2020-2030 Asset Management Plan

1 April 2020

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EXECUTIVE SUMMARY

I am pleased to present Electra's AMP for March 2020, which sets out the asset management strategies and investment plans for the next 10 years. The starting point for my remarks is the great progress that Electra has made towards its strategic goals, especially the core values of safety and the strategic pillars of customer-focus and operation excellence. I then want to introduce the more visible alignment of Electra's asset management strategies and programmes with Electra's group strategy and business plans and conclude by commenting on the key work streams going forward.

Electra's progress to date

Key achievements during previous years include:

- Focus on customers

Electra is continuing to give attention to improving customer experience, extending beyond its historical high-level focus on the core price-reliability trade-off through to broader and more frequent interactions such as real-time communication of network status and reliability, more flexible pricing options, consultation on price and reliability possibilities, technical advice, assistance with lines owned by customers and progressing with the implementation of a customer relationship management (CRM) system to better track the resolution of customer enquiries. The on-going development and adoption of the Milsoft advanced distribution management system (ADMS) also remains a key aspect of this initiative.

- Advancement in progress towards a target of zero harm (zero LTI's).

Electra is committed to ensuring the safety of its customers, its staff and contractors and the public at large, as noted in the 2019 Annual Report. Key asset management and system implications of this commitment to safety include continuing replacement of components such as pitch-filled metallic cable terminations, metal link pillar boxes, deck-mounted transformers and oil-filled switches, and the implementation of Vault as an H&S incident recording and analysis platform.

- Maintaining Electra's current mix of high reliability and low costs

Electra has undertaken a comprehensive analysis based on the last 6 years disclosure data[1] performed to better understand its costs and performance against a peer group of eight lines businesses based on network characteristics, network density and customer size and these networks include Alpine, Aurora, Counties Power, Horizon, Network Tasman, The Lines Co and Top Energy. This analysis concludes the following:

Measure	Position within peer group	Position within overall industry
Revenue per customer	Best (lowest)	Best (lowest)
OPEX per customer	Best (lowest)	Within lowest quartile
CAPEX per customer	Second lowest	Within lowest quartile
Unplanned interruptions (Class C SAIDI)	Best (lowest)	Within lowest quartile
Overall reliability and cost	Highest reliability and lowest cost per customer	

Electra's asset strategy and works programmes will continue to focus on maintaining this high reliability -low cost position within the peer group.

[1] Sources: Commerce Commission Information Disclosure data for financial years 2014-2018; 2019 data is extracted from Information Disclosure schedules from the relevant EDB's website.

- Undertaking a range of tactical engineering and operational programmes to improve the core business capabilities.

This has included targeted reliability improvements on the Northern 33kV network, further integration of remote devices and sensors to the advanced distribution management system (ADMS) to provide improved visibility of the LV network, and a network-wide protection review and standardisation programme.

In collaboration with Charge Net NZ, the Kapiti Coast and Horowhenua District Councils, and with support from EECA, Electra will have installed nine additional electric vehicle (EV) fast chargers across our region. This achievement not only assists the adoption of clean fuelled vehicles, but is critical in ensuring the EV fast-charging network is able to meet the target of a fast charger every 75km. Additionally Electra is gaining practical experience in the monitoring and management of low speed EV charging technology by deploying Smart Charging infrastructure to its offices and depots. Electra has also installed an 8kWh photovoltaic battery system at its Head Office to better manage and understand the impact of PV on its network and gain insight into how a trans active grid of the future might look like.

- Recognition that emerging technologies present both challenges and opportunities to our business.

Electra's current business model is based on a mix of fixed and variable revenue streams that recover costs that are almost totally fixed. The location, magnitude and timing of the electricity demand and injections from emerging technologies such as LED street lighting, electric vehicles, solar panels and batteries could significantly alter the resulting mix of revenues and costs. Electra is examining these developments closely and is working on strategies to pre-empt the change that includes development of cost-reflective pricing covered in our pricing methodology.

More visible alignment to Electra's group strategy

Electra's asset management strategies, tactical programmes and work plans have always been aligned to the wider strategic direction, we have paid attention to make that alignment more visible by setting out the linkages between the group strategy and the asset management activities at the start of Section 1 of this year's AMP. This is also consistent with the line-of-sight principle of ISO 55001.

Key work streams going forward

Section 1.1 of this AMP sets out the key strategies that contribute to three of the five pillars of Electra's group strategy (providing a focus on customer needs, excellence in operations and development of new technologies for core business) by facilitating the transition to a transactive network and supporting that transition with the following asset management practice improvements:

- Enhancing evidence-based investment decisions with risk and criticality dimensions to quantify and prioritise investments.
- Improving cost, risk and performance, with a view to reduce SAIDI and OPEX.
- Enhancing and supporting sustainability, climate change and renewables initiatives.

These will in turn result in more detailed year-by-year actions included in the annual business plan and work programmes.

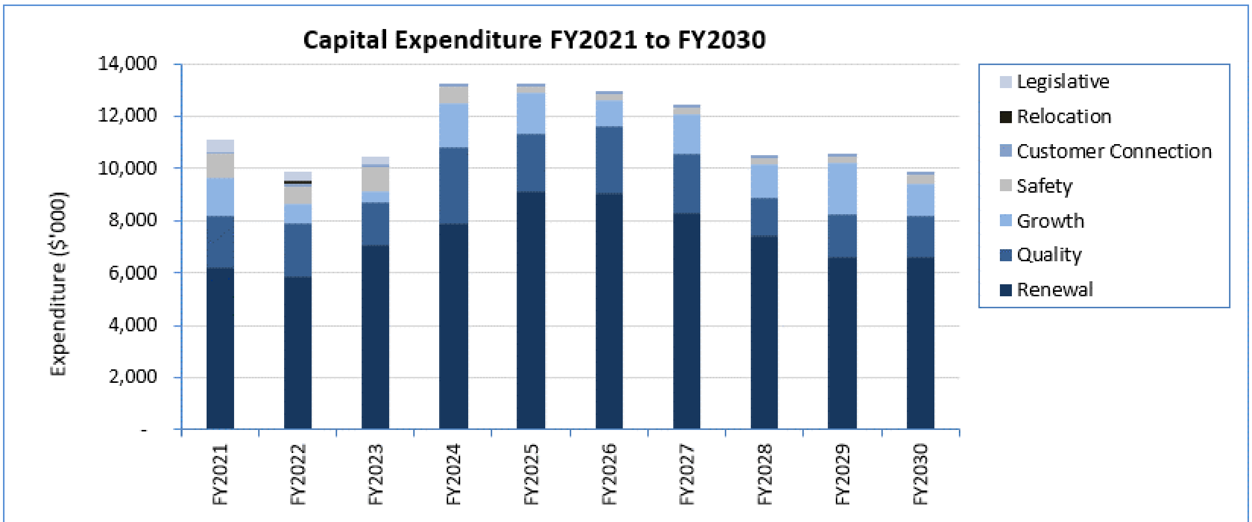
Material projects

In deriving the programmes for network development, Electra optimises expenditure to consider demand growth, existing network conditions and capacity, customer input and service levels for reliability, quality and safety. The significant programmes for the planning period include the following projects:

Description	Main driver	Proposed timing
Paraparaumu West Zone Substation: New 11kV feeder to transfer load off feeder 405	Growth	FY2021
Electrical Protection Upgrade	Quality of Supply	FY2021-FY2023 and FY2028-FY2030
Replacement of 12 km of 35mm^2 copper conductor along Foxton-Shannon Road	Renewal	FY2022-FY2025
Levin East Zone Power Transformer Replacement	Renewal	FY2023-FY2028
Otaki Zone Substation: New 11kV feeder to transfer load off feeder L351	Growth	FY2024
Mangahao to Levin East 33kV Sub transmission Line Upgrade to a double circuit	Renewal	FY2024-FY2027
Rebuild Raumati Substation	Renewal	FY2024-FY2026
Foxton to Levin West 33kV Sub transmission Line Upgrade	Growth	FY2025-FY2027
Rural Substation at Waikawa Beach Road	Growth	FY2028-FY2029
New Zone Substation for load growth at Foxton and Shannon: Conceptual Design Stage	Growth	FY2029-FY2030
Upgrade of ERP -Business Central	ICT	FY2021
Acquisition of an Asset Management System	ICT	FY2021
Deployment of IoT sensors to monitor the electricity network	Quality of Supply	FY2021-FY2030

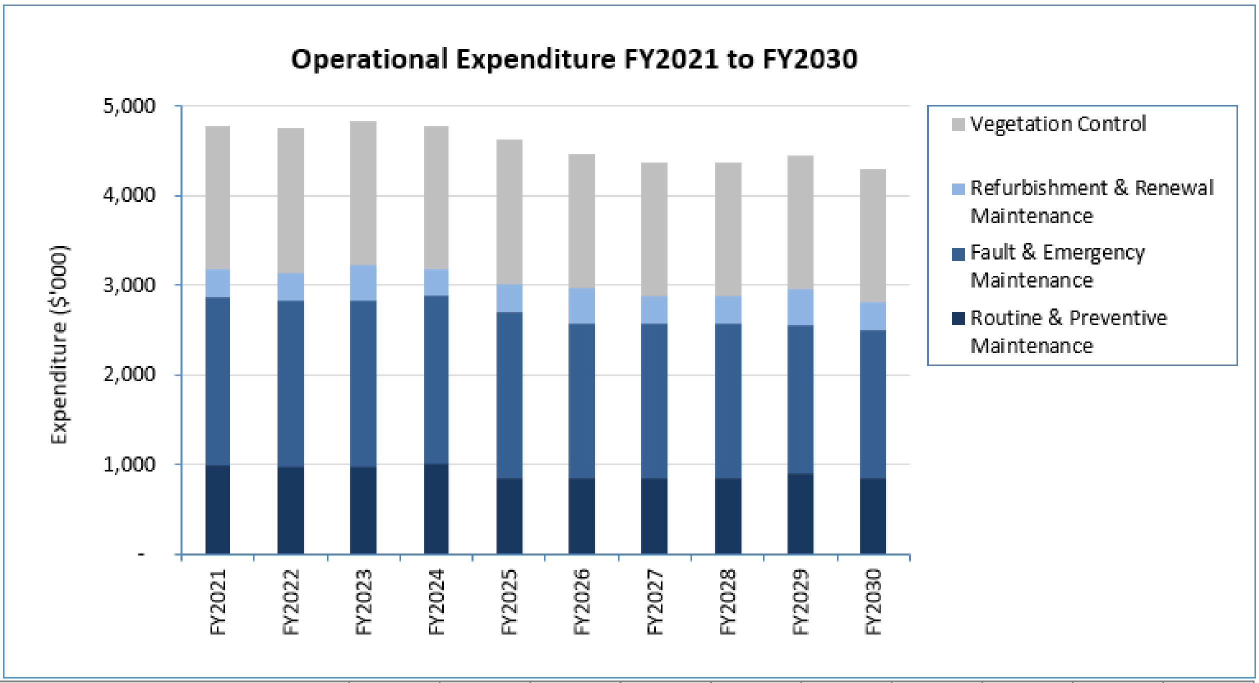
Forecast expenditure

Projected capital expenditure drivers over the next 10 years are expected to be 11.1% of total for growth, 23.7% of total for reliability, safety and environment and 65.2% of total for renewal and replacement work. Capital costs (depicted in Figure A) are expected to average $11.4M per year over the next 10 years while operational costs (Figure B) are expected to average $4.6M per year over the same period. Electra has the flexibility to adjust this investment if growth accelerates beyond our expectations. The expenditure forecasts are based on 2020 constant New Zealand dollars.



Capital Expenditure (Current $'000)	FY2021	FY2022	FY2023	FY2024	FY2025	FY2026	FY2027	FY2028	FY2029	FY2030
Renewal	6,217	5,889	7,109	7,931	9,116	9,090	8,317	7,459	6,634	6,614
Quality	2,002	2,006	1,611	2,879	2,231	2,534	2,264	1,420	1,620	1,592
Growth	1,450	784	424	1,710	1,550	980	1,500	1,300	1,961	1,225
Safety	895	635	920	615	250	250	250	250	250	340
Customer Connection	95	95	95	95	95	95	95	95	95	95
Relocation	-	102	-	-	-	-	-	-	-	-
Legislative	450	375	300	-	-	-	-	-	-	-
Total (CAPEX) :	11,109	9,886	10,459	13,229	13,242	12,948	12,425	10,524	10,560	9,866

Figure A: Projected Capital Expenditure from FY2020 to FY2030



Operations & Maintenance (Current $'000)	FY2021	FY2022	FY2023	FY2024	FY2025	FY2026	FY2027	FY2028	FY2029	FY2030
Routine & Preventive Maintenance	999	969	970	1,019	849	850	849	849	900	849
Fault & Emergency Maintenance	1,859	1,859	1,859	1,859	1,859	1,728	1,728	1,728	1,653	1,653
Refurbishment & Renewal Maintenanc	312	312	397	297	312	397	312	312	397	312
Vegetation Control	1,608	1,608	1,608	1,608	1,608	1,488	1,488	1,488	1,488	1,488
Total (OPEX) :	**4,778**	**4,748**	**4,834**	**4,783**	**4,628**	**4,462**	**4,377**	**4,377**	**4,437**	**4,302**

Figure B: Projected OPEX from FY2020 to FY2030

Electra's AMP is an important and evolving document for which your feedback is welcome. Our General Manager – Lines Business and I would be happy to hear from you.

Kind regards

Neil Simmonds

Chief Executive

1 Introduction

Purpose of the Asset Management Plan

This Asset Management Plan (AMP) documents Electra's strategy to manage our electricity distribution assets. It is structured to meet regulatory compliance of the Electricity Distribution Information Disclosure Determination 2012. These requirements include target service levels, asset details, lifecycle management plans, network development, risk management, performance measurement, evaluation and improvement initiatives.

This AMP documents Electra's governance and management framework, applying Electra's asset management thinking, systems and processes to develop and deliver work programmes aimed at achieving intended customer and community experience of supply reliability, pricing and safety.

1.1 Company strategy

This AMP is supported by key strategic documents of Electra namely the Statement of Corporate Intent, company strategic plan and pricing methodology. These documents are further explained in the following sub-sections. Section 1.7 contains the details of other documents and the relationship between these key documents.

1.1.1 Mission and vision

Electra's Statement of Corporate Intent (SCI) identifies the Group's vision and mission as "to enhance the Horowhenua/Kapiti Coast community and its regional development through the provision of 21st Century infrastructure and new technologies".

More specifically, this AMP sets out how Electra will build, operate and maintain infrastructure to maximise long-term value for consumers and owners through competitive prices and quality services with safe and efficient operations.

1.1.2 Key strategies

The SCI identifies five focus areas for the company as depicted in Figure 1-1. These key business objectives and initiatives are:

- **A focus on customers**: to establish world-class communication with customers and meet the needs and wants of customers and build strong community ties with customers and businesses to support regional growth
- **Excellence in operation**: to improve system reliability performance and operational efficiency by managing cost and procurement processes while implementing greater automation in the operation of the business
- **Develop our people and keep safe**: improve safety and environment for public, staff and contractors and create a culture of organisational learning
- **Prepare for change**: to improve knowledge and information management in rapidly changing industries
- **Develop the new and grow**: to grow our existing businesses and continue to scan for complementary and infrastructure opportunities.

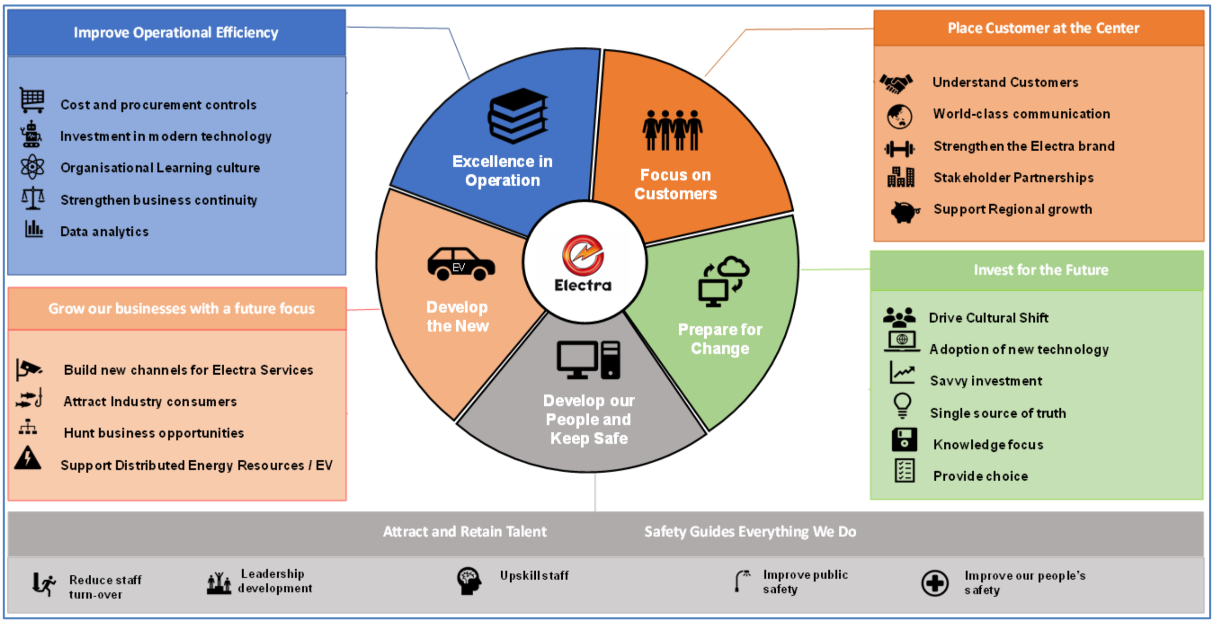


Figure 1-1: Electra Group strategic model for FY2019 to FY2023

1.1.3 Values

Electra's corporate values are:

- **Safety:** safety guides everything we do - we will stop work if it is unsafe
- **Respect:** we all treat our customers and colleagues as they would want to be treated
- **Professional:** our people have the knowledge, skills and ethics to perform their roles at a consistently high standard
- **Accountable:** we account for and accept responsibility for our activities
- **Integrity:** we always do the right thing in all circumstances, no matter what the consequences will be.

1.1.4 Pricing methodology

Electra's pricing methodology allows the company to safely and reliably build, operate and maintain an electricity network to serve electricity customers in the Horowhenua and Kapiti Coast region. It complies with regulatory requirements and promotes cost reflective distribution price options and transparency to customers. The pricing principles are depicted in Figure 1-2 and further information and these principles are reflected in the investment of suitable infrastructure and asset management reflected in the AMP. Details of the pricing methodology are available on Electra's website.

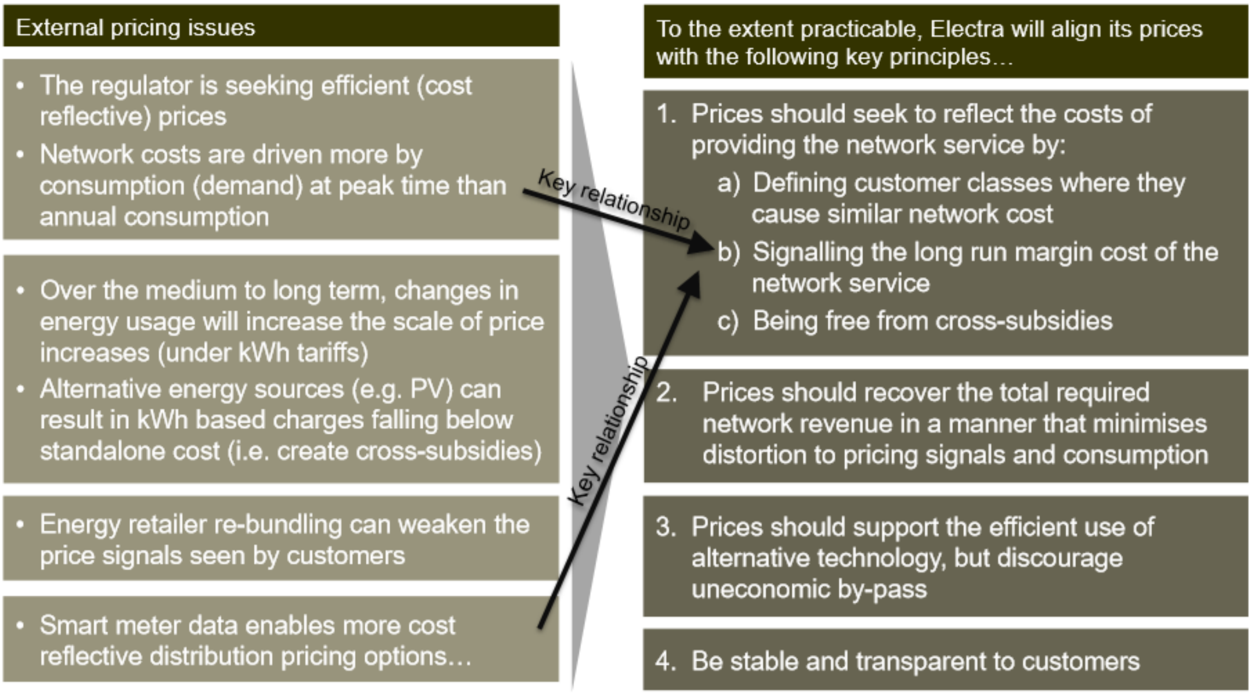


Figure 1-2: Electra's Pricing Principles

1.2 Asset management strategy

1.2.1 Asset management policy

Asset management is a broad strategic framework encompassing many disciplines and involves the entire organisation. Our asset management policies have been developed to guide the lines business on the application of sound technical, social and economic principles that considers present and future needs of users of, and the service from our network assets. To achieve asset management outcomes, we will:

- Maintain and manage our network assets at defined levels to enable the safe, efficient and effective delivery of electricity to our customers
- Monitor standards and service levels to ensure that they meet/support customer and Board goals and objectives
- Develop and maintain asset inventories of our entire infrastructure
- Establish infrastructure replacement strategies using full life cycle costing principles
- Plan financially for the appropriate level of maintenance and replacement of assets to deliver service levels and extend the useful life of assets
- Plan for and provide stable long-term pricing/funding to replace and/or renew and/or decommission infrastructure assets
- Report to customers and other stakeholders on the status and performance of work related to the implementation of this asset management policy.

1.2.2 Asset management strategy

Our asset management strategy sets the direction for managing our electricity network assets. It has been developed to achieve the following aims:

- Describe how the asset management policy is used to develop asset management objectives

- Support the delivery of best value services to our customers
- Help to achieve Electra's core function as a lines business by safely and reliably delivering electricity to our customers
- Drive our continuous improvement programme to ensure we continue to be an efficient, forward-thinking network business
- Ensure our asset management practices deliver on the overall corporate objectives.

Five asset management objectives sit at the heart of our asset management strategy in line with our group's objectives in Section 1.1.2 namely:

- Focus on customers
- Excellence in operation
- Develop our people and keep everyone safe
- Embrace change
- Develop the new and grow.

They reflect our lifecycle asset management approach and consider all aspects of asset decision-making and activities from inception to decommissioning.

Key asset management strategies in line with the objectives are tabulated in Figure 1-3.

Strategy objectives		Strategy initiatives	
1	**Focus on customer**: placing the customer in the centre of all activities, processes and design	1.1	Undertake surveys in different market segments to gain insights to develop customer service strategy
2	**Excellence in operations**: delivery of quality service using well-utilised, modern systems, and be prepared for major events	2.1	Greater investment in automated switching on the electricity network
		2.2	Conformance with ISO 55000 for electricity network management to achieve improved cost control, reliability improvement, greater resilience for BCMP, HILP and major events
3	**Develop our people and keep everybody safe**: retention of talent with safety guiding everything we do	3.1	Creation of an earthing inspection and advisory programme for network and customer assets to reduce risk of earth related faults via greater identification and rectification works
		3.2	Focus on proactive vegetation management with increased trimming and education of customers
		3.3	Improving safety performance by supporting zero target of lost time injuries, documentation of safety procedures and reporting on industry benchmarking on safety performances
4	**Embrace change**: investment in people, systems and technologies to ready us for changes on the horizon	4.1	Increase the deployment of automated, remote switching and sensors with the investment in network technologies using IoT for faster restoration
		4.2	Adoption of asset criticality-based assessment practices in asset investment decision making
		4.3	Continued creation of a common information model for electricity network on phasing and connectivity
		4.4	Lead the development of relationships, systems and tariffs to provide improved customer choices
5	**Develop the new and grow**: growth of our existing businesses and continue to scan for opportunities	5.1	Building relationships with DER/EV sector and demonstrate support by attending meetings and implementing at least one project

Figure 1-3: Alignment of Asset Management Strategies to Group objectives

Key features of Electra's asset strategy and delivery include:

- A visible alignment with the SCI and the Group strategic plan
- Visible inclusion of each phase of an asset's lifecycle
- Consideration of reliability, safety and lifecycle costs as an integral part of managing assets lifecycle (safety in design)
- Migration from a simple condition-based approach to a more comprehensive criticality and health (risk) based approach
- Seeking lower cost methods of carrying out required OPEX and CAPEX identified by the AMP.

Electra's key focus areas namely - customers, employees as well as sustainability, climate change and new energy futures are elaborated in the following sections.

1.3 Customers

The AMP is developed to serve current and future customers connected to the network. Customers are in the centre of Electra's decision-making as reflected in the strategic plan where "focus on customer" is the first strategic objective. This commitment is demonstrated through the annual customer survey (Sections 3.7.1 - 3.7.2), consultations with large electricity users and our community engagement through business forums. The investment in our network considers customer reported faults and disruptions to customers such as the reduction of repeated power failures in Section 3.9.7. Affordability is considered in our pricing methodology in Section 1.1.4.

Safety is a key component and Electra strives to ensure that assets and network systems are safe for our customers as well as our contractors.

Our commitment to our customers is further supported by the recent implementation of customer relationship management (CRM) which is used by Call Centre and wider company.

We communicate our AMP to our customers by publishing on our website and in 2020, we have created a pamphlet that will be made readily available at community gatherings and on the website.

1.4 Employees

Electra's employees are the most valuable asset to our business. Their safety, working environment, well-being and job satisfaction are paramount to Electra. All employees contribute to the success of our business.

Electra has a wellness programme, supported by our People and Capability team, with such things as access to EAP (or Employee Assistance Programme) services, health and life insurance as well as guest speakers on topics like mental health, financial and, physical and nutritional wellbeing.

Electra invests in a comprehensive training and development programme to develop our workforce with increased competencies and career pathways. A performance management framework has been established to enable all employees to receive formal feedback on their individual performance and to establish individual development plans. This process involves regular feedback and discussions with their line manager around their performance against key performance indicators and their behaviours which reflect our values.

Electra achieved 6,000 training hours in 2019 and we expect to continue our commitment to training in the following years. In FY2020, team members who work on Electra's Distribution assets have attained 18 National Certificates, with three Line Mechanic trainees and four electricians due to complete their qualifications this year. A structured Leadership Programme is being developed, which includes the commencement of a Leading Hand Development Programme in January 2020.

Changes and updates on the Asset Management Plan as well as technical standards and safety requirements are communicated to employees effectively and regularly. The GM (Lines Business) attends monthly depot meetings to provide Network updates, and to respond to questions, compliments and concerns. Bi-annual EWRB (or Electrical Workers Registration Board) competence training days are held, and the recently established Common Competency Framework is being implemented into our business.

1.5 Sustainability, climate change and renewables

Electra integrates environmental sustainability into planning and delivery activities from three viewpoints; minimising the impact on the environment, improving our resilience to changing environmental conditions and facilitating the adoption of new energy technologies or renewables that support the decarbonising of our regional and the wider New Zealand economies.

Reducing our environmental impact spans the tools and equipment we use, longer life and recycling of consumables, the sustainability of the materials we procure, regularly reviewing risks in our Public Safety Management System, improving operational efficiencies and carefully managing risky materials, particularly oils and SF6 gas.

Over recent years, parts of the network have been impacted by: (a) high rainfall causing previously stable land to slip, and (b) increasing populations of birds resulting in higher incidents of bird strikes. Also, the prevailing north westerly winds and coastal marine environment have contributed to consumption of asset life. As a result, Electra considers current and emerging environmental risks in network planning and eventual designs and asset lifecycle management plans.

New energy futures or renewables present opportunities to decarbonise transport fuels, increase the portion of renewable energy in New Zealand’s electricity system and adopt more efficient energy use and energy exchange. We have been pursuing the implementation of interactive enabling technologies and actively promoting how consumers can optimise their energy use and costs. We are already supporting the connection of renewable energy sources and electricity to be used as a transport fuel and we are preparing the network, systems and customer communications to enable a much wider range of distributed energy resources to exchange and trade surplus renewable energy.

Electra is also proactively trialling photovoltaics and associated storage (Section 4.3.4), as well as electric vehicle charging stations throughout the company and supporting regional initiatives.

1.6 Innovation and initiatives

Systems: As part of our continued growth, Electra has installed new customer-relationship management system (CRM), Advanced Distribution Management System (ADMS) and billing systems. These systems improve the consistency in the delivery of operational processes to improve the quality of our services. Details about these systems are available in Sections 1.12, 8.4.2 and 8.4.3.

Sensors: The details of new technology development and implementation are included in Section 4.3.6 covering IoT, distributed energy resources (DER), electric vehicle supply equipment management (EVSE) and monitoring, foundation linking technologies as well as low voltage status monitoring.

Industry initiatives: Electra chair the CIO Forum of North Island Electricity Lines Businesses as well as the National Risk Forum for Electricity Lines Businesses. We are also a founding member of the IoT working group of the lines businesses in New Zealand. Electra participates in industry working groups organised by the Electricity Authority, Commerce Commission and Electricity Network Association.

1.7 Asset management framework

Electra's asset management framework (shown in Figure 1-4) provides structure and identifies the process in the development of the AMP. It ensures that:

- Objectives, plans and actions are in alignment with our vision, values and corporate goals
- Services are delivered to meet service levels and resilience to respond to high impact low probability events.

1.7.1 Key plans and documents

Electra's key plans and documents include:

Document title	Purpose
Statement of Corporate Intent (SCI)	Articulates key strategies, governance philosophy, scope of activities and high-level goals of business performance and customer experience. The SCI is approved by the Trust as the owner of the company.
Group strategic plan	Consolidates the strategic plans of Electra's subsidiaries into a coordinated Group plan.
Pricing methodology	Provides the details of pricing including principles and objectives.
Asset management plan	Connects management of long-life assets to Electra's strategic direction.
Annual group business plan and financial plans	Presents the tactical plans for the year ahead and allocates resources.
Annual network business plan and annual works programme	Define detail of specific works on a 12-month basis.

1.7.2 Relationship between plans and documents

The relationship between Electra's key plans and documents is depicted in Figure 1-4 which shows our asset management framework.

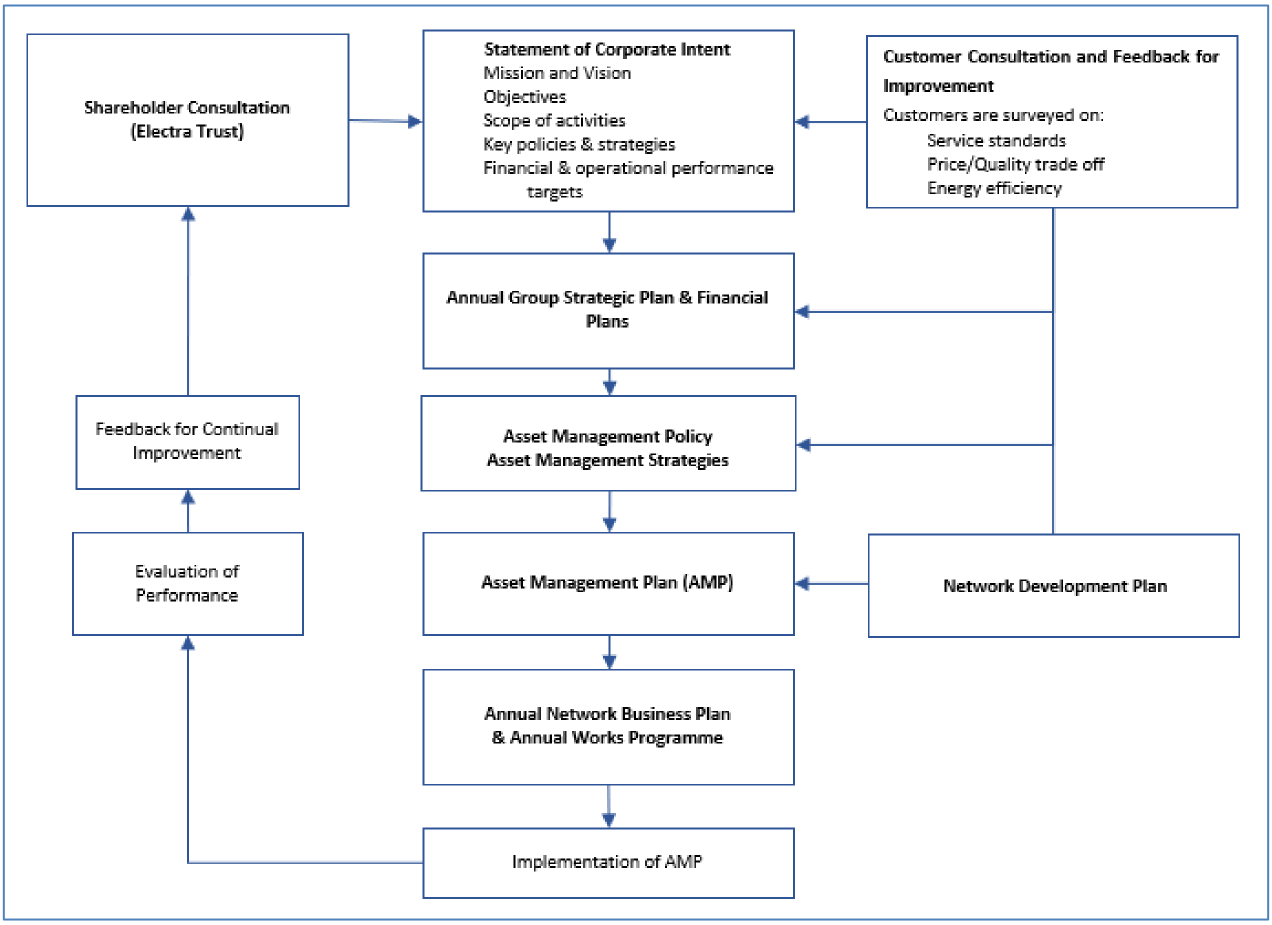


Figure 1-4: Asset management framework

1.7.3 Linkages between planning goals

The above sub-sections emphasize the line-of-sight and progressive refinement of our approach from the strategic model through to tactical programmes to operational plans and budgets. This is complemented by a small and close working environment.

1.8 Planning period

The planning period for this AMP is 1 April 2020 to 31 March 2030. The AMP embodies three levels of increasing certainty for nearer term plans:

Period	Scope	Cost	Timing
1 April 2020 – 31 March 2021	Firm, approved in principle	±5%	Quarter/month
1 April 2021 – 31 March 2026	Major components	±10%	Quarter
1 April 2026 – 31 March 2030	Indicative	±25%	Year

1.9 Board approval

This AMP was submitted in draft to the December Board meeting to allow for inclusion of the Board's comments before final approval on 28th February 2020.

1.10 Stakeholder interests

Electra defines stakeholders as any person or organisation who affects or are affected by Electra's business.

1.10.1 Stakeholder interests and how they are identified

Electra defines stakeholders as any person, class of persons or organization that does or may do one or more of the following:

- Have a financial interest in Electra (be it equity or debt)
- Be physically connected to Electra's network (a customer)
- Uses Electra's network for conveying electricity
- Supplies Electra with goods or services
- Is affected by the existence, nature or condition of Electra's network (especially if it is in an unsafe condition), or
- Has a statutory obligation to perform an activity in relation to the network's existence (such as request disclosure data or regulate the location of assets).

