pole-mounted reclosers relates to a controller replacement programme, which is the driver of health/risk issues with the fleet. Forecast renewals for pole-mounted switches relates to our ABS replacement programme. There is planned renewal programme for dropout fuses and links. These assets are replaced as part of other programmed work or when defects are identified. Forecast RMU replacements are higher than forecast risk due to the replacement of ABB Safelink 1 RMUs (that have a known type issue) and additional replacements in conjunction with GM transformer renewals.
Other networks assets	Varies	Varies	$104k	Refurbishment of the ripple injection plant at Shannon
Secondary systems	Varies	Varies	$3.3m	Replacement of DC systems, SCADA RTU and communication equipment at zone substations

Table 73: Distribution fleet risk and renewal summary (10-year fleet plans)

Asset fleet plans	10 Year forecast assets with high risk and above[128]	10 Year forecast renewals and refurbishment	10-year forecast capex	Reason for differences
Pole-mounted transformers	RG5: 66	120	$2.3m	Due to the lower consequence of failure associated with distribution transformers, we are forecasting replacing assets that transition to RG5.
Ground-mounted transformers	RG5: 95	75	$4.8m	
LV connections and pillar boxes	2,661	2,578	Renewal $16.1m Safety $0.8m	The forecast renewal is for the replacement of all steel pillars by FY35 and all steel link pillars by FY30. Plastic boxes are performing better than the risk-based forecasting suggests and their replacement is an estimate based on prior inspection-driven replacement rates.

12.7 Asset fleet plans included in this AMP

Table 74 shows the material asset classes for Electra. This AMP includes detailed fleet plans for our zone substation assets. Summary fleet plans are included for other assets. Detailed fleet plans for these assets will be included in the 2027 AMP (we had planned to complete this work for the 2026 AMP, but this was delayed).

Table 74: Material fleet plans

Asset fleet plans	Asset classes (Commerce Commission)	Status
Power transformers	Zone substation transformers	Comprehensive ten-year fleet plan included in this AMP

[128] Before renewal or refurbishment intervention

Asset fleet plans	Asset classes (Commerce Commission)	Status
Zone Substations 33kV Circuit Breakers	22/33kV CB (Indoor)	As above
	22/33kV CB (Outdoor)	
Zone Substation 11kV Circuit Breakers	3.3/6.6/11/22kV CB (ground mounted)	As above
Zone Substation Secondary Systems	Protection relays (electromechanical, solid state and numeric)	As above
	Note: SCADA is discussed in Sections 8.4 and 9.4.2.	
Overhead structures (poles and crossarms)	Concrete poles / steel structure	Five-year fleet plan included in this AMP. Ten-year fleet plan to be included in the 2027 AMP
	Wood poles	
	Crossarms[129]	
Conductor	Subtransmission OH up to 66kV conductor	As above
	Distribution OH Open Wire Conductor	
	LV OH Conductor	
Cable	Subtransmission UG up to 66kV (XLPE)	As above
	Distribution UG XLPE or PVC	
	Distribution UG PILC	
	LV UG Cable	
Distribution switchgear	3.3/6.6/11/22kV CB (pole mounted) - reclosers and sectionalisers	As above
	3.3/6.6/11/22kV Switches and fuses (pole mounted)	
	3.3/6.6/11/22kV RMU	
Distribution transformers	Ground Mounted Transformer	Comprehensive ten-year fleet plan included in this AMP
	Pole Mounted Transformer	
LV connections and pillar boxes	OH/UG consumer service connections	As above

We provide a high-level view of other (less material) assets in Section 12.18.

12.8 Power Transformer Fleet Plan

12.8.1 Fleet Overview

Electra has 19 power transformers located across ten zone substations. Power transformers convert energy from the 33kV sub-transmission network to the 11kV distribution network. Except for the Paekākāriki substation (where 11kV backup is available), all substations have N-1 security available for these assets.

The power transformer fleet makes up approximately 3% of the overall assets by value. Individually, these are the most valuable assets. Power transformers have a high initial investment and operational costs. Therefore, the total lifecycle costs are assessed before purchasing new transformers.

There are two major components to a power transformer—the transformer (consisting of the tank, windings and cooling system) and the tap-changer (which allows the output voltage to be changed while the transformer is carrying load).

Power transformers are critical assets, and a failure can result in a loss of supply or reduced supply security, depending on the zone substation's network security level and failure mode. For this reason, we take a more conservative approach to their management than we do for distribution assets.

[129] These are an identified asset class for asset management purposes, but are not a Commerce Commission asset class

Over the past 12 months, we have reviewed our approach to the renewal and refurbishment of this fleet. In the 2025 AMP, we proposed a mix of renewals and refurbishment to maintain the fleet within the fleet strategy (<HIB3 and <RG3). This strategy sought to extend the life of transformers that are currently in good condition, while replacing those in poor condition. Following a lifecycle cost analysis, we have decided to operate the transformers until they approach end-of-life. At that point, they will be replaced. The end-of-life renewal strategy offers a lower lifecycle cost and reduced capex for eight transformer replacements. The decline in health as the transformer approaches end-of-life is managed by maintaining a quality-critical spare and through online monitoring. Should urgent replacement be required, there may be a period of elevated risk above the fleet strategy

Figure 120: Power Transformers

Power Transformers T1 and T2, Waikanae Zone Substation

12.8.2 Fleet Management Strategy

The 10-year power transformer fleet strategy is as follows:

Power transformers are very high criticality assets that can take significant time to replace should they fail. Hence, the fleet strategy requires them to be operated, monitored, maintained, and renewed to ensure fleet risk remains at medium (RG3) or below. This requires:

- Operating the assets within the required security levels (for foreseeable normal loading conditions);
- Upgrading all assets structure to achieve Importance Level 4[130] by the end of FY2028[131];
- Taking a conservative position on asset health and risk where assets are replaced *before* health risks emerge (HIB3) and *before* risks increase above medium (RG3 and below);
- Monitoring the condition of the asset fleet to ensure asset health can be reliably predicted;
- Maintaining the assets consistent with the manufacturer’s guidelines and Electra’s standards to ensure assets are kept in serviceable condition (HIB2 and below).

[130] Importance Level 4 is defined as a structure that is essential to post-disaster recover. They require higher resilience to seismic, wind, snow and flooding hazards.

[131] This currently relates to seismic, wind and snow loadings. The resilience strategy includes a plan to assess flood resilience to an equivalent IL4 standard. The target date is indicative as site geotechnical and flooding assessment is ongoing.

12.8.3 What is driving our fleet strategy

Current fleet performance

We have adopted a transformer age index model (TAIM) to assess the biological age of our fleet. The biological age is primarily determined by the condition of the insulating system (paper and oil), which is influenced by thermal and electrical stress, moisture, oil quality, and the natural degradation of the paper.

The power transformer fleet is performing well, but some issues are emerging on some older assets. The issues are consistent with the analysis and output from TAIM.

Dissolved gas analysis (DGA) results show signs of some internal arcing in the transformer tank at T1 Levin East and T1 Paraparaumu East. This is likely due to heightened moisture within the transformer oil, which has been noted using online monitoring. T1 Paraparaumu is 55 years old, and end-of-life drivers can be expected. T1 Levin East is only 46 years old, so the presence of end-of-life drivers is earlier than expected.

Specific fleet risks and failure modes

Table 75 shows the top risks and failure modes for the power transformers. Condition monitoring and maintenance (as shown in Table 77 and Table 78) identify and reduce failure risks.

Table 75: Specific risks

Asset	Risk/failure modes	Current controls or treatments
Power transformer	Coastal exposure resulting in tank corrosion that can reduce asset life	• Regular visual condition monitoring of the tank and remediation of corrosion as required • A location factor is incorporated in CBARMM as coastal exposure (within 3.6km of the coast) can reduce the nominal expected life of an asset.
	Overloading of the transformer can damage the winding insulation, reducing asset life and causing asset failure	• SCADA monitoring transformer loading. The load can be transferred to other zone substations if required. • Condition assessment (dissolved gas analysis) of the transformer oil.
	Moisture ingress and contamination of transformer oil can damage the winding insulation, reducing asset life and causing asset failure	• Regular (or online) oil moisture testing. • The transformer oil may be changed or filtered as required.
	Failure of a bushing or connection	• Inspection of bushing and thermal imaging of connection points with follow-up maintenance as required
	Mechanical failure of the tap-changer	• Regular maintenance of the tap-changer

As no known type issues are associated with the fleet and the current performance issues are not systemic, the reliability factor within CBARMM is set at 1.0, meaning the asset fleet has high reliability.

Fleet population and age

Table 76 shows the power transformer population and age. There are two transformers within five years of nominal expected life (**NEL**), which are T1 and T2 Paraparaumu East. Two more transformers will reach NEL over the next ten years (T2 Levin East and T2 Shannon). The two transformers at Ōtaki will reach NEL in 11 years.

Table 76: Asset fleet quantity and age

Asset	Type	Population	Average Age (years)	NEL[132] (years)	Population within 5 years of NEL
Power transformer	3 Phase Transformer (including tap-changer)	19	36	60	2

Fleet health, criticality and risk

The recently adopted TAIM complements CBARMM and provides comprehensive age and health insights into Electra's power transformer fleet. As shown in Figure 121 and Figure 122, most assets are in serviceable condition. However, we have a group of nine transformers due for replacement over the next 11 years due to health or age-based end-of-life (Figure 123). This is an increase from the seven transformers identified in the 2025 AMP. As noted in the fleet strategy, intervention is required before the risk increases, given the very high criticality and the long lead time to replace power transformers.

Figure 121: Power Transformer TAIM

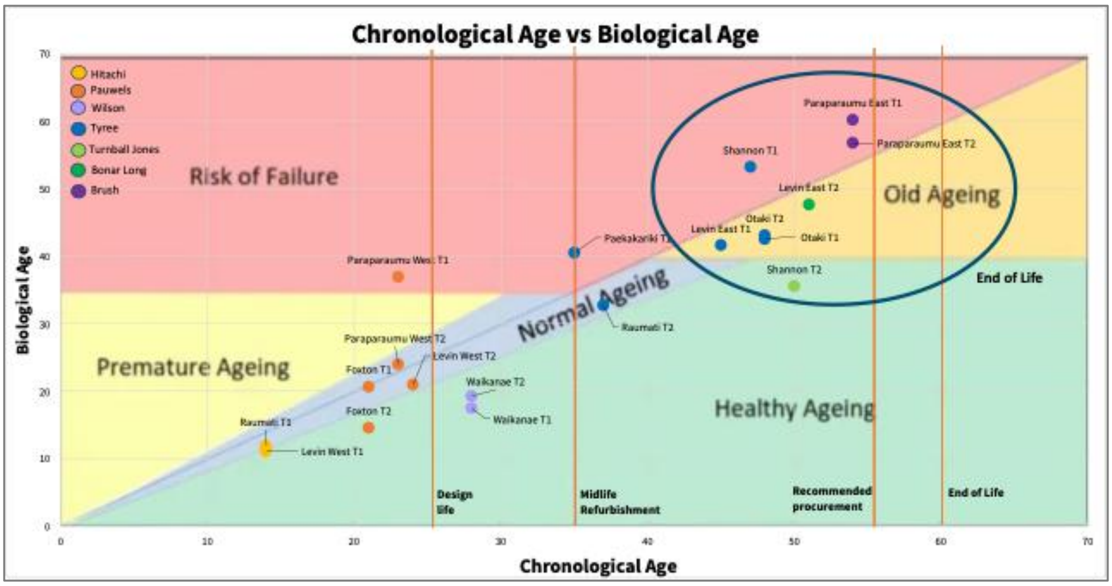


Figure 122: Current Asset Health Risk Assessment

	HIB1	HIB2	HIB3	HIB4	HIB5
C4	8	2	4	5	-
C3	-	-	-	-	-
C2	-	-	-	-	-
C1	-	-	-	-	-

Figure 123: 10-Year Asset Health Risk Assessment

	HIB1	HIB2	HIB3	HIB4	HIB5
C4	6	4	4	5	-
C3	-	-	-	-	-
C2	-	-	-	-	-
C1	-	-	-	-	-

12.8.4 How the asset fleet is operated, monitored and maintained

Operating the assets

Power transformers are one of the primary assets within a zone substation (which also includes switchgear, secondary assets, and measurement equipment). The tap-changer is used to regulate the voltage output depending on the load it is supplying. As the only moving part within a transformer, the tap-changer is more susceptible to faults than other components. Faults for power transformers are identified through SCADA monitoring of the protection devices. This usually includes Buchholz relays, pressure relief valves, and tap-changer overload relays. Faults on transformers can vary in criticality, and technicians are dispatched to the

[132] Nominal expected life. This is the age when it would be expected to first observe significant deterioration. This represents the average service life of the asset. Assets can operate longer than NEL based on active monitoring of condition.

site to investigate the cause of a fault should monitoring equipment be unable to provide adequate information.

Condition assessment

Table 77 summarises the power transformer fleet's current inspection and testing regime. The inspection and testing cover the transformer and tap-changer. Observed condition data is captured through regular inspections of the zone substation, and measured condition data (such as DGAs) is captured annually or bi-annually. Appropriately qualified technicians perform visual inspections, and external contractors perform the tests and measurements.

Our current condition assessment program is suitable for an aging asset fleet. However, the testing frequency may be shortened if we detect any deterioration. We are enhancing our condition assessments by installing online moisture analysis for each transformer. By the end of FY2026, eight of the fleet of 19 power transformers have online monitoring, and the remainder will have online monitoring installed by the end of FY2030.

Table 77: Condition assessments

Asset	Type	Scope of assessment	Trigger
Power transformer	Observed	Routine inspection checks for oil leaks, corrosion, oil levels and tap-changer operation. This is completed as part of the zone substation inspection programme.	Time-based, timing varies between bi-monthly and annual, depending on health
	Observed	Thermal imaging of connection points and checking for hot spots	Time-based, annually
	Measured	DGA and Furan analysis	Time-based, annually
	Measured	Transformer loading Winding temperature Online moisture via ETE probes (partial fleet coverage)	Continuous
	Measured	Duty of the transformer and operation of the tap-changer	SCADA measurement
	Measured	Insulation resistance and winding resistance	Time-based, 3-yearly, in conjunction with maintenance

Maintaining the asset

Power transformer maintenance typically consists of work associated with the tap-changer. Planned maintenance is based on the manufacturer’s recommendations and good industry practice.

Table 78: Corrective and preventive maintenance

Asset	Type	Scope of maintenance	Trigger
Power transformer	Corrective	Defects (on subcomponents of the assets) are repaired following identification during inspection, maintenance or fault. The technician and the substation engineer assess the defect repair.	• Oil test results exceeding manufacturers’ recommendations • Poor results for tests such as partial discharge, Furan analysis, paper sampling • Integrity of gaskets and flexible seals on tank and fittings; • Oil leaks or staining suggests ongoing leakage • Corrosion
	Preventive	**Tap-changer:** Oil replacement, cleaning of components, removal of arcing products, contact alignment and tap resistance	Time-based, 3-yearly
	Preventive	**Transformer:** Detailed inspection of components, checking operation of secondary equipment, insulation resistance,	Time-based, at commissioning, then 3-yearly, in conjunction with the tap-changer maintenance

Asset	Type	Scope of maintenance	Trigger
		winding resistance, etc... Repairs and maintenance as required	

12.8.5 How renewal decisions are made on the fleet

Table 79 shows the specific drivers for asset renewal forecasting and the triggers for selecting specific asset renewal projects.

Table 79: Drivers and triggers for renewal forecasts and projects

Asset	Type	Drivers/triggers
Power transformer	Renewal forecasts	A combination of TAIM and CBARMM is used to forecast asset renewals. Due to the critical nature of the fleet, we forecast renewals for all assets where the risk increases above medium (above RG3). Asset health is determined using a combination of asset age, location, duty, reliability and condition. The condition inputs include the observed condition assessment and the measured condition concerning oil moisture, oil dissolved gases and furan tests shown in Table 77. These measurements are generally applicable to both the transformer and the tap-changer.
	Renewal and refurbishment Projects	Specific renewal or refurbishment projects are defined based on our engineering assessment of the presence of end-of-life drivers, including: • Oil impurity, acidity, gas content and moisture content indicate deterioration of the insulation; • Poor results for tests such as partial discharge, furan analysis, insulation resistance, winding resistance and paper sampling; • Issues identified with the transformer or tap-changer, oil leaks or staining on the tank suggesting that the material, structural integrity or performance issues; • Deterioration (i.e. corrosion) of the tanks or cooling fins. Refurbishment of power transformers may be feasible and provide an economic life extension (instead of renewal). Refurbishment will consider the capacity available to support future load growth, the transformer age, the specific drivers for the deteriorating health (and whether refurbishment will mitigate these drivers), and the overall lifecycle cost implications of refurbishment vs. renewal. Project timing considers the ability to manage the risks associated with the emergence of end-of-life drivers. This includes the redundancy available at the substation, critical spares, and the availability of spares.
	Corrective renewal of refurbishment	Not applicable to power transformers.

12.8.6 Asset renewal and refurbishment forecasts

Table 80 shows the forecast power transformer asset risk and renewals over the next ten years. Four of the seven transformers forecast for renewal are due in the next five years. As shown in Figure 124, the forecast renewals will maintain the fleet at medium or lower risk. The one high-risk transformer not replaced is at Paekākāriki. In the event of a transformer outage, this substation can be fully supported by the 11kV network. We are also considering a transformer upgrade at that site to meet the needs of a customer (see Section 11.13.4). A decision on the renewal of the Paekākāriki power transformer will be made when discussions on the upgrade are concluded.

Table 80: Current and forecast asset risk and renewals

Asset	Type	Population	Current assets with high risk and above	10 Year forecast assets with high risk and above[133]	10 Year forecast renewals and refurbishment
Power transformer	3 Phase Transformer (including tap-changer)	19	2	9	7[134]

Figure 124: 10 Year Asset Health Risk Assessment, after Renewals

	HIB1	HIB2	HIB3	HIB4	HIB5
C4	14	4	-	1	-
C3	-	-	-	-	-
C2	-	-	-	-	-
C1	-	-	-	-	-

12.8.7 Asset renewal and refurbishment projects and provisions

Table 81 and Figure 125 shows the specific projects proposed. These projects cover the assets identified for renewal in Table 80. Given their value, specific business cases will be prepared, and approval will be sought. The business case considers the drivers, scope, costs, and alternatives, which may alter the timing and scope of the projects listed in Table 81.

Our current forecast are based on end-of-life replacement (which differs from that presented in the 2025 AMP).

Figure 125: Renewal strategy

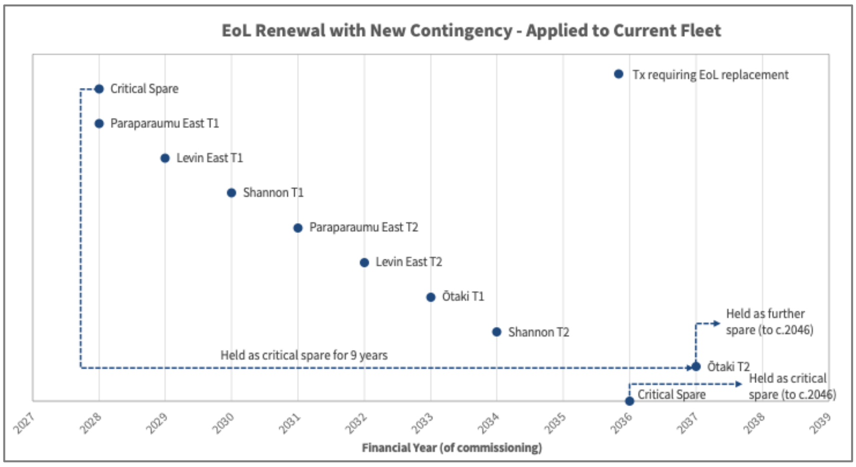


Table 81: Specific renewal and refurbishment projects (Real$)

Project	Driver	Cost/Year	Options considered/comments
Critical spare purchase No.1	Purchase of a critical spare transformer that will be held until installed at Ōtaki T1	$1,583k FY27-28	• Options for critical spare holdings were considered in the development of the EoL replacement strategy. Holding a new spare is appropriate to mitigate the EoL failure risk during this replacement cycle
T1 Paraparaumu East, replacement with new 16/23 MVA unit	Replacement is required due to asset risk which is driven by asset age, current condition and very high criticality. The DGA results show internal arcing and	$1,583k FY27-FY28	The options considered were: • Delay replacement and manage risk: Internal arcing is an irreversible end-of-life condition that will worsen over time and presents unacceptable risk

133 Before renewal or refurbishment intervention

134 A further transformer is scheduled for replacement in FY37 (year 11).

Project	Driver	Cost/Year	Options considered/comments
	gassing in the transformer tank, which is an end-of-life condition. The transformer will be 58 years old when replaced, which is close to end-of-life.		• Refurbishment: The transformer is end-of-life. Refurbishment is no longer viable for a transformer of this vintage and winding damage • Major maintenance: There are no maintenance solutions available to resolve internal arcing
T1 Levin East, replacement with new 16/23 MVA unit	Replacement is required due to asset risk which is driven by the current condition and very high criticality. The DGA results show internal arcing and gassing in the transformer tank, which indicates end-of-life. The transformer is 55 years old, which is close to end-of-life.	$1,583k FY27-FY29	The options considered were: • Delay replacement and manage risk: Internal arcing is an irreversible end-of-life condition that will worsen over time and presents unacceptable risk • Refurbishment: The refurbishment costs will be uneconomic due to the likely damage to the windings. Parts for older Tyree transformers are difficult to procure, which will be exacerbated if refurbished • Major maintenance: There are no maintenance solutions available to resolve internal arcing
T1 Shannon Substation replacement with new 16/23 MVA unit	Replacement is based on current DGA results, moisture count of oil which require regular drying. It is suspected that the existing gaskets are reaching end of life, as is the rest of the transformer	$1,583k FY28-30	The options considered were: • Delay replacement and manage risk: We are currently in this phase. • Refurbishment: The refurbishment costs will be uneconomic due to the likely damage to the windings from the sustained period of moisture exposure • Major maintenance: not possible due to the level of deterioration
T2 Levin East, replacement with new 16/23 MVA unit	Replacement is forecast due to asset risk which is driven by asset age, expected condition the very high criticality. The transformer will be 59 years old at the time of replacement.	$1,583k FY30-32	• We are forecasting health deterioration similar to T1 Levin East. The transformer health is being closely monitored. The options will be considered during business case development.
T1 Ōtaki, replacement with new 16/23 MVA unit	Replacement is forecast based on age-based EoL. The transformer will be 58 years old at the time of replacement.	$1,583k FY31-33	• The transformer health is being closely monitored. The options will be considered during business case development.
Critical spare purchase No.2	Purchase of a critical spare transformer that will be held until installed 2046, when it will be installed at Paraparaumu West T2 in FY46	$1,583k FY34-36	• This replaces the No.1 spare, which is installed at Ōtaki T1. Options for critical spare holdings were considered in the development of the EoL replacement strategy. Holding a new spare is appropriate to mitigate the EoL failure risk during this replacement cycle
T2 Paraparaumu East, replacement with new 16/23 MVA unit	Replacement currently forecast based on increasing asset risk. The transformer will be around 60 years old when replaced.	$1,583k FY29-31	• The options will be considered during business case development.
T2 Shannon Substation replacement	Replacement is forecast based on age-based EoL. The transformer will be around 60 years old when replaced.	$1,583k FY32-34	• As above
T2 Ōtaki, replacement with Critical Spare No.1 16 23 MVA unit	Replacement is forecast based on age-based EoL. The transformer will be 60 years old at the time of replacement.	Outside of planning period FY37	• As above
Cooling fins replacement at Foxton Zone substation	Replace due to asset health (corrosion)	$342k FY26-27	• Maintenance solution is not possible due to the location of the corrosion. Replacement of the radiators is required.

Project	Driver	Cost/Year	Options considered/comments
Programme to install moisture sensors on all power transformers	Moisture monitoring is appropriate as it is an end-of-life driver for transformer winding insulation	$326k FY27-30	• This is a continuation of an existing programme
Total	**Asset replacement and renewal capex**	**$14.9m**	**FY27-36**

Table 82: Asset replacement and renewal capex (Real $000)

Item	FY27	FY28	FY29	FY30	FY31	FY32	FY33	FY34	FY35	FY36	Total
Zone substation transformers	1,424	2,852	1,648	1,648	1,583	1,584	1,396	1,395	192	1,206	14,928

Forecasts for fault repair, inspection and maintenance of these assets are included within the network opex forecasts contained in Section 12.19.

12.9 Zone Substation 33kV Circuit Breaker Fleet Plan

12.9.1 Fleet Overview

Electra has 35 indoor and 22 outdoor 33kV circuit breakers (**CBs**) across ten zone substations. These CBs switch and protect the 33kV bus, power transformers and sub-transmission feeders. This fleet consists of indoor and outdoor CBs from various manufacturers.

We are moving to modular 33kV outdoor switchgear to enhance network resilience and reliability (refer to Section 11.9.4). New and replacement 33kV switchgear will be modular where it can be accommodated on the existing sites.

33kV CBs are critical assets, and a failure can result in a loss of supply or reduced supply security, depending on the network security level of the zone substation. For this reason, we take a more conservative approach to managing them than we do for distribution assets.

Figure 126: 33kV Circuit Breakers

33kV indoor circuit breakers Merlin Gerin F400

33kV outdoor circuit breakers Nulec

12.9.2 Fleet Management Strategy

The 10-year fleet strategy is as follows:
Circuit breakers are critical assets and can disrupt supply should they fail. The fleet strategy requires them to be tested, maintained, monitored, and renewed to ensure fleet risk remains at medium (RG3) or below. This requires: • Minimising switching operations and limiting testing to the 5 yearly maintenance programme; • Tested in accordance with manufacturer's guidelines, good industry practice and network standards. Annual non-intrusive testing to assess condition shall be implemented whenever possible ; • Taking a conservative position on asset health and risk where assets are refurbished or replaced *before* health risks emerge (HIB3) and *before* risks increase above medium (RG3 and below); • Monitoring the condition of the asset fleet to ensure asset health can be reliably predicted.

12.9.3 What is driving our fleet strategy

Current fleet performance

The current fleet is performing well. All switchgear is well within the age-based NEL (50-60 years) and operations (10,000 operations and 180 fault trips) end-of-life limits.

Specific fleet risks and failure modes

Table 83 shows the principal risks and failure modes for 33kV CBs. The key risks relate to historical design issues (indoor CB connectors and outdoor operational clearances to live 33kV), coastal conditions and obsolescence.

Table 83: Specific risks

Asset	Risk/failure mode	Current controls or treatments
33kV indoor CB	Where the indoor CB has flexible connections between the racking CB and the panel, the umbilical cord connections can deteriorate	• Minimising CB operation • Annual partial discharge (PD) and acoustic monitoring • 5 yearly testing of contact integrity • We hold spares of these cords and terminal plugs
	Some substations have sub-optimal working clearances to live 33kV, which presents safety and operational risks. These were compliant when designed but do not meet newer standards for working clearances	A programme is in place to replace CBs with low working clearances where the site is considered to be high-risk
33 kV Outdoor CB	Bushing failure	• Annual acoustic surveys • 5 yearly maintenance cleaning
	Exposure to coastal conditions causing corrosion and early failure	• Corrosion detection as part of routine inspection, with remediation as required. • Proximity to the coast is considered in CBARMM, and accelerated deterioration rates are included where appropriate
All CBs	Obsolescence due to unavailability of spare parts	Electra has two models that no longer have manufacturer's support: • Two GEC OX36 outdoor (38 and 36 years old); • Three MERLIN GERIN SF1 outdoor. These are all set for replacement

Fleet population and age

Table 84 shows the population and age of the 33kV CB fleet. There are Three CBs aged 35,36and 386 years that have reached NEL at Raumati, Levin East with no other CBs within five years of NEL. Due to other drivers, these older CBs are scheduled for replacement within the next ten years. has been reduced due to obsolescence.

Table 84: Asset fleet quantity and age

Asset	Type	Population	Average Age (years)	NEL[135] (years)	Population within 5 years of NEL
33kV Outdoor CB	MERLIN GERIN SF1	3	31	60	Nil
	GEC- OX36	3	37	30	Nil
	Schneider Nulec N36-ACR-SF6-38-12	3	22	50	Nil
	Schneider Nulec-N36-ACR-SF6-38-16	1	18	50	Nil
	Schneider Nulec-N38-ACR-SF6-38-16-170	6	16	50	Nil
	Schneider NULEC-N38S-ACR-SF6-38-16-170	6	18	50	Nil
33kV Indoor CB	MERLIN GERIN SF1	10	26	60	Nil
	MERLIN GERIN F400	10	11	60	Nil
	MERLIN GERIN FG 4	6	29	60	Nil
	Schneider NULEC N38	1	18	50	Nil
	Schneider F400 AD6	8	10	60	Nil

Fleet health, criticality and risk

Asset health and risk are determined using CBARMM. For indoor and outdoor 33kV CBs, we calculated asset health using a combination of asset age, location, duty, and operations. We have very good quality data that can reliably determine asset health. We intend to improve the range of inputs used to determine asset health, including condition and test results, obsolescence risk, industry performance reports, and type issues.

As shown in Figure 127 and Figure 128, assets are in good condition, with only four CBs with forecast risk above RG3. The three assets currently at HIB4 and RG4 relate to the GEC OX-36 CB (which are obsolete).

However, the risk profiles exclude the safety risks associated with switchgear clearances to live 33kV and the Merlin Gerin F1 CBs (which are approaching EoL due to obsolescence). These items will be included in CBARMM in future revisions of the AMP.

Figure 127: Current Asset Health Risk Assessment

	HIB1	HIB2	HIB3	HIB4	HIB5	Total
C4	-	-	-	-	-	-
C3	18	1	-	-	-	19
C2	18	-	-	2	-	20
C1	17	-	-	1	-	18
Total	53	1	-	3	-	57

Figure 128: 10-Year Asset Health Risk Assessment

	HIB1	HIB2	HIB3	HIB4	HIB5	Total
C4	-	-	-	-	-	-
C3	18	-	1	-	-	19
C2	18	-	-	-	2	20
C1	17	-	-	-	1	18
Total	53	-	1	-	3	57

12.9.4 How the asset fleet is operated, monitored and maintained

Operating the assets

33kV CBs operate to break load during routine network reconfiguration and by the protection relays to interrupt fault current. The number of routine and fault operations are end-of-life drivers, so these are minimised whenever possible. Faults are identified through SCADA monitoring of the protection relays.

[135] Nominal expected life. This is the age when it would be expected to first observe significant deterioration. This represents the average service life of the asset. Assets can operate longer than NEL based on active monitoring of condition.

Faults on 33kV CBs can vary in criticality, and technicians are dispatched to the site to investigate the cause of a fault in all circumstances.

Condition assessment

Table 85 summarises the 33kV CB fleet's current inspection and testing regime. Under normal conditions, the zone substations are inspected every two months; this is a visual, non-intrusive inspection of the external condition of the SWGR and captures the number of operations. Annual non-intrusive testing is also undertaken.

Table 85: Condition assessments

Asset	Type	Scope of assessment	Trigger
33kV CB	Observed	External condition – cabinet assessment	Routine, time-based, bi-monthly
		Internal condition - cabinet assessment	
		Number of operations	
	Measured	Partial discharge assessment for electrical discharge that could indicate insulation breakdown or other condition issues	Routine, time-based, annually
		Acoustic assessment for noise that could indicate conditions issues	
		Infra-red assessment for hotspots	

Maintaining the asset

Table 86 summarises the CB maintenance and operational testing. Follow-up corrective maintenance may occur to address any adverse test results.

Table 86: Corrective and preventive maintenance

Asset	Type	Scope of maintenance	Trigger
33kV CB, all types	Operational testing and Preventive maintenance	• Comprehensive operational testing using the Omicron CIBANO 500 test set, which includes contact resistance, dynamic contact resistance, various timing tests, motor current, under-voltage release, overcurrent release, insulation resistance, demagnetisation • PD testing before and after cleaning • For indoor CBs, The CB is racked out, and the bushing and framework are cleaned and maintained as per the manufacturer's recommendation • Outdoor CBs are mainly self-contained, and maintenance is limited to lubrication and cleaning of the exposed bushings and terminations	Routine, time-based, 5 yearly
	Corrective	Follow-up corrective maintenance occurs as required	Inspection and test results

12.9.5 How renewal decisions are made on the fleet

CBARMM is used to forecast asset renewals based on risk. Table 87 shows the specific drivers for asset renewal forecasting and the triggers for selecting specific asset renewal projects (within the overall asset renewal forecast).

Table 87: Drivers and triggers for renewal forecasts and projects

Asset	Type	Drivers/triggers
33kV CB types	Renewal forecasts	Includes all assets that are forecast to reach Risk Grades 4 and 5.

Asset	Type	Drivers/triggers
	Planned renewal and refurbishment Projects	Specific renewal or refurbishment projects are defined based on the presence of end-of-life drivers; these include observed or measured conditions outside of acceptable parameters, obsolescence, exceeding design fault operations, exceeding design mechanical operations, age-based end-of-life criteria
	Corrective renewal of refurbishment	Replacement or refurbishment of an asset under fault or defect conditions is typically driven by immediate safety concerns or where the risk of failure is assessed to be possible within the next 24 months.

12.9.6 Asset renewal and refurbishment forecasts

Table 88 shows the forecast asset risk and renewals for the 33kV circuit breaker over the next ten years. We are forecasting the renewal of 16 outdoor 33kV CBs, which is materially higher than that forecast by CBARMM. The drivers for the additional renewals are to address safety risks by removing CBs with clearance to live 33kV below modern standards (at Foxton, Levin East, and Levin West). The renewals will eliminate the forecast RG4 and RG5 assets at Raumati and Levin West.

Table 88: Current and forecast asset risk and renewals

Asset	Type	Population	Current assets with high risk and above[136]	10 Year forecast assets with high risk and above[137]	10 Year forecast renewals and refurbishment
22/33kV CB	Indoor	35	Nil	Nil	Nil
	Outdoor	22	3	4	16

12.9.7 Asset renewal and refurbishment provisions and projects

Table 89 shows the specific projects proposed. These projects cover the assets identified in Table 88. Specific business cases have not yet been prepared for the two projects commencing after FY29. Hence, the scope and costs may alter for those projects.

Table 89: Specific renewal and refurbishment projects (real$)

Project	Driver	Cost/Year	Options considered/comments
Replacement of 33kV bus and CBs (with modular type), Foxton	Risk-based replacement (working clearances to live 33kV does not meet the current standard) and protection does not meet current standard (missing line differential protection, which requires additional CT cores in CB) Customer works within the region also require an extension to the bus.	$1.3m FY27 (in progress at total of $2.5m)	Option 1: Refurbish the outdoor bus and install external CTs, which will address the protection risk but not the customer issues and operational safety risk Option 2: Refurbish the existing bus and replace the CBs with those of sufficient CT cores, which will address protection and customer issues but not the operational safety risk Option 3: Doing nothing is not considered viable, given the importance of the three drivers
Replacement of 33kV CBs (with modular type), Levin West	Risk-based replacement (working clearances to live 33kV do not meet the current standard). One outdoor CB is also approaching end-of-life due to obsolescence and age.	$2.0m FY28-FY30	Still under consideration. The project scope depends on the outcome of the building's seismic reinforcement design.

136 HIB4 and HIB5 (equivalent to EEA health index of H2 and H1). Before renewal or refurbishment intervention.

137 Before renewal or refurbishment intervention

Project	Driver	Cost/Year	Options considered/comments
Replacement of 33kV CBs (with ex-Foxton CBs), Levin East	The CBs are being replaced in conjunction with protection upgrade as this is the primary driver. The ex-Foxton CBs are being used. The projection upgrade also achieves the risk-based replacement (working clearances to live 33kV does not meet current standard).	Refer to the protection upgrade at Levin East	The project is being driven by the protection upgrade. Ex-Foxton CBs are being used to save cost.
Replacement of 33kV CBs, Raumati	Risk-based replacement of CBs (assets are at end-of-life due to obsolescence)	$2.1m FY32-FY35	The business case has not yet been prepared. Timing will be adjusted based on maintenance results and site conditions
Total	**Asset replacement and renewal capex**	**$5.5m**	**FY27 to FY36**

Table 90: Forecast asset replacement and renewal capex (Real $000)

Item	FY27	FY28	FY29	FY30	FY31	FY32	FY33	FY34	FY35	FY36	Total
33kV CB renewal	1,246	188	208	1,667	-	52	52	1,532	523	-	5,468

Forecasts for fault repair, inspection and maintenance of these assets are included within the network opex forecasts contained in Section 12.19.

12.10 Zone Substation 11kV Circuit Breaker Fleet Plan

12.10.1 Fleet Overview

Electra has 80 indoor 11kV circuit breakers (**CBs**) across ten zone substations. These CBs connect and disconnect the power transformers and 11kV feeders and sectionalise the 11kV bus.

Eight South Wales CBs were replaced at Levin East substation in FY26. The fleet now consists of all RPS switchgear manufactured in New Zealand (formerly Reyrolle Pacific). The assets include a fixed panel and bus with CBs that rack into the panel. The standardisation of switchgear aids maintenance and operations.

As the switchgear is manufactured in Wellington, we have direct factory support, increasing resilience and reliability with spare parts readily available when required.

11kV CBs are critical assets, and a failure can result in loss of supply or reduced supply security, depending on the network security level of the zone substation. For this reason, we take a more conservative approach to their management than we do for distribution assets.

Figure 129: 11kV Indoor Circuit Breakers

11kV Circuit Breakers, Paekākāriki Zone Substation

12.10.2 Fleet Management Strategy

The 10-year fleet strategy is as follows:

Circuit breakers are seen as critical assets and can disrupt supply should they fail. The fleet strategy requires them to be tested, maintained, monitored, and renewed to ensure fleet risk remains at medium (RG3) or below. This requires:

- Minimising switching operations and limiting testing to the 5 yearly maintenance programme;
- Tested in accordance with manufacturer's guidelines, good industry practice and network standards. Annual non-intrusive testing to assess condition shall be implemented whenever possible;
- Taking a conservative position on asset health and risk where assets are refurbished or replaced *before* health risks emerge (HIB3) and *before* risks increase above medium (RG3 and below);
- Monitoring the condition of the asset fleet to ensure asset health can be reliably predicted.

12.10.3 What is driving our fleet strategy

Current fleet performance

The current fleet is performing well. All switchgear is within the age-based (60 years) and operating (10,000 operations and 180 fault trips) end-of-life limits.

Specific fleet risks and failure modes

Table 91 shows the principal risks and failure modes related to 11kV indoor CBs. The key risks relate to historical design issues (indoor CB connectors) and building structural risks.

Table 91: Specific risks

Asset	Risk/failure mode	Current controls or treatments
11kV indoor CB	Where the indoor CB does have flexible connections between the racking CB and the panel, the umbilical cord connections can deteriorate	• Minimising CB operation • Annual partial discharge (PD) and acoustic monitoring • 5 yearly testing of contact integrity • We hold spares of these cords and terminal plugs
	Switchgear is located in a building with structural or other defect (3 zone substations do not currently meet IL4)	Reinforcing of existing building or construction of new building and switchgear.
	Cracking insulators	• Annual partial discharge (PD) and acoustic monitoring

Asset	Risk/failure mode	Current controls or treatments
		• 5 yearly maintenance and replacement as required
	~~Obsolescence due to unavailability of spare parts~~	~~The South Wales switchgear is obsolete and unsupported. It is scheduled for replacement.~~ (complete)
	Arc flash containment risk	Exclusion areas marked. Full PPE required on entry. There is ongoing evaluation work to assess options for remediation.

Fleet population and age

Table 92 shows the population and age of the 11kV indoor CB fleet. There are no CBs within five years of NEL. The average age of the fleet is 20. The oldest eight CBs are 35 years old, and these will be replaced in 2025.

Table 92: Asset fleet quantity and age

Asset	Type	Population	Average Age (years)	NEL[138] (years)	Population within 5 years of NEL
11kV Indoor CBs	RPS LM23VP/QMRO	4	1	60	Nil
	RPS LMVP RPM1 / QMRO	18	4	60	Nil
	RPS LMVP RPM3 / QMRO	11	11	60	Nil
	RPS LMVP/X11/QMRO	1	17	60	Nil
	RPS LMVP/X4/QMRO	5	29	60	Nil
	RPS LMVP/X4B/QMRO	17	23	60	Nil
	RPS LMVP/X5B/QMRO	24	23	60	Nil

Fleet health, criticality and risk

Asset health is determined using CBARMM. For 11kV indoor CB, we calculated asset health using a combination of asset age, asset location, duty and operations. We have very good quality data that can reliably determine asset health. We intend to expand the range of inputs used to determine asset health, including condition and test results, obsolescence risk, industry performance reports, and type issues.

As shown in Figure 130 and Figure 131, all assets are in good condition.

Figure 130: Current Asset Health Risk Assessment

	HIB1	HIB2	HIB3	HIB4	HIB5	Total
C4	-	-	-	-	-	-
C3	12	-	-	-	-	12
C2	45	-	-	-	-	45
C1	23	-	-	-	-	23
Total	80	-	-	-	-	80

Figure 131: 10-Year Asset Health Risk Assessment

	HIB1	HIB2	HIB3	HIB4	HIB5	Total
C4	-	-	-	-	-	-
C3	12	-	-	-	-	12
C2	45	-	-	-	-	45
C1	23	-	-	-	-	23
Total	80	-	-	-	-	80

12.10.4 How the asset fleet is operated, monitored and maintained

Operating the assets

11kV CBs operate to break load during routine network reconfiguration and by the protection relays to interrupt fault current. The number of routine and fault operations are end-of-life drivers, so these are minimised whenever possible. Faults are identified through SCADA monitoring of the protection relays. Faults on 11kV CBs can vary in criticality, and technicians are dispatched to the site to investigate the cause of a fault in all circumstances.

[138] Nominal expected life. This is the age when it would be expected to first observe significant deterioration. This represents the average service life of the asset. Assets can operate longer than NEL based on active monitoring of condition.

Condition assessment

Table 93 summarises the 11kV CB fleet's current inspection and testing regime. Under normal conditions, the zone substations are inspected every two months; this is a visual, non-intrusive inspection of the external condition of the SWGR and captures the number of operations. Annual non-intrusive testing is also undertaken.

Table 93: Condition assessments

Asset	Type	Scope of assessment	Trigger
11kV indoor CB	Observed	External condition – cabinet assessment	Routine, time-based, bi-monthly
		Internal condition - cabinet assessment	
		Number of operations	
	Measured	Partial discharge assessment for electrical discharge that could indicate insulation breakdown or other condition issues	Routine, time-based, annually
		Acoustic assessment for noise that could indicate conditions issues	
		Infra-red assessment for hotspots	

Maintaining the asset

Table 94 summarises the CB maintenance and operational testing. Follow-up corrective maintenance may occur to address any adverse test results.

Table 94: Corrective and preventive maintenance

Asset	Type	Scope of maintenance	Trigger
11kV Indoor CB	Operational testing Preventive maintenance	• Comprehensive operational testing which includes contact resistance, dynamic contact resistance, various timing tests, motor current, under-voltage release, overcurrent release, insulation resistance and demagnetisation • PD testing before and after cleaning • For indoor CBs, The CB is racked out, and the bushing and framework are cleaned and maintained as per the manufacturer's recommendation • Outdoor CBs are mainly self-contained, and maintenance is limited to lubrication and cleaning of the exposed bushings and terminations	Routine, time-based, 5 yearly
	Corrective	Follow-up corrective maintenance occurs as required	Inspection and test results

12.10.5 How renewal decisions are made on the fleet

CBARMM is used to forecast asset renewals based on risk. Table 95 shows the specific drivers for asset renewal forecasting and the triggers for selecting specific asset renewal projects (within the overall asset renewal forecast).

Table 95: Drivers and triggers for renewal forecasts and projects

Asset	Type	Drivers/triggers
11kV CB types	Renewal forecasts	Includes all assets that are forecast to reach Risk Grades 4 and 5.

Asset	Type	Drivers/triggers
	Planned renewal and refurbishment Projects	Specific renewal or refurbishment projects are defined based on the presence of end-of-life drivers; these include observed or measured conditions outside of acceptable parameters, obsolescence, exceeding design fault operations, exceeding design mechanical operations, age-based end-of-life criteria
	Corrective renewal of refurbishment	Replacement or refurbishment of an asset under fault or defect conditions is typically driven by immediate safety concerns or where the risk of failure is assessed to be possible within the next 24 months.

12.10.6 Asset renewal and refurbishment forecasts

Table 96 shows the forecast 11kV CB risk and renewals over the next ten years. 9 CBs are due for renewal in the next five years. These renewals are driven by factors not included in CBARMM. It is not currently considered economic to bring the building that contains the switchgear at Levin West up to the seismic requirements of IL4. As such, Electra is considering options, which include constructing a new building and installing new switchgear.

Table 96: Current and forecast asset risk and renewals

Asset	Type	Population	Current assets with high risk and above	10 Year forecast assets with high risk and above[139]	10 Year forecast renewals and refurbishment
3.3/6.6/11/22kV CB (ground mounted)	All types	80	Nil	Nil	9

12.10.7 Asset renewal and refurbishment provisions and projects

Table 97 shows the specific projects that are proposed. These projects cover the assets identified in Table 96. Specific business cases have not yet been prepared for the Levin West project. Hence, the scope and costs may change.

Table 97: Specific renewal and refurbishment projects

Project	Driver	Cost/Year	Options considered/comments
11kV Switchboard replacement, Levin West	Risk-based replacement of CBs is due to the substation building being less than IL4[140]. A new building is required and will be commissioned with new switchgear to enable feeder transfers to occur.	$1.6m FY29-FY31	The business case has not yet been prepared. Timing will be adjusted based on maintenance results and site conditions
Total	**Asset replacement and renewal capex**	**$1.6m**	**FY27 to FY36**

Table 98: Asset replacement and renewal capex (Real $000)

Item	FY27	FY28	FY29	FY30	FY31	FY32	FY33	FY34	FY35	FY36	Total
11kV CB renewal	-	-	208	208	1,147	-	-	-	-	-	1,563

Forecasts for fault repair, inspection and maintenance of these assets are included within the network opex forecasts contained in Section 12.19.

139 Before renewal or refurbishment intervention

140 Zone substation buildings should meet IL4 under the national building standard. IL4 means that post-disaster function can be maintained.

12.11 Secondary Systems Fleet Plan

12.11.1 Fleet Overview

This secondary systems fleet plan includes protection relays and other power quality meters. Secondary systems predominantly consist of Intelligent Electronic Devices deployed for network protection, monitoring, control, and data acquisition. These systems are essential for ensuring the safe and efficient delivery of electricity, providing alarms, monitoring equipment status, and measuring and recording relevant electrical parameters of the sub-transmission and distribution network. Within CBARMM, we hold details on 196 protection relays and high voltage power quality meters.

Electra replaced almost all electromechanical relays (commencing in the late 1990s) with first-generation numerical relays. These first generation numerical relays offered better reliability, less maintenance, and improved protection functionality. Modern-generation numerical relays, which have been available since the mid-2010s, provide material improvements in protection functionality over the first generation. They allow more types of faults to be detected and more advanced protection schemes to be implemented cost-effectively.

Seven electromechanical relays are being used for transformer protection with zone substations. These are due for replacement.

Electra has completed the installation of high voltage power quality meters (PQMs) on the network at all zone substations to monitor the 11kV buses.

DC systems, SCADA RTU, communication gateways and communication systems (which are also secondary systems) are discussed in Section 12.18. The SCADA system is discussed in Sections 8.4 and 9.4.2.

Figure 132: Protection Relays

1st Generation Numerical Protection Relay SEL 351S

Current Generation Numerical Protection Relay SEL 751

<u>Note:</u> The SCADA system is discussed in Sections 8.4 and 9.4.2 and the communication system is discussed in Section 12.18.5.