Electra has identified the following specific stakeholder interests:

Stakeholder	Key stakeholder interests				How those interests are identified
	Viability	Supply quality	Safety	Compliance	
Electra Trust	✓	✓	✓		• Statement of Corporate Intent • Quarterly briefings • Informal discussions with the Board and Chief Executive
Bankers	✓				• Terms and conditions of financing arrangements • Quarterly meetings • General negotiations
Connected customers	✓	✓	✓		• Enquiries via 0800 phone number and website enquiry section • Questions and comments at AGM • Customer survey responses • Community feedback • Media comment
Energy retailers	✓	✓			• Negotiation of terms and conditions • Pricing amendments • Regular meetings • Informal communication • Resolution of billing disputes
Mass-market representative groups	✓	✓			• AGM • Feedback from interest groups. • Electricity Networks Association (ENA) focus groups
Industry representative groups	✓	✓			• Annually via meetings and conferences

Stakeholder	Key stakeholder interests				How those interests are identified
	Viability	Supply quality	Safety	Compliance	
Staff and contractors	✓	✓	✓	✓	• Weekly staff meeting • Monthly contractor meetings • As required for specific projects • General workplace interactions • Performance appraisals
Suppliers of goods and services	✓				• General interactions during service deliveries • Price and volume negotiations
Public (as distinct from customers)			✓		• As required via 0800 phone number and website enquiry section • General interactions
Landowners			✓	✓	• As required for specific projects
Councils (excluding as a consumer)			✓	✓	• Monthly Emergency Management meeting • Annual planning disclosure • As required for specific projects • During and after drills and actual events
Land Transport			✓	✓	• Reading of bulletins • Meetings to discuss specific projects
Ministry of Business Innovation and Employment			✓	✓	• Reading of bulletins • Attending seminars • Responding to consultations
Energy Safety Service			✓	✓	• Reading of bulletins • general interaction around safety requirements • Incident investigations
Commerce Commission	✓	✓		✓	• Reading bulletins and determinations • Attending seminars and workshops • Complying with determinations and disclosure requirements
Electricity Authority				✓	• Reading bulletins and determinations • Attending seminars and workshops • Complying with Code requirements
Utilities Disputes		✓		✓	• Reading bulletins, responding to complaint investigations
Ministry of Consumer Affairs		✓		✓	• Reading bulletins • Responding to complaint investigations
Transpower	✓	✓	✓	✓	• Quarterly updates • Annual planning meetings • General interactions about grid connections • Discussions about specific grid connection issues such as price and capacity

1.10.2 Linking stakeholder interests to asset management practices

Electra's stakeholders' interests are linked to asset management practices as follows:

Safety	→	Electra keeps the public at large safe by keeping all above-ground assets structurally sound, live conductors are well out of reach, all enclosures are secure, and all exposed metal is earthed Electra's Safety Management System (SMS) provides a structured approach to maintaining public safety Electra maintains safety of the staff and contractors by providing all necessary equipment, improving safe work practices, and stopping work in unsafe conditions Motoring safety is assisted by placing above-ground structures as far as practically possible from the carriage way within the constraints of private land and road reserve
Supply quality	→	Electra will accommodate stakeholders' needs for supply quality by focussing resources on continuity and restoration. Many of the renewal jobs discussed in this AMP are aimed at maintaining Electra's security of supply. Electra's most recent mass-market survey (Q1 2018) indicated a general satisfaction with the present supply quality
Viability	→	Electra will accommodate stakeholders' needs for long-term viability by delivering earnings that are sustainable and reflect an appropriate risk-adjusted return on capital employed. In general terms this will need to be at least as good as Electra's owners could obtain from a term deposit at the bank plus a margin to reflect the risks to capital from opportunities associated with emerging energy technologies and regulatory settings Price is the key to viability but must be managed to be in line with similar network companies, other energy options and to provide a satisfactory discount to Electra's consumer/owners
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 Electra discloses performance information in a timely and compliant fashion

1.10.3 Managing conflicting stakeholder interests

Stakeholder interests are managed in the following order of priority:

- Safety of the public, our staff and contractors: this will be achieved for new works by developing design and construction options through the application of safety in design principles, and by routine inspection, hazard assessments and targeted renewals during the assets operating life
- Customer's requirements for a reliable and efficient energy supply will be given second priority
- Non-safety compliance
- Viability.

1.11 Accountabilities for asset management

Electra's organisational structure emphasising the lines business is shown in Figure 1-5.

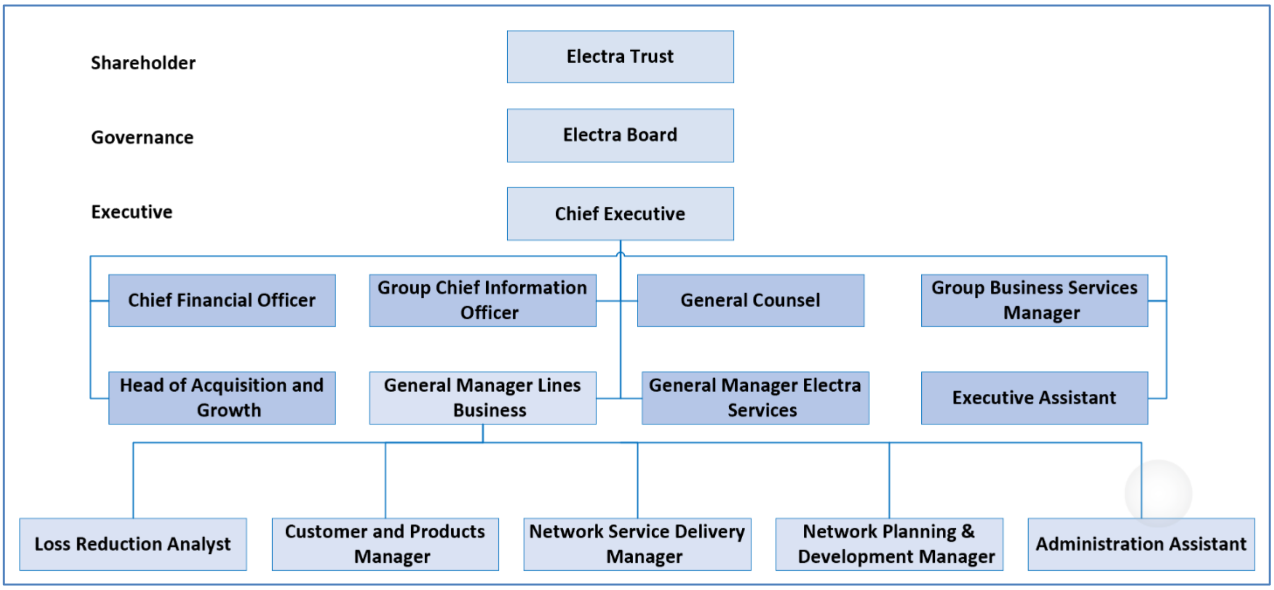


Figure 1-5: Organisational chart

This chart emphasises the short distance between the lines business managers (aiding line of sight), and the logical alignment of the three lines business managers with the asset lifecycle.

Accountability at the governance level is by two mechanisms, namely:

- Electra's Board of Directors are obliged to govern the company commercially, on behalf of the Trust as beneficial owners via the Statement of Corporate Intent
- The Electra Trust are accountable to the connected consumers through the Trustee elections.

Accountability at management level is primarily through the performance criteria set out in employment contracts and achievement of planning goals. The Chief Executive is accountable to the Board while the General Manager (Lines Business) is accountable to the Chief Executive. There are three managers accountable to the General Manager (Lines Business) as shown in the organisational chart.

Accountability at field operations level is primarily with the Programme Manager and the Service Delivery Manager for overall delivery of work packages.

1.11.1 Summary of roles, delegated authorities and reporting

The roles, delegated authorities and reporting are summarised as follows:

Activity	Board	Chief Executive	GM – Lines Business
Preparing SCI	Key role in preparing and amending under instruction from the Trust	Key role under direct delegation from the Board	Consulted for contribution
Role with strategic plan	Input - key role is reviewing and approving	Preparation, submit to Board for approval	Contributes together with the Executive Team
Role with AMP	Approval	Provide strategic direction, submit to Board for approval	Preparation
Role with annual business plan	Approval	Preparation	Preparation
Approval of works from approved budget	In excess of Chief Executive's authority	In excess of GM – Lines Business authority ($1,000,000)	In excess of Lines Business Managers' authorities ($200,000)

Activity	Board	Chief Executive	GM – Lines Business
Approval of works not from approved budget	In excess of Chief Executive's authority	In excess of GM – Lines Business authority ($100,000)	In excess of Lines Business Managers' authorities ($50,000)
Reviewing performance of works and projects	Noting progress of projects over $500,000 or that are strategically significant	Notes progress of all works programmes and significant projects	Responsible for detailed oversight of all works programmes
Reporting of outages	Summary included in monthly Board reports	Summary included in monthly Board reports, immediate involvement in major events	Receives a report of incidents, causes and follow up actions

1.11.2 Use of external contractors and advisers

Electra uses a range of external contractors and advisers in the following circumstances:

- Where specific expertise is required
- Where additional resourcing is required due to temporary overflow of requirement
- Where an independent viewpoint is required (typically by a statutory agency).

Electra's preference is to retain frequently required core expertise in-house, and to use external advisers or contractors for work that is encountered infrequently or backfilling extended vacancies or efficiently providing commoditised services. Parties contracted for work directly by Electra include:

- ICONA Ltd of Ashurst are contracted to maintain SCADA and Control Centre radio communications
- Eagle Technology of Wellington for GIS support for the ESRI system used by several other EDB's and Local Authorities
- Spark provide primary telecommunications and digital procurement services
- Sandfield provide SQL database provisioning
- Energia of New Plymouth for regulatory and valuation advice
- Tesla Consultants for engineering design and drafting
- Connetics for procurement, project stock management and overflow field work
- Tatana Contracting and PEL for civil works and traffic management.

1.12 Asset management systems and information management

Electra is developing an asset management road map to comprehensively link the improvement and alignment of our asset management practices to the implementation of the transactive grid, the best in class supporting initiatives and to the elements of ISO 55001.

Electra has the following data repositories and software that are used to capture, manage and derive insights to support asset management decisions:

System	Data held	What data is used for	Extent of integration
Advanced Distribution Management System (ADMS), commissioned in 2018	An integrated system containing geospatial information of assets, customers and has an engineering model which takes input from SCADA which can carry out load flows	Used by field, real-time operators, planning and project management staff within the Network team to update the	Integrated with GIS, SCADA, Job Dispatch, IoT and outage web viewer

System	Data held	What data is used for	Extent of integration
		customer outage viewer, obtain information about assets and carrying out engineering studies	
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
AXOS Billing System, commissioned in 2018	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
AMP project website	Central depository of AMP requirements	Links from this site to required documents used within the AMP	LAN links to documents from SMS or attached to tasks
Customer Relationship Management (CRM)	Customer Information, complaint information, 3rd party service requests and customer queries	Customer relations and service delivery management	Integrates with electricity registry, Business Central, Office 365, email and SharePoint Online
Electra Data Lake	The Electra Data Lake holds copies of information from SCADA and IoT platforms as well as from Electra controlled EV chargers and the head office PV battery system. This data includes network status information as well as digital and analogue readings from field devices, sensors and other systems	Primarily used for post analysis and network data mining without the security risks of operators having direct access to live platforms while offloading compute away from critical systems	Integrated with ADMS, IoT, SCADA business systems (Power BI) and third-party analysis tools
Electronic Document Management System (EDMS) (Microsoft Office 365 SharePoint Online Platform)	Corporate policies, processes and general information	Provision of information on the Intranet, easily accessible to staff and to serve as a document management system and single source of truth	Integrates with Office 365 for emailing functionality

System	Data held	What data is used for	Extent of integration
IoT network status monitoring	The status information of specific network assets – RMU fault condition, DDO fuse status, voltage present indicators, power quality meters, client outage sensing devices, plus other non-critical data used for post analysis	IoT communications can have significant latency so are not typically used for “real-time” decisions. The platform is primarily 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	Integrated with the Data Lake, ADMS and SCADA. IoT devices can report to the control room in the same way as SCADA/ADMS
iAuditor (part of NIMS)	GPS co-ordinates for all scheduled maintenance assets. This information includes, but is not limited to asset ID, date of inspection and condition of asset	Used to determine the maintenance work for the following year	Fully integrated
Information Disclosure Compilation Tool	Network asset data	Compilation of Information disclosure data for various schedules as well as the generation of age profiles	Manual upload of GIS data currently with automated macros to produce schedules and charts
NIMS (GIS)	Contains geospatial information for all assets including asset description, location, age, electrical attributes, condition 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.
SCADA	System Control and Data Acquisition System being 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 load on various parts of the network. This is used for assessing security, load forecasts and feeder configurations	Low level of integration with outage web page
Safety Management System	Electronic library of safety documents held in the EDMS	Used by all staff to obtain safety information, policies and operational standards	
Strategic Vegetation Management Database	Tree owners, requests, trimming works, proactive and reactive plans	Monitoring of requests, works, costs, proactive and reactive planning, reporting	Manual input of tree requests

System	Data held	What data is used for	Extent of integration
Vault	Risk register (organisation and H&S): 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 incident; used to report to senior leaders and Board; automatically notifies the above for critical events; audit and checks through mobile apps	Stand-alone system

1.12.1 Data Integrity

Reconciliation between the various data sets means that Electra now has improved data quality levels for our assets. These are summarised in the table below:

Asset type	Information held	Information quality	Methods for ensuring data accuracy
33kV Lines	Size and material	Accurate	• Documents recording installation • Site inspection
	Age	Accurate to within 6 months	• Documents recording installation
33kV Cables	Size and material	Accurate	• Documents recording installation
	Age	Accurate to within 3 months	• Documents recording installation
11kV Lines	Size and material	Accurate	• Documents recording installation • Site inspection
	Age	Accurate to within 6 months post 1995 Accurate to within 5 years pre 1995	• Documents recording installation
11kV Cables	Size and material	Accurate	• Documents recording installation
	Age	Accurate to within 3 months post 1995 Accurate to within 5 years pre 1995	• Documents recording installation
400V Lines	Size and material	Accurate post 1995 70% accurate pre 1995	• Documents recording installation • Site inspection
	Age	Accurate to within 3 months post 1995 Accurate to within 5 years pre 1995	• Documents recording installation
400V Cables	Size and material	Accurate	• Documents recording installation
	Age	Accurate to within 3 months post 1995 Accurate to within 5 years pre 1995	• Documents recording installation
Poles	Material	Accurate	• Site inspection
	Age	Accurate to within 3 months post 1995 Accurate to within 5 years pre 1995	• Documents recording installation
Pillars	Type and material	Accurate	• Site inspection

Asset type	Information held	Information quality	Methods for ensuring data accuracy
	Age	Accurate to within 3 months post 1995 Accurate to within 5 years pre 1995	• Documents recording installation
Transformers	Rating, manufacturer, age	Accurate	• Site inspection • Documents recording installation
RMU's	Rating, manufacturer, age	Accurate	• Site inspection • Documents recording installation
Circuit Breakers	Rating, manufacturer, age	Accurate	• Site inspection • Documents recording installation
Other Switches	Rating, manufacturer	Accurate	• Documents recording installation
	Age	Accurate to within 3 months post 1995 Accurate to within 5 years pre 1995	• Documents recording installation

Asset condition information is recorded as part of the regular inspection cycle for each asset class as described in Section 5.

Further, with the Electronic Documentation Management System and Lines Business Reference Library going live in March 2019, the sharing of centralised information on the Intranet means that relevant documents are readily assessable for all staff and users. Feedback surveys on its availability and ease of access are being conducted with the objective of transforming this site to be the "single source of truth" for the lines business.

1.13 Overview of key lifecycle processes

The summary of the key processes follow in the sub-sections and details of asset management performance and improvement processes are included in Section 8.4.

1.13.1 Routine inspections

Electra routinely inspects all classes of assets on a time basis. The timing and scope of inspections varies by asset class, asset health and criticality, and public safety risk and are described in detail in Section 5.

1.13.2 Maintenance

Electra uses the following range of maintenance strategies where the timing and scope of most maintenance is driven by the results of condition inspections, subject to manufacturer's minimum requirements or industry safety recommendations. Low value, low risk components are managed on a run-to-breakdown basis.

1.13.3 Development projects

The key drivers of all development projects are:

- Demand growth within existing network capacity (requiring a customer connection and minor network change)
- Demand growth in excess of existing network capacity
- Demand growth that requires network extension.

Electra considers the following approaches to meeting new demand:

Approach	Effect on asset utilisation	Effect on failure risk
Supplying the demand without any alterations to either asset capacity or operational processes (the "do-nothing" approach). This approach will be adopted if a risk analysis has confirmed that the overall risk exposures (particularly of in-service asset failure) remains acceptable	Increases (capacity headroom declines)	Increases
Supplying the demand through an operational process e.g. insisting that new load is controllable or designing a tariff that encourages off-peak use	Increases in some locations (capacity headroom declines) but declines in other locations. The net effect is minimal change in asset utilisation	Ideally nil, probably minimal in practice
If the above approaches are both unacceptable, Electra will invest in new assets	Ideally nil (capacity headroom maintained by matching investment level to demand increase). In practice, a decrease if the next highest rated component is installed	Nil, possibly decrease depending on how much capacity is added

These are described more fully in Section 4.

1.13.4 Measuring performance

Electra measure the performance within the following areas:

- Performance of the overall network (reliability)
- Performance of individual asset classes and assets (reliability, efficiency)
- Works delivery performance (timeliness, budget and unit costs)
- Asset management performance (alignment to long-term company objectives).

We have adopted the approach that it is not only important for both physical and financial budgets to be met, it is also critical that those budgets accurately reflect the network condition and capacity utilisation to avoid a long-term accumulation of asset deterioration.

1.14 Overview of documentation and controls

Electra manages our documentation and information records through controls of various levels. These include:

- Allocation of a unique numerical identifier to all key documents that is traceable
- Assigning an authorisation level for altering or approving documents
- Specifications for the nature and accuracy of asset data that is to be returned from field services staff and contractors.

These documentation and data controls are described in Section 1.12.1.

1.15 Overview of communication processes

Electra communicates the key features of asset management planning and activities to the staff and contractors in the following ways:

- Asset Planning & Development staff prepare the AMP and its associated work programmes and budgets
- The Finance team compile budgets for personnel, IT, AMP and non-network assets

- Our Programme Management, Service Delivery and Operations teams are advised of the key AMP themes and trends and consulted on the scope, method, timing and budgets of the works programme
- We have a panel of pre-qualified field service contractors that are available to meet overflow work. They are informed when Electra identifies a likely overflow of work volumes
- Consultants can obtain the public copy of the AMP to understand our priorities and work programmes.

These communication processes are described in the AMMAT section in Section 8.4.

1.16 Significant assumptions

Significant assumptions for this AMP are:

Assumption class	**Assumption**	**What if assumption occurs?**	**What if assumption doesn't occur?**
Resident population growth	Horowhenua District's resident population is forecasted to increase by 8,600 people over the next 20 years, including an expected 4,900 houses and 3,000 jobs created From the 2018 census[2] released by Statistics New Zealand, the district has a population of 32,949, which increased at a rate of 2% per year since 2013	Implement Growth CAPEX projects as planned	Implication would be a mismatch of asset capacity and demand, which can be minimised by regularly monitoring demand growth and either advancing or delaying capital projects
	The Kapiti Coast District's resident population is forecast to increase by 6,300 people over the next 15 years The 2018 census identified a population of 53,940 residents; the growth rate was 1.9% per annum since 2013		
Technology uptake	As the Government is increasing the incentives and subsidies for EV's, uptake is expected to be about 640 in Kapiti and 160 in Horowhenua by 2021, with a further 270 EV's travelling the SH1 corridor daily[3]	Implement Growth CAPEX projects as demand requires	Implication would be a mismatch of asset capacity (primarily network, but possibly also chargers) and demand. Any mismatch can be minimised by regularly monitoring EV numbers and also by encouraging off-peak charging[4]
	That EV fast charging rates may increase from the current 50kW to 300kW as vehicle size and range increases and the recharging period emerges as the barrier to EV uptake[5]	Implement Growth CAPEX projects as demand requires (minimal overall impact, as there would only be a few within the network area)	Fast charging rates remain at about 50kW, reducing the need for network reinforcement

[2] Statistics New Zealand, Dataset: "Age and sex by ethnic group (grouped total responses), for census night population counts, 2006, 2013, and 2018 Censuses"

[3] Source – "Compiling an EV charging strategy" prepared for Electra by Utility Consultants.

[4] Mercury recently noted that even a 10% price discount has been enough to encourage EV owners to shift charging to off-peak periods.

[5] Another EDB has been approached by a vendor offering a 300kW charger

Assumption class	Assumption	What if assumption occurs?	What if assumption doesn't occur?
	The number of roof-top solar and battery installations will increase, possibly to the point of creating localised voltage disturbances	Active control of LV system voltage may be required	Voltage disturbances will be less likely
	Evolving application of device interconnectivity (the internet of things) will expand into energy transmission and network operations	Opportunities will emerge to increase the number and nature of asset condition monitoring	The existing level of monitoring will continue
	Penetration of LED streetlighting increases, leading to further reductions kWh sales	kWh revenue will decline	Existing level of kWh sales will prevail
Financial parameters	The rate of inflation for the Planning Period will be 1.7%, which is based on the ANZ Bank forecasts	Actual costs and margins should align with budgets	Actual revenues, costs and margins may vary from budget, budgets may need to be revised, with the possibility that work volumes may need to be reduced
Public policy	That the Government's climate change initiatives will see increased emphasis on renewable generation	Generation mix likely to include more renewables, possibly leading to price increases and declining kWh sales	Generation mix and hence prices and kWh consumption likely to stay the same
	That the Government's climate change initiatives will see substitution of electricity for oil (transport) and coal (industrial)	Increased generation (almost certainly requiring new capacity), and increased kWh sales	kWh consumption likely to remain similar to current levels
	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, cost of additional land access requirements will need to be recovered either from specific customers or at large
	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	
	The Wellington Northern Corridor roading development will continue as stated in the Roads of National Significance (the NZTA's website)	Declining diversity between Kapiti zone substations as more commuters arrive home earlier may increase coincident GXP demand. Also, possibility of people moving northwards from Wellington to Kapiti, and from Kapiti to Horowhenua	Kapiti population growth may not be as high as forecast, such that Growth CAPEX projects can be deferred
Sector regulation	The current Electricity Authority emphasis on cost reflective pricing will continue.	Could require extensive rebalancing of fixed and variable charges	Tariffs and revenue principles should be able to remain similar to present
	That trust owned EDB's will continue to be exempted from revenue and quality regulation	Continue to set own revenue and quality targets	Compliance costs would increase, possibility that revenue may be reduced

1.16.1 Causes of possible material differences

Key factors that may result in material differences between this AMP and future disclosures include:

Class of cause	Cause	Result	Possible response(s)	Ability to recover costs of response
Transport policy	Variations to the established motorway development plans, most likely a deferral	Slowdown in Horowhenua population growth	Delay CAPEX to meet demand	Currently strong
	A shift in Government policy towards a more aggressive uptake of EV's (possibly like the California Zero Emission Vehicles programme) that could provide subsidies for EV's and restrictions for gasoline vehicles	Possible increase in peak demand unless charging is incentivised to off-peak periods	Growth CAPEX to meet demand, introduce peak pricing to manage demand	Currently strong, possibility that ability to recover costs may be weakened[6]
	An inability to manage electric car recharging to off-peak periods (whether through policy or otherwise)	Likely increase in peak demand		
Costs	Variations from forecast labour and material costs	Actual costs may exceed budget	Either increase total budget or reduce work volumes to fit within existing budget subject to risk assessment	Currently strong
	Increased health, safety and traffic management requirements that increase the cost of work	Increased time per job, resulting in increased costs per job	Decrease work volumes to fit within budget subject to risk assessment	Currently strong
	Increased requirements for access to land by NZTA or KiwiRail that increase the cost of work	Increased time per job and costs per job	Reduce number of jobs to fit within budget, subject to risk assessment	Currently strong
Performance	Migration of tree trimming from a responsive approach to a planned approach may reduce SAIDI to below forecasts	Possible that actual SAIDI will be below long-term targets	Reduce tree trimming budget in the long-term	Currently strong
Asset condition	A previously unknown widespread asset defect emerges that effects a large number of assets	Requires an accelerated replacement programme	Increased Replacement CAPEX after performing specific risk assessment	Currently strong
Customer behaviour	Changes to the rate of customer adoption of new technologies	Variations between actual and forecast demand	Advance or delay Growth CAPEX	Currently strong
Sector regulation	Shifts in government preference for electricity sector regulation	Possible increase in compliance costs	Recover costs through increased prices, or reduce consumer discount	Possibility of reduced cost recovery

1.16.2 Financial forecasts

During the planning period, we will face different input price pressures to those captured by a general measure of inflation, such as the consumers price index (CPI) where pricing will be based on global demand for commodities as well as market trends for various assets. These are then applied to our

[6] It is noted that investor-owned electric companies in California were restricted in their ability to recover the full costs of peak-time charging.

real expenditure forecasts to produce the forecasts in nominal dollars for our budgets as well as Information Disclosure schedules in Appendix 2 (CAPEX forecast) and Appendix 3 (OPEX forecast), which are based on 2020 constant New Zealand dollars.

1.16.3 Limitations of this AMP

Compilation of this AMP has revealed the following possible limitations:

- Some classes of asset condition data are either known or thought to be inaccurate; an on-going identification and cleansing process is in place.
- Demand forecasting methods have historically used linear extrapolations. We recognise that demand forecasting particularly for the southern network includes an increasing number of variables that are more complicated to predict and we intend to develop a more comprehensive methodology that will include consideration of emerging technologies, declining kWh consumption and increasing kW demand.
- Rapid changes in technology and uncertain rates of technology uptake make a 10-year forecast less certain than in previous years.
- Despite the less certain long-term view, we remain confident that we can continue to operate and maintain a safe, reliable network and recover the true economic cost of the network.

2 Network overview

2.1 Network area

2.1.1 Regions covered

Electra's assets are spread over the Horowhenua and Kapiti districts on the narrow strip of land between the Tasman Sea and the Tararua Ranges, stretching from Foxton and Tokomaru in the north to Paekakariki in the south, as illustrated below. The network covers approximately 1,628 km^2.

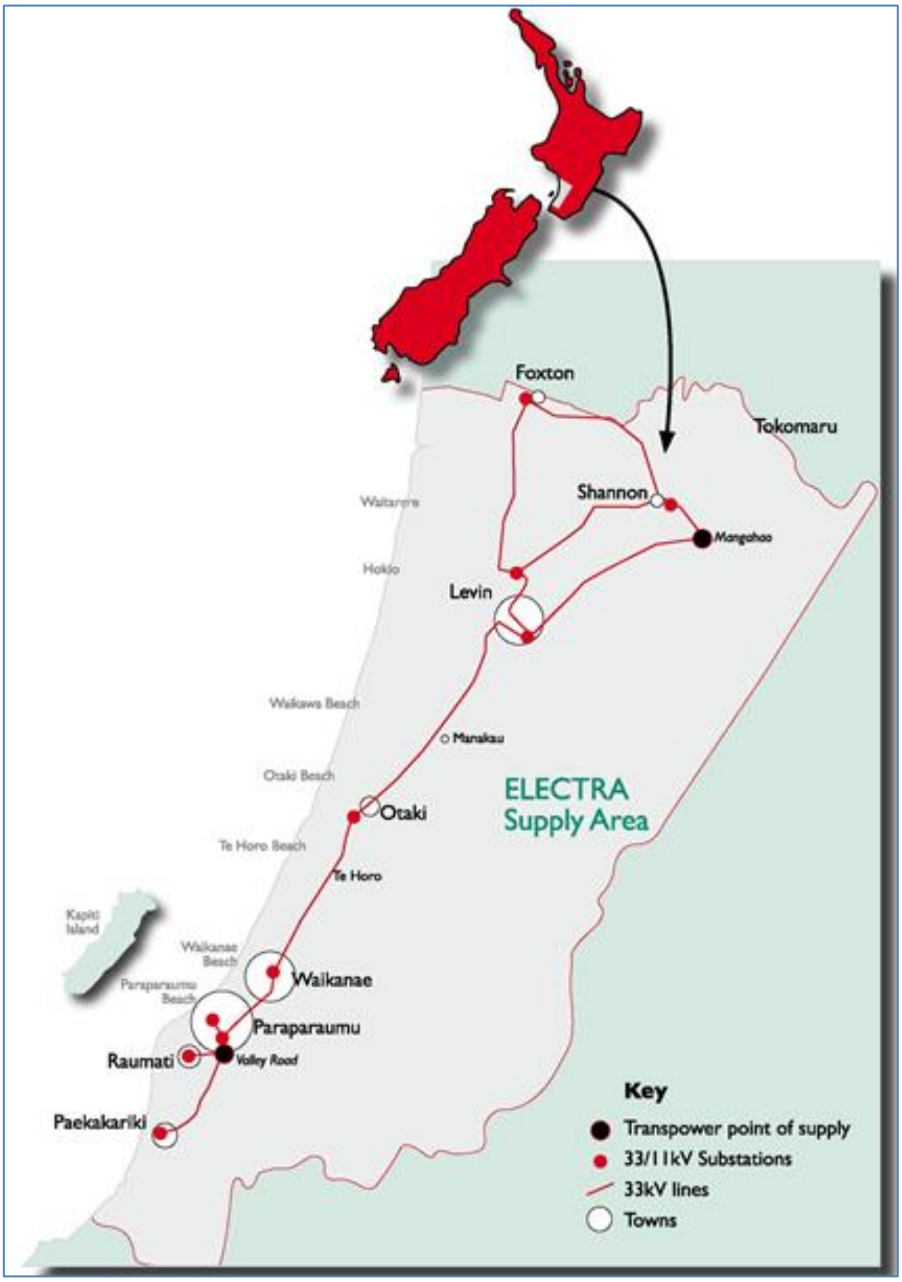


Figure 2-1: Electra sub-transmission 33kV network with 33/11kV substations and Transpower GXPs

2.1.2 Large consumers

Electra's largest network customers are:

- Alliance Group, Levin (Meat processing)
- Kapiti Coast District Council (Sewage and water treatment)
- Pak'nSave, Paraparaumu (Supermarket)
- Oji Fibre Solutions, Levin (Packaging manufacturer)
- Unisys, Paraparaumu (Data processing)
- New World, Levin (Supermarket)
- RJ's Liquorice, Levin (Confectionary)
- Kapiti Coast District Council (Aquatic Centre).

These consumers represent 5.5% of the energy conveyed through our network. Accordingly, Electra faces a low revenue risk from its large industrial consumers' consumption trends with the exception of Unisys, who will cease its operations in 2022.

Each of these consumers forecast demand and security requirements are discussed with Electra's key account manager, and specific requirements are included in the AMP as required.

2.1.3 Network load characteristics

While Electra's network is electrically contiguous, it is best considered as two market segments:

- A northern network depicted in Figure 2-2 supplied predominantly from the Mangahao GXP, and embedded Mangahao generation supplying Levin, Foxton and Shannon in a ring configuration. The economy of this market segment is strongly tied to both root and leaf vegetable prices, and dairy prices, and has demonstrated low growth in both MW demand and ICP numbers.
- A southern network (Figure 2-3) supplied predominantly from Valley Road Paraparaumu GXP, and supplying Paekakariki, Paraparaumu, Raumati, Waikanae and Otaki by a double spur configuration. This market segment has a broader demographic comprising a range of features including strongly urbanised through to lifestyle rural to agricultural production. A key feature of the southern network is that because many people in this area commute to Wellington, the day-time demand is considerably less than the evening demand, leading to a low load factor.

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

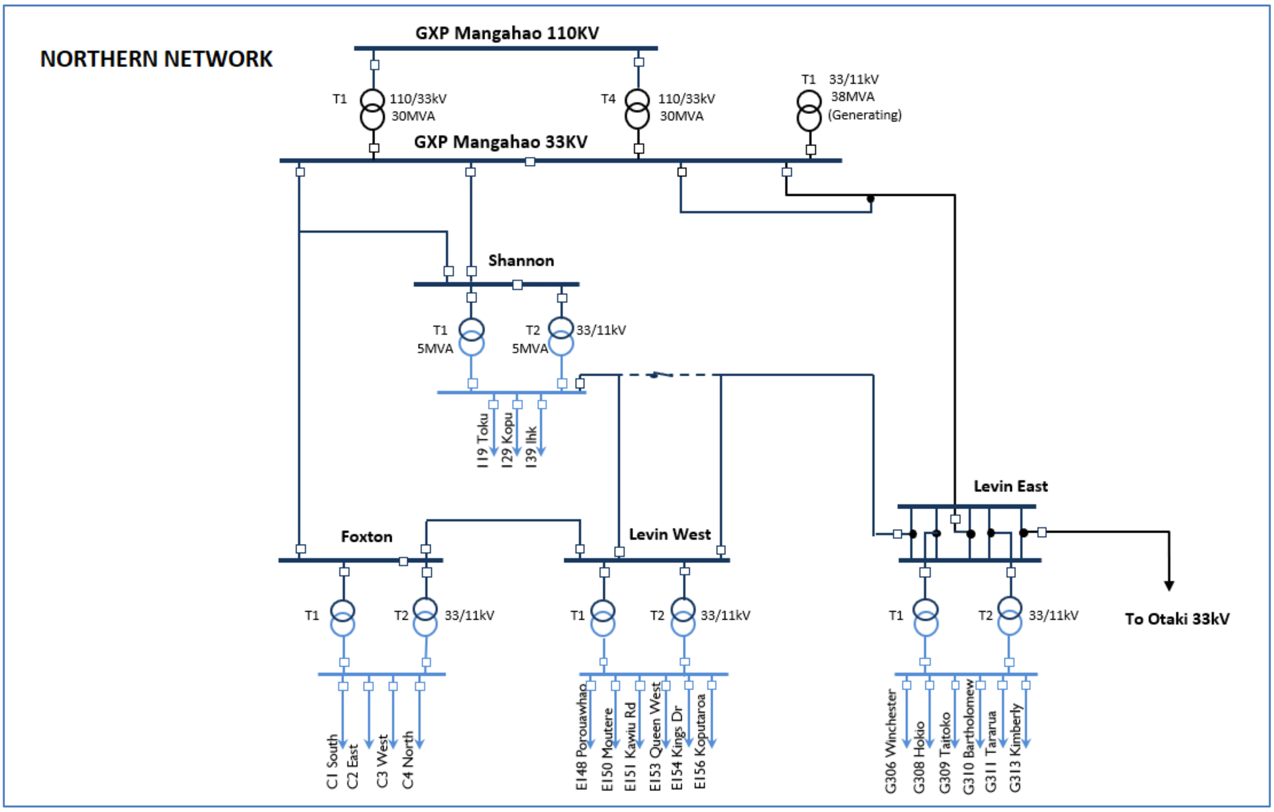


Figure 2-2: Northern 33/11kV network

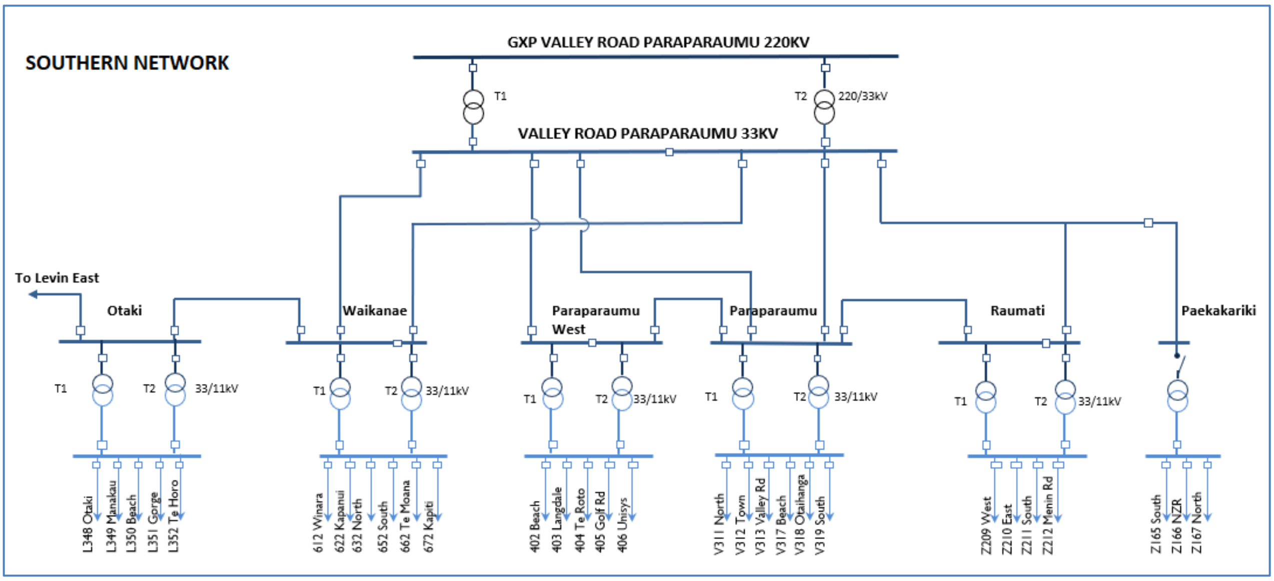


Figure 2-3: Southern 33/11kV network

2.1.4 Demand and energy

Key parameters of Electra's network as of 31st March 2019 are:

Parameters	Quantity
Average number of customers in disclosure year	44,799
Maximum demand	102 MW
Annual electricity conveyance	447 GWh
Line and cable length	2,287 km

Parameters	Quantity
Number of zone substations	10
Number of distribution transformers	2,560
Network asset valuation	$180m

As demonstrated by the graph in Figure 2-4 a, ICP growth has been slowly increasing at a rate of about 1% annually between 2014 to 2019 versus a 0.2% average yearly increase of the total system length during the same period. The number of ICPs is extracted from the Registry for active customers up to 30/9/2019 and is based on the ICP creation date. The ICP growth rate in the region is expected to increase as depicted in the change in population map (Figure 2-4 b) between the 2013 and 2018 census.