12.11.2 Fleet Management Strategy

The 10-year secondary systems fleet strategy is as follows:
Secondary systems devices are considered as important as the assets they protect/monitor. To keep the fleet relevant and effective, the assets are maintained and replaced based on the following requirements: • To implement a reliable, selective, sensitive, and stable protection scheme for subtransmission, zone substation and distribution network (which is available with modern generation numerical protection relays); • Taking a conservative position on asset health and risk where assets are refurbished or replaced *before* risks increase above medium (RG3 and below); • Adopting a NEL of 20 years to avoid the risk of obsolescence; • Replacing assets with known type issues; • Maintained 5 yearly except when governed by external factors (i.e. Automatic Underfrequency Load Shedding (AUFLS))

12.11.3 What is driving our fleet strategy

Current fleet performance

Protection systems are complex, and failures are rare. We have a range of legacy protection schemes (which were appropriate when implemented); however, some recent failures have highlighted vulnerabilities within these schemes, including:

- Slow backup protection response during the 33kV bus fault at Shannon substation. The bus fault indicated that a layered approach using bus-zone protection (using differential relays) would improve the speed and effectiveness of the protection;
- Cascade outages on the subtransmission system due to mutual coupling[141] and reliance on overcurrent and earth-fault protection. These faults indicate that differential protection schemes are appropriate;
- Reliance on over-current and earth-fault protection can result in some faults not being correctly detected and isolated. Advanced protection schemes improve selectivity by adding additional fault pick-ups via sensitive earth fault, high impedance fault, and intermittent earth fault functionality.
- Lack of resolution at substation-level in system power quality

Modern-generation numerical protection relays and high-speed communication between substations enables more advanced protection schemes to be implemented. High-resolution power quality meters improve monitoring of the distribution system at the zone substation bus level, enabling auditing and diagnosis of disturbances caused by harmonics, voltage transients, and external influences.

Specific fleet risks and failure modes

Table 99 shows secondary systems assets' top risks and failure modes. The key risks are technical obsolescence and protection scheme vulnerabilities.

[141] This is the phenomenon where electromagnetic fields generated by one power line induce currents in a nearby parallel line.

Table 99: Specific risks

Asset	Risk/failure mode	Current controls or treatments
Intelligent Electronic Devices	Technical obsolescence (where parts and/or support become unavailable)	• We have adopted a NEL of 20 years to ensure that protection schemes remain relevant, current and effective.
	Scheme vulnerabilities	• There is a current project underway to implement standardised, comprehensive protection schemes within Electra's network
	Type issues	• Assess type issues and possible solutions like firmware upgrades. Schedule replacement work if no mitigation is found to resolve the type issue.
	Exposure to the external environment	• Outdoor cabinets are inspected during routine inspections, and any corrosion or other issues that could result in moisture ingress are identified and resolved.

Fleet population and age

Table 100 shows the population and age of the secondary systems. We have adopted a 20-year NEL for protection relays to mitigate obsolescence risk. As a result, we have 44 relays exceeding and a further 18 relays within five years of NEL.

Table 100: Asset fleet quantity and age

Asset	Type	Population	Average Age (years)	NEL[142] (years)	Population within 5 years of NEL
Protection relays	Numerical first- and modern-generation	172	14	20	66
	Electromechanical/Static	5	35	20	5
Power quality meters	Digital Monitoring Device	19	2	20	0

Fleet health, criticality and risk

The health of protection relays is determined using CBARMM. We calculated asset health using a combination of asset age, asset location and reliability. We have very good quality asset age data that can provide a reliable indicator of asset health (primarily because obsolescence is the key driver).

As shown in Figure 133 and Figure 134, assets are generally in good condition. Asset health and risk drivers are predominantly asset age (concerning the older electromechanical and static relays and the older first-generation numerical relays).

[142] Nominal expected life. This is the age when it would be expected to first observe significant deterioration. This represents the average service life of the asset. Assets can operate longer than NEL based on active monitoring of condition.

Figure 133: Current Asset Health Risk Assessment

	HIB1	HIB2	HIB3	HIB4	HIB5	Total
C4	-	-	-	-	-	-
C3	13	-	2	-	5	20
C2	103	19	23	-	9	154
C1	12	-	10	-	-	22
Total	128	19	35	-	14	196

Figure 134: 10-Year Asset Health Risk Assessment

	HIB1	HIB2	HIB3	HIB4	HIB5	Total
C4	-	-	-	-	-	-
C3	6	-	5	1	8	20
C2	55	3	23	15	58	154
C1	2	-	7	1	12	22
Total	63	3	35	17	78	196

12.11.4 How the asset fleet is monitored and maintained

Condition assessment

Table 101 summarises the fleet's current inspection and testing regime.

Table 101: Condition assessments

Asset	Type	Scope of assessment	Trigger
Relays	Observed	Observed during routine substation inspections	Routine substation inspections
	Measured	Primary and secondary injection tests	Suspect operation or malfunction

Maintaining the asset

Maintenance on protection relays is undertaken on a 5-yearly schedule, excluding devices configured for AUFLS. Devices set up to comply with the AUFLS will be tested on a 4-yearly basis as required by legislation.

Table 102: Corrective and preventive maintenance

Asset	Type	Scope of maintenance	Trigger
Relays	Corrective	Defects	• Suspect operation or malfunction
	Preventive	Primary and Secondary injection tests	• Routine time-based, 4 or 5-yearly

High voltage power quality meters have only been recently installed on the network. Inspection and maintenance plans for these assets are being considered (based on the manufacturers' recommendation) and will be included in future AMPs.

12.11.5 How renewal decisions are made on the fleet

Table 103 shows the specific drivers for asset renewal forecasting and the triggers for selecting specific asset renewal projects (within the overall asset renewal forecast) for secondary systems.

Table 103: Drivers and triggers for renewal forecasts and projects

Asset	Type	Drivers/triggers
Relays	Renewal forecasts	Includes all assets that are forecast to reach Risk Grades 4 and 5, where the assets are forecast to reach NEL, or where specific protection scheme vulnerabilities need to be remediated.
	Renewal and refurbishment Projects	All assets identified in the renewal forecasts will be included as specific renewal projects.
	Corrective renewal of refurbishment	Replacement of an asset under fault or defect conditions is typically driven by immediate safety concerns or where the risk of failure is assessed to be possible within the next 24 months.

12.11.6 Asset renewal and refurbishment forecasts

Table 104 shows the protection relay forecast asset risk and renewals over the next ten years. Of the 99 relays forecast for renewal, 79 are due in the next five years. The forecast renewals will maintain the fleet at an acceptable risk level as relays exceeding their NEL (i.e. at end-of-life) have been prioritised for replacement. The replacement projects will address any vulnerabilities that will result in an overall increase in the asset register.

Forecast renewals are higher than forecast risk for protection relays as some relays are being replaced to remove known protection vulnerabilities.

Table 104: Current and forecast asset risk and renewals

Asset	Type	Population	Current assets with high risk and above	10 Year forecast assets with high risk and above[143]	10 Year forecast renewals and refurbishment
Relays	Numerical	172	9	90	94
Relays	Static and Electromechanical	5	5	5	5
Power quality meters	Digital Monitoring Device	19	0	0	0

12.11.7 Asset renewal and refurbishment provisions and projects

Table 105 shows the specific projects or provisions that are proposed. These projects cover the protection relays in Table 104.

Table 105: Specific renewal and refurbishment projects

Project	Driver	Cost/Year	Options considered/comments
Waikanae transformer protection replacement	Electromechanical relays have reached end-of-life (being 40 years old). (4 relays)	$358k FY27	Risk-based replacement. Given the importance of these assets, replacement is appropriate to remove obsolescence risk and vulnerabilities associated with the legacy protection schemes. The project will also implement bus zone protection.
Waikanae sub-transmission protection upgrade	Sub-transmission protection relays are reaching end-of-life. (6 relays)	$470k FY34-35	Risk-based replacement. Given the importance of these assets, replacement is appropriate to remove obsolescence risk and vulnerabilities associated with the legacy protection schemes The project will also implement unit protection.
Foxton Line differential protection replacement	The protection relays are reaching end-of-life. The scheme also has vulnerabilities due to mutual coupling. (12 relays)	$192k FY27	Risk-based replacement. Given the importance of these assets, replacement is appropriate to remove obsolescence risk and vulnerabilities associated with the legacy protection schemes The project will also implement unit protection.
Foxton protection replacement	The protection relays are reaching end-of-life. (6 relays)	$327k FY27	Risk-based replacement. Given the importance of these assets, replacement is appropriate to remove obsolescence risk and vulnerabilities associated with the legacy protection schemes. The project will also implement bus zone protection.
Ōtaki line differential and bus zone upgrade. This is the secondary systems	The protection relays are reaching end-of-life. The scheme also has vulnerabilities due to mutual coupling. (4 relays)	$205k FY27	Aligned with a primary system upgrade. The project will also implement unit and bus zone protection.

[143] Before renewal or refurbishment intervention

Project	Driver	Cost/Year	Options considered/comments
component only			
Levin East Bus zone protection upgrade (and 33kV CB replacement)	The protection relays are reaching end-of-life. The scheme also has vulnerabilities due to mutual coupling and lacks bus zone protection. CB replacement is required to implement the scheme and 33kV CBs from Foxton are being used (4 relays)	$820k FY27 (In progress, total is $1.2m)	Risk-based replacement. The project will implement unit and bus zone protection. This project includes the replacement of the 33kV CBs.
Paraparaumu West 11kV protection replacement	The protection relays are reaching end-of-life. (8 relays)	$1.26m FY28-29	Risk-based replacement.
Shannon protection upgrade	The protection relays are reaching end-of-life. (20 relays)	$990k FY29-30	As above
Raumati protection upgrade	The protection relays are reaching end-of-life. (13 relays)	$1.04m FY29-30	As above
Raumati sub-transmission protection upgrade	The protection relays are reaching end-of-life. (2 relays)	$323k FY29-30	As above
Paraparaumu East protection upgrade	The protection relays are reaching end-of-life. (20 relays)	$1.05m FY33-34	As above
Total	**Asset replacement and renewal capex**	**$7.0 m**	**FY27-36**

Table 106: Asset replacement and renewal capex (Real $000)

Item	FY27	FY28	FY29	FY30	FY31	FY32	FY33	FY34	FY35	FY36	Total
Secondary systems	1,902	914	2,022	677	-	-	836	574	105	-	7,029

Protection upgrades are also required at Levin West. This will be scoped and added to the programme for the 2027 AMP.

We also have a programme to manage and maintain the reliability and resilience of the communication system by installing fibre links between some substations (refer to Section 11.12.2). The differential/unit protection schemes will rely on these links.

Forecasts for fault repair, inspection and maintenance of these assets are included within the network opex forecasts contained in Section 12.19.

12.12 Overhead Structures Fleet Plan

12.12.1 Fleet Overview and Strategy

Our overhead structure fleet consists of concrete and steel poles, wood poles and crossarms. These assets form the backbone of the network and support the sub-transmission, distribution and LV conductors.

Electra has 20,445 concrete poles (over 95%), 25 steel and 950 wood poles.[144] These range in age from new to 85 years and have been sourced from various suppliers, including the Horowhenua Electric Power Board's pole factory. Each pole has at least one crossarm, but there can be multiple crossarms where the pole is carrying multiple lines, which may be at different voltages.

The concrete poles are predominantly mass-reinforced (~86% of the fleet), with the remainder being of pre-stressed construction. Wood poles are a mix of hardwood and softwood.

Electra utilises traditional hardwood crossarms. Hardwood crossarms' expected life is around half that of a pre-stressed concrete pole; hence, mid-life crossarm replacements are required. This is driving the higher crossarm replacement rate (c.f. poles).

Figure 135: Example of Pole Structures

New 11kV and LV Pre-Stressed Concrete Pole

Existing 33kV Two-Pole Structure

There are a large number of assets in this fleet, and failures can occur, interrupting supply. However, the sub-transmission and distribution network has inherent security, meaning supply can generally be restored to the unfaulted line sections through alternative lines. Overall, the fleet is performing as expected, but some issues are emerging from aging assets and harsh environmental conditions in coastal areas. This is consistent with the asset age and location.

As part of Chorus' removal of their old copper network, they are vesting their old poles that have electricity assets attached. To align with our inspection programme and requirements we undertake an asset inspection of these poles as they are vested to us.

The 10-year fleet strategy is as follows:
Our strategy for the fleet is to: • Replace all assets commensurate with their risk—that is, to replace assets before failure (under normal loading), which is at Risk Grade 4 and 5;

[144] As at 31 March 2025.

- Continually enhance our asset age and condition data to improve the reliability of the asset health forecasting (including reducing the number of assets with default ages);
- Prioritise the renewal of wood poles due to their short life expectancy and complexity in accurately determining asset health.

12.12.2 What is driving our fleet strategy

Current fleet performance

Over the past six years, the overhead line fault rate (from all causes, including overhead structures and conductors) was 18.2 faults/100km for distribution lines and 1.2 faults/100km for sub-transmission[145]. This is similar to our peers for distribution lines (16.2 faults/100km) and substantially better for sub-transmission (3.9 faults/100km).[146] The good subtransmission performance reflects the higher level of security and condition monitoring (and associated follow-up) for these assets.

Defective equipment fault rates are recorded at 0.4 faults per 10,000 units per year for poles and 1.4 per 10,000 units per year for crossarms. Most overhead structure defective equipment faults relate to insulators and jumpers (averaging nearly 8 per year).[147] Given the very few defective equipment failures and no observable deteriorating trend, we consider the overhead structure fleet is operating reliably.

Overhead hardware is exposed to the elements, including sea spray in coastal environments and higher winds. As with most assets in New Zealand, the sun also plays a significant role in accelerating asset aging due to UV exposure. Accelerated corrosion occurs in some insulator types.

We have been experiencing corrosion of the internal structural rebar in concrete poles, leading to spalling and cracking. We only install concrete poles for new installations as they are known to last longer and perform better over their life.

We have observed that more heavily loaded concrete poles are deteriorating faster.

Also, issues stem from brittle insulators, again arising from corrosion, which is prominent on our DDOs and kidney strain insulators.

We have also observed a new issue during FY26 with polymer 33kV post insulators. This issue was detected in our recent 33kV line survey, and we are currently investigating the impact and potential solution (see Figure 136). Our initial assessment indicates a batch issue.

Figure 136: deterioration of 33kV polymer insulators

[145] Based on ID data FY20-FY26

[146] Average, FY20-FY26.

[147] Defective equipment faults for FY20 to FY24. Benchmark data is not readily available. We don't have reliable quantity data for insulators and jumpers, so per unit fault rates are not available.

Specific fleet risks and failure modes

Table 107 shows the top risks and failure modes for overhead structures. Condition monitoring and maintenance (as shown in Table 109 and Table 110) identify and reduce failure risks.

Table 107: Specific risks

Asset	Risk/failure mode	Current controls or treatments
Softwood poles	Rot and checking of wood	All wood pole types are assigned an appropriate NEL within CBARMM. Where end-of-life condition drivers are identified from routine inspection, an increased deterioration rate is applied with CBARMM. Assets are scheduled for replacement within one year when significant end-of-life drivers are found (which raises the risk to RG5).
Concrete Poles	Spalling and cracking exposing rebar	Where end-of-life condition drivers are identified from routine inspection, an increased deterioration rate is applied with CBARMM. Assets are scheduled for replacement within one year when significant end-of-life drivers are found (which raises the risk to RG5).
Concrete Poles	Leaning poles due to deteriorating blocking	Routine inspection and replacement of blocking and straightening of poles
Steel poles	Corrosion	Where end-of-life condition drivers are identified from routine inspection, an increased deterioration rate is applied with CBARMM. Assets are scheduled for replacement within one year when significant end-of-life drivers are found (which raises the risk to RG5).
All poles	Loading exceeding design limits due to external factors (e.g. storm windspeed or tree fall)	Poles designed to NZS 4676:2000 Overhead lines designed to AS/NZS 7000:2016 Implement the vegetation management plan to reduce the risk of vegetation damage (refer to Section 12.19.2).
	Vehicle damage	Additional physical protection or pole relocation in areas of know vehicle damage risks
Crossarms	Rot and checking of wood and king bolt/nut failure	Asset replacement is scheduled where end-of-life condition drivers are identified from routine inspection.
Kidney strain insulators	Fracturing of brittle insulators due to tension	Asset replacement is scheduled where end-of-life condition drivers are identified from routine inspection. Proactive replacement of where this can be achieved in conjunction with other scheduled work.
Polymer insulators	Premature deterioration leading to failure	This is a new issue that we are investigating.

Fleet population and age

Table 108 shows the population and age of the overhead structure fleet. We have only a few wood poles reaching NEL presently (which is a data issue, hence we are relying on condition data for wood poles). The number of concrete poles within 5 years of NEL has reduced materially as we increased NEL from 65 to 80 years, which reflects the life we are seeing.

We intend to conduct further testing to verify the residual strength of our old concrete poles, wood poles, and crossarms. We plan to undertake a destructive testing programme to provide greater confidence in the recent change to NEL and to assess whether any other changes are appropriate. This is planned for FY2027 to FY2029, then on a three-yearly basis.

Table 108: Asset fleet quantity and age

Asset	Type	Population	Average Age (years)	NEL[148] (years)	Population within 5 years of NEL
Poles	Softwood	397	36	45	68[149]
Poles	Hardwood	90	60	50	13[150]
Poles	Unknown material	553	unknown	45-50	unknown
Poles	Concrete poles	20,445	32	80	16
Poles	Steel structure	25	30	65	2
Crossarms	Distribution Crossarms	41,368[151]	-	40	-

Fleet health and risk

Asset health is determined using CBARMM. For overhead structures, we calculated asset health using a combination of asset age, asset location, asset type reliability, asset material, and inspected condition. We have good quality asset age for concrete poles and good quality condition data that is a reasonable health predictor. There are still outlying data issues within the distribution fleet (related to pre-1995 assets), and we plan to improve data quality and address known issues further.

Concrete poles are in good condition and around 0.5% of the assets will be at risk grade 4 or 5 within five years (refer to Figure 137). This has reduced from the 2025 AMP with the increase in NEL. Wood poles show more significant health deterioration indicators due to their shorter NEL (around 8% at HIB4-5). However, many wood poles are located in areas with low criticality. Hence, fewer high-risk poles need to be replaced (refer to Figure 138). As new condition information is captured during routine inspections, we expect to see movement in the health and risk assessments in future AMPs.

For crossarms, 3% will be at risk grade 4 or 5 within five years (refer to Figure 139). We are undertaking further analysis and verification of crossarm data over the next 1-2 years; hence our view on risk may change in future AMPs.

Figure 137: Asset Health and Risk, Concrete and Steel Poles

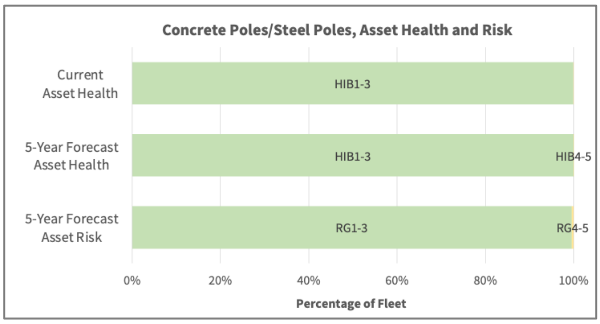
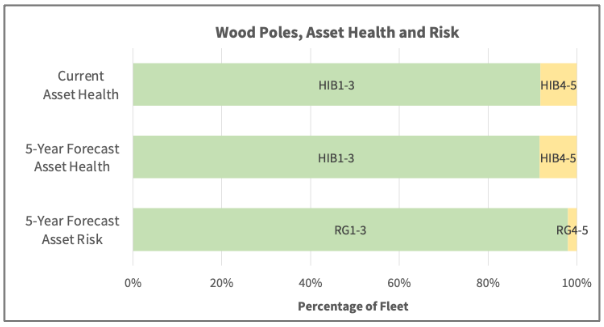


Figure 138: Asset Health and Risk, Wood Poles



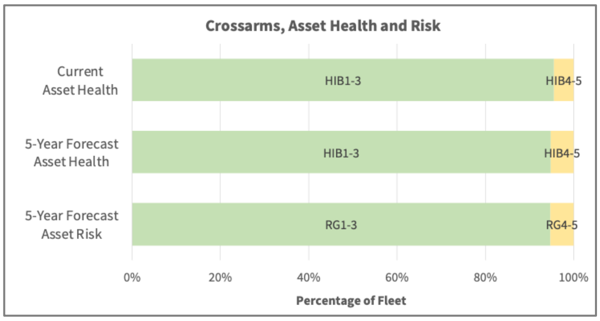
148 Nominal expected life. This is the age when it would be expected to first observe significant deterioration. This represents the average service life of the asset. Assets can operate longer than NEL based on active monitoring of condition.

149 We are missing age data for many of the assets. This is likely to be materially higher.

150 We are missing age data for many of the assets. This is likely to be materially higher and closer to the total population.

151 The crossarm data is to be validated through the next inspection cycles.

Figure 139: Asset Health and Risk, Crossarms



12.12.3 How the asset fleet is operated, monitored and maintained

Condition assessment

Table 109 summarises the distribution fleet's current inspection and testing regime. Electra makes use of full-time network inspectors to assess the distribution network. These inspections happen routinely, and the entire distribution fleet is inspected at least once every 5 years. Sub-transmission assets are inspected annually.

Table 109: Condition assessments

Asset	Type	Scope of assessment	Trigger
Concrete/Steel poles	Observed	Routine inspection of visual condition including the integrity of concrete and reinforcing, corrosion (of steel poles), pole lean, line clearances, foundation slumping or subsidence	11kV and LV time-based, 5 yearly 33kV time-based, annual
Softwood/Hardwood poles	Observed	Routine inspection of visual condition, including rot, fungus, splitting of timber becomes greater than finger-width, warping or twisting of timber strains, heart timber becomes exposed, deterioration of timber more than surface deep (especially at ground level), pole lean, line clearances, foundation slumping or subsidence	11kV and LV time-based, 5 yearly 33kV time-based, annual
Crossarms	Observed	Routine inspection for rot, fungus, lichen/moss, burning or scorching possibly from tracking, rust on galvanised steel arms more than surface deep, corrosion of stays significant enough to reduce physical strength, loose or fallen stays, corrosion of bolts, missing nuts, plate washers or spring washers, chipped or cracked insulators, broken binders	11kV and LV time-based, 5 yearly 33kV time-based, annual
ex-Chorus poles	Observed	Undertake detailed condition assessment	FY27-FY28

Maintaining the asset

Where necessary, corrective maintenance occurs following routine inspection results and fault responses. Maintenance is undertaken to minimise the risk of faults due to asset condition or where further asset deterioration could increase safety risk. Maintenance occurs where this is more economic than asset replacement (from a total lifecycle perspective).

Table 110: Corrective and preventive maintenance

Asset	Type	Scope of maintenance	Trigger
Poles	Corrective	Straightening or reblocking of poles	• Routine inspections or defect order: where the lean is greater than 7°
Poles, concrete	Corrective	Repair of hairline cracks in concrete using commercially proven grout and treatments	• Routine inspections or defect order: concrete cracking detected

Asset	Type	Scope of maintenance	Trigger
Crossarms	Corrective	Replace insulators	• Routine inspections or defect order: Cracked/broken/leaning insulators • Monitoring of the surface condition of polymer insulators

12.12.4 How renewal decisions are made on the fleet

CBARMM is used to forecast asset renewals. Table 111 shows the specific drivers for asset renewal forecasting and the triggers for selecting specific asset renewal projects (within the overall asset renewal forecast). When projects are being selected, priority is given to the worst performing feeders (refer to Section 4.5.9).

Table 111: Drivers and triggers for renewal forecasts and projects

Asset	Type	Drivers/triggers
All pole types and crossarms	Renewal forecasts	Includes all assets where the risk increases above RG4
	Corrective renewal of refurbishment	Replacement or refurbishment of an asset under fault or defect conditions is typically driven by immediate safety concerns or where the risk of failure is assessed to be possible within the next 3 months
Wood poles	Renewal and refurbishment projects	Specific renewal or refurbishment projects are defined based on the presence of end-of-life drivers, including checking, rotting at ground level, damage to wood around fittings (such as crossarm kingbolt)
Concrete poles	Renewal and refurbishment projects	Specific renewal or refurbishment projects are defined based on the presence of end-of-life drivers, including cracking or missing concrete, exposed rebar, bending, leaning over acceptable limits
Steel Poles	Renewal and refurbishment Projects	Specific renewal or refurbishment projects are defined based on the presence of end-of-life drivers, including bending, leaning over acceptable limits, rust/corrosion
Crossarms	Renewal and refurbishment Projects	Specific renewal or refurbishment projects are defined based on the presence of end-of-life drivers, including rot, checking, cracking

12.12.5 Asset renewal and refurbishment forecasts

Table 112 shows the forecast overhead structure asset health, risk and renewals over the next five years. Forecast renewals address all high-risk assets. We have allowed for a higher replacement rate for concrete poles and crossarms to account for additional replacements during the reconductoring programme (a proportion of poles and crossarms are replaced during reconductoring due to health or strength assessments). However, pole replacement rates have reduced from those included in the 2025 AMP, as we have allowed for a lower replacement during reconductoring (based on recent projects).

As mentioned in Section 12.12.2, condition data and health assessment is constantly evolving; hence, we expect to see movement in forecast renewals in future AMPs.

Table 112: Current and forecast asset risk and renewals

Asset	Type	Population[152]	5 Year forecast of assets with low health grade[153]	5 Year forecast of assets with high risk and above[154]	5 Year forecast renewals and refurbishment
Poles	Concrete and Steel	20,467	0.1%	0.6%	2.5%
	Wood	950	8.4%	2.0%	9.9%
Crossarms	All types	~41,368	5.2%	5.3%	10.7%[155]

12.12.6 Asset renewal and refurbishment programmes

Table 113 shows the planned pole and crossarm renewal programmes. These projects/provisions cover the assets identified in Table 112. Most of the pole and crossarm replacements occur during reconductoring.

Forecast expenditure has reduced from $58.9m in the 2025 AMP to $46.5m in this AMP. This has been driven by reductions in 11kV and LV inspection-driven pole replacements, as well as in pole replacements during reconductoring. We have also reviewed the cost of crossarm replacements during reconductoring, and these are lower than we included in the 2025 AMP (due to economies of scale for large reconductoring jobs).

Table 113: Renewal and refurbishment programmes (Real $000)

Project/Programme	Description	FY27-31	FY32-FY36	Total
Poles				
33kV pole replacements, risk and inspection driven	Approximately 22 poles p.a.	1,722	1,728	3,449
11kV pole replacements, risk and inspection driven	Approximately 6 poles p.a.	273	274	547
11kV pole replacements during reconductoring	Some poles need to be replaced during reconductoring to meet existing network standards or due to condition or strength. Approximately 24 poles p.a.	1,098	1,101	2,199
LV pole replacements, risk and inspection-driven	Approximately 6 poles p.a.	206	207	413
LV pole replacements during reconductoring	Some poles need to be replaced during reconductoring to meet existing network standards or due to condition or strength. Approximately 64 poles p.a.	2,193	2,201	4,394
Unplanned replacement of poles (all voltages)	Fault/urgent defect pole replacement includes car vs. poles and normal-year weather events Note: No allowance is included for major storm replacements.	1,214	1,218	2,432
Crossarms				
33kV crossarm replacements, risk and inspection driven	Approximately 60 crossarms p.a.	2,321	2,329	4,649
11kV crossarm replacements, risk and inspection driven	Approximately 150 crossarms p.a. Note: This includes the programme prioritising kidney strain insulator replacements, which will be factored into the prioritisation for renewals	3,010	3,021	6,030

152 As at 31 March 2024.
153 HIB4 and HIB5 (equivalent to EEA health index of H2 and H1). Before renewal or refurbishment intervention.
154 Risk Grade 4 and 5. Before renewal or refurbishment intervention.
155 4,420 crossarms are forecast for replacement. The crossarm count needs to be validated, hence, the percentage may not be correct.

Project/Programme	Description	FY27-31	FY32-FY36	Total
11kV crossarm replacements during reconductoring	Some crossarms need to be replaced during reconductor to meet existing network standards or due to condition or strength. Approximately 184 crossarms p.a.	1,098	1,101	2,199
LV crossarm replacements, risk and inspection-driven	Approximately 82 crossarms p.a.	1,652	1,658	3,310
LV crossarm replacements, during reconductoring	Some crossarms need to be replaced during reconductor to meet existing network standards or due to condition or strength. Approximately 437 crossarms p.a.	6,491	6,513	13,004
Unplanned replacement of crossarms (all voltages)	Fault and urgent defect replacement of crossarms	156	157	313
Total	**Asset replacement and renewal capex**	**23,475**	**23,108**	**46,583**

Table 114: Asset replacement and renewal capex (Real $000)

Item	FY27	FY28	FY29	FY30	FY31	FY32	FY33	FY34	FY35	FY36	Total
Overhead structures (poles and crossarms)	4,680	4,703	4,696	4,696	4,700	4,612	4,621	4,617	4,629	4,629	46,583

Forecasts for fault repair, inspection, and maintenance of these assets are included in the network opex forecasts in Section 12.19. A $350k destructive testing programme covering poles, crossarms and conductor has been included in the opex budgets. A $50k pole inspection programme has also been included in opex for ex-Chorus poles that are vested to us.

12.13 Overhead Conductor Fleet Plan

12.13.1 Fleet Overview and Strategy

Electra has 186km of 33kV overhead conductor, 849km of 11kV overhead conductor, and 523km of LV overhead conductor.[156] Most overhead conductors were installed between 1960 and 1990, when the network grew significantly. 7% of the 11kV and 55% of LV overhead conductors are copper—much of this was installed before 1960 and is falling due for replacement. The remaining overhead conductor is mostly aluminium or aluminium conductor steel reinforced (**ACSR**). ACSR combines highly conductive aluminium with a steel core for good conductivity and strength. It is used extensively on the 11kV network.

All LV copper overhead conductors are bare, and 151km of the aluminium LV overhead conductors are also bare. All new LV overhead conductors are covered (i.e. insulated), which improves safety.

As with overhead structures, this fleet has a large number of assets, and failures can disrupt supply. However, the sub-transmission and distribution network has inherent security, meaning supply can generally be restored to the unfaulted line sections through alternative lines.

The 10-year fleet strategy is as follows:
Our strategy for the fleet is to: • Replace all assets commensurate with their risk—that is, to replace assets before failure (under normal loading), which is at Risk Grade 4 and 5;

156 As at 31 March 2025.

- Prioritise the renewal of old copper overhead conductors that are reaching end-of-life;
- Assess and adopt industry standard condition assessment techniques to improve condition data and the reliability of the asset health forecasting;
- Build data on joints and develop a strategy for health assessment and proactive joint replacements.

12.13.2 What is driving our fleet strategy

Current fleet performance

Overhead conductors have generally operated reliably, with very low rates of defective equipment faults. Defective equipment fault rates have averaged 1.0 faults per 100km/year over the past six years. Many of these faults relate to conductor connectors and clamps (rather than the conductor).[157] There is no observable deteriorating trend.

End-of-life drivers for replacement are appearing on copper overhead conductors. This is driven by corrosion due to exposure to coastal conditions. Failures are highest where assets are exposed to coastal conditions. We are also experiencing increased joint failures from thermal expansion/contraction caused by load changes. This can lead to water ingress, dissipation of the jointing paste, galvanic corrosion, and eventual failure.

Our overhead line fault rate (including structures and overhead conductors) is comparable to the industry for distribution lines and favourable for subtransmission lines (refer to Section 12.12.2). The good subtransmission performance reflects the higher level of condition monitoring (and associated follow-up) for these assets.

Specific fleet risks and failure modes

Table 115 shows the top risks and failure modes overhead conductors. Condition monitoring and maintenance (as shown in Table 117 and Table 118) identify and reduce failure risks.

Table 115: Specific risks

<table>
<tr><th>Asset</th><th>Risk/failure mode</th><th>Current controls or treatments</th></tr>
<tr><td>All overhead conductors</td><td>Joints failure</td><td rowspan="3">Where end-of-life condition drivers are identified from routine inspection, an increased deterioration rate is applied with CBARMM.
Assets are scheduled for replacement within one year when significant end-of-life drivers are found (which raises the risk to RG5).</td></tr>
<tr><td>Bare overhead conductor</td><td>Corrosion and failure of overhead conductor strands</td></tr>
<tr><td>Copper overhead conductor</td><td>Embrittlement of overhead conductor strains due to vibration</td></tr>
<tr><td>All overhead conductors</td><td>Loading exceeding design limits due to external factors (e.g. storm windspeed or tree fall)</td><td>Overhead conductor tension designed to AS/NZS7000:2016.
Implement the vegetation management plan to reduce the risk of vegetation damage (refer to Section 12.19.2).</td></tr>
<tr><td>All overhead conductor</td><td>Overhead conductor sagging which breaches minimum line clearances to the ground and buildings</td><td>Line clearances are assessed during routine inspections and any issues are resolved</td></tr>
</table>

[157] Defective equipment faults for FY20 to FY25. Benchmark data is not readily available.

Fleet population and age

Table 116 shows the population and age of the overhead conductors. 14% of the 33kV overhead conductor is above NEL. 6% of 11kV conductors are within five years of NEL. This has decreased relative to the 2025 AMP due to the reconductoring programme. The average age of 11kV copper conductors has also reduced following recent reconductoring. 88% of LV overhead conductors are also within five years of NEL, reflecting the lower NEL applied to those assets.

We are undertaking an extensive copper reconductoring programme (which is driven in part by the conductor NEL). We intend to conduct testing to verify the residual strength of conductors removed from service. We plan to conduct a destructive testing programme to assess whether changes to NEL are appropriate. This is planned for FY2027 to FY2029, then on a three-yearly basis. This may alter our view of our renewal programme.

Table 116: Asset fleet quantity and age

Asset	Type	Population[158]	Average Age (years)	NEL[159] (years)	Population within 5 years of NEL
33kV overhead conductor	Aluminium	126.7 km	40	65	Nil
	Copper	57.3 km	39	60	25.1 km
11kV overhead conductor	Aluminium	792.8 km	34	65	5.5 km
	Copper	56.3 km	57	60	45.3 km
LV overhead conductor	Bare Aluminium	155.6 km	45	55	8.6 km
	Covered Aluminium	83.3 km	28	60	5.7 km
	Bare copper	213.6 km	60	55	208.3 km
	Covered copper	73.4 km	60	60	45.3 km

Electra also has 64km of streetlighting overhead conductors. These are managed in conjunction with the associated LV overhead conductors.

Fleet health and risk

Asset health is determined using CBARMM. For overhead conductors, we calculated asset health using a combination of asset age, asset location, asset type reliability and asset material. Asset age data is very good for subtransmission and good for distribution and LV overhead conductors. Due to the complexity of assessing overhead conductor condition, our modelling only provides an indicative view of asset health.

For the 33kV overhead conductor, the lower health assets are predominantly driven by older copper overhead conductors on the Mangahao to Levin East circuit. Most segments on these circuits have high criticality. Hence, the forecast risk largely follows the health forecast (refer to Figure 140).

For the 11kV overhead conductor, the lower health assets are driven by older copper overhead conductors; however, due to lower criticality, none of these overhead conductors are forecast to transition to high risk (refer to Figure 141).

[158] As at September 2025.

[159] Nominal expected life. This is the age when it would be expected to first observe significant deterioration. This represents the average service life of the asset. Assets can operate longer than NEL based on active monitoring of condition.

For the LV overhead conductor, a high proportion of older copper overhead conductors is driving asset risk. The high-risk assets account for approximately 50% of the fleet (see Figure 142).

The fleet health is similar to that included in the 2025 AMP (save for the minor improvements due to the 11kV and LV reconductoring).

Figure 140: Asset Health and Risk, 33kV Overhead Conductor

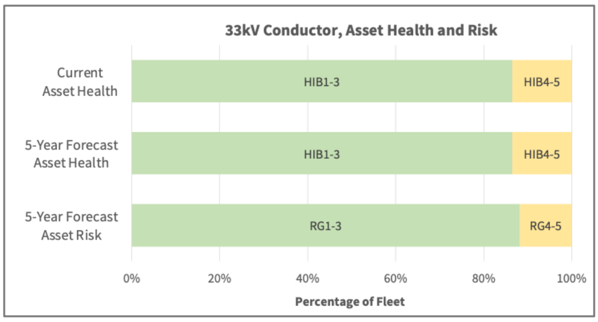


Figure 141: Asset Health and Risk, 11kV Overhead Conductor

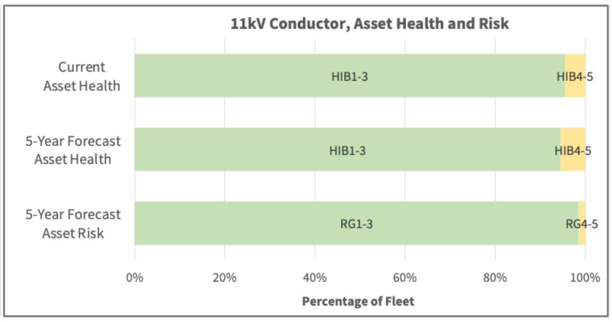
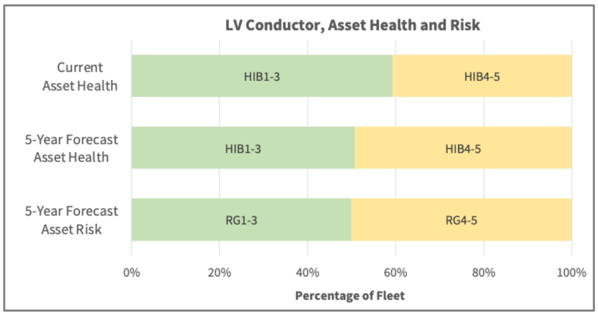


Figure 142: Asset Health and Risk, LV Overhead Conductor



12.13.3 How the asset fleet is operated, monitored and maintained

Condition assessment

Currently, our routine inspections do not deliver reliable data to drive overhead conductor asset health in CBARMM. We are keeping abreast of industry developments for overhead conductor condition assessment (as aging overhead conductor fleets is an industry-wide issue). We plan to adopt better assessment techniques when these become available. Table 117 summarises the distribution fleet's current inspection and testing regime—this data is used to identify defects and define specific renewal projects.

11kV and LV assets are inspected at least once every 5 years. Sub-transmission assets are inspected annually.

Electra intends to complete the physical strength and remaining life tests on 33kV overhead conductors removed from service. These test results are a critical part of condition assessment and will be used to assist the development of the replacement programme for 33kV and 11kV circuits

Table 117: Condition assessments

Asset	Type	Scope of assessment	Trigger
Overhead conductors, all	Observed	Routine inspection for stretching, elongation or necking consistent with annealing, bird-caging of complete overhead conductor, clearance of live overhead conductors from ground, trees, other parties' wires and surrounding structures, excessive surface corrosion, overall integrity of complete overhead conductor	11kV and LV, time-based, 5 yearly 33kV, time-based, annually

Asset	Type	Scope of assessment	Trigger
Overhead conductors, 33kV	Measured	Thermography survey for heating of joints and terminations (including on overhead switchgear)	Time-based, 5 yearly

Maintaining the asset

Overhead conductor maintenance is limited to re-tensioning and joint/termination replacements (refer to Table 118).

Table 118: Corrective and preventive maintenance

Asset	Type	Scope of maintenance	Trigger
Overhead conductors, all	Corrective	Re-tensioning of lines that do not meet NZECP 34	• Routine 5 yearly inspections where the distance between the ground/structure and the overhead conductor
	Corrective	Joint or termination replacements	• Routine 5 yearly inspections where corrosion on joints and terminations is observed

12.13.4 How renewal decisions are made on the fleet

Table 119 shows the specific drivers for asset renewal forecasting and the triggers for selecting specific asset renewal projects (within the overall asset renewal forecast). CBARMM is used to forecast asset renewals. For overhead conductors, this is aged-based for 33kV and 11kV and observed-condition-based for LV.

When projects are being selected, priority is given to the worst performing feeders (refer to Section 4.5.9).

Table 119: Drivers and triggers for renewal forecasts and projects

Asset	Type	Drivers/triggers
Overhead conductors, all	Renewal forecasts	Age-based health and risk forecasting. All assets where the age is above NEL are defined as HIB4 or HIB5. The risks associated with many of the HIB4 assets are manageable. For LV overhead conductors, the forecast renewals reflect known condition issues (which are lower than the forecast age-based health/risk forecasts).
	Renewal and refurbishment Projects	Specific renewal or refurbishment projects are defined based on the age of the asset and the presence of end-of-life drivers, including spragging, powdering, bird-caging, inline joints, EPOs

12.13.5 Asset renewal and refurbishment forecasts

Table 120 shows the forecast for overhead conductor asset health, risk, and renewals over the next five years.

Sections of the Levin West to Levin East and Foxton to Levin West lines are being assessed for planned replacement. These projects have dual renewal and development drivers and are included in the development section (see Section 11.9.3). These projects represent the renewal of 7.6% of the 33kV overhead conductor between FY2030 and FY2034.[160] 33kV overhead conductor upgrade is being considered for the Mangahao to Levin East lines[161] (see Section 11.8.1).

The 11kV conductor renewals are higher than forecast risk due to the copper conductor renewal programme, which is addressing all low health copper conductors.

[160] This is 3.15km on the Levin West to Levin East 33kV line and 11km on the Foxton to Levin West 33kV line. The Mangahao to Levin East lines are not yet included as that project is still in the concept phase.

[161] The Levin East 2 circuit.

The current forecast renewals for LV overhead conductors are below forecast health and risk—the current forecast addresses assets with observed condition issues (around 50% of assets at Risk Grade 5). As noted in Table 119, the current renewal forecasts are age-based. We are not seeing any material deterioration in LV performance or outages that would indicate a higher renewal rate is required.

As outlined in the fleet strategy, we are exploring ways to enhance condition data to improve asset health and risk forecasts. Over time, this will improve asset health and risk forecasting.

Table 120: Current and forecast asset risk and renewals

Asset	Type	Population[162]	5 Year forecast of assets with low health grade[163]	5 Year forecast of assets with high risk and above[164]	5 Year forecast renewals and refurbishment
Overhead conductor	33kV overhead conductor	186 km	13.5%	11.8%	0.04%[165]
	11kV overhead conductor	849 km	5.4%	1.5%	7.3%
	LV overhead conductor	523 km	49.3%	50.1%	15.4%

12.13.6 Asset renewal and refurbishment programmes

Table 121 shows the planned overhead conductor programmes. The reconductoring programme is the same as included in the 2025 AMP.[166]

Table 121: Renewal and refurbishment programmes (Real $000)

Project/Programme	Description	FY27-31	FY32-36	Total
33kV reconductoring	Replacement of sections of the Levin West to Levin East and Foxton to Levin West lines (refer to Section 11.9.3)	-	-	-[167]
11kV reconductoring	Replacement of all old copper overhead conductors over the next ten years 12.4km overhead reconductoring p.a.	5,230	5,248	10,477
LV reconductoring	Replacement of all old copper overhead conductors over the next ten years 16.2km overhead reconductoring p.a.	11,724	11,765	23,490
Unplanned replacement of overhead conductor (33kV)	Fault/urgent defect overhead conductor replacement (includes normal-year weather events only)	42	42	84
Unplanned replacement of overhead conductor (11kV and LV)	Fault/urgent defect overhead conductor replacement (includes normal-year weather events only)	36	36	73
Total	**Asset replacement and renewal capex**	**17,032**	**17,092**	**34,124**

Table 122: Asset replacement and renewal capex (Real $000)

Item	FY27	FY28	FY29	FY30	FY31	FY32	FY33	FY34	FY35	FY36	Total
Conductor	3,396	3,412	3,407	3,407	3,410	3,411	3,418	3,415	3,424	3,424	34,124

[162] As at 31 March 2025.
[163] HIB4 and HIB5 (equivalent to EEA health index of H2 and H1). Before renewal or refurbishment intervention.
[164] Risk Grade 4 and 5. Before renewal or refurbishment intervention.
[165] This is the unplanned renewal rate.
[166] Over the comparable FY27-FY35 period in 2026$.
[167] Included as system growth capex in Section 11.9.3.

Note: the LV reconductoring project includes the replacement of any associated street lighting or pilot wire overhead conductor.

Forecasts for fault repair, inspection and maintenance of these assets are included within the network opex forecasts contained in Section 12.19. A $350k destructive testing programme covering poles, crossarms and conductor has been included in the opex budgets.

12.14 Cable Fleet Plan

12.14.1 Fleet Overview and Strategy

Electra has 31km of 33kV cable, 270km of 11kV cable and 541km of LV cable.[168] The 33kV cables are modern cross-linked polyethene insulated with steel wire armour (**XLPE**) installed progressively since the 1990s. The 11kV cables consist of XLPE-insulated and older paper-insulated lead-sheathed (PILC). There are approximately 5km of first-generation XLPE cables that are prone to water treeing and insulation breakdown. The PILC cables were mainly installed between 1960 and 1990. LV cables are predominantly modern PVC-insulated (87%) and XLPE-insulated (12%), with a very small amount of old PILC-insulated (0.2%).

Figure 143: Cable Types

There are a high number of assets in this fleet, and failures can interrupt supply; however, these are rare as cables are generally not exposed to environmental factors. The sub-transmission and distribution network has inherent security, meaning supply can usually be restored to the unfaulted line sections through alternative lines.

We have an aging fleet of 11kV and LV cables, and reliability- and defect-driven replacements will likely increase for this fleet in future AMPs. We also have some old pitch-filled pothead and in-line cable joints on poles that present risks that need to be addressed.

The 10-year fleet strategy is as follows:
Our strategy for the fleet is to:

[168] As at 31 March 2025.

- For 33kV cables (where health can be reliably determined), replace assets commensurate with their risk—that is, to replace all assets forecast at Risk Grade 4 and 5;
- For 11kV and LV cables (where health cannot be reliably determined), replace assets where performance issues are detected;
- Investigate any reliability issues to determine if any associated asset health issues need to be addressed;
- Identify and replace all in-line cable joints on poles and all older pothead terminations;
- Assess and adopt industry standard condition assessment techniques to improve condition data and the reliability of the asset health forecasting for 11kV and LV cables.

12.14.2 What is driving our fleet strategy

Current fleet performance

Over the past five years, the underground cable fault rate (all causes) was 6.3 faults/100km for distribution cables and 0.0 faults/100km for sub-transmission. The fault rate for 11kV cables has increased as in FY2025, we experienced an increase in the number of 11kV cable termination failures (refer to Section 4.5.3). The impact of cable termination outages is exacerbated by the low security on many of our underground feeders (see Section 3.5.3).

This is higher than our peers for distribution cables (3.5 faults/100km) and similar for sub-transmission (0.03 faults/100km).[169] In FY2025, we recorded 16 cable-related equipment faults, compared with an average of 3.8 p.a. over the prior 5 years.

End-of-life drivers for replacement are beginning to appear on older PILC cables and some older-style joints and terminations. These are rare; however, we expect failures to increase with the aging fleet. Repairing underground cables, joints, and terminations can be time-consuming, leading to extended outages for customers supplied from the faulted assets.

Specific fleet risks and failure modes

Table 123 shows the top risks and failure modes of cables. These include failure modes from normal deterioration and type issues relating to pitch-filled potheads and in-line joints on poles.

Pitchfilled potheads have failure modes related to the trifurcation within the bitumen insulation that could result in leaks, fires, and explosions. There was a short historic practice of installing 11kV in-line cable joints on poles, which poses a safety risk should the joint fail. All the in-line cable joints were fitted with pole covers which partially mitigates the risk.

Table 123: Specific risks

Asset	Risk/failure mode	Current controls or treatments
Cables (all)	Insulation deterioration due to the natural aging process	Partial discharge condition data is only available for subtransmission, which can reliably determine asset health in CBARMM. Assets are scheduled for replacement within one year when significant end-of-life drivers are found. For 11kV and LV, health and risk cannot be reliably forecast, so it is assessed based on reliability. Assets are scheduled for
	Failure due to in-line joints	
Cables (LV)	Failure due to in-line joints and deterioration of internal connections resulting in livening of pillar lid	

[169] All fault cases. Median, FY20-FY24.