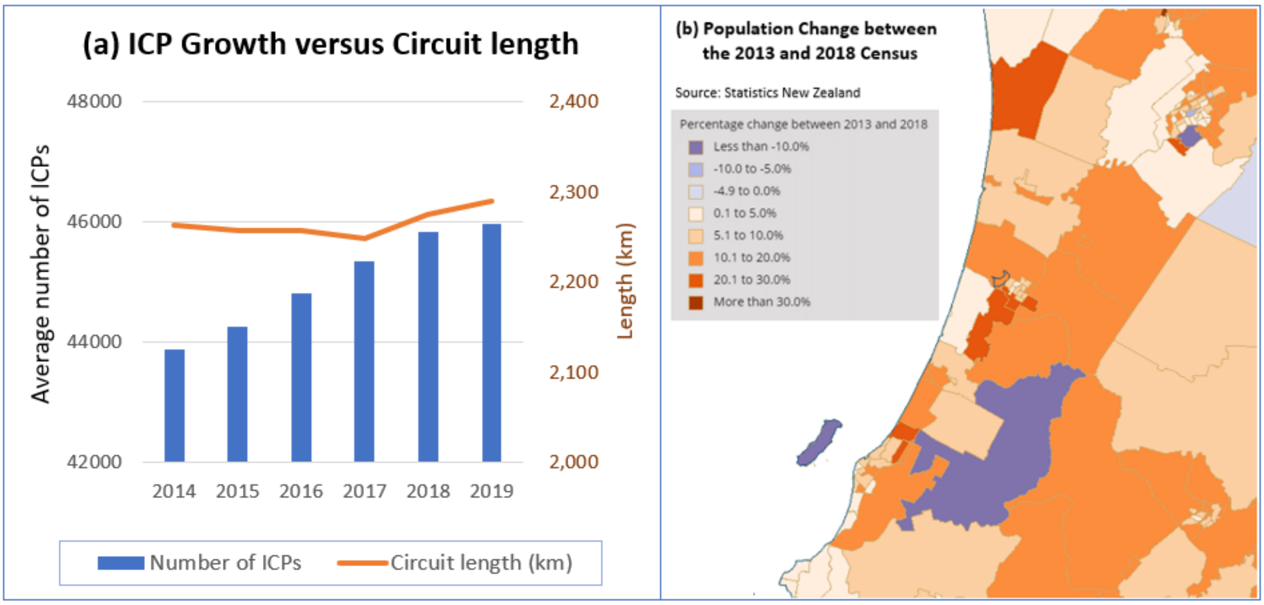


Figure 2-4: (a) Growth of ICPs and circuit length, and (b) Population change between the 2013 and 2019 census

2.2 Network configuration

Electra takes bulk supply from the following two GXPs:

- Mangahao GXP, which supplies the northern area
- Valley Road Paraparaumu GXP, which supplies the southern area.

Otaki zone substation may be supplied from either GXP but it is usually supplied from Valley Road.

Key features of these bulk supply points are:

GXP	Winter firm capacity (MVA)	Peak demand (MVA)	
		2018	2019
Mangahao	30	37.0	38.5
Paraparaumu	120	65.5	63.3

The 38 MW Mangahao hydro generation station is embedded in Electra's network with a direct connection to Transpower's 33 kV bus at Mangahao to resolve constraints of Mangahao's (n-1) firm capacity, which has been exceeded since 2015. Further analysis is included in Section 4.6.4.

Key "at a glance" features of Electra's network follow and details of individual asset categories and lifecycle management of these assets are set out in Section 5.

System level	Key features at a glance
Bulk supply and embedded generation	• GXP's supplying a coincident maximum demand of 102 MW • Embedded hydro generation of 38 MW (Mangahao) • About 470 solar installations with a total capacity of 1.8MW
Sub-transmission	• Circuits of 14km of overhead 110kV line that will be repurposed and operated at 33kV • 152 km of overhead 33kV line • 29 km of underground 33kV cable
	• Four zone substations supplied from Mangahao GXP • Five zone substations supplied from Valley Road GXP • One zone substation that can be supplied from either Valley Road or Mangahao
Distribution network	• 848 km of overhead line • 240 km of underground cable
Distribution substations	• 2,560 substations ranging in capacity from 5 kVA to 1,000 kVA

The network lengths of Electra's sub-transmission and distribution network follow:

Description	Length in km as of 30-Sep-2019				Network %
	33kV	11kV	Low Voltage (LV)	Sub-total	
Underground cables	29.3	239.9	493.6	762.8	33%
Overhead lines	152.2	847.8	524.1	1,524.1	67%
Total:	181.5	1,087.7	1,017.7	2,286.9	100%

Figure 2-5: Network circuit lengths of overhead lines and underground cables

As per Figure 2-5, we have 848 km of 11kV overhead lines and 240 km of 11kV cables connecting our ten zone substations to distribution substations. This 11kV network is constructed mainly of:

- CBD areas are almost exclusively supplied by underground cable. In older urban areas with low load growth such as Levin and Foxton, these cables are of PILC 185mm^2 aluminium construction. New installations are constructed of XLPE cables
- Suburban areas tend to be a mix of overhead lines and underground cables depending on whether the area was developed before or after undergrounding was widely adopted around 1970. Underground cable construction tends to be PILC aluminium conductor, whilst overhead conductors are a variety of Bee, 19/0.064" and 7/0.083" copper, almost totally on concrete poles
- Rural areas are mostly of overhead line construction but with increasing lengths are being cabled. These lines are Gopher or 7/0.064".

Electra has 524 km of overhead LV or low voltage line (400V) and 494 km of LV underground cable connecting its distribution substations to its customers, with an associated 11,079 pillars and cabinets.

Distribution overhead line and underground cable lengths by the ten zone substation areas follow:

Zone substation	Distribution network length (km) up to 30/9/2019			LV network length (km) up to 30/9/2019		
	Overhead line	Underground cable	Total	Overhead line	Underground cable	Total
Levin East	124	28	**153**	80	56	**136**
Levin West	122	24	**146**	90	49	**139**
Shannon	185	9	**193**	71	10	**81**
Foxton	105	17	**121**	65	19	**85**

Zone substation	Distribution network length (km) up to 30/9/2019			LV network length (km) up to 30/9/2019		
	Overhead line	Underground cable	Total	Overhead line	Underground cable	Total
Paraparaumu	26	33	**59**	18	65	**83**
Paraparaumu West	7	31	**38**	12	81	**94**
Raumati	13	13	**26**	26	33	**59**
Waikanae	64	42	**106**	48	117	**165**
Paekakariki	16	6	**22**	10	4	**14**
Otaki	187	37	**224**	104	59	**163**
Total	**848**	**240**	**1,088**	**524**	**494**	**1,018**

2.3 Customer connections

The consumer connection assets connect Electra's 45,170 consumers (as it 30/9/2019) to the 11kV and 400V distribution networks. These connection assets include simple pole fuses, suburban distribution pillars, and dedicated lines and transformer installations supplying single large consumers.

In most cases the fuse holder forms the demarcation point between Electra's network and the consumers' assets (the "service main"). This is usually located at or near the physical boundary of the consumers' property. These assets form the point of delivery for Electra's distribution services.

The key systemic issue with consumer connections has been the corrosion of some earlier thin steel pillars and the degradation of non-UV stabilised polymer pillars. The affected pillars are replaced progressively based on risk they pose to network and public safety.

2.4 Asset valuation (RAB) allocation

Electra's Regulated Asset Base (RAB) increased from $175.9 million to $179.6M from FY2018 to FY2019. The FY2019 RAB comprises of network assets as shown in Figure 2-6.

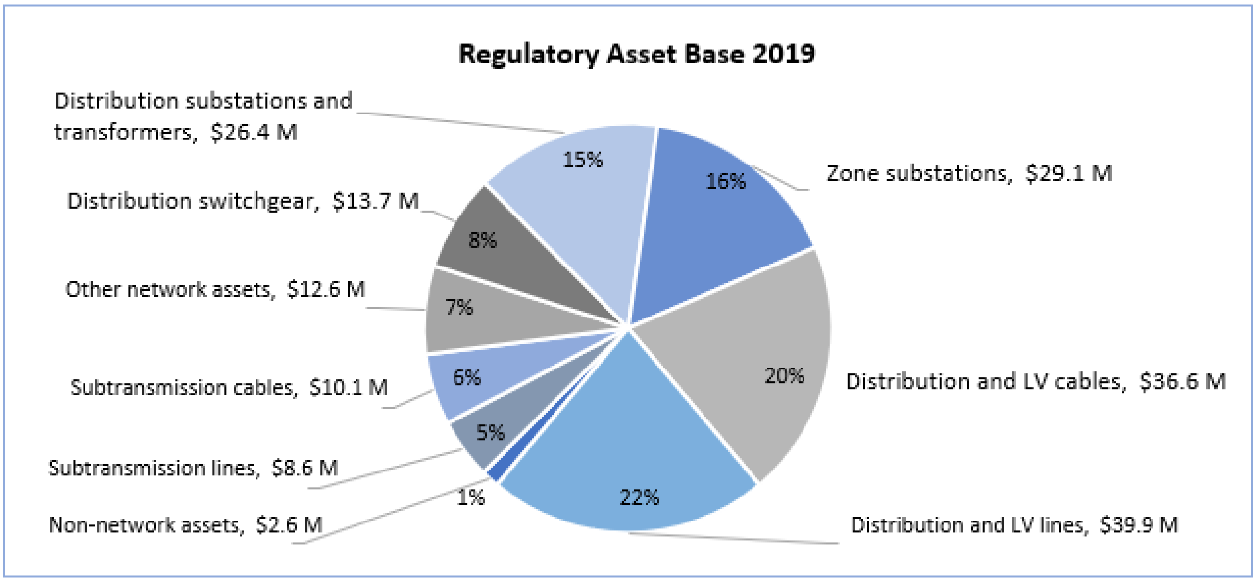


Figure 2-6: Regulatory Asset Base 2019 depicting asset categories and values

3 Service levels

Four key value drivers have been identified in the Statement of Corporate Intent (SCI) linking Electra's group strategies to the operational targets and measures that are critical to achieving these strategies. These drivers are Revenue, Profit, Assets and People. The relevant targets are explained in the following sections.

3.1 Primary customer service levels

A key objective of the Asset Management Plan is a focus on customers, on their needs and wants and to support the delivery of best value services to our customers.

3.1.1 Reliability

Electra's primary customer service level is supply continuity and restoration, as measured by using internationally accepted performance measures known as:

- **SAIDI:** System Average Interruption Duration Index indicating the average time in minutes all customers are interrupted
- **SAIFI:** System Average Interruption Frequency Index indicating the average number of interruptions per customer or the frequency of interruptions
- **CAIDI:** Customer Average Interruption Duration Index, indicating the average time in minutes affected customers are interrupted.

Electra does not distinguish between customers in different geographical areas, but the radial configuration of its rural network inevitably means that while all customers will experience a similar frequency of interruptions, those in rural areas are likely to experience longer supply interruptions.

Electra's historical and forecast SAIDI, SAIFI and CAIDI are:

Measure	Actual (historical)					Forecast →				
	FY2015	FY2016	FY2017	FY2018	FY2019	FY2020	FY2021	FY2022	FY2023	FY2024
SAIDI B (Planned)	16.18	19.35	17.13	26.73	32.32	15	15	15	15	15
SAIDI C (Unplanned)	123.12	80.71	79.23	95.00	57.00	68	68	68	68	68
SAIDI	158.83	100.06	96.90	121.73	89.33	83	83	83	83	83
SAIFI B (Planned)	0.05	0.06	0.05	0.08	0.10	0.06	0.06	0.06	0.06	0.06
SAIFI C (Unplanned)	2.20	1.10	1.45	2.00	1.17	1.6	1.6	1.6	1.6	1.6
SAIFI	2.63	1.16	1.63	2.08	1.26	1.66	1.66	1.66	1.66	1.66
CAIDI B (Planned)	344.26	328.02	342.60	321.21	323.20	250	250	250	250	250
CAIDI C (Unplanned)	56.01	73.64	54.64	47.58	48.72	42.5	42.5	42.5	42.5	42.5
CAIDI	60.44	86.63	59.45	58.53	70.90	50	50	50	50	50

Historical unplanned and planned SAIDI versus the total 83-minute target is shown in Figure 3-1(a) while planned SAIDI against its target is depicted in Figure 3-1 (b). Appendix 7 contains Schedule 12d, the report on forecast interruptions and duration required by the Commerce Commission's Determination.

Comments on the historical performance include:

- An unplanned interruption on the back up supply to Levin whilst the main 33kV supply was out of service for maintenance meant the FY2016 SAIDI exceeded target
- Kaikoura earthquake related faults led to FY2017 SAIDI target exceeded
- A further 33kV interruption during the FY2018 year has focused Electra's attention on the resilience of its 33kV network and resulted in specific programmes of work to systematically improve the reliability of sub transmission network through protection improvements and component replacements

- Unplanned SAIDI for FY2019 was dominated by a major 33kV outage caused by a bird strike resulting in the loss of the northern network which contributed 10.2 SAIDI minutes.

3.1.2 Justification for reliability targets

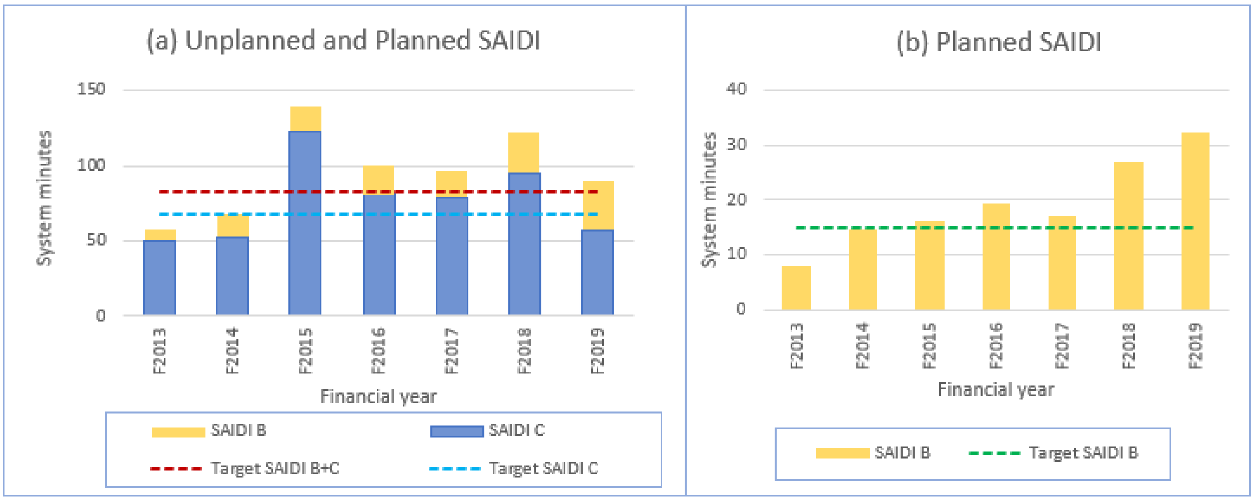


Figure 3-1: Historical unplanned and planned SAIDI trends

The frequency of unplanned interruptions or SAIFI has reduced from 2 in FY2018 to 1.17 in FY2019 as demonstrated in Figure 3-2a. Planned SAIFI and CAIDI (in Figure 3-2b and Figure 3-2c respectively) have increased above the targets set due to the increase in asset renewal and replacement programmes to improve network performance. Though unplanned CAIDI has reached the target of 43 minutes, Electra's CAIDI is still the best amongst its peer group (Section 8.2.1).

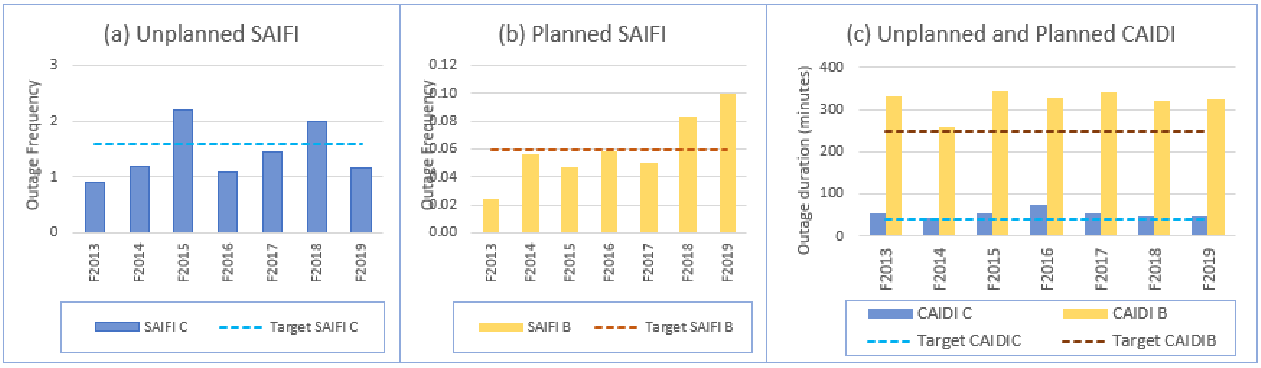


Figure 3-2: Historical unplanned and planned SAIFI and CAIDI trends

Customer consultation and community engagement reveals that Electra's customers prefer not to pay more for further improvements in reliability. Such findings were reported in the recent study by the Electricity Networks Association on the "Quality of Service Regulation"[7]. However, Electra has identified several tactical programmes to maintain the performance at optimal this level and deliver improved customer experience as discussed in Section 3.9.

[7] Electricity Networks Association, "ENA Working Group on Quality of Service Regulation Interim Report to the Commerce Commission", 1 October 2018.

3.2 Secondary customer service levels

Electra's secondary customer service levels include the following aspects:

- Processing an application for a new connection
- Providing technical advice
- Giving sufficient notice for planned shutdowns.

Electra's target for these secondary customer service levels are as follows:

Attribute	Measure	Forecast →				
		FY2021	FY2022	FY2023	FY2024	FY2025
Processing new connection application	Number of working days to process	3	3	3	3	3
Providing technical advice	Number of working days to acknowledge by mail	4	4	4	4	4
	Number of working days to acknowledge by phone	2	2	2	2	2
	Number of working days to investigate inquiry or validate complaint	5	5	5	5	5
	Number of working days to provide advice for non-complaint matter	3	3	3	3	3
	Number of working days to resolve proven complaint (unless non-minor asset modification required)	10	10	10	10	10
Notice for planned shutdowns	Number of customers to who 3 working days of a shutdown is not provided.	5	5	5	5	5
	Number of large customers to whom 60 minutes advanced notice of a planned shutdown is not provided.	1	1	1	1	1
	Number of large customers whose preferred shutdown times cannot be accommodated.	2	2	2	2	2

Customer surveys by both Electra and other EDB's have identified these service attributes as less important than supply reliability (continuity and restoration). A key feature of these secondary service attributes is that they are based on processes rather than fixed asset investment.

Electra shares the view of the ENA study (Section 3.1.2) that identified the ease of connection and timely planned outage notification as two key opportunities to positively impact our customer experience.

3.3 Asset performance levels

Electra's asset performance levels include:

- Load factor
- Capacity utilisation
- Network losses
- Economic effectiveness.

Electra's historical and forecast performance values are:

Measure	Actual (historical)					Forecast					
	FY2015	FY2016	FY2017	FY2018	FY2019	FY2020	FY2021	FY2022	FY2023	FY2024	FY2025
Load factor	53%	56%	48%	49%	50%	50%	51%	52%	52%	53%	53%
Capacity utilisation	26%	25%	31%	31%	30%	>30%	>31%	>31%	>32%	>32%	>32%
Network losses	7.4%	6.7%	6.7%	8.4%	6.9%	6.9%	6.9%	6.8%	6.8%	6.8%	6.8%

The above values are also included in the Commerce Commission's Determination Schedule 12c, which is the report on forecast network demand (Appendix 6).

3.3.1 Load factor

Load factor is calculated as the average load passing through a network divided by the maximum load experienced in any given year. Electra seeks to optimise load factor as this indicates better utilisation of capacity in the network. Section 8.3.1 contains a further discussion on the derivation of the targets for our load factors.

3.3.2 Capacity utilisation

Capacity utilisation ratio measures the utilisation of transformers installed on our network. It is calculated as the maximum demand experienced on the network divided by the distribution transformer capacity on the network. In FY2019, our distribution transformer utilisation was 30% and based on industry utilisation performance versus network density discussed in Section 8.3.2, we have set our utilisation target to be greater than 30%. We aim to ensure maximum economic efficiency by ensuring good design and lifecycle management practices.

3.3.3 Network losses

Electricity networks incur energy losses caused by the technical losses (heating of transformers and conductors) and non-technical losses like meter/billing errors and theft. Electrical losses are the difference between energy (GWh) entering the Electra network and the energy leaving the network at consumer connections. Section 8.3.3 contains some information on our forecast.

3.3.4 Financial efficiency

Financial economic efficiency reflects the asset investment required to provide network services to customers and the operational costs associated with operating and maintaining assets. The measures Electra use to monitor our financial efficiency includes:

Financial ratios	Actual		Target and forecast
	FY2018	FY2019	
Capital expenditure on assets per total circuit length (km)	$5,148	$5,065	Within 2% of the previous year's figures.
Capital expenditure on assets per connection point	$264	$259	
Operational expenditure on assets per total circuit length (km)	$5,306	$5,308	
Operational expenditure on assets per connection point	$272	$271	

The above measures are published yearly on Electra's website through Information Disclosure schedules.

The trends in our operational (OPEX) and capital asset expenditure (CAPEX) per ICP and per circuit length (in km) are depicted in Figure 3-3.

Electra aims to maintain its OPEX and CAPEX per ICP and per circuit length (km) within 2% of the previous year's figures. Further evaluation of the above indicators is included in Section 8.3.4.

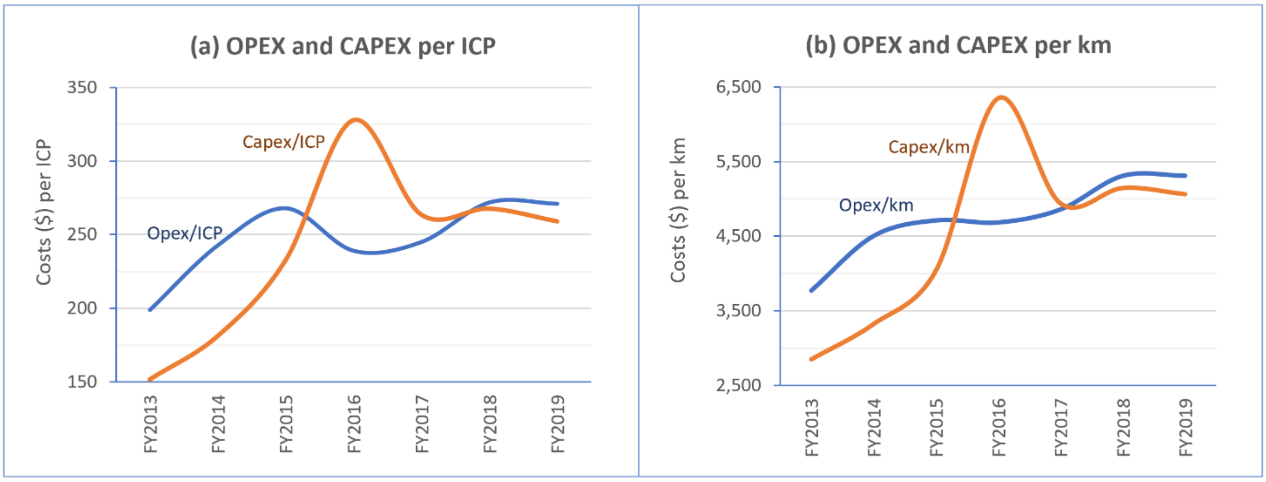


Figure 3-3: OPEX and CAPEX (a) per ICP, and (b) per circuit length (km)

The costs for both OPEX and CAPEX per ICP and per circuit length (km) decreased from FY2018 to FY2019 with OPEX/km reducing by 0.3% and CAPEX/ICP falling by 3.2%. Further comparison of our performance is included in Section 8.3.4. The OPEX includes direct and indirect costs.

3.4 Safety and environmental performance levels

Electra's safety and environmental performance measures for the last three financial years as well as our targets are shown in the following table:

Service criteria	Indicator	FY2018	FY2019	Target and forecast	Performance measurement
Public safety: safety of staff, contractors and the public	Number of incidents	3	8	Zero harm	Safety audits - zero non-compliance
Personnel safety	Lost Time Injury (LTI)	9	4	Zero LTI	Annual measurement
Environmental responsibility	Number of environmental incidents	0	0	Zero harm to the environment	SF6 Leak rate, transformer leak rate, zone transformers - dissolved gas analysis
Legislative requirements	Compliance with relevant regulations	Full compliance	Full compliance	Full compliance	Annual measurement

The number of safety incidents has increased since FY2017 with this increase attributed to improved record-keeping and data capture. The number of lost time injury or LTI has decreased over the three years. Electra is committed to ensuring a zero-harm safety incident rate.

The above targets include compliance with applicable safety and environmental legislations covering:

- Health and Safety at Work Act 2015
- Health and Safety (Asbestos) Regulations 2016
- Building Code, Section C5 of the Engineering Assessment Guidelines - Seismic assessment of existing buildings
- Electricity (Safety) Regulations 2010
- Electricity (Hazards from Trees) Regulations 2003
- Resource Management Act 1991
- Maintaining an independently certified Safety Management System, which conforms to the Safety management systems for public safety, NZS 7901:2014.

Other legislative requirements are stated in Section 3.7.2.

3.5 Regulatory performance levels

Regulatory performance levels are generally set by statutory agencies and include the compliance to various legislations listed in both Sections 3.4 and 3.7.3 as well as the following:

- Compliance with the operative Horowhenua and Kapiti Coast district plans
- Compliance with the operative Wellington and Horizons regional plans
- Participation in regional disaster recovery initiatives such as Life Lines
- Compliance with New Zealand Transport Agency requirements for locating assets within road reserve, and for working within road corridors
- Compliance with KiwiRail requirements for locating assets near railway lines, and for working within rail corridors
- Compliance with electrical worker certification and training requirements.

Electra aims to fully comply with all of the above requirements.

3.6 Public good service levels

Electra also provides a range of (non-safety) services that are for the public good. These include:

- Switching of controlled loads, including streetlights and under veranda lighting
- Laying ducts during other parties' excavations to avoid future excavations
- Allowing other parties to suspend cables from Electra's poles
- Allowing other parties to mount signs on Electra's poles
- Relocating assets to better suit other parties, especially near roadways
- Facilitating and possibly contributing EV charging infrastructure
- Facilitating the installation of renewable generation.

3.7 Justification for service levels

Electra has adopted its current and planned future service levels based on customer expectations, regulatory requirements, and our group's strategies and objectives.

3.7.1 Customer expectations

With a group strategy on a focus on customers and world-class communication, Electra has deployed new technologies to keep customers informed and has also significantly improved the outage information available on its website. The website now provides customers with up-to-date access to detailed outage information including the location of faults vehicles, easy-to-understand icons as well as creating an Electra Customer Outage App, available for use on mobile devices.

Electra gauges customer expectations by conducting yearly Customer Service Surveys since the late 1990s. These surveys involve interviews with approximately 300 customers who have contacted Electra's faults service in the two to three months immediately prior to the survey period. Electra commissioned the 2018/19 survey[8] to track any changes in perceived service delivery relating to the servicing of faults, compare the satisfaction levels of customers with previous surveys, gain an updated measurement of customers' preferred information sources during interruptions to electricity supply, as well as to offer participating customers the opportunity to provide feedback to Electra's Chief Executive.

Research participants were asked to identify which information source would be their preferred choice during a fault. As depicted in Figure 3-4 (a), preference was split largely between the '0800 Lost Power information line' (45%) and 'text messaging' (38%), which has significantly increased since the last survey. Other sources include a call from Contact Centre (6%), Smartphone App (4%), website (3%) and Facebook or Twitter (2%). Electra will continue to monitor and enhance the uptake of newer technologies by its customers.

Figure 3-4 (b) indicates the information sources gaining prominence with our customers. The internet (32%) continues to be the leading source of information for contact details, followed by the 0800 number (26%) and the fridge magnet (17%).

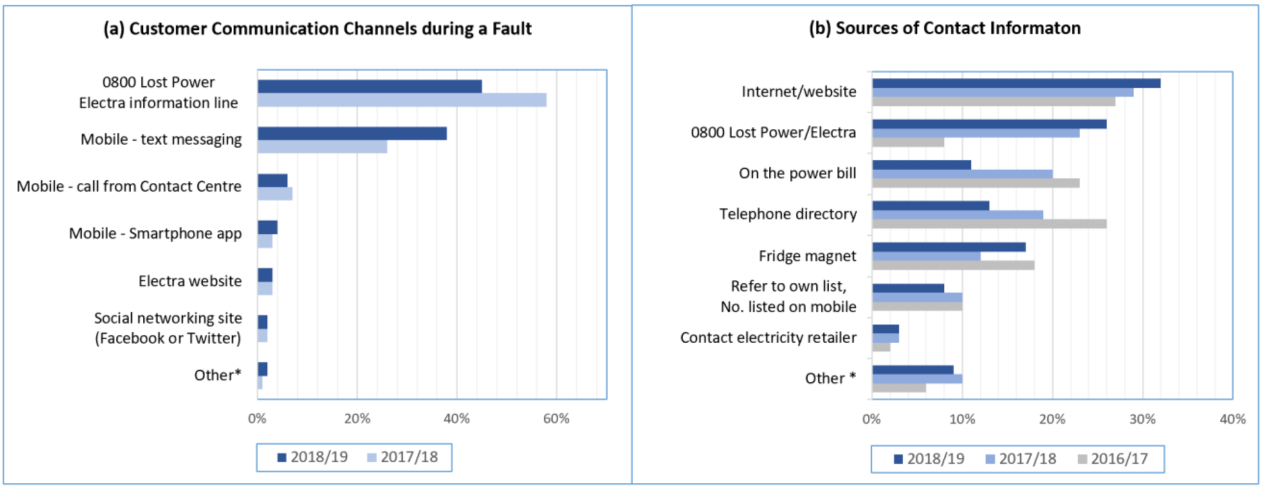


Figure 3-4: (a) Preferred customer communication channels during a fault and (b) Sources of contact information

Figure 3-5 (a) shows most respondents are satisfied with the resolution of faults with only 1% of respondents dissatisfied. The results in Figure 3-5 (b) also indicate the ratings given for the 'timeliness of faults resolution' remain positive, with 90% of respondents considering it to be 'excellent' or 'very good'. There was also a significant movement in the level of 'excellence' from 67% in FY2018 to 76% in FY2019.

[8] Data extracted from "Customer Service Survey 2018-2019" Report prepared for Electra by Peter Glen Research, Mar-2019

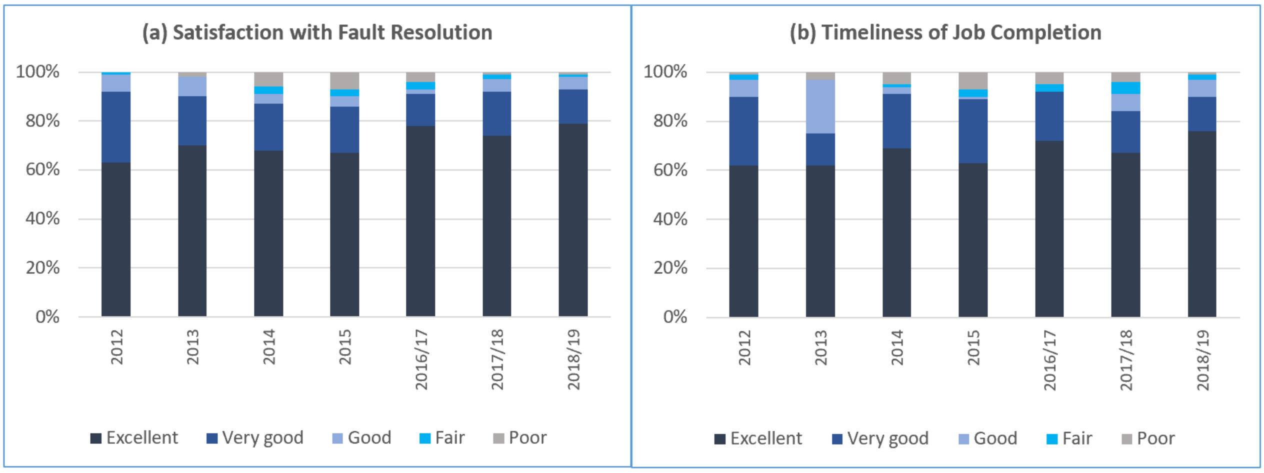


Figure 3-5: (a) Satisfaction with fault resolution, and (b) Timeliness of job completion

The graph in Figure 3-6 a shows residents in north and south Otaki gave similar service ratings. Further as per Figure 3-6 b, the results of the latest study again reveal the majority of respondents who had contacted Electra previously detected " no change" in service delivery though an increased 5% stated that the service had changed "for the better".

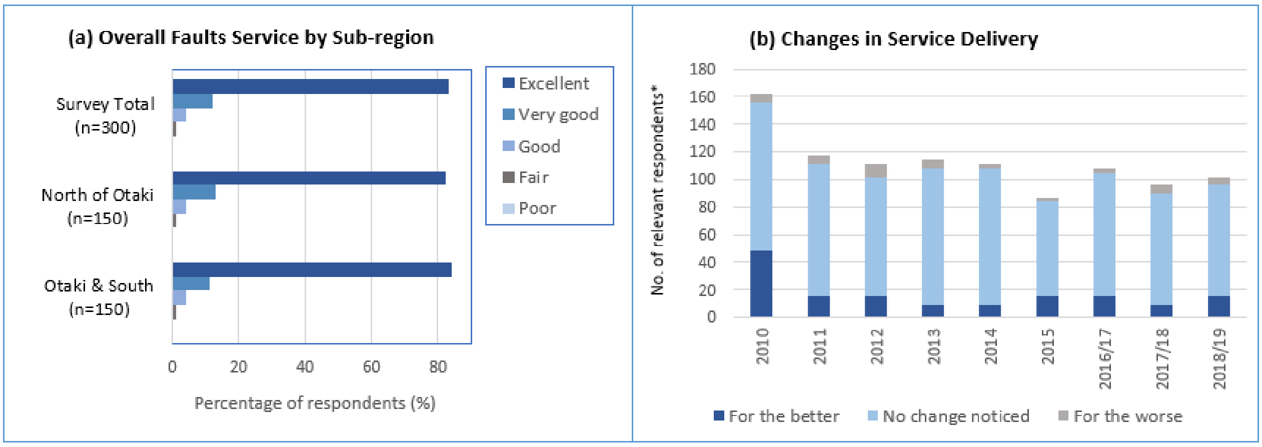


Figure 3-6: Perception of respondents: (a) Overall faults services by sub-region in 2018-19, and (b) Changes in service delivery

91% of research participants in the FY2019 survey did not have a suggestion for improvement to Electra's services and many expressed their satisfaction with the service received. Requests from the remaining 9% include a price reduction in the line charges, reduce repeated outages and clear identification of Electra personnel.

The overall results of the FY2019 survey show that the satisfaction levels of Electra customers remain very high and has improved to 93% for respondents who rate the Call Centre service as "excellent" or "very good" as shown in Figure 3-7a. Similarly, the ratings for service personnel have also remained very high as depicted in Figure 3-7b.