Asset	Risk/failure mode	Current controls or treatments
		replacement within one year when reliability issuers are identified.
11kV inline cable joints on poles	Failure of the cable joint that could result in leaks, fires, explosions	These are currently ducted to contain arc flash. However, a proactive replacement program is planned
Pitchfilled pothead OH/UG cable trifurcation	Failure of trifurcation within bitumen that could result in leaks, fires, explosions	Implementation of the replacement programme for all potheads over the next ten years
11kV cable terminations	Failure of heat-shrink cable terminations. This can lead to multi-termination failures if these occur with transformers HV boxes where multiple cables are terminated.	The recent increase in termination failures is being investigated We are considering projects to install switchgear to remove daisy-chain terminations
Cables (all)	Damage from third-party	Implementation of the public safety management system, including the dial-before-you dig process.

Fleet population and age

Table 124 shows the population and age of the cables. Around 12% of the 11kV cable fleet is within 5 years of NEL. LV cables are the only asset with material quantities within five years of NEL (~33%).

Table 124: Asset fleet quantity and age

Asset	Type	Population[170]	Average Age (years)	NEL[171] (years)	Population within 5 years of NEL
33kV cable	XLPE-insulated	31 km	20	45	0.3 km
11kV cable	XLPE-insulated	147 km	17	45	Nil
	XLPE-insulated, 1st generation	5.2 km	45	30	5.2 km
	PILC-insulated	124 km	47	60	28.7 km
LV Cable	XLPE-insulated	70 km	10	45	1.5 km
	PVC-insulated	499 km	31	45	155 km
	PILC-insulated	1.2 km	unknown	60	unknown

Fleet health and risk

Asset health is assessed using CBARMM. For cables, we determine asset health by considering asset age, location, reliability, and material type. Asset age data is good for all cables. Due to the complexity of assessing cable condition, our modelling only offers a general indication of asset health.

There are no current or forecast health or asset risks for 33kV cables (refer to Figure 144).

Asset health and risk are expected to worsen for 11kV and LV cables. This is due to the aging of the 11kV PILC cables, first-generation XLPE, and LV cables, mainly PVC (see Figure 145 and Figure 146). The risks related to heat shrink-type terminations, pitch-filled potheads, and in-line cable joints concern cable components and are not included in the health and risk assessments below.

[170] As at October 2025. LV includes streetlighting.

[171] Nominal expected life. This is the age when it would be expected to first observe significant deterioration. This represents the average service life of the asset. Assets can operate longer than NEL based on active monitoring of condition.

Figure 144: Asset Health and Risk, 33kV Cable

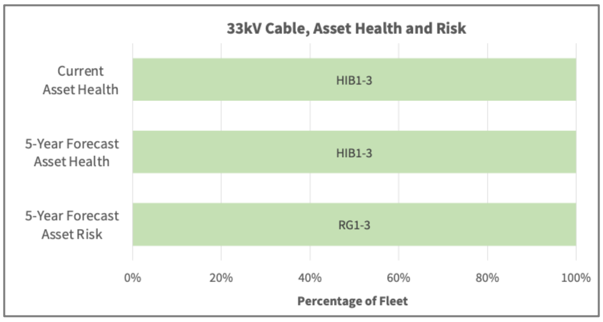


Figure 145: Asset Health and Risk, 11kV Cable

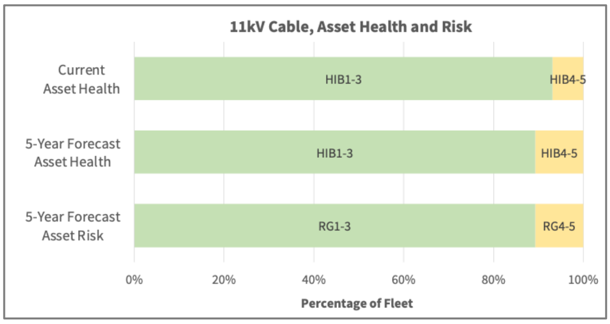
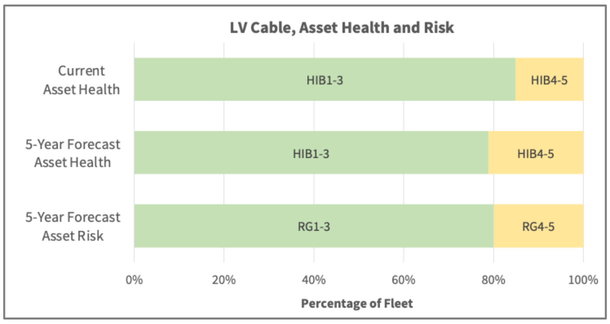


Figure 146: Asset Health and Risk, LV Cable



12.14.3 How the asset fleet is operated, monitored and maintained

Condition assessment

Our 11kV and LV routine inspections do not deliver reliable data to drive cable asset health in CBARMM, due to the inherent nature of buried assets. We are keeping abreast of industry developments for cable condition assessment (as aging cable fleets is an industry-wide issue). We plan to adopt better assessment techniques when these become available. Table 125 summarises the distribution fleet's current inspection and testing regime—this data is used to identify defects and define specific renewal projects.

We have added a programme for 11kV cable partial-discharge testing of cables with performance issues or approaching their nominal expected life. This data will support our renewal planning for this fleet (currently age- and performance-based) and address the current cable termination issue.

Table 125: Condition assessments

Asset	Type	Scope of assessment	Trigger
Cables, 33kV	Observed	Inspection of route and terminations, including visible deterioration of potheads or composite terminations, visible deterioration of cable sheathing, visible shifting of the cable within the mountings or ground that may be straining internal components	Time-based, annually
Cables, 33kV	Measured	Partial discharge testing of single core XLPE insulated cables to assess deterioration of cable insulation (on some cables where the cable screens have been extended)	As required
Cables, 33kV	Measured	Tan Delta testing (also called Loss Angle or Dissipation Factor testing) to assess the quality of the cable insulation	Time-based, 3 yearly
		Thermography of cable terminations reveals excessive temperatures	

Asset	Type	Scope of assessment	Trigger
Cables, 11kV	Measured	Partial discharge testing of cable terminations	An annual programme to test terminations in areas where we have seen termination failures
Cables, 11kV and LV	Observed	Underground cables are generally not inspected except at terminations in zone substations, ground-based transformers or switchgear. Observations are as per 33kV cables.	Time-based (in conjunction with zone substation and switchgear inspections)

Maintaining the asset

Cable maintenance is limited to work on terminations and associated fixings. We are expecting cable-termination replacements to increase.

We have a programme to extend the 33kV cable screens in our other zone substations (as part of the 5-year maintenance programme). This will enable testing for transient earth voltage to detect partial discharge (a measure to detect changes in cable insulation condition).

12.14.4 How renewal decisions are made on the fleet

Table 126 shows the specific drivers for asset renewal forecasting and the triggers for selecting specific asset renewal projects (within the overall asset renewal forecast). CBARMM is used to forecast asset renewals. For cables, this is age-based for 33kV and 11kV and observed-condition-based for LV.

Table 126: Drivers and triggers for renewal forecasts and projects

Asset	Type	Drivers/triggers
Cables (all)	Renewal forecasts	CBARMM risk grade, adjusted for known asset reliability issues. There are no known reliability issues (other than the pothead and in-line joint type-issues).
	Renewal and refurbishment Projects	For sub-transmission, we initiate projects based on asset condition. For distribution and LV cables, we initiate projects based on reliability or defects.

12.14.5 Asset renewal and refurbishment forecasts

Table 127 shows the forecast for cable asset health, risk, and renewals over the next five years. We are not forecasting any health or risk issues with 33kV cables. The 33kV cable renewals involve conductor relocations for the O2NL project.

We forecast health and risk issues at 10% and 20% of the 11kV and LV fleets—these are age-based forecasts. Currently, renewal forecasts are based on known reliability or defect issues (none are known at this time, aside from the termination, pothead and in-line joint issue). The small amount of forecast renewal relates to our unplanned replacement provision.

As noted in Sections 5.4 and 5.5, our assets are aging, and the risk of end-of-life drivers leading to asset failures will grow—this is expected to be the case for 11kV and LV cables. Based on our reliability and defect-driven renewal forecasts, we anticipate an increase in forecast renewals in future AMPs.

Table 127: Current and forecast asset risk and renewals

Asset	Type	Population[172]	5 Year forecast of assets with low health grade[173]	5 Year forecast of assets with high risk and above[174]	5 Year forecast renewals and refurbishment
Cable	33kV cable	31 km	0.0%	0.0%	2.2%[175]
	11kV cable	268 km	10.7%	10.7%	0.3%
	LV cable	535 km	21.2%	20.0%	0.1%

12.14.6 Asset renewal and refurbishment programmes

As shown in Table 128, asset renewals currently consist of an unplanned provision for unforeseen cable replacement (which is based on historical quantities). There are no planned cable renewal programmes. Table 129 shows the safety-related replacement of pitch-filled potheads and in-line joints on poles.

Table 128: Renewal and refurbishment programmes (Real $000)

Project/Programme	Description	FY27-31	FY32-37	Total
33kV cable	Some 33kV cables will be replaced in conjunction with the O2NL project (refer to Section 11.14)	-	-	-
Unplanned replacement of cable (all voltages)	Fault/urgent defect cable replacement (includes normal-year weather events only)	142	143	285
Total	**Asset replacement and renewal capex**	**142**	**143**	**285**

Table 129: Other reliability, safety and environmental programmes (Real $000)

Project/Programme	Description	FY27-31	FY32-37	Total
Pitch-filled pothead replacement	Replacement of all pitch-filled potheads with composite termination. The programme is targeting the replacement of all potheads by FY35.	729	731	1,460
In-line cable joint replacement	543 possible sites for in-line joints on poles have been identified. Many of the in-line joins were installed around head-height, and if there is a fault there is a potential safety issue. Further work to determine extent of the conversion programme. The programme is targeting the replacement of all in-line joints by FY30.	733	-	733
Total	**Other reliability, safety and environmental capex**	**1,462**	**731**	**2,193**

Table 130: Asset replacement and renewal capex (Real $000)

Item	FY27	FY28	FY29	FY30	FY31	FY32	FY33	FY34	FY35	FY36	Total
Cables	28	28	28	28	28	28	29	28	29	29	285

Table 131: Other reliability, safety and environmental capex (Real $000)

Item	FY27	FY28	FY29	FY30	FY31	FY32	FY33	FY34	FY35	FY36	Total
Cable pothead and in-line joint replacements	328	330	329	329	146	146	146	146	147	147	2,193

Forecasts for fault repair, inspection, and maintenance of these assets are included in the network opex forecasts in Section 12.19. We have added $20k p.a. for partial discharge testing of 11kV cables with

172 As at 31 March 2024.

173 HIB4 and HIB5 (equivalent to EEA health index of H2 and H1). Before renewal or refurbishment intervention.

174 Risk Grade 4 and 5. Before renewal or refurbishment intervention.

175 Driven by asset relocations.

performance issues. We have not yet increased our provision for cable maintenance, but expect it to increase in future years once the outcome of the termination PD testing is known.

12.15 Distribution Switchgear Fleet Plan

12.15.1 Fleet Overview and Strategy

Electra has 73 distribution pole-mounted reclosers and sectionalisers, over 3,000 11kV pole-mounted drop-out fuses and switches (including 336 air break switches) and 197 ground-mounted ring-main units (**RMUs**).[176] These assets are integral to the operation of the network during planned and unplanned outages. The switches allow the network to be reconfigured to restore supply when a section of the network is de-energised due to a fault or planned work. Pole-mounted fuses and reclosers are essential components of the electrical protection system and can reduce outage areas when faults occur.

Figure 147: Ground-Mounted Ring Main Unit

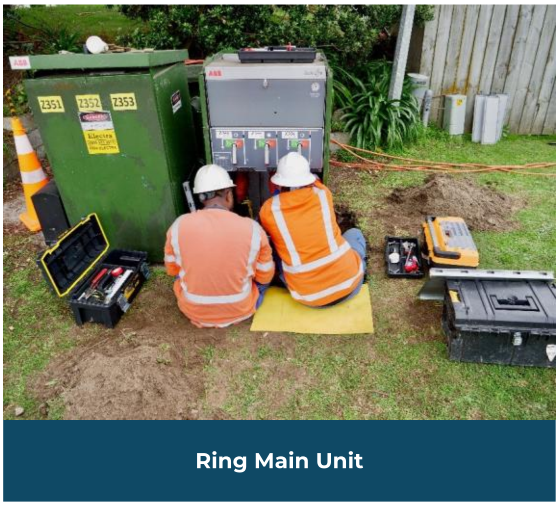


Figure 148: Pole-Mounted Switches

[176] As at 31 March 2025.

The use of reclosers expanded in the 2000s, so a large proportion of this fleet is relatively new.

We have good data on our fleet of air-break switches (**ABSs**) and have identified various issues with these assets that require accelerated replacement and a change in maintenance practice. We do not currently have good data on drop-out fuses and links; hence, our renewal forecast for these assets is an estimate and reflects their replacement in conjunction with other renewal programmes.

Our fleet of RMUs is relatively new; however, some of these assets are located in coastal areas, reducing their expected life and driving earlier renewal under normal conditions. There are also 11 units with a type issue that requires replacement. Our fleet of RMUs is expected to expand as more switches on the underground network are required to meet our planned criteria. This programme is covered in Section 11.10.3.

The 10-year fleet strategy is as follows:
Our strategy for the fleet is to: • Replace all assets commensurate with their risk—at Risk Grade 4 and 5; • Prioritise the renewal of assets with type issues, including Mahanga ABSs and ABB Safelink 1 RMUs; • Implement operational testing and maintenance of our ABS fleet; • Review the health and risk for reclosers and develop an appropriate replacement programme; • Improve the data quality of drop-out fuses and links; • Ensure that public safety risks are managed as required under our Public Safety Management System.

12.15.2 What is driving our fleet strategy

Current fleet performance

The switchgear fleet has generally operated reliably, although there have been higher defective equipment fault rates for ABSs and reclosers than other distribution switchgear. Defective equipment fault rates are recorded at 25 faults per 1,000 units per year for reclosers, 6.0 per 1,000 units per year for ABSs, 1.6 per 1,000 units per year for fuses and links, and <1 per 1,000 units per year for RMUs.[177] Given the very few defective equipment failures, there is no observable deteriorating trend.

We are experiencing some operating restrictions and ABS failures due to a manufacturing defect.

Specific fleet risks and failure modes

Table 132 shows the top risks and failure modes for distribution switchgear. The key risks relate to type issues, corrosion and public access.

Table 132: Specific risks

Asset	Risk/failure mode	Current controls or treatments
Air-break switches	We have type issues with Mahanga ABSs manufactured between 1995 and 2015. When mounted vertically, water ingress between the external insulation and internal pin causes	The ABS fleet has been inspected, and all type issues have been identified. A replacement programme has been implemented for the 69 units identified. Operational restrictions are placed on ABSs as required.

[177] For FY20 to FY25. Benchmark data is not readily available.

Asset	Risk/failure mode	Current controls or treatments
	corrosion, resulting in non-operating or failure during operation	
	The prior management practices has led to the seizing of blades and switching mechanisms, misalignment of arc chutes and failure during operation	We are changing this approach by operating the entire ABS fleet to identify ABS with operational issues. These will be scheduled for maintenance or replacement ABS operational checks and maintenance are now being implemented A replacement program for non-operation switches has also been implemented. Operational restrictions are placed on ABSs, which include additional visual inspections before operation. Operational staff also wear appropriate PPE.
	Exposure to coastal conditions causing corrosion and early failure	Corrosion detection as part of routine inspection, with remediation as required. Proximity to the coast is considered in CBARMM, and accelerated deterioration rates are included where appropriate
	Public access to ABS switch handles	Implementation of our Public Safety Management System.
Reclosers	Controllers reach end-of-life ahead of the main tank. This can be from technological obsolescence of control components and corrosion of the control box	Controller replacement programme
Drop-out fuses and links	Fracturing of brittle insulators on some types of drop-out fuses	Replacement of asset types with known issues occurring during other scheduled work
RMUs	Exposure to coastal conditions causing corrosion and early failure	Corrosion detection as part of routine inspection, with remediation as required Proximity to the coast is considered in CBARMM, and accelerated deterioration rates are included where appropriate
	Cable box or bus chamber partial discharge	Partial discharge testing is initiated when this is suspected.
	ABB Safelink 1 RMUs have a type issue causing overtravel during operation. These assets are not considered high risk in their current state, but replacement is seen as prudent	Replacement of the 11 units with known risks by FY36.
	loss/leakage of insulating medium (SF6 mainly)	Routine SF6 monitoring and remediation.
	Public access to equipment and exposure to live parts	Implementation of our Public Safety Management System, which includes various public safety checks

Fleet population and age

Table 133 shows the population and age of distribution switchgear. The ageing of the recloser and RMU fleets has led to an increase in the population within 5 years of NEL for reclosers (to 12%) and RMUs (to 3%). 32% of ABSs are within five years of NEL, which is the same as in the 2025 AMP. We are undertaking further work on the drop-out fuse and link data and will clarify the aging of that fleet in future AMPs.

Table 133: Asset fleet quantity and age

Asset	Type	Population[178]	Average Age (years)[178]	NEL[179] (years)	Population within 5 years of NEL
Reclosers and Sectionalisers	All types	73	21	45	9
Pole-mounted switches and fuses	ABSs	339	24	45	107
	Drop-out fuses and links	2,681	unknown	15	unknown
RMUs	All types	197	11	45	6

Fleet health and risk

Asset health and risk are determined using CBARMM (refer to Figure 149, Figure 150 and Figure 151). For distribution switchgear, we calculated asset health using a combination of asset age, asset location, asset reliability, asset material, and condition. We have average data on reclosers and good data on RMUs, and have provided forecasts of the health and risk of those assets. We have good data on ABSs but poor data on drop-out fuses and links, so we have not provided health and risk forecasts for those assets. This is a work-on for future AMPs.

Recent condition assessments indicate improved health of the recloser fleet. However, condition issues persist with the controllers, which are nearing end-of-life. There are no material changes to the RMU health forecasts.

Figure 149: Asset Health and Risk, Reclosers and Sectionalisers

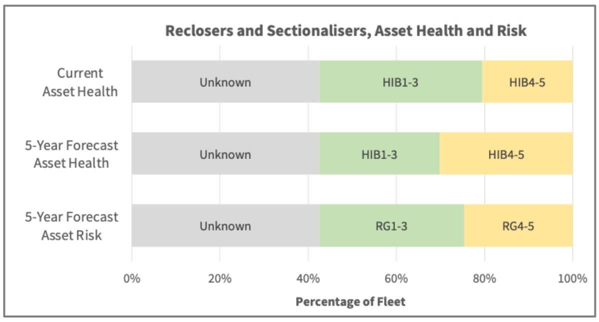
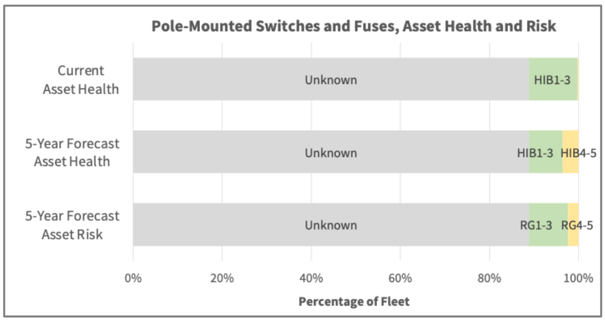


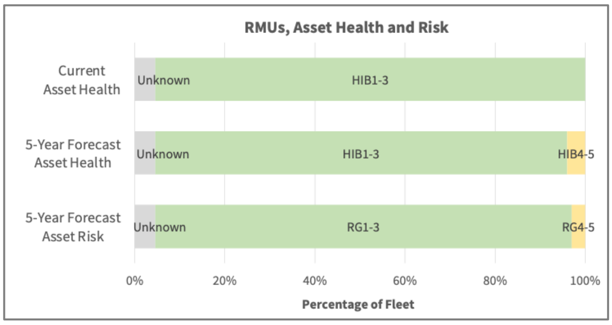
Figure 150: Asset Health and Risk, Pole-Mounted Switches and Fuses



[178] As at October 2025.

[179] Nominal expected life. This is the age when it would be expected to first observe significant deterioration. This represents the average service life of the asset. Assets can operate longer than NEL based on active monitoring of condition.

Figure 151: Asset Health and Risk, RMUs



12.15.3 How the asset fleet is operated, monitored and maintained

Condition assessment

Table 134 summarises the distribution fleet's current inspection and testing regime—this data is used to identify defects and define specific renewal projects.

Table 134: Condition assessments

Asset	Type	Scope of assessment	Trigger
Reclosers	Observed	Routine visual inspection, including for corrosion and cracked insulators, checking of oil or SF6 levels	Time-based, 5 yearly
ABSs	Observed	Routine inspection, including for corrosion, cracked insulators, misaligned blades or flickers	Time-based, 5 yearly
DDOs	Observed	Routine inspection, including for corrosion and cracked insulators	Time-based, 5 yearly
Ring main Units	Observed	Routine inspection for corrosion, damage to lock, missing hold-down bolts, and checking of SF6 gauges	Time-based, 2 yearly
	Observed	Partial discharge testing of Cable box or bus chamber	Suspected during inspection
	Measured	Earth impedance readings	Time-based, 2 yearly

Maintaining the asset

A summary of the typical distribution switchgear maintenance is shown in Table 135.

Table 135: Corrective and preventive maintenance

Asset	Type	Scope of maintenance	Trigger
Reclosers	Preventive	Manufacturers recommend maintenance depending on type and make, in line with manufacturer recommendations Operational testing, including contact separation timing. Maintenance may vary based on the number of operations, oil levels, SF6 pressure and results of operational testing	• Routine 5 yearly inspections and maintenance.
ABSs	Preventive	Maintenance of mechanisms, arc chutes, and blades in line with manufacturer recommendations	• Routine 5 yearly maintenance
Distribution switchgear	All	Painting, galvanising or greasing individual switches near coastal areas	• Corrosion is observed during routine inspections

12.15.4 How renewal decisions are made on the fleet

Table 136 shows the specific drivers for asset renewal forecasting and the triggers for selecting specific asset renewal projects (within the overall asset renewal forecast). CBARMM is used to forecast asset renewals for reclosers, ABSs and RMUs. Pole-mounted drop-out fuses and links are replaced in conjunction with other renewal work or when defective.

When projects are being selected, priority is given to the worst performing feeders (refer to Section 4.5.9).

Table 136: Drivers and triggers for renewal forecasts and projects

Asset	Type	Drivers/triggers
Reclosers	Renewal forecasts	The current forecast is based on recent inspection and operational data, which is being reviewed
	Renewal and refurbishment Projects	The replacement programme is being revised and will be included in the 2026 AMP
ABSs	Renewal forecasts	Includes all assets where the risk increases above RG4
	Renewal and refurbishment Projects	Specific renewal or refurbishment projects are defined based on the presence of end-of-life drivers, including type issues (Mahanga ABSs), fractures of porcelain insulators, tracking on polymer insulators, deterioration of mounting bracket
Drop-out fuses as links	Renewal forecasts	Based on historical replacement rates
	Renewal and refurbishment Projects	No specific projects were identified. Renewal coordinated with other projects or initiated from defects or fault
RMUs	Renewal forecasts	Includes all assets where the risk increases above RG4 and any known type-issues
	Renewal and refurbishment Projects	Projects are defined based on asset condition, risk grade and type issues. RMUs with a high public safety risk will be marked for accelerated replacement.

12.15.5 Asset renewal and refurbishment forecasts

Table 137 shows the forecast distribution switchgear asset health, risk, and renewals over the next five years. Based on known condition issues, we estimate that around 22% of the recloser fleet will require controller replacements over the next 5 years. We expect that some recloser tanks will also need to be replaced, and this replacement programme will be assessed over the next 12 months.

We have not forecast low-health and high-risk pole-mounted switches in this AMP. We have good data on our ABS fleet but less reliable data on pole-mounted fuses and lines. The forecast renewals for this fleet relate to the ABS replacement programmes (in Table 138), and an estimate of the renewal of drop-out fuses and links during reconductoring, pole replacements, pole-mounted transformer replacements and pothead replacements (due to the unreliability of our drop-out fuse and link health data we do not have a specific renewal programme for these assets, but instead they are replaced in conjunction with other renewal programmes or where defects are identified).

Table 137: Current and forecast asset risk and renewals

Asset	Type	Population[180]	5 Year forecast of assets with low health grade[181]	5 Year forecast of assets with high risk and above[182]	5 Year forecast renewals and refurbishment
Pole-mounted switchgear	Reclosers and sectionalisers	73	30.1%	24.7%	21.9%[183]
	Switches and fuses	3,020	unknown	unknown	5.1%
Ground-mounted switchgear	RMUs	197	4.1%	3.0%	4.2%

[180] As at 31 March 2024.

[181] HIB4 and HIB5 (equivalent to EEA health index of H2 and H1). Before renewal or refurbishment intervention.

[182] Risk Grade 4 and 5. Before renewal or refurbishment intervention.

[183] The health, risk and renewal assessments relates to controllers, not the recloser tank.

12.15.6 Asset renewal and refurbishment programmes

Table 138 shows the distribution switchgear renewal programmes. Additional ABSs are expected to be replaced as part of our reliability improvement programmes (refer to Section 11.10.4). Compared to the 2025 AMP, we are commencing a recloser controller replacement programme and the installed RMUs when distribution transformers are renewed. Expenditure on this fleet has increased by $3.4m compared to the 2025 AMP.[184]

Table 138: Renewal and refurbishment programmes (Real $000)

Project/Programme	Description	FY27-31	FY32-36	Total
Pole-mounted switchgear				
ABS replacements, Mahanga	Risk-driven replacement of Mahanga ABSs. 10 units p.a. to FY30	1,344	-	1,344
ABS replacement, Other	Asset health/risk replacement of 4 ABSs p.a. This includes the replacement of non-operational switches.	672	674	1,346
Recloser controller replacement	Programme to replace controllers on reclosers as these are reaching end-of-life	204	-	204
Unplanned replacement	Fault and defect replacement of ABSs, drop-out fuses, automated switches and reclosers	354	355	710
Dropout fuses and link replacements	These are replaced in conjunction with other renewal projects (the expenditure is included in those renewal projects)	-	-	-
Ground-mounted switchgear				
RMU replacements	Asset health/risk replacement of and 2 p.a. from FY27-FY31	462	-	462
Unplanned replacement	Fault and defect replacement of RMUs	289	290	579
RMUs for GM transformer renewals	RMUs to install when GM transformers are renewed. This removes the piggy-backing of cable terminations	1,647	1,984	3,631
Total	**Asset replacement and renewal capex**	**4,972**	**3,303**	**8,275**

Table 139: Asset replacement and renewal capex (Real $000)

Item	FY27	FY28	FY29	FY30	FY31	FY32	FY33	FY34	FY35	FY36	Total
Distribution switchgear	1,091	1,097	1,095	1,095	593	659	660	660	662	662	8,275

Forecasts for fault repair, inspection and maintenance of these assets are included within the network opex forecasts contained in Section 12.19.

12.16 Distribution Transformer Fleet Plan

12.16.1 Fleet Overview and Strategy

Electra's distribution transformers range from rural single-phase 5kVA pole-mounted transformers with basic fuse protection to three-phase 1,000kVA ground-mounted transformers with ring-main-unit and circuit-breaker protection.

[184] In 2026$ over the comparable FY27-35 period.

Electra has 1,645 distribution pole-mounted transformers and 1,022 ground-mounted transformers.[185] These assets convert electricity from 11kV to 400V, which is distributed via the LV network to homes and businesses. Distribution transformers may supply electricity to a single large consumer, several large consumers or many small consumers.

Pole-mounted transformer installations include 11kV fuse protection. Before 2021, all ground-mounted transformers include 11kV fuses in the tank. Newer transformers are unfused, as protection is provided by upline fusing.

Figure 152: Transformers

Pole-Mounted Transformer (recently removed from service) | **Ground-Mounted Transformer (being installed)**

There are generally low consequences of failure for distribution transformers, so we operate these assets at higher risk levels where there are no public safety issues.

Some of these assets are located in coastal areas, reducing their expected life and prompting earlier renewal under normal conditions.

Electra had a legacy network practice of daisy-chaining multiple ground-mounted transformers between switching points (i.e., underground cables were directly connected to the transformer HV bushings rather than through an RMU, which is the modern practice). For some GM transformers, this resulted in the piggybacking of multiple cables within the 11kV cable box. This has safety clearances, operational and protection implications due to the potential for incorrect fusing and reduced ability to reduce isolation segments. There is a programme (under review) to install RMUs when GM transformers are renewed to remove piggybacking of cable terminations (refer to Section 11.10.3).

All two-pole transformer structures have been seismically assessed, and all remediation work completed.

The 10-year fleet strategy is as follows:

[185] As at 31 March 2025.

Our strategy for the fleet is to:

- Due to the lower consequence of failure associated with distribution transformers, we target replacement at Risk Grade 5. However, where public safety risks are present, replacement occurs earlier at Risk Grade 4;
- Progressively remove the daisy-chaining of multiple ground-mounted transformers;
- Ensure earthing remains compliant and expansion of earthing systems when required;
- Ensure that public safety risks are managed as required under our Public Safety Management System.

12.16.2 What is driving our fleet strategy

Current fleet performance

The transformer fleet operates reliably, with a defective equipment fault rate of 5.9 per 1000 units/year for pole-mounted transformers and 5.5 per 1000 units/year for ground-mounted transformers.[186] Given the low number of defective equipment failures, there is no discernible trend of deterioration.

Damage from lightning is the only performance issue relating to pole-mounted transformers.

For ground-mounted transformers, other than the 11kV cable piggybacking, there are no performance issues relating to the fleet.

Specific fleet risks and failure modes

Table 140 shows the top risks and failure modes for distribution transformers. The key risks are corrosion, in-tank liquid fusing, 11kV pitch-filled potheads, and public access.

Table 140: Specific risks

Asset	Risk/failure mode	Current controls or treatments
Pole-mounted transformers	Exposure to coastal conditions causing corrosion and early failure	Corrosion detection as part of routine inspection, with remediation as required. Proximity to the coast is considered in CBARMM, and accelerated deterioration rates are included where appropriate (which advances their renewal commensurate with risk)
	Leaking of oil due to tank or gasket due to corrosion	Routine inspection and replacement of assets if the tank is affected. Refurbishment of assets if gasket or bushings
	Lightning strikes	There has been a programme to install lightning arrestors in areas with historical lightning strikes. This programme is now complete.
	Vehicle damage	Additional physical protection or asset relocation in areas of known vehicle damage risks
Ground-mounted transformers	Exposure to coastal conditions causing corrosion and early failure	Corrosion detection as part of routine inspection, with remediation as required (see corrosion below) Proximity to the coast is considered in CBARMM, and accelerated deterioration rates are included where appropriate
	Some transformers have liquid CF4 fuses inside the tank that can fail and interrupt the supply	These transformers have increased condition deterioration with CBARMM. The renewal programme prioritises the replacement of transformers with CF4 fuses
	Pitch-filled terminations to connect on 11kV bushings	These transformers have increased condition deterioration with CBARMM.

[186] For FY20 to FY25. Benchmark data is not readily available.

Asset	Risk/failure mode	Current controls or treatments
		The installation of RMUs prioritises transformers with Pitch-filled potheads.
	Corrosion, including: • Surface rust on bays and tank • Penetrating rust exposing live components in bays • Rust of cooling fins or tank causing oil leakage	Controls include: • Refurbishment through rust removal and painting • Temporary measures to restrict access to bays. Refurbishment through rust removal, painting, and replacement of bays/doors • Temporary measures to limit leaks. Refurbishment of cooling fins or replacement for issues on tanks
	Piggybacking of cable terminations in the 11kV cable box has safety clearances, operational and protection implications	When GM transformers are renewed, an RMU is added to removed cable piggybacking.
	Overloading due to increased load from existing customer connections	Schedule of work to upgrade transformers with capacity issues (refer to Section 11.11.2)
	Public access to equipment and exposure to live parts	Implementation of our Public Safety Management System, which includes various public safety checks

Fleet population and age

Table 141 shows the population and age of distribution transformers. 9.1% of pole-mounted and 6.2% of ground-mounted transformers are within ten years of NEL. For pole-mounted transformers, there are currently 35 transformers above NEL. There are three ground-mounted transformers currently above NEL.

Given the performance of our older fleet of transformers, we increased the NEL from 40 to 60 years. This also better aligns with the EEA AHI guide, which has MPL at 70 years (note MPL and NEL are not directly comparable). This has reduced the number of transformers approaching NEL.

Table 141: Asset fleet quantity and age

Asset	Type	Population[187]	Average Age (years)	NEL[188] (years)	Population within 10 years of NEL
Pole-mounted transformers	All types	1,645	22.8	60	150
Ground-mounted transformers	All types	1,022	17.3	60	63

Fleet health and risk

Asset health and risk are determined using CBARMM (refer to Figure 153 to Figure 156). For distribution transformers, we calculated asset health based on asset age, location, reliability, material, and condition. We have good data on distribution transformers, and the forecasts are reliable.

CBARMM indicates that we are forecasting 66 pole-mount and 95 ground-mount transformers will reach risk grade 5 over the next 10 years. The main driver for high-risk assets is the condition of the transformer tank due to exposure to the coastal environments.

[187] As at October 2025.

[188] Nominal expected life. This is the age when it would be expected to first observe significant deterioration. This represents the average service life of the asset. Assets can operate longer than NEL based on active monitoring of condition.

Figure 153: Pole-Mounted Transformers, Current Asset Risk

	HIB1	HIB2	HIB3	HIB4	HIB5	Total
C4	23	-	-	-	-	23
C3	79	2	14	3	1	99
C2	1,310	88	79	32	8	1,517
C1	-	-	-	-	-	-
Unknown						6
Total	1,412	90	93	35	9	1,645

Figure 154: Pole-Mounted Transformers, Forecast Asset Risk

	HIB1	HIB2	HIB3	HIB4	HIB5	Total
C4	22	1	-	-	-	23
C3	64	8	5	13	9	99
C2	1,151	137	56	116	57	1,517
C1	-	-	-	-	-	-
Unknown						6
Total	1,237	146	61	129	66	1,645

Figure 155: Ground-Mounted Transformers, Current Asset Risk

	HIB1	HIB2	HIB3	HIB4	HIB5	Total
C4	20	3	5	-	3	31
C3	132	12	19	4	4	171
C2	387	26	65	18	8	504
C1	288	8	14	3	3	316
Unknown						-
Total	827	49	103	25	18	1,022

Figure 156: Ground-Mounted Transformers, Forecast Asset Risk

	HIB1	HIB2	HIB3	HIB4	HIB5	Total
C4	15	4	2	3	7	31
C3	100	24	9	16	22	171
C2	297	65	30	51	61	504
C1	256	27	4	14	15	316
Unknown						-
Total	668	120	45	84	105	1,022

12.16.3 How the asset fleet is operated, monitored and maintained

Condition assessment

Table 142 summarises the current inspection and testing regime for distribution transformers. The condition data informs CBARMM, identifies defects, and defines specific renewal projects and corrective measures.

Table 142: Condition assessments

Asset	Type	Scope of assessment	Trigger
Pole-mounted transformers	Observed	Routine inspection, including for oil leaks, rust, missing hold-down bolts, earth connections	Time-based, 5 yearly
	Measured	Earth impedance test	Time-based, 5 yearly
ground-mounted transformers	Observed	Routine inspection, including for oil leaks, rust, missing hold-down bolts, vegetation, graffiti, paint, depreciated cable breakout constructions, overheating	Time-based, 2 yearly
	Measured	Earth impedance tests	Time-based, 2 yearly

Maintaining the asset

A summary of the typical distribution transformer maintenance is shown in Table 143.

Table 143: Corrective and preventive maintenance

Asset	Type	Scope of maintenance	Trigger
Pole-mounted transformers	Corrective	Extension of earthing system to meet required impedance standard	• Routine 5 yearly testing: Earthing impedance above required standards
Ground-mounted transformers	Corrective	Extension of earthing system to meet required impedance standard	• Routine 2 yearly testing: Earthing impedance above required standards
	Corrective	Transformer HV and LV bay clearing, removing of spiderwebs, vegetation, or other obstructions from within the bays	• Routine 2 yearly Inspections where obstructions are observed
	Corrective	Painting, rust that has not penetrated through to live parts or tank or graffiti	• Routine 2 yearly Inspections where corrosion is observed
	Corrective	Clearing access obstructions, removing vegetation, refuse, or other obstructions that limit access to transformers	• Routine 2 yearly Inspections where obstructions are observed
	Corrective	Replacing public safety signage inline with PSMS requirements	• Routine 2 yearly Inspections where signage is observed as missing

Asset	Type	Scope of maintenance	Trigger
	Preventative	Replacement or removal of liquid fuses with HRC fuses	• Undertaken in conjunction with any planned work on transformers with liquid fuses installed

12.16.4 How renewal decisions are made on the fleet

Table 144 shows the specific drivers for asset renewal forecasting and the triggers for selecting specific asset renewal projects (within the overall asset renewal forecast).

Table 144: Drivers and triggers for renewal forecasts and projects

Asset	Type	Drivers/triggers
Pole-mounted transformers	Renewal forecasts	Includes all assets where the risk is forecast to transition to RG5
	Renewal and refurbishment Projects	For large transformers, projects are defined based on the presence of end-of-life drivers (from routine inspections) and risk grade, including oil leaks, damage to LV or 11kV bushings, and surface or penetrating corrosion. No specific projects are defined for small PM transformers where renewal is coordinated with other projects or initiated from defects or faults
Ground-mounted transformers	Renewal forecasts	Includes all assets where the risk is forecast to transition to RG5
	Renewal and refurbishment Projects	Projects are defined based on the presence of end-of-life drivers (from routine inspections) and risk grade, including measured loading over-rated limits, the risk of public access to live components, oil leaks, equipment design and detrimental configurations that are inconsistent with current design standards

12.16.5 Asset renewal and refurbishment forecasts

Table 145 shows the forecast distribution transformer asset health, risk, and renewals over the next ten years. Due to the lower consequence of failure associated with distribution transformers, we are forecasting replacing assets that transition to RG5 (that is, in most cases, we expect to operate these assets at RG4). Hence, we are operating some assets older than NEL. However, where there is a high public safety risk, we will replace the transformer at RG4.

More pole-mounted transformers are forecast to be renewed than the RG5 metric indicates. This higher number has been selected based on the number of assets well beyond their NEL, as noted in 12.16.2.

For ground-mount transformers, the forecast renewals are slightly below the forecast RG5. Additional ground-mounted transformers are being replaced during capacity upgrades. This is projected to cover the difference between RG5 and forecast renewals (refer to Section 11.11.2 and 11.11.3).

Table 145: Current and forecast asset risk and renewals

Asset	Type	Population[189]	10 Year forecast of assets with low health grade[190]	10 Year forecast of assets with high risk and above[191]	10 Year forecast renewals and refurbishment
Pole-mounted transformers	All types	1,645	HIB5: 66	RG5: 66	120
Ground-mounted transformers	All types	1,022	HIB5: 105	RG5: 95	75

[189] As at 31 March 2025.

[190] HIB4 and HIB5 (equivalent to EEA health index of H2 and H1). Before renewal or refurbishment intervention.

[191] Risk Grade 4 and 5. Before renewal or refurbishment intervention.

12.16.6 Asset renewal and refurbishment programmes

Table 146 shows the distribution transformer renewal programmes. Renewal expenditure has increased from FY2032, in line with the forecast risk grade, which has added around $1.2m to renewal capex compared to the 2025 AMP.[192]

Table 146: Renewal and refurbishment programmes (Real $000)

Project/Programme	Description	FY27-31	FY32-36	Total
Pole-mounted transformer				
Condition-based replacements	Condition-driven replacement of pole-mounted transformers (based on routine inspections). 8 units p.a. for FY27-31 then 16 units p.a. from FY32	647	1,299	1,946
Unplanned replacements	Defect and fault replacement of pole-mounted transformers	154	155	309
Ground-mounted transformer				
Risk-based replacements	Risk-driven replacement of ground-mounted transformers (based on CBARMM and routine inspections) 6 units p.a. for FY27-31 then 9 units p.a. from FY32	1,680	2,529	4,209
Unplanned replacements	Defect and fault replacement of ground-mounted transformers	286	287	573
Total	**Asset replacement and renewal capex**	**2,767**	**4,269**	**7,036**

Table 147: Asset replacement and renewal capex (Real $000)

Item	FY27	FY28	FY29	FY30	FY31	FY32	FY33	FY34	FY35	FY36	Total
Distribution transformer	552	554	554	554	554	852	854	853	855	855	7,036

Forecasts for fault repair, inspection and maintenance of these assets are included within the network opex forecasts contained in Section 12.19.

12.17 OH/UG Consumer Service Connections Fleet Plan

12.17.1 Fleet Overview and Strategy

Electra has 48,500 LV connections, which comprise overhead pole fuse connections and ground-mounted pillar box connections.[193]

Pole fuse connections are replaced as part of other projects or when they fail.

Electra has approximately 11,888 ground-mounted LV service pillar boxes, LV link boxes, and LV joint boxes. There are 2,584 old steel pillars, which require additional risk management. The new pillar boxes are plastic. In urban areas, pillar boxes typically supply two customers.

LV link boxes interconnect LV circuits, allowing customers to be supplied from adjacent distribution transformers in the event of a planned or unplanned outage. Steel link boxes have potential safety issues; all are scheduled for replacement by FY30.

[192] In 2026$. Over the comparable FY27-35 period.

[193] Estimated at YE 31 March 2025. The average number of connections during FY25 was 48,291.

Ground-mounted pillars and link boxes are inspected, and their health is monitored.

Figure 157: Example of pillar and link boxes

The 10-year fleet strategy is as follows:
Our strategy for the fleet is to: • Replace all steel link boxes by FY30 due to design issues and increased public safety risk; • Replace all steel pillars by FY35 due to increased public safety risk; • Replace other assets commensurate with their risk—at Risk Grade 4 and 5; • Ensure that public safety risks are managed as required under our Public Safety Management System.

12.17.2 What is driving our fleet strategy

Specific fleet risks and failure modes

Table 148 shows LV pillars and link boxes' top risks and failure modes. The key risks are corrosion and damage to steel boxes, a design issue concerning steel link boxes, and public safety.

Table 148: Specific risks

Asset	Risk/failure mode	Current controls or treatments
Steel pillars	Corrosion of base, lid, or locking mechanisms creates the potential for exposure of live parts	Replacement of all steel pillar boxes by FY35
	Exposure to coastal conditions causing corrosion and early failure, and the potential for livening of metal parts	Corrosion detection as part of routine inspection, with replacement as required Replacement of all steel pillar boxes by FY35
	Damage to locking mechanisms and the potential for exposure of live parts	Damage detection as part of routine inspection, with replacement as required. Replacement of all steel pillar boxes by FY35
Steel link pillars	These were designed with the neutral link close to the external housing, which creates a potential hazard should the neutral contact the housing	All 160 of these link boxes are scheduled for replacement by FY30
Pillars, all	Vehicle damage or vandalism resulting in exposure to live parts	Damage assessment as part of routine inspection or fault reporting. Repair or replacements are implemented as required Implementation of our Public Safety Management System

Fleet population and age

Table 149 shows the population and age of LV pillars and link boxes. Over 95% of steel pillars are within ten years of NEL. There are only a few plastic pillars with five years of NEL. We do not carry information on the age profile of overhead pole fuse connections.

Due to the good performance of our plastic pillar fleet, we have increased their NEL from 45 to 60 years. This has reduced the number of plastic pillars within ten years of NEL.

Table 149: Asset fleet quantity and age

Asset	Type	Population[194]	Average Age (years)	NEL[195] (years)	Population within 10 years of NEL
Pillar and link boxes	Plastic LV pillars	8,734	17	60	20
	Steel LV pillars	2,654	46	45	2,584
	Other types of LV pillars	500	26	45-50	66

Fleet health and risk

Asset health and risk are determined using CBARMM (refer to Figure 158). For LV pillars, we calculated asset health using a combination of asset age, asset location, asset type reliability, asset material, and inspected condition. We do not assess health and risk for overhead pole fuse connections.

The driver for high-risk assets is the older steel pillar and link box assets. This is consistent with the age of steel pillar boxes.

Figure 158: Pillar and Link Boxes, Current Asset Risk

	HIB1	HIB2	HIB3	HIB4	HIB5	Total
C4	20	8	79	2	1	110
C3	150	25	2,443	51	32	2,701
C2	269	2	-	2	-	273
C1	8,380	14	6	54	-	8,454
Unknown						350
Total	8,819	49	2,528	109	33	11,888

Figure 159: Pillar and Link Boxes, 10-Year Forecast Asset Risk

	HIB1	HIB2	HIB3	HIB4	HIB5	Total
C4	8	4	11	13	74	110
C3	107	33	12	138	2,411	2,701
C2	256	13	2	-	2	273
C1	7,921	458	4	16	55	8,454
Unknown						350
Total	8,292	508	29	167	2,542	11,888

Note: The health data for OH/UG consumer service connections in Schedule 12a only relates to pillar and link boxes.

12.17.3 How the asset fleet is operated, monitored and maintained

Condition assessment

Table 150 summarises the current inspection and testing regime for LV pillars and link boxes. The condition data informs CBARMM, identifies defects, and defines specific renewal projects.

Pole fuse connections are inspected during the routine overhead inspections, and defects are identified and remediated as required.

[194] As at October 2025.

[195] Nominal expected life. This is the age when it would be expected to first observe significant deterioration. This represents the average service life of the asset. Assets can operate longer than NEL based on active monitoring of condition.

Table 150: Condition assessments

Asset	Type	Scope of assessment	Trigger
Plastic Pillars	Observed	Routine inspection, including for broken locks, deteriorated fuses/holders, damaged lids/bases	Time-based, 5 yearly
Steel Pillars	Observed	Routine inspection, including for rusted bases, damaged locking bolts, deteriorated fuses/fuse mounts	Time-based, 5 yearly

Maintaining the asset

A summary of the typical LV pillar maintenance is shown in Table 151. We do not maintain steel pillars and link boxes—any issues observed during the routine inspection result in the box being scheduled for replacement.

Table 151: Corrective and preventive maintenance

Asset	Type	Scope of maintenance	Trigger
Plastic Pillars	Corrective	Replacement of locking mechanism. Replacement of lid if alterations to locking systems have been made to make the pillar safe.	• Routine 5 yearly Inspections where a pillar was inaccessible due to locking mechanism failures

12.17.4 How renewal decisions are made on the fleet

Table 152 shows the specific drivers for asset renewal forecasting and the triggers for selecting specific asset renewal projects (within the overall asset renewal forecast).

Table 152: Drivers and triggers for renewal forecasts and projects

Asset	Type	Drivers/triggers
Plastic Pillars	Renewal forecasts	Includes all assets where the risk increases above RG4
	Renewal and refurbishment Projects	Specific projects are defined from the most recent inspections. Assets in high-risk areas are prioritised
Steel Pillars	Renewal forecasts	All steel pillar and link boxes are scheduled for renewal by FY35
	Renewal and refurbishment Projects	Specific projects are defined from the most recent inspections. Assets in high-risk areas are prioritised
Overhead connections	Renewal forecasts	No renewal forecasts or projects are prepared for these assets. These assets are replaced in conjunction with other projects or on failure
	Renewal projects	

12.17.5 Asset renewal and refurbishment forecasts

Table 153 shows the forecast LV pillar and link box asset health, risk, and renewals over the next ten years. The forecast renewals are mostly steel pillars and reflect all steel pillars being replaced by FY35. Plastic boxes are performing better than the risk-based forecasting suggests, and their replacement is an estimate based on prior inspection-driven replacement rates.

Table 153: Current and forecast asset risk and renewals

Asset	Type	Population[196]	10 Year forecast of assets with low health grade[197]	10 Year forecast of assets with high risk and above[198]	10 Year forecast renewals and refurbishment
	Pillar and link boxes	11,888	2,709	2,661	2,578

[196] As at October 2025.

[197] HIB4 and HIB5 (equivalent to EEA health index of H2 and H1). Before renewal or refurbishment intervention.