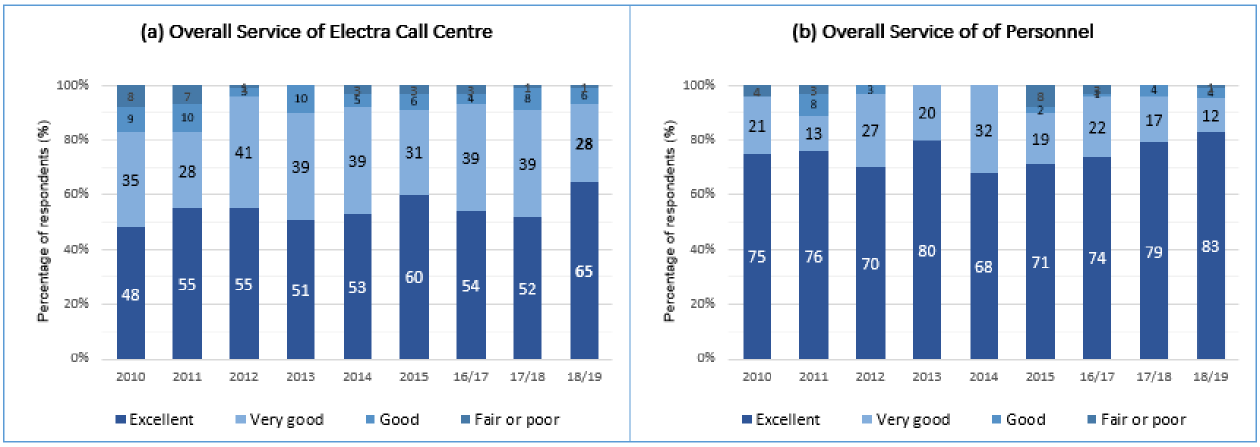


Figure 3-7: Overall services of: (a) Electra Call Centre, and (b) Service personnel

3.7.2 What our customers tell us

Electra's annual survey results of Section 3.7.1 inform us we have performed well in our customer services but we also look a bit closer to find areas of our products and service where we could do better. The survey is one way we seek to gain insights into opportunities to improve our customers' experience.

Our customers are telling us that:

- They'd like our profile and brand to be higher in the community
- While we're pretty good at communications, it is also the area where the most suggested improvements have been provided
- They have an appetite for, and increasing awareness of renewable energy though are mindful of the cost they would bear in adopting it
- They like help in accessing WINZ winter energy grants
- To keep electricity prices down
- There are a set of common questions from our rural customers around reliability, cost of connection, tree faults and risk of grass fires that FAQs for our call centre that could help
- Electra's discount is mostly welcome but there are perceptions of disparity and how its calculated that could be added to our FAQs we send out with our discount letter.

Occasionally, we are criticised for poor performance of retailers or other infrastructure owners though we accept this as a communications issue that we can help with.

When reminded of Electra, over 80% of participants cited specific knowledge about what Electra does, though prior to naming of Electra, less than 30% knew who the local electricity distributor was.

Common themes that participants thought we do well are:

- Is conscious of public safety
- Provides a reliable supply of electricity
- Works hard to keep the power on
- Has well-maintained poles and wires
- Is professional
- Is dependable
- Cares about the community
- Fixes faults quickly

- Takes a responsible approach to business
- Is friendly and helpful.

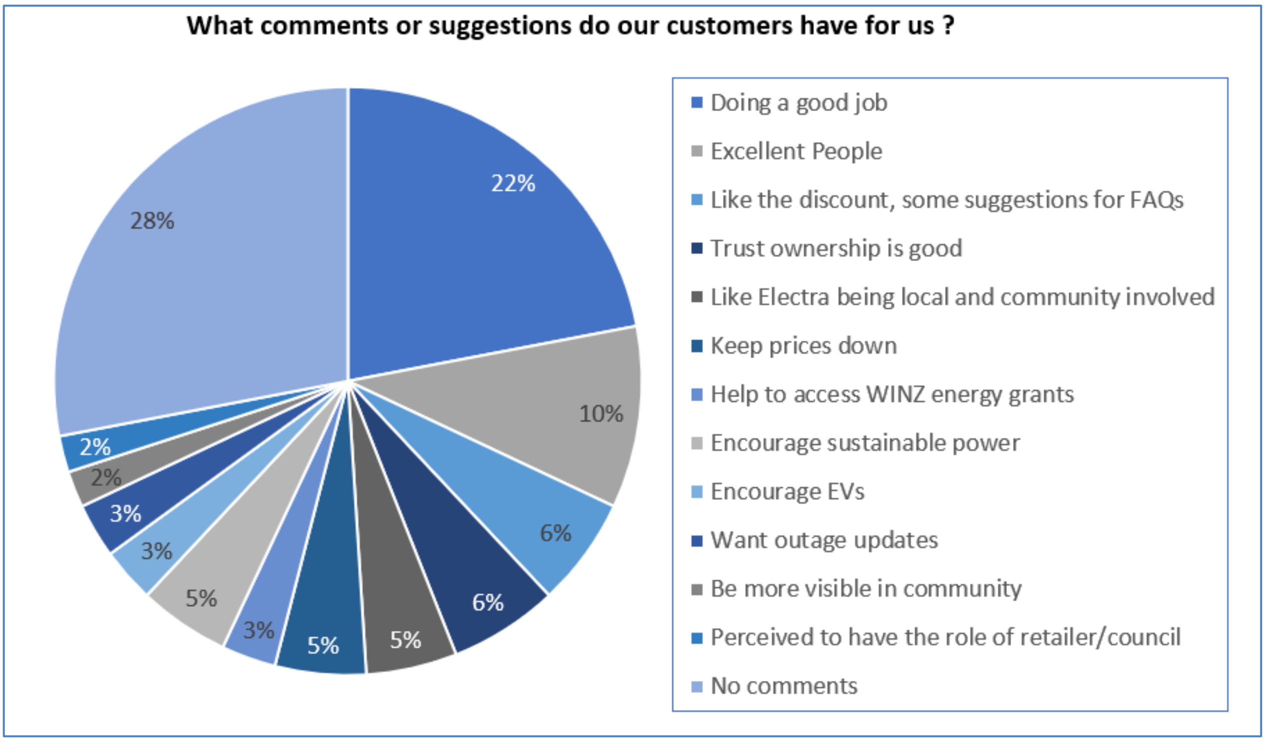


Figure 3-8: Customer comments and suggestions

There is an appetite for renewable energy and new technologies, expressed by:

- A desire for solar power to be more affordable
- A desire for more efficient use and more sustainable power sources
- A desire for help with EV chargers being installed at workplaces.

Communication and presence were things we did well in but also attracted the greatest number of improvement suggestions:

- Follow through with updates during planned and unplanned outages via text messaging
- Follow up where there have been ongoing issues/repeat faults
- Improving the Call Centre's level of knowledge and empathy about faults enquiries
- Electra doesn't seem as present in the community as it was a couple of years ago
- A hub to come and ask questions would be good
- Directions to EV charging stations on street and highway signs would be useful
- Help people feel part of good things such as community improvement initiatives
- Use of the website or Electra App is rising slowly though around 30% indicated they would refer to the phone book and phone for updates.

With respect to customer interest in products and technologies supporting energy efficiency, comfort and cost reduction, around 20% of Electra's customers are interested in products that improve management of their energy use and energy costs.

Product/service		Residential	Commercial
Water heating control	Have adopted	14%	22%
	Want to know more	27%	29%
Energy efficient lighting	In all lights	42%	36%
	In some	55%	50%
Heat pumps	Customers that have this	53%	55%
	Owners that want advice to improve cost effectiveness	20%	18%
Solar water/power	Customers that don't have this	>92%	>93%
	Likely to consider if benefits improve	>23%	>17%

Development of these customer-centric product offerings is supported by Electra's strategic focus areas of: Focus on the Customer, Prepare for Change and Develop the New. In addition to the product offerings surveyed, our customers are, unprompted, telling us they are interested in electricity as a transport fuel.

Since the 2019 customer survey, Electra has progressed a programme to implement nine EV fast chargers across the network as well as installing charging infrastructure in the depots plus public charging at its Levin, Bristol St offices. Further information is included in Section 4.3.6.

3.7.3 Regulatory compliance

Electra sets service levels to comply with the legislative obligations and some key legislation that relates to the management and operation of electricity networks in New Zealand includes:

- The Electricity Act 1992 and pursuant Electricity (Safety) Regulations 2010
- Electricity Industry Act 2010 including the Electricity Industry Participation Code 2010
- Health and Safety at Work Act 2015
- Health and Safety (Asbestos) Regulations 2016
- Resource Management Act 1991
- Electricity Codes of Practice (ECPs) such as NZECP 34:2001 on Electrical Safe Distances, NZECP 35:1993 on Power Systems Earthing
- Electricity (Hazard from Trees) Regulations 2003;
- Commerce Act 1986 including the Electricity Distribution Information Disclosure Determination 2012 (consolidated April 2018)
- Electricity Distribution Services Input Methodologies Determination 2012 (in as much as that Determination applies to an exempt EDB)
- AS/NZS 3000:2007: Electrical installations (known as the Australian/New Zealand Wiring Rules)
- Building Act 2004 and pursuant Building Code
- Building Code, Section C5 of the Engineering Assessment Guidelines regarding the seismic assessment of existing buildings
- Civil Defence Emergency Management Act 2002
- Horowhenua and Kapiti Coast District Councils requirements.

Such legislative requirements and its amendments will affect our service levels.

3.7.4 Group business strategic objectives

Electra's Group business mission, objectives and strategies provide the direction for setting key service levels as outlined in Section 1.1. The Statement of Corporate Intent further identifies the operational targets covering network service performance standards, network reliability and safety targets identified in this AMP.

3.8 Translating stakeholder needs into service levels

Electra translates stakeholders' needs into service levels as follows:

Service level attribute		Consumer response		Service levels
What do consumers want the most?	➔	Continuity and restoration first and foremost	➔	Give priority to continuity and restoration of supply first and foremost
How much do they want?	➔	About the same as they are currently getting	➔	Maintain continuity and restoration performance at about the current level
How much do they want to pay?	➔	About the same as they are currently paying	➔	Keep line charges at about the same level as they currently are
Are the consumers happy?	➔	Yes	➔	Keep delivering similar service levels for other attributes

3.9 Tactical programmes

In order to meet its service level targets, Electra has identified the following tactical programmes to improve the resilience of the 33kV sub transmission and 11 kV distribution networks:

Issue/concern	Requirement	Programme	Linkage to AMP programmes
Declining component condition is leading to an increase in the number of 33kV outages on the Northern ring	Avoid an increase in the number of unplanned interruptions due to component deterioration	Improve northern 33kV resilience	4.7.2, 4.7.3, 5.4.2
Increasing number of spurious protection operations on the 33kV	Avoid an increase in the number of unplanned interruptions due to spurious protection trippings	33kV protection study and strategy development	4.7.1, 4.7.2
New connections leading to more customers interrupted by any single fault	Reduce the number of customers effected by an unplanned interruption. Reduce the time to restore supply may result from increased interconnection	Increase network sectionalisation	4.4, 4.7.1, 4.7.2
Legacy copper conductor becoming increasingly brittle	Remove brittle conductor which is a safety hazard	Replacement of copper conductors.	5.4
Legacy copper conductor has limited capacity	Reduce the time to restore supply (by allowing more 11kV back-feed options)		
Specific classes or makes of assets known to be of less than acceptable reliability or safety remain in service	Remove specific classes or makes of assets	Reduce number of risky assets	5
Responsive tree-trimming	Improve value of tree-trimming programme by considering improvements to customer reliability	Migration to risk-based tree trimming	5.11
Repeated HV feeder trippings	Reduce the number of repeated 11kV feeder failures (SAIFI) as well as reduce SAIDI minutes	Identification of 11kV Worst Feeders	3.9.7

3.9.1 Improvement of northern 33kV resilience

This issue has been the subject of a dedicated tactical study during 2017 in which Electra has identified the following circuits within the Northern 33kV ring as being particularly unreliable:

- Mangahao to Levin East (2 parallel circuits as far as Waihou Rd, then single circuit from Waihou Rd to Levin East)
- Foxton to Levin West
- Shannon to Foxton.

The most effective and efficient approach to improving the reliability of these circuits would be to isolate them one at a time for a prolonged period and work intensely, rather than working on a day-by-day basis and returning to service overnight. Unfortunately, the respective back-up circuits are not considered sufficiently reliable to rely on for prolonged periods.

The proposed solution is a planned sequence of work that begins with reconfiguring both 110kV lines as a 33kV line between Mangahao and Levin East to provide (n-1) security to Levin East whilst the Waihou Rd – Levin East line is isolated. The reasoning is:

- The identified circuits each have a less-than-acceptable reliability that is likely to decline as the individual circuits deteriorate. This occurred during a cross arm replacement project between Mangahao and Shannon where the NZI brown porcelain insulators were falling apart as they were removed. It also provided insight into trippings we are having on 33kV in the northern region
- A sequence of work has been identified that will enable prolonged isolation of each circuit whilst still providing (n-1) security to all zone substations.

3.9.2 33kV protection study and strategy development

A 33kV interruption during the 2017/18 year has focused Electra’s attention on the less-than-acceptable resilience of its 33kV network and resulted in specific programme of work to systematically improve the reliability of sub transmission network through protection improvements.

Technical investigations reveal that spurious protection tripping have been partly to blame for unplanned outages. In 2018 Electra engaged a protection specialist to review the protection schemes and develop a strategy, starting with the Southern network. The objectives of that strategy were to:

- Create a roadmap to improve the main and back up protection schemes(standardise) for various asset classes based on cost risk and performance
- Extract value out of Transpower investments e.g. ODID (outdoor to indoor conversion) to install relays supporting unit protection schemes
- Validate that existing protection settings are fit for purpose.

3.9.3 Sectionalisation of networks

As more customers are added to individual feeders (mainly in Kapiti), the customers at risk of interruption from any single fault increases. Electra intends to insert switches (automated where required) into the 11kV network to:

- Reduce the number of customers exposed to any single fault
- Enable increased meshing of the 11kV to enable restoration by switching rather than by repair.

At this stage, Electra’s approach will be to:

- Identify feeders that have exceeded Electra's planning criteria of either 1,500 domestic customers or 5,000kVA of commercial load
- Identify suitable locations for inserting switches that will both reduce the customers at risk and allow for meshing, thus providing a dual win of reduced customers effected by a fault and reduced restoration time.

3.9.4 Replacement of copper conductors

Electra's network still has 7/0.083, 19/0.064 and 19/0.092 copper conductor, which presents the following operational constraints and risks:

- The low current rating of 7/0.083 limits the ability to restore supply by back feeding on the 11kV
- The relatively high impedance of these conductors also contributes to voltage regulation issues
- The conductor has work-hardened and become brittle over many years, increasing the risk of in-service failure
- Field services do not work on live copper lines due to the increased risk of it snapping during work and recoiling onto other conductors. This issue makes jobs expensive due to generator utilisation otherwise it will be an inconvenience to customers as a result of shutdowns.

Electra will prioritise the replacement of copper conductors due to these contributing drivers other than just condition-based asset renewal.

3.9.5 Reduction of the number of risky assets

Electra's network still contains some assets that are now considered to have an unacceptable risk of in-service failure to staff and public (e.g. pitch filled metal pot heads, metallic link pillar boxes, deck mounted transformer structures etc). Electra has included provisions in the AMP to remove these high-risk assets based on their location and the risk they present.

3.9.6 Migration to planned tree trimming

Electra's vegetation management programme has evolved over recent years. During 2018 Electra has overlaid an additional analytical tool, over and above the requirements of the Electricity (Hazards from Trees) Regulations, to systematically identify the greatest risk to customer service and safety from trees close to network.

The resulting tactical programme strongly reflects two of this AMP's strategic themes:

- Continuing to implement approaches which improve cost, risk and performance
- Implement asset criticality (and the associated medium-term goal of the asset criticality framework driving all network investment decision).

Key features of this strategic improvement include:

• Leveraging the tree regulations to deliver safety and performance outcomes • Tree cutting driven from routine and customer requested survey. • Improve network performance where impacted by vegetation	➔	• Risk rather than performance-based management of safety and SAIDI • Progressively reduce reactive trimming, and instead proactively cutting trees back and engaging with tree owners to implement longer term solutions • Systematically reduce risk in network sections between automated switches and circuit breakers • Leverage data of historical tree work to strategically develop a work programme to systematically reduce vegetation based SAIDI and safety risk

The key features of our strategic vegetation management programme link to the strategic goal of reducing SAIDI follow:

Feature		Improve safety and SAIDI		Reduce operational expenses	
		Reduce number of customers at risk	Reduce outage duration	Reduce work volume	Reduce unit costs
Key driver will be trees that affect the largest number of customers		•	•		
Augment responsive tree work with plans to reduce risk by feeder section	➔	•			•
Engage with tree owners to implement longer term solutions		•		•	
Stronger connection of tree data with network data		•	•	•	•

3.9.7 Reduction of repeated power failures

The feedback from customers (Section 3.7.1) identified the need to reduce the number of repeated power failures. Besides its 33kV resilience program explained in Section 3.9.2, Electra regularly monitors the least reliable or "worst" 11kV distribution feeders on the network in terms or SAIDI and SAIFI as these high voltage power failures have the greatest impact on customers.

With the feedback on repeated failures, we studied the impact of faults on feeders further in terms of the number of failures over a 3-year period from FY2017 to FY2019. The worst ten 11kV feeders in terms of the number of failures are shown in Figure 3-9 as well as SAIDI (Figure 3-10a) and SAIFI (Figure 3-10b) impact.

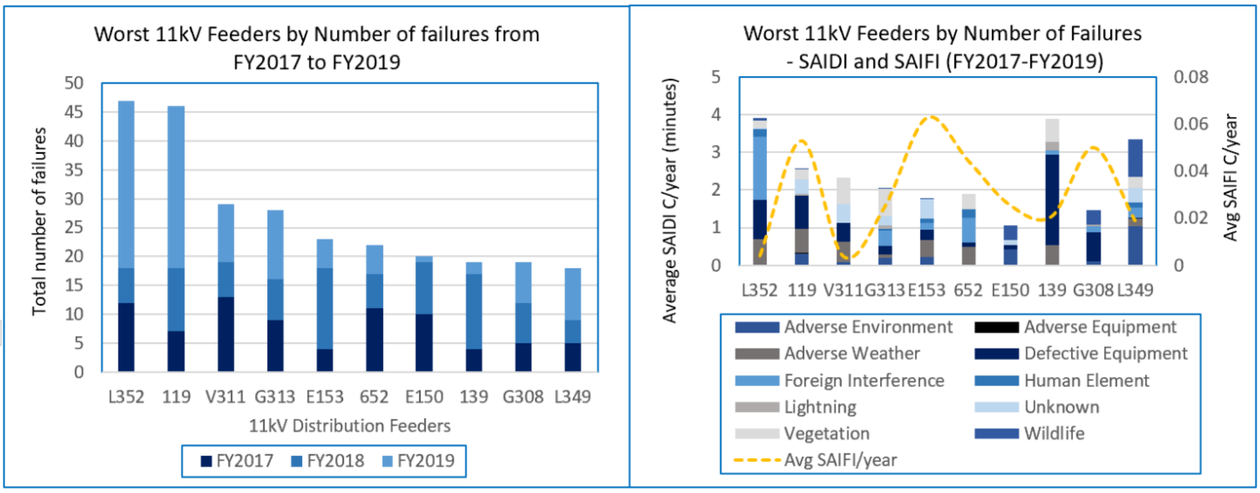


Figure 3-9: Worst 11kV feeders by the number of faults and their related SAIDI and SAIFI impact: FY2017 to FY2019

The worst feeders vary when monitoring by the number of failures (L352, 119), the impact to SAIDI (L352, 139) or SAIFI (V311, E153).

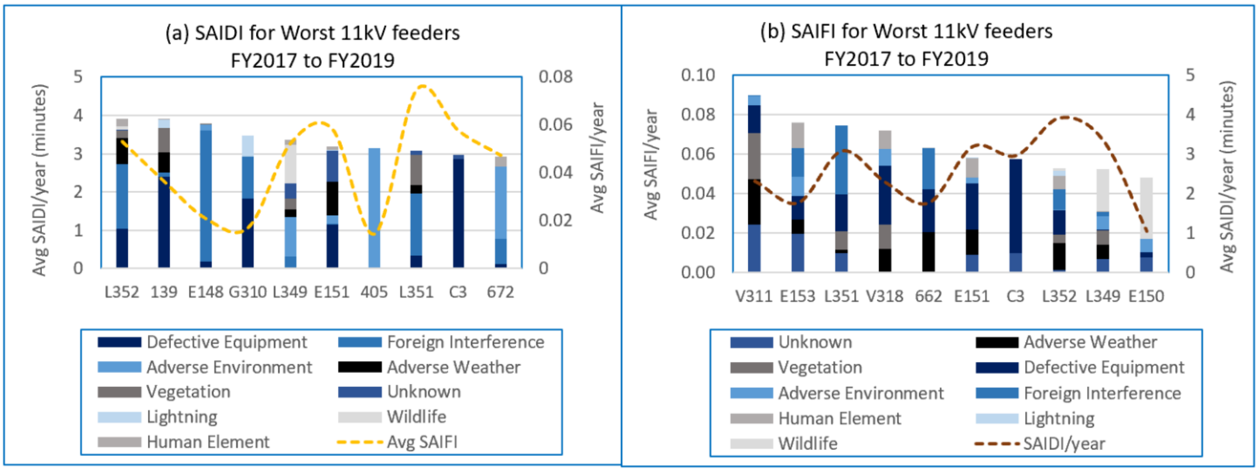


Figure 3-10: Worst 11kV feeders due to faults for FY2017 to FY2019 by: (a) SAIDI and (b) SAIFI

Initiatives such as circuit reconfiguration, sectionalisation, network automation and/or other reinforcement options are then undertaken to reduce the impact of these failures to our customers. Such initiatives are described further in Section 4.7. The prioritisation process for reliability-improvement projects for the worst feeders is discussed further in Section 8.4.6 where the process flow is shown in Figure 8-21: Fault intervention process for worst 11kV distribution feeders.

4 Network development

4.1 Development context

Electra's development plans are driven primarily by capacity constraints (which almost always occur due to increasing demand), declining reliability, voltage excursions, or security of supply.

At its most fundamental level, demand is created by consumers drawing energy from or by injecting energy into their individual connections. Electra recognises that the issues that have historically led to demand growth are now more complex with the uptake of smart home and business technologies and Distributed Energy Resources (DER).

Electra has been in discussion regarding developments and opportunities with product and service providers, as well as individually with other EDBs and collegially through the ENA and EEA.

The ENA work has developed some helpful groupings of consumers based on values and behaviours; Prosumer, Off grid, Grid as Back Up, Set and Forget. This is consistent with how Electra articulated the view of smart grid in the 2018/19 AMP.

The discussions with individual providers and EDBs have advanced Electra's thinking in the future development of products and services to consumers. Together with organisational changes to strengthen Electra's capabilities to develop new customer products, Electra will now be developing a trial to collaboratively test technologies and price options that enable consumers with options to better manage their energy and enable Electra to manage load from new technologies such as electric vehicle chargers.

4.2 Development criteria

Electra considers the following driving factors as the criteria for developing its network:

- Capacity and voltage
- Reliability
- Security of supply.

4.2.1 Capacity and voltage triggers

If any of the triggers below are exceeded, Electra will intervene which may include adding additional capacity to the network:

Asset category	**System growth (consider adding capacity)**	
	Capacity trigger	**Voltage trigger**
400V lines and cables	Not applicable – tends to manifest as voltage constraint	Voltage at consumers' premises consistently drops below 94% of the nominal value
Distribution substations	Where fitted, MDI reading exceeds 100% of nameplate rating	Voltage at LV terminals consistently drops below 100% of the nominal value
Distribution lines and cables	Conductor current consistently exceeds 70% of thermal rating for more than 3,000 half-hours per year	Voltage at HV terminals of transformer consistently drops below 10.5kV and cannot be compensated by local tap setting
	Conductor current exceeds 100% of thermal rating for more than 10 consecutive half-hours per year	
Zone substations	Max demand consistently exceeds 100% of nameplate rating	11kV voltage Alarms from SCADA as recorded in SCADA Alarm and Event history
Sub-transmission lines and cables	Conductor current consistently exceeds 66% of thermal rating for more than 3,000 half-hours per year	33kV voltage below 31.5kV at Zone substation supplied

Asset category	System growth (consider adding capacity)	
	Capacity trigger	**Voltage trigger**
	Conductor current exceeds 100% of thermal rating for more than 10 consecutive half-hours per year	Low volts alarms from Scada and reported in Scada Alarm and event history

4.2.2 Reliability triggers

In order to limit the load interrupted by any one fault, Electra will consider intervening when the following levels are reached:

- An aggregation of up to 1,500 urban domestic consumer connections on any one feeder
- An aggregation of about 5,000 kVA of urban commercial load on any one feeder.
- Interventions may include:
- Inserting a recloser to reduce the number of customers affected by a fault
- Meshing the 11kV (typically by inserting a ring main unit) to reduce the restoration time
- Constructing a new feeder and moving some customers to that new feeder to reduce the number of customers effected by a fault
- Integration of previously discrete network ICT systems through the Milsoft E&O is expected to reduce restoration times including through more precise dispatch of fault crews.

4.2.3 Security of supply triggers

Electra's security of supply standards are set out below. In setting target security levels Electra's preferred means of providing security to urban zone substations will be by alternative sub-transmission assets with any available back-feeding on the 11kV providing a second tier of security.

System level	Load type	First fault	Second fault
GXP	Greater than 12MW or 6,000 consumers	No loss of supply	50% of load restored in 15 minutes, 100% of load restored in 2 hours
Zone substation	Between 4 and 12MW or 2,000 to 6,000 consumers	No loss of supply	All load restored within 60 minutes
Zone substation	Less than 4 MW	Loss of supply, 100 % load restored within 30 minutes from adjacent substations	Fault repair time
11kV feeder	Between 2.0 and 4.0 MW	Loss of supply, supply restored within 30 minutes from adjacent feeders	Loss of supply, supply restored within 4 hours from adjacent feeders
11kV feeder	Between 0.5 and 2.0 MW	Loss of supply, supply restored within 30 minutes from adjacent feeders where available.	Fault repair time
11kV feeder	Less than 0.5 MW	Fault repair time	Fault repair time
400V feeder	About 30 to 40 residential customers	Fault repair time	Fault repair time

4.3 Development policies, standards and methods

4.3.1 Methods and approaches used to standardise activities

Electra uses standards, codes and guidelines to achieve the following purposes (essentially all risk management tools):

Method	Purpose			
	Achieve construction and operational safety and asset performance	Minimise inventory costs	Minimise operating costs	Minimise design and construction costs
Use of standard design concepts			●	●
Use of technical design standards	●		●	
Use of standard asset sizes and configuration		●	●	●
Use of preferred purchasing	●	●		●
Use of in-house field staff	●			●

4.3.2 Consideration of energy efficiency

Electra recognises that network losses are significant (about 6.7% of energy entering the network), hence the following approaches are used:

- Upgrading of overloaded conductors to reduce the I^2R losses
- Consideration of Iron and Copper losses when purchasing equipment
- Identify and improve poor power factor installations to a minimum of 0.95
- Optimisation of open points.

4.3.3 Policies on embedded generation

Electra's policies for embedded generation are on its website. 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.

4.3.4 Impact of distributed generation

Apart from Mangahao (37MW embedded at the GXP) and Unisys (0.96MW x 2) generators, there are 581 known distributed generation sites on the Electra network with a combined capacity of about 2.1 MW as at September 2019 (as shown in Figure 4-1a). There are likely to be few occasions when that capacity will exceed 20% of the prevailing load that is recognised as the level that complicates operation. Electra is engaging with prospective customers and partners to integrate dynamic Distributed Energy Resources (DERs) into the network. Simultaneously Electra keeps a watching brief on developments in overseas markets and other NZ EDB areas.

4.3.4.1 Uptake of photovoltaic panels

Residential solar photovoltaic (PV) generation is growing in New Zealand. The Electricity Authority reported that 19,497 New Zealand residential connections now had solar panels (as at 30 September 2018), 3,840 more than the same time last year with a combined capacity of 67.6 MW, 14.7 MW more than a year ago.

As illustrated in Figure 4-1b, the PV yearly uptake in Electra rose from 72 customers in FY2018 to 104 customers in FY2019. Most of the PV panels installed are less than 10kW capacity and we will continue to monitor and support the development of distribution generation in line with its policies. Electra has also installed a 3 kW photovoltaic panel (with an 8kWh battery capacity) at their Head Office to better manage and understand the impact (Section 6.3.1) on the network and provide assistance to customers.

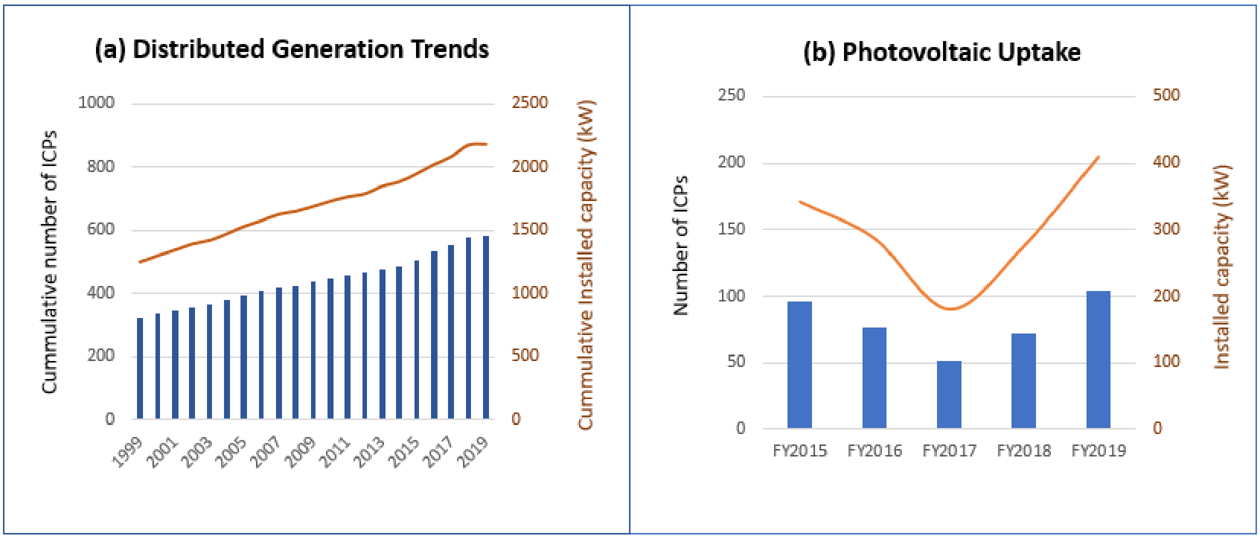


Figure 4-1: Electra (a) Photovoltaic uptake from FY2013 to FY2019; (b) Installed distributed generation trends (all types)

4.3.5 Options for meeting or managing demand

Electra considers the following three classes of options for meeting or managing demand:

Class of option	Specific approach	Description
Do nothing		Where one or more parameters have exceeded a trigger point, the "do nothing" option may be a "do nothing yet but watch more frequently" option. Essentially, "do nothing" is acceptable only when Electra is confident that service levels can be maintained, and risks remain acceptable
Non-network (low investment)	Operational activities	Actions such as switching the distribution network to shift load from heavily loaded to lightly loaded feeders or winding up a tap changer to mitigate a voltage problem will be considered. The downside to this approach is that it may increase line losses, reduce security of supply, or compromise protection settings

Class of option	Specific approach	Description
	Influence consumers to alter their consumption patterns	This allows assets to perform at levels below the trigger points. Examples include shifting demand to different time periods, negotiating interruptible and other tariffs with certain consumers so that overloaded assets can be relieved, or assisting a consumer to adopt a substitute energy source to avoid new capacity
	Install distributed generation or batteries	This allows adjacent assets to perform at levels below the trigger point. Distributed generation may be particularly useful where additional network capacity could eventually be stranded or where primary energy is going to waste (e.g. waste steam from a process)
	Modify an asset	Allowing the trigger point to move to a level that is not exceeded (e.g. by adding forced cooling). This approach is more suited to larger classes of assets such as 33/11kV transformers
	Install voltage regulator	Installing an 11kV voltage regulator may relieve voltage constraints, which defers or avoids the need for upgrading to 33kV
	Retrofitting high-technology devices	These can exploit the features of existing assets, including historically generous design margins (e.g. using remotely switched air-breaks to improve reliability or using advanced software to thermally re-rate heavily loaded lines) Electra expects that installation of smart meters will provide more accurate demand data including the duration of peak loads
Network solution	Install new assets with a greater capacity	This will increase the assets trigger point to a level at which it is not exceeded (e.g. replacing a 200kVA distribution transformer with a 300kVA transformer so that the capacity trigger is not exceeded)

4.3.6 New technology

Electra views the implementation of the Smart Grid in six interrelated areas:

- Smart technology on the network
- Smart technology in the homes and businesses of our customers
- Back office systems for the processing of information exchange with the above smart technologies
- Web-based systems serving information for contract-based customer and Electra decisions
- Customer engagement and product offerings
- Seamless inter-operability amongst available technology.

We have identified a range of prospective partners and products that can make up a functioning ecosystem for customers to lower their energy costs as well as participate in a transactive grid where energy is traded across the distribution network.

The roadmap for development comprises the activities in the following sub-sections.

4.3.6.1 Network

Activities on the network comprise of:

- Remotely operable sectionalisation
- Fault passage indicators
- Provision of faulted phase and distance to fault information to the Control Room
- Selection of simple IoT sensing devices for installation across the network to provide richer status information e.g. voltage levels along 11 kV feeders and selected 400 V reticulation.

4.3.6.2 Homes and businesses

The second area comprises of homes and businesses where:

- Devices are selected to connect via customer Wi-Fi and independent IoT channels to enable remote monitoring and provide local customer insights on consumption and demand, including such services as the WeR@Home platform
- Electra, 3rd party or customer-owned inverters and devices are identified for remote monitoring and control for dispatch of load, energy and VArs
- Selected retailers are identified for the development of energy trading products, offering customers better than wholesale prices, with the view of enabling Electra to establish a non-zero export price option.

4.3.6.3 Foundation linking technologies

Electra has established channels and servers for the retrieval and provision of secured information to customers and business partners.

In practice, we apply the following options:

- The annual planning process identifies where triggers have been or are likely to be exceeded for the planning period
- For small assets, the do-nothing option will be considered, often informally based on individual engineers' knowledge of the assets and their judgement
- It generally won't be formally documented unless the network solution is expensive
- It is generally accepted that eventually a network solution will be required as opportunities for doing nothing and for non-network solutions are exhausted
- Non-network solutions such as demand management and embedded generation often require the continued participation of a third party over time, and hence are not always easy to implement.

4.3.6.4 Distributed energy resources

Distributed Energy Resources (DER) are energy systems that can export power back to the grid. With lowered battery costs and technology improvements, domestic energy storage is now an option for many consumers other than PVs. The addition of energy storage to DER installations creates a fully controllable energy management system and an opportunity to investigate remote DER management.

Electra's investigations into Distributed Energy Resources has classified DER into three categories:

- **Domestic**: single and three phase systems. Energy export at 3.5kW (approximately) per phase
- **Network:** three phase systems. Energy export 25kW and above
- **Grid:** three phase systems. Energy export 500kW and above.

Domestic DER

Typical domestic DER solutions are single phase due to single phase network connections. For Electra to have balanced load management, the DER needs to be on the correct phase, in the correct location and with enough device penetration, exporting simultaneously, to have an effect. The quantity of controllable domestic DER has vastly increased and the efficiency at a large scale could be high.

Penetration of domestic DER options in New Zealand is growing, however the quantity of remotely accessible compatible systems within the Electra region is low.

Network DER

Network DER described large scale three phase installations typically with 25kW or more of available generation, connected directly to the LV network. These can be mobile, relocatable or permanently placed depending on installations. As this type of DER solution is "in-front-of-the-meter", a primary focus is AC/DC conversion efficiency and small PV installations can be included to offset or reduce conversion losses.

Electra is investigating DER solutions at the network level (25kW and above) as these systems have the potential to have multiple uses in supporting network operations:

- Reinforce areas of high network load until permanent solutions are installed. (e.g. new public EV charger locations or periodic load such as holiday batches)
- Provide supply support to critical locations during network maintenance and reconfiguration. (e.g. clients with chillers)
- Provide emergency support for system failures, generator failures and similar situations
- Provide access to other network support operations such as peak-load periods.

4.3.6.5 Electric Vehicle Supply Equipment (EVSE) management and monitoring

Domestic electric vehicle charging is at relatively low loads and does not pose a problem to the network at a high level. Home AC charger do have the ability to impact local areas of the network if they are used during peak periods. We will use technology and prices to support growth of these chargers across the network.

With the continued installation of public high-speed DC chargers accelerating in the region and these draw enormous loads so a strategy for managing these devices is being developed by Electra.

Electra has classified Electric Vehicle charging systems into two categories:

- **Domestic:** EVSE charging systems for private use at homes or small businesses typically AC devices
- **Commercial:** EVSE charging systems for public, commercial and industrial vehicles. including DC charging infrastructure.