[198] Risk Grade 4 and 5. Before renewal or refurbishment intervention.

Asset	Type	Population[196]	10 Year forecast of assets with low health grade[197]	10 Year forecast of assets with high risk and above[198]	10 Year forecast renewals and refurbishment
OH/UG consumer service connections	Overhead connections	No data available			

12.17.6 Asset renewal and refurbishment programmes

Table 154 and Table 155 show the LV pillar renewal and safety replacement programmes. There is no material change to forecast expenditure compared to the 2025 AMP.

Table 154: Renewal and refurbishment programmes (Real $000)

Project/Programme	Description	FY27-31	FY32-36	Total
Plastic LV pillar replacement programme	Inspection-driven replacement of plastic LV pillars, ~45 p.a.	1,183	1,187	2,370
Steel LV pillar replacement programme	Inspection-driven replacement of steel LV pillars, ~200 p.a.	6,309	6,332	12,641
Unplanned replacements	Defect and fault replacement of LV pillars	481	483	964
Total	**Asset replacement and renewal capex**	**7,974**	**8,001**	**15,975**

Table 155: Safety Improvement Programme (Real $000)

Project/Programme	Description	FY27-31	FY32-36	Total
Steel link pillar replacements	The programme will replace all 160 steel link pillars due to safety risks associated with a design issue (32 p.a.).	807	-	807
Total	**Other reliability, safety and environmental capex**	**807**	**-**	**807**

Table 156: Asset replacement and renewal capex (Real $000)

Item	FY27	FY28	FY29	FY30	FY31	FY32	FY33	FY34	FY35	FY36	Total
LV connections and pillar boxes	1,590	1,598	1,595	1,595	1,596	1,597	1,600	1,599	1,603	1,603	15,975

Table 157: Other reliability, safety and environmental capex (Real $000)

Item	FY27	FY28	FY29	FY30	FY31	FY32	FY33	FY34	FY35	FY36	Total
Steel link pillar	201	202	202	202	-	-	-	-	-	-	807

Forecasts for fault repair, inspection and maintenance of these assets are included within the network opex forecasts contained in Section 12.19.

12.18 Management of Other Network Assets

12.18.1 Zone substation buildings

Electra has ten zone substation buildings that typically house the 11kV circuit breakers and secondary systems. The 33kV circuit breakers are housed indoors at most substations (Shannon, Ōtaki, Waikanae, Paraparaumu East, Paraparaumu West, Raumati). The zone substation building fleet ranges in age from 16 to 50 years. The NEL varies based on the building's construction, and all are appropriately maintained.

Our fleet strategy for zone substation buildings for new zone substations is to:

- Meet our resilience standard (as defined in Section 11.4.6) and for all existing zone substations when it is practical and economic to do so;
- Be inspected and maintained to ensure that there are no defects or other issues that cause the building condition to deteriorate to HIB4 or HIB5;

Zone substation buildings are inspected during the routine bi-monthly and annual inspections. Appropriately skilled people address any defects or maintenance requirements.

CBARMM is not used to determine the health of zone substation buildings. Health is determined based on information from routine inspections or specific building assessments, the results of which are included in Schedule 12a.

The key work on the substation fleet is the seismic upgrade programme (to meet the resilience standard). Seismic upgrades have been completed on seven of the ten substation buildings, with work at Foxton and Paraparaumu East due for completion in late FY26. The solution for Levin West is under consideration. Expenditure forecasts for the seismic upgrade programme at zone substations are included in Section 11.9.4.

There are no forecast renewals for zone substation buildings.

12.18.2 Load control plant

Electra operates the following load control plant:

- One Zellweger 80kVA SFU-K/203 injection plant at Shannon which provides ripple control signals to the northern area. This was installed in 2011 as part of the substation rebuild;
- One Landis + Gyr 200kVA SFU-K/403 injection plant at Paraparaumu East zone substation which provides ripple control signals to the southern area. This was installed in 2016;

Both the Shannon and the Valley Road plants inject into the 33kV at 283Hz. There are no known capacity, security, or reliability constraints with Electra's load control plant.

We have two Zellweger 80kVA SFU-K/203 injection plant controllers and coupling cell components in storage as critical spares.

The plants are tested and maintained in line with manufacturers' requirements. These include visual inspections, regular testing to confirm signal frequency and strength, and a five-year rolling inspection and maintenance contract with Landis+Gyr to ensure plant reliability.

The load control plants are in good condition (HIB2 and HIB3)[199]. Table 158 shows the planned refurbishment of the load control plant. We are planning to refurbish the plant at Shannon in FY28. The expected life of these assets is around 20 years; at this stage, we are not forecasting replacing these plants, given the future uncertainty concerning traditional load control (refer to Section 10). However, this project has not been fully scoped, and further testing may determine that a more powerful signal generator is required to cater for the expanding network.

[199] H3 and H4 as per schedule 12a.

Table 158: Renewal and refurbishment programmes (Real $000)

Project/Programme	Description	FY27-31	FY32-36	Total
Refurbishment of injection plant	Refurbishment of the Zellweger plant at Shannon in FY28	104	-	104
Total	**Asset replacement and renewal capex**	**104**	**-**	**104**

Table 159: Asset replacement and renewal capex (Real $000)

Item	FY27	FY28	FY29	FY30	FY31	FY32	FY33	FY34	FY35	FY36	Total
Injection plant	-	104	-	-	-	-	-	-	-	-	104

12.18.3 Load control relays

The energy retailer owns most customer load control relays. However, Electra still owns 1,924 relays for controlling streetlights, under veranda lighting and pilot-wire load control. There are 1,486 load control relays of unknown age. We have poor quality data on this fleet, and the relays are replaced upon failure (relays are quick to replace and have minimal service impact should they fail). We are indicating that around 10% of the relay fleet will need to be replaced in the next five years, which equates to about 40 p.a. These low-value asset replacements are included in the opex forecasts.

12.18.4 LV OH/UG Streetlight circuits

We have around 64km of overhead and underground streetlighting circuits and forecast to replace around 15% of the fleet over the next five years (as this will be replaced as the LV reconductoring programme progresses). The inspection of overhead streetlighting occurs during routine overhead line inspections. Underground streetlight circuits are not inspected. We do not maintain health data on this fleet, and these assets are renewed in conjunction with other projects or when faults or defects are identified.

12.18.5 DC system, RTUs, communication system and IoT

Our other secondary systems include substation DC systems, RTUs, communication systems and IoT devices.

DC systems were recently inspected and are all nearing end-of-life. We are planning to replace systems at all 10 zone substations over the next 10 years. This programme involves designing a new standardised system to install at each substation progressively.

SCADA RTU and communication gateway hardware is reaching end-of-life and requires replacement (due to technological obsolescence risk). SCADA RTUs have an expected life of around 20 years and gateways have an expected lifespan of 7 to 10 years. We have a programme to replace these between FY2027 and FY2032.

Electra’s communication system consists of fibre, point-to-point microwave, point-to-point radio and multi-access channel radio. Microwave radio and voice connect all sites with a self-healing topology. Its primary purpose is to carry voice and data communication to operate and control the network. The data communication links connect the SCADA master station (discussed in Sections 8.4 and 9.4.2) with the substation’s remote terminal units (RTUs). SCADA is one of our key operational technology systems and is being upgraded over the next few years (as discussed in Section 9.4.2).

To improve the reliability of the communication system and support the protection scheme upgrades, we are upgrading several links from radio to fibre (refer to Section 11.12.2). We are also upgrading the Levin

West substation's communications tower and the Southern region's backup communications container (refer to Table 160).

Electra uses IoT (Industrial Internet of Things) communications technology to gather network status data to further improve network reliability, customer services, and asset investment decisions. Fifteen LoRaWAN gateways, installed in the early 2020's, are deployed in the Electra region at key locations, including substations and eight repeater sites. The gateways are recent additions to the Electra communications network and are in Class 1 (new) condition. There are no known systemic issues or constraints with Electra's IoT platform. Resilience, reliability, and cyber security are key design parameters for deployment.

Table 160: Renewal and refurbishment programmes (Real $000)

Project/Programme	Description	FY27-31	FY32-36	Total
SCADA RTU and replacements	Replacement of SCADA RTU and communication equipment replacement at zone substations	1,587	205	1,792
Back-up communication container	Fit out a container to hold comms equipment in Southern Area. Current main site and backup are both in Northern Area. The project is planned for complete in FY26.	Complete		
Refurbishment of Levin West Comms Tower	Refurbishment of the communications tower at Levin West substation in FY26-27	279	-	279
Replacement of the DC system	Programme to replace the DC system with a modern and standardised system at all zone substations DC systems are replaced on a 10-yearly basis in line with manufacturer recommendations. A business case is being prepared that may alter the timing and costs.	625	627	1,252
Total	**Asset replacement and renewal capex**	**2,482**	**831**	**3,313**

Table 161: Asset replacement and renewal capex (Real $000)

Item	FY27	FY28	FY29	FY30	FY31	FY32	FY33	FY34	FY35	FY36	Total
Secondary systems	759	431	431	431	431	329	125	125	126	126	3,313

Forecasts for fault repair, inspection and maintenance of these assets are included within the network opex forecasts contained in Section 12.19.

12.19 Network Operations and Maintenance

12.19.1 System Interruption and Emergency

System interruption and emergency (**SIE**) response (also known as fault response and restoration) relates to the response to an unplanned event or incident that impacts the normal operation of the network. At Electra, this typically involves first and second-call fault response. First-call is where a fault person responds to a fault on the network (which may have been identified from the SCADA, ADMS, a notification from a retailer or a notification from a customer through to our call centre). The second-call response is where additional crews are called in to respond. This occurs when the first-call fault person cannot restore supply, and in this case, they make the site safe until other personnel can attend. Specialist personnel may be required depending on the nature of the fault.

Electra's fault staff are all from our its in-house Service Delivery team. The in-house team maintains a roster of first- and second-call fault personnel and specialist staff to respond to any fault on the network.

We may deploy mobile generators where restoration could take some time.

In the 2025 AMP, we forecast higher system interruption and emergency opex due to an expected increase in 11kV underground faults (which we have seen in recent years due to the aging of that fleet) and an increase in typical-year adverse weather (due to climate change). We reviewed our storm-related allocation (some of which is covered by the increase in vegetation management costs), and it has been reduced, which is why forecast expenditure has decreased.

Most of the expenditure relates to fault response on the overhead network (due to the higher fault rate associated with those assets).

Table 162: System Interruption and Emergency Opex (Real $000)

Item	FY27	FY28	FY29	FY30	FY31	FY32	FY33	FY34	FY35	FY36	Total
Historical average SIE[200]	2,540	2,540	2,540	2,540	2,540	2,540	2,540	2,540	2,540	2,540	25,400
Reduction in storm related costs	(280)	(280)	(280)	(280)	(280)	(280)	(280)	(280)	(280)	(280)	(2,797)
Additional SIE to cater for network growth	-	35	74	115	156	197	238	281	324	368	1,788
Total	**2,260**	**2,295**	**2,335**	**2,376**	**2,416**	**2,457**	**2,499**	**2,541**	**2,584**	**2,628**	**24,390**

Note: The forecasts assume a typical year for adverse weather and do not include a contingency for significant weather events.

12.19.2 Vegetation Management

Obligation to manage vegetation near lines

Electra's overhead lines are surrounded by trees of varying heights, types, growth rates and ownership, and we have significant obligations under the Electricity (Hazards from Trees) Regulations 2003 to provide security of supply and safety to the public by keeping trees clear of conductors. The Electricity (Hazards from Trees) Regulations were amended in 2024 to extend the notice zone by one metre. While these zones provide clearance from interference from branches (though greater clearance would be useful), they are inadequate to manage tree-fall risk and interference during storm events, where greater separation is needed.[201]

We adhere to the ENA/EEA's risk-based methods as recommended by the Risk-Based Vegetation Management Guide, which provides direction on how to proactively manage vegetation risk to improve supply reliability, security, performance and the safety of our network.

Section 4.5.6 provides a detailed analysis of our vegetation outage performance. In recent years, vegetation-related outages have been concentrated on a few feeders, and climate change is likely to exacerbate vegetation contact. Our approach and operational plans have been prioritised to address the worst-performing feeders (for vegetation).

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[200] Based on FY2026 budget.

[201] The Electricity (Hazards from Trees) Regulations specifies minimum distances from overhead power lines that vegetation must be clear from, with distances varying depending on voltage and conductor span length (the GLZ). These were updated in November 2024, extending the notice zone by one metre and making the zones clear to the sky. For 11kV lines, the GLZ is 1.6m, the cut-back zone is 2.6m and the notice zone at 3.6m from the line.

Management Approach

Our vegetation management process integrates a planned programme where cyclic trimming is undertaken based on a risk-based assessment strategy.

Our vegetation control team continue to survey the network, issue hazard warning notices and cut-or-trim to tree owners and complete follow-up hazard warning and cut-or-trim jobs. We continue to use a vegetation management database to record all notices that are issued, be it hazard warning notices or cut-or-trim notices, including tree owner, contact details, number of trees identified, species, voltage involved, between pole/plant numbers, work completion date and information regarding the work site or ownership. Using this system to its full potential, we build a site history, including reinspection intervals.

The primary objective of our vegetation management activities is to ensure the safety of the public, customers, and Electra personnel. Other drivers include mitigating the risk of supply interruption by maintaining minimum clearances (specified in the tree regulations), removing out-of-zone trees that present a fall risk to the network, and mitigating the encroachment of tree roots to cables and ground-mounted assets.

The criteria for maintenance include:

- Number of customers at risk of interruption from specific tree contacts;
- Branches or leaves encroach into the minimum clearances specified in the Regulations;
- Roots that are interfering with ground-mounted assets;
- Unsafe trees within the fall zone.

Priority is given to our worst-performing feeders (refer to Section 4.5.9).

We are forecasting an increase in our vegetation management spend. This additional expenditure is in response to real cost increases (in particular for traffic management), an increase in vegetation growth rates, an increase in typical year adverse weather (due to climate change), the high cost of addressing out-of-zone trees, and targeting vegetation management on our worst-performing feeders.

Table 163: Vegetation Management Opex (Real $000)

Item	FY27	FY28	FY29	FY30	FY31	FY32	FY33	FY34	FY35	FY36	Total
Base vegetation management	2,067	2,067	2,067	2,067	2,067	2,067	2,067	2,067	2,067	2,067	20,673
Increase in vegetation management	542	542	542	542	542	542	542	542	542	542	5,415
Total	**2,609**	**2,609**	**2,609**	**2,609**	**2,609**	**2,609**	**2,609**	**2,609**	**2,609**	**2,609**	**26,088**

Note: The forecasts assume a typical year for adverse weather and do not include a contingency for significant weather events.

12.19.3 Routine and Corrective Maintenance and Inspections

Routine and corrective maintenance and inspections (**RCMI**) means operational expenditure for routine inspection, testing and maintenance. We are continually improving our inspection and testing to ensure that we can capture appropriate condition information on network assets. This enables us to more accurately determine the health of the assets and optimise the timing for maintenance, renewal or refurbishment.

Around 50% of the expenditure relates to the inspection and follow-up maintenance on the overhead networks (due to the high number of assets and the time taken to inspect). 15% is spent on zone substation inspection and maintenance, and just over 10% each for ground-mounted distribution assets and pillar and link boxes.

We have recently changed the inspection regimes for some zone substation assets, distribution overhead lines, ground-mounted transformers and pole-mounted switches. These changes have increased the cost of the inspection work—we expect to see better optimisation of our asset renewals in future AMPs as new data is utilised. Zone substation tapchanger maintenance is now included in RCMI (having been transferred from asset replacement and renewal). RCMI costs also increase as the network expands (as there are more assets to inspect and maintain).

Changes in our inspection and testing include:

- Moving from an annual to 2-yearly 33kV line inspections;
- As noted in the overhead structure and conductor fleet plans, we plan to conduct testing to verify the residual strength of poles, crossarms and conductors removed from service. This is a destructive testing programme to assess whether changes to NEL are appropriate. This is planned for FY2027 to FY2029, then on a three-yearly basis;
- $50k for the inspection of Chorus poles that are being transferred to our ownership;
- $20k p.a. programme for cable partial discharge testing.

Table 164: Routine and Corrective Maintenance and Inspection Opex (Real $000)

Item	FY27	FY28	FY29	FY30	FY31	FY32	FY33	FY34	FY35	FY36	Total
Historical average RCMI	1,688	1,688	1,688	1,688	1,688	1,688	1,688	1,688	1,688	1,688	16,885
5-year 110kV assets condition assessment	-	-	-	-	125	-	-	-	-	125	251
Changes in inspections and testing	93	185	67	90	(3)	160	(3)	90	67	90	836
Additional RCMI to cater for network growth	-	29	58	91	125	161	178	221	252	310	1,423
Total	**1,781**	**1,902**	**1,813**	**1,869**	**1,936**	**2,009**	**1,863**	**1,999**	**2,007**	**2,214**	**19,395**

12.19.4 Asset replacement and renewal (opex)

Asset replacement and renewal (**ARR**) opex relates to replacing subcomponents of assets that are not capital items. This includes preventative replacement programmes and replacement of low-value assets (i.e., single batteries at zone substations, ripple control relays, fuse elements). Over 60% of the expenditure relates to zone substation assets, and another 20% relates to ground-mounted distribution transformers. Again, ARR costs are increasing as the network expands.

Table 165: Asset Replacement and Renewal Opex (Real $000)

Item	FY27	FY28	FY29	FY30	FY31	FY32	FY33	FY34	FY35	FY36	Total
Historical average ARR	758	758	758	758	758	758	758	758	758	758	7,581
Real cost increases	12	12	12	12	12	12	12	12	12	12	119
Additional ARR to cater for network growth	-	12	25	39	53	67	81	96	110	125	609
Total	**770**	**782**	**795**	**809**	**823**	**837**	**851**	**866**	**880**	**895**	**8,309**

13. Delivery Capability

13.1 Introduction

In this section, we describe our resourcing to enable the business to deliver:

- The asset management strategy (Section 6);
- The asset management improvement plan (Section 9);
- The energy transformation roadmap (Section 10); and,
- The asset lifecycle plans (Sections 11 and 12).

We also describe our safety management system, which is critical to ensure the safety of our staff, contractors, and the public.

13.2 Drivers of our resourcing strategy

Our resourcing strategy and Electra's in-house resources have evolved over decades to support the needs of the business. Our resourcing strategy continues to evolve, and we have identified eight key drivers shaping the current strategy. These include:

Alignment to corporate strategy

Electra's corporate strategy is to develop our people, keep everyone safe, and maintain operational excellence. Our drive for operational excellence is key to supporting our customer service goals and is core to our maintaining in-house resourcing of the business where it is efficient to do so.

Alignment to our asset management strategy

Having suitable resources in all areas of the business is necessary to support the delivery of the asset management strategy. This is particularly important for:

- **#2 Implementing the energy transformation roadmap**—where complexity will increase as we need to manage more significant penetration of DERs, utilise flexibility and other non-network alternatives, and support customers as they use the network differently;
- **#5 Improve asset management maturity to level 3**—as set out in Section 9, we have a wide-ranging improvement programme that needs to be supported. We have a near-term focus on improving our front-end engineering design (FEED) and outsourcing processes to support fieldwork delivery.

Maintaining and improving efficiency

As set out in our efficiency strategy (see Section 6.5), we are focused on reducing network work costs and improving efficiency through standardisation. Optimising our use of outsourced service providers to efficiently manage peak and variable workloads, and ensuring external contractors maintain our standards, are important drivers of our outsourcing strategy.

Ensuring work delivery

Delivering the capex works program relies on design, property rights, procurement, materials availability, and field resources availability. As discussed in Section 4.7, our capital works delivery has been behind plan in FY2022 to FY2024 (due to design and workflow issues), but improved in FY2025. However, as our work programme expands, we need to continue to focus on our design and delivery processes.

Regarding opex, the only constraint in recent years has been asset inspections, where retirement and recruitment delays have affected the workforce. These constraints have now been resolved.

Changing nature of fieldwork

We are observing an increase in operational technology (**OT**) content in fieldwork as monitoring and control of network devices become more prevalent. Field staff are now required to program devices and undertake additional commissioning testing and fault diagnostics. This type of work will increase as the addition of monitoring and control devices to the network is set to continue.

Increasing work volumes

In this AMP, we are forecasting an increase in fieldwork. Over the next five years, we are forecasting:

- An 80% increase in work on the subtransmission, distribution and LV networks since FY2022;
- Asset replacement and renewal drivers requiring substantial renewal works at zone substations including to communication and protection systems;
- System growth and customer connection drivers requiring new zone substations to be built and commissioned;
- New connections increasing from around 400 to 800 per annum;
- The development or upgrading of most of our significant IT/OT systems, including the EAMS, ERP, GIS, SCADA and ADMS.

National market constraints

Our growth is consistent with that of most other distribution businesses nationally and internationally. This creates national constraints on field resources and puts upward pressure on field staff wages and external contractor costs. There is also a ready market for skilled field staff, creating staff retention issues upon completion of training.

Aging workforce

The workforce's age profile is a key factor shaping Electra’s resourcing strategy. Around 14% of the total workforce is expected to reach retirement age within the next 10 years, with higher proportions in Network (20%), Field Services (12%), and Asset Management and Planning (10%). This is already evident, with 9% of Field Services employees and 7% of Network employees currently aged 65 and over. These trends highlight the need to plan ahead to maintain capability and ensure continuity of asset management and network operations.

13.3 Resourcing strategy

Consistent with our resourcing strategy drivers, we maintain core in-house corporate and asset management resources, as well as in-house fault, construction and maintenance capability to deliver most of our fieldwork programmes.

We utilise external resources for:

- Specialist work (where it would be inefficient to maintain those capabilities in-house);
- Civil work activities that can be well-defined and where a local competitive market exists, such as trenching, directional drilling and building/general construction, which ensures our prices are efficient;
- To meet peak workload requirements (including customer-initiated work);
- Where we decide it is more efficient and effective.

We currently outsource our procurement and warehouse management services to Connetics. This ensures we capture economies of scale in our procurement costs, improving the efficiency and effectiveness of our materials supply.

How this strategy is applied across the business is discussed below.

13.4 Resourcing Strategy Implementation

13.4.1 Asset management

We have increased resourcing within our Network Team to enhance our asset management capabilities in response to network growth, manage network performance, and optimise renewal demands. As part of this work, we recently established a new Design and Engineering team focused on engineering standards, design and field assurance, bringing the design function across from Service Delivery. Network Control is also now part of the Network Team, and was formerly part of Service Delivery. The changes were made to more closely align Network Control with the engineering teams, to improve the front-end engineering and design functions, and to better position the Service Delivery as a field service provider. We also established a two-year graduate engineer programme.

We are progressing arrangements with preferred designers to support our in-house design team.

Given the increasing use of information, the network information team is integrated into the asset management and planning teams to ensure close collaboration with the planning and engineering staff. Growth is expected in the team.

These changes respond to our strategy to improve asset management maturity, to increase work volumes, and to address our aging workforce.

13.4.2 Corporate (including IT/OT team)

Our corporate resourcing has evolved in response to the increasing complexity of the business. Recent increases in resourcing have been driven by our continued focus on health, safety, and wellbeing, as well as enhancements to our customer engagement and commercial areas of the business. Over the past two years, we have established an in-house Customer Experience team to support the business with all activities related to customer engagement, communication, and community connection. This function is supported by an external contact centre to deliver 24x7 support around unplanned outages.

We also established a Commercial team, bringing regulatory, pricing, and commercial expertise in-house.

The Digital Team has recently added the Operational Technology infrastructure and systems to the digital portfolio, where opportunities for standardisation and efficiency have been identified. Our resource plan to support the delivery of these systems will be balanced and includes upskilling our current team, recruiting specialised expertise, and outsourcing additional expertise as required. We have recently increased resourcing to support our data strategy (refer to Section 9.5).

13.4.3 Field services

Our in-house field services team provides construction and maintenance across our subtransmission, zone substation, distribution, and LV networks, as well as vegetation management. The team's capabilities also include estimation, scheduling, and project management.

Since the 2024 AMP, we have continued building our internal field resource capability. This included creating 12 new roles for trainee line mechanics, cable jointers, arborists, technicians, electricians, and a control room operator, with many of these now filled. We continue to pursue a range of other strategies, including:

- Multi-skilling—part of the capability matrix is to upskill 30% of the workforce to be multi-skilled in different disciplines to provide operational flexibility. In particular, training line mechanics in cable jointing will address the respective surplus and shortfall issues;
- Upskilling—there looks to be a need for upskilling given the increasing OT requirement for field work, as mentioned in the issues Section 5.6;
- Building capabilities in-house—we have a programme of recruiting 5-7 new apprentices annually as part of our long-term succession planning.

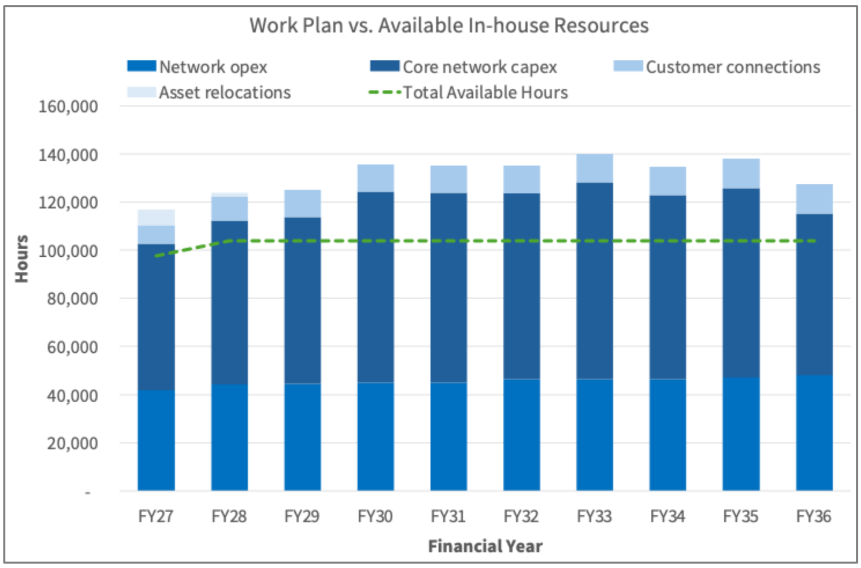
During FY26, we increased the project management capabilities within the team (two new roles).

These changes respond to recent delivery performance, national resource constraints, increasing work volumes, our aging workforce, and changes to the customer-initiated work process.

Fieldwork availability is forecast at 97,500 labour-hours in FY27, increasing to around 104,000 from FY28 as existing vacancies are filled and training hours normalise.

We have analysed the capex and opex work forecast in this AMP (refer to Figure 160). This indicates that our in-house delivery team is resourced at around 95% for FY27 core network capex and opex, then dropping to around 90% for FY29 and FY30, and then dropping again to around 85% from FY31. Hence, we expect to increase the level of work outsourced to our approved field service providers.

Figure 160: Fieldwork analysis



13.4.4 Use of consultants and field service providers

Consultants

We currently use consultants who provide additional resources and skills in areas such as:

- Subject matter experts on asset management, data, systems, safety, risk management and protection studies.
- Detailed designs (mainly relating to zone substations, but also to support peak work volumes).

We are reviewing our outsourcing to consultants for design work to identify a group of preferred consultants that we can engage to ensure work quality, familiarity with our design standards, workflow and cost efficiency.

Field Service Providers

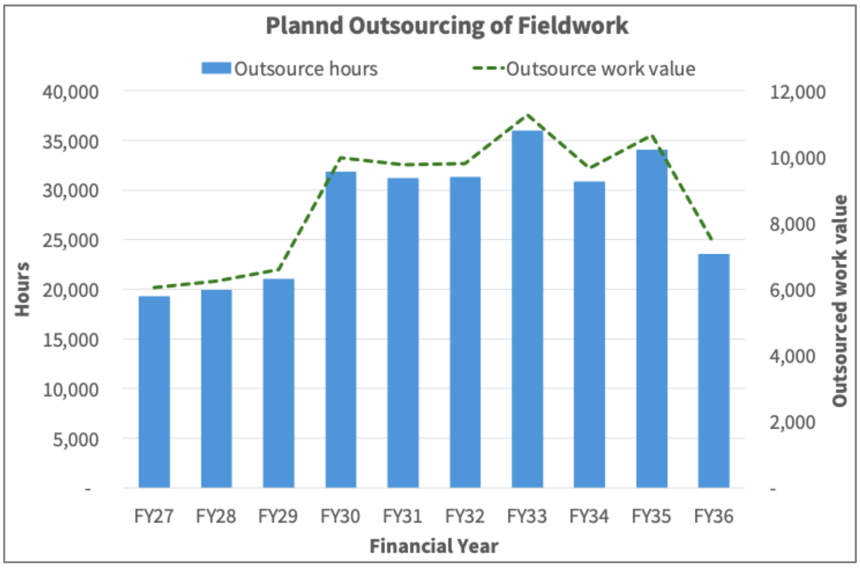
We currently use external field service providers to provide additional resources and skills in areas such as:

- Core network capex and customer-initiated work;
- Operational technology, including communications systems and SCADA;
- Civil works, including trenching, directional drilling, duct and cable laying, and reinstatement;
- Traffic management;
- Specialised inspections, maintenance and investigations (mainly on power transformers and tap-changers).

Our approach is to work closely with a shortlist of approved contractors. We forecast an increase in outsourcing (see Figure 161). This is due to increased core capex work and changes to our customer-initiated work process (where this work is now managed between Electra and the field service provider, rather than directly between the customer and the field service provider). Excluding major material purchases, external work will increase from around $6m p.a. in FY27 to F29 to around $10m p.a. from FY30.

We aim to provide contractors with a detailed 24-month view of our forecast work programme. We recognise that their resources are finite and in high demand, and that scheduling commitments well in advance benefits both parties.

Figure 161: Estimated outsource work[202]



13.5 Future resources required to deliver energy transformation roadmap

Section 10 outlines our energy transformation roadmap (**ETR**). In this roadmap, we identify the need to recruit new skills to enable Electra to effectively and efficiently support the energy supply transition. We have already brought in additional resources for network planning. The timing for recruiting further staff will hinge on the progress of flexibility market developments, the adoption of DERs, and the evolution of the DSO role. This remains uncertain, and we have not yet included additional staff in our forecasts.

13.6 Safety management system

We are committed to ensuring the safety of our customers, employees, contractors, and the public. Electra's overarching safety goal is to make sure people go home safe and well every day (no serious harm and zero LTIs from critical risks).

Operating and maintaining an electrical network involves hazardous situations with risks that cannot always be eliminated. For this reason, we operate a mature safety management system (**SMS**) and continuously seek improvement.

The core elements of our SMS are:

- **Competency management**—All staff and contractors are required to adhere to our competency requirements and undertake regular refresher training. This ensures we have a highly competent workforce;
- **Contractor approval process**— Contractors undergo a thorough process to become approved to work on our network. This involves an initial pre-qualification questionnaire, followed by a visit by our Health, Safety, and Wellbeing (HSW) Team to meet and review their systems and processes. This is repeated annually, with frequent interaction with contractors on work sites to verify their systems are managing their risks.
- **Fieldwork auditing**—All people leaders have key performance indicators for engaging with our field teams and approved contractors, including site safety observations and, where applicable, safety and

[202] The outsourced work value excludes the purchase of power transformers for our replacement programme. These will be purchased by Electra.

quality audits. The number of engagements is increasing, focusing on critical safety risks and the effectiveness of controls used to mitigate them.

- **Hazard identification, management, and communication**—Our SMS includes hazard and risk management identification procedures and processes supported by a critical risk framework. Safety starts in our design and planning processes (refer to Section 11.5.2). At the worksite, on-site tailgate start-up meetings identify hazards, risks, and mitigations before starting work. Communication between all parties, including our approved contractors and the public, is a key feature of our work systems.
- **Safe Operating Procedures**—The EEA Safety Management-Electricity Industry (**SM-EI**) rules govern much of what we do and how we do it. These form the basis of our procedures, from project inception through to delivery. These procedures are incorporated in our SMS. Standards are introduced and reviewed through an internal Standards Review Forum, which meets regularly.
- **Live line procedures**—We have comprehensive live line procedures covering all live line work. Our procedures are compliant with SM-EI and are reviewed annually. The live line crews are fully trained and undergo refresher training and certification at prescribed periods. Their work and equipment are being audited regularly.
- **Public safety management system (PSMS)**—The PSMS operates to safeguard the public and their property from safety-related risks arising from the presence or operation of the electricity network. Our PSMS complies with all elements of and certified to NZS7901:2014 and is independently audited by Telarc annually.

13.7 Offices, depots, vehicles and tools

13.7.1 Offices and depots

Electra currently has three key buildings where staff are located:

- Bristol St, Levin —This supports corporate, IT/OT, asset management staff and the control room (until FY28);
- Roe St, Levin—This is our new depot and office for the Northern region and supports our service delivery team in the Northern region (from FY26) and corporate, IT/OT, asset management staff and the control room (from FY28);
- Tongariro St, Paraparaumu—This supports our service delivery team in the Southern region together with corporate, IT/OT, and asset management staff.

We develop, maintain and renew our offices and depots to provide a safe and comfortable working environment, site resilience and flexible working arrangements. We have two planned developments in relation to offices and depots:

- The Coventry St, Levin site is no longer fit for purpose, and a new property on Roe St is being developed to consolidate the Bristol St and the Coventry St sites;
- Further expansion of office space at the Tongariro St depot is required. This is being undertaken following the purchase of the land and building, which is currently leased.

Table 166: Offices and depots, non-network capex

Project	Driver	Cost/Year	Justification/options considered
Roe St Depot and Office	Development for Roe Street property to accommodate the field services team (FY26) and the Levin office staff (FY28)	$2.7m	• The Coventry depot is no longer fit-for-purpose and there is no workable upgrading option. We are using the opportunity to consolidate the Levin

Project	Driver	Cost/Year	Justification/options considered
		FY28[203]	office and depot and will sell the current Levin office when staff have been relocated.
Paraparaumu Depot and Office	Development of a Paraparaumu depot and office	$4.2m FY27	• Development of a site in Paraparaumu is needed to accommodate our corporate, asset management and service delivery teams
Premise security	Replacement, renewal and upgrade to security of all depots, offices and substations	$188k FY27-36	• End-of-life replacement of existing system and expanding camera coverage across all sites
Office equipment replacements	General provision for the renewal of office equipment at offices and depots	$470k FY27-36	• General provision of replacement or equipment at end-of-life
Minor building works	General provision for minor external works at offices and depots	$550k FY27-36	• n/a
EV chargers	Expanding internal EV charging network at existing premises	$31k FY29, FY31	• As we expand our fleet of EVs we will increase the access to EV chargers at our sites
Total	**Non-network capex**	**$8.1m**	**FY27-36**

13.7.2 Vehicle fleet

Electra supports New Zealand's transition into a low-carbon economy and transport decarbonisation initiatives. We are transitioning our vehicle fleet to EVs and have installed EV chargers at all our zone substations and a number at each of our office and depots.

Our vehicle policy is to:

- Evaluate ownership versus leasing for each vehicle purchase. We currently have many vehicles on lease; as these become due for replacement (some still have over three years remaining), ownership will be assessed;
- Replace light vehicles (non-utility) at 5 years/180,000. EV or PEHV will be adopted as replacements where possible;
- Replace vans and utes at 6 years/280,000. We are monitoring the market for viable EV or PEHV alternatives;
- Truck and other specialist vehicle replacements are evaluated individually, typically every 13 years.

Factors considered for replacement include load capacity, terrain capability, and range (to align with key network features), as well as passenger requirements, cargo, and towing capacity. We are monitoring the market for viable EV alternatives.

All vehicles are maintained in good condition to the manufacturer's requirements.

Table 167: Offices and depots, non-network capex

Project	Driver	Cost/Year	Justification/options considered
Vehicle replacements	Ongoing replacement of Electra fleet, including contracting (trucks, utes, , mulchers, trailers, digger) and office fleet (EVs and pool vehicles)	$16.3m FY26-35	• Electra owns its vehicle fleet and the vehicles are replaced as required to keep the fleet operational
Total	**Non-network capex**	**$16.3m**	**FY27-36**

[203] Commenced in FY26. Total cost of $5.7m.

13.7.3 Tools and equipment

We operate all tools and equipment (including specialist testing equipment) as required to develop, monitor, and maintain the assets. Where possible, we replace petrol equipment with battery alternatives. Tools and equipment are typically replaced in accordance with the expected depreciation or when their condition or functionality declines. We are monitoring advances in asset condition monitoring and will adopt new test equipment when appropriate.

Table 168: Offices and depots, non-network capex

Project	Driver	Cost/Year	Justification/options considered
Testing equipment	General provision for the upgrade or replacement of test equipment	$261k FY27-36	• n/a
Field services equipment	Replacement, renewal and upgrade of tools and equipment	$3.5m FY27-36	• n/a
Total	**Non-network capex**	**$3.8m**	**FY27-36**

13.8 Forecast Expenditure

The forecast for non-network capex for offices, depots, vehicles, tools and equipment is shown in Table 169.

Table 169: Depot, offices, vehicles and tools non-network capex (Real $000)

Item	FY27	FY28	FY29	FY30	FY31	FY32	FY33	FY34	FY35	FY36	Total
Offices and depots	3,387	4,280	2,825	138	123	139	123	123	123	123	8,121
Vehicles	1,539	2,170	1,503	1,936	2,048	2,060	1,300	1,353	1,302	1,305	16,282
Tools and equipment	406	444	376	326	346	366	376	417	367	378	3,773
Total	**5,332**	**6,895**	**4,704**	**2,400**	**2,517**	**2,564**	**1,800**	**1,893**	**1,791**	**1,806**	**28,176**

Other non-network capex related to IT/OT systems is included in Sections 9.8 and 9.9.

14. Risk management

14.1 Introduction

Electra faces a wide array of risks, not only those inherent in operating an electrical network but also external threats such as legislation, environmental changes, and stakeholder satisfaction. Beyond obvious physical dangers like cars hitting poles, vandalism, public safety issues, and storm damage, the network business is subject to a broader spectrum of risks that must be addressed. As a lifeline utility, we acknowledge our duty to keep the network safe, secure, and resilient.

In this section, we describe our risk management framework and system, business and network risks, our resilience strategy and our emergency response and readiness activities.

14.2 Risk management framework

We completed a revision of our risk management policy and framework, which was approved in June 2025. Risk management is an essential component of our governance framework and supports the achievement of the company's goals and objectives. It applies to all Electra activities at all work locations.

Key principles

The key principles of Electra's approach to risk management are:

- To ensure risk management is an integral part of our business processes;
- Transparent and based on the best available information;
- Responsive and timely;
- Based on best practices;
- Is continually improved.

Framework and processes

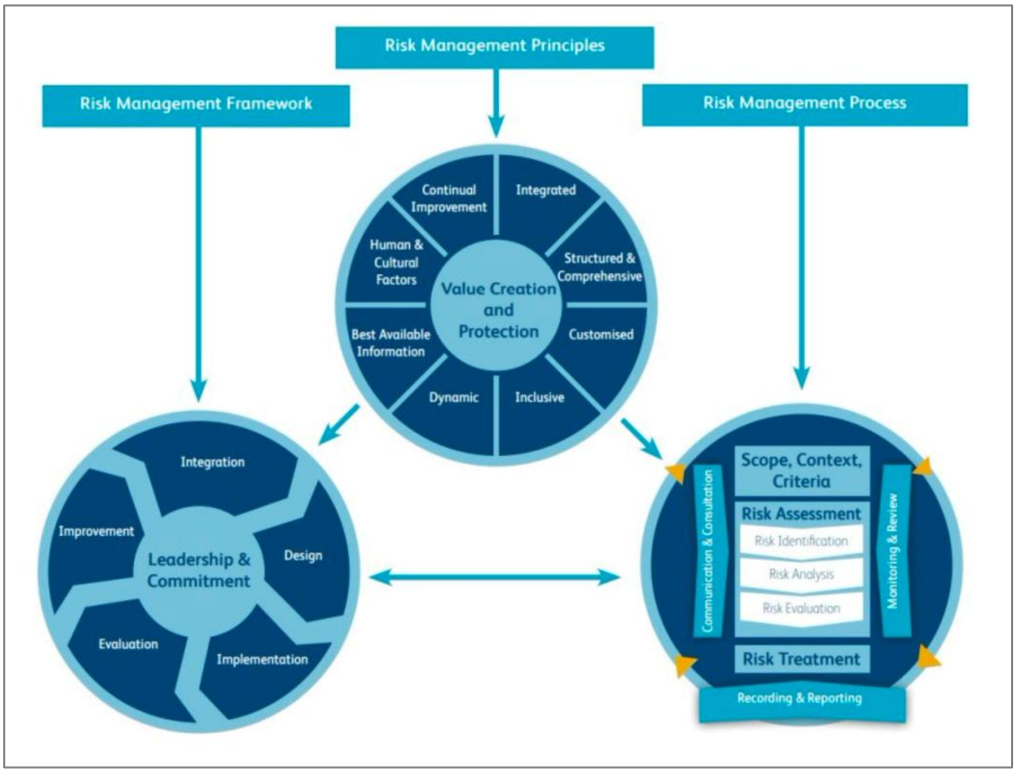
This framework uses well-established processes based on AS/NZS ISO 31000 to (see Figure 162):

- Identify risks that could impact the safety (of staff, contractors and the public), customer service, finance, and the environment;
- Assess the consequence and likelihood of the risk occurring;
- Identify controls that will mitigate the risk;
- Assess the effectiveness of controls;
- Identify the top residual risks (after controls have been applied);
- Regularly assess the residual risk to assess whether additional treatments could further minimise risks.

The framework is always looking at emerging risks, being inquisitive and proactive.

An essential part of this process is the identification of workplace hazards and maintaining a register of incidents and accidents consistent with the Health and Safety at Work Act (**HSWA**).

Figure 162: Electra's risk management framework



14.3 Responsibilities for risk management

All staff are responsible for risk management (Figure 163). Our approach includes line-of-sight linkages from risk governance to detailed risk identification and mitigation. We have a well-established Audit and Risk Committee, with the GM Commercial acting as the company's Risk Manager. The Audit and Risk Committee reviews key risks and engages in a schedule of 'deep dives' into Electra's key and emerging risks.

Staff regularly complete comprehensive risk analysis on the network and the business. The risk analysis is reviewed and agreed by the Audit and Risk Committee comprised of Electra Directors, the Chief Executive, Chief Financial Officer, and the Risk Manager.

Figure 163: Responsibilities for risk management

14.4 Risk management system

The risk register is the primary tool for recording how risk is managed. The risk register records all risks, the person responsible for managing each risk, and references the associated risk action plans. Electra is implementing Quantate as the preferred risk management application and risk register for corporate risks. We continue to use the Vault risk management system to record and manage all risks, incidents, injuries, illnesses, near misses and incident investigations. Vault is a stand-alone cloud-based risk management and incident reporting tool available to staff via desktop or mobile application.

We apply a consistent risk evaluation and scoring system, which enables us to readily identify the greatest risks to the business.

Electra's risk register identifies and measures risks using a scoring system. A risk's raw risk score is based on the probability of it occurring and its consequences; its current (or residual) risk score is calculated after existing controls are applied, and the target risk score is calculated after any proposed treatments are applied. The risk register also monitors actions taken against any agreed risk treatment.

14.5 Significant business risks

Electra has identified significant business risk areas that encompass harm to workers and the public, stakeholder expectations, network performance and delivery, financial risk, digital capabilities and cybersecurity, strategy, regulation and compliance, and the environment. We discuss the key asset management-related risks in the sections below.

<u>Note:</u> Risk is defined as the impact of uncertainty on our objectives. Hence, the description of the risks under each risk area generally outlines the impact we are seeking to avoid (i.e., a *failure*).

14.5.1 Harm to people and property

Operating and maintaining an electricity network involves hazardous conditions and risks that cannot be fully eliminated. We are committed to ensuring the safety of our customers, employees, contractors, and the public. Failure to ensure these outcomes is a key risk for the business.

We have developed a health, safety and wellbeing policy supported by a comprehensive safety management system (**SMS**). Implementation of the SMS is our key control for safety (refer to Section 13.6).

Key aspects of the health, safety and wellbeing policy and our SMS are to:

- Identify and control risks by eliminating, or minimising them;
- Workers actively identify, report and deal with any potential hazard and associated risk to them or any other person while at work;
- Have a critical risk framework that focuses on our most significant risks and controls to prevent harm from exposure to these;
- Provide and maintain training and information to enable team members to fulfil their own and the Company's personal obligations for health, safety and wellbeing;
- Any accident, health and safety incident, near miss or significant health or safety issue must be reported;

- Following investigation into the causes of any accident, incident, near miss or significant safety issue identified Electra will, so far as is reasonably practicable, action any recommendations arising to prevent a recurrence through a process of elimination or minimisation;
- Worksite safety observations and auditing are carried out continually internally, and by an industry expert at least twice a year. Issues identified are recorded as actions and tracked to completion within set time frames and reported on to senior leaders and the Electra Board.;
- Contractor management; 3rd party education. Contractors carrying our work on the network or for our Service Delivery team go through an approval process including pre-qualification, annual assessment, and regular on-site engagement including safety observations and audits. Third parties working near or around our assets are also engaged with regularly, ensuring compliance with codes of practice when working near live overhead lines (close approach consents), and performing their work safely so that no members of the public or their workers are at risk from Electra's assets.

14.5.2 Network reliability, performance and delivery

Key network-related risks include: the network's performance not aligning with customer expectations; inadequate response to outages and incidents; failure to manage asset health and risk; and failure to deliver the work plan. Mitigating these risks is a core focus of our asset management.

This AMP outlines the key controls for managing network reliability, performance and delivery. Key aspects of our risk management include:

- Continuously reviewing network and asset performance issues and responding to those issues. These issues, and our responses, are discussed at a summary level in Section 4;
- Mitigating performance risk through applying appropriate supply of security standards. The consequences of a network fault (from whatever cause) are mitigated through our security of supply arrangements. The security of supply is a planning standard that the network is designed to meet (refer to Section 11.4.2). It provides redundancy or backup supply in the event of a network fault. This minimises supply interruptions;
- Risk mitigation due to our asset renewal strategy. Assets are more likely to fail towards the end of their useful life. All network assets are inspected to ensure we understand their condition and to identify any end-of-life drivers. We have developed comprehensive fleet plans that use a condition-based asset risk model to determine an asset's health and risk and schedule the asset for replacement ahead of failure (refer to Section 12.4). This approach reduces the risk of asset failures;
- Ensuring that we have resources available to respond to faults and to deliver the planned development and renewal work (see Section 13.4.3);
- Ensuring the network is resilient against low-probability, high-consequence events, and that we have plans in place to respond and recover from major events. Our approach is set out in our resilience strategy (see Section 14.6 below). We have emergency response plans for major events (see Section 14.9).

Another key risk is that the network is not *future-ready* to deliver the capacity to meet electrification needs in our region. We are managing this future risk through our energy transformation roadmap, demand forecasting and development plans (see Sections 10 and 11). We continually review our demand forecasts and development plans to ensure they align with our customers' future capacity needs.

We discuss typical asset-related risks and controls in Section 14.8.

14.5.3 Digital capabilities and cybersecurity

Enhancing our digital capabilities supports key initiatives to enable Electra's business strategy, reduce costs, drive decision-making, and improve innovation. Failure to deliver on our digital strategy will impede strategy and decision-making that could result in a higher cost-to-serve and operational efficiencies. Our key control is the quality of implementation of our digital strategy and the capability of our digital team. These are discussed in Sections 9.4 and 9.5.

Cyber attacks continue to increase globally and in New Zealand, posing a key risk to Electra and mitigating this threat is a key focus for the business. We have carried out a series of assessments and have undertaken a series of activities on cyber security controls. Networking with similar EDBs is on-going to drive the sharing of knowledge and key learnings in the industry around cyber security controls, policy, and framework for information security management.

Operational Technology (**OT**) cybersecurity is a critical area of focus. As we continue to build on the Purdue model, we are implementing an effective cyber-physical system (**CPS**) designed to provide robust exposure management, network protection, secure access, and threat detection. This comprehensive approach ensures that all layers of our control systems are fortified against potential cyber threats, safeguarding our critical infrastructure.