Domestic EVSE

WorkSafe NZ regulations require EVSE chargers that plug into standard AC outlets be limited to 8A. Dedicated industrial and caravan style plugs can supply more, however currents beyond 16A require a dedicated EVSE charger using an EVSE charging cable.

To avoid domestic users from using low quality or non-compliant EVSE hardware, Electra is investigating sourcing necessary EVSE components, confirming their certification and offering them at a discount to Electra clients. The intention of this program is to assist in standardising domestic EVSE installations by offering a reduced cost incentive yet maintain hardware quality and commercial viability.

Electra has designed a domestic EVSE charge controller that is WorkSafe compliant for EVSE load management. It can be tied to existing hot water load management systems or queried directly using point to point communications. Unlike hot water load sheading systems, EVSE charging will be turned down, not off. This is to ensure EVs are charged and available when needed. Electra is researching new energy tariffs for EV charging (combined with load management) to provide a range of options to Electra EV users.

In 2019, Electra installed a selection of domestic EVSE chargers to test domestic EVSE load management. Testing has been successful, and further planning is underway to incorporate domestic EVSE load control into Electra backend systems as part of Electra load sheading (during high demands in winter).

Commercial EVSE

Electra has chosen to install devices that support Open Charge Point Protocol (OCCP). The latest release (1.6J) provides load management by setting charge profiles that set a maximum charge current in half hourly increments. Commercial EVSE systems at 7kW, 22kW and 50kW are common and can draw large loads from the network.

4.3.6.6 Low voltage network status monitoring

Electra has installed a Lora WAN IoT network with a series of gateways (effectively Long-Range Wi-Fi routers) in Levin, Moutere and Forest Heights as shown in Figure 4-2. These gateways have typical ranges of 10 km or more depending on antenna placement. LoRa operates on an unlicensed spectrum, so there are no direct communication fees. LoRa is a low power communication protocol that allows nodes to run on batteries for up to 10 years. Battery powered systems allow monitoring to continue during an outage – a significant advantage for an electricity distribution company.

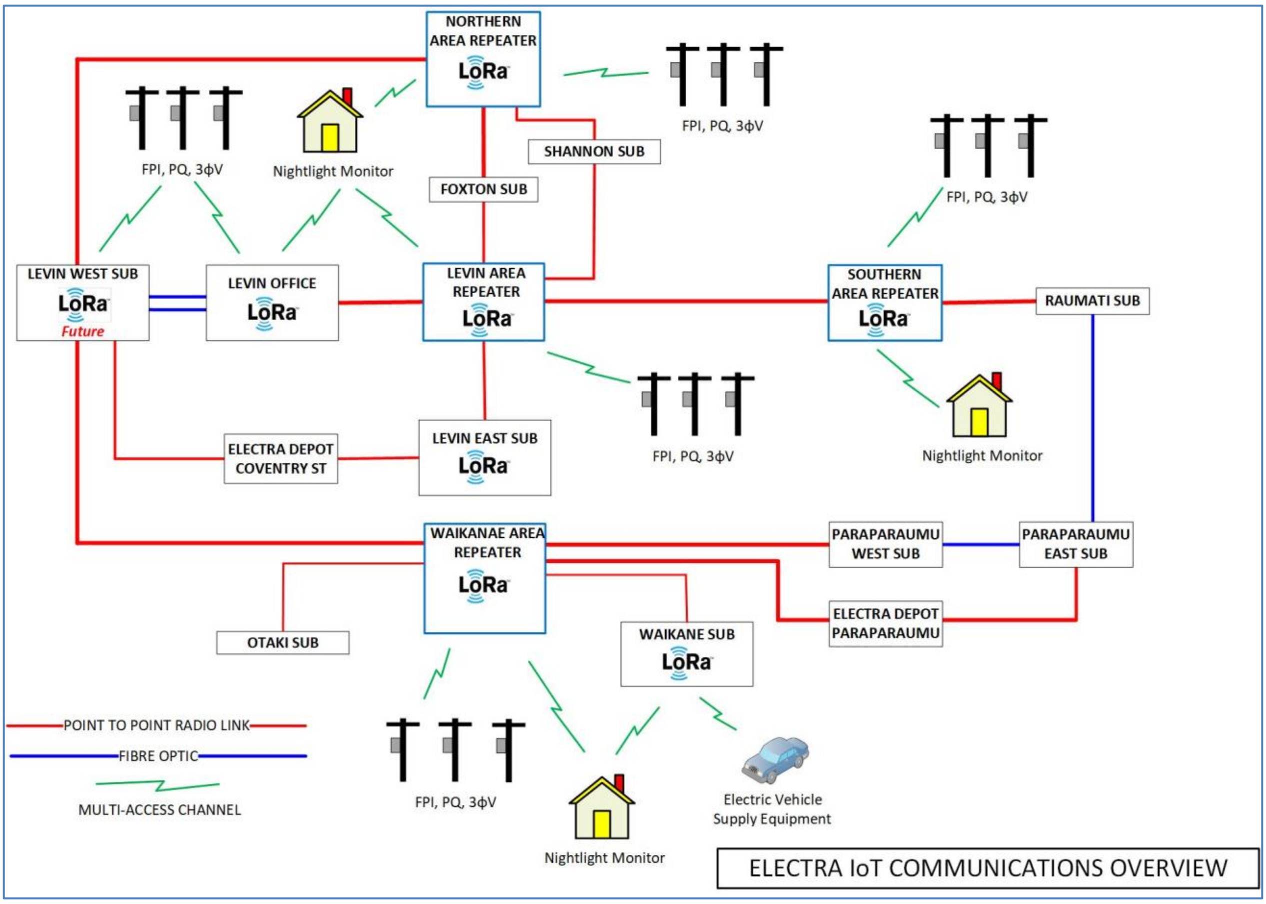


Figure 4-2: Electra IoT communications overview

Electra is planning to expand the utilisation of IoT communications for monitoring transformer power quality, outage and fault detection, distributed energy resource (DER) control, electric vehicle (EVSE) charger control, and general network status monitoring. The LoRa gateways are owned, installed and operated by Electra and are located at substations and repeater sites. Installation control maximises resilience and removes 3rd party involvement in obtaining network status information as all communications are within the Electra network.

4.3.7 Role of the ADMS in choosing options

Adoption of non-network (low investment) solutions requires network status and load information that is disaggregated (possibly to the level of individual ICP's), in real time (for fault indication and restoration) and very accurate (for matching capacity to demand), information that has traditionally not been available.

Electra sees that completion of the ADMS project will provide such information, which will eliminate the reliance on many of the assumptions that traditional network planning has relied upon. This will increase the confidence and correspondingly reduce the risk associated with adopting non-network or low-investment options (e.g. deferring transformer upgrades based on half-hourly demand profiles rather than one max demand reading).

4.4 Known constraints

Electra faces the following significant constraints (all security rather than capacity per se):

Constraint	Description	Intended remedy
Mangahao GXP	Limited rating of Transpower transformers can mean full (n-1) security is not available when Electra is taking full load and Mangahao is not generating	Transpower to install larger transformers as part of replacing existing old transformers (provisionally timed for 2031/32)
Shannon - Foxton - Levin West 33kV circuit	When load is above 35MVA and the Levin East 33kV circuit(s) trip, the Shannon – Foxton – Levin East 33kV circuit will overload	Re-configure and operate the recently purchased Transpower 110kV circuits at 33kV to duplicate the Mangahao – Levin East 33kV circuit(s)
Shannon - Foxton - Levin West 33kV circuit	If the Levin East 33kV circuit trips when Otaki is supplied from Mangahao GXP, the 3km of Bee in the Shannon – Foxton – Levin West 33kV circuit will overload	Operate the recently purchased Transpower 110kV circuits at 33kV to duplicate the Mangahao – Levin East 33kV circuit(s)

The annual planning process has revealed a low rate of demand growth in the Northern area and combined with the fact that there is sufficient capacity for the current planning period, means that it is unlikely that the capacity of any significant assets will be exceeded without sufficient time to react.

Electra does however recognise that demand growth in the Southern area is higher, due to both residential sub-division development in Paraparaumu and Waikanae and retail development around Paraparaumu. Most of the development is 11kV feeder duplication and meshing to increase available capacity and to reduce the number of customers effected by individual faults.

Specific issues which arise from load projections are:

- Increasing air conditioning load is likely to over-lap into peak periods when demand is already high, but possibly with some offset by solar at customer sites. The potential impact on the network is not yet known and feeder loading information is being captured, along with temperature and rainfall to identify any relevant trends. This issue has not been factored into the load forecast

- The increasing popularity of beach-front settlements will require up-sizing or duplication of existing 11kV lines. This is required to minimise the effects of outages which have an impact on the security levels.

4.5 Development prioritisation

The finite funds that are available each year (both from revenue, and from borrowing) require development work to be prioritised or ranked by their contribution to Electra's goals. These goals closely reflect the priority of stakeholder interests and how competing or conflicting interests will be managed (described in Section 1.10).

Prioritisation is also strongly linked to risk management (Section 7). Projects that reduce risks with high likelihood and high consequence are assigned a higher priority.

Each of the possible approaches to meeting demand that are outlined in Section 4.3.5 provide potential solutions that are considered.

4.6 Demand forecasts

Historically Electra has used a simple linear projection of recent zone substation demand growth rates to forecast demand and has supplemented these by inclusion of localised factors (e.g. known industrial developments, observations of farmland being sold for residential development, etc). The uncertain implications of emerging technologies mean that such an approach is less likely to accurately forecast demand. Electra has started work on the following proposed scenario-based forecasting methodology and expects to progress this work through to individual substation and possibly 11kV levels.

4.6.1 Forecasting approach

Electra has adopted the following forecasting approach:

Identify demand drivers	→	Compile scenarios	→	Translate scenarios into kW demand	→	Compile zone sub forecasts	→	Aggregate to GXP

4.6.2 Demand drivers

Electra considers the following demand drivers (which reflect the assumptions set out in 1.16) that will impact on:

- Demand per customer connection, noting that this could range from negative (predominantly exporting) to very high (home-based EV charging)
- Number of customer connections.

Class of driver	Detailed driver	Impact on demand per customer	Impact on number of customers
Resident population growth	Organic population growth at large	Minimal of itself	Increase
	Property price differentials between the Wellington metro area, Kapiti and Horowhenua encouraging northward migration, and in particular any housing policies that cause property prices to retreat	Minimal of itself	Increase

Class of driver	Detailed driver	Impact on demand per customer	Impact on number of customers
	Residential sub-division growth around Waikanae and Paraparaumu	Minimal of itself	Increase
	Commercial growth around Paraparaumu	Minimal of itself	Increase
Transport policy	Slowdown in established motorway build programme	Minimal of itself, but likely to preserve existing diversity between zone substations if commute times remain the same	Possible decline in new house growth in Horowhenua
	Uptake of EV's, compounded by any policies that require any-time charging	Potentially large especially if policies don't discourage any-time charging	Minimal
Customer preferences	Increasing use of domestic air conditioning	Potentially significant if installed cost of air conditioners declines	Minimal
	Increased expectation of air conditioning in retail and commercial premises	Possibly significant	Minimal
	Increasing popularity of beach front settlements	Possibly significant if existing beach houses have air conditioning installed	Increase if new beach houses are built
Air quality policies	Policies that restrict solid fuel home heating, and essentially require a shift to electric heating	Potentially significant	Minimal
Emerging technologies	Uptake of rooftop solar and batteries	Potential to reduce demand if policy incentives are correct, but also possibility of disrupting existing kWh-based revenue model	Minimal
	Affordability of devices, especially battery-power devices, power tools, garden tools etc	Possibly significant depending on user preferences for recharging	Minimal

The following specific technologies and their likely implications for demand growth or contraction have been considered:

Specific technology	Mode of operation	Implications for Electra
Conventional, well understood loads	Consumption	• Increasing demand per customer
Inverter heat pumps	Consumption	• Increasing peak demand, but with no commensurate increase in kWh • Declining load factor • Declining power factor • Increasing harmonics
Roof top solar	Injection	• Possible off-set of GXP demand (but probably not during peak periods) • Possible increase in peak loading of some feeders, possibly leading to export congestion • Over voltages during periods of high generation and low demand • Increased bi-directional power flows that require changes to protection and control settings • Reduced kWh sales if located behind the meter • Peak seen by the GXP's may shift later into summer evenings

Specific technology	Mode of operation	Implications for Electra
Batteries	Consumption	• Possible improving load factor if charging restricted to off-peak.
	Injection	• Possible off-set of GXP demand • Ability to maintain supply during faults may reduce criticality of fault restoration processes
Electric vehicles	Consumption	• Possible improving load factor if charging restricted to off-peak • Increased demand if charging unmanaged
	Injection	• This is speculative and application of this capability will be monitored
Low energy interior lighting	Consumption	• Reduced demand and consumption
Low energy streetlighting	Consumption	• Reduced demand and consumption. Lower consumption-based revenue will impact the value of this supply business

4.6.3 Zone substation demand forecasts

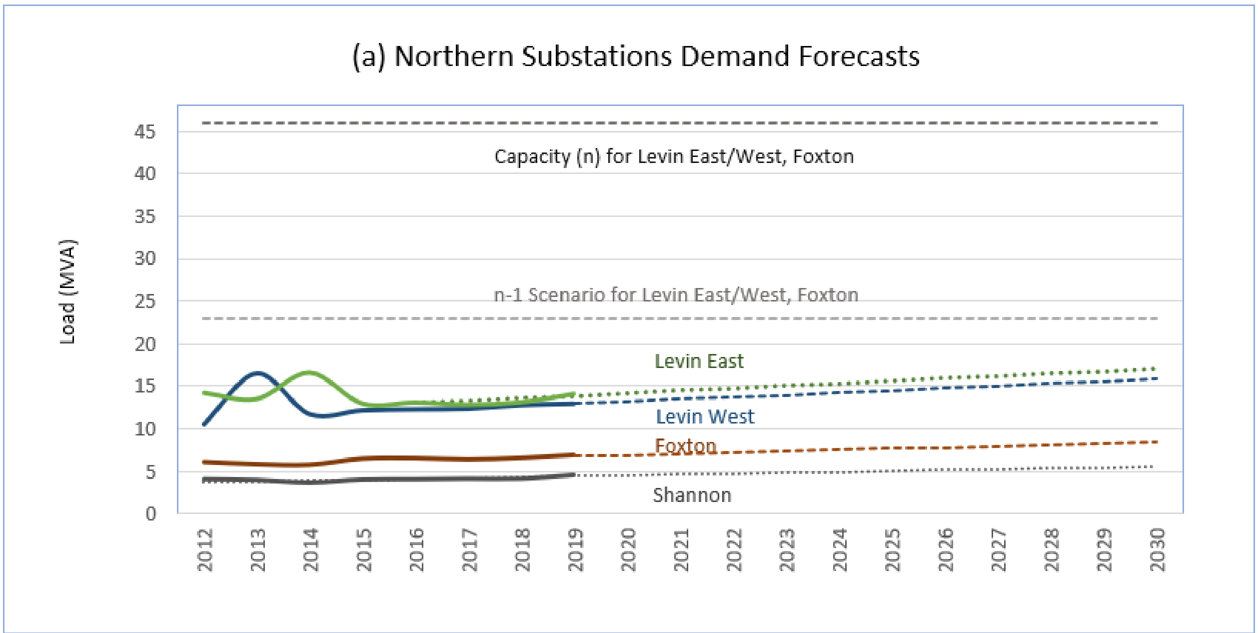
Electra's zone substation demand forecasts are set out below based on the following growth assumptions:

Zone substation	Nature of growth	Average annual load increase	Annual average population growth[9]	Provision for growth
Shannon	Mainly lifestyle blocks around Tokomaru	2.3%	2.9%	None required
Foxton	Mainly residential development at Foxton Beach	2.2%	2.3%	None required
Levin East	Mainly commercial and lifestyle blocks to the south and east of Levin. Possible large off-peak industrial load growth	2.0%	2.2%	None required
Levin West	Mainly residential properties at Waitarere Beach and lifestyle properties to the north and west of Levin	2.1%	2.2%	None required
Otaki	Mainly lifestyle blocks in Manakau and Te Horo	2.3%	2.4%	Load is being managed by redistribution amongst existing feeders. An additional feeder is proposed within the planning period to offload Feeder L351 and meet the increasing demand
Waikanae	Mainly residential	3%	3%	Capacity on existing feeders continues to increase before end of life replacement. An additional feeder is proposed to Te Moana Road to offload Feeder 662 and supply the increasing load
Paraparaumu	Mainly commercial and residential infill	1.5%	1.7%	Increased utilisation of existing capacity. The construction of Paraparaumu West has allowed much of the former load to be transferred

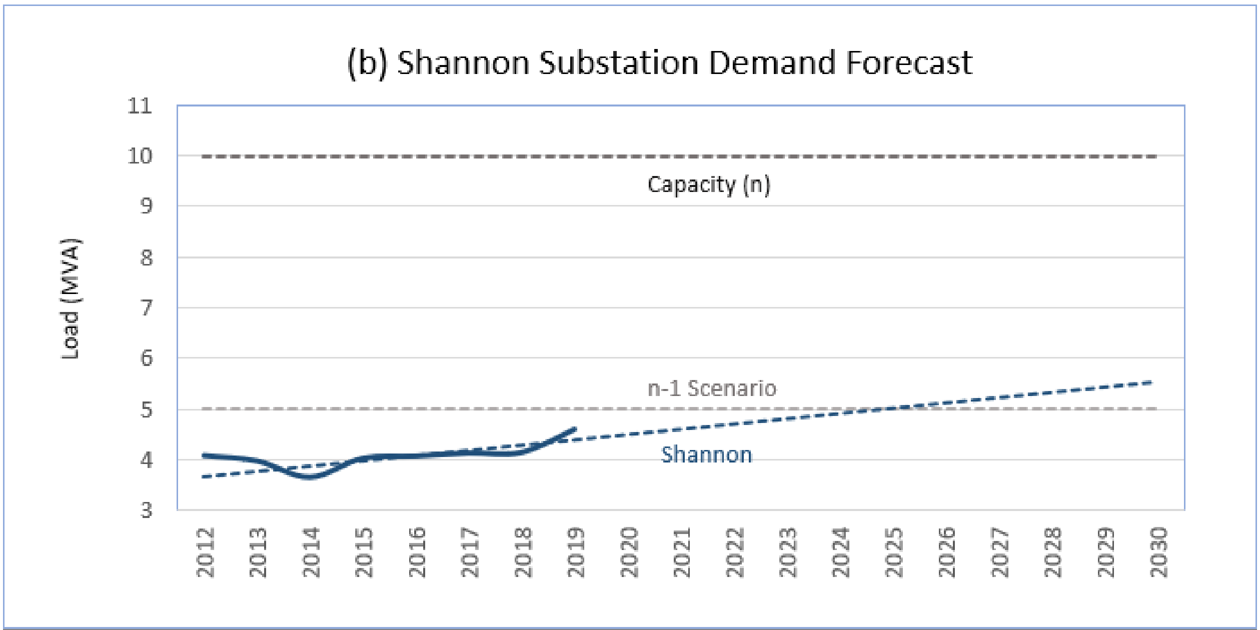
[9] Statistics New Zealand, Dataset: Age and sex by ethnic group (grouped total responses), for census night population counts, 2006, 2013, and 2018 Censuses (RC, TA, SA2, DHB)

Zone substation	Nature of growth	Average annual load increase	Annual average population growth[9]	Provision for growth
Paraparaumu West	Mainly commercial and residential infill	1.7%	1.7%	An additional 11kV feeder is proposed to Kapiti Rd to off-load Feeder 405 and also to supply the increasing demand
Raumati	Mainly residential infill	1.7%	1.6%	An additional feeder is proposed to Matai Rd to offload Feeder Z210 and supply the increasing demand
Paekakariki	Mainly residential infill	1 %	0.8%	No loading parameters are expected to be exceeded during the planning period, therefore no growth-related projects are proposed either

The northern substations' demand forecasts are shown in Figure 4-3a. The maximum demand growth rate is about 2% for Levin East, Levin West and Foxton and these rates are well below their n-1 capacity, so no action is required. In Figure 4-3b, the projected demand for Shannon substation suggests that the (n-1) rating will be exceeded after 2025 if the growth continue at 2.3% per annum. However, this can be managed by some load shifts at 11kV feeder level to Foxton substation.



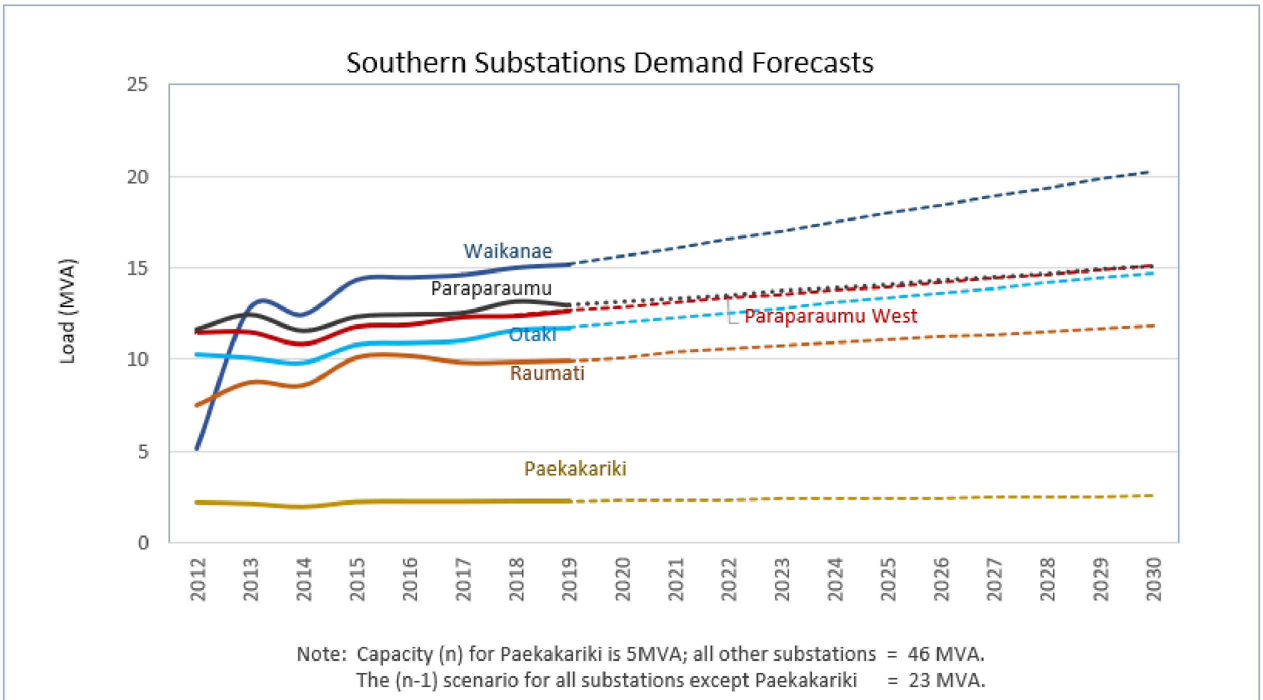
Zone Substation	Actual	Forecast Maximum Demand (MVA)											Annual
	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	Increase
Levin West	12.9	13.2	13.4	13.7	14.0	14.2	14.5	14.8	15.0	15.3	15.6	15.8	2.0%
Levin East	14.4	14.2	14.4	14.7	15.0	15.3	15.6	15.9	16.2	16.5	16.8	17.1	2.1%
Foxton	6.8	6.9	7.1	7.2	7.4	7.5	7.7	7.8	8.0	8.1	8.3	8.4	2.2%
Shannon	4.6	4.5	4.6	4.7	4.8	4.9	5.0	5.1	5.2	5.3	5.4	5.5	2.3%



Zone Substation	Actual	Forecast Maximum Demand (MVA)											Annual
	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	Increase %
Shannon	4.6	4.5	4.6	4.7	4.8	4.9	5.0	5.1	5.2	5.3	5.4	5.5	2.3%

Figure 4-3: (a) Northern substations demand forecasts, and (b) Shannon with scenarios

The southern substations demand forecasts are shown in Figure 4-4.



Zone Substation	Actual	Forecast Maximum Demand (MVA)											Annual
	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	Increase
Waikanae	15.2	15.6	16.1	16.6	17.0	17.5	18.0	18.4	18.9	19.3	19.8	20.3	3.0%
Otaki	11.7	12.0	12.3	12.5	12.8	13.1	13.4	13.6	13.9	14.2	14.4	14.7	2.3%
Paraparaumu	12.9	13.1	13.3	13.5	13.7	13.9	14.1	14.3	14.5	14.7	14.9	15.1	1.5%
Paraparaumu West	12.7	12.9	13.1	13.3	13.5	13.8	14.0	14.2	14.4	14.7	14.9	15.1	1.7%
Raumati	9.9	10.1	10.4	10.6	10.8	10.9	11.1	11.2	11.4	11.5	11.7	11.9	1.7%
Paekakariki	2.3	2.3	2.3	2.4	2.4	2.4	2.4	2.5	2.5	2.5	2.5	2.6	1.0%

Figure 4-4: Southern substations demand forecasts

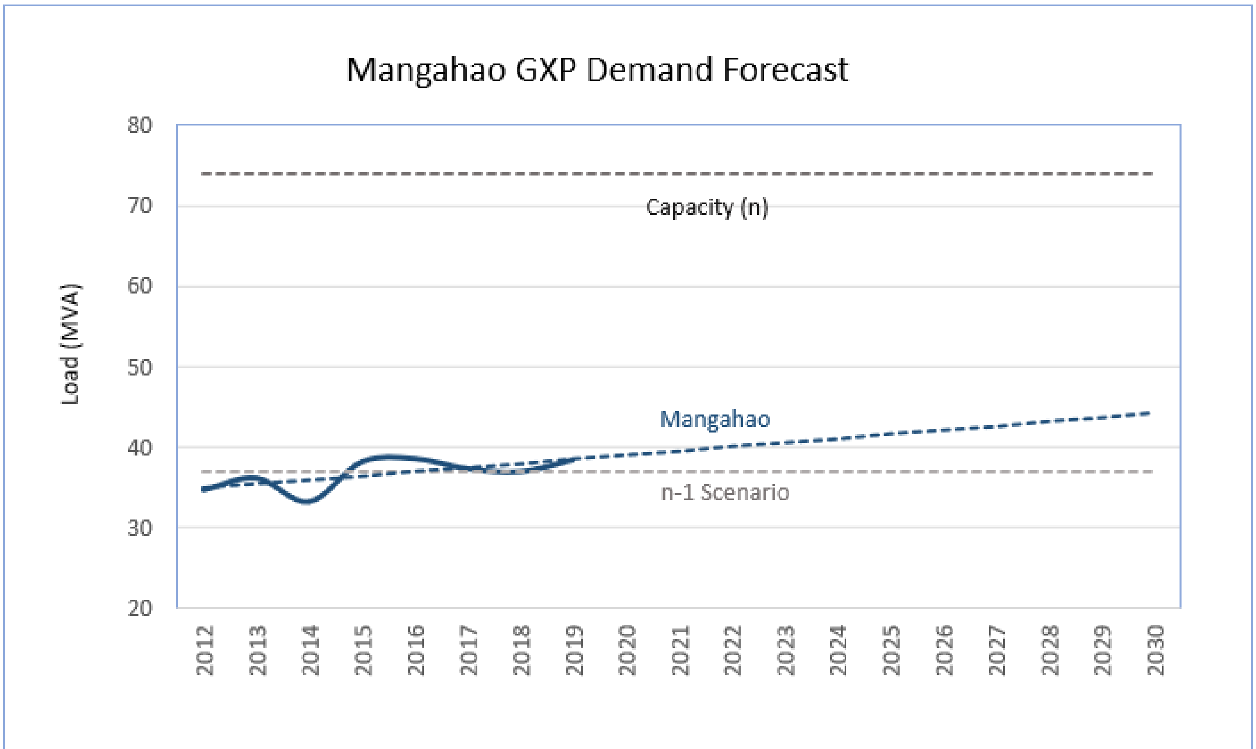
4.6.4 GXP demand forecasts

Major network constraints that Electra may face in the future will occur mainly at the Mangahao grid exit point on the network. As depicted in Figure 4-5, Mangahao GXP first exceeded the transformers (n-1) winter capacity of 37MVA by approximately 2.5MW in 2015 and for the winter demand this year, the (n-1) capacity was exceeded by 1.5MVA. The supply transformer overload is managed operationally by Mangahao generation which is usually available at peak load periods. If Mangahao continues to generate at 13MW or more, this issue could be delayed beyond the forecast period.

With the increased number of transportation projects, load growth is expected to increase more rapidly with the completion of Transmission Gully and Peka-Peka to Otaki Expressway projects by 2021. The upgrading of Paraparaumu GXP (as a result of the Transmission Gully highway project) has increased its capacity and removed any transmission constraints in the Kapiti area.

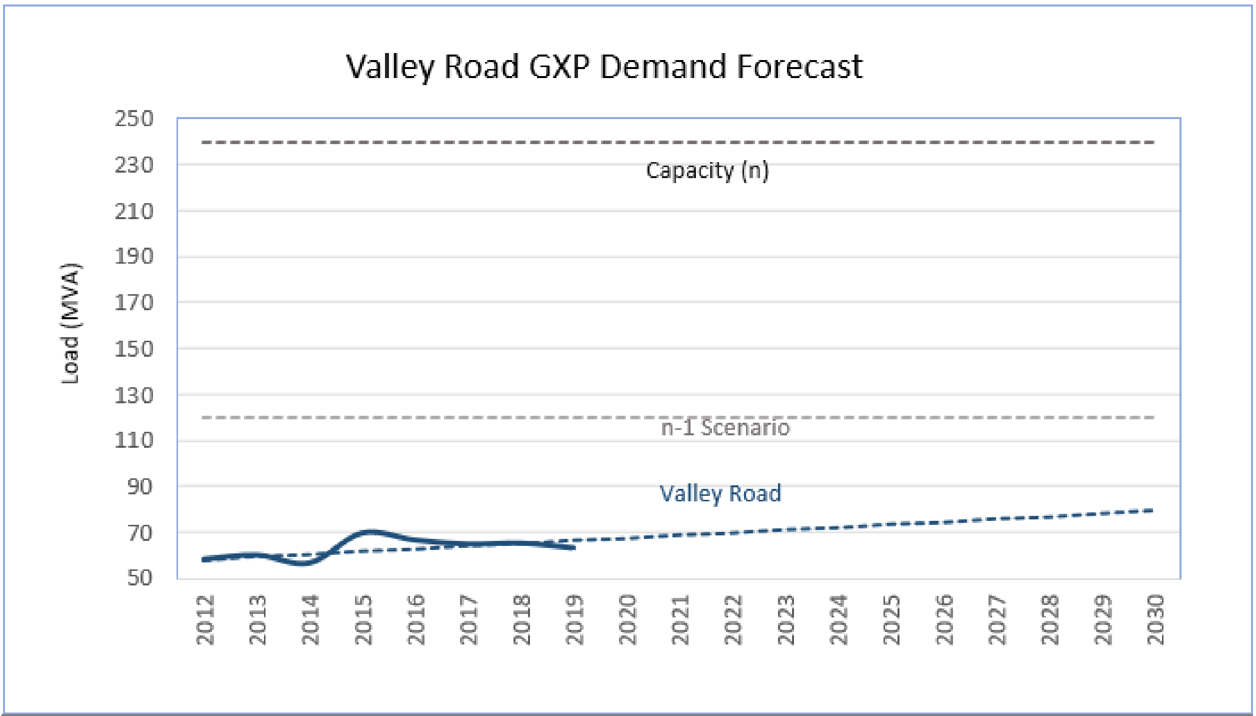
The zone substation demand forecasts have been aggregated to the following GXP demand forecasts:

GXP	Average annual demand increase	Provision for growth
Mangahao	1.3%	No provision for capacity or security growth will be possible until about 2030 when it is expected that the existing transformers will be upgraded to approximately 60MVA
Paraparaumu	1.8%	None required. This GXP has recently been reconfigured to obtain supply from Transpower's 220kV network to accommodate the proposed Transmission Gully highway. The result is that firm capacity has increased from 68 MVA to 120MVA. This means that any future growth can be met from the existing supply and the provisional measures outlined in previous AMP's to delay upgrade work are no longer needed



GXP	Actual	Forecast Maximum Demand (MVA)											Annual
	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	Increase %
Mangahau	-	39.1	39.6	40.1	40.6	41.1	41.7	42.2	42.7	43.2	43.7	44.2	1.3%

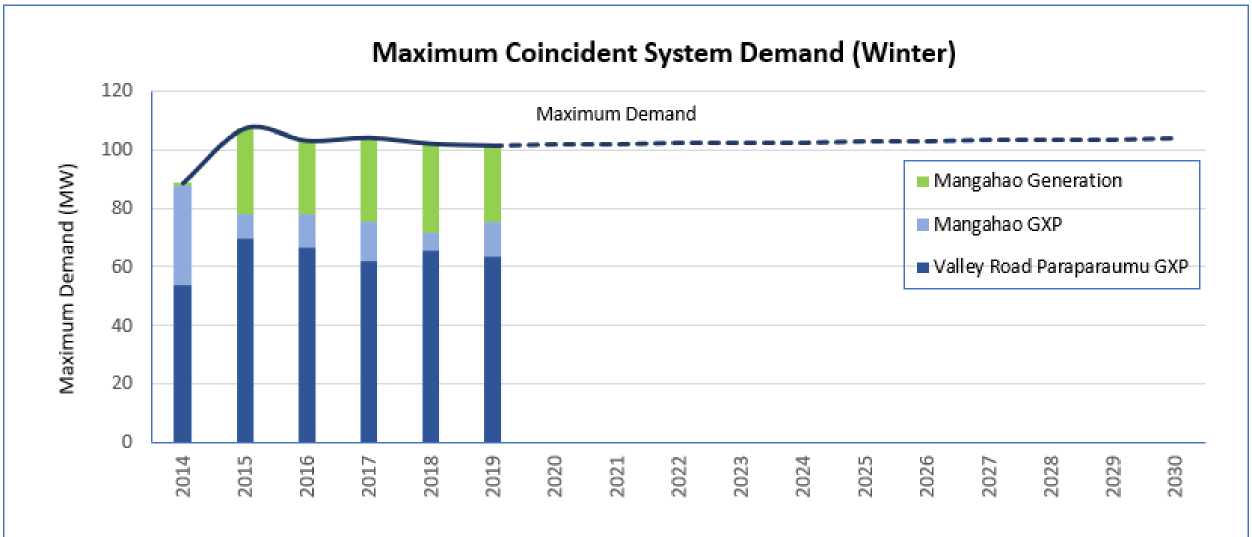
Figure 4-5: Mangahao GXP demand forecast



GXP	Actual	Forecast Maximum Demand (MVA)											Annual
	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	Increase %
Valley Road	63.3	67.5	68.7	69.9	71.1	72.2	73.4	74.6	75.8	77.0	78.2	79.3	1.8%

Figure 4-6: Valley Road GXP demand forecast

The maximum coincident system demand (winter) for calendar 2019 is 101.4 MW and the projected demand is shown in Figure 4-7 where the coincident maximum demand is projected to grow at 2% per year. Since 2015, Mangahao generation (to the 33kV bus) has accounted for an average of 27% of coincident maximum demand with Valley Road and Mangahao GXPs contributing 63% and 10% respectively.



GXP	Actual	Coincident Maximum Demand (MW)											Annual
	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	Increase %
Maximum Coincident Demand	101.4	101.9	102.1	102.3	102.5	102.7	102.9	103.1	103.3	103.5	103.7	103.9	2%

Figure 4-7: Projected maximum coincident system demand

4.6.5 Improving demand forecasting

Electra plans to develop a suite of Low, Medium (Base) and High demand scenarios based on the following 5 factors which are expected to dominate demand growth or contraction:

- National and regional economic growth
- Aspects of transport policy that incentivise EV uptake
- Further decline in the cost of rooftop solar and residential batteries
- Housing policies that cause property prices to retreat from recent high levels, reducing the incentive to migrate from Wellington to Kapiti to Horowhenua
- Further penetration of domestic and retail premise air conditioning.

Electra expects these scenarios to look something like the following:

Driver	Low scenario	Mid (base) scenario	High scenario
National and regional economic growth	National GDP troughed at about 1.7% in Dec 2019 and expected to grow at a moderate pace into 2020	National GDP is expected to track at about 2.3% to 2.4% over the next couple of years [10, 11]	National GDP peaks at about 2.5% around mid-2020 and is expected to gradually improve.
Aspects of transport policy that incentivise EV uptake	Expect 400 EV's in Kapiti and 50 in Horowhenua by about 2021, again with an even mix of peak and off-peak charging	Expect 640 EV's in Kapiti and 160 in Horowhenua by about 2021, with an even mix of peak and off-peak recharging	Expect 1,000 EV's in Kapiti and 200 in Horowhenua by about 2021, with an even mix of peak and off-peak charging
Further decline in the costs of rooftop solar and batteries	The installed cost of a 2kW solar plus batteries supply will remain at about $14,000	The installed cost of a 2kW solar plus batteries supply that currently costs about $14,000 will decline to about $11,000 by 2022[12, 13] and then remain constant	The installed cost of a 2kW solar plus batteries supply will decline from the current $14,000 to about $9,000 by 2022 and then remain constant
Housing policies that cause property prices to retreat from recent high levels	House price growth in the lower North Island will drop sharply into a retreat	House price growth in the lower North Island will slow and eventually retreat into a decline in prices	House prices in the lower North Island will continue to grow, albeit at a slightly lower rate
Further penetration of domestic and retail premise air conditioning	Air conditioning penetration remains at about 45% for planning period	Air conditioning penetration will increase from about 45% in 2016 to about 50% by 2021 and then remain constant[14]	Air conditioning penetration increased to about 60% by 2021 and then remains constant

Electra also expects to have to consider component loading at an 11kV and LV feeder level as increasing penetration of batteries and solar panels may lead to localised demand growth that is not seen at a zone substation level.

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[10] ANZ Research, Quarterly Economic Outlook "Through the looking glass", January 2020

[11] BNZ Markets Outlook, 16 December 2019

[12] https://www.mysolarquotes.co.nz/about-solar-power/residential/how-much-does-a-solar-power-system-cost/

[13] https://www.greentechmedia.com/articles/read/solar-costs-are-hitting-jaw-dropping-lows-in-every-region-of-the-world#gs.XYIx1yw

[14] https://www.transpower.co.nz/sites/default/files/publications/resources/E528-use-forecasting-for-heat-pumps-jul-09.pdf

4.7 Development projects

The following sections contain the development projects planned for the ten-year period commencing from 1 April 2020 until 31 March 2030. Schedule 11a: Report on Forecasted Capital Expenditure in Appendix 2 reflects the costs incurred in these sections.

Figure 4-8 displays the location and estimated budgeted costs of major network projects in the Kapiti and Horowhenua districts.

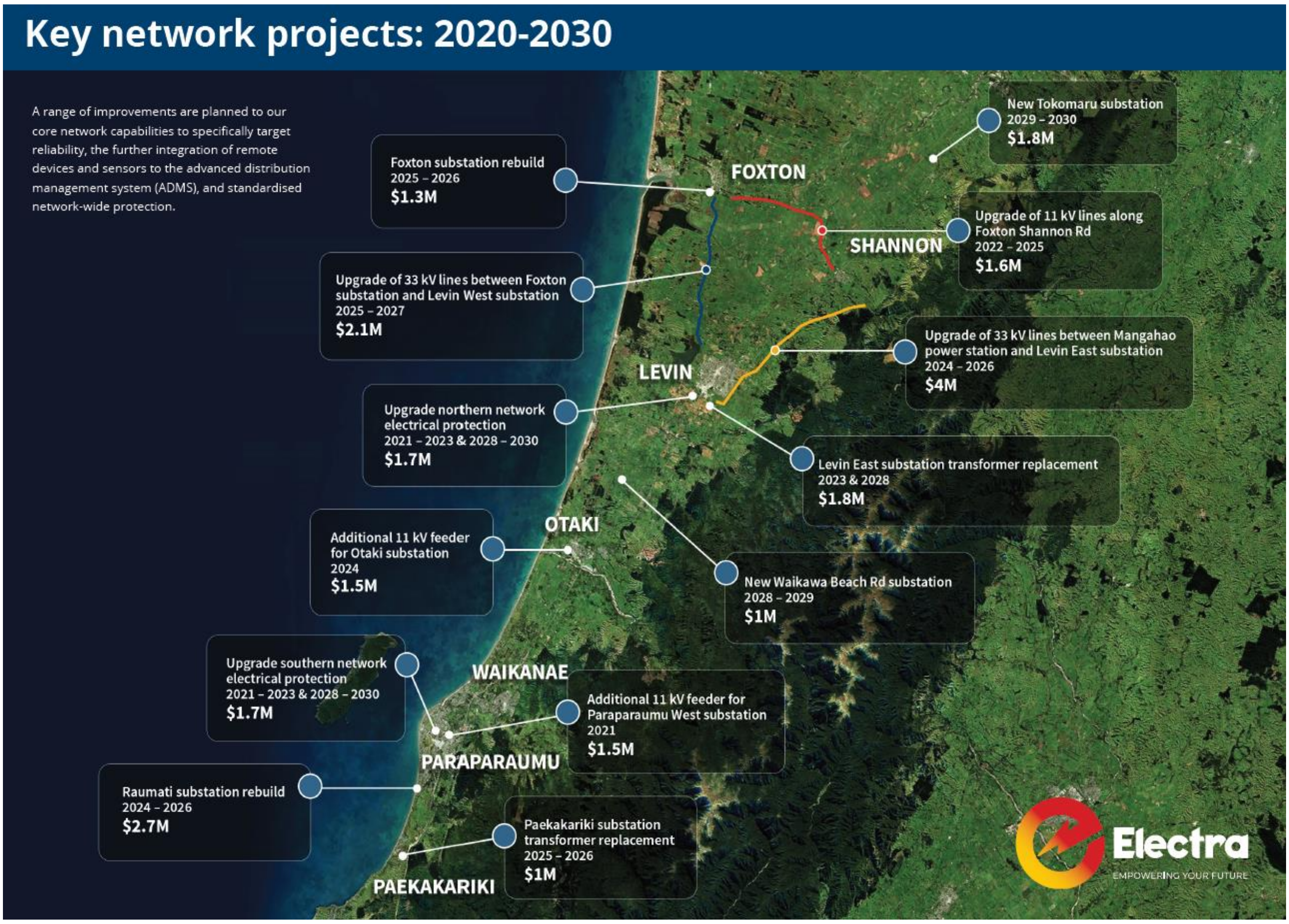


Figure 4-8: Key network projects

4.7.1 Development projects for FY2021 year

Development projects over $200,000 for FY2021 as well as their alternative options are shown on the following page.

Ref.	Description and purpose of project	Category	Cost	Options considered			Option chosen and reason
				Do-Nothing	Non-Network	Network	
1	Install a new feeder to Kapiti Rd to offload customers from Feeder 405	Growth	$1,450,000	Allow load and customer numbers on existing feeder to increase	Encourage customers to uptake solar and/or battery storage	• Reconfiguration of feeders • Add new feeder	• Add new feeder • Simply adding more customers will increase its asset utilisation and risk of in-service failure. This is inconsistent with Electra's policy on asset loading and increasing asset capacity • As more customers are added to the feeder, the number of customers affected by a fault will also increase which is undesirable. Offloading customers will reduce the number of customers affected • Customer uptake of solar and/or batteries are on an ad-hoc basis and cannot be predicted • Any connected solar or batteries may not be of reliable source due to intermittency of supply All the nearby feeders also have a significant number of customers connected and also has high loading
2	Substation protection and communication work	Quality	$750,000	Slow operating protection		Upgrade to digital SEL relays	• Upgrade to digital SEL relays • Inadequate protection operating speed is both an operational and a safety risk

Ref.	Description and purpose of project	Category	Cost	Options considered			Option chosen and reason
				Do-Nothing	Non-Network	Network	
3	Install sectionalisers on specified feeders to reduce number of customers affected by faults	Quality	$500,000	Continue with existing feeder sections		Install line sectionalisers on specific feeder locations	• Sectionalise feeders As more customers are added to feeders, the number of customers effected by a fault will also increase, which is undesirable. Sectionalising will reduce the number of customers affected
4	Seismic strengthening of zone substation building	Legislative	$450,000	Continue with high risk buildings, which are prone to earthquake damage		Get buildings seismically assessed and carry out modifications to rate the building to L4 of the code	To carry out studies and carry out recommendations to get buildings compliant to the code to reduce the risk levels
5	Automation of switchgear on specified feeders to reduce restoration times	Quality	$170,000	Continue with existing manual switching arrangements	Improve existing manual switching arrangements	Automate specific switches	Automate specific switches As more customers are added to feeders, the number of customers effected by a fault will also increase, which is undesirable. Automating specific switches will reduce supply restoration time These devices will provide network data, which will help to improve network investment decisions of future

* includes “low investment” options.

Non-material projects (<$200,000) for the FY2021 as well as their alternative options follow:

Ref.	Description and purpose of project	Category	Cost	Options considered			Option chosen and reason
				Do-Nothing	Non-Network	Network	
6	Install LV -power quality monitors	Quality	$100,000	Continue with no visibility of LV power quality information	Install smart sensors on selected distribution transformers		Install LV PQ monitors on selected transformers This will provide valuable information to create a baseline of existing power quality, validate ADMD assumptions and additionally can feed information To ADMS to inform LV outages
7	Sub-division extensions	Customer Connection	$94,640	Continue with existing LV network configuration		Install links between LV circuits	Install links between LV circuits Allow supply restoration in switching time rather than repair time
8	Install additional permanent fault locators to allow quicker location of faults	Quality	$100,000	Rely on existing telemetered devices to locate faults		Install fault locators	Install fault locators Quicker location of faulted section of feeder is consistent with strategy of improving reliability
9	Link LV network where gaps exist to reduce fault restoration times	Quality	$40,772	Continue with existing LV network configuration		Install links between LV circuits	Install links between LV circuits Allow supply restoration in switching time rather than repair time
10	Install comm's on specified fault locators to allow remote indication	Quality	$28,392	Continue with existing fault locaters that require manual observation		Install comms to allow remote indication of faults	Install comms to allow remote indication of faults Remote indication of faults allows quicker directing of fault men to faults, reducing restoration times

* includes "low investment" options.

4.7.2 Development projects for FY2022 to FY2025

The development projects proposed for FY2022 to FY2025 with considerations made to alternative solutions include:

Ref.	Description and purpose of project	Category	Cost	Options considered			Option chosen and reason
				Do-Nothing	Non-Network	Network	
1	Install new feeder to offload L351	Growth	$1,560,000	Allow load and customer numbers on existing feeder to increase	Encourage customers to uptake solar and/or battery storage	• Reconfiguration of feeders • Add new feeder	• Add new feeder • Simply adding more customers will increase its asset utilisation and risk of in-service failure. This is inconsistent with Electra's policy on asset loading and increasing asset capacity • As more customers are added to the feeder, the number of customers effected by a fault will also increase which is undesirable. Offloading customers will reduce the number of customers affected • Customer uptake of solar and/or batteries are on an ad-hoc basis and cannot be predicted • Any connected solar or batteries may not be of reliable source due to intermittency of supply • All the nearby feeders also have significant number of customers connected to it and has high loading
2	Network sectionalisation	Quality	$1,150,000	Continue with existing feeder sections		Install line sectionalisers on specific feeder location	• Sectionalise feeders • As more customers are added to feeders, the number of customers effected by a fault will also increase, which is undesirable. Sectionalising will reduce the number of customers affected

Ref.	Description and purpose of project	Category	Cost	Options considered			Option chosen and reason
				Do-Nothing	Non-Network	Network	
3	Automation of switchgear	Quality	$1,080,000	Continue with existing manual switching arrangements		Automate specific switches	• Automate specific switches • As more customers are added to feeders, the number of customers effected by a fault will also increase, which is undesirable. Automating specific switches will reduce supply restoration time • These devices will provide network data, which will help to improve network investment decisions of future
4	Substation protection work	Quality	$1,050,000	Slow operating protection		Upgrade to digital SEL relays	• Upgrade to digital SEL relays • Inadequate protection operating speed is both an operational and a safety risk
5	Install a new feeder to Matai Rd to offload Z210	Growth	$784,000	Allow load and customer numbers on existing feeder to increase	Encourage customers to uptake solar and/or battery storage	• Reconfiguration of feeders • Add new feeder	• Add new feeder • Simply adding more customers will increase its asset utilisation and risk of in-service failure. This is inconsistent with Electra's policy on asset loading and increasing asset capacity • As more customers are added to the feeder, the number of customers effected by a fault will also increase which is undesirable. Offloading customers will reduce the number of customers affected • Customer uptake of solar and/or batteries are on an ad-hoc basis and cannot be predicted • Any connected solar or batteries may not be of reliable source due to intermittency of supply • The nearby feeder is a critical feeder.

Ref.	Description and purpose of project	Category	Cost	Options considered			Option chosen and reason
				Do-Nothing	Non-Network	Network	
6	Upgrade to butterfly-Foxton to Levin West 33kV to remove constraint if Levin East circuit trips.	Growth	$700,000	Leave section of Bee in place	Install station class battery banks in substations to supply load during contingency	Replace section of Bee with Butterfly	• Replace section of Bee with Butterfly • Leaving the section of Bee in place limits the capacity of this circuit should the Levin East 33kV circuit trip, which is unacceptable • Whole life cost of battery banks doesn't justify the investment
7	Link between Waitarere and Hokio Beach.	Quality	$700,000	Continue with existing spur network arrangement	Install backup generators/battery for redundancy	Install a cable section to close the ring	• Install ring feed cable • Diesel generators and battery solutions are not cost effective • Meshing of circuits allows reduced restoration times which is consistent with Electra's strategy of improving reliability
8	Seismic strengthening of zone substation building	Legislative	$675,000	Continue with high risk buildings, which are prone to earthquake damage		Get buildings seismically assessed and carry out modifications to rate the building to L4 of the code	• To carry out studies and carry out recommendations to get buildings compliant to the code to reduce the risk levels
9	Install alternative supply between W468 and Z50 to allow quicker restoration of faults	Quality	$260,000	Continue with existing unmeshed feeders		Install link between W468 and Z50	• Install link between W468 and Z50 • Being able to back-feed un-faulted sections of both feeders provides an opportunity to reduce restoration times
10	Ripple plant installation at Otaki to cover whole network if either of the existing plants are out of service	Quality	$500,000	Ripple plant installation at Otaki to cover whole network if either of the existing plants are out of service	Ripple plant installation at Otaki to cover whole network if either of the existing plants are out of service	Ripple plant installation at Otaki to cover whole network if either of the existing plants are out of service	• Ripple plant installation at Otaki to cover whole network if either of the existing plants are out of service
11	Install cable and switchgear to close ring at specified locations and underground the LV to allow quicker restoration of faults	Quality	$465,000	Retain existing spur configuration		Install ring feed cable	• Install ring feed cable • Meshing of circuits allows reduced restoration times which is consistent with Electra's strategy of improving reliability

Ref.	Description and purpose of project	Category	Cost	Options considered			Option chosen and reason
				Do-Nothing	Non-Network	Network	
12	Install a new feeder to Te Moana Rd to offload Feeder 662	Growth	$424,000	Allow load and customer numbers on existing feeder to increase	Encourage customers to uptake solar and/or battery storage	Reconfiguration of feeders Add new feeder	• Add new feeder • Simply adding more customers will increase its asset utilisation and risk of in-service failure. This is inconsistent with Electra's policy on asset loading and increasing asset capacity • As more customers are added to the feeder, the number of customers effected by a fault will also increase which is undesirable. Offloading customers will reduce the number of customers affected • Customer uptake of solar and/or batteries are on an ad-hoc basis and cannot be predicted • Any connected solar or batteries may not be of reliable source due to intermittency of supply • All the nearby feeders also have significant number of customers connected to it and also has high loading
13	T106 to T57 install cable close ring	Quality	$408,845	Retain existing spur configuration		Install ring feed cable	• Meshing of circuits allows reduced restoration times which is consistent with Electra's strategy of improving reliability
14	Subdivision extensions	Customer connection	$378,560	Continue with existing LV network configuration		Install links between LV circuits	• Continue with existing LV network configuration
15	Close 11kV rings	Quality	$300,000	Retain existing spur configuration		Install ring feed cable	• Install ring feed cable • Meshing of circuits allows reduced restoration times which is consistent with Electra's strategy of improving reliability
16	Install additional fault locators - permanent	Quality	$228,318	Rely on existing telemetered devices to locate faults		Install fault locators	• Install fault locators • Quicker location of faulted section of feeder is consistent with strategy of improving reliability

Ref.	Description and purpose of project	Category	Cost	Options considered			Option chosen and reason
				Do-Nothing	Non-Network	Network	
17	Install switch gear and reconfigure	Quality	$205,200	Retain existing spur configuration		Install a ring main unit and improve the back-feed capability	• Install an RMU • Meshing of circuits allows reduced restoration times
18	Install LV -power quality monitors	Quality	$175,000	Continue with no visibility of LV power quality information	Install smart sensors on selected distribution transformers		• Install LV PQ monitors on selected transformers • This will provide valuable information to create a baseline of existing power quality, validate ADMD assumptions and additionally can feed information to ADMS to inform LV outages
19	Link LV network where gaps exist to reduce fault restoration times	Quality	$163,088	Continue with existing LV network configuration		Install links between LV circuits	• Install links between LV circuits • Allow supply restoration in switching time rather than repair time
20	Install cable and switch gear close ring at Mill Road	Quality	$153,317	Retain existing spur configuration		Install ring feed cable	• Install ring feed cable • Meshing of circuits allows reduced restoration times which is consistent with Electra's strategy of improving reliability
21	Relocate a 33/11kV transformer to act as a cold standby at Paekakariki	Quality	$130,000	Continue with existing single transformer configuration and relocate a transformer from another substation in the event of failure	Relocate a transformer from another substation and keep as a cold standby at Paekakariki that could be livened in 6 to 8 hours	Purchase second transformer and keep as a cold standby at Paekakariki that could be livened in 6 to 8 hours	• Relocate a transformer from another substation to keep as a cold standby at Paekakariki • Only some Paekakariki customers can be back fed on the 11kV from other substations, so a transformer failure would interrupt supply until the transformer was repaired (possibly months) or replaced
22	Install comms on specified fault locators to allow remote indication	Quality	$113,568	Retain existing spur configuration		Install ring feed cable	• Install ring feed cable • Meshing of circuits allows reduced restoration times
23	Relocate access issues		$102,211				
24	Install alternative supply between W38 and W39	Quality	$102,211	Retain existing spur configuration		Install ring feed cable	• Install ring feed cable. Install ring feed cable • Meshing of circuits allows reduced restoration times which is consistent with Electra's strategy of improving reliability

Ref.	Description and purpose of project	Category	Cost	Options considered			Option chosen and reason
				Do-Nothing	Non-Network	Network	
25	Install cable switch gear close ring at Hokio Beach Road - underground LV(SWITCHGEAR)	Quality	$90,000	Continue with existing fault locaters that require manual observation		Install comms to allow remote indication of faults	• Install comms to allow remote indication of faults • Remote indication of faults allows quicker directing of fault men to faults, reducing restoration times
26	Replace W300 switch gear and close ring W532 to allow quicker restoration of faults.	Quality	$80,000	Retain existing spur configuration		Install ring feed cable	• Install ring feed cable • Meshing of circuits allows reduced restoration times
27	Install new cable switch gear close ring upgrade conductor to T180	Quality	$40,000	Retain existing spur configuration		Install ring feed cable	• Install ring feed cable • Meshing of circuits allows reduced restoration times
28	Install ring feed cable to back up L21 to L332	Quality	$300,000	Retain existing spur configuration		Install ring feed cable	• Install ring feed cable • Meshing of circuits allows reduced restoration times
29	Link between W42 and W293 -Paraparaumu Airport and install CFC	Quality	$260,000	Continue with existing spur network arrangement	Install backup generators/battery for redundancy	Install a cable section to close the ring	• Install ring feed cable • Diesel generators and battery solutions are not cost effective • Meshing of circuits allows reduced restoration times which is consistent with Electra's strategy of improving reliability

* includes "low investment" options.

4.7.3 Development projects for FY2026 to FY2030

Development projects proposed for FY2026 to FY2030 that have been considered are:

Ref.	Description	Category	Cost
1	New zone sub to back up Foxton and Shannon and load growth and possible new grid exit point	Growth	$1,825,000
2	Automation of switchgear - ground mounted	Quality	$1,840,000
3	Close 11kV rings	Growth	$1,350,000
4	Rural substation around Waikawa	Growth	$1,311,056
5	Network sectionalisation-pole mounted	Quality	$1,400,000
6	LVE-Mangahao connection-ex-110kV LINE	Quality	$1,100,000
7	Install conductor and close ring	Quality	$1,022,112
8	Upgrade to butterfly - Foxton to Levin West 33kV	Growth	$700,000
9	Upgrade to butterfly - Levin West to Levin East 33kV	Growth	$700,000
10	Tesla protection work	Quality	$550,000
11	Sub-division extensions	Customer connection	$473,200
12	Install new cable switchgear close ring upgrade conductor to T180	Quality	$360,000
13	Install additional fault locators - permanent	Quality	$330,530
14	Cable replacement between W97 and W98	Growth	$250,000
15	Alternative supply between W38 and W39	Quality	$204,422
16	Link LV network where gaps exist	Quality	$203,860
17	Cable installation between W494 and W502	Growth	$130,000
18	Fault locator communications	Quality	$113,568
19	Install cable and switchgear to close ring from Q91 to P271	Quality	$306,634
20	Install alternative supply between W468 and Z50	Quality	$250,000

5 Lifecycle management

5.1 Asset lifecycle management

This section describes the robust and transparent processes in place for managing all phases of the network life cycle, from conception to disposal which is one of the objectives of the AMP. We manage our assets through the asset lifecycle according to the process illustrated in Figure 5-1. Asset lifecycle management means taking a long-term view to make informed and sound investment decisions to deliver our service levels at an appropriate cost. Benefits of a whole of life approach are:

- Minimising safety risks and future legacy issues through safety in design analysis conducted throughout the asset's lifecycle
- Establishing forecasts for operational and replacement expenditure, thus avoiding surprises
- Minimising the total cost of ownership while meeting accepted standards of performance.

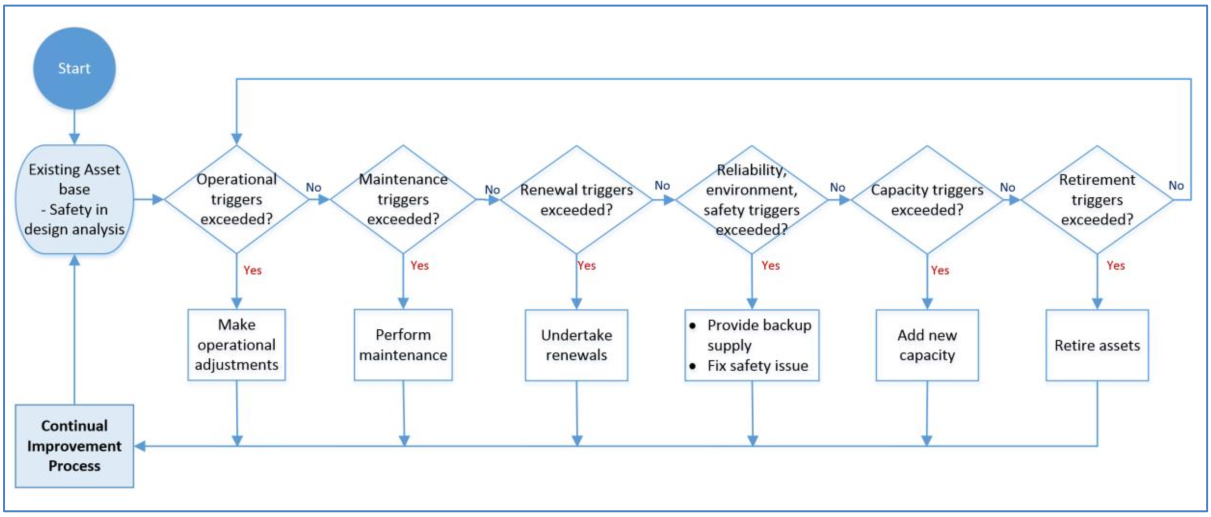


Figure 5-1: Management of the asset lifecycle

The key steps in the asset lifecycle are:

- **Operations**: altering the operating parameters of the asset (i.e. its configuration)
- **Inspection and maintenance**: predominantly associated with routine inspection, testing, vegetation management, and replacing or renewing items that are component parts of an asset (including both pre-planned and fault/emergency maintenance)
- **Renewal**: replacing non-consumable components with an identical item with similar functionality which may significantly extend the asset's life
- **Reliability, safety and environment**: associated with maintaining or improving the safety of the network for consumers, employees and the public, or with the improvement of reliability or service standards, or with meeting new or enhanced environmental requirements
- **System growth** (add new capacity): replacing non-consumable components with a similar item with greater capacity
- **Retirement**: removing an asset from service and disposing of it.

Risk review activities involving project team members are conducted to achieve the safe and smooth delivery of our projects where safety in design (SiD) analysis is integrated into our processes as depicted in Figure 5-1. We are committed to safety being the paramount consideration in the work we do for our customers and records of SiD workshops provide traceability of Electra's application of this approach in support of Electra's commitment to the Health and Safety at Work Act 2015. Further SiD development and assurance stages continue to be included in the project delivery lifecycle.

The following sections discuss the first two key steps of the asset life cycle (Operations; and Inspection and Maintenance) in detail including policies, programmes and actions. It also provides a summary of the renewal, reliability, system growth and retirement criteria. Electra's detailed plans for these steps are in Section 4.7 on Development projects.

5.1.1 Asset operations criteria and assumptions

Actively operating electricity distribution assets predominantly involves letting the electricity flow from the GXPs to consumers' premises. However, occasional intervention is required when a trigger point is exceeded. The following Figure 5-2 outlines the key operational triggers adopted by Electra for each class of assets.

Asset category	Voltage trigger	Demand trigger	Temperature trigger
400V lines and cables	Voltage routinely drops too low to maintain at least 94% of nominal voltage at the point of supply Voltage routinely rises too high to maintain no more than 106% of nominal voltage at the point of supply	Consumers' pole or pillar fuse blows repeatedly Transformer fuses blow repeatedly	Signs of overheating on fittings Infra-red survey reveals hot joint
Distribution substations	Voltage routinely drops too low to maintain at least 94% of nominal voltage at the point of supply Voltage routinely rises too high to maintain no more than 106% of nominal voltage at the point of supply	Load routinely exceeds rating where MDIs are fitted LV fuse blows repeatedly Short term loading exceeds guidelines in IEC 354	Infra-red survey reveals hot connections
Distribution lines and cables	Voltage falls below regulatory requirements and is not able to be adjusted with the distribution transformer tap changers	HV and or LV fusing routinely exceeds ratings HV and or LV fuse failures	Infra-red survey reveals hot joint
Zone substations	Voltage drops below level at which OLTC can automatically raise taps	Load exceeds guidelines in IEC 354	Top oil temperature exceeds manufacturers' recommendations Core hot-spot temperature exceeds manufacturers' recommendations
Sub-transmission lines and cables	Supply voltage at Zone outside of on-load tap changer requirements	SCADA reports over or under voltage alarms	Infra-red survey reveals hot joint

Figure 5-2: Key operational triggers

If any of the above operational triggers are reached, Electra's first efforts to relieve the problem are through one of the following operational activities:

- Operating a tap-changer to correct voltage excursions
- Opening and closing ABSs or RMUs to relieve an over-loaded asset

- Opening and closing ABSs or RMUs to shut down or restore power either planned or fault related
- Operating load control plant to reduce demand
- Activating fans or pumps on transformers to increase the cooling rate.

5.1.2 Asset maintenance planning criteria and assumptions

Maintenance is primarily about replacing consumable components. Continued operation of such components will eventually lead to failure. Failure of such components is usually based on physical characteristics. Exactly what leads to failure may be a complex interaction of parameters such as quality of manufacture, quality of installation, age, operating hours, ambient temperature, previous maintenance history and presence of contaminants. The need to avoid failure determines when maintenance is performed. The obvious trade-off with avoiding failure is the increased cost of labour and consumables over the asset lifecycle along with the cost of discarding unused component life.

Electricity networks are not only constrained electrically but also by the environment within which they are constructed. Electra's network is built within a coastal marine environment. This environment is hostile to most components used in an electricity network and is the principal driver of any accelerated maintenance programmes required to maintain service to consumers. Where possible, equipment designed for this environment is used.

Maintenance decisions are made on the basis of cost-benefit criteria with the principal benefits being avoiding supply interruption and minimising safety risks. Component condition is the key trigger for maintenance however the precise conditions that trigger maintenance are very broad, ranging from oil acidity to dry rot. Figure 5-3 describes the maintenance triggers Electra has adopted for its lifecycle maintenance programme.

Asset category	Components	Maintenance triggers	
400V, distribution and sub-transmission lines and cables	Poles, arms, stays and bolts	• Evidence of dry rot • Loose bolts, moving stays	• Displaced arms
	Pins, insulators and binders	• Obviously loose pins • Visibly chipped or broken insulators	• Visibly loose binder • Missing nuts
	Conductor	• Visibly splaying or broken conductor • Low conductor	• Evidence of heating • Oxidation
	Ground-mounted switches (distribution only)	• Visible signs of oil leaks • Corrosion	• Visibly chipped or broken bushings • Cable damage
Distribution substations	Poles, arms and bolts	• Evidence of dry rot • Loose bolts, moving stays	• Displaced arms
	Enclosures	• Visibly splaying or broken conductor • Partial Discharge	• Thermal Imaging
	Transformer	• Visible signs of oil leaks • Excessive moisture in breather	• Visibly chipped or broken bushings
	Switches and fuses	• Evidence of heating and burning • Evidence of arcing	• Insulation failure

Asset category	Components	Maintenance triggers	
Zone substations	Fences and enclosures	• Corroded wire and or posts • Damaged wire and or posts	• Forced entry • Three yearly maintenance
	Buildings	• Build-up of dirt/grime • Flaking paint • Damaged and or rotting boards	• Leaks • Three yearly maintenance
	Bus work and conductors	• Damaged insulators • Evidence of heating • Splaying conductors	• Oxidation • Three yearly maintenance
	33kV switchgear	• From oil and gas analysis results • Number of operations due to fault tripping or switching • Visible signs of oil leaks • Corrosion	• Evidence of heating • Visibly chipped or broken bushings • Cable damage • Three yearly maintenance
	Transformer	• From oil and gas analysis results • Corrosion • Evidence of heating • Visibly chipped or broken bushings	• Cable damage • Tap changer number of operations • Three yearly maintenance
	11kV switchgear	• From oil and gas analysis results • Number of operations due to fault tripping or switching • Visible signs of oil leaks • Corrosion	• Evidence of heating • Visibly chipped or broken bushings • Cable damage • Three yearly maintenance
	Bus work and conductors	• Evidence of heating • Splaying conductors	• Oxidation • Three yearly maintenance
	Instrumentation	• Requirement of regulation • Failure to operate correctly	• Three yearly maintenance

Figure 5-3: Key maintenance triggers

5.1.3 Reliability, safety and environment criteria and assumptions

If any of the following triggers are exceeded on a feeder Electra will consider adding a duplicate feeder to minimise the number of consumers impacted by an outage of a feeder:

- Maximum of 1,500 urban domestic consumer connections
- Maximum of 200 urban commercial consumer connections
- Maximum of approximately 20 or 30 urban light industrial consumer connections.

Details of the reliability, safety and environmental programmes and associated expenditures are provided in Section 4.7 on Development projects.

5.1.4 Asset renewal and refurbishment criteria and assumptions

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). A key criterion for renewing an asset is when its capitalised operating and maintenance costs exceed the renewal cost, and this can occur in the following ways:

- Operating costs become excessive for example: increasing level of inputs into a SCADA system requires an increased number of staff
- Maintenance costs begin to accelerate - for example, a transformer needs more frequent oil changes as the seals and gaskets perish
- Supply interruptions due to component failure become excessive as determined by the number and nature of consumers affected
- Renewal costs decline, particularly where life-time costs of new technologies decrease significantly.

Figure 5-4 lists Electra's renewal triggers for key asset classes:

Asset category	Components	Renewal trigger
Sub-transmission, Distribution and LV lines and cables	Poles, arms, stays and bolts	• Rotting wooden poles • Concrete has spalled to the extent that it impacts on strength • Arms have rotted, broken or been damaged • Stays have severe corrosion affecting strength • Bolts are corroded beyond repair
	Pins, insulators and binders	• Affecting reliability • Affecting safety
	Conductor	• Over or at maximum load • Obviously beyond repair
	Ground-mounted switches	• Severe corrosion impacting on safety and or security • Beyond economic repair • Oil and gas tests indicate switch is under stress
Distribution substations	Poles, arms and bolts	• Wooden poles • Concrete has spalled to the extent that it impacts on strength • Arms have rotted, broken or been damaged • Stays have severe corrosion affecting strength • Bolts are corroded beyond repair
	Enclosures	• Severe corrosion impacting on safety and or security • Beyond economic repair
	Transformer	• Over 40 years old with associated impact on losses • Oil and gas tests indicate transformer is under stress.
	Switches and fuses	• Severe corrosion impacting on safety and or security • Beyond economic repair • Oil and gas tests indicate switch is under stress • Fuses are damaged or no longer available
Zone substations	Fences and enclosures	• Corroded beyond economic repair
	Buildings	• Damaged beyond economic repair
	Bus work and conductors	• Damaged or worn beyond economic repair

Asset category	Components	Renewal trigger
	33kV switchgear	• Damaged or worn beyond economic repair
	Transformers	• Damaged or worn beyond economic repair
	11kV switchgear	• Damaged or worn beyond economic repair
	Bus work and conductors	• Damaged or worn beyond economic repair
	Instrumentation	• Damaged or worn beyond economic repair

Figure 5-4: Guidelines for renewal/replacement of assets

Details of the renewal or refurbishment programmes and associated expenditures are provided in Section 4.7 on Development projects.

5.1.5 System growth criteria and assumptions

If any of the triggers depicted in Figure 5-1 and described in Section 4.2 are exceeded, we will consider adding additional capacity to the network.

We use a range of technical and engineering standards to achieve an optimal mix of the following outcomes:

- Comply with environmental and public safety requirements
- Meet likely demand growth for a reasonable time horizon including consideration of modularity and scalability
- Minimise the risk of long-term stranding
- Maximise operational flexibility
- Maximise the fit with software capabilities such as engineering and operational expertise and vendor support.

Standard designs on our network are generally adopted for all asset classes with minor site-specific alterations. Work identified by Electra as needing to be done is almost solely carried out by Electra's Distribution Operations staff.

As part of the building and commissioning process, our information records are recorded through the "as-built" process and all testing of new assets is documented.

Details of the system growth programmes and associated expenditures are provided in Section 4.7 on Development projects.

5.1.6 Consumer connection criteria and assumptions

These projects are driven by consumers. Typically, these projects include assets to connect a consumer to the existing network. This category includes upstream assets that are changed to meet the load of a new consumer (or existing consumer requesting a larger capacity). Given the nature of this work, consumers are able to approach up to three contractors authorised to work on Electra's network.

5.1.7 Retiring assets criteria and assumptions

Key criteria for retiring an asset include:

- Its physical presence is no longer required (usually because a consumer has reduced or 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 - for example, replacing lubricated bearings with high-impact nylon bushes
- Where an asset has been up sized, and no suitable opportunities exist for re-deployment.

5.2 Management of our assets

Electra manages network assets by asset class or type. The lifecycle plans for each asset class are set out in following Sections of 5.3 onwards, which describe the detailed approach adopted to inspect and maintain all asset classes covering:

- Overhead structures: poles, crossarms
- **Overhead conductors**: sub transmission, distribution and low voltage lines
- **Underground cables**: sub transmission, distribution and low voltage cables
- **Zone substations**: power transformers, zone switchgear, buildings, protection relays, load control
- **Distribution transformers**: ground and pole-mounted transformers
- **Distribution switchgear**: reclosers, pole-mounted fuses and switches
- **Secondary systems**: SCADA and communications.

This includes a description of the primary features, inspections and condition-monitoring carried out, and the actions taken to address any systemic problems by asset category. The inspections of various assets are planned and Figure 5-5 shows some of the inspection areas.