The Purdue model is a hierarchical framework for developing secure control systems and is the foundation for our OT cybersecurity strategy. By integrating advanced CPS, we enhance our ability to monitor and protect each level of the Purdue architecture, from the enterprise network to the physical process. Our focus extends beyond traditional IT security measures to encompass the unique requirements of OT environments, where the convergence of digital and physical systems necessitates a nuanced approach to security.

Complementing this cyber-physical system is our unified IT/OT Security Operations Centre (**SOC**) service. The SOC plays a pivotal role in monitoring and analysing anomalous activity across IT and OT domains. By leveraging sophisticated automated response mechanisms, the SOC effectively stops any detected threats. This unified approach enhances our security posture and facilitates seamless collaboration between IT and OT security teams, fostering a culture of shared responsibility and continuous improvement in our cybersecurity efforts.

This work programme is dedicated to establishing a resilient and secure cyber-physical ecosystem. By building on the Purdue model and integrating state-of-the-art CPS and SOC services, we are committed to providing robust protection for our operational technology environments against the evolving landscape of cyber threats. This proactive and holistic approach to OT cybersecurity is essential for maintaining the integrity, availability, and safety of our critical infrastructure.

We discuss planned cybersecurity improvements in Section 9.4.3.

14.5.4 Regulation and legislative compliance

A breach of material legislation or regulation is a risk for the business. The volume of regulatory reform has increased substantially in recent years. A regulatory team, including external experts, has been established to oversee compliance. Compliance is also overseen by the Audit and Risk Committee.

A further control is our compliance programme. Directors, Management and key staff complete a Legal and Statutory Compliance survey quarterly using the ComplyWith system. The process ensures that we monitor our legal obligations and educate our staff on legal requirements. ComplyWith includes regular reporting of changes to legislation sent directly to the 'obligation holder' to inform and update them of new or altered requirements. This proactive approach ensures that Electra keeps abreast of its legal compliance requirements and with the aid of ComplyWith's information function, staff can check what compliance means for each particular requirement.

The most recent certification process covered 44 pieces of legislation, with 415 responses completed. There were no non-compliances identified.

14.5.5 Environment

Changing climate features (sea-level rise, shifting rainfall patterns, rising air temperatures, and more frequent windy days) are widely regarded as the single most significant risk facing civilisation in general and built infrastructure. Our network is not immune to changes in the environment like coastal erosion and the rising sea level, and we are exploring how these types of changes impact the way we build and support our network with a view to augmenting our procedures and processes to enable a more resilient network in the future. Implementing our resilience strategy is our key control (see Section 14.6).

There is a risk that our business activities could negatively impact the environment and emissions. Implementation of our sustainability initiatives is our key control (see Section 14.7).

14.6 Resilience strategy

14.6.1 High Impact Low Probability (HILP) Events

HILP events have a higher impact than what typically occurs during the normal network operation. These include multiple contingency events at a significant site or widespread outages that impact many assets. It is difficult to predict these events, and some examples of HILP events include the following:

- February 2011: Christchurch earthquake where electricity to 75% of the city was cut;
- October 2014: Penrose cable trench fire causing blackouts to 85,000 Auckland customers;
- February 2023: Cyclone Gabrielle that resulted in the loss of supply to 240,000 customers across the North Island.

HILP events can cause long-duration outages that can cause significant economic and social impacts on communities. Our resilience strategy has been developed to reduce the risk of these events and minimise the consequences through effective readiness and response processes. Our resilience strategy covers:

- Risk identification: understand the type and impact of the events the network could potentially experience;
- Risk reduction: minimise the consequence of these events with investment in new technologies and asset renewal and replacement;
- Readiness: reduce the impact of these events by improving network resilience;
- Response: develop plans in our business processes to respond to such events, including contingency plans to invoke a staged and controlled network restoration.

14.6.2 Importance of resilience

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

14.6.3 Definition of resilience

In the modern context, resilience means:

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

For the electricity distribution businesses, this means:

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

14.6.4 Objectives of our Resilience Strategy

The objective of our resilience strategy is to improve the resilience of our network to reduce the impact of HILP events within acceptable customer tolerances.

Our approach to improving network resilience is to identify which assets are at risk, quantify that risk, and compare the cost of remediation against its current asset health index and expected life cycle. This approach that will see efficient investments consistent with our customers' interests and appetite for risk.

The outcomes of this strategy will be:

- An improvement in our RMMAT score to 3 in all areas and 4 in critical areas;
- A reduction in the duration of loss of supply to customers and the number of customers affected during major adverse weather events and other natural hazards (in particular to asset failures and vegetation outages);
- Assessment and adaption to climate change;
- Improved emergency management response and community support.

The resilience strategy supports our asset management strategy #4, which is to *continuously improve the security, reliability and resilience of the distribution network*.

Our objective focuses on resilience to various natural and other hazards and excludes cyber security. However, this is not excluded from a business perspective, and our work on cyber security is discussed in Section 14.5.3. We will include our implementation timeline in the 2026 AMP.

14.6.5 Resilience strategy

Improving resilience will take a multi-faceted approach over the next decade. This will be addressed principally through risk reduction, readiness and response activities. To provide a comprehensive view of resilience, our strategy includes new initiatives and existing programmes that enhance resilience. Our strategy is shown in Figure 164.

Figure 164: Resilience strategy

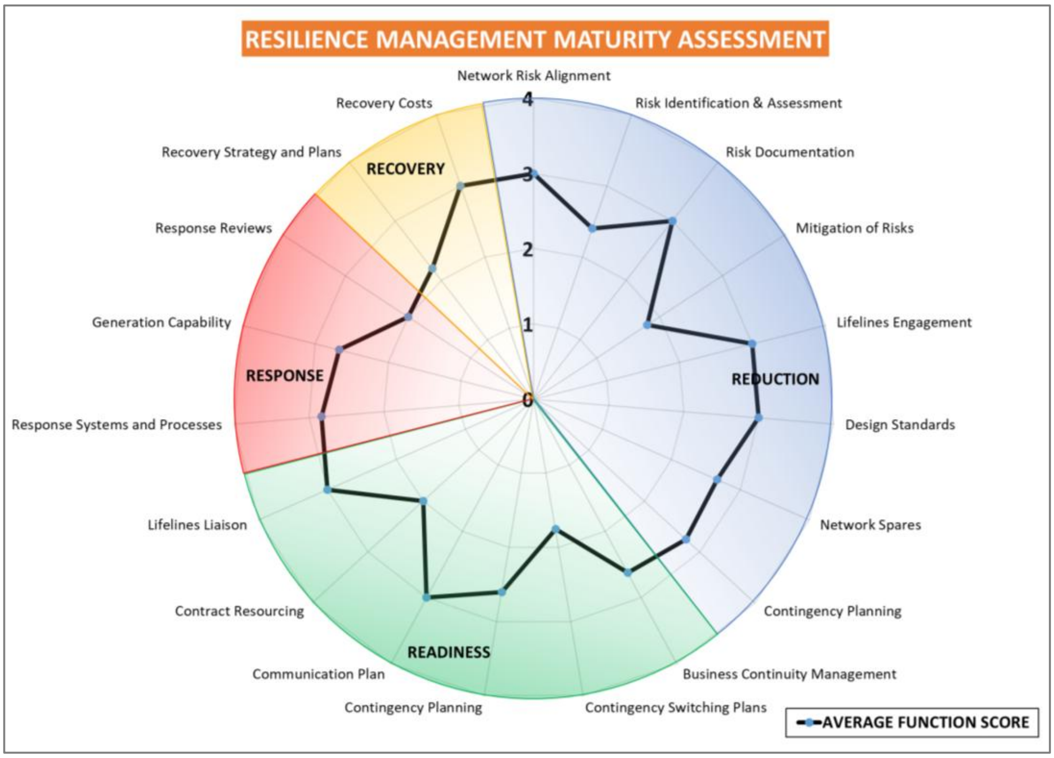
Community engagement		Strategy action	Description	Status
Community engagement	Review	Conduct annual RMMAT assessment FY26	Assess our resilience maturity and determine improvement activities	Assessment complete
Community engagement	Risk identification actions	Resilience Explorer GIS layers	The resilience explorer developed by Urban intelligence will be used to assess our network vulnerabilities to natural hazards (wind, seismic, river flooding, coastal inundation, peak rainfall, land stability), as well as the impact of climate change on these hazards.	In progress
Community engagement	Risk identification actions	Resilience & Condition based asset risk management methodology	Apply resilience-based risks & probabilities on top of current condition-based asset risk management methodology.	In progress
Community engagement	Risk mitigation actions	Increase the physical resilience of critical assets in vulnerable locations	Assess the options to increase the resilience of critical assets that are vulnerable to natural hazards	To commence in FY26
Community engagement	Risk mitigation actions	Resilience process implementation	Process controls to prevent new assets being placed in hazardous locations. Where alternative locations are not possible, additional strengthening and engineering signoff will be required.	To commence in FY26
Community engagement	Response and readiness actions	Diversity of critical spares storage	Establish additional storage locations for critical spares. Both northern and southern locations to increase resilience and access to critical spares in an emergency.	In progress
Community engagement	Response and readiness actions	Improve major event response	Review of response to storms and implement actions to improve our processes Develop switching contingency plans	Continuous improvement process
Community engagement	Response and readiness actions	Enhance community support	Following Cyclone Gabrielle, the government is looking at increasing support of community resilience. We will support these initiatives	Awaiting government recommendation
Improvement in asset resilience				

We have commented further on the resilience activities below.

14.6.6 The outcome of the recent resilience review

Figure 165 shows the results of the self-assessment of our resilience practices. The RMMAT assessed our work on reduction, readiness, response and recovery (the 4Rs of resilience). The areas for improvement identified in the review were risk assessment and reduction, contingency planning and response systems. The resilience strategy incorporates a range of actions that address these areas. We expect to see consistent improvements in our RMMAT score in the near future, with our long-term goal to achieve RMMAT scores of 3 in all areas and scores of 4 in key areas.

Figure 165: Resilience management maturity assessment



14.6.7 Risk identification and assessment

Two tools are in development that will allow a more structured approach to risk identification and assessment, these being:

- Resilience and condition-based asset risk management methodology (R-CBARMM): This is an extension of the CBARMM (refer to Section 12.4.1). R-CBARMM incorporates resilience-based risks and probabilities, such as quantifying the impact of a flood on each asset class using return periods consistent with the importance or security level of the asset.[204] This is used to determine risk exposure in dollar values;
- Resilience explorer: These GIS-based layers visually represent each hazard overlayed upon our network. Each hazard layer is based on published environmental studies. This is used to determine which assets will be affected during different hazard scenarios.

14.6.8 Increasing the physical resilience of critical assets in vulnerable locations

We are already in a good position regarding the extensive usage of modern concrete/steel structures throughout our network, and our substation assets are progressively being upgraded to better withstand seismic hazard. Following the development and expected implementation of the risk identification and assessment tools, there may be other resilience-driven projects (under network development) or changes in asset renewal priorities (in the fleet plans).

Whilst this strategy focuses on natural hazards, resilience is also supported by our work on reducing the impact of third-party damage incidents, outlined in the distribution structure fleet plan (Section 12.12).

[204] The importance level or security level defines the standard of post-disaster performance required by the assets. Refer to our resilience planning standard in Section 11.4.6.

14.6.9 Resilience process implementation and revision to design standards

We are in the process of reviewing our network design standards. This presents the opportunity to improve resilience steadily through scheduled network renewal projects and as new assets are installed. Following the revision, there may be other resilience-driven projects (under network development) or changes in asset renewal priorities (in the fleet plans).

14.6.10 Minimising the impact of outages where they occur

Reducing outages through sectionalisation, automation and improving backfeed capabilities are existing development programmes, albeit currently under review (refer to Sections 11.10.3 and 11.10.4). These programmes improve reliability and resilience. As we progress on our resilience journey, the priorities and targeting of these programmes may be altered.

14.6.11 Diversity of critical spares storage

We have two storage locations, one at Levin East and the other at Paraparaumu East Zone substations. These locations give us good diversity, with each location able to serve either the Northern or Southern regions, providing a degree of resilience should access over the Ōtaki River be compromised in an event.

14.6.12 Improve major event response

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

- Develop switching contingency plans. While we have the basic methodology to follow during a major event, we need to develop switching contingency plans to guide Network Controllers when restoring power during a widespread network event.
- Undertake a critical load study to identify high-sensitivity customers that must be prioritised during power restoration, such as medical facilities, community centres, etc.

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

14.6.13 Resilience expenditure

Our expenditure forecasts include current programmes and projects that link to resilience. This includes work on seismic strengthening of zone substations, sectionalisation and automation. These are already included in the expenditure forecasts.

There will be a minor increase in opex to cover the implementation and ongoing support for the resilience explorer tool. Once this tool is completed and implemented into our workflows, we expect an increase in our forecast for resilience-related capex expenditure to address critical areas of the network identified as at risk.

14.7 Sustainability strategy

Electra is committed to reducing the human impact on climate change and ensuring we understand how Electra's activities can materially impact this change. We have adopted the ESG framework for sustainability reporting. This enables us to have sustainability as a core part of our operations. We have updated our Environmental Policy and we are in the process of updating our Sustainability Policy. This gives clear direction on where our sustainability efforts should be focused, which we have determined as:

Environmental

- Greenhouse gas (GHG) emissions reporting and Toitū Carbon Reduce certification;
- Supply chain engagement for GHG reduction;
- Circular economy and waste minimisation;
- Environmental Management System (EMS) implementation and Toitū Envirocare certification.

Social

- Energy efficiency;
- Energy hardship;
- Supporting local organisations;
- Community engagement and education around the electricity sector.

Governance

- Maintaining and reporting on both EMS and GHG Toitū certifications;
- Implementation of our Environmental Policy and our Sustainability Policy.

Decarbonisation

Electra is committed to supporting the government's low-carbon initiatives delivered through EECA and other government agencies. Converting process heat from coal and gas to clean energy and decarbonising the transport sector by moving operators from petroleum products are major opportunities for Electra.

To support these government initiatives, we are:

- Regularly meeting local councils to discuss plans;
- Approaching and working with customers that may benefit from moving from fossil fuels;
- Participating in relevant national workgroups and events.

Given New Zealand produces most of its electricity from renewable sources, electricity is the most environmentally friendly source of energy in our country. This places Electra in the enviable position of being a significant enabler of decarbonisation in our region. As a first step, we have identified large and medium process heat users in our network area and are planning an engagement with each customer to understand their decarbonisation plans, which will feed into our future AMPs.

14.8 Typical asset-specific risks and controls

Table 170 summarises typical asset-specific risk and controls applied at Electra. Our risk register contains a comprehensive register of all network risks and controls.

Table 170: Typical network risks and controls

Typical risks	Asset	Controls
Oil leaks and contamination of the environment	Transformers and switchgear	• All zone transformers have individual oil containment and water/oil separators • Oil spill kits located at each zone substation in case of other spills • Where a distribution transformer or switchgear has leaked, all affected ground is removed and suitably disposed of in accordance with local by-laws
Building damage due to seismic, wind or snow*	Buildings and zone substations	• All buildings are designed to an appropriate importance level (refer to the resilience standard in Section 11.4.6) • All power transformers seismically engineered bracing • Aspirating smoke detection systems for fire containment are installed at each zone substation's switchgear building

Typical risks	Asset	Controls
		• All zone transformers and switchboards have annual diagnostic testing to locate potential faults before they occur
Line damage due to wind, snow or ice loadings*	Overhead lines	• All new lines are designed to AS/NZS 7000 to security level 3, and relevant legislative requirements • Safety in design principles are followed during the design process • All lines are inspected on a five year cycle and asset health and risk is monitored. Lines with degrading health or risk are replaced
Network damage due to vehicles*	Overhead lines and ground mounted equipment	• Electra's line poles are generally set back from the road carriageway. A recent study indicated that most vehicle damage incidents occur on long straight sections of road, where our poles were not located in a vulnerable position. • All ground mounted assets are located away from the road carriageway or physical barriers are installed. • We review all vehicle damage incidents to see if improvements need to be made. • We have a high load procedure for managing oversized/height loads travelling through our network.
Line damage due to vegetation*	Overhead lines	• We have implemented a vegetation management strategy as presented in Section 12.19.2.
Cable damage due to contractor damage*	Underground cables	• All contractors excavating in the road reserve are required to obtain plans for all underground utilities. • We maintain accurate plans of our underground assets in the GIS. • Cable location and safety stand-over services are also provided as required. • We review all contractor damage incidents to see if improvements need to be made.
Harm to employees and contractors working on the network	All	• We operate a mature safety management system (refer to Section 13.6). The system comprises: competency management, contractor approval and review process, fieldwork auditing, hazard identification, management and communication, safe operating procedure, live line procedures, close approach consenting, and management of change
Harm to the public caused by network	All	• We operate a public safety management system (**PSMS**). The PSMS operates to safeguard the public and their property from safety-related risks arising from the presence or operation of the electricity network. Our PSMS complies with all elements of NZS7901 and is independently audited annually.
Supply chain constraints leading to project delays	All	• We are improving our front-end engineering design to ensure we begin the procurement process well in advance of need to ensure that purchases are efficient and delivery meets project requirements
Poor work quality leading to asset failure*	All	• We operate a web portal for approved contractors which gives access to our latest technical and construction standards. These standards are being revised and updated and a number of new standards and standard drawing are being drafted. • We have implemented a commissioning standard for new installations to ensure consistency across contractors. This is planned to be expanded further to encompass refurbishment to existing assets or for after fault events. • All significant works are audited upon completion and any defects found are notified to the contractor for remediation. While there are some minor gaps in our standard documentation we are relying more heavily on this audit process.
Inability to connect new customers due to insufficient capacity	All	• Electra undertakes demand forecasting and network planning to ensure that the network is developed to meet the future needs of customers. Our development plans are outlined in Section 11. • Active engagement with customers and developers to understand their requirements well in advance of need.
Inability to respond to the changing needs of customers	All	• We have developed an energy transformation roadmap (**ETR**) to prepare the network for the future needs of customers (refer to Section 10)

Typical risks	Asset	Controls
Inability to access the network to operate or maintenance	Assets on private property	• All new assets on private property are suitably protected by registered easements or are protected by existing use rights
Unauthorised access to assets that could result in damage or harm to people	Zone substation and ground-mounted assets	• All zone substations, switchgear and distribution transformers access locks use a controlled and tiered key system. Access keys are only provided to employees and contractors on a "need to have" basis. • Security fences at zone substations. • Bi-monthly visual inspections of all zone substations, which includes all security arrangements. Any necessary repairs are scheduled immediately
Loss of network records	n/a	• Electra records asset information electronically. The principal servers are located within Electra's Levin and Paraparaumu offices. The inherent risk with this is reduced by replication between physical sites, both cloud and offsite storage of computer backups, including SCADA, and contracts with suppliers to provide temporary support if required. • Scheduled recovery tests occur in our accordance with the Electra IT Security Policy • Access controls include the use of Microsoft Active Directory, multifactor authentication, and expected antimalware and behaviour monitoring software.

* The asset damage may cause an outage to customers depending on the network configuration and location.

14.9 Emergency response and readiness activities

14.9.1 Business Continuity Management Plan

Electra has an active Business Continuity Management Plan (**BCMP**), which is reviewed and updated regularly. Recent inclusions and updates include pandemic, climate change and seismic threats. An event simulation exercise was conducted in mid-2024, and again in mid-2025 and learnings have been incorporated into a revised BCMP.

14.9.2 Emergency response plans

Electra has a Major Network Event Guideline that is used in a storm or other major network event affecting supply to Electra's customers. The document guides what needs to occur in the lead-up to an event, at the announcement of an event and during the event. It defines the roles and responsibilities of team members involved in managing the event. It is planned to further develop this guide to include for other events.

14.9.3 Contingency plans

Contingency plans concerning minimum critical spares and an evacuation of the control room are included in our standard documents. We have also undertaken a double contingency risk analysis of our sub-transmission network to evaluate the supply options should a second contingency occur while an existing event occurs.

We have a Participant Rolling Outage Plan to comply with the Electricity Industry Participant Code 2010. The plan defines our response to major generation shortages and/or significant transmission constraints. It defines how we will shed load when requested by the System Operator. Reducing demand by disconnecting supply to customers is a last resort after all other forms of savings, including voluntary savings, have been exhausted.

For our IT/OT we have incident response plans in the event of a cyber-attack.

14.9.4 Readiness Activities

Biennial simulation exercises are undertaken to ensure the BCMP remains relevant. The Major Network Event Guideline are tested regularly and also tested during major storm events.

14.10 Critical spares

Electra holds an appropriate inventory of modern equivalent spares covering the most commonly used assets. These are located at the Paraparaumu and Levin depots. Overall, our spares holdings are sufficient to respond to a significant event. However, until the power transformer renewal project at Paraparaumu East in FY27 we have no critical spare transformer, which presents a risk to Electra. The spare we had was used at Paekākāriki in Q4 of FY24.

Individual zone substations have site-specific spares stored at each site as appropriate. We are enhancing substation spares and have a project in Section 11.9.4 to add a 33kV outdoor modular switchgear. We are also reviewing our approach to holding a spare power transformer.

14.11 Insurance

Electra uses insurance to transfer risk where it is economic to do so. Electra's insurance program covers professional and director's indemnity, public liability, material damage, fire and business interruption for buildings and plant, and vehicle cover. Other than zone substations, Electra cannot economically insure the electricity network for material damage.

In the past years, with several natural disasters affecting New Zealand, the cost of insurance cover has risen substantially. To manage costs Electra undertakes an annual review of its cover programme and retained limits. In 2023 Electra widened the marketing of its insurance programme to add new insurers and provide a range of future flexibility for increasing limits and cover. A full review of the insurance strategy has been implemented across 2025 and 2026 including a detailed Risk Assessment Survey of insured assets that has allowed Electra to market its exposure to the London insurance market; exercises to identify Maximum Probable Insured and Uninsured Loss, to better inform insurance decisions and will conclude with a comprehensive assessment of risk appetite to inform insurance versus self-insurance options.

Electra requires design consultants to hold professional indemnity insurance and contractors to hold contract work and public liability insurance.

15. Expenditure Forecasts

15.1 Introduction

This Section summarises the material drivers of forecast expenditure and the material changes relative to the 2025 AMP[205]. All of the commentary in this Section is expressed in 2026 constant dollars. We have focused our commentary on the first five years (FY2027 to FY2031) as our forecast for this period generally reflects known projects and programmes. The expenditure forecasts for the outer years (FY2032 to FY2036) reflect high level forecasts rather than specific projects and programmes. Where specific projects or programmes do exist, the timing and costs are uncertain and may change if economic conditions, electrification demand, subdivision activity, asset health or asset risk change.

15.2 Material drivers for the change in expenditure forecasts

15.2.1 Summary of changes

Overall our forecast capital expenditure (**capex**), after customer contributions, is lower than in the 2025 AMP due to the optimisation we have conducted to our forecast programme. The changes we are implementing to our capital contribution policy brings in more expense, yet that increase is customer funded and now becomes visible to us.

Operational expenditure (**opex**) is also lower than the 2025 AMP, largely due to changes in service interruptions and emergencies, and network support costs.

Capex

The capex forecast for the next five years is $162m before deducting capital contributions (Table 171). Compared to the 2025 AMP, this is an increase of $9.5m (6%).

Table 171: Capex Forecast (Real 2026 $000)[205]

Forecast	FY27	FY28	FY29	FY30	FY31	FY32	FY33	FY34	FY35	FY36	FY27-31	FY27-36
Capex 2026 AMP	35,165	32,113	32,262	31,624	30,787	30,739	29,120	28,257	25,007	24,990	161,951	300,065
Capex 2025 AMP	37,964	37,292	26,051	24,579	26,619	26,924	26,195	26,995	22,951	-	152,505	-
Change	**(2,799)**	**(5,178)**	**6,211**	**7,044**	**4,167**	**3,815**	**2,926**	**1,262**	**2,055**	**-**	**9,446**	**-**

The material drivers of the changes in capex over the first five years are:

- A $15.7m increase in customer connection capex, which reflects a change in our capital contribution policy (moving from a vested asset model where customers organised and pay for their own connections, to a model where Electra manages the connection process and then bills customers for the connection cost);
- A $2.8m increase in system growth capex due to the change in timing of zone substation work, which has been deferred from FY2026 into the FY2027 to FY2031 period, and an increase in distribution transformer and switchgear upgrades due to the change in our capital contribution policy (refer to Section 11.9 and 11.13);
- A $14.4m decrease in quality of supply capex, which reflects the removal of most reliability and security improvement programmes whilst these are reviewed and the impact on the energy trilemma is assessed;

[205] 2026 AMP forecast expenditure has been adjusted for inflation and are expressed in constant 2026 dollars.

- A $6.2m increase in non-network capex due to the change in timing for the development of a new Levin depot and higher vehicle replacement costs for the Service Delivery division (refer to Section 13.7);
- Minor increase in asset renewals ($0.4m) and a minor reduction in asset relocations ($0.9m) and other reliability, safety and environment ($0.4m);

However, after deducting changes from the new capital contribution policy, net capex drops to $141m for the first five years. Compared to the 2025 AMP, this represents a $3.3m (2%) reduction.

The capex forecast for the 10-year planning period is $300m, which is $20m higher than the 2025 AMP.[206] Again, the driver for the increase is the change in our capital contribution policy and higher system growth capex. These increases are offset by a reduction in asset renewals, which reflects the optimisation work undertaken over the past 12 months.

Opex

Total opex forecast for the next five years is $130m (Table 2). Compared to the 2025 AMP, this is a decrease of $4.9m (4%).

The material drivers of the changes in opex over the first five years are:

- A $1.2m decrease in business support costs. The reduction is primarily lower overall IT project and data strategy costs (refer to Section 9.8);
- A $3.4m decrease in system operations and network support costs, which reflects a reduction in our forecast of additional IT/OT costs. The forecasts include the project costs to implement the EAMS, but now exclude the costs for the replacement of the ADMS (refer to Section 9.9);
- A $1.9m reduction in service interruption and vegetation management costs, which reflects our current review of these costs in a normal year (refer to Section 12.19.1);
- A $1.5m increase in our vegetation management programme in response to real cost increases an increase in vegetation work due to growth rates, climate change and a focus on our worst performing feeders (refer to Section 12.19.2);

For the 10-year planning period, network opex is $260m, which is $9.6m lower than the 2025 AMP.[207]

Table 172: Opex Forecast (Real 2026 $000)

Forecast	FY27	FY28	FY29	FY30	FY31	FY32	FY33	FY34	FY35	FY36	FY27-31	FY27-36
Opex 2026 AMP	26,596	26,653	25,548	25,608	25,729	25,858	25,767	25,960	26,026	26,291	130,134	260,036
Opex 2025 AMP	27,502	27,070	26,653	26,816	26,949	26,884	26,998	27,173	27,335	-	134,990	-
Change	**(906)**	**(417)**	**(1,105)**	**(1,208)**	**(1,220)**	**(1,026)**	**(1,231)**	**(1,213)**	**(1,309)**	**-**	**(4,856)**	**-**

15.2.2 The impact of inflation

The escalation of real costs between the 2025 AMP and this AMP has been modest (CPI was 3.0% and PPI was 1.9%).[208] We reviewed significant projects for this AMP and adjusted costs based on our assessment of

206 When comparing forecasts to the 2025 AMP, we can only compare the period FY2027 to FY2035 as this was the extent of the forecasts included in the 2025 AMP. Before deducting Capital Contributions.

207 When comparing forecasts to the 2025 AMP, we can only compare the period FY2027 to FY2035 as this was the extent of the forecasts included in the 2025 AMP.

208 Source Stats NZ for September 2024 to September 2025. CPI included all goods. PPI is the construction cost for energy generation, transmission, and distribution.

current material and labour costs. Where project costs were not reviewed, we applied a composite CPI/PPI adjustment to bring prior costs to 2026 real$ (constant prices), equating to 2.3%.

Since September 2025 (when our project budgets were finalised), steel prices have risen by approximately 14%, reflecting heightened global demand and supply chain constraints. Aluminium has seen a surge of around 11%, largely driven by energy cost pressures and market volatility. Meanwhile, copper prices have increased by about 10%, influenced by ongoing infrastructure investment and limited mining output. We have not factored in these increases in our project budgets, which may result in some project delays, to manage our overall capital expenditure profile.

15.2.3 Forecasts in normal dollars

Schedule 11a(i) and 11b(i) provide capex and opex forecasts in nominal dollars. For FY2027, we applied a composite CPI/PPI escalation of 2026 real$ (constant prices) to FY2027 Nominal of 2.28%. From FY2028 onwards, we have applied forecast CPI to escalate the real$ (constant price) forecasts to nominal (refer to Table 173). Our forecasts reflect Westpac's forecasts through to FY2030,[209] then 2.0% thereafter (the middle of the Reserve Bank's inflation target range).

Table 173: Real to Nominal price inflation

Forecast	FY27	FY28	FY29	FY30	FY31	FY32	FY33	FY34	FY35	FY36
Nominal price inflator	2.28%	2.01%	2.19%	2.22%	2.00%	2.00%	2.00%	2.00%	2.00%	2.00%

15.3 System Growth Capex

System growth expenditure is related to the development of the network to meet growth requirements across subtransmission, zone substations, distribution, and LV assets (refer to Section 11). System growth amounts to $31m over the first five years and $66m over the planning period (Figure 166). The material drivers for expenditure in the first five years are:

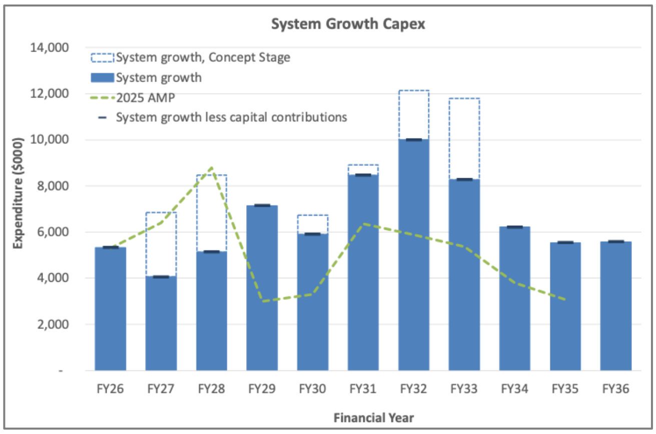
- The development of two new zone substations (refer to Section 11.9.3);
- The installation of Statcom for voltage support at the Ōtaki zone substation (refer to Section 11.9.3);
- Capacity upgrades of two subtransmission lines in the Northern region (refer to Section 11.9.3);
- The development of five new 11kV feeders (a total of 11 are included over the planning period), (refer to Section 11.10.2);
- Distribution transformer capacity upgrades (refer to Section 11.11.2) and new distribution transformers in relation to new connections (refer to Section 11.13).

Over the first five years, system growth capex has increased by $2.8m due to a change in the timing of zone substation work, planned for FY2026 but now forecast for the FY2027 to FY2031 period, and an increase in distribution transformer and switchgear upgrades due to a change in our capital contribution policy.

Figure 166 also shows the value of projects still in the concept phase. This work relates to subtransmission and zone substation developments, as well as feeder developments, that are not yet fully defined or for which customer needs are uncertain.

[209] April 2025 forecasts.

Figure 166: System Growth Capex



15.4 Asset Replacement and Renewal Capex

Asset replacement and renewal capex relates to the end-of-life replacement of assets and is the most significant area of expenditure on the network. Assets are replaced when the risk of continued operation is considered too high (defined in the relevant fleet plans included in Section 12). Asset replacement and renewal amounts to $80m over the first five years and $148m over the planning period (Figure 167).

Expenditure in the first five years is largely being driven by:

- The replacement of LV and 11kV conductors;
- The replacement of crossarms and poles;
- Zone substation transformers and protection relays;
- Pillar box replacements.

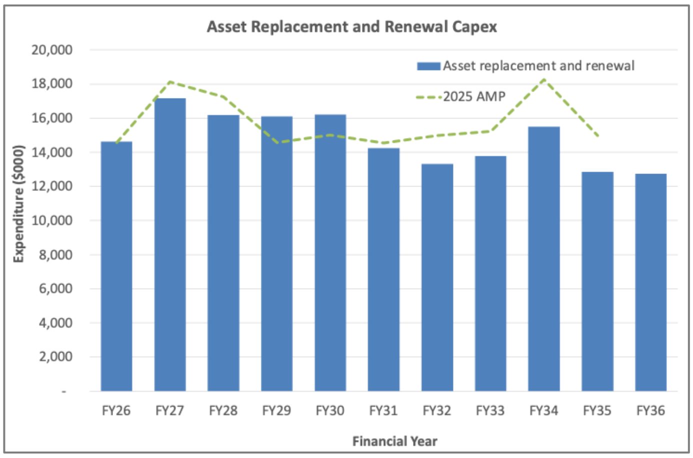
These programmes help reduce the reliability risk and ensure safety mentioned in Section 7.3.

Over the first five years, asset replacement and renewal expenditure has increased by $0.4m, but decreased by $7.6m over the 10-year planning period compared to the 2025 AMP.[210] The changes are due to the impact of the latest condition data and our ongoing optimisation of the fleet plans. Over the planning period, this has resulted in:

- An increase in the number of power transformers planned for replacement, but at a slightly lower overall cost (as we are no longer looking to undertake mid-life refurbishments);
- A $9m reduction in pole replacement costs and a $6m reduction in crossarm replacement costs, largely due to fleet plan optimisation;
- A $4.6m increase in distribution transformer and switchgear replacements, largely due to condition data impacting forecast renewals from FY2032 to FY2036;
- A $2.4m increase in other network asset replacement for the replacement of AC/DC systems and SCADA RTU and communication gateways.

[210] When comparing forecasts to the 2025 AMP, we can only compare the period FY2027 to FY2035 as this was the extent of the forecasts included in the 2025 AMP.

Figure 167: Asset Replacement and Renewal Capex



15.5 Reliability, Safety and Environmental Capex

Reliability, safety and environment capex relates to improving the security of supply or reliability and addressing regulatory environment, safety or resilience issues. Security, reliability, regulatory, environmental and resilience projects are included in Section 11 and safety projects in Section 12.

Reliability, safety and environment capex amounts to $8.8m over the first five years and $12.5m over the planning period (Figure 168, Figure 169 and Figure 170). The material drivers for expenditure in the first five years are:

- Enhancing subtransmission and distribution protection and associated communication links (refer to Sections 11.12.2 and 11.12.3);
- Improving distribution and LV network security (refer to Sections 11.10.3 and 11.11.3);
- Safety programmes to remove pitch-filled 11kV cable potheads, remove 11kV in-line cable joints on poles, and remove LV steel link boxes (refer to Section 12.14);
- Substation resilience, critical spares and environmental improvements (refer to Section 11.9.4 and 11.9.5).

The security projects help reduce the reliability risk mentioned in Section 7.3.

Over the first five years, reliability, safety and environment capex has reduced by $14.8m compared to the prior AMP (and by $22.7m over the comparable FY2027 to FY2035 period). Some of these programmes have been moved to "concept" as we review and assess their business cases to ensure they balance reliability and affordability with customer expectations.

Figure 168: Quality of Supply Capex

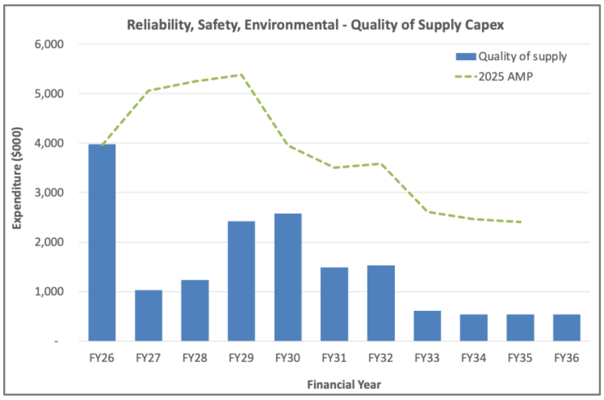


Figure 169: Legislative and Regulatory Capex[211]

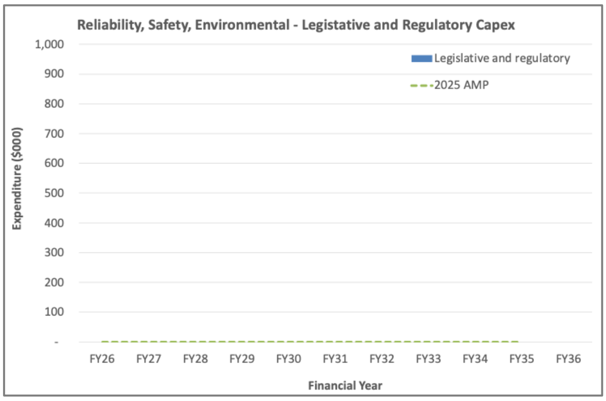
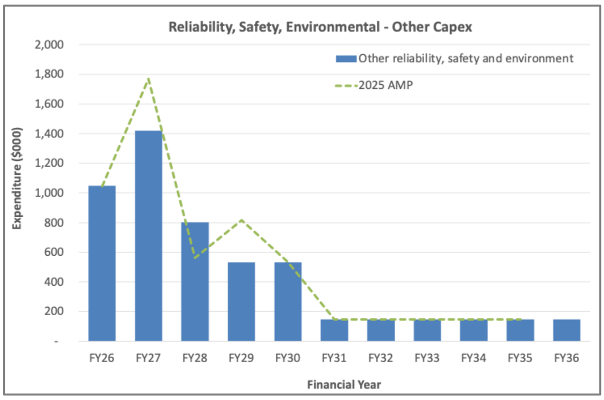


Figure 170: Other Reliability, Safety and Environmental Capex[212]



15.6 Customer Connections, Vested Assets and Asset Relocations Capex

Customer connection capex relates to connecting new customers or upgrading supply arrangements for existing customers. We have revised our forecasts relative to the 2025 AMP to reflect our new capital contribution policy (see Section 11.13.2). From 1 April 2026, we will not be using the vested asset process, so we no longer forecast any vested assets (refer to Figure 171 and Figure 172).

Asset relocation capex relates to the cost of moving our lines and cables to meet the needs of developers and other utility providers. The effective cost to Electra is the net cost (asset relocations less capital contributions), which amounts to $160k over the first five years (refer Figure 173). Asset relocation capex is less predictable as the scope and timing reflect customer requests and is not in Electra's direct control.

[211] The reduction in legislative and regulatory compliance related to zone substation seismic strengthening, which is now classified as other reliability, safety and environmental capex.

[212] The increase in other reliability, safety and environmental capex relates to the transfer of zone substation seismic strengthening from legislative and regulatory compliance capex.

Figure 171: Customer Connection Capex

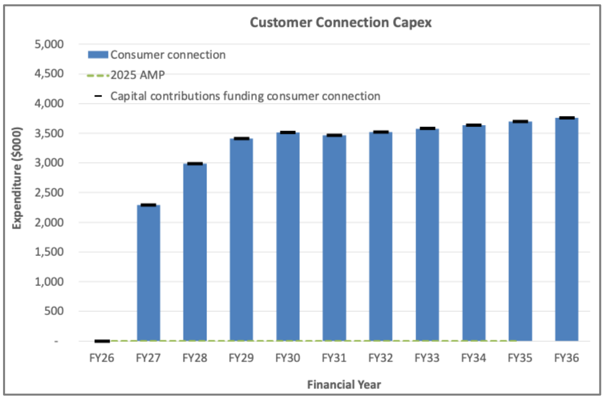


Figure 172: Vested Assets Capex

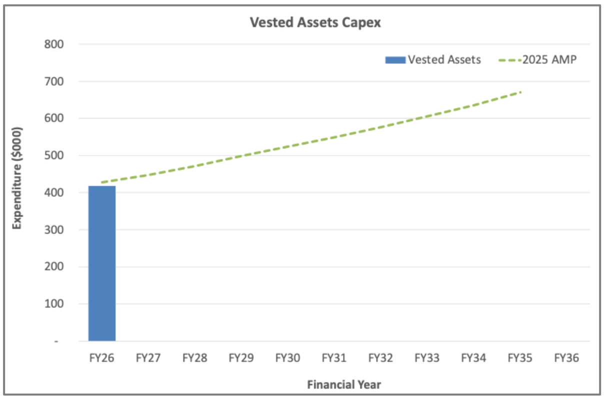
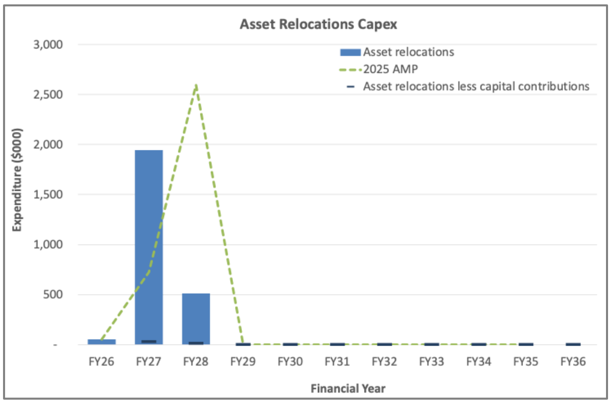


Figure 173: Asset Relocations Capex



15.7 Non-Network Capex

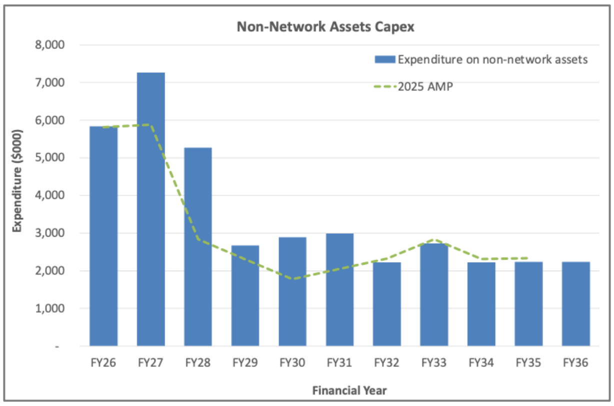
Non-network capex amounts to $21m over the first five years and $33m over the planning period (Figure 174). The material drivers for expenditure in the first five years are:

- Vehicle and plant replacement costs for the Service Delivery division;
- The new Levin depot and office and the development of the depot in Paraparaumu;
- IT and OT hardware costs.

Over the first five years, non-network expenditure has increased by $6.2m compared with the 2025 AMP. The material drivers for the increase are:

- $4.1m due to higher Levin depot costs and the development of the depot in Paraparaumu;
- $2.2m increase in vehicle and plant replacement costs;.

Figure 174: Non-Network Capex



15.8 Network opex

Our network opex forecasts are shown in Figure 175 to Figure 178. Network opex amounts to $38m over the first five years and $78m over the planning period. Network opex covers response and restoration of faults[213], vegetation management, inspection and maintenance of the assets, and replacement of subcomponents of assets[214] that are not large enough to constitute an asset. We discuss these opex categories further in Section 12.19.

We forecast network opex based on historical average costs (less material one-off costs), plus changes in scope, project cost, increases in network scale, increases in real$ costs, and less efficiency improvements. In this AMP, we have not forecast real cost increases or efficiency gains, which will be assessed in future AMPs.

Over the first five years, network opex has reduced by $0.2m compared to the prior AMP. This has been driven by:

- A $1.9m reduction in service interruption and emergency management costs, which reflects our current review of these costs in a normal year (refer to Section 12.19.1);
- A $1.5m increase in our vegetation management programme in response to cost increases, an increase in vegetation work due to growth rates, climate change and a focus on our worst performing feeders (refer to Section 12.19.2);
- A $200k decrease in routine and corrective maintenance and inspection costs, which reflects some minor changes to our maintenance and inspection programmes.

Our real$ (constant price) forecasts generally increase over the forecast period. This reflects an expected increase in network scale (i.e., more assets to inspect, maintain, and respond to faults).

[213] Service interruptions and emergencies
[214] Asset replacement and renewal opex

Figure 175: Service Interruptions and Emergencies Opex

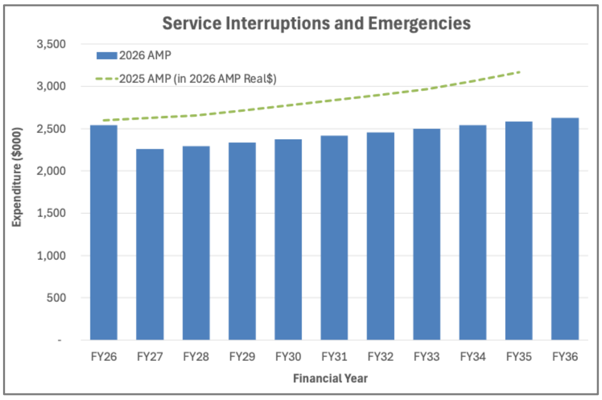


Figure 176: Vegetation Management Opex

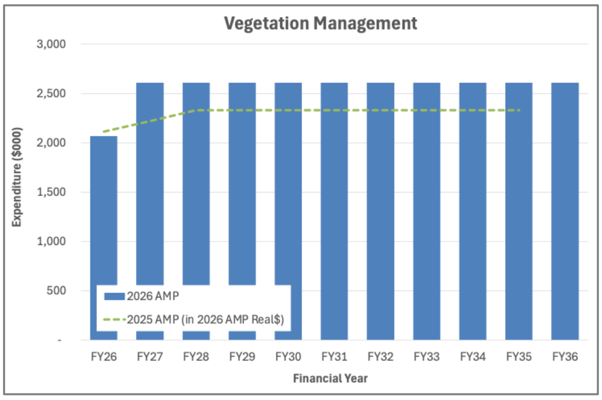


Figure 177: Routine, Corrective Maintenance and Inspection Opex

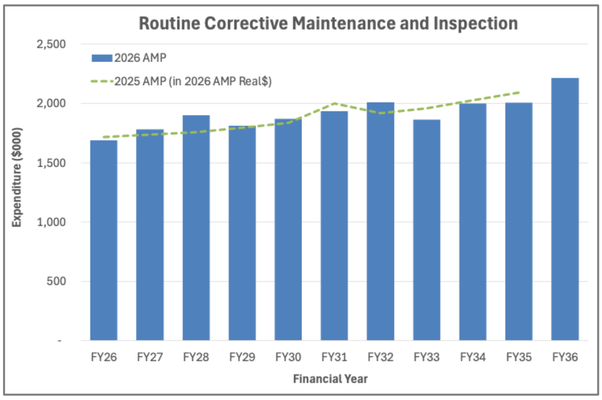
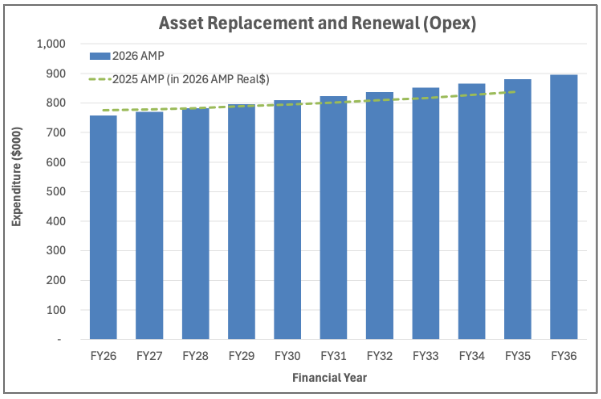


Figure 178: Asset Replacement and Renewal Opex



15.9 Non-network opex

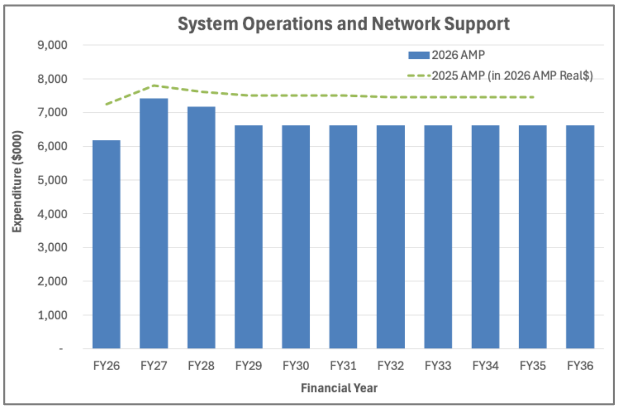
15.9.1 System operations and network support

System operations and network support (**SONS**) expenditure relate to the management and operation of the network and is discussed in Section 9.9. It includes the operations team, control centre, asset information team, engineering team and planning team. Most of the expenditure relates to salaries, wages, and related staff costs. These costs are forecasts based on headcount, net of any capitalisation of design and project management work on capex projects. SONS now includes software-as-a-service (SaaS) expenditure, which is a recent change.