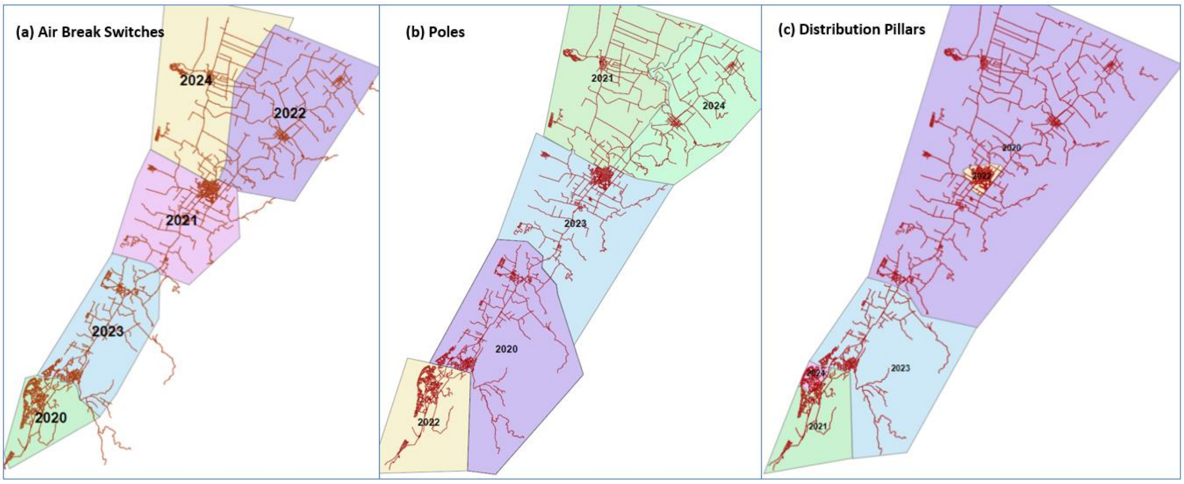


Figure 5-5: Five-year inspection cycle areas for (a) Air break switches, (b) Overhead line poles and (c) Distribution pillars

The condition of the asset is provided in Figure 5-6 which aligns the grades of asset condition with the grades set out in the Commerce Commission's Determination[15]:

Grade	Determination definition	Condition	Electra definition
0	Not used in the determination	0	Imminent risk of failure. Schedule replacement for next working day unless repair or replacement required immediately
1	End of serviceable life, immediate intervention required	1	Close to failure, schedule for replacement within next 3 months
2	Material deterioration but asset condition still within serviceable life parameters. Intervention likely to be required within 3 years	2	Will require replacement before next scheduled inspection. Schedule for replacement, scope to be confirmed during first half of next inspection cycle
3	Normal deterioration requiring regular monitoring	3	Does not require replacement during this inspection cycle. Continue with scheduled inspection cycle
4	Good or as new condition	4	No sign of deterioration. Continue with scheduled inspection cycle
Unknown	Unknown or not yet assessed		Unknown or not yet assessed. Criticality is determined as part of the asset identification, and it will be assigned an inspection cycle
			Condition assessment methods are periodically evaluated for low-value, low-risk asset categories that are otherwise run to failure

Figure 5-6: Electra - grades of asset condition

Data accuracy levels used in this section also refer to the said Commerce Commission's Determination and refers to the definition of the assessment of the accuracy of the data provided:

1. Means that good quality data is not available for any of the assets in the category and estimates are likely to contain significant error
2. Means that good quality data is available for some assets but not for others and the data provided includes estimates of uncounted assets within the category
3. Means that data is available for all assets but includes a level of estimation where there is understood to be some poor-quality data for some of the assets within the category
4. Means that good quality data is available for all the assets in the category.

5.3 Overhead structures

5.3.1 Concrete and steel poles

Electra has 20,288 concrete poles and 25 steel poles on its network. These range in age from new to 79 years and have been sourced from a range of suppliers including the HEPB's own pole factory. The pole population and age profile of wooden, concrete and steel poles follow:

[15] Commerce Commission, "Electricity Distribution Information Disclosure Determination 2012 (consolidated April 2018)"

Sub-class	Number	Unit	Percent	Key features of sub-class
Pre-stressed concrete	2218	Each	10.92%	No known concerns but observed that heavily loaded poles are deteriorating faster
Solid concrete	18,068	Each	88.95%	No known concerns but observed that heavily loaded poles are deteriorating faster
Spun concrete	2	Each	0.01%	
Steel	19	Each	0.094%	
Oclyte	6	Each	0.026%	
Total	**20,313**	**Each**	**100%**	

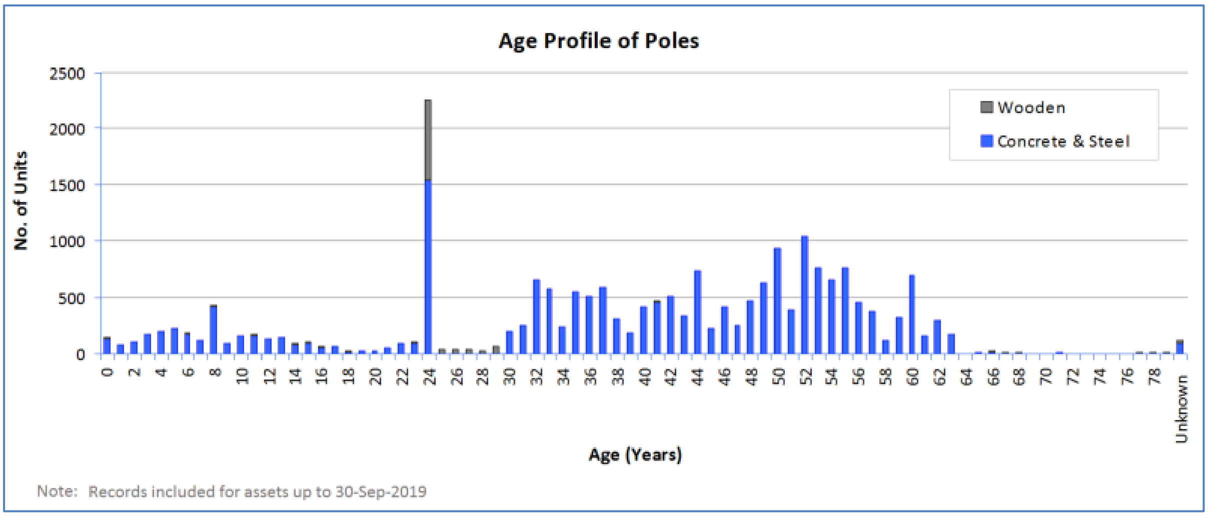


Figure 5-7: Age profile of poles

Key design parameters used are:

Parameter	Value
Durability	General design life of 60 years
Structural strength	Minimum strength embodied in Electra's Overhead Line Design Standard

5.3.1.1 Condition

The condition of the poles is graded as shown in the following table:

Condition:	Grade 1	Grade 2	Grade 3	Grade 4	Grade unknown	Data accuracy	Percent forecast for replacement over next 5 years
		2.3%	92.70%	5.0%	-	3	2.50%

There are no known systemic issues with Electra's concrete or steel poles.

The key drivers for maintenance are:

- Overall integrity of concrete
- Verticality of pole in all directions, including slumping or subsidence of surrounding ground
- Clearance of live conductors from both ground and surrounding structures
- Corrosion of steel poles, especially at ground level.

The overhead network is inspected on a five-yearly cyclic basis. Maintenance criteria include:

- Cracking or spalling of concrete becomes greater than hairline or more than 250mm long
- Reinforcing steel becomes exposed
- Supporting ground shows evidence of erosion or subsidence e.g. pole slumping
- Pole leans to the point where conductors are overly strained, or sag below minimum allowable height
- Steel pole corroded to more than surface deep, especially near ground level.

The assumptions for the above include:

- Spalling of concrete will lead to unsafe pole condition within 5 years in inland areas, and 3 years in coastal areas
- Erosion of ground will lead to unsafe condition within 2 years
- Surface corrosion of steel poles will continue to corrode deeper
- Deterioration at ground level is most critical due to greater bending moment.

Condition assessment techniques and methods are primarily visual and may include any one or more of accepted industry techniques for either structural (loading) testing or estimating remaining cross-section.

Besides the poles being replaced in renewal projects, poles are also replaced or installed during key capital projects such as line upgrades, customer work or asset relocation projects due to road widening projects etc.

5.3.1.2 Inspections and maintenance

The grading of inspections together with refurbishment or renewals applied follow:

Grade	Inspection	Refurbishment	Renewal
1	No further inspections, will be replaced within 1 year	Will not be refurbished	Renew within 3 months
2	Bi-monthly inspections and close monitoring, and is likely to be replaced within 3 years if repair or refurbish options are not cost effective	Will not be refurbished, may have minor repairs to lift from Grade 1	Renew within inspection cycle
3	Continue to inspect, amend grade as required	Repair to extend life as considered appropriate by Planning & Development Manager	-
4	Continue to inspect, amend grade as required	-	-

Defect corrections are carried out within the following time frames:

- **Public safety defects**: correction within one week of identification
- **Significant structural integrity defects**: correction within 1 week of identification
- **Minor structural integrity defects**: repair by approved method within three months of identification.

Lifecycle decision criteria include:

- Electra will repair hairline cracks in concrete poles using commercially proven grout and treatments

- The criteria for replacement of the pole is whether the crack is bigger than hairline, more than 250mm long, or has exposed the reinforcing steel
- For poles with a planned replacement date, an optimised reduced maintenance programme maybe developed if analysis concludes that the risks can be prudently managed. This may include different approaches for specific assets in sensitive areas such as parks or near schools.

Life extension and investment deferral techniques follow:

- Electra views poles as safety-critical and therefore weighs the risk of failure more heavily in its “refurbish-replace” decisions, which creates a bias for replacement (rather than squeezing a few remaining years out of pole).

5.3.1.3 Major projects and programmes

Projects and programmes FY2021:

Ref	Location	Description	Category	Cost
1	All	400V pole replacements (approx. 33 poles) - inspection driven	Renewal	$230,000
2	All	11kV pole replacements (approx. 31 poles) - inspection driven	Renewal	$305,000
3	All	33kV pole replacements (approx. 13 poles) - inspection driven	Renewal	$170,000
4	All	Fault/urgent defect replacement	Renewal	$50,000

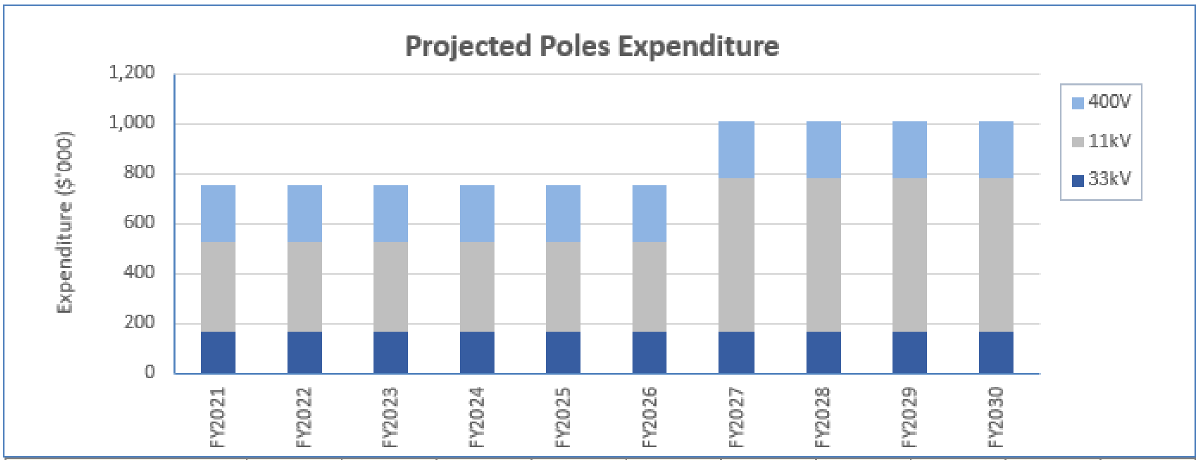
Projects and programmes FY2022 to FY2025:

Ref	Location	Description	Category	Cost
1	All	400V pole replacements (approx. 131 poles) - inspection driven	Renewal	$920,000
2	All	11kV pole replacements (approx. 122 poles) - inspection driven	Renewal	$1,220,000
3	All	33kV pole replacements (approx. 52 poles) - inspection driven	Renewal	$680,000
4	All	Fault/Urgent defect replacement	Renewal	$200,000

Projects and programmes FY2026 to FY2030:

Ref	Location	Description	Category	*Cost*
1	All	400V pole replacements (approx. 164 poles) - inspection driven	Renewal	$1,150,000
2	All	11kV pole replacements (approx. 255 poles) - inspection driven	Renewal	$2,553,648
3	All	33kV pole replacements (approx. 65 poles) - inspection driven	Renewal	$850,000
4	All	Fault/urgent defect replacement	Renewal	$250,000

The forecast budget for 33kV, 11kV and LV poles is shown in Figure 5-8.



Description	FY2021	FY2022	FY2023	FY2024	FY2025	FY2026	FY2027	FY2028	FY2029	FY2030
Capital Expenditure ($'000)										
33kV	170	170	170	170	170	170	170	170	170	170
11kV	355	355	355	355	355	355	612	612	612	612
400V	230	230	230	230	230	230	230	230	230	230
Total:	**755**	**755**	**755**	**755**	**755**	**755**	**1,012**	**1,012**	**1,012**	**1,012**

Figure 5-8: Projected poles expenditure

5.3.2 Wooden poles

Electra has nine hardwood poles on its 11kV network. There are records of a further 1,136 service line poles whose ownership may include Chorus, or customers, and is very unlikely to include Electra. These range in age from new to 78 years old and is depicted in the age profile of Figure 5-7.

Sub-class	Number	Unit	Percent
Soft wood	837	Each	74%
Hard wood	299	Each	26%
Total	**1,136**	**Each**	**100%**

5.3.2.1 Condition

The condition of our hardwood poles is indicated in the following table and these will be replaced eventually by concrete poles.

Condition:	Grade 1	Grade 2	Grade 3	Grade 4	Grade unknown	Data accuracy	Percent forecast for replacement over next 5 years
11kV hardwood distribution	-	40.00%	60.00%	-	-	2	45.00%

There are no known systemic issues with Electra-owned wood poles.

Electra has been developing a customer-owned (wood) pole strategy during 2018 which will present a range of options for Electra to assist customers in maintaining their service lines and service mains in a safe condition.

5.3.2.2 Inspections and maintenance

Our maintenance drivers consist of:

- Overall integrity of timber, including absence of splits, warping or enlarging of knots
- Verticality of pole in all directions

- Evidence of rot or fungus, especially at ground level
- Clearance of live conductors from both ground and surrounding structures.

The criteria for maintenance include:

- Splitting of timber becomes greater than finger-width
- Warping or twisting of timber strains or slackens conductors
- Heart timber becomes exposed
- Supporting ground shows evidence of erosion or subsidence
- Pole leans to the point where conductors are overly strained, or sag below minimum allowable height
- Deterioration of timber becomes more than surface deep, especially at ground level.

Assumptions for the above maintenance criteria include:

- Splitting of timber will lead to unsafe pole condition within 5 years in inland areas, and 3 years in coastal areas
- Erosion of ground will lead to unsafe condition within 2 years
- Surface deterioration of timber will continue to deteriorate deeper
- Deterioration at ground level is most critical due to greater bending moment.

Condition assessment techniques and methods are primarily visual, noting that very few remain on Electra's network.

Results of our inspections are graded as shown in the following table with refurbishment or renewals applied.

Grade	Inspection	Refurbishment	Renewal
1	No further inspections, will be replaced within 1 year	Will not be refurbished	Renew within 1 year
2	Bi-monthly inspections and close monitoring, and is likely to be replaced within 3 years	Minor repairs only	Renew within 3 years
3 & 4	Continue to inspect, amend grade as required	Repair to extend life as considered appropriate by Planning & Development Manager	-

Defect corrections are carried out within the same time frames as for concrete poles.

Lifecycle decision criteria includes:

- Electra will increase the frequency of inspection when a pole exceeds any of the maintenance criteria
- Electra will schedule replacement of wood poles when inspections reveal it to be structurally unsound or placing undue load on other components including straining or slackening conductors.

The programme and budget for the replacement of wood poles is included with concrete poles in Section 5.3.1.3.

5.3.3 Pole-top hardware

Electra has 43,970 wooden cross arms and 4,552 galvanised steel cross arms as tabulated below:

Sub-class	Number	Unit	Percent
Hard wood	8,445	Each	17.39%
Soft wood	82	Each	0.17%
Tallow wood	35,374	Each	72.86%
Steel	557	Each	1.15%
Steel box section	3,995	Each	8.23%
Polymer	83	Each	0.17%
Unknown	15	Each	0.03%
Total	48,551	Each	100%

The age profile of these crossarms are shown in Figure 5-9a for wooden crossarms, and Figure 5-9b for steel crossarms.

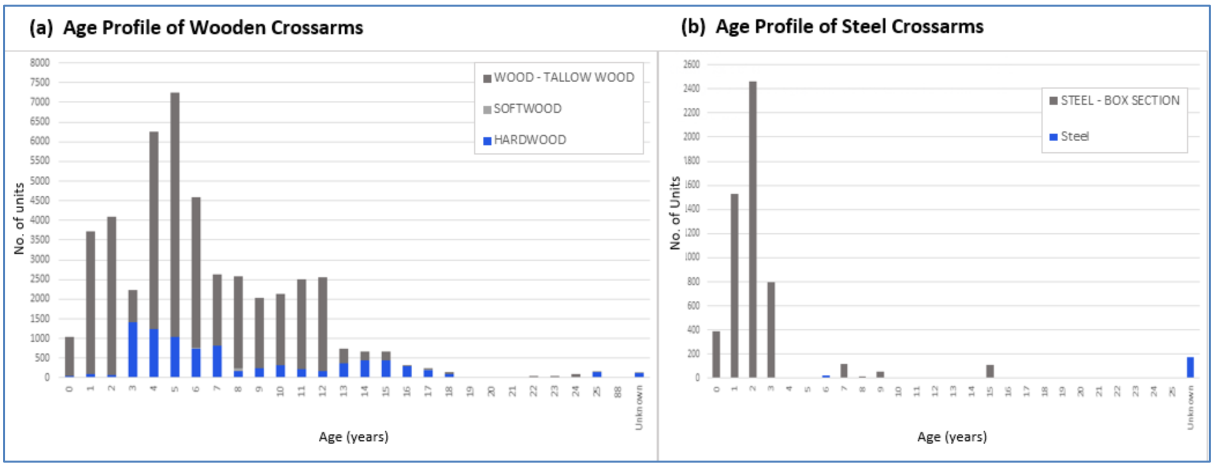


Figure 5-9: (a) Wooden and (b) Steel crossarms age profile

The key design parameters are tabulated below:

Parameter	Value
Weight	Minimise, to ease carrying to site and ease (safety) of installation
Durability	Expect to last 35 to 40 years
Insulation	May be designed to higher voltage for salty coastal areas (e.g. 22kV instead of 11 kV)
Structural strength	Embodied in Electra's overhead line design standards and includes consideration of static and wind loads

5.3.3.1 Condition

The condition of our crossarms follow:

Condition:	Grade 1	Grade 2	Grade 3	Grade 4	Grade unknown	Data accuracy	Percent forecast for replacement over next 5 years
		3.5%	77.6%	18.9%		-	4%

Systemic issues include pollutants on our insulators and mitigation measures follow:

Systemic issue	Mitigation	Magnitude of issue and impact on Electra
Wind-borne pollutants tracking on porcelain insulators	Electra has standardised on polymeric insulators from 2013	This issue is of minimal magnitude and doesn't significantly impact on Electra

5.3.3.2 Inspection and maintenance

The overhead network is inspected on a five-yearly cyclic basis. The drivers for pole-top maintenance include:

- Splitting, warping or bending of wooden arms
- Brown, white or soft rot of wooden cross arms, including sap staining as an early indicator of rot
- Mildew or lichen (as an indicator of moisture and as an early indicator of possible rot)
- Fungus, especially fruiting (indicative of significant decay)
- Burning or scorching possibly from tracking
- Rust on galvanised steel arms more than surface deep as observed from ground level
- Corrosion of stays significant enough to reduce physical strength
- Loose or fallen stays
- Corrosion of bolts
- Missing nuts, plate washers or spring washers
- Deterioration of air break switches, and associated actuators and linkages.

The criteria for maintenance include:

- Splitting of wooden arms more than 300mm long, risk of pin or bolt disengaging due to split width, or fungus beginning to form in split
- Brown rot (spotting or streaking) covering most of arm surface, shrinkage leading to cracking or risk of pin or bolt disengaging
- White rot (stripes) more than about 300mm long and 50mm wide, or emerging fungus (later stage)
- Soft rot (dark spots or streaks) more than about 100mm long and 15 mm thick
- Thickening mildew or lichen (possible early indicator of rot)
- Round fungus about the size of a golf ball or flat fungus more than about 100mm long
- Intermittent burn marks between pin and pole
- Visibly chipped or broken insulators
- Loose or missing nuts or washers
- Visibly loose binder
- Stay has become unfastened or is missing
- Air break switch becomes difficult to operate.

Assumptions include:

- Splitting of timber arms may lead to sudden failure
- Warping or bending or timber arms may unevenly strain conductors, leading to excessive binding tension
- Burning or scorching indicates electrical tracking
- Lichen or mildew indicates retained moisture which may lead to rot
- Visible fungus indicates likely internal decay
- Loose nuts or washers may be caused by timber arms shrinking or warping

- Tightening of air break switch operation indicates corrosion
- Visible cracking of insulators could result in water ingress and further cracking.

Condition assessment techniques and methods are primarily visual for cross-arms, looking specifically for splits, enlarged holes or fungal growth as well as visual inspections for stay straps, bolts, air-break switches with follow up on any switches reported to be stiff or not fully operating.

Inspection results are graded as follows with refurbishment or renewals applied:

Condition	Inspection	Refurbishment	Renewal/replacement
0	Scheduled for immediate replacement	Pole top components are generally renewed rather than refurbished General servicing of air break switches on a 5-year cycle	Replace either immediately or next working day
1	No further inspections, schedule for replacement within next 3 months	Pole top components are generally renewed rather than refurbished General servicing of air break switches on a 5-year cycle	Replace with 3 months
2	No further inspection, replacement scope to be confirmed during first half of next inspection cycle	Pole top components are generally renewed rather than refurbished General servicing of air break switches on a 5-year cycle	Renew within 3 years
3	Will not meet replacement criteria during this inspection cycle, continue inspecting	Pole top components are generally renewed rather than refurbished General servicing of air break switches on a 5-year cycle	Replace within first half of next inspection cycle
4	No sign of deterioration, continue scheduled inspections	Pole top components are generally renewed rather than refurbished General servicing of air break switches on a 5-year cycle	No replacement required

Defect correction:

- **Public safety defects**: correction within one week of identification
- **Significant defects that could lead to asset failure** (e.g. arm breaking): correction within one week of identification
- **Minor defects**: repair by approved method within 3 months of identification.

Lifecycle decision criteria:

- Worn, damaged or broken components are generally renewed at the first convenient opportunity
- Loose cross arm bolts would generally be re-tightened unless there was evidence of excessive arm shrinkage, warping, mould, lichen, rot or fungus in which case the arm would be renewed.

Life extension and investment deferral techniques:

- Electra does apply any life extension techniques to pole top hardware.

5.3.3.3 Major projects and programmes

The projects and programmes for FY2021:

#	Location	Description	Category	Cost
1	All	Inspection driven crossarm replacements - 11kV	Renewal	$275,000
2	All	Inspection driven crossarm replacements - 400V	Renewal	$600,000
3	All	Inspection driven crossarm replacements - 33kV	Renewal	$120,000
4	All	Fault/urgent defect replacement of cross arms	Renewal	$70,000

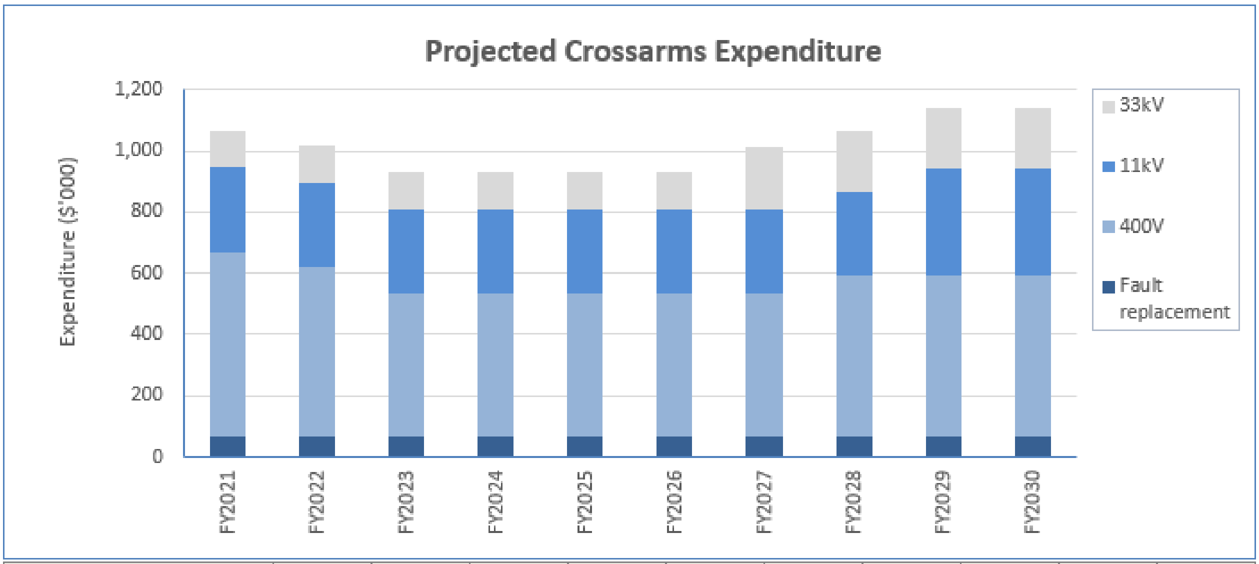
The projects and programmes for FY2022 to FY2025:

#	Location	Description	Category	Cost
1	All	Inspection driven crossarm replacements – 11kV	Renewal	$1,100,000
2	All	Inspection driven crossarm replacements – 400V	Renewal	$1,946,887
3	All	Inspection driven crossarm replacements – 33kV	Renewal	$480,000
4	All	Fault/urgent defect replacement of cross arms	Renewal	$280,000

The projects and programmes for FY2026 to FY2030:

#	Location	Description	Category	Cost
1	All	Inspection driven crossarm replacements – 11kV	Renewal	$1,525,000
2	All	Inspection driven crossarm replacements – 400V	Renewal	$2,491,258
3	All	Inspection driven crossarm replacements – 33kV	Renewal	$920,000
4	All	Fault/urgent defect replacement of cross arms	Renewal	$350,000

The budget forecast is depicted in Figure 5-10.



Description	FY2021	FY2022	FY2023	FY2024	FY2025	FY2026	FY2027	FY2028	FY2029	FY2030
Capital Expenditure ($'000)										
33kV	120	120	120	120	120	120	200	200	200	200
11kV	275	275	275	275	275	275	275	275	350	350
400V	600	550	466	466	466	466	466	520	520	520
Fault replacement	70	70	70	70	70	70	70	70	70	70
Total:	**1,065**	**1,015**	**931**	**931**	**931**	**931**	**1,011**	**1,065**	**1,140**	**1,140**

Figure 5-10: Projected crossarm expenditure

5.4 Overhead line conductors

5.4.1 Overhead sub-transmission lines

5.4.1.1 Inspection policies and programmes on overhead sub-transmission lines

Electra inspects the 33kV overhead circuits annually as one part of its life-cycle asset management process. Special inspections, including the use of thermal imaging every five years, are also used to enhance the maintenance planning process.

All line surveys are carried out by experienced linemen who walk the line route and note any visual defects. Under certain conditions, these inspections may be undertaken using live line techniques. This is usually when a close-in inspection is required such as the three yearly ABS inspections. All overhead circuits are visually inspected as follows:

Asset	Inspection guidelines
Poles	Type, leaning, spalling of concrete/or rot
Cross arms and insulators	Type, rot, lean, brackets, contamination
Conductor	Incorrect sag, damaged conductor
Trees	Growth around overhead lines, new planting, or potential fire sources
Slips etc	Slips or other ground disturbances threatening poles, structures or underground cables
Buildings	Construction under/near lines or over cables
Telecommunication lines	Clearance from ground and Electra's circuits
Thermography	Five-yearly – 33kV only

We record and store this information electronically. All inspection results are filtered by condition and purchase orders are raised for remedial or replacement works in the next financial year, urgent work is completed immediately.

Electra intends to complete the physical strength and remaining life tests on 33kV 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.

Electra also carries out three yearly live line condition assessments of all 33kV and 11kV ABSs on a rotating basis. These inspections examine operation, contacts, vegetation and contamination.

5.4.1.2 Maintenance policies and programmes on overhead sub-transmission lines

Circuit faults, in particular overhead lines, are the largest contributor to SAIDI. Therefore, maintenance of these circuits is essential to maintain the operating flexibility and capacity of the electricity network and minimise the risk of expensive failures and loss of supply to consumers.

The maintenance plan includes vegetation control and any works required as a result of the routine inspections and tests and is allowed for in the maintenance budget.

Cross-arms and insulators are replaced on overhead circuits as required after condition assessment inspection. This expenditure is treated as maintenance. Electra has, through its routine inspections, identified poles, cross-arms and insulators for replacement, these have been included as renewals in the budget.

5.4.1.3 Key features

Electra has 10 sub-transmission feeders as follows:

GXP	Feeder	Rating (A)	Typical loading (%)		Performance and risk concerns
			2018	2019	
Mangahao	Mangahao – Shannon 1	600	6%	7%	Nil
	Mangahao – Shannon 2	600	10%	10%	Nil
	Mangahao – Levin East 1	390	28%	29%	Mangahao CB 332 will be replaced before its rating of 390A is likely to be constrained by N-1 rating when feeding Otaki
	Mangahao – Levin East 2	390	29%	32%	Mangahao CB 312 will be replaced before its rating of 390A is likely to be constrained by n-1 rating when feeding Otaki
Valley Road	Valley Road – Waikanae 1	530	19%	19%	Nil
	Valley Road – Waikanae 2	600	22%	22%	Nil
	Valley Road – Para West	530	22%	21%	Nil
	Valley Road – Paraparaumu 1	600	18%	18%	Nil
	Valley Road – Paraparaumu 2	600	14%	14%	Nil
	Valley Road – Paekakariki	600	3%	3%	Nil

Electra has 151 km of 33kV overhead conductor, and its age profile is shown in Figure 5-11. The circuit lengths of its overhead and underground sub-transmission network can be found in Section 2.2.

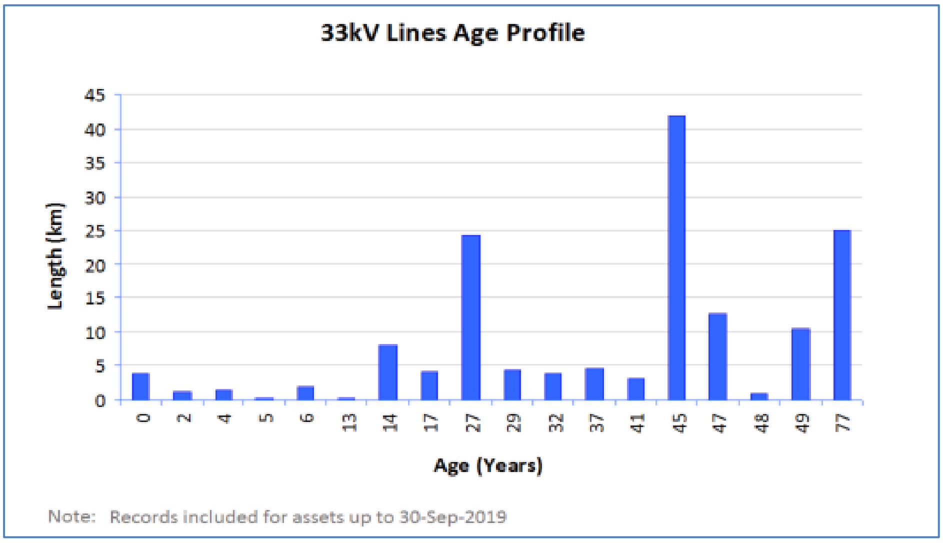


Figure 5-11: 33kV line age profile

5.4.1.4 Condition

The condition of these lines is tabulated below where 10% is forecasted to be replaced in the next 5 years.

Condition:	Grade 1	Grade 2	Grade 3	Grade 4	Grade unknown	Data accuracy	Percent forecast for replacement over next 5 years
33kV conductor		9.50%	87.9%	2.6%		4	10.0%

5.4.1.5 Reliability

Figure 5-12a shows our sub-transmission fault rate compared to other electrical distribution businesses or EDBs over the last two years (FY2018 to FY2019). At a fault rate per 100km of 0.985, we are 71% below the median of 3.3. Figure 5-12b graph will be discussed in Section 5.4.2.1.

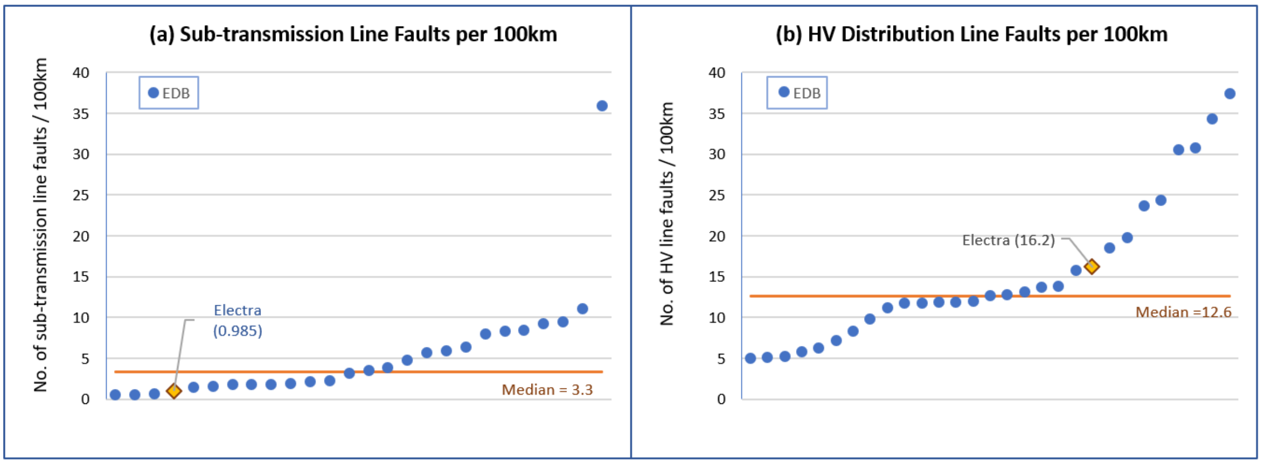


Figure 5-12: FY2018-19 number of faults per 100km of line for (a) Sub-transmission lines, and (b) HV distribution lines

The details of its inspection and maintenance criteria, programmes and budget are included in Sections 5.4.2.3 to 5.4.2.5.

The projected sub-transmission overhead lines expenditure is shown in Figure 5-15.

5.4.2 Overhead distribution conductors

Electra has 848 km of 11kV overhead conductor, and 524 km of LV overhead. These conductors are a mix of Gopher, Bee, Butterfly, 7/0.083 Copper, 19/0.064 Copper and 19/0.092 Copper.

The age profile for these distribution lines are shown in Figure 5-13 for 11kV line and Figure 5-14 for low voltage lines.