SONS expenditure is $38m over the first five years and $68m over the planning period.

Over the first five years, SONS has decreased by $3.4m due to a lower forecast for additional IT/OT costs. The forecasts include project costs to implement the EAMS but exclude costs for replacing the ADMS (see Section 9.9). We are undertaking scoping work on the ADMS replacement during FY27, and this will drive an increase in SONS from FY29, which will be included in future AMPs.

Figure 179: System Operations and Network Support Opex



15.9.2 Business Support Costs

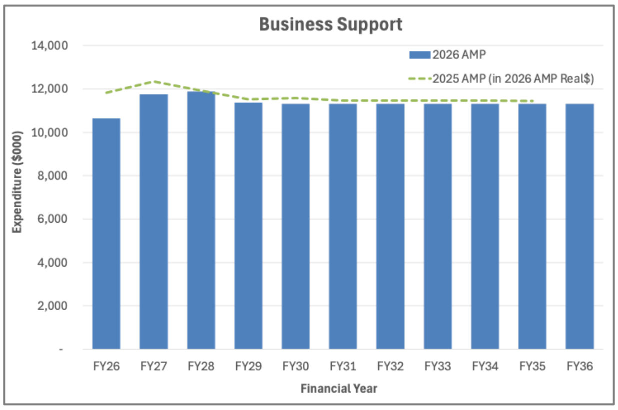
Business support costs relate to the corporate overhead costs required to operate Electra. These include corporate support: Board, executive management, finance, treasury, regulatory and internal legal. It also includes corporate IT support, corporate IT SaaS, insurance, HR, external legal, audit and assurance fees, professional advice and office costs.

Most of these costs relate to salaries, wages, and related staff costs (training, travel, accommodation, etc.). Staff numbers, Electra's strategic work programme, the scale of the field work programme these overheads support drive these costs.

Business support opex amounts to $59m over the first five years and $108m over the planning period.

Over the first five years, business support has decreased by $1.2m due to a lower forecast IT project and data strategy costs (refer to Section 9.8).

Figure 180: Business Support Opex



15.10 Detailed expenditure forecasts

Detailed expenditure forecasts are included in Schedule 11a and 11b in Appendix 4 and 5.

Appendices

Appendix 1: Reconciliation of Asset Management Plan to Electricity Distribution Information Disclosure Determination 2012

The following table reconciles the sections of this AMP to Attachment A of the Electricity Distribution Information Disclosure Determination 2012 (consolidated to February 2024)[215].

Determination Clause (Attachment A of Determination[215])	AMP Section(s)
Contents of the AMP 3. The AMP must include the following-	
3.1 A summary that provides a brief overview of the contents and highlights information that the EDB considers significant;	Section 1
3.2 Details of the background and objectives of the EDB's asset management and planning processes;	Section 2.1 and 2.2 Section 5 Section 6 Section 8.2
3.3 A purpose statement which-	
3.3.1 makes clear the purpose and status of the AMP in the EDB's asset management practices. The purpose statement must also include a statement of the objectives of the asset management and planning processes;	Section 2.2 and 2.3 Section 6.2 and 6.3
3.3.2 states the corporate mission or vision as it relates to asset management;	Section 2.5 Section 6.2 and 6.3
3.3.3 identifies the documented plans produced as outputs of the annual business planning process adopted by the EDB;	Section 8.2 and 8.3
3.3.4 states how the different documented plans relate to one another, with particular reference to any plans specifically dealing with asset management; and	Section 2.9 Section 8.2 and 8.3 Section 11.3 Section 12.3
3.3.5 includes a description of the interaction between the objectives of the AMP and other corporate goals, business planning processes, and plans; *The purpose statement should be consistent with the EDB's vision and mission statements, and show a clear recognition of stakeholder interest.*	Section 2.9 Section 8.2 and 8.3
3.4 Details of the AMP planning period, which must cover at least a projected period of 10 years commencing with the disclosure year following the date on which the AMP is disclosed; *Good asset management practice recognises the greater accuracy of short-to-medium term planning, and will allow for this in the AMP. The asset management planning information for the second five years of the AMP planning period need not be presented in the same detail as the first 5 years.*	Section 2.1
3.5 The date that it was approved by the directors;	Section 2.1
3.6 A description of stakeholder interests (owners, consumers etc) which identifies important stakeholders and indicates-	Section 2.4
3.6.1 how the interests of stakeholders are identified	Section 2.4
3.6.2 what these interests are;	Section 2.4
3.6.3 how these interests are accommodated in asset management practices; and	Section 2.4
3.6.4 how conflicting interests are managed;	Section 2.4
3.7 A description of the accountabilities and responsibilities for asset management on at least 3 levels, including-	Section 2.7
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;	Section 2.7 Section 8.2

[215] Commerce Commission, "Electricity Distribution Information Disclosure (Targeted Review 2024) Amendment Determination 2024", 29 February 2024.

Determination Clause (Attachment A of Determination[215])	AMP Section(s)
3.7.2 executive—an indication of how the in-house asset management and planning organisation is structured; and	Section 2.7
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;	Section 1.12 Section 13.2, 13.3 and 13.4
3.8 All significant assumptions-	
3.8.1 quantified where possible;	Appendix 2
3.8.2 clearly identified in a manner that makes their significance understandable to interested persons, including-	Appendix 2
3.8.3 a description of changes proposed where the information is not based on the EDB's existing business;	
3.8.4 the sources of uncertainty and the potential effect of the uncertainty on the prospective information; and	Appendix 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	Section 15.2.2 and 15.2.3
3.9 A description of the factors that may lead to a material difference between the prospective information disclosed and the corresponding actual information recorded in future disclosures;	Appendix 2
3.10 An overview of asset management strategy and delivery; *To support the Report on Asset Management Maturity disclosure and assist interested persons to assess the maturity of asset management strategy and delivery, the AMP should identify-* • *how the asset management strategy is consistent with the EDB's other strategy and policies;* • *how the asset strategy takes into account the life cycle of the assets;* • *the link between asset management strategy and the AMP; and* • *processes that ensure costs, risks and system performance will be effectively controlled when the AMP is implemented.*	Section 6.2 and 6.3 Section 12
3.11 An overview of systems and information management data;	Section 8.4, 8.5 and 8.6 Section 9.4 and 9.5
3.11.1 To support the Report on Asset Management Maturity disclosure and assist interested persons to assess the maturity of systems and information management, the AMP should describe-	
(a) the processes used to identify asset management data requirements that cover the whole of life cycle of the assets;	Section 8.5
(b) the systems used to manage asset data and where the data is used, including an overview of the systems to record asset conditions and operation capacity and to monitor the performance of assets;	Section 9.5
(c) the systems and controls to ensure the quality and accuracy of asset management information;	Section 12.5
(d) the extent to which these systems, processes and controls are integrated;	Section 8.2, 8.3 and 8.4
(e) how asset management data informs the models that an EDB develops and uses to assess asset health; and	Section 12.5 and 12.4
(f) how the outputs of these models are used in developing capital expenditure projections.	Section 12.4 to 12.18
3.12 A statement covering any limitations in the availability or completeness of asset management data and disclose any initiatives intended to improve the quality of this data; *Discussion of the limitations of asset management data is intended to enhance the transparency of the AMP and identify gaps in the asset management system*	Section 8.5 Section 9.5
3.13 A description of the processes used within the EDB for-	
3.13.1 managing routine asset inspections and network maintenance;	Refer to the asset inspection and maintenance sections included in all fleet plans. Refer to Section 12.8 to 12.18.
3.13.2 planning and implementing network development projects; and	Section 11.3 and 11.4
3.13.3 measuring network performance;	Section 4
3.14 An overview of asset management documentation, controls and review processes.	Section 5.6 Section 9.2.2

Determination Clause (Attachment A of Determination[215])	AMP Section(s)
To support the Report on Asset Management Maturity disclosure and assist interested persons to assess the maturity of asset management documentation, controls and review processes, the AMP should- *(i) identify the documentation that describes the key components of the asset management system and the links between the key components;* *(ii) describe the processes developed around documentation, control and review of key components of the asset management system* *(iii) where the EDB outsources components of the asset management system, the processes and controls that the EDB uses to ensure efficient and cost effective delivery of its asset management strategy;* *(iv) where the EDB outsources components of the asset management system, the systems it uses to retain core asset knowledge in-house; and* *(v) audit or review procedures undertaken in respect of the asset management system*	
3.15 An overview of communication and participation processes; *To support the Report on Asset Management Maturity disclosure and assist interested persons to assess the maturity of asset management documentation, controls and review processes, the AMP should* *(i) communicate asset management strategies, objectives, policies and plans to stakeholders involved in the delivery of the asset management requirements, including contractors and consultants; and* (ii) *demonstrate staff engagement in the efficient and cost effective delivery of the asset management requirements.*	Section 2.8
3.16 The AMP must present all financial values in constant price New Zealand dollars except where specified otherwise; and	Section 2.11 The AMP uses constant price NZ dollars. This is generally referred to as Real 2026 $000 throughout the AMP
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.	The AMP is structured in three parts. • Part 1: The key issues facing our network; • Part 2: Strategies to address the key issues and performance; • Part 3: How we are implementing our strategy.
<u>Assets covered</u> 4. The AMP must provide details of the assets covered and non-network solutions, including-	Section 3.5 Section 6.3 and 6.5 Section 7.6
4.1 a high-level description of the service areas covered by the EDB and the degree to which these are interlinked, including-	Section 3.2
4.1.1 the region(s) covered;	Section 3.2
4.1.2 identification of large consumers that have a significant impact on network operations or asset management priorities;	Section 3.3 and 3.4
4.1.3 description of the load characteristics for different parts of the network;	Section 3.3 and 3.4
4.1.4 peak demand and total energy delivered in the previous year, broken down by sub-network, if any.	Section 3.4
4.2 a description of the network configuration, including-	Section 3.5
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;	Section 3.5 and 3.7 Section 11.9.6
4.2.2 A description of the sub transmission system fed from the bulk electricity supply points, including the capacity of zone substations and the voltage(s) of the sub transmission network(s). The AMP must identify the supply security provided at individual zone substations, by describing the extent to which each has n-x sub transmission security or by providing alternative security class ratings;	Section 3.5.2 Section 11.8 and 11.9.2
4.2.3 a description of the distribution system, including the extent to which it is underground;	Section 3.5.3
4.2.4 a brief description of the network's distribution substation arrangements;	Section 3.5.2 and 3.5.3

Determination Clause (Attachment A of Determination[215])	AMP Section(s)
4.2.5 a description of the low voltage network including the extent to which it is underground;	Section 3.5.4 Section 12.13, 12.14 and 12.17
4.2.6 an overview of secondary assets such as protection relays, ripple injection systems, SCADA and telecommunications systems; and	Section 12.11 and 12.18
4.2.7 a quantification of the contribution each non-network solution makes towards solving a network risk or constraint, and a description of the extent to which those non-network solutions are provided by a related party or third party. *To help clarify the network descriptions, network maps and a single line diagram of the subtransmission network should be made available to interested persons. These may be provided in the AMP or, alternatively, made available upon request with a statement to this effect made in the AMP.*	Section 10.8.1 and 10.8.2 Section 11.10.3
4.3 If sub-networks exist, the network configuration information referred to in clause 4.2 must be disclosed for each sub-network.	n/a
Network assets by category 4.4 The AMP must describe the network assets by providing the following information for each asset category-	Refer to the fleet plan in Section 12.8 to 12.18.
4.4.1 voltage levels;	Voltage levels are discussed in each fleet plan. Refer to Section 12.8 to 12.18.
4.4.2 description and quantity of assets;	Descriptions and quantities of assets are discussed in each fleet plan. Refer to Section 12.8 to 12.18.
4.4.3 age profiles; and	Section 5.4 Fleet age is discussed in each fleet plan. Refer to Section 12.8 to 12.18.
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.	Asset health and risk of assets is discussed in each fleet plan. Refer to Section 12.8 to 12.18.
4.5 The asset categories discussed in clause 4.4 should include at least the following-	
4.5.1 the categories listed in the Report on Forecast Capital Expenditure in Schedule 11a(iii);	Fleet plans are in more detail. Refer to Section 12.8 to 12.18
4.5.2 assets owned by the EDB but installed at bulk electricity supply points owned by others;	Section 3.7
4.5.3 EDB owned mobile substations and generators whose function is to increase supply reliability or reduce peak demand; and	Section 3.5.5
4.5.4 other generation plant owned by the EDB.	Section 3.5.5
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.	Section 7
6. Performance indicators for which targets have been defined in clause 5 must include SAIDI values and SAIFI values for the next 5 disclosure years.	Section 4.3 Section 5.5 Section 7.3
7. Performance indicators for which targets have been defined in clause 5 should also include-	
7.1 Consumer oriented indicators that preferably differentiate between different consumer types; and	Section 4.3 and 4.4 Section 7.3 and 7.4
7.2 Indicators of asset performance, asset efficiency and effectiveness, and service efficiency, such as technical and financial performance indicators related to the efficiency of asset utilisation and operation.	Section 4.5 and 4.6 Section 7.5 and 7.6
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.	Section 7
9. Targets should be compared to historic values where available to provide context and scale to the reader.	Section 7

Determination Clause (Attachment A of Determination[215])	AMP Section(s)
10. Where forecast expenditure is expected to materially affect performance against a target defined in clause 5, the target should be consistent with the expected change in the level of performance. *Performance against target must be monitored for disclosure in the Evaluation of Performance section of each subsequent AMP.*	Section 7.3 and 7.5
Network Development Planning 11. AMPs must provide a detailed description of network development plans, including—	Section 11
11.1 A description of the planning criteria and assumptions for network development;	Section 11.4 and 11.5
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;	Section 11.4 and 11.5
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;	Section 11.5.5
11.4 The use of standardised designs may lead to improved cost efficiencies. This section should discuss-	
11.4.1 the categories of assets and designs that are standardised; and	Section 11.5.3 and 11.5.4
11.4.2 the approach used to identify standard designs;	Section 11.5.3
11.5 A description of strategies or processes (if any) used by the EDB that promote the energy efficient operation of the network; *The energy efficient operation of the network could be promoted, for example, though network design strategies, demand side management strategies and asset purchasing strategies.*	Section 11.5.5
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; *The criteria described should relate to the EDB's philosophy in managing planning risks.*	Section 11.4.2 and 11.5.4
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;	Section 11.4.9
11.8 Details of demand forecasts, the basis on which they are derived, and the specific network locations where constraints are expected due to forecast increases in demand;	Section 10.8
11.8.1 explain the load forecasting methodology and indicate all the factors used in preparing the load estimates;	Section 10.8
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,	Section 11.9.2
11.8.3 identify any network or equipment constraints that may arise due to the anticipated growth in demand during the AMP planning period; and	Section 11.8.1, 11.9.3, 11.10.2 and 11.10.3
11.8.4 discuss the impact on the load forecasts of any anticipated levels of non-network solutions in a network;	Section 11.8.1, 11.9.3 and 11.10.2
11.9 Analysis of the significant network level development options identified and details of the decisions made to satisfy and meet target levels of service, including-	Section 11.8.1, 11.9.3, 11.10.2, 11.10.3, 11.10.3, 11.11.2 and 11.11.3
11.9.1 the reasons for choosing a selected option for projects where decisions have been made;	Covered in all the descriptions of proposed projects throughout Section 11
11.9.2 the alternative options considered for projects that are planned to start in the next five years and the potential for non-network solutions described; and	Covered in all the descriptions of proposed projects and the sections on the justification for projects and expenditure discussed throughout Section 11
11.9.3 consideration of planned innovations that improve efficiencies within the network, such as improved utilisation, extended asset lives, and deferred investment;	Section 10.7 Section 11.6 Section 12.8.4
11.10 A description and identification of the network development programme including non-network solutions and actions to be taken, including associated expenditure projections. The network development plan must include-	Section 11 Section 11.9.4 and 11.12.3
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;	Section 9 .4 Section 11.9 to 11.12 Section 12.8 to 12.18

Determination Clause (Attachment A of Determination[215])	AMP Section(s)
11.10.2 a summary description of the programmes and projects planned for the following four years (where known); and	Section 9 .4 Section 11.9 to 11.12 Section 12.8 to 12.18
11.10.3 an overview of the material projects being considered for the remainder of the AMP planning period; *For projects included in the AMP where decisions have been made, the reasons for choosing the selected option should be stated which should include how target levels of service will be impacted. For other projects planned to start in the next five years, alternative options should be discussed, including a detailed description of the investigations undertaken in respect of the potential for non-network solutions to be more cost effective than network augmentations and vice versa. This should specify if any third parties were approached in relation to non-network solutions, and if so, whether those third parties are related parties. For the purposes of disclosing the information described in clause 11.10.3, an EDB is not required to include commercially sensitive or confidential information.*	Section 9 .4 Section 11.9 to 11.12 Section 12.8 to 12.18
11.11 A description of the EDB's policies on distributed generation, including the policies for connecting distributed generation. The impact of such generation on network development plans must also be stated; and	Section 11.4.8
11.12 A description of the EDB's policies on non-network solutions, including-	Section 11.8.4, 11.9.8, 11.10.9, and 11.11.8
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; and	Section 11.8.4, 11.9.8, 11.10.8, and 11.11.7
11.12.2 the potential for non-network solutions to address network problems or constraints; and	Section 11.8.4, 11.9.8, 11.10.8, and 11.11.7
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.	Section 10.3
Lifecycle Asset Management Planning (Maintenance and Renewal) 12. The AMP must provide a detailed description of the lifecycle asset management processes, including—	
12.1 The key drivers for maintenance planning and assumptions;	This is provided in all fleet plans. Refer to Section 12.8 to 12.18.
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-	This is provided in all fleet plans. Refer to Section 12.8 to 12.18.
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;	This is provided in all fleet plans. Refer to Section 12.8 to 12.18.
12.2.2 any systemic problems identified with any particular asset types and the proposed actions to address these problems; and	This is provided in all fleet plans. Refer to Section 12.8 to 12.18.
12.2.3 budgets for maintenance activities broken down by asset category for the AMP planning period;	Section 12.19
12.3 Identification of asset replacement and renewal policies and programmes and actions to be taken for each asset category, including associated expenditure projections. This must include-	This is provided in all fleet plans. Refer to Section 12.8 to 12.18.
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;	An overview is presented in Section 12.3. This is provided in all fleet plans. Refer to Section 12.8 to 12.18.
12.3.2 a description of innovations that have deferred asset replacements;	This is provided in all fleet plans when relevant. Refer to Section 12.8 to 12.18.
12.3.3 a description of the projects currently underway or planned for the next 12 months;	This is provided in all fleet plans. Refer to Section 12.8 to 12.18.
12.3.4 a summary of the projects planned for the following four years (where known); and	This is provided in all fleet plans. Refer to Section 12.8 to 12.18.
12.3.5 an overview of other work being considered for the remainder of the AMP planning period; and	This is provided in all fleet plans. Refer to Section 12.8 to 12.18.
12.4 The asset categories discussed in clauses 12.2 and 12.3 should include at least the categories in clause 4.5.	

Determination Clause (Attachment A of Determination[215])	AMP Section(s)
12.5 Identification of the approach used for developing capital expenditure projections for lifecycle asset management. This must include an explanation of:	This is provided in all fleet plans. Refer to Section 12.8 to 12.18.
12.5.1 the approach that the EDB uses to inform its capital expenditure projections for lifecycle asset management; and	This is provided in all fleet plans. Refer to Section 12.8 to 12.18.
12.5.2 the rationale for using the approach for each asset category.	This is provided in all fleet plans. Refer to Section 12.8 to 12.18.
12.6 Identification of vegetation management related maintenance. This must include an explanation of the approach and assumptions that the EDB uses to inform its vegetation management related maintenance.	Section 12.19.2
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;	This is provided in all fleet plans when relevant. Refer to Section 12.8 to 12.18.
Non-Network Development, Maintenance and Renewal 13. AMPs must provide a summary description of material non-network development, maintenance and renewal plans, including—	Section 13.7, 15.7 and 15.9
13.1 a description of non-network assets;	Section 13.7, 15.7 and 15.9
13.2 development, maintenance and renewal policies that cover them;	Section 13.7.1 and 13.7.2
13.3 a description of material capital expenditure projects (where known) planned for the next five years; and	Section 15.7
13.4 a description of material maintenance and renewal projects (where known) planned for the next five years.	Section 15.9
Risk Management 14. AMPs must provide details of risk policies, assessment, and mitigation, including—	Section 14
14.1 Methods, details and conclusions of risk analysis;	Section 14.2
14.2 Strategies used to identify areas of the network that are vulnerable to high impact low probability events and a description of the resilience of the network and asset management systems to such events;	Section 14.5 and 14.6.1
14.3 A description of the policies to mitigate or manage the risks of events identified in clause 14.2; and	Section 14.4, 14.6 and 14.8
14.4 Details of emergency response and contingency plans. *Asset risk management forms a component of an EDB's overall risk management plan or policy, focusing on the risks to assets and maintaining service levels. AMPs should demonstrate how the EDB identifies and assesses asset related risks and describe the main risks within the network. The focus should be on credible low-probability, high-impact risks. Risk evaluation may highlight the need for specific development projects or maintenance programmes. Where this is the case, the resulting projects or actions should be discussed, linking back to the development plan or maintenance programme.*	Section 14.9
Evaluation of performance 15. AMPs must provide details of performance measurement, evaluation, and improvement, including—	Section 4
15.1 A review of progress against plan, both physical and financial; • *referring to the most recent disclosures* • *or other problems experienced; and* • *commenting on progress against maintenance initiatives and programmes and discuss the effectiveness of these programmes noted.*	Section 4.2 to 4.8
15.2 An evaluation and comparison of actual service level performance against targeted performance; • *in particular, comparing the actual and target service level performance for all the targets discussed under the Service Levels section of the AMP in the previous AMP and explain any significant variances.*	Section 4.2 to 4.8
15.3 An evaluation and comparison of the results of the asset management maturity assessment disclosed in the Report on Asset Management Maturity set out in Schedule 13 against relevant objectives of the EDB's asset management and planning processes.	Section 9.2
15.4 An analysis of gaps identified in clauses 15.2 and 15.3. Where significant gaps exist (not caused by one-off factors), the AMP must describe any planned initiatives to address the situation.	Section 5.5 Section 9.3

Determination Clause (Attachment A of Determination[215])	AMP Section(s)
Capability to deliver 16. AMPs must describe the processes used by the EDB to ensure that-	Section 13
16.1 The AMP is realistic and the objectives set out in the plan can be achieved; and	Section 13.2 and 13.3
16.2 The organisation structure and the processes for authorisation and business capabilities will support the implementation of the AMP plans.	Section 13.4 and 13.5
Requirements to provide qualitative information in narrative form 17 AMPs must include qualitative information in narrative form, as prescribed in clauses 17.1-17.7 below:	
Notice of planned and unplanned interruptions 17.1 a description of how the EDB provides notice to and communicates with consumers regarding planned interruptions and unplanned interruptions, including any changes to the EDB's processes and communications in respect of planned interruptions and unplanned interruptions;	Section 6.4.3
Voltage quality and constraints 17.2 a description of the EDB's practices for:	
17.2.1 monitoring voltage, including:	Section 10.10
(a) the EDB's practices for monitoring voltage quality on its low voltage network;	Section 10.10.1
(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;	Section 10.10.2 and 10.10.3
(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;	Section 10.10.6
(d) how the EDB communicates with affected consumers regarding the voltage quality work it is carrying out on its low voltage network; and	Section 10.10.6
(e) any plans for improvements to any of the practices outlined at clauses (a)-(d) above;	Section 10.10.4 and 10.10.5
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	Section 10.10.3
(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).	Section 10.10.4
Customer service practices *There may be a degree of overlap between the information required under this clause and the information required in respect of customer charters under clause 2.5.3. For the avoidance of doubt, if there is overlap, EDBs should disclose the information in both places.*	
17.3 a description of the EDB's customer service practices, including:	Section 4.4 Section 6.4
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;	Section 4.4 Section 6.4.1 and 6.4.2
17.3.2 the EDB's approach to planning and managing customer complaint resolution;	Section 6.4.1
Practices for connecting new consumers and altering existing connections 17.4 a description of the EDB's practices for connecting consumers, including:	Section 11.13.2
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	Section 11.13.2
(b) alterations to existing connections (offtake and injection connections);	Section 11.13.2
17.4.2 how the EDB is seeking to minimise the cost to consumers of new or altered connections;	Section 11.13.2
17.4.3 the EDB's approach to planning and managing communication with consumers about new or altered connections;	Section 11.13.3
17.4.4 commonly encountered delays and potential timeframes for different connections; and.	Section 11.13.3

Determination Clause (Attachment A of Determination[215])	AMP Section(s)
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.	Section 11.13.3
New connections likely to have a significant impact on network operations or asset management priorities *The following requirements focus on the EDB's capability and risk management regarding demand, generation, or storage capacity that the EDB considers are likely to have a significant impact on its network operations or asset management priorities. The EDB may consider voltage, network location, or other factors in making this assessment.*	
17.5 A description of the following:	
17.5.1 how the EDB assesses the impact that new demand, generation, or storage capacity will have on the EDB's network, including: (a) how the EDB measures the scale and impact of new demand, generation, or storage capacity; (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, eg, the network location of new demand, generation, or storage capacity; and	Section 11.13.3
17.5.2 how the EDB assesses and manages the risk to the network posed by uncertainty regarding new demand, generation, or storage capacity;	Section 11.13.3
Innovation practices 17.6 a description of the following:	
17.6.1 any innovation practices the EDB has planned or undertaken since the last AMP or AMP update was publicly disclosed, including case studies and trials;	Section 10.7 (FlexTalk) Section 11.6 Section 11.9.4 (Vista switchgear) Section 11.12.3 (Tripsaver) Section 12.8.4 (moisture analysis)
17.6.2 the EDB's desired outcomes of any innovation practices, and how they may improve outcomes for consumers;	Section 10.7 (FlexTalk) Section 11.12.3 (Tripsaver)
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;	Section 11.6
17.6.4 how the EDB's decision-making and innovation practices depend on the work of other companies, including other EDBs and providers of non-network solutions; and	Section 11.6 Section 10.7 (FlexTalk)
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.	Section 11.6
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.	No commercially sensitive information has been included

Appendix 2: Significant Assumptions

Introduction

This appendix contains details of:

- The significant assumptions used in this AMP;
- Sources of uncertainty.

Significant assumptions

The significant assumptions for this AMP are:

Assumption	Assumption	Response if assumption occurs	Response if the assumption *does not* occur
Resident population growth	• Horowhenua District Council view on population growth (75th percentile view). Our current review implies a compounding annual growth rate of 2.1% over the AMP forecast period. • Kāpiti Coast District Council view on population growth (75th percentile view). Our current review implies a compounding annual growth rate of 1.7% over the AMP forecast period. • Refer to Section 5.2.	Implement development plan (in response to capacity and security) projects as planned in Section 10.	Our approach to demand uncertainty is outlined in Sections 11.7, 11.8.3, 11.9.7, 11.10.8 and 11.11.7.
Future electricity intensity	• This factor accounts for future changes in the efficiency of electricity • Continued improvement in efficiency of 0.6% is assumed • Informed by Transpower's "accelerated electrification" scenario[216] • Refer to Section 10.8.1.	Implement development plan (in response to capacity and security) projects as planned in Section 10 (for controlled demand outturn).	As above
Uptake of electric vehicles	• 6 MW increase in demand by 2050 • Penetration of EVs is forecast to be 51% in the Northern region and 61% in the Southern region by 2050 • The impact on ADMD is 0.13 kW per ICP with an EV. This accounts for the diversity of controlled charging • Informed by Transpower's accelerated electrification scenario[85], but moderated by average income levels across our two regions • The forecasts have been reduced over the next ten years due to the recent changes in Government policy • Refer to Section 10.8.1.	As above	As above
Electrification of gas	• 17 MW increase in demand by 2050 • 5.6 MW relates to the electrification of boiler load[217] • ~22% of Electra's customers currently use natural gas or LPG, with an average annual consumption of 24 GJ for residential and 374 GJ for commercial customers	As above	As above

[216] Transpower, "Whakamana i Te Mauri Hiko", 2020

[217] Based on a report of potential low temperature heat conversion. The report was prepared by DETA in 2024.

Assumption	Assumption	Response if assumption occurs	Response if the assumption *does not* occur
	• These customers are all assumed to use low and medium heat and switch to electricity by 2050, consistent with accelerated electrification[85] • Refer to Section 10.8.1.		
Demand control	• Demand reduces by 0.4 MW by 2050 • Electra's current demand control amounts to 10 MW (refer to Section 3.4) • Existing ripple control is by-passed (as per the uncontrolled scenario); however, effective demand response is available through flexibility market or other means, which increases the level of demand response • Refer to Section 10.8.1.	As above	As above
Uptake of distributed energy resources	• Controllable DERs reduce demand by 11 MW by 2050 • DERs uptake based on accelerated electrification penetration rate for both controllable and non-controllable DERs[85], moderated for regional sunshine hours • External financing is assumed to overcome household income differences	As above	As above
Controlled on uncontrolled demand	• We revised our demand forecasts (included in Section 10.8), and they indicate material growth due to the impact of electrification. There is significant uncertainty regarding the extent of demand growth, and material reductions are possible using flexibility from EV smart charging and other sources of demand response.	As above	As above
Constant price inflation	Our future price inflation is set out in Sections 15.2.2 and 15.2.3. Schedule 11a(i) and 11b(i) provide capex and opex forecasts in nominal dollars. We have applied forecast CPI to escalate the real$ (constant price) forecasts to nominal (refer to Table 2). Our forecasts reflect Westpac's forecasts to FY30, then 2.0% after that (the middle of the Reserve Bank's target for inflation).	n/a	Future expenditure forecasts may change.
Asset health	We have developed a Condition-Based Asset Risk Management Model (CBARMM) to forecast asset risk and renewals. The model is based on the DNO Methodology. CBARMM models have been developed for all network assets. These models apply a risk-based, information-driven approach to asset renewal forecasting. The health assessment inputs include nominal expected life, location, duty, asset age, operations, reliability, and condition inputs. Location factors are principally used to assess the impact of the coastal environment on an asset's expected life. Duty factors are used where equipment loading can impact an asset's expected life. The number of operations (typically under fault conditions) is used, and this impacts the condition of the assets over time. The reliability factor is applied to an asset class based on the asset's performance history and	The forecast asset renewal and associated expenditure forecasts will be as set out in Section 12.	The forecasts will be adjusted based on the latest asset health information.

Assumption	Assumption	Response if assumption occurs	Response if the assumption *does not* occur
	experience in managing and operating the asset. Condition inputs include those observed (through inspections) and those measured (through standardised testing). Refer to Section 12.4.		
Availability of field resources	Field resources are available to complete the planned work. We have provided analysis of the resource requirements to deliver this AMP in Sections 13.4.3 and 13.4.4.	The work will be delivered as per this AMP.	Additional external resources will be engaged to complete the work programme. This may result in some short-term delays.
Material costs	The cost of materials increases at the forecast rate of inflation	n/a	n/a
Public policy	Public policy concerning Net Zero 2050, climate change response and the emissions reduction plan continues on its current course (as set out in Sections 5.3 and 10)	Refer to the assumptions on future electricity intensity, uptake of electric vehicles, electrification of gas and demand control above.	Refer to the assumptions on future electricity intensity, uptake of electric vehicles, electrification of gas and demand control above.
Council land use policy	No significant changes in Council land use policy that will increase the cost of Electra doing work	Continue locating assets on Council land with no increase in costs	Electra may have to purchase land for new network assets, increasing capex
NZTA and KiwiRail land use policy	No significant changes in land access policy by NZTA or by KiwiRail that will increase the cost of Electra doing work	Continue locating assets on NZTA or KiwiRail land with no increase in costs	
Wellington Northern Roading corridor	The Wellington northern roading corridor development will continue as stated in the Roads of National Significance (the NZTA's website)	People may move northwards from Wellington to Kāpiti and from Kāpiti to Horowhenua. This has been included in our population growth forecasts	Kāpiti population growth may not be as high as forecast, such that Growth CAPEX projects can be deferred

Sources of uncertainty and impact on future disclosures

Factors that may result in material differences between this AMP and future disclosures include:

Assumption	Factors that could change	Impact on future disclosures
Resident population growth	• Growth could be higher • Growth could be lower	• Higher growth could result in additional system growth capex • Lower growth could result in a reduction in system growth capex
Future electricity intensity	• Electricity intensity could be lower • Electricity intensity could be lower	• Lower intensity could result in additional system growth capex • Higher intensity could result in a reduction in system growth capex
Uptake of electric vehicles	• EV uptake could be higher • EV uptake could be lower	• Higher EV uptake could result in additional system growth capex • Lower EV uptake could result in a reduction in system growth capex
Electrification of gas	• Electrification of gas could be higher • Electrification of gas could be lower	• Higher electrification of gas could result in additional system growth capex • Lower electrification of gas could result in a reduction in system growth capex
Demand control	• Demand response could be lower • Demand response could be higher	• Lower demand response could result in additional system growth capex and require the energy transformation roadmap implementation to be delayed

Assumption	Factors that could change	Impact on future disclosures
		• Higher demand response could result in a reduction in system growth capex and require the energy transformation roadmap implementation to be advanced
Uptake of distributed energy resources	• Uptake of distributed energy resources could be lower • Uptake of distributed energy resources could be higher	• Lower uptake of distributed energy resources could result in additional system growth capex and require the energy transformation roadmap implementation to be delayed • Higher uptake of distributed energy resources could result in a reduction in system growth capex and require the energy transformation roadmap implementation to be advanced
Controlled on uncontrolled demand	• Refer to the assumptions on future electricity intensity, uptake of electric vehicles, electrification of gas and demand control above.	• Refer to the assumptions on future electricity intensity, uptake of electric vehicles, electrification of gas and demand control above.
Constant price inflation	• Inflation could be higher • Inflation could be lower	• Higher inflation will lead to higher capex and opex, which will lead to higher prices • Lower inflation will lead to lower capex and opex, which will lead to higher prices
Asset health	• Asset health could be lower than currently assessed • Asset health could be better than currently assessed	• Lower asset health could lead to an increase in asset replacement and renewal capex and maintenance-related opex • Better asset health could lead to a decrease in asset replacement and renewal capex and maintenance-related opex
Availability of field resources	• n/a	• n/a
Material costs	• Material costs could be higher • Material costs could be lower	• Higher material costs will lead to higher capex and opex, which will lead to higher prices • Lower material costs will lead to lower capex and opex, which will lead to higher prices
Public policy	• These could impact the assumptions on future electricity intensity, uptake of electric vehicles, electrification of gas and demand control	• Refer to the assumptions on future electricity intensity, uptake of electric vehicles, electrification of gas and demand control
Council land use policy	• Land use policies could become more restrictive • Land use policies could become more permissive	• Restrictive land use policies could delay project work, increase project costs, and increase forecast capex • Permissive land use policies could reduce project costs and lower forecast capex
NZTA and KiwiRail land use policy	• As above	• As above
Wellington Northern Roading corridor	• The project could be delayed	• Growth assumptions could be overstated (particularly in the Northern region); hence, system growth capex could be reduced or delayed

Appendix 3: Glossary

Term	Description
ABS	Air Break Switch
ADMS	Advanced Distribution Management System
Adverse environment cause outages	All unplanned interruptions where the primary cause is adverse environment, such as slips or seismic events.
Adverse weather cause outages	All unplanned interruptions where the primary cause is adverse weather, other than those caused by directly by lightning, vegetation contact or adverse environment
AMMAT	Asset Management Maturity Assessment Tool
AMP	Asset Management Plan
ARMM	Asset Risk Management Model
ARR	Asset Replacement & Renewal
AUFLS	Automatic Underfrequency Load Shedding
BCMP	Business Continuity Management Plan
CAIDI	Customer Average Interruption Duration Index is the average total duration of interruptions per interrupted customer
Capacity utilisation	A ratio which measures the utilisation of transformers in the system. It is calculated as the maximum demand experienced on an electricity network in a year divided by the transformer capacity on that network.
Capex	Capital Expenditure used to buy, improve, or maintain fixed assets i.e., vehicles, buildings, equipment
CB	Circuit Breaker
CBARMM	Condition-Based Asset Risk Management Model
CBD	Central Business District
CO_2e	Represents an amount of a greenhouse gas (GHG) whose atmospheric impact has been standardized to that of one unit mass of carbon dioxide (CO2), based on the global warming potential (GWP) of the gas.
CoF	Consequence of failure
Conductor	Includes overhead lines which can be covered (insulated) or bare (not insulated), and underground cables which are insulated
Continuous rating	The constant load which a device can carry at rated primary voltage and frequency without damaging and/or adversely affecting its characteristics.
Controllable DER	DERs whose output or consumption can be increased or decreased on demand – for example, diesel generation, batteries, and controllable EV chargers, but not intermittent renewable generation like wind or solar. The impact of controllable DERs is flexibility.
CRM	Customer Relationship Management an approach to manage and record interactions with current and potential customers
CT	Current transformer
Current	The movement of electricity through a conductor, measured in amperes.
DDO	Drop-out fuse
Defective equipment cause outages	All unplanned customer interruptions resulting from equipment failure, either mechanical or electrical
DER	Distributed Energy Resource
DERMS	Distributed Energy Resource Management System
DG	Distributed Generation
DGA	Dissolved Gas Analysis
DNO	Distribution Network Operators
DNP	Distributed Network Protocol
DPP	Default Price Path (Commerce Commission)
DSO	Distribution System Operator. Entities responsible for managing energy and other services (like flexibility services) across the distribution network.
Distribution substation	A kiosk, outdoor ground mounted substation or pole mounted substation taking its supply at 11kV and distributing at 400V.

Term	Description
ECP	Electrical Code of Practice
EDB	Electricity Distribution Business
EF	Earth fault
EOL	End of Life
EV	Electric vehicle
EVSE	Electric vehicle supply equipment
Feeder	A physical grouping of conductors that originate from a district substation circuit breaker.
Flexibility	Customers (or merchant providers) changing their usage patterns by either switching on generators or reducing consumption in response to a signal
Flexibility Purchaser	These are buyers of flexibility services and could be: • Energy retailers or generators who buy alternatives to energy on the spot market; • System operator who buys reserve energy alternatives or ancillary services alternatives; • Transpower, who buys alternatives to transmission assets; • Distributors, who buys alternatives to distribution assets.
Flexibility Markets	Mechanisms for matching and rewarding traders of controllable DERs, including providing dispatch instruction in response to prices.
Flexibility resources	Flexibility resources are delivered through DERs that are controllable. Distributed solar without a battery is not a flexibility resource because it is not controllable.
Flexibility Traders	Owners of DER portfolios who manage their DERs portfolio to allocate it to its highest value usage. Flexibility traders interact with flexibility buyers to provide the flexibility that they require. Importantly, flexibility traders maximise the value of DERs by allocating them to their highest value use ("value stacking") rather than dedicating individual DERs to one use.
Frequency	On AC circuits, the designated number of times per second that polarity alternates from positive to negative and back again, expressed in Hertz (Hz)
FLISR	Fault location, isolation and service restoration
FY	Financial Year e.g., FY2021 is Financial Year 2021 which covers 1st April 2020 to 31st March 2021
GWh	Gigawatt hours
GXP or Grid Exit Point	The point at which Transpower's Grid is connected to Electra's equipment
H1 or HIB5	A measure of asset heath. End of serviceable life. Immediate intervention required.[218]
H2 or HIB4	A measure of asset heath. Material deterioration but condition still within serviceable life parameters. Intervention likely within three years.[218]
H3 or HIB3	A measure of asset heath. Normal deterioration requiring regular monitoring[218] , but with an increasing risk of failure.
H4 or HIB2	A measure of asset heath. Normal deterioration requiring regular monitoring.[218]
H5 or HIB1	A measure of asset heath. As new condition.218
H&S	Health & Safety
Harmonics (wave for distortion)	A distortion to the supply voltage which can be caused by network equipment and equipment owned by consumers including electric motors or even computer equipment.
High voltage	Voltage exceeding 1,000 volts, generally 11,000 volts (known as 11kV)
HILP	High Impact Low Probability
Hosting Capacity	The amount of new production or consumption that can be connected to the network without endangering the reliability or voltage quality for other customers.
HR	Human Resources
Human error cause outages	All unplanned customer interruptions resulting from contractors or staff, commissioning errors, incorrect protection settings, SCADA problems, switching errors, dig-in and overhead contact
HV	High Voltage. Voltages typically above 1,000 Volts.
ICP	Installation connection point. The point of connection for an electricity consumer.
IP	Internet Protocol
IT	Information Technology

[218] EEA Asset Health Indicator definition.

Term	Description
IoT	Internet of things
Interruption	An electricity supply outage caused by either an unplanned event (e.g., Weather, trees) or a planned even (e.g., Planned maintenance).
kV	Kilovolt
kW	Kilowatt
kWh	kilowatt hour
kVA	kilovolt amp output rating designates the output which a transformer can deliver for a specified time at rated secondary voltage and rated frequency.
LCP	Load Control Plant
LED	Light-emitting diode
Lightning cause outages	All unplanned customer interruptions where the primary cause is a lightning strike, resulting in insulation breakdown and or flashovers. Typically protection is the only observable operation
Load Factor	The measure of annual load factor is calculated as the average load that passes through a network divided by the maximum load experienced in a given year.
LoRaWAN	Long Range Wide Area Network
Low Voltage (LV)	Voltage not exceeding 1,000 volts, generally 230 or 400 volts
Maximum Demand (peak demand)	The maximum demand for electricity during the course of the year
$MtCO_2e$	Abbreviation of a million tonnes of carbon dioxide equivalent (see also CO_2e)
m	Million
MD	Maximum Demand. The peak demand (measured in MW or MVA) for the network, element of the network, or load.
MDI	Maximum Demand Indicator
MED	Major Event Day
MPL	Maximum Practical Life. The age at which the majority of assets can be expected to have been removed from service. Approximately defined as the age where nominally 95% of assets from the population would be retired for end-of-life reasons.
MVA	megavolt amp
MW	megawatt
MWh	megawatt hour (one million watt hour)
N-1 Security	A load is said to have N-1 security if for the loss of any one item of equipment supply to that load is not interrupted or can be restored in the time taken to switch to alternate supplies.
NEL	Nominal Expected Life. The time (in years) in an asset's life when it would be expected to first observed significant deterioration based on consideration of the asset alone (equivalent to a health score of 5.5).
NIMs	A Network Information Management System which contains geospatial information for all assets including asset description, location, age, electrical attributes, etc.
OC	Overcurrent
OCPI	Open charge point interphase
OCPP	Open charge point protocol
ODRC	Optimised Depreciated Replacement Cost.
ODV	Optimised Deprival Value.
ONAF	Oil Natural Air Forced
ONAN	Oil Natural Air Natural
Opex	Operational Expenditure an ongoing expense for running a business e.g., rent, power. wages
OT	Operations technology, which means digital technology used for process control, protection of machinery and assurance of product quality
PILC	Paper-insulated, lead-covered - a type of cable insulation.
PoF	Probability of failure
PQ	Power quality
PRV	Pressure relief valve
Photovoltaic	The conversion of light into electricity using solar panels

Term	Description
Ripple Control system	A system used to control the electrical load on the network by, for example switching domestic water heaters, street lighting.
REF	Restricted earth fault
RMU	Ring Main Unit
RTU	Remote Terminal Unit
SAIDI	System Average Interruption Duration Index is the average total duration of interruptions per connected customer
SAIFI	System Average Interruption Frequency Index is the average number of interruptions per connected customers
SCADA	Electra's computerized System Control and Data Acquisition System being the primary tool for monitoring and controlling access and switching operations for Electra's Network.
SCI	Statement of Corporate Intent
Subtransmission	The lines and cables that connect zone substation and the GXP.
SWER	Single Wire Earth Return
Transformer	A device that changes voltage up to a higher voltage or down to a lower voltage.
Transpower	The state-owned enterprise that operates New Zealand's transmission network. Transpower delivers electricity from generators to various networks around the country.
Third party interference cause outages	All unplanned customer interruptions resulting from external contractors or members of the public and includes dig-in, overhead contact, vandalism, and vehicle damage
UG	Underground
UHF	Ultra-High Frequency
Unknown cause outages	All unplanned interruptions where the cause is not known
Vegetation cause outages	All unplanned customer interruptions resulting from vegetation contact, includes debris, grass and tree contact
VHF	Very High Frequency
VT	Voltage Transformer
Voltage	Electric pressure; the force which causes current to flow through an electrical conductor.
Voltage Regulator	An electrical device that keeps the voltage at which electricity is supplied to consumers at a constant level, regardless of load fluctuations.
WACC	Weighted Average Cost of Capital
Wildlife cause outages	All unplanned customer interruptions resulting from wildlife contact - includes birds, possums, vermin, cats etc
XLPE	Cross linked Polyethylene. Type of insulation for cables.
Zone Substation	A major building substation and/or switchyard with associated high voltage structure where voltage is transformed from 33kV to 11kV.

Appendix 4: Forecast Capital Expenditure (Schedule 11a)

Company Name	**Electra Limited**
AMP Planning Period	**1 April 2026 – 31 March 2036**

SCHEDULE 11a: REPORT ON FORECAST CAPITAL EXPENDITURE

This schedule requires a breakdown of forecast expenditure on assets for the current disclosure year and a 10 year planning period. The forecasts should be consistent with the supporting information set out in the AMP. The forecast is to be expressed in both constant price and nominal dollar terms. Also required is a forecast of the value of commissioned assets (i.e., the value of RAB additions)

EDBs must provide explanatory comment on the difference between constant price and nominal dollar forecasts of expenditure on assets in Schedule 14a (Mandatory Explanatory Notes). EDBs must express the information in this schedule (11a) as a specific value rather than ranges. Any supporting information about these values may be disclosed in Schedule 15 (Voluntary Explanatory Notes).

This information is not part of audited disclosure information.

sch ref		Current Year CY	CY+1	CY+2	CY+3	CY+4	CY+5	CY+6	CY+7	CY+8	CY+9	CY+10
55	**Difference between nominal and constant price forecasts**	**$000**										
56	Consumer connection	-	46	127	224	309	380	465	553	646	744	847
57	System growth	-	81	218	468	519	928	1,318	1,278	1,104	1,114	1,256
58	Asset replacement and renewal	-	346	688	1,056	1,426	1,563	1,758	2,132	2,754	2,586	2,869
59	Asset relocations	-	39	22	-	-	-	-	-	-	-	-
60	Reliability, safety and environment:											
61	Quality of supply	-	21	52	159	227	163	201	95	96	109	122
62	Legislative and regulatory	-	-	-	-	-	-	-	-	-	-	-
63	Other reliability, safety and environment	-	29	34	35	47	16	19	23	26	29	33
64	**Total reliability, safety and environment**	-	49	87	194	274	179	221	117	122	138	155
65	**Expenditure on network assets**	-	562	1,141	1,942	2,528	3,051	3,762	4,081	4,626	4,582	5,125
66	Expenditure on non-network assets	-	146	224	175	255	328	294	421	395	450	504
67	**Expenditure on assets**	-	708	1,365	2,117	2,783	3,379	4,056	4,502	5,021	5,032	5,629

69 **Commentary on options and considerations made in the assessment of forecast expenditure**

70 *EDBs may provide explanatory comment on the options they have considered (including scenarios used) in assessing forecast expenditure on assets for the current disclosure year and a 10 year planning period in Schedule 15*

74 **11a(ii): Consumer Connection**

sch ref		Current Year CY	CY+1	CY+2	CY+3	CY+4	CY+5	CY+6	CY+7	CY+8	CY+9	CY+10
		$000 (in constant prices)										
75	*Consumer types defined by EDB**											
76	Customer connections	-	2,295	2,987	3,409	3,513	3,463	3,521	3,578	3,638	3,699	3,759
77		-	-	-	-	-	-	-	-	-	-	-
78		-	-	-	-	-	-	-	-	-	-	-
79		-	-	-	-	-	-	-	-	-	-	-
80		-	-	-	-	-	-	-	-	-	-	-
81	**include additional rows if needed*											
82	**Consumer connection expenditure**	-	2,295	2,987	3,409	3,513	3,463	3,521	3,578	3,638	3,699	3,759
83	*less* Capital contributions funding consumer connection	-	2,294	2,986	3,411	3,514	3,464	3,521	3,579	3,639	3,699	3,760
84	**Consumer connection less capital contributions**	-	1	0	(2)	(1)	(0)	(0)	(1)	(1)	0	(2)

85 **11a(iii): System Growth**

sch ref		Current Year CY	CY+1	CY+2	CY+3	CY+4	CY+5	CY+6	CY+7	CY+8	CY+9	CY+10
86	Subtransmission	104	51	51	-	52	782	2,294	2,298	731	-	-
87	Zone substations	2,765	2,090	2,301	1,908	2,038	2,039	-	-	-	-	-
88	Distribution and LV lines	-	383	498	568	585	577	587	596	606	617	626
89	Distribution and LV cables	2,285	590	813	2,643	690	3,738	5,770	4,013	3,498	3,516	3,526
90	Distribution substations and transformers	168	550	666	736	754	745	755	765	775	785	795
91	Distribution switchgear	-	383	498	568	585	577	587	596	606	617	626
92	Other network assets	-	-	306	713	1,196	-	-	-	-	-	-
93	**System growth expenditure**	5,323	4,046	5,134	7,137	5,900	8,459	9,992	8,269	6,216	5,534	5,574
94	*less* Capital contributions funding system growth	-	-	-	-	-	-	-	-	-	-	-
95	**System growth less capital contributions**	5,323	4,046	5,134	7,137	5,900	8,459	9,992	8,269	6,216	5,534	5,574

Company Name	Electra Limited
AMP Planning Period	1 April 2026 – 31 March 2036

SCHEDULE 11a: REPORT ON FORECAST CAPITAL EXPENDITURE

This schedule requires a breakdown of forecast expenditure on assets for the current disclosure year and a 10 year planning period. The forecasts should be consistent with the supporting information set out in the AMP. The forecast is to be expressed in both constant price and nominal dollar terms. Also required is a forecast of the value of commissioned assets (i.e., the value of RAB additions)

EDBs must provide explanatory comment on the difference between constant price and nominal dollar forecasts of expenditure on assets in Schedule 14a (Mandatory Explanatory Notes). EDBs must express the information in this schedule (11a) as a specific value rather than ranges. Any supporting information about these values may be disclosed in Schedule 15 (Voluntary Explanatory Notes).

This information is not part of audited disclosure information.

sch ref			Current Year CY	CY+1	CY+2	CY+3	CY+4	CY+5	CY+6	CY+7	CY+8	CY+9	CY+10
7			Current Year CY	CY+1	CY+2	CY+3	CY+4	CY+5	CY+6	CY+7	CY+8	CY+9	CY+10
8													
9		**11a(i): Expenditure on Assets Forecast**	**$000 (in nominal dollars)**										
10		Consumer connection	-	2,341	3,114	3,632	3,822	3,843	3,985	4,132	4,284	4,444	4,605
11		System growth	5,323	4,128	5,352	7,605	6,419	9,387	11,311	9,547	7,320	6,648	6,829
12		Asset replacement and renewal	14,619	17,510	16,871	17,147	17,632	15,805	15,084	15,922	18,252	15,436	15,603
13		Asset relocations	52	1,984	532	-	-	-	-	-	-	-	-
14		Reliability, safety and environment:											
15		Quality of supply	3,981	1,048	1,286	2,584	2,806	1,647	1,728	707	634	649	661
16		Legislative and regulatory	-	-	-	-	-	-	-	-	-	-	-
17		Other reliability, safety and environment	1,049	1,447	836	566	578	162	165	169	172	176	180
18		**Total reliability, safety and environment**	5,029	2,495	2,122	3,150	3,384	1,809	1,893	876	806	825	841
19		**Expenditure on network assets**	25,023	28,459	27,990	31,534	31,257	30,845	32,273	30,477	30,663	27,352	27,879
20		**Expenditure on non-network assets**	5,836	7,414	5,488	2,845	3,149	3,321	2,522	3,145	2,615	2,687	2,741
21		**Expenditure on assets**	30,860	35,873	33,478	34,380	34,406	34,166	34,795	33,622	33,278	30,039	30,619
22													
23	*plus*	Cost of financing	301	374	349	358	358	356	362	350	347	313	319
24	*less*	Value of capital contributions	-	4,295	3,635	3,634	3,823	3,844	3,986	4,133	4,285	4,443	4,607
25	*plus*	Value of vested assets	418	-	-	-	-	-	-	-	-	-	-
26													
27		**Capital expenditure forecast**	31,579	31,952	30,192	31,103	30,942	30,678	31,172	29,840	29,340	25,909	26,331
28													
29		Assets commissioned	29,838	31,890	30,486	30,951	30,969	30,722	31,090	30,062	29,423	26,480	26,261
30			Current Year CY	CY+1	CY+2	CY+3	CY+4	CY+5	CY+6	CY+7	CY+8	CY+9	CY+10
31													
32			**$000 (in constant prices)**										
33		Consumer connection	-	2,295	2,987	3,409	3,513	3,463	3,521	3,578	3,638	3,699	3,759
34		System growth	5,323	4,046	5,134	7,137	5,900	8,459	9,992	8,269	6,216	5,534	5,574
35		Asset replacement and renewal	14,619	17,165	16,183	16,091	16,206	14,242	13,326	13,791	15,498	12,850	12,734
36		Asset relocations	52	1,945	510	-	-	-	-	-	-	-	-
37		Reliability, safety and environment:											
38		Quality of supply	3,981	1,028	1,233	2,425	2,579	1,484	1,526	612	538	540	540
39		Legislative and regulatory	-	-	-	-	-	-	-	-	-	-	-
40		Other reliability, safety and environment	1,049	1,419	802	531	531	146	146	146	146	147	147
41		**Total reliability, safety and environment**	5,029	2,446	2,035	2,956	3,110	1,630	1,672	759	685	686	686
42		**Expenditure on network assets**	25,023	27,897	26,849	29,593	28,729	27,794	28,511	26,397	26,037	22,770	22,753
43		Expenditure on non-network assets	5,836	7,268	5,264	2,670	2,895	2,992	2,228	2,724	2,220	2,237	2,237
44		**Expenditure on assets**	30,860	35,165	32,113	32,262	31,624	30,787	30,739	29,120	28,257	25,007	24,990
45													
46		**Subcomponents of expenditure on assets (where known)**											
48		Energy efficiency and demand side management, reduction of energy losses	-	-	-	-	-	-	-	-	-	-	-
49		Overhead to underground conversion	-	-	-	-	-	-	-	-	-	-	-
50		Research and development	-	-	-	-	-	-	-	-	-	-	-
52													

Company Name	Electra Limited
AMP Planning Period	1 April 2026 – 31 March 2036

SCHEDULE 11a: REPORT ON FORECAST CAPITAL EXPENDITURE

This schedule requires a breakdown of forecast expenditure on assets for the current disclosure year and a 10 year planning period. The forecasts should be consistent with the supporting information set out in the AMP. The forecast is to be expressed in both constant price and nominal dollar terms. Also required is a forecast of the value of commissioned assets (i.e., the value of RAB additions)

EDBs must provide explanatory comment on the difference between constant price and nominal dollar forecasts of expenditure on assets in Schedule 14a (Mandatory Explanatory Notes). EDBs must express the information in this schedule (11a) as a specific value rather than ranges. Any supporting information about these values may be disclosed in Schedule 15 (Voluntary Explanatory Notes).

This information is not part of audited disclosure information.

sch ref		Current Year CY	CY+1	CY+2	CY+3	CY+4	CY+5	CY+6	CY+7	CY+8	CY+9	CY+10
97												
98												
99	**11a(iv): Asset Replacement and Renewal**	$000 (in constant prices)										
100	Subtransmission	810	814	818	817	817	818	818	820	819	821	821
101	Zone substations	2,802	2,670	3,040	2,064	3,522	1,738	1,636	1,448	2,936	715	1,306
102	Distribution and LV lines	5,947	7,262	7,298	7,288	7,288	7,292	7,206	7,210	7,211	7,212	7,212
103	Distribution and LV cables	1,308	1,618	1,626	1,623	1,624	1,625	1,625	1,626	1,627	1,632	1,631
104	Distribution substations and transformers	555	552	554	554	554	554	852	854	853	855	855
105	Distribution switchgear	658	1,091	1,097	1,095	1,095	580	659	660	660	662	662
106	Other network assets	3,312	3,158	1,750	3,052	1,307	631	539	1,162	1,400	913	326
107	**Asset replacement and renewal expenditure**	14,619	17,165	16,180	16,091	16,206	14,142	13,326	13,791	15,498	12,850	12,734
108	*less* Capital contributions funding asset replacement and renewal	-	-	-	-	-	-	-	-	-	-	-
109	**Asset replacement and renewal less capital contributions**	14,619	17,165	16,180	16,091	16,206	14,142	13,326	13,791	15,498	12,850	12,734
110												
111												
112												
113	**11a(v): Asset Relocations**	$000 (in constant prices)										
114	*Project or programme**	Current Year CY	CY+1	CY+2	CY+3	CY+4	CY+5	CY+6	CY+7	CY+8	CY+9	CY+10
115	NZTA and Council asset relocations	52	1,218	510	-	-	-	-	-	-	-	-
116	Other	-	727	-	-	-	-	-	-	-	-	-
117												
118												
119												
120	**include additional rows if needed*											
121	All other project or programmes – asset relocations											
122	**Asset relocations expenditure**	52	1,945	510	-	-	-	-	-	-	-	-
123	*less* Capital contributions funding asset relocations	52	1,916	500	-	-	-	-	-	-	-	-
124	**Asset relocations less capital contributions**	-	29	10	-	-	-	-	-	-	-	-
125												
126												
127												
128	**11a(vi): Quality of Supply**	$000 (in constant prices)										
129	*Project or programme**	Current Year CY	CY+1	CY+2	CY+3	CY+4	CY+5	CY+6	CY+7	CY+8	CY+9	CY+10
130	Network protection enhancements	631	613	1,192	1,888	1,417	947	640	-	-	-	-
131	Network interconnection enhancements	1,143	405	42	537	1,162	538	887	612	538	540	540
132	Network automation and sectionalisation enhancements	878	-	-	-	-	-	-	-	-	-	-
133	Network switching enhancements	1,055	-	-	-	-	-	-	-	-	-	-
	Fault location enhancements	-	-	-	-	-	-	-	-	-	-	-
	Voltage improvement	273	-	-	-	-	-	-	-	-	-	-
134		-	-	-	-	-	-	-	-	-	-	-
135	**include additional rows if needed*											
136	All other projects or programmes – quality of supply											
137	**Quality of supply expenditure**	3,981	1,018	1,233	2,425	2,579	1,484	1,526	612	538	540	540
138	*less* Capital contributions funding quality of supply											
139	**Quality of supply less capital contributions**	3,981	1,018	1,233	2,425	2,579	1,484	1,526	612	538	540	540
140												

Company Name: **Electra Limited**
AMP Planning Period: **1 April 2026 – 31 March 2036**

SCHEDULE 11a: REPORT ON FORECAST CAPITAL EXPENDITURE

This schedule requires a breakdown of forecast expenditure on assets for the current disclosure year and a 10 year planning period. The forecasts should be consistent with the supporting information set out in the AMP. The forecast is to be expressed in both constant price and nominal dollar terms. Also required is a forecast of the value of commissioned assets (i.e., the value of RAB additions)
EDBs must provide explanatory comment on the difference between constant price and nominal dollar forecasts of expenditure on assets in Schedule 14a (Mandatory Explanatory Notes). EDBs must express the information in this schedule (11a) as a specific value rather than ranges. Any supporting information about these values may be disclosed in Schedule 15 (Voluntary Explanatory Notes).
This information is not part of audited disclosure information.

sch ref

11a(vii): Legislative and Regulatory

$000 (in constant prices)

sch ref	Project or programme*	Current Year CY	CY+1	CY+2	CY+3	CY+4	CY+5	CY+6	CY+7	CY+8	CY+9	CY+10
145	Electricity code compliance programme	-	-	-	-	-	-	-	-	-	-	-
146	High-load crossing improvement programme	-	-	-	-	-	-	-	-	-	-	-
147												
148												
149												
150	*include additional rows if needed											
151	All other projects or programmes - legislative and regulatory											
152	**Legislative and regulatory expenditure**	-	-	-	-	-	-	-	-	-	-	-
153	*less* Capital contributions funding legislative and regulatory											
154	**Legislative and regulatory less capital contributions**	-	-	-	-	-	-	-	-	-	-	-

11a(viii): Other Reliability, Safety and Environment

$000 (in constant prices)

sch ref	Project or programme*	Current Year CY	CY+1	CY+2	CY+3	CY+4	CY+5	CY+6	CY+7	CY+8	CY+9	CY+10
159	Seismic resilience improvements	382	104	-	-	-	-	-	-	-	-	-
160	Weather and environmental resilience improvements	-	-	-	-	-	-	-	-	-	-	-
161	Other resilience improvements	-	674	278	-	-	-	-	-	-	-	-
162	Safety improvements	542	529	524	531	531	146	146	146	146	147	147
	Environmental improvements	125	112	-	-	-	-	-	-	-	-	-
163		-	-	-	-	-	-	-	-	-	-	-
164	*include additional rows if needed											
165	All other projects or programmes - other reliability, safety and environment											
166	**Other reliability, safety and environment expenditure**	1,049	1,419	802	531	531	146	146	146	146	147	147
167	*less* Capital contributions funding other reliability, safety and environment											
168	**Other reliability, safety and environment less capital contributions**	1,049	1,419	802	531	531	146	146	146	146	147	147

sch ref		Current Year CY	CY+1	CY+2	CY+3	CY+4	CY+5	CY+6	CY+7	CY+8	CY+9	CY+10

11a(ix): Non-Network Assets

Routine expenditure

$000 (in constant prices)

sch ref	Project or programme*	Current Year CY	CY+1	CY+2	CY+3	CY+4	CY+5	CY+6	CY+7	CY+8	CY+9	CY+10
175	Land	-	-	-	-	-	-	-	-	-	-	-
176	Office buildings, depots and workshops	3,400	4,288	1,773	86	71	86	71	71	71	71	71
177	Office furniture, fittings, and office equipment	125	-	52	52	52	52	51	51	51	51	52
178	Tools, plant, machinery and PPE	2,029	2,614	1,879	3,362	3,396	2,415	1,677	1,770	1,688	1,683	1,683
	Business Information Systems	-	-	-	-	308	308	209	209	209	209	209
	IT Hardware	248	373	568	178	178	128	220	621	220	221	221
	Network Information Systems	42	-	-	-	-	-	-	-	-	-	-
	OT Hardware	-	-	-	-	-	-	-	-	-	-	-
179		-	-	-	-	-	-	-	-	-	-	-
180	*include additional rows if needed											
181	All other projects or programmes - routine expenditure											
182	**Routine expenditure**	5,806	7,268	5,264	3,678	3,895	2,992	2,228	2,724	2,220	2,207	2,207

Atypical expenditure

sch ref	Project or programme*	Current Year CY	CY+1	CY+2	CY+3	CY+4	CY+5	CY+6	CY+7	CY+8	CY+9	CY+10
185												
186												
187												
188												
189												
190	*include additional rows if needed											

	Company Name	Electra Limited
	AMP Planning Period	1 April 2026 – 31 March 2036

SCHEDULE 11a: REPORT ON FORECAST CAPITAL EXPENDITURE

This schedule requires a breakdown of forecast expenditure on assets for the current disclosure year and a 10-year planning period. The forecasts should be consistent with the supporting information set out in the AMP. The forecast is to be expressed in both constant price and nominal dollar terms. Also required is a forecast of the value of commissioned assets (i.e., the value of RAB additions)

EDBs must provide explanatory comment on the difference between constant price and nominal dollar forecasts of expenditure on assets in Schedule 14a (Mandatory Explanatory Notes). EDBs must express the information in this schedule (11a) as a specific value rather than ranges. Any supporting information about these values may be disclosed in Schedule 15 (Voluntary Explanatory Notes).

This information is not part of audited disclosure information.

sch ref												
251	All other projects or programmes - atypical expenditure											
252	Atypical expenditure	-	-	-	-	-	-	-	-	-	-	-
288												
289	Expenditure on non-network assets	5,836	7,268	5,266	2,672	2,895	2,992	2,228	2,716	2,210	2,217	2,217

Appendix 5: Forecast Operational Expenditure (Schedule 11)

Company Name: **Electra Limited**
AMP Planning Period: **1 April 2026 – 31 March 2036**

SCHEDULE 11b: REPORT ON FORECAST OPERATIONAL EXPENDITURE

This schedule requires a breakdown of forecast operational expenditure for the disclosure year and a 10 year planning period. The forecasts should be consistent with the supporting information set out in the AMP. The forecast is to be expressed in both constant price and nominal dollar terms.

sch ref

Row	Operational Expenditure Forecast	Current Year CY	CY+1	CY+2	CY+3	CY+4	CY+5	CY+6	CY+7	CY+8	CY+9	CY+10
9		$000 (in nominal dollars)										
10	Service interruptions and emergencies	2,540	2,306	2,393	2,488	2,585	2,681	2,781	2,885	2,993	3,104	3,220
11	Vegetation management	2,067	2,681	2,720	2,780	2,838	2,895	2,953	3,012	3,072	3,134	3,196
12	Routine and corrective maintenance and inspection	1,688	1,957	1,983	1,933	2,034	2,148	2,275	2,151	2,355	2,411	2,713
13	Asset replacement and renewal	758	785	815	848	881	913	947	983	1,019	1,057	1,097
14	**Network Opex**	7,054	7,570	7,911	8,048	8,337	8,838	8,956	9,031	9,439	9,706	10,225
15	System operations and network support	6,176	7,575	7,481	7,061	7,209	7,353	7,500	7,650	7,803	7,959	8,119
16	Business support	10,641	11,988	12,395	12,115	12,315	12,562	12,813	13,069	13,331	13,597	13,869
17	Non-network solutions provided by a related party or third party	-	-	-	-	-	-	-	-	-	-	-
18	**Non-network opex**	16,817	19,561	19,876	19,176	19,524	19,915	20,313	20,719	21,134	21,557	21,988
19	**Operational expenditure**	23,871	27,131	27,786	27,224	27,862	28,553	29,269	29,751	30,573	31,263	32,213

Row		Current Year CY	CY+1	CY+2	CY+3	CY+4	CY+5	CY+6	CY+7	CY+8	CY+9	CY+10
22		$000 (in constant prices)										
23	Service interruptions and emergencies	2,540	2,260	2,295	2,335	2,376	2,418	2,457	2,499	2,541	2,584	2,628
24	Vegetation management	2,067	2,609	2,609	2,609	2,609	2,609	2,609	2,609	2,609	2,609	2,609
25	Routine and corrective maintenance and inspection	1,688	1,781	1,903	1,813	1,869	1,936	2,009	1,863	1,999	2,007	2,214
26	Asset replacement and renewal	758	770	783	795	809	823	837	851	866	880	896
27	**Network Opex**	7,054	7,421	7,588	7,553	7,663	7,784	7,912	7,822	8,015	8,080	8,346
28	System operations and network support	6,176	7,424	7,176	6,626	6,626	6,626	6,626	6,626	6,626	6,626	6,626
29	Business support	10,641	11,751	11,889	11,369	11,319	11,319	11,319	11,319	11,319	11,319	11,319
30	Non-network solutions provided by a related party or third party	-	-	-	-	-	-	-	-	-	-	-
31	**Non-network opex**	16,817	19,175	19,065	17,995	17,945	17,945	17,945	17,945	17,945	17,945	17,945
32	**Operational expenditure**	23,871	26,596	26,653	25,548	25,608	25,729	25,858	25,767	25,960	26,026	26,291

Subcomponents of operational expenditure (where known)

Row		Current Year CY	CY+1	CY+2	CY+3	CY+4	CY+5	CY+6	CY+7	CY+8	CY+9	CY+10
36	Energy efficiency and demand side management, reduction of energy losses											
37	Direct billing*											
38	Research and Development											
39	Insurance	1,177	1,340	1,340	1,340	1,340	1,340	1,340	1,340	1,340	1,340	1,340

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

Row	Difference between nominal and real forecasts	Current Year CY	CY+1	CY+2	CY+3	CY+4	CY+5	CY+6	CY+7	CY+8	CY+9	CY+10
45		$000										
46	Service interruptions and emergencies	-	46	98	153	209	265	324	386	451	520	592
47	Vegetation management	-	53	111	171	230	286	344	403	464	525	588
48	Routine and corrective maintenance and inspection	-	86	81	119	164	212	265	288	355	404	499
49	Asset replacement and renewal	-	16	33	53	71	90	110	132	154	177	202
50	**Network Opex**	-	149	323	496	674	854	1,044	1,209	1,424	1,626	1,880
51	System operations and network support	-	149	305	435	583	727	874	1,024	1,177	1,333	1,493
52	Business support	-	237	505	746	996	1,242	1,499	1,750	2,011	2,278	2,550
53	Non-network solutions provided by a related party or third party	-	-	-	-	-	-	-	-	-	-	-
54	**Non-network opex**	-	386	810	1,181	1,579	1,970	2,368	2,774	3,189	3,611	4,043
55	**Operational expenditure**	-	535	1,133	1,677	2,253	2,824	3,412	3,983	4,613	5,237	5,922

57 **Commentary on options and considerations made in the assessment of forecast expenditure**

58 *EDBs may provide explanatory comment on the options they have considered (including scenarios used) in assessing forecast operational expenditure for the current disclosure year and a 10 year planning period in Schedule 15.*

Appendix 6: Asset Condition (Schedule 12a)

Company Name **Electra Limited**

AMP Planning Period **1 April 2026 – 31 March 2036**

SCHEDULE 12a: REPORT ON ASSET CONDITION

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

sch ref

sch ref	Voltage	Asset category	Asset class	Units	H1	H2	H3	H4	H5	Grade unknown	Data accuracy (1–4)	% of asset forecast to be replaced in next 5 years
7					Asset condition at start of planning period (percentage of units by grade)							
9												
10	All	Overhead Line	Concrete poles / steel structure	No.	0.03%	0.08%	1.01%	5.22%	76.06%	17.59%	3	2.54%
11	All	Overhead Line	Wood poles	No.	0.84%	7.37%	6.63%	0.21%	20.00%	64.95%	2	9.89%
12	All	Overhead Line	Other pole types	No.	-	-	-	-	-	-	N/A	-
13	HV	Subtransmission Line	Subtransmission OH up to 66kV conductor	km	13.54%	-	-	-	85.59%	0.88%	4	0.04%
14	HV	Subtransmission Line	Subtransmission OH 110kV+ conductor	km	-	-	-	-	-	-	N/A	-
15	HV	Subtransmission Cable	Subtransmission UG up to 66kV (XLPE)	km	-	-	-	-	75.58%	24.42%	4	2.20%
16	HV	Subtransmission Cable	Subtransmission UG up to 66kV (Oil pressurised)	km	-	-	-	-	-	-	N/A	-
17	HV	Subtransmission Cable	Subtransmission UG up to 66kV (Gas pressurised)	km	-	-	-	-	-	-	N/A	-
18	HV	Subtransmission Cable	Subtransmission UG up to 66kV (PILC)	km	-	-	-	-	-	-	N/A	-
19	HV	Subtransmission Cable	Subtransmission UG 110kV+ (XLPE)	km	-	-	-	-	-	-	N/A	-
20	HV	Subtransmission Cable	Subtransmission UG 110kV+ (Oil pressurised)	km	-	-	-	-	-	-	N/A	-
21	HV	Subtransmission Cable	Subtransmission UG 110kV+ (Gas Pressurised)	km	-	-	-	-	-	-	N/A	-
22	HV	Subtransmission Cable	Subtransmission UG 110kV+ (PILC)	km	-	-	-	-	-	-	N/A	-
23	HV	Subtransmission Cable	Subtransmission submarine cable	km	-	-	-	-	-	-	N/A	-
24	HV	Zone substation Buildings	Zone substations up to 66kV	No.	-	-	20.00%	20.00%	60.00%	-	4	-
25	HV	Zone substation Buildings	Zone substations 110kV+	No.	-	-	-	-	-	-	N/A	-
26	HV	Zone substation switchgear	22/33kV CB (Indoor)	No.	-	-	-	-	100.00%	-	4	-
27	HV	Zone substation switchgear	22/33kV CB (Outdoor)	No.	-	9.09%	-	4.55%	86.36%	-	4	50.00%
28	HV	Zone substation switchgear	33kV Switch (Ground Mounted)	No.	-	-	-	-	-	-	N/A	-
29	HV	Zone substation switchgear	33kV Switch (Pole Mounted)	No.	-	7.89%	31.58%	55.26%	5.26%	-	3	-
30	HV	Zone substation switchgear	33kV RMU	No.	-	-	-	-	-	-	N/A	-
31	HV	Zone substation switchgear	50/66/110kV CB (Indoor)	No.	-	-	-	-	-	-	N/A	-
32	HV	Zone substation switchgear	50/66/110kV CB (Outdoor)	No.	-	-	-	-	-	-	N/A	-
33	HV	Zone substation switchgear	3.3/6.6/11/22kV CB (ground mounted)	No.	-	-	-	-	100.00%	-	4	11.25%
34	HV	Zone substation switchgear	3.3/6.6/11/22kV CB (pole mounted)	No.	-	-	-	-	-	-	N/A	-
35												

Company Name **Electra Limited**

AMP Planning Period **1 April 2026 – 31 March 2036**

SCHEDULE 12a: REPORT ON ASSET CONDITION

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

sch ref

sch ref	Voltage	Asset category	Asset class	Units	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
39	HV	Zone Substation Transformer	Zone Substation Transformers	No.	-	26.32%	21.05%	21.05%	31.58%	-	4	21.05%
40	HV	Distribution Line	Distribution OH Open Wire Conductor	km	0.20%	4.30%	1.49%	0.51%	92.25%	1.26%	3	7.29%
41	HV	Distribution Line	Distribution OH Aerial Cable Conductor	km	-	-	-	-	-	-	N/A	-
42	HV	Distribution Line	SWER conductor	km	-	-	-	-	-	-	N/A	-
43	HV	Distribution Cable	Distribution UG XLPE or PVC	km	2.56%	0.86%	-	37.63%	57.16%	1.79%	3	0.29%
44	HV	Distribution Cable	Distribution UG PILC	km	6.81%	-	5.23%	85.08%	2.57%	0.31%	3	0.24%
45	HV	Distribution Cable	Distribution Submarine Cable	km	-	-	-	-	-	-	N/A	-
46	HV	Distribution switchgear	3.3/6.6/11/22kV CB (pole mounted) - reclosers and sectionalisers	No.	-	20.55%	4.11%	15.07%	17.81%	42.47%	3	21.92%
47	HV	Distribution switchgear	3.3/6.6/11/22kV CB (Indoor)	No.	-	-	-	-	-	-	N/A	-
48	HV	Distribution switchgear	3.3/6.6/11/22kV Switches and fuses (pole mounted)	No.	0.23%	-	4.01%	0.36%	6.52%	88.87%	3	5.10%
49	HV	Distribution switchgear	3.3/6.6/11/22kV Switch (ground mounted) - except RMU	No.	-	-	-	-	-	-	N/A	-
50	HV	Distribution switchgear	3.3/6.6/11/22kV RMU	No.	-	-	4.06%	0.51%	90.86%	4.57%	3	4.23%
51	HV	Distribution Transformer	Pole Mounted Transformer	No.	0.55%	1.76%	5.47%	5.59%	86.26%	0.36%	4	3.07%
52	HV	Distribution Transformer	Ground Mounted Transformer	No.	1.76%	2.34%	9.38%	4.49%	81.84%	0.20%	4	3.50%
53	HV	Distribution Transformer	Voltage regulators	No.	-	-	-	-	-	-	N/A	-
54	HV	Distribution Substations	Ground Mounted Substation Housing	No.	-	-	-	-	-	-	N/A	-
55	LV	LV Line	LV OH Conductor	km	-	40.73%	10.21%	15.74%	33.29%	0.01%	3	15.39%
56	LV	LV Cable	LV UG Cable	km	-	15.10%	6.08%	6.31%	72.23%	0.28%	3	0.05%
57	LV	LV Streetlighting	LV OH/UG Streetlight circuit	km	-	-	-	-	-	100.00%	2	15.39%
58	LV	Connections	OH/UG consumer service connections	No.	0.28%	0.92%	21.24%	0.38%	74.24%	2.94%	3	10.30%
59	All	Protection	Protection relays (electromechanical, solid state and numeric)	No.	7.14%	-	17.86%	9.69%	65.31%	-	4	40.31%
60	All	SCADA and communications	SCADA and communications equipment operating as a single system	Lot	21.43%	64.29%	14.29%	-	-	-	3	91.67%
61	All	Capacitor Banks	Capacitors including controls	No.	-	-	-	-	-	-	N/A	-
62	All	Load Control	Centralised plant	Lot	-	-	50.00%	50.00%	-	-	4	50.00%
63	All	Load Control	Relays	No.	-	-	-	-	-	100.00%	2	-
64	All	Civils	Cable Tunnels	km	-	-	-	-	-	-	N/A	-

Appendix 7: Forecast Capacity (Schedule 12b)

Company Name: Electra Limited
AMP Planning Period: 1 April 2026 – 31 March 2036

SCHEDULE 12b: REPORT ON FORECAST CAPACITY

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

sch ref

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

sch ref	Existing Zone Substations	Current peak load (MVA)	Current peak load period	Installed operating capacity (MVA)	Current security of supply classification (type)	Current constraint type	Current available capacity (MVA)	Peak load period +5 yrs	Available capacity +5 yrs (MVA)	Security of supply classification +5 yrs (type)	Peak load period +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	Constraint primary cause	Constraint solution type	Constraint solution progress	Temporary constraint solution remaining lifespan	Explanation
9	Shannon	4.6	Winter	5	N-1	No constraint	0.4	Winter	0.1	N-1	Winter	(0.5)	(0.1)	N-1	Capacity	8	Zone substation transformer	Overload to alternative substation	Planning stage	Not applicable	Refer Section 11.9.1, Project 1: Transfer demand to Levin West and Foxton using the 11kV network.
10	Foxton	7.6	Winter	23	N-1	No constraint	15.6	Winter	14.7	N-1	Winter	11.1	13.8	N-1	Capacity	None	Not applicable	Not required	Not applicable	Not applicable	
11	Levin West	14.3	Winter	23	N-1	No constraint	8.7	Winter	6.7	N-1	Winter	1.1	4.9	N-1	Capacity	None	Not applicable	Not required	Not applicable	Not applicable	
12	Levin East	15.9	Winter	23	N-1	No constraint	7.1	Winter	4.9	N-1	Winter	(4.3)	2.6	N-1	Capacity	None	Not applicable	Not required	Not applicable	Not applicable	
13	Ōtaki	12.7	Winter	23	N-1	No constraint	(0.2)	Winter	(1.8)	N-1	Winter	(4.0)	(2.4)	N-1	Capacity	1	Subtransmission circuit	Network upgrade	Planning stage	Not applicable	There is a voltage constraint from FY26 when fed from the North. This is not currently material and can be managed by load control. However, when supplied from the south, Ōtaki is forecast to exceed its minimum voltage limit in FY31. Refer Section 11.9.3, Project 10: Voltage compensation at Ōtaki substation. This project is under review. There is a potential capacity constraint when supplied from the South under contingency conditions. The Paraparaumu GXP to Waikanae circuit 1 is forecast to exceed its normal operation capacity limit in FY30. Additionally, Paraparaumu GXP to Waikanae circuits 1 & 2 are forecast to exceed their contingency operation capacity limits in FY32. Refer Section 11.9.3, Project 12: Project to resolve forecast capacity constraints on Paraparaumu GXP to Waikanae 33kV circuits 1 and 2 is under investigation
14	Waikanae	15.3	Winter	23	N-1	No constraint	7.5	Winter	5.9	N-1	Winter	(1.3)	4.2	N-1	Capacity	None	Not applicable	Not required	Not applicable	Not applicable	
15	Paraparaumu East	13.2	Winter	23	N-1	No constraint	9.8	Winter	8.3	N-1	Winter	3.6	6.7	N-1	Capacity	None	Not applicable	Not required	Not applicable	Not applicable	
16	Paraparaumu West	11.3	Winter	23	N-1	No constraint	11.7	Winter	10.6	N-1	Winter	6.3	9.5	N-1	Capacity	None	Not applicable	Not required	Not applicable	Not applicable	
17	Raumati	10.9	Winter	23	N-1	No constraint	12.1	Winter	11.5	N-1	Winter	8.4	10.8	N-1	Capacity	None	Not applicable	Not required	Not applicable	Not applicable	
18	Paekākāriki	4.1	Winter	5	N-1 switched	No constraint	0.9	Winter	0.3	N-1 switched	Winter	(4.0)	(4.3)	N-1 switched	Capacity	10+	Zone substation transformer	Undecided	No active planning	Not applicable	Marginal constraint for controlled demand in FY36. However, constraint will emerge if [illegible] demand growth occurs. The Paekākāriki back-up supply (11 kV) is forecast to exceed its contingency operation capacity limit in FY30, should [illegible] increase demand. The constraint will be resolved via customer connection (Refer to Section 11.13.3) and zone substation development (refer to Section 11.9.3)
19																					
20																					

21 ¹ Extend table as necessary to disclose all capacity and constraint information by each zone substation

Appendix 8: Forecast Demand (Schedule 12c)

Company Name	Electra Limited
AMP Planning Period	1 April 2026 – 31 March 2036

SCHEDULE 12c: REPORT ON FORECAST NETWORK DEMAND

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

sch ref

7 **12c(i): Consumer Connections**

8 *Number of ICPs connected during year by consumer type*

sch ref	*Consumer types defined by EDB**	*Current Year CY*	*CY+1*	*CY+2*	*CY+3*	*CY+4*	*CY+5*
10		**Number of connections**					
12	Residential	467	473	616	703	725	714
13	Non-residential	81	82	106	121	125	123
14							
15							
16							
17	**Connections total**	548	555	722	825	850	837

18 **include additional rows if needed*

sch ref	**Distributed generation**	*Current Year CY*	*CY+1*	*CY+2*	*CY+3*	*CY+4*	*CY+5*
23	Number of connections made in year	423	459	518	532	507	455
24	Capacity of distributed generation installed in year (MVA)	3	4	4	5	4	4

25 **12c(ii): System Demand**

sch ref			*Current Year CY*	*CY+1*	*CY+2*	*CY+3*	*CY+4*	*CY+5*
27		**Maximum coincident system demand (MW)**						
28		GXP demand	83	84	86	88	91	93
29	*plus*	Distributed generation output at HV and above	26	26	26	26	26	26
30		**Maximum coincident system demand**	109	110	112	114	117	119
31	*less*	Net transfers to (from) other EDBs at HV and above						
32		**Demand on system for supply to consumers' connection points**	109	110	112	114	117	119
33		**Electricity volumes carried (GWh)**						
34		Electricity supplied from GXPs	330	333	337	344	353	363
35	*less*	Electricity exports to GXPs						
36	*plus*	Electricity supplied from distributed generation	124	124	124	124	124	124
37	*less*	Net electricity supplied to (from) other EDBs						
38		**Electricity entering system for supply to ICPs**	454	457	461	468	477	487
39	*less*	Total energy delivered to ICPs	424	426	430	437	446	455
40		**Losses**	30	30	30	31	32	32
42		**Load factor**	48%	47%	47%	47%	47%	47%
43		**Loss ratio**	6.6%	6.6%	6.6%	6.6%	6.6%	6.6%

Appendix 9: Forecast Interruptions and Duration (Schedule 12d)

Company Name	**Electra Limited**
AMP Planning Period	**1 April 2026 – 31 March 2036**
Network / Sub-network Name	**All**

SCHEDULE 12d: REPORT FORECAST INTERRUPTIONS AND DURATION

This schedule requires a forecast of SAIFI and SAIDI for disclosure and a 5 year planning period. The forecasts should be consistent with the supporting information set out in the AMP as well as the assumed impact of planned and unplanned SAIFI and SAIDI on the expenditures forecast provided in Schedule 11a and Schedule 11b.

sch ref		*Current Year CY*	*CY+1*	*CY+2*	*CY+3*	*CY+4*	*CY+5*
8							
9							
10	**SAIDI**						
11	Class B (planned interruptions on the network)	35.0	35.0	35.0	35.0	35.0	35.0
12	Class C (unplanned interruptions on the network)	63.0	63.0	63.0	63.0	63.0	63.0
13	**SAIFI**						
14	Class B (planned interruptions on the network)	0.15	0.15	0.15	0.15	0.15	0.15
15	Class C (unplanned interruptions on the network)	1.40	1.40	1.40	1.40	1.40	1.40

Appendix 10: Asset Management Maturity (Schedule 13)

Company Name	Electra Limited
AMP Planning Period	1 April 2026 – 31 March 2036
Asset Management Standard Applied	ISO 55000

SCHEDULE 13: REPORT ON ASSET MANAGEMENT MATURITY

This schedule requires information on the EDB'S self-assessment of the maturity of its asset management practices .

Question No.	Function	Question	Score	Evidence—Summary	Why	Who	Record/documented Information
3	Asset management policy	To what extent has an asset management policy been documented, authorised and communicated?	3	A Board approved asset management policy exists and published (AMP Section 6). A revised policy was approved in FY25 and it has been published and communicated to relevant staff.	Widely used AM practice standards require an organisation to document, authorise and communicate its asset management policy (eg, as required in PAS 55 para 4.2 i). A key pre-requisite of any robust policy is that the organisation's top management must be seen to endorse and fully support it. Also vital to the effective implementation of the policy, is to tell the appropriate people of its content and their obligations under it. Where an organisation outsources some of its asset-related activities, then these people and their organisations must equally be made aware of the policy's content. Also, there may be other stakeholders, such as regulatory authorities and shareholders who should be made aware of it.	Top management. The management team that has overall responsibility for asset management.	The organisation's asset management policy, its organisational strategic plan, documents indicating how the asset management policy was based upon the needs of the organisation and evidence of communication.
10	Asset management strategy	What has the organisation done to ensure that its asset management strategy is consistent with other appropriate organisational policies and strategies, and the needs of stakeholders?	3	There are clearly articulated asset management strategies included in th AMP (AMP Section 6). There are clear linkages between Electra's strategic plan, stakeholder needs and the asset management strategies, which are explained in the AMP (AMP Section 6 and 8).	In setting an organisation's asset management strategy, it is important that it is consistent with any other policies and strategies that the organisation has and has taken into account the requirements of relevant stakeholders. This question examines to what extent the asset management strategy is consistent with other organisational policies and strategies (eg, as required by PAS 55 para 4.3.1 b) and has taken account of stakeholder requirements as required by PAS 55 para 4.3.1 c). Generally, this will take into account the same polices, strategies and stakeholder requirements as covered in drafting the asset management policy but at a greater level of detail.	Top management. The organisation's strategic planning team. The management team that has overall responsibility for asset management.	The organisation's asset management strategy document and other related organisational policies and strategies. Other than the organisation's strategic plan, these could include those relating to health and safety, environmental, etc. Results of stakeholder consultation.
11	Asset management strategy	In what way does the organisation's asset management strategy take account of the lifecycle of the assets, asset types and asset systems over which the organisation has stewardship?	3	The combination of the key issues section (AMP Section 5), the asset management strategy (Section 6), and fleet strategies in the fleet plans (AMP Sections 12.6, 12.8 to 12.18) takes account of the lifecycle of all of its assets, asset types and asset systems. There is a robust linkage between the asset management strategies and the fleet strategies.	Good asset stewardship is the hallmark of an organisation compliant with widely used AM standards. A key component of this is the need to take account of the lifecycle of the assets, asset types and asset systems. (For example, this requirement is recognised in 4.3.1 d) of PAS 55). This question explores what an organisation has done to take lifecycle into account in its asset management strategy.	Top management. People in the organisation with expert knowledge of the assets, asset types, asset systems and their associated life-cycles. The management team that has overall responsibility for asset management. Those responsible for developing and adopting methods and processes used in asset management	The organisation's documented asset management strategy and supporting working documents.
26	Asset management plan(s)	How does the organisation establish and document its asset management plan(s) across the life cycle activities of its assets and asset systems?	2.8	The combination of the development plan (AMP Section 11), fleet plans (AMP Section 12), asset management system (AMP Section 8), and asset management improvement plans (AMP Section 8) demonstrates that plans are established and documented for asset systems and critical assets to achieve the asset management strategy and asset management objectives across all life cycle. There is direct line-of-sight from the asset risk and the asset fleet plans (AMP Section 12.8 to 12.18). Our plans described in Sections 8, 9, 11 and 12 have matured compared to the 2025 AMP, hence the modest increase in score.	The asset management strategy need to be translated into practical plan(s) so that all parties know how the objectives will be achieved. The development of plan(s) will need to identify the specific tasks and activities required to optimize costs, risks and performance of the assets and/or asset system(s), when they are to be carried out and the resources required.	The management team with overall responsibility for the asset management system. Operations, maintenance and engineering managers.	The organisation's asset management plan(s).

Company Name	Electra Limited
AMP Planning Period	1 April 2026 – 31 March 2036
Asset Management Standard Applied	ISO 55000

SCHEDULE 13: REPORT ON ASSET MANAGEMENT MATURITY (cont)

Question No.	Function	Question	Maturity Level 0	Maturity Level 1	Maturity Level 2	Maturity Level 3	Maturity Level 4
3	Asset management policy	To what extent has an asset management policy been documented, authorised and communicated?	The organisation does not have a documented asset management policy.	The organisation has an asset management policy, but it has not been authorised by top management, or it is not influencing the management of the assets.	The organisation has an asset management policy, which has been authorised by top management, but it has had limited circulation. It may be in use to influence development of strategy and planning but its effect is limited.	The asset management policy is authorised by top management, is widely and effectively communicated to all relevant employees and stakeholders, and used to make these persons aware of their asset related obligations.	The organisation's process(es) surpass the standard required to comply with requirements set out in a recognised standard. The assessor is advised to note in the Evidence section why this is the case and the evidence seen.
10	Asset management strategy	What has the organisation done to ensure that its asset management strategy is consistent with other appropriate organisational policies and strategies, and the needs of stakeholders?	The organisation has not considered the need to ensure that its asset management strategy is appropriately aligned with the organisation's other organisational policies and strategies or with stakeholder requirements. OR The organisation does not have an asset management strategy.	The need to align the asset management strategy with other organisational policies and strategies as well as stakeholder requirements is understood and work has started to identify the linkages or to incorporate them in the drafting of asset management strategy.	Some of the linkages between the long-term asset management strategy and other organisational policies, strategies and stakeholder requirements are defined but the work is fairly well advanced but still incomplete.	All linkages are in place and evidence is available to demonstrate that, where appropriate, the organisation's asset management strategy is consistent with its other organisational policies and strategies. The organisation has also identified and considered the requirements of relevant stakeholders.	The organisation's process(es) surpass the standard required to comply with requirements set out in a recognised standard. The assessor is advised to note in the Evidence section why this is the case and the evidence seen.
11	Asset management strategy	In what way does the organisation's asset management strategy take account of the lifecycle of the assets, asset types and asset systems over which the organisation has stewardship?	The organisation has not considered the need to ensure that its asset management strategy is produced with due regard to the lifecycle of the assets, asset types or asset systems that it manages. OR The organisation does not have an asset management strategy.	The need is understood, and the organisation is drafting its asset management strategy to address the lifecycle of its assets, asset types and asset systems.	The long-term asset management strategy takes account of the lifecycle of some, but not all, of its assets, asset types and asset systems.	The asset management strategy takes account of the lifecycle of all of its assets, asset types and asset systems.	The organisation's process(es) surpass the standard required to comply with requirements set out in a recognised standard. The assessor is advised to note in the Evidence section why this is the case and the evidence seen.
26	Asset management plan(s)	How does the organisation establish and document its asset management plan(s) across the life cycle activities of its assets and asset systems?	The organisation does not have an identifiable asset management plan(s) covering asset systems and critical assets.	The organisation has asset management plan(s) but they are not aligned with the asset management strategy and objectives and do not take into consideration the full asset life cycle (including asset creation, acquisition, enhancement, utilisation, maintenance decommissioning and disposal).	The organisation is in the process of putting in place comprehensive, documented asset management plan(s) that cover all life cycle activities, clearly aligned to asset management objectives and the asset management strategy.	Asset management plan(s) are established, documented, implemented and maintained for asset systems and critical assets to achieve the asset management strategy and asset management objectives across all life cycle phases.	The organisation's process(es) surpass the standard required to comply with requirements set out in a recognised standard. The assessor is advised to note in the Evidence section why this is the case and the evidence seen.

			Company Name	Electra Limited
			AMP Planning Period	1 April 2026 – 31 March 2036
			Asset Management Standard Applied	ISO 55000

SCHEDULE 13: REPORT ON ASSET MANAGEMENT MATURITY (cont)

Question No.	Function	Question	Score	Evidence—Summary	Why	Who	Record/documented Information
27	Asset management plan(s)	How has the organisation communicated its plan(s) to all relevant parties to a level of detail appropriate to the receiver's role in their delivery?	2.6	The work plans described in the development plans (AMP Section 11) and the fleet plans (AMP Section 12) are communicated by the asset management team to the service delivery team and external contractors (where they are doing network work). The asset management improvement plan (AMP Section 9) is communicated to relevant internal and external service providers to ensure the projects are scoped and delivered. We have made modest improvements in the communication of the work plan, hence the small increase in score this year.	Plans will be ineffective unless they are communicated to all those, including contracted suppliers and those who undertake enabling function(s). The plan(s) need to be communicated in a way that is relevant to those who need to use them.	The management team with overall responsibility for the asset management system. Delivery functions and suppliers.	Distribution lists for plan(s). Documents derived from plan(s) which detail the receivers role in plan delivery. Evidence of communication.
29	Asset management plan(s)	How are designated responsibilities for delivery of asset plan actions documented?	2.7	Section 2 of the AMP documents the responsibilities for asset management. These responsibilities are also documented in relevant position descriptions. We have improved our communication of responsibilities for delivery following the restructure of the Network and Service Delivery Teams this year.	The implementation of asset management plan(s) relies on (1) actions being clearly identified, (2) an owner allocated and (3) that owner having sufficient delegated responsibility and authority to carry out the work required. It also requires alignment of actions across the organisation. This question explores how well the plan(s) set out responsibility for delivery of asset plan actions.	The management team with overall responsibility for the asset management system. Operations, maintenance and engineering managers. If appropriate, the performance management team.	The organisation's asset management plan(s). Documentation defining roles and responsibilities of individuals and organisational departments.
31	Asset management plan(s)	What has the organisation done to ensure that appropriate arrangements are made available for the efficient and cost effective implementation of the plan(s)? (Note this is about resources and enabling support)	3	The development plans, fleet plans, and asset management improvement plans are delivered as per Electra's procurement/outsourcing policy and procedures. Electra has an internal field service function, with support from external contractors as required for specialist tasks and peak workload. Some improvements have been identified in our project management processes which are currently being reviewed and improved.	It is essential that the plan(s) are realistic and can be implemented, which requires appropriate resources to be available and enabling mechanisms in place. This question explores how well this is achieved. The plan(s) not only need to consider the resources directly required and timescales, but also the enabling activities, including for example, training requirements, supply chain capability and procurement timescales.	The management team with overall responsibility for the asset management system. Operations, maintenance and engineering managers. If appropriate, the performance management team. If appropriate, the performance management team. Where appropriate the procurement team and service providers working on the organisation's asset-related activities.	The organisation's asset management plan(s). Documented processes and procedures for the delivery of the asset management plan.
33	Contingency planning	What plan(s) and procedure(s) does the organisation have for identifying and responding to incidents and emergency situations and ensuring continuity of critical asset management activities?	2.5	Electra has various guidelines for the management of major network events. These guidelines define escalation actions, key roles and communication requirements. The current suite of contingency plans & emergency response plans basic and further development is required.	Widely used AM practice standards require that an organisation has plan(s) to identify and respond to emergency situations. Emergency plan(s) should outline the actions to be taken to respond to specified emergency situations and ensure continuity of critical asset management activities including the communication to, and involvement of, external agencies. This question assesses if, and how well, these plan(s) triggered, implemented and resolved in the event of an incident. The plan(s) should be appropriate to the level of risk as determined by the organisation's risk assessment methodology. It is also a requirement that relevant personnel are competent and trained.	The manager with responsibility for developing emergency plan(s). The organisation's risk assessment team. People with designated duties within the plan(s) and procedure(s) for dealing with incidents and emergency situations.	The organisation's plan(s) and procedure(s) for dealing with emergencies. The organisation's risk assessments and risk registers.

Company Name	Electra Limited
AMP Planning Period	1 April 2026 – 31 March 2036
Asset Management Standard Applied	ISO 55000

SCHEDULE 13: REPORT ON ASSET MANAGEMENT MATURITY (cont)

Question No.	Function	Question	Maturity Level 0	Maturity Level 1	Maturity Level 2	Maturity Level 3	Maturity Level 4
27	Asset management plan(s)	How has the organisation communicated its plan(s) to all relevant parties to a level of detail appropriate to the receiver's role in their delivery?	The organisation does not have plan(s) or their distribution is limited to the authors.	The plan(s) are communicated to some of those responsible for delivery of the plan(s). OR Communicated to those responsible for delivery is either irregular or ad-hoc.	The plan(s) are communicated to most of those responsible for delivery but there are weaknesses in identifying relevant parties resulting in incomplete or inappropriate communication. The organisation recognises improvement is needed as is working towards resolution.	The plan(s) are communicated to all relevant employees, stakeholders and contracted service providers to a level of detail appropriate to their participation or business interests in the delivery of the plan(s) and there is confirmation that they are being used effectively.	The organisation's process(es) surpass the standard required to comply with requirements set out in a recognised standard. The assessor is advised to note in the Evidence section why this is the case and the evidence seen.
29	Asset management plan(s)	How are designated responsibilities for delivery of asset plan actions documented?	The organisation has not documented responsibilities for delivery of asset plan actions.	Asset management plan(s) inconsistently document responsibilities for delivery of plan actions and activities and/or responsibilities and authorities for implementation inadequate and/or delegation level inadequate to ensure effective delivery and/or contain misalignments with organisational accountability.	Asset management plan(s) consistently document responsibilities for the delivery of actions but responsibility/authority levels are inappropriate/ inadequate, and/or there are misalignments within the organisation.	Asset management plan(s) consistently document responsibilities for the delivery actions and there is adequate detail to enable delivery of actions. Designated responsibility and authority for achievement of asset plan actions is appropriate.	The organisation's process(es) surpass the standard required to comply with requirements set out in a recognised standard. The assessor is advised to note in the Evidence section why this is the case and the evidence seen.
31	Asset management plan(s)	What has the organisation done to ensure that appropriate arrangements are made available for the efficient and cost effective implementation of the plan(s)? (Note this is about resources and enabling support)	The organisation has not considered the arrangements needed for the effective implementation of plan(s).	The organisation recognises the need to ensure appropriate arrangements are in place for implementation of asset management plan(s) and is in the process of determining an appropriate approach for achieving this.	The organisation has arrangements in place for the implementation of asset management plan(s) but the arrangements are not yet adequately efficient and/or effective. The organisation is working to resolve existing weaknesses.	The organisation's arrangements fully cover all the requirements for the efficient and cost effective implementation of asset management plan(s) and realistically address the resources and timescales required, and any changes needed to functional policies, standards, processes and the asset management information system.	The organisation's process(es) surpass the standard required to comply with requirements set out in a recognised standard. The assessor is advised to note in the Evidence section why this is the case and the evidence seen.
33	Contingency planning	What plan(s) and procedure(s) does the organisation have for identifying and responding to incidents and emergency situations and ensuring continuity of critical asset management activities?	The organisation has not considered the need to establish plan(s) and procedure(s) to identify and respond to incidents and emergency situations.	The organisation has some ad-hoc arrangements to deal with incidents and emergency situations, but these have been developed on a reactive basis in response to specific events that have occurred in the past.	Most credible incidents and emergency situations are identified. Either appropriate plan(s) and procedure(s) are incomplete for critical activities or they are inadequate. Training/ external alignment may be incomplete.	Appropriate emergency plan(s) and procedure(s) are in place to respond to credible incidents and manage continuity of critical asset management activities consistent with policies and asset management objectives. Training and external agency alignment is in place.	The organisation's process(es) surpass the standard required to comply with requirements set out in a recognised standard. The assessor is advised to note in the Evidence section why this is the case and the evidence seen.

SCHEDULE 13: REPORT ON ASSET MANAGEMENT MATURITY (cont)

Company Name	Electra Limited
AMP Planning Period	1 April 2026 – 31 March 2036
Asset Management Standard Applied	ISO 55000

Question No.	Function	Question	Score	Evidence—Summary	Why	Who	Record/documented Information
37	Structure, authority and responsibilities	What has the organisation done to appoint member(s) of its management team to be responsible for ensuring that the organisation's assets deliver the requirements of the asset management strategy, objectives and plan(s)?	3	Section 2 of the AMP documents the responsibilities for asset management. The relevant authorities are documented in the Board approved delegated authority policy.	In order to ensure that the organisation's assets and asset systems deliver the requirements of the asset management policy, strategy and objectives responsibilities need to be allocated to appropriate people who have the necessary authority to fulfil their responsibilities. (This question, relates to the organisation's assets eg, para b), s 4.4.1 of PAS 55, making it therefore distinct from the requirement contained in para a), s 4.4.1 of PAS 55).	Top management. People with management responsibility for the delivery of asset management policy, strategy, objectives and plan(s). People working on asset-related activities.	Evidence that managers with responsibility for the delivery of asset management policy, strategy, objectives and plan(s) have been appointed and have assumed their responsibilities. Evidence may include the organisation's documents relating to its asset management system, organisational charts, job descriptions of post-holders, annual targets/objectives and personal development plan(s) of post-holders as appropriate.
40	Structure, authority and responsibilities	What evidence can the organisation's top management provide to demonstrate that sufficient resources are available for asset management?	2	High level planning of resources to deliver Asset Management activities has been completed, however this stops short of a specific numbers of each staff category required over the timeframe. There have been shortfalls in delivery owing to staff vacancies and a mismatch between internal capacity to deliver and external resource support. Further work is to be completed in FY27 to address this.	Optimal asset management requires top management to ensure sufficient resources are available. In this context the term 'resources' includes manpower, materials, funding and service provider support.	Top management. The management team that has overall responsibility for asset management. Risk management team. The organisation's managers involved in day-to-day supervision of asset-related activities, such as frontline managers, engineers, foremen and chargehands as appropriate.	Evidence demonstrating that asset management plan(s) and/or the process(es) for asset management plan implementation consider the provision of adequate resources in both the short and long term. Resources include funding, materials, equipment, services provided by third parties and personnel (internal and service providers) with appropriate skills competencies and knowledge.
42	Structure, authority and responsibilities	To what degree does the organisation's top management communicate the importance of meeting its asset management requirements?	2.7	Key asset management planning and works delivery requirements are planned and monitored. This includes fortnightly Progress To Plan and other project management practices to ensure that works are completed to target. There is also a monthly business unit meeting that includes field staff that deals with operational issues (eg. issuing of latest schematics), safety, quality and some works progress. The CE and Board also monitor progress through the monthly reporting process.	Widely used AM practice standards require an organisation to communicate the importance of meeting its asset management requirements such that personnel fully understand, take ownership of, and are fully engaged in the delivery of the asset management requirements (eg, PAS 55 s 4.4.1 g).	Top management. The management team that has overall responsibility for asset management. People involved in the delivery of the asset management requirements.	Evidence of such activities as road shows, written bulletins, workshops, team talks and management walk-abouts would assist an organisation to demonstrate it is meeting this requirement of PAS 55.
45	Outsourcing of asset management activities	Where the organisation has outsourced some of its asset management activities, how has it ensured that appropriate controls are in place to ensure the compliant delivery of its organisational strategic plan, and its asset management policy and strategy?	2.5	There is appropriate project governance in place controlling development plans and fleet plans delivery. The development plans, fleet plans are delivered as per Electra's procurement/outsourcing policy and procedures. We have undertaken further work on our outsourcing strategy and controls as set out in Section 14 of the AMP, hence the increase in score this year.	Where an organisation chooses to outsource some of its asset management activities, the organisation must ensure that these outsourced process(es) are under appropriate control to ensure that all the requirements of widely used AM standards (eg, PAS 55) are in place, and the asset management policy, strategy objectives and plan(s) are delivered. This includes ensuring capabilities and resources across a time span aligned to life cycle management. The organisation must put arrangements in place to control the outsourced activities, whether it be to external providers or to other in-house departments. This question explores what the organisation does in this regard.	Top management. The management team that has overall responsibility for asset management. The manager(s) responsible for the monitoring and management of the outsourced activities. People involved with the procurement of outsourced activities. The people within the organisations that are performing the outsourced activities. The people impacted by the outsourced activity.	The organisation's arrangements that detail the compliance required of the outsourced activities. For example, this this could form part of a contract or service level agreement between the organisation and the suppliers of its outsourced activities. Evidence that the organisation has demonstrated to itself that it has assurance of compliance of outsourced activities.

Company Name	**Electra Limited**
AMP Planning Period	**1 April 2026 – 31 March 2036**
Asset Management Standard Applied	**ISO 55000**

SCHEDULE 13: REPORT ON ASSET MANAGEMENT MATURITY (cont)

Question No.	Function	Question	Maturity Level 0	Maturity Level 1	Maturity Level 2	Maturity Level 3	Maturity Level 4
37	Structure, authority and responsibilities	What has the organisation done to appoint member(s) of its management team to be responsible for ensuring that the organisation's assets deliver the requirements of the asset management strategy, objectives and plan(s)?	Top management has not considered the need to appoint a person or persons to ensure that the organisation's assets deliver the requirements of the asset management strategy, objectives and plan(s).	Top management understands the need to appoint a person or persons to ensure that the organisation's assets deliver the requirements of the asset management strategy, objectives and plan(s).	Top management has appointed an appropriate people to ensure the assets deliver the requirements of the asset management strategy, objectives and plan(s) but their areas of responsibility are not fully defined and/or they have insufficient delegated authority to fully execute their responsibilities.	The appointed person or persons have full responsibility for ensuring that the organisation's assets deliver the requirements of the asset management strategy, objectives and plan(s). They have been given the necessary authority to achieve this.	The organisation's process(es) surpass the standard required to comply with requirements set out in a recognised standard. The assessor is advised to note in the Evidence section why this is the case and the evidence seen.
40	Structure, authority and responsibilities	What evidence can the organisation's top management provide to demonstrate that sufficient resources are available for asset management?	The organisation's top management has not considered the resources required to deliver asset management.	The organisations top management understands the need for sufficient resources but there are no effective mechanisms in place to ensure this is the case.	A process exists for determining what resources are required for its asset management activities and in most cases these are available but in some instances resources remain insufficient.	An effective process exists for determining the resources needed for asset management and sufficient resources are available. It can be demonstrated that resources are matched to asset management requirements.	The organisation's process(es) surpass the standard required to comply with requirements set out in a recognised standard. The assessor is advised to note in the Evidence section why this is the case and the evidence seen.
42	Structure, authority and responsibilities	To what degree does the organisation's top management communicate the importance of meeting its asset management requirements?	The organisation's top management has not considered the need to communicate the importance of meeting asset management requirements.	The organisations top management understands the need to communicate the importance of meeting its asset management requirements but does not do so.	Top management communicates the importance of meeting its asset management requirements but only to parts of the organisation.	Top management communicates the importance of meeting its asset management requirements to all relevant parts of the organisation.	The organisation's process(es) surpass the standard required to comply with requirements set out in a recognised standard. The assessor is advised to note in the Evidence section why this is the case and the evidence seen.
45	Outsourcing of asset management activities	Where the organisation has outsourced some of its asset management activities, how has it ensured that appropriate controls are in place to ensure the compliant delivery of its organisational strategic plan, and its asset management policy and strategy?	The organisation has not considered the need to put controls in place.	The organisation controls its outsourced activities on an ad-hoc basis, with little regard for ensuring for the compliant delivery of the organisational strategic plan and/or its asset management policy and strategy.	Controls systematically considered but currently only provide for the compliant delivery of some, but not all, aspects of the organisational strategic plan and/or its asset management policy and strategy. Gaps exist.	Evidence exists to demonstrate that outsourced activities are appropriately controlled to provide for the compliant delivery of the organisational strategic plan, asset management policy and strategy, and that these controls are integrated into the asset management system	The organisation's process(es) surpass the standard required to comply with requirements set out in a recognised standard. The assessor is advised to note in the Evidence section why this is the case and the evidence seen.

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SCHEDULE 13: REPORT ON ASSET MANAGEMENT MATURITY (cont)

Question No.	Function	Question	Score	Evidence—Summary	Why	Who	Record/documented Information
48	Training, awareness and competence	How does the organisation develop plan(s) for the human resources required to undertake asset management activities - including the development and delivery of asset management strategy, process(es), objectives and plan(s)?	2.5	Section 18 of the AMP summarises the resourcing strategy across corporate, asset management and service delivery. The development of the strategy, and it implementation is the responsibility of HR and the senior leadership team	There is a need for an organisation to demonstrate that it has considered what resources are required to develop and implement its asset management system. There is also a need for the organisation to demonstrate that it has assessed what development plan(s) are required to provide its human resources with the skills and competencies to develop and implement its asset management systems. The timescales over which the plan(s) are relevant should be commensurate with the planning horizons within the asset management strategy considers e.g. if the asset management strategy considers 5, 10 and 15 year time scales then the human resources development plan(s) should align with these. Resources include both 'in house' and external resources who undertake asset management activities.	Senior management responsible for agreement of plan(s). Managers responsible for developing asset management strategy and plan(s). Managers with responsibility for development and recruitment of staff (including HR functions). Staff responsible for training. Procurement officers. Contracted service providers.	Evidence of analysis of future work load plan(s) in terms of human resources. Document(s) containing analysis of the organisation's own direct resources and contractors resource capability over suitable timescales. Evidence, such as minutes of meetings, that suitable management forums are monitoring human resource development plan(s). Training plan(s), personal development plan(s), contract and service level agreements.
49	Training, awareness and competence	How does the organisation identify competency requirements and then plan, provide and record the training necessary to achieve the competencies?	2.5	There is a competency framework (HR's database). This has transitioned to the OurHub system. It will contain position descriptions and training requirements for all roles. Population of OurHub is ongoing.	Widely used AM standards require that organisations to undertake a systematic identification of the asset management awareness and competencies required at each level and function within the organisation. Once identified the training required to provide the necessary competencies should be planned for delivery in a timely and systematic way. Any training provided must be recorded and maintained in a suitable format. Where an organisation has contracted service providers in place then it should have a means to demonstrate that this requirement is being met for their employees. (eg, PAS 55 refers to frameworks suitable for identifying competency requirements).	Senior management responsible for agreement of plan(s). Managers responsible for developing asset management strategy and plan(s). Managers with responsibility for development and recruitment of staff (including HR functions). Staff responsible for training. Procurement officers. Contracted service providers.	Evidence of an established and applied competency requirements assessment process and plan(s) in place to deliver the required training. Evidence that the training programme is part of a wider, co-ordinated asset management activities training and competency programme. Evidence that training activities are recorded and that records are readily available (for both direct and contracted service provider staff) e.g. via organisation wide information system or local records database.
50	Training, awareness and competence	How does the organization ensure that persons under its direct control undertaking asset management related activities have an appropriate level of competence in terms of education, training or experience?	2.5	There is a competency framework with the OurHub system, which is maintained by HR and Managers to ensure competency is maintained. Field staff competency is also controlled under NZQA framework and authorisation/entry competency framework.	A critical success factor for the effective development and implementation of an asset management system is the competence of persons undertaking these activities. organisations should have effective means in place for ensuring the competence of employees to carry out their designated asset management function(s). Where an organisation has contracted service providers undertaking elements of its asset management system then the organisation shall assure itself that the outsourced service provider also has suitable arrangements in place to manage the competencies of its employees. The organisation should ensure that the individual and corporate competencies it requires are in place and actively monitor, develop and maintain an appropriate balance of these competencies.	Managers, supervisors, persons responsible for developing training programmes. Staff responsible for procurement and service agreements. HR staff and those responsible for recruitment.	Evidence of a competency assessment framework that aligns with established frameworks such as the asset management Competencies Requirements Framework (Version 2.0); National Occupational Standards for Management and Leadership; UK Standard for Professional Engineering Competence, Engineering Council, 2005.

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SCHEDULE 13: REPORT ON ASSET MANAGEMENT MATURITY (cont)

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

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SCHEDULE 13: REPORT ON ASSET MANAGEMENT MATURITY (cont)

Question No.	Function	Question	Score	Evidence—Summary	Why	Who	Record/documented Information
53	Communication, participation and consultation	How does the organisation ensure that pertinent asset management information is effectively communicated to and from employees and other stakeholders, including contracted service providers?	2.5	The development plans, fleet plans, and asset management improvement plans are communicated to relevant service delivery people. Operational information is communicated by the Control Centre, and escalated to relevant staff as required. The recent restructure of the Network and Service Delivery Teams has also clarified the communication channels for work delivery. We have also reviewed our processes for delivery of work via external service providers, hence the increase in score this year.	Widely used AM practice standards require that pertinent asset management information is effectively communicated to and from employees and other stakeholders including contracted service providers. Pertinent information refers to information required in order to effectively and efficiently comply with and deliver asset management strategy, plan(s) and objectives. This will include for example the communication of the asset management policy, asset performance information, and planning information as appropriate to contractors.	Top management and senior management representative(s), employee's representative(s), employee's trade union representative(s); contracted service provider management and employee representative(s); representative(s) from the organisation's Health, Safety and Environmental team. Key stakeholder representative(s).	Asset management policy statement prominently displayed on notice boards, intranet and internet; use of organisation's website for displaying asset performance data; evidence of formal briefings to employees, stakeholders and contracted service providers; evidence of inclusion of asset management issues in team meetings and contracted service provider contract meetings; newsletters, etc.
59	Asset Management System documentation	What documentation has the organisation established to describe the main elements of its asset management system and interactions between them?	2.5	A high level overview of the asset management system is included in the AMP (Section 8). There is supporting policy, procedure and standard documentation with the Electra document management system. This document is reviewed and updated as required.	Widely used AM practice standards require an organisation maintain up to date documentation that ensures that its asset management systems (ie, the systems the organisation has in place to meet the standards) can be understood, communicated and operated. (eg, s 4.5 of PAS 55 requires the maintenance of up to date documentation of the asset management system requirements specified throughout s 4 of PAS 55).	The management team that has overall responsibility for asset management. Managers engaged in asset management activities.	The documented information describing the main elements of the asset management system (process(es)) and their interaction.
62	Information management	What has the organisation done to determine what its asset management information system(s) should contain in order to support its asset management system?	2.5	The asset management system, asset management data, and asset management improvement plans (that include system and data improvements) are included in the AMP (AMP Section 8 and 9).	Effective asset management requires appropriate information to be available. Widely used AM standards therefore require the organisation to identify the asset management information it requires in order to support its asset management system. Some of the information required may be held by suppliers. The maintenance and development of asset management information systems is a poorly understood specialist activity that is akin to IT management but different from IT management. This group of questions provides some indications as to whether the capability is available and applied. Note: To be effective, an asset information management system requires the mobilisation of technology, people and process(es) that create, secure, make available and destroy the information required to support the asset management system.	The organisation's strategic planning team. The management team that has overall responsibility for asset management. Information management team. Operations, maintenance and engineering managers	Details of the process the organisation has employed to determine what its asset information system should contain in order to support its asset management system. Evidence that this has been effectively implemented.
63	Information management	How does the organisation maintain its asset management information system(s) and ensure that the data held within it (them) is of the requisite quality and accuracy and is consistent?	2.2	The asset management system, asset management data, and asset management improvement plans (that include system and data improvements) are included in the AMP (AMP Section 8 and 9). We undertook a review of CBARMM during the year to review the data to ensure it was of the required quality and improvements were made, hence the improvement in score this year.	The response to the questions is progressive. A higher scale cannot be awarded without achieving the requirements of the lower scale. This question explores how the organisation ensures that information management meets widely used AM practice requirements (eg, s 4.4.6 (a), (c) and (d) of PAS 55).	The management team that has overall responsibility for asset management. Users of the organisational information systems.	The asset management information system, together with the policies, procedure(s), improvement initiatives and audits regarding information controls.

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

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SCHEDULE 13: REPORT ON ASSET MANAGEMENT MATURITY (cont)

Question No.	Function	Question	Score	Evidence—Summary	Why	Who	Record/documented Information
64	Information management	How has the organisation's ensured its asset management information system is relevant to its needs?	2	The asset management system, asset management data, and asset management improvement plans (that include system and data improvements) are included in the AMP (AMP Section 8 and 9).	Widely used AM standards need not be prescriptive about the form of the asset management information system, but simply require that the asset management information system is appropriate to the organisations needs, can be effectively used and can supply information which is consistent and of the requisite quality and accuracy.	The organisation's strategic planning team. The management team that has overall responsibility for asset management. Information management team. Users of the organisational information systems.	The documented process the organisation employs to ensure its asset management information system aligns with its asset management requirements. Minutes of information systems review meetings involving users.
69	Risk management process(es)	How has the organisation documented process(es) and/or procedure(s) for the identification and assessment of asset and asset management related risks throughout the asset life cycle?	3	The risk management framework is defined in the AMP Section 10. The fleet plans (AMP Section 12.8 to 12.18) contains details of the material asset risks and controls. Electra also operates a safety management system that identifies risks. This includes a process to implement mitigations or controls.	Risk management is an important foundation for proactive asset management. Its overall purpose is to understand the cause, effect and likelihood of adverse events occurring, to optimally manage such risks to an acceptable level, and to provide an audit trail for the management of risks. Widely used standards require the organisation to have process(es) and/or procedure(s) in place that set out how the organisation identifies and assesses asset and asset management related risks. The risks have to be considered across the four phases of the asset lifecycle (eg, para 4.3.3 of PAS 55).	The top management team in conjunction with the organisation's senior risk management representatives. There may also be input from the organisation's Safety, Health and Environment team. Staff who carry out risk identification and assessment.	The organisation's risk management framework and/or evidence of specific process(es) and/ or procedure(s) that deal with risk control mechanisms. Evidence that the process(es) and/or procedure(s) are implemented across the business and maintained. Evidence of agendas and minutes from risk management meetings. Evidence of feedback in to process(es) and/or procedure(s) as a result of incident investigation(s). Risk registers and assessments.
79	Use and maintenance of asset risk information	How does the organisation ensure that the results of risk assessments provide input into the identification of adequate resources and training and competency needs?	2.5	Asset risks are identified in the fleet plans (AMP Section 12.8 to 12.18). Relevant operational risks are communicated to the service delivery team and contractors via safety forums.	Widely used AM standards require that the output from risk assessments are considered and that adequate resource (including staff) and training is identified to match the requirements. It is a further requirement that the effects of the control measures are considered, as there may be implications in resources and training required to achieve other objectives.	Staff responsible for risk assessment and those responsible for developing and approving resource and training plan(s). There may also be input from the organisation's Safety, Health and Environment team.	The organisations risk management framework. The organisation's resourcing plan(s) and training and competency plan(s). The organisation should be able to demonstrate appropriate linkages between the content of resource plan(s) and training and competency plan(s) to the risk assessments and risk control measures that have been developed.
82	Legal and other requirements	What procedure does the organisation have to identify and provide access to its legal, regulatory, statutory and other asset management requirements, and how is requirements incorporated into the asset management system?	2.5	Electra uses ComplyWith and ComplyWatch to ensure awareness of its legal and regulatory compliance requirements. Electra regularly completesComply With survey to monitor ongoing compliance. Some gaps exist in the explicit linkages between regulatory requirements and the AM processes/standards, although are monitored through external PSMS audits.	In order for an organisation to comply with its legal, regulatory, statutory and other asset management requirements, the organisation first needs to ensure that it knows what they are (eg, PAS 55 specifies this in s 4.4.8). It is necessary to have systematic and auditable mechanisms in place to identify new and changing requirements. Widely used AM standards also require that requirements are incorporated into the asset management system (e.g. procedure(s) and process(es))	Top management. The organisations regulatory team. The organisation's legal team or advisors. The management team with overall responsibility for the asset management system. The organisation's health and safety team or advisors. The organisation's policy making team.	The organisational processes and procedures for ensuring information of this type is identified, made accessible to those requiring the information and is incorporated into asset management strategy and objectives

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Question No.	Function	Question	Maturity Level 0	Maturity Level 1	Maturity Level 2	Maturity Level 3	Maturity Level 4
64	Information management	How has the organisation's ensured its asset management information system is relevant to its needs?	The organisation has not considered the need to determine the relevance of its management information system. At present there are major gaps between what the information system provides and the organisations needs.	The organisation understands the need to ensure its asset management information system is relevant to its needs and is determining an appropriate means by which it will achieve this. At present there are significant gaps between what the information system provides and the organisations needs.	The organisation has developed and is implementing a process to ensure its asset management information system is relevant to its needs. Gaps between what the information system provides and the organisations needs have been identified and action is being taken to close them.	The organisation's asset management information system aligns with its asset management requirements. Users can confirm that it is relevant to their needs.	The organisation's process(es) surpass the standard required to comply with requirements set out in a recognised standard. The assessor is advised to note in the Evidence section why this is the case and the evidence seen.
69	Risk management process(es)	How has the organisation documented process(es) and/or procedure(s) for the identification and assessment of asset and asset management related risks throughout the asset life cycle?	The organisation has not considered the need to document process(es) and/or procedure(s) for the identification and assessment of asset and asset management related risks throughout the asset life cycle.	The organisation is aware of the need to document the management of asset related risk across the asset lifecycle. The organisation has plan(s) to formally document all relevant process(es) and procedure(s) or has already commenced this activity.	The organisation is in the process of documenting the identification and assessment of asset related risk across the asset lifecycle but it is incomplete or there are inconsistencies between approaches and a lack of integration.	Identification and assessment of asset related risk across the asset lifecycle is fully documented. The organisation can demonstrate that appropriate documented mechanisms are integrated across life cycle phases and are being consistently applied.	The organisation's process(es) surpass the standard required to comply with requirements set out in a recognised standard. The assessor is advised to note in the Evidence section why this is the case and the evidence seen.
79	Use and maintenance of asset risk information	How does the organisation ensure that the results of risk assessments provide input into the identification of adequate resources and training and competency needs?	The organisation has not considered the need to conduct risk assessments.	The organisation is aware of the need to consider the results of risk assessments and effects of risk control measures to provide input into reviews of resources, training and competency needs. Current input is typically ad-hoc and reactive.	The organisation is in the process ensuring that outputs of risk assessment are included in developing requirements for resources and training. The implementation is incomplete and there are gaps and inconsistencies.	Outputs from risk assessments are consistently and systematically used as inputs to develop resources, training and competency requirements. Examples and evidence is available.	The organisation's process(es) surpass the standard required to comply with requirements set out in a recognised standard. The assessor is advised to note in the Evidence section why this is the case and the evidence seen.
82	Legal and other requirements	What procedure does the organisation have to identify and provide access to its legal, regulatory, statutory and other asset management requirements, and how is requirements incorporated into the asset management system?	The organisation has not considered the need to identify its legal, regulatory, statutory and other asset management requirements.	The organisation identifies some its legal, regulatory, statutory and other asset management requirements, but this is done in an ad-hoc manner in the absence of a procedure.	The organisation has procedure(s) to identify its legal, regulatory, statutory and other asset management requirements, but the information is not kept up to date, inadequate or inconsistently managed.	Evidence exists to demonstrate that the organisation's legal, regulatory, statutory and other asset management requirements are identified and kept up to date. Systematic mechanisms for identifying relevant legal and statutory requirements.	The organisation's process(es) surpass the standard required to comply with requirements set out in a recognised standard. The assessor is advised to note in the Evidence section why this is the case and the evidence seen.

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SCHEDULE 13: REPORT ON ASSET MANAGEMENT MATURITY (cont)

Question No.	Function	Question	Score	Evidence—Summary	Why	Who	Record/documented Information
88	Life Cycle Activities	How does the organisation establish implement and maintain process(es) for the implementation of its asset management plan(s) and control of activities across the creation, acquisition or enhancement of assets. This includes design, modification, procurement, construction and commissioning activities?	2.5	Electra has Standards for design and construction of works to minimise non-conformance. A wide range of operating policies ensure compliant operation.Electra's standards closely follow the Powerco standards to help lower costs for suppliers, contractors, training and our engineering . These standards are currently being reviewed and updated.	Life cycle activities are about the implementation of asset management plan(s) i.e. they are the "doing" phase. They need to be done effectively and well in order for asset management to have any practical meaning. As a consequence, widely used standards (eg, PAS 55 s 4.5.1) require organisations to have in place appropriate process(es) and procedure(s) for the implementation of asset management plan(s) and control of lifecycle activities. This question explores those aspects relevant to asset creation.	Asset managers, design staff, construction staff and project managers from other impacted areas of the business, e.g. Procurement	Documented process(es) and procedure(s) which are relevant to demonstrating the effective management and control of life cycle activities during asset creation, acquisition, enhancement including design, modification, procurement, construction and commissioning.
91	Life Cycle Activities	How does the organisation ensure that process(es) and/or procedure(s) for the implementation of asset management plan(s) and control of activities during maintenance (and inspection) of assets are sufficient to ensure activities are carried out under specified conditions, are consistent with asset management strategy and control cost, risk and performance?	2.5	Electra has some inspection, testing, maintenance standards. These are presently being reviewed and revised as required, with any identified gaps to be addressed. The inspection and testing standards are being aligned to the requirements for CBARMM.	Having documented process(es) which ensure the asset management plan(s) are implemented in accordance with any specified conditions, in a manner consistent with the asset management policy, strategy and objectives and in such a way that cost, risk and asset system performance are appropriately controlled is critical. They are an essential part of turning intention into action (eg, as required by PAS 55 s 4.5.1).	Asset managers, operations managers, maintenance managers and project managers from other impacted areas of the business	Documented procedure for review. Documented procedure for audit of process delivery. Records of previous audits, improvement actions and documented confirmation that actions have been carried out.
95	Performance and condition monitoring	How does the organisation measure the performance and condition of its assets?	2.7	Condition is measured by the condition and testing standards (mentioned in Q91) . these are summarised in the fleet plans (AMP Section 12.8 to 12.18). The operational performance of the assets is measured via the control room and the Milsoft OMS. We have made ongoing improvements to our performance analysis (Section 4) and have commenced detailed condition assessment of conductors (via lab testing of removed conductor), hence the improvement in score this year.	Widely used AM standards require that organisations establish implement and maintain procedure(s) to monitor and measure the performance and/or condition of assets and asset systems. They further set out requirements in some detail for reactive and proactive monitoring, and leading/lagging performance indicators together with the monitoring or results to provide input to corrective actions and continual improvement. There is an expectation that performance and condition monitoring will provide input to improving asset management strategy, objectives and plan(s).	A broad cross-section of the people involved in the organisation's asset-related activities from data input to decision-makers, i.e. an end-to end assessment. This should include contactors and other relevant third parties as appropriate.	Functional policy and/or strategy documents for performance or condition monitoring and measurement. The organisation's performance monitoring frameworks, balanced scorecards etc. Evidence of the reviews of any appropriate performance indicators and the action lists resulting from these reviews. Reports and trend analysis using performance and condition information. Evidence of the use of performance and condition information shaping improvements and supporting asset management strategy, objectives and plan(s).
99	Investigation of asset-related failures, incidents and nonconformities	How does the organisation ensure responsibility and the authority for the handling, investigation and mitigation of asset-related failures, incidents and emergency situations and non conformances is clear, unambiguous, understood and communicated?	2.5	There is a process for Investigation Of Network Incidents. A minor and major fault (i.e. ICAM) process is being developed.	Widely used AM standards require that the organisation establishes implements and maintains process(es) for the handling and investigation of failures incidents and non-conformities for assets and sets down a number of expectations. Specifically this question examines the requirement to define clearly responsibilities and authorities for these activities, and communicate these unambiguously to relevant people including external stakeholders if appropriate.	The organisation's safety and environment management team. The team with overall responsibility for the management of the assets. People who have appointed roles within the asset-related investigation procedure, from those who carry out the investigations to senior management who review the recommendations. Operational controllers responsible for managing the asset base under fault conditions and maintaining services to consumers. Contractors and other third parties as appropriate.	Process(es) and procedure(s) for the handling, investigation and mitigation of asset-related failures, incidents and emergency situations and non conformances. Documentation of assigned responsibilities and authority to employees. Job Descriptions, Audit reports. Common communication systems i.e. all Job Descriptions on Internet etc.

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SCHEDULE 13: REPORT ON ASSET MANAGEMENT MATURITY (cont)

Question No.	Function	Question	Maturity Level 0	Maturity Level 1	Maturity Level 2	Maturity Level 3	Maturity Level 4
88	Life Cycle Activities	How does the organisation establish implement and maintain process(es) for the implementation of its asset management plan(s) and control of activities across the creation, acquisition or enhancement of assets. This includes design, modification, procurement, construction and commissioning activities?	The organisation does not have process(es) in place to manage and control the implementation of asset management plan(s) during activities related to asset creation including design, modification, procurement, construction and commissioning.	The organisation is aware of the need to have process(es) and procedure(s) in place to manage and control the implementation of asset management plan(s) during activities related to asset creation including design, modification, procurement, construction and commissioning but currently do not have these in place (note: procedure(s) may exist but they are inconsistent/incomplete).	The organisation is in the process of putting in place process(es) and procedure(s) to manage and control the implementation of asset management plan(s) during activities related to asset creation including design, modification, procurement, construction and commissioning. Gaps and inconsistencies are being addressed.	Effective process(es) and procedure(s) are in place to manage and control the implementation of asset management plan(s) during activities related to asset creation including design, modification, procurement, construction and commissioning.	The organisation's process(es) surpass the standard required to comply with requirements set out in a recognised standard. The assessor is advised to note in the Evidence section why this is the case and the evidence seen.
91	Life Cycle Activities	How does the organisation ensure that process(es) and/or procedure(s) for the implementation of asset management plan(s) and control of activities during maintenance (and inspection) of assets are sufficient to ensure activities are carried out under specified conditions, are consistent with asset management strategy and control cost, risk and performance?	The organisation does not have process(es)/procedure(s) in place to control or manage the implementation of asset management plan(s) during this life cycle phase.	The organisation is aware of the need to have process(es) and procedure(s) in place to manage and control the implementation of asset management plan(s) during this life cycle phase but currently do not have these in place and/or there is no mechanism for confirming they are effective and where needed modifying them.	The organisation is in the process of putting in place process(es) and procedure(s) to manage and control the implementation of asset management plan(s) during this life cycle phase. They include a process for confirming the process(es)/procedure(s) are effective and if necessary carrying out modifications.	The organisation has in place process(es) and procedure(s) to manage and control the implementation of asset management plan(s) during this life cycle phase. They include a process, which is itself regularly reviewed to ensure it is effective, for confirming the process(es)/ procedure(s) are effective and if necessary carrying out modifications.	The organisation's process(es) surpass the standard required to comply with requirements set out in a recognised standard. The assessor is advised to note in the Evidence section why this is the case and the evidence seen.
95	Performance and condition monitoring	How does the organisation measure the performance and condition of its assets?	The organisation has not considered how to monitor the performance and condition of its assets.	The organisation recognises the need for monitoring asset performance but has not developed a coherent approach. Measures are incomplete, predominantly reactive and lagging. There is no linkage to asset management objectives.	The organisation is developing coherent asset performance monitoring linked to asset management objectives. Reactive and proactive measures are in place. Use is being made of leading indicators and analysis. Gaps and inconsistencies remain.	Consistent asset performance monitoring linked to asset management objectives is in place and universally used including reactive and proactive measures. Data quality management and review process are appropriate. Evidence of leading indicators and analysis.	The organisation's process(es) surpass the standard required to comply with requirements set out in a recognised standard. The assessor is advised to note in the Evidence section why this is the case and the evidence seen.
99	Investigation of asset-related failures, incidents and nonconformities	How does the organisation ensure responsibility and the authority for the handling, investigation and mitigation of asset-related failures, incidents and emergency situations and non conformances is clear, unambiguous, understood and communicated?	The organisation has not considered the need to define the appropriate responsibilities and the authorities.	The organisation understands the requirements and is in the process of determining how to define them.	The organisation are in the process of defining the responsibilities and authorities with evidence. Alternatively there are some gaps or inconsistencies in the identified responsibilities/authorities.	The organisation have defined the appropriate responsibilities and authorities and evidence is available to show that these are applied across the business and kept up to date.	The organisation's process(es) surpass the standard required to comply with requirements set out in a recognised standard. The assessor is advised to note in the Evidence section why this is the case and the evidence seen.

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SCHEDULE 13: REPORT ON ASSET MANAGEMENT MATURITY (cont)

Question No.	Function	Question	Score	Evidence—Summary	Why	Who	Record/documented Information
105	Audit	What has the organisation done to establish procedure(s) for the audit of its asset management system (process(es))?	3	Process auditing is currently limited to safety. The PSMS internal Audit and the TELARC Revalidation have been inspected.	This question seeks to explore what the organisation has done to comply with the standard practice AM audit requirements (eg, the associated requirements of PAS 55 s 4.6.4 and its linkages to s 4.7).	The management team responsible for its asset management procedure(s). The team with overall responsibility for the management of the assets. Audit teams, together with key staff responsible for asset management. For example, Asset Management Director, Engineering Director. People with responsibility for carrying out risk assessments	The organisation's asset-related audit procedure(s). The organisation's methodology(s) by which it determined the scope and frequency of the audits and the criteria by which it identified the appropriate audit personnel. Audit schedules, reports etc. Evidence of the procedure(s) by which the audit results are presented, together with any subsequent communications. The risk assessment schedule or risk registers.
109	Corrective & Preventative action	How does the organisation instigate appropriate corrective and/or preventive actions to eliminate or prevent the causes of identified poor performance and non conformance?	3	Corrective and preventative actions are initiated via the Control Room in relation to network faults. Corrective and preventative actions are initiated via Network Engineers where they are identified during routine inspection and testing. Typical corrective and preventative maintenance is described in the fleet plans (AMP Section 12.8 to 12.18)	Having investigated asset related failures, incidents and non-conformances, and taken action to mitigate their consequences, an organisation is required to implement preventative and corrective actions to address root causes. Incident and failure investigations are only useful if appropriate actions are taken as a result to assess changes to a businesses risk profile and ensure that appropriate arrangements are in place should a recurrence of the incident happen. Widely used AM standards also require that necessary changes arising from preventive or corrective action are made to the asset management system.	The management team responsible for its asset management procedure(s). The team with overall responsibility for the management of the assets. Audit and incident investigation teams. Staff responsible for planning and managing corrective and preventive actions.	Analysis records, meeting notes and minutes, modification records. Asset management plan(s), investigation reports, audit reports, improvement programmes and projects. Recorded changes to asset management procedure(s) and process(es). Condition and performance reviews. Maintenance reviews
113	Continual Improvement	How does the organisation achieve continual improvement in the optimal combination of costs, asset related risks and the performance and condition of assets and asset systems across the whole life cycle?	2.8	We have introduced the energy trilemma balance into the 2025 AMP as the principle basis to measure the balance between cost and performance, namely security/reliability and sustainability (AMP Section 7). The balance between lifecycle risks, asset condition and costs is addressed by the fleet strategies in the fleet plans (AMP Section 12.8 to 12.18).	Widely used AM standards have requirements to establish, implement and maintain process(es)/procedure(s) for identifying, assessing, prioritising and implementing actions to achieve continual improvement. Specifically there is a requirement to demonstrate continual improvement in optimisation of cost risk and performance/condition of assets across the life cycle. This question explores an organisation's capabilities in this area—looking for systematic improvement mechanisms rather that reviews and audit (which are separately examined).	The top management of the organisation. The manager/team responsible for managing the organisation's asset management system, including its continual improvement. Managers responsible for policy development and implementation.	Records showing systematic exploration of improvement. Evidence of new techniques being explored and implemented. Changes in procedure(s) and process(es) reflecting improved use of optimisation tools/techniques and available information. Evidence of working parties and research.
115	Continual Improvement	How does the organisation seek and acquire knowledge about new asset management related technology and practices, and evaluate their potential benefit to the organisation?	2.7	Electra current obtains data via the EEA and manufacturers. Attendance of Electra staff at industry events has been observed. Comparative analysis work was examined.	One important aspect of continual improvement is where an organisation looks beyond its existing boundaries and knowledge base to look at what 'new things are on the market'. These new things can include equipment, process(es), tools, etc. An organisation which does this (eg, by the PAS 55 s 4.6 standards) will be able to demonstrate that it continually seeks to expand its knowledge of all things affecting its asset management approach and capabilities. The organisation will be able to demonstrate that it identifies any such opportunities to improve, evaluates them for suitability to its own organisation and implements them as appropriate. This question explores an organisation's approach to this activity.	The top management of the organisation. The manager/team responsible for managing the organisation's asset management system, including its continual improvement. People who monitor the various items that require monitoring for 'change'. People that implement changes to the organisation's policy, strategy, etc. People within an organisation with responsibility for investigating, evaluating, recommending and implementing new tools and techniques, etc.	Research and development projects and records, benchmarking and participation knowledge exchange professional forums. Evidence of correspondence relating to knowledge acquisition. Examples of change implementation and evaluation of new tools, and techniques linked to asset management strategy and objectives.

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SCHEDULE 13: REPORT ON ASSET MANAGEMENT MATURITY (cont)

Question No.	Function	Question	Maturity Level 0	Maturity Level 1	Maturity Level 2	Maturity Level 3	Maturity Level 4
105	Audit	What has the organisation done to establish procedure(s) for the audit of its asset management system (process(es))?	The organisation has not recognised the need to establish procedure(s) for the audit of its asset management system.	The organisation understands the need for audit procedure(s) and is determining the appropriate scope, frequency and methodology(s).	The organisation is establishing its audit procedure(s) but they do not yet cover all the appropriate asset-related activities.	The organisation can demonstrate that its audit procedure(s) cover all the appropriate asset-related activities and the associated reporting of audit results. Audits are to an appropriate level of detail and consistently managed.	The organisation's process(es) surpass the standard required to comply with requirements set out in a recognised standard. The assessor is advised to note in the Evidence section why this is the case and the evidence seen.
109	Corrective & Preventative action	How does the organisation instigate appropriate corrective and/or preventive actions to eliminate or prevent the causes of identified poor performance and non conformance?	The organisation does not recognise the need to have systematic approaches to instigating corrective or preventive actions.	The organisation recognises the need to have systematic approaches to instigating corrective or preventive actions. There is ad-hoc implementation for corrective actions to address failures of assets but not the asset management system.	The need is recognized for systematic instigation of preventive and corrective actions to address root causes of non compliance or incidents identified by investigations, compliance evaluation or audit. It is only partially or inconsistently in place.	Mechanisms are consistently in place and effective for the systematic instigation of preventive and corrective actions to address root causes of non compliance or incidents identified by investigations, compliance evaluation or audit.	The organisation's process(es) surpass the standard required to comply with requirements set out in a recognised standard. The assessor is advised to note in the Evidence section why this is the case and the evidence seen.
113	Continual Improvement	How does the organisation achieve continual improvement in the optimal combination of costs, asset related risks and the performance and condition of assets and asset systems across the whole life cycle?	The organisation does not consider continual improvement of these factors to be a requirement, or has not considered the issue.	A Continual Improvement ethos is recognised as beneficial, however it has just been started, and or covers partially the asset drivers.	Continuous improvement process(es) are set out and include consideration of cost risk, performance and condition for assets managed across the whole life cycle but it is not yet being systematically applied.	There is evidence to show that continuous improvement process(es) which include consideration of cost risk, performance and condition for assets managed across the whole life cycle are being systematically applied.	The organisation's process(es) surpass the standard required to comply with requirements set out in a recognised standard. The assessor is advised to note in the Evidence section why this is the case and the evidence seen.
115	Continual Improvement	How does the organisation seek and acquire knowledge about new asset management related technology and practices, and evaluate their potential benefit to the organisation?	The organisation makes no attempt to seek knowledge about new asset management related technology or practices.	The organisation is inward looking, however it recognises that asset management is not sector specific and other sectors have developed good practice and new ideas that could apply. Ad-hoc approach.	The organisation has initiated asset management communication within sector to share and, or identify 'new' to sector asset management practices and seeks to evaluate them.	The organisation actively engages internally and externally with other asset management practitioners, professional bodies and relevant conferences. Actively investigates and evaluates new practices and evolves its asset management activities using appropriate developments.	The organisation's process(es) surpass the standard required to comply with requirements set out in a recognised standard. The assessor is advised to note in the Evidence section why this is the case and the evidence seen.

Appendix 11: Mandatory Explanatory Notes on Forecast Information (Schedule 14A)

Electricity Distribution Information Disclosure Determination 2012

Schedule 14a Mandatory Explanatory Notes on Forecast Information

1. This Schedule requires EDBs to provide explanatory notes to reports prepared in accordance with clause 2.6.6.

This Schedule is mandatory—EDBs must provide the explanatory comment specified below, in accordance with clause 2.7.2. This information is not part of the audited disclosure information, and so is not subject to the assurance requirements specified in section 2.8.

Commentary on difference between nominal and constant price capital expenditure forecasts (Schedule 11a)

2. In the box below, comment on the difference between nominal and constant price capital expenditure for the current disclosure year and 10 year planning period, as disclosed in Schedule 11a.

Box 1: Commentary on difference between nominal and constant price capital expenditure forecasts
For FY2027, we applied a composite CPI/PPI escalation of 2026 real$ (constant prices) to FY2027 Nominal of 2.28%. From FY2028 onwards, we have applied forecast CPI to escalate the real$ (constant price) forecasts to nominal. Our forecasts reflect Westpac's forecasts (as at April 2025): FY2028 at 2.01%, FY2029 at 2.19%, and FY2030 at 2.22%. From FY2031, we escalated real$ (constant prices) to Nominal$ at 2.0% (the middle of the Reserve Bank's inflation target range).

Commentary on difference between nominal and constant price operational expenditure forecasts (Schedule 11b)

1. In the box below, comment on the difference between nominal and constant price operational expenditure for the current disclosure year and 10 year planning period, as disclosed in Schedule 11b.

Box 2: Commentary on difference between nominal and constant price operational expenditure forecasts
For FY2027, we applied a composite CPI/PPI escalation of 2026 real$ (constant prices) to FY2027 Nominal of 2.28%. From FY2028 onwards, we have applied forecast CPI to escalate the real$ (constant price) forecasts to nominal. Our forecasts reflect Westpac's forecasts (as at April 2025): FY2028 at 2.01%, FY2029 at 2.19%, and FY2030 at 2.22%. From FY2031, we escalated real$ (constant prices) to Nominal$ at 2.0% (the middle of the Reserve Bank's inflation target range).

Appendix 12: Director Certification

We, Murray Ian Bain and James Albert Carmichael, being directors of Electra Limited certify that, having made all reasonable enquiry, to the best of our knowledge:

(a) the following attached information of Electra Limited prepared for the purposes of clauses 2.6.1, 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 Electra Limited's corporate vision and strategy and are documented in retained records.

Signed

Murray Ian Bain, Director

James Albert Carmichael, Director

26 March 2026

Report Ends.