The key design parameters are:

Parameter	Value
Capacity	Nominal load of 70% of manufacturer's rating
Mechanical strength	Embodied in Electra's overhead line design standard, which in turn are referenced to span lengths and tension

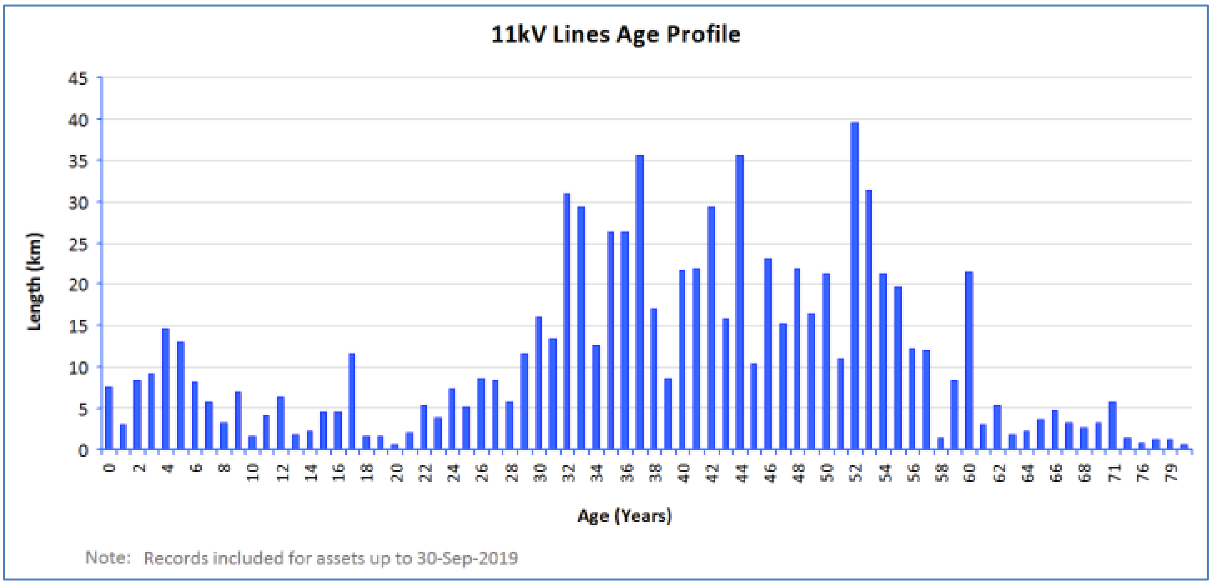


Figure 5-13: 11kV line age profile

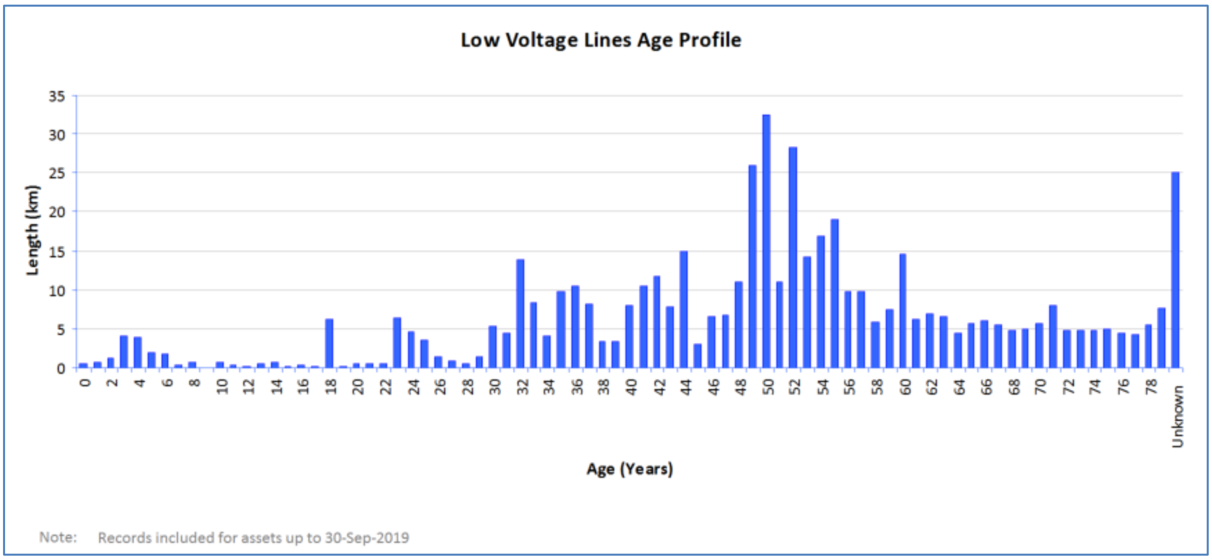


Figure 5-14: Low voltage line age profile

5.4.2.1 Condition

The condition of our 11kV and low voltage lines are graded as shown in the following table with the forecasted replacement over the next five years:

Condition:	Grade 1	Grade 2	Grade 3	Grade 4	Grade unknown	Data accuracy	Percent forecast for replacement over next 5 years
11kV conductor		7.00%	83.4%	9.60%		3	7.2%
LV conductor		4.0%		2.3%	93.70%	2	4.0%

Capacity, security and reliability constraints have been identified in Section 4.4.

A systemic issue involving ACSR conductors in coastal areas and mitigation measures are identified below:

Systemic issue	Mitigation	Magnitude of issue and impact on Electra
ACSR conductors in coastal area have had problems with corrosion	Electra's standards have been changed so that ACSR conductors have aluminium coated rather than grease coated steel reinforced	This issue is of minimal magnitude and does not significantly impact on Electra

5.4.2.2 Reliability

Figure 5-12b shows our HV distribution line fault rate (11kV) compared to other EDBs over FY2018 to FY2019. At a fault rate per 100km of 16.2, we are 28% above the median of 12.6. We are committed to improving our performance through the various strategies identified in Sections 3.9 and 4.7.

5.4.2.3 Inspection and maintenance

The 11kV conductors and major 400V feeders are inspected on a five-year basis as compared to 33kV lines which are inspected annually.

The drivers for the maintenance of overhead conductors follow:

- Breakage, fraying or splaying of individual strands
- Stretching, elongation or necking consistent with annealing
- Bird-caging of complete conductor
- Clearance of live conductors from ground, trees, other parties' wires and surrounding structures
- Excessive surface corrosion, or
- Overall integrity of complete conductor.

The criteria for maintenance or replacement are:

- Cross-section area reduced to less than 85% of as-new conductor
- One or more strands of a 7-strand conductor visibly broken or close to breaking
- Three or more strands of a 19-strand conductor visibly broken or close to breaking
- Corrosion (especially black or green) appears more than surface deep for significant fractions of individual spans
- Individual strands visibly bird-caging
- Evidence of overheating
- Excess tension (usually a pole leaning issue)
- Sag below minimum allowable distance (usually a pole leaning issue).

Assumptions for our maintenance criteria include:

- Fraying of individual strands will place more strain on remaining strands and lead to accelerated failure
- Corrosion that is deeper than surface will place more strain on remaining strands and lead to accelerated failure
- Heavy loading for prolonged periods may anneal the conductor, reducing its tensile strength.

Condition assessment techniques and methods are primarily visual with a focus on looking specifically for cracked or corroded strands or splaying of strands.

5.4.2.4 Lifecycle policies, criteria and activities

Inspections are graded as follows and refurbishment or renewals applied as follows:

Condition	Inspection	Refurbishment	Renewal/replacement
0	Scheduled for immediate replacement	Will not be refurbished	Replace either immediately or next working day
1	No further inspections, schedule for replacement within next 3 months	Will not be refurbished	Replace with 3 months
2	No further inspection, replacement scope to be confirmed during first half of next inspection cycle	Minor repairs only	Renew within 3 years
3	Continue to inspect, amend grade as required	Repair to extend life as considered appropriate by Planning & Development Manager	Replace within first half of next inspection cycle
4	No sign of deterioration, continue scheduled inspections	Repair to extend life as considered appropriate by Planning & Development Manager	No replacement required

Defect corrections are made as follows:

- **Public safety defects**: correction within one week of identification
- **Significant structural integrity defects**: correction within one week of identification
- **Minor structural integrity defects**: repair by approved method within three months of identification.

Upgrading activities are carried out based on the following criteria:

- **Renewal/replacement**: progressive replacement of all copper conductor with a thicker conductor to allow 11kV back feeding and eliminate safety hazard (breakage and whipping), starting with 7/0.064 where possible
- **Lifecycle decision criteria**: up-size if conductor is loaded beyond 70% of nominal rating for more than about 3,000 hours per year; replace if more than 1 strand of a 7-strand conductor or 3 strands of a 19-strand conductor are visibly broken or splayed
- **Life extension and investment deferral techniques**: use of aluminium-coated steel-reinforced ACSR rather than grease coated steel reinforcing.

5.4.2.5 Major projects and programmes

The projects and programmes for FY2021 follow:

Ref	Location	Description	Category	Cost
1	All	400V reconductors	Renewal	$525,000
2	All	Inspection driven conductor replacements	Renewal	$57,354
3	Puriri Rd and Greenaway Rd	Replace 16mm Cu with Gopher (0.9km)	Renewal	$122,400
4	Kuku Beach road	Replace 16mm Cu with BEE(2.05kms)	Renewal	$278,800

Ref	Location	Description	Category	Cost
5	Stafford Street	Replace 35mm Cu with BEE (2km in 2yrs)	Renewal	$136,000
6	Bartholomew and Middlesex Street	Replace 1.2km of Cu with BEE(1.2kms)	Renewal	$163,200
7	Rata Rd	Replace 16mm Cu with Gopher (0.7km)	Renewal	$95,200
8	Takapu Road	Replace the existing Gopher with Gopher (1km in FY2021)	Renewal	$136,000
9	Graham Street	Replace 16mm Cu with BEE(0.34km)	Renewal	$46,240
10	Makerua Rd and Tawa St	Replace 16mm Cu with BEE(1.6km)	Renewal	$217,600
11	Temuera St and Matai St	Replace 16mm Cu with Gopher(0.83km)	Renewal	$112,880
12	Green Avenue	Replace 16mm Cu with Gopher(0.21km)	Renewal	$28,560
13	Koputaroa Rd	Replace 16mm Cu with BEE(0.9km)	Renewal	$122,400

Projects and programmes for FY2022 to FY2025 are:

Ref	Location	Description	Category	Cost
3	Domain Road	Replace 16mm Cu with Gopher (0.5km)	Renewal	$68,000
4	Stafford Street	Replace 35mm Cu with BEE (1km in FY 2022)	Renewal	$136,000
5	Te Manuao Rd	Replace 16mm Cu with BEE (1km)	Renewal	$136,000
6	Tui Crescent	Replace 16mm Cu with Gopher(0.68km)	Renewal	$92,480
7	Foxton Shannon Rd	Replace 35mm Cu with BEE (total 12.08kms in 4yrs)	Renewal	$1,642,880
8	Mangahao Rd	Replace 16mm Cu with Gopher (4 km in 4 yrs)	Renewal	$544,000
9	Takapu Rd	Replace the existing Gopher with Gopher(1.64km)	Renewal	$223,040
10	SH57	Replace 35mm Cu with BEE (total 3.9kms in 3yrs)	Renewal	$530,400
11	Whakahoro Rd	Replace 16mm Cu with Gopher(1.1kms)	Renewal	$149,600
12	Tiro and Mako Rd	Replace existing 35mm Cu with BEE (2.5kms in 2 yrs)	Renewal	$340,000
13	SH1, Manakau L224 to L4	Replace 35mm Cu with BEE (1.86kms)	Renewal	$252,960
14	Tasman Road	Replace 35mm Cu with BEE (1.45kms)	Renewal	$197,200
15	Valley Road	Replace 16mm Cu with Gopher (0.75kms)	Renewal	$102,000
16	Bledisloe St	Replace 16mm Cu with Gopher(0.21km)	Renewal	$28,560
17	Read St	Replace 16mm Cu with Gopher(0.21km)	Renewal	$28,560
18	Alexander Rd	Replace 16mm Cu with Gopher (0.28km)	Renewal	$38,080
19	Engles Rd	Replace 16mm Cu with Gopher (2km)	Renewal	$272,000
20	Armagh St	Replace 16mm Cu with Gopher (0.22km)	Renewal	$29,920
21	Ngarara Rd	Replace 16mm Cu with BEE (1.2km)	Renewal	$163,200
22	Tame Porati St	Replace existing 16mm Cu with Gopher(0.46kms)	Renewal	$62,560
23	Titoki St	Replace existing 16mm Cu with Gopher(0.2kms)	Renewal	$27,200
24	SH1, Manakau L4 to H86	Replace 35mm Cu with BEE (2kms)	Renewal	$272,000
25	Bryce St	Replace 16mm Cu with Gopher (1.8kms)	Renewal	$244,800
26	SH1, Levin H86 to H166	Replace 35mm Cu with BEE (1.2kms)	Renewal	$163,200
27	Makora Road	Replace 16mm Cu with BEE (1.3kms)	Renewal	$176,800
28	Mangahao to Levin East 33kV	Upgrade to Butterfly double circuit	Renewal	$2,100,000

Projects and programmes FY2026 to FY2030 follow:

Ref	Location	Description	Category	Cost
1	All	400V reconductors	Renewal	$3,025,000
2	All	Inspection driven conductor replacements	Renewal	$6,887,040
3	Mangahao to Levin East 33kV	Upgrade to Butterfly double circuit	Renewal	$1,000,000
4	SH1, Levin H166 to H102	Replace 35mm Cu with BEE (1.8kms)	Renewal	$244,800
5	Whyte St	Replace 16mm Cu with Gopher (0.24kms)	Renewal	$32,640
6	Wilton St	Replace 16mm Cu with Gopher (0.4km)	Renewal	$54,000
7	SH1 Waitarere Beach Rd to Koputaroa Rd	Replace Mink with Bee (2.5km)	Renewal	$340,000
8	SH1, Levin H102 to H219	Replace 35mm Cu with BEE(0.82kms)	Renewal	$111,520

The projected distribution overhead lines expenditure is shown in Figure 5-15.

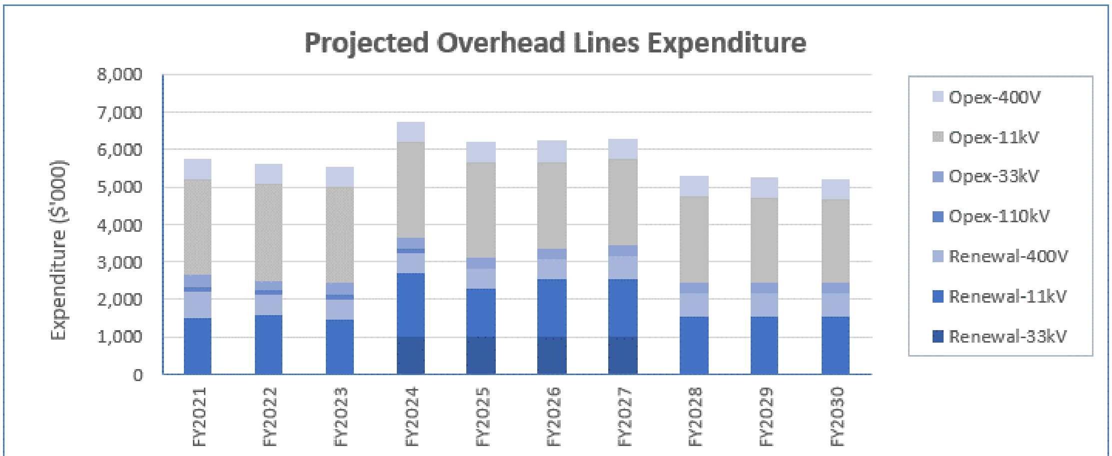
5.4.3 Customer-owned lines

Whilst customer-owned lines (broadly defined as any line on the customer's side of the property boundary) are not owned by Electra, these lines form an integral part of the electricity supply chain.

Electra has commenced a programme to inform customers about risks associated with customer owned powerlines and offer a service to assist them in reducing any identified issues.

5.4.4 Overhead lines forecast

The projected sub-transmission, 11kV and low voltage overhead lines expenditure is shown in Figure 5-15.



Description	FY2021	FY2022	FY2023	FY2024	FY2025	FY2026	FY2027	FY2028	FY2029	FY2030
Capital Expenditure ($'000)										
Renewal-33kV	0	0	0	1,000	1,000	1,000	1,000	0	0	0
Renewal-11kV	1,517	1,586	1,480	1,707	1,300	1,534	1,534	1,534	1,534	1,534
Renewal-400V	700	525	525	525	525	525	625	625	625	625
Total (Capex):	**2,217**	**2,111**	**2,005**	**3,232**	**2,825**	**3,059**	**3,159**	**2,159**	**2,159**	**2,159**
Operational Expenditure ($'000)										
Opex-110kV	120	120	120	120	0	0	0	0	0	0
Opex-33kV	307	277	307	277	277	307	277	277	307	277
Opex-11kV	2,560	2,560	2,560	2,560	2,560	2,308	2,308	2,308	2,233	2,233
Opex-400V	543	543	543	543	543	543	543	543	543	543
Total (Opex):	**3,530**	**3,500**	**3,530**	**3,500**	**3,380**	**3,158**	**3,128**	**3,128**	**3,083**	**3,053**

Figure 5-15: Projected overhead lines expenditure

5.5 Underground cables

5.5.1 Sub-transmission cables

5.5.1.1 Inspection policies and programmes on underground sub-transmission assets

Underground cables are generally not inspected except at terminations in zone substations, ground based transformers or switchgear. The sole exceptions are 33kV underground cables where the route is visually inspected annually on a similar basis as to overhead lines. Further, partial discharge testing of these single core XLPE insulated cables is carried out every three years.

5.5.1.2 Maintenance policies and programmes on underground sub-transmission assets

33kV cables are subject to annual visual inspections of all above ground terminations including annual thermograph scans of all terminations including annual visual inspections of all above ground terminations and triennial thermal tests. Partial discharge testing of these single core XLPE insulated cables is carried out every three years.

Electra has eight 33kV underground circuits; these are mainly in the Kapiti Coast except for one laid from Mangahao to Shannon, each being single core XLPE cables laid in tre-foil.

5.5.1.3 Key features

Electra has 29.34 km of 33kV cable and associated terminations. The composition of these cables follows:

Sub-class	Length	Unit	Percentage
500 mm^2 aluminium XLPE	6.1	km	20.7%
630 mm^2 aluminium XLPE	17.6	km	60.0%
800 mm^2 aluminium XLPE	5.6	km	19.3%
Total	**29.3**	**km**	**100%**

The key design parameters include:

Parameter	Value
Load rating	Load to about 70% of manufacturer’s rating before application of any other de-rating factors (e.g. proximity, soil thermal conductivity, ambient temperature, etc)
Durability	Expect XLPE cable to last 50 to 60 years

Figure 5-16 shows the age profile of these cables.

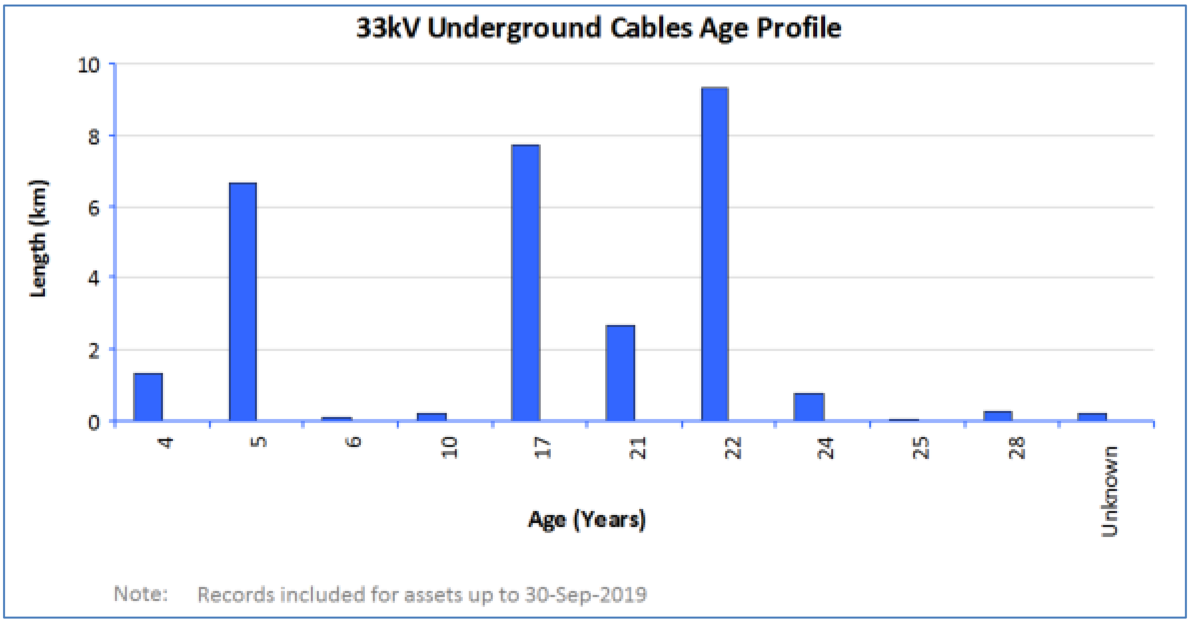


Figure 5-16: 33kV cable year of installation

5.5.1.4 Condition

The condition of these cables is tabulated in the following table and 4% are forecasted to be replaced over the next five years.

Condition:	Grade 1	Grade 2	Grade 3	Grade 4	Grade unknown	Data accuracy	Percent forecast for replacement over next 5 years
			69%	31%		4	0%

There are no known systemic issues with Electra's 33kV cables, and neither are there capacity nor reliability constraints.

5.5.1.5 Inspection and maintenance

The drivers for maintenance are:

- Visible deterioration of pot heads or terminations
- Visible deterioration of cable sheathing
- Deterioration of cable insulation
- Visible shifting of the cable within the mountings or ground that may be straining internal components.

To verify the condition of our 33kV cables, we carry out Tan Delta, also called Loss Angle or Dissipation Factor testing, which is a diagnostic method of testing cables to determine the quality of the cable insulation. One of the criteria for maintenance is when Tan Delta as well as partial discharge test results exceeds limits. Other maintenance criteria include:

- Thermography of cable terminations reveals excessive temperatures
- Splitting or cracking of PVC cable sheath such that armour wire or insulation is visible
- Excessive UV deterioration of PVC sheaths
- Movement of anchor points relative to supports or ground that may be straining internal components.

Assumptions made for the above maintenance criteria include:

- Unacceptable Tan Delta readings will continue to deteriorate rather than plateau
- Deterioration of PVC sheaths will lead to cracking, exposure of armour wires and eventual failures
- Straining of internal components due to movement is likely to damage insulation.

Condition assessment techniques and methods include the visual inspection of exposed components, surveying of cable routes to check for excavation or penetrations, regular Tan Delta and similar insulation checks.

Inspections are graded as follows and refurbishment or renewals applied as follows:

Grade	Inspection	Refurbishment	Renewal
1	No further inspections, will be replaced within 1 year	Will not be refurbished	Renew within 1 year
2	Bi-monthly inspections and close monitoring, and is likely to be replaced within 3 years	Minor repairs only	Renew within 3 years
3 & 4	Continue to inspect, amend grade as required	Repair to extend life as considered appropriate by Planning & Development Manager	-

Correction of defects are carried out as follows:

- **Public safety defects**: correction within one week of identification
- **Significant structural integrity defects**: correction within one week of identification
- **Minor structural integrity defects**: repair by approved method within three months of identification.

The criteria for lifecycle decisions include:

- Consider up-sizing if loading beyond 70% of manufacturer's rating occurs for more than 3,000 hours per year
- Consider up-sizing if fault level exceeds cable fault rating.

Cable life is designed to achieve the correct rating at the design stage by understanding the cable loading and thermal characteristics of the soil, and by careful handling at the installation stage including adherence to minimum bending radii.

5.5.2 High voltage 11kV distribution cable

Electra has 240 km of 11kV cable and the composition of the cables follows:

Sub-class	Number	Unit	Percent
PILC	118	km	49.2%
XLPE, PVC or HDPE	122	km	50.8%
Total	**240**	**km**	**100%**

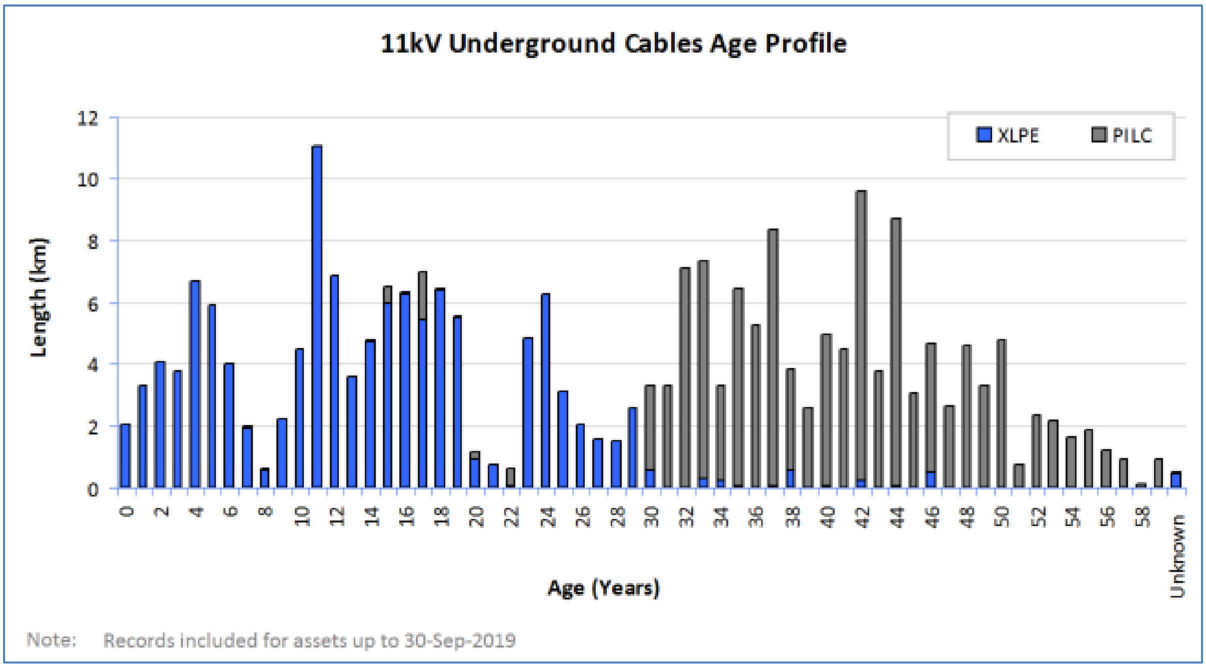


Figure 5-17: 11kV XLPE and PILC underground cables age profile

Key design parameters include:

Parameter	Value
Load rating	Nominally loaded to about 70% of manufacturer's rating
Durability	Expect XLPE cable to last 50 to 60 years

5.5.2.1 Condition

Condition:	Grade 1	Grade 2	Grade 3	Grade 4	Grade unknown	Data accuracy	Percent forecast for replacement over next 5 years
XLPE, PVC or HDPE	-	-	91.20%	8.8%	-	3	-
PILC	-	2.0%	98%	-	-	2	2.00%

There are no known systemic issues with Electra's 11kV cable and neither are there capacity, security nor reliability constraints.

5.5.2.2 Reliability performance

Figure 5-18 depicts the HV distribution cable fault rate per 100km amongst EDBs. At 7.3 fault rate, there is a difference of 4.5 as compared with the median of 2.8. These cable faults are due to third party interference or excavations, and some attributed to termination faults. Our annual review of these faults has not identified a systemic issue. Each fault is considered uniquely, and remedial action taken where appropriate. The following sections identify our inspection and maintenance activities.

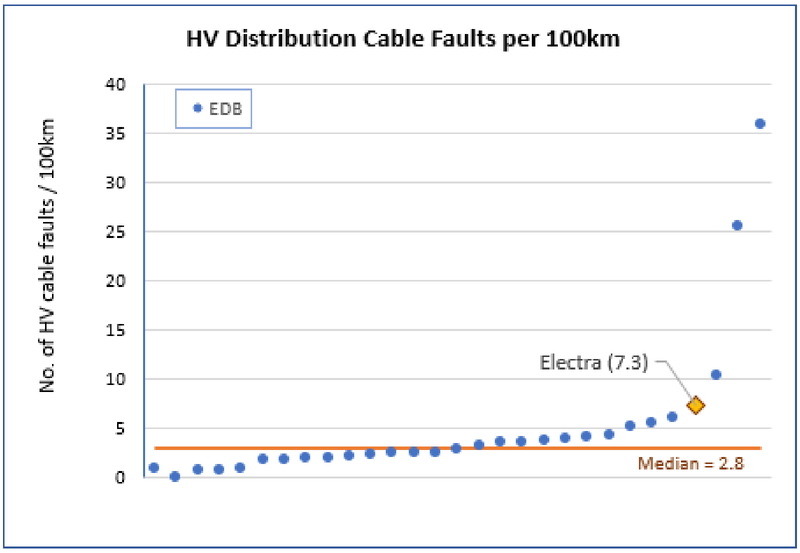


Figure 5-18: FY2018 to FY2019 HV underground cable faults per 100km for all EDBs

5.5.2.3 Inspection and maintenance

The drivers for maintenance are visible deterioration of cable sheathing, pot heads or terminations, the deterioration of cable insulation as well as visible shifting of the cable within the mountings or ground that may be straining internal components.

The maintenance criteria include:

- Splitting or cracking of PVC cable sheath such that armour wire or insulation is visible
- Excessive UV deterioration of PVC sheaths
- Movement of anchor points relative to ground that may be straining internal components.

The assumptions for maintenance are:

- The deterioration of PVC sheaths will lead to cracking, exposure of armour wires and eventual failures
- Straining of internal components due to movement is likely to damage insulation.

Condition assessment techniques and methods used are primarily visual inspection of exposed components only, mainly for chipped or broken bushings or perishing insulation.

Inspections are graded as follows with refurbishment or renewals applied:

Grade	Inspection	Refurbishment	Renewal
1	No further inspections, will be replaced within 1 year	Will not be refurbished	Renew within 1 year
2	Bi-monthly inspections and close monitoring, and is likely to be replaced within 3 years	Minor repairs only	Renew within 3 years
3 & 4	Continue to inspect, amend grade as required	Repair to extend life as considered appropriate by Planning & Development Manager	-

Correction of defects are made as follows:

- **Public safety defects**: correction within one week of identification
- **Significant structural integrity defects**: correction within one week of identification

- **Minor structural integrity defects**: repair by approved method within three months of identification.

The following activities are considered as follows:

- Lifecycle decision criteria
- Consider up-sizing if loading beyond 70% of manufacturer's rating occurs for more than 3,000 hours per year
- Consider up-sizing if fault level exceeds cable fault rating
- Life extension and investment deferral techniques: design cable life is achieved by correct rating at the design stage, understanding the cable loading and thermal characteristics of the soil, and by careful handling at the installation stage including adherence to minimum bending radii.

5.5.2.4 Major projects and programmes

The projects and programmes for FY2021 are:

Ref	Location	Type of work	Category	Cost
1	All	Design line/cable jobs	Renewal	$150,000
2	Bath St, Levin	Replace 11kV cable E313-E83	Renewal	$125,000
3	All	Replace pitch filled potheads with Raychem terminations	Safety	$60,000
4	All	Fault/urgent defect replacement of 11kV cables	Renewal	$60,000

Projects and programmes for FY2021 to FY2024 follow:

Ref	Location	Type of work	Category	Cost
1	All	Design line/cable jobs	Renewal	$600,000
2	All	Fault/urgent defect replacement of 11kV cables	Renewal	$240,000
3	All	Replace pitch filled potheads with Raychem terminations	Safety	$180,000
4	Tui Rd, Raumati	Replace cable between Z92 and Z103 – 11kV	Renewal	$81,769

The projects and programmes for FY2025 to FY2029 follow:

Ref	Location	Type of work	Category	Cost
1	All	Design line/cable jobs	Renewal	$750,000
2	All	Fault/urgent defect replacement of 11kV cables	Renewal	$660,000
3	All	Replace pitch filled potheads with Raychem terminations	Safety	$200,000
4	Tui Rd, Raumati	Replace cable between Z92 and Z103 – 11kV	Renewal	$163,538

The projected underground HV cables expenditure is shown in Figure 5-20.

5.5.3 LV cable

Electra has 494 km of LV cable and associated distribution pillars and fittings. The LV cable profile is shown in Figure 5-19.

The key design parameters are:

Parameter	Value
Load rating	Load to about 70% of manufacturer's rating before application of any other de-rating factors (e.g. proximity, soil thermal conductivity, ambient temperature, etc)
Durability	Expect XLPE cable to last 50 to 60 years

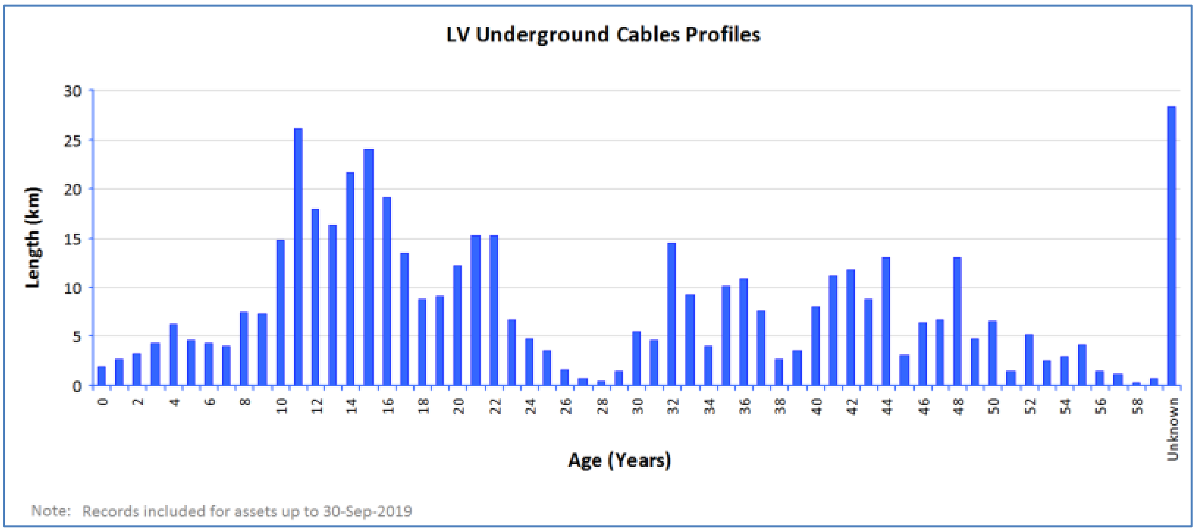


Figure 5-19: Low Voltage (LV) underground cable age profile

5.5.3.1 Condition

Condition:	Grade 1	Grade 2	Grade 3	Grade 4	Grade unknown	Data accuracy	Percent forecast for replacement over next 5 years
			35.00%	9.00%	56.00%	2	2.00%

There are no known systemic LV cable issues. The following problems have been encountered in the past, but have been corrected:

- Failures of tee joints on pre-1970 cables
- Ground level corrosion of pre-1980 steel pillars.

There are no known LV cable constraints. As load constraints are met, they are managed by paralleling transformers at link pillars.

Inspection and maintenance for LV cables are similar to that for 11kV cables listed in Section 5.5.2.3 and the operational expenses forecasted are shown in Figure 5-20.

5.5.3.2 Major projects and programmes

The projects and programmes FY2021 follow:

Ref	Location	Type of work	Category	Cost
1	All	Steel link pillar removal	Customer connection/ safety	$250,000

Ref	Location	Type of work	Category	Cost
2	All	Inspection driven renewals – pillars	Customer connection/ renewal	$198,085
3	All	Fault/urgent defect replacement of 400V /streetlight cables	Renewal	$40,000
4	All	Unplanned - pillars	Customer connection/ renewal	$30,000

Projects and programmes 2022 to 2025:

Ref	Location	Type of work	Category	Cost
1	All	Steel link pillar removal	Customer connection/ safety	$850,000
2	All	Inspection driven renewals - pillars	Customer connection/ renewal	$792,340
3	All	Fault/urgent defect replacement of 400V /streetlight cables	Renewal	$160,000
4	All	Unplanned - pillars	Customer connection/ renewal	$120,000

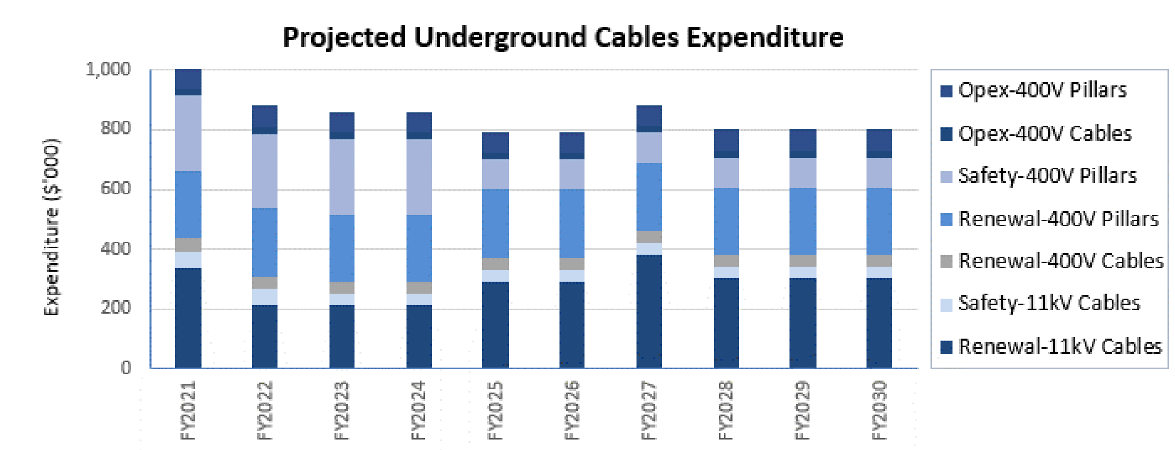
Projects and programmes 2025 to 2030:

Ref	Location	Type of work	Category	Cost
1	All	Steel link pillar removal	Customer connection/ safety	$500,000
2	All	Inspection driven renewals - pillars	Customer connection/ renewal	$990,425
3	All	Fault/urgent defect replacement of 400V /streetlight cables	Renewal	$200,000
4	All	Unplanned - pillars	Customer connection/ renewal	$150,000

The projected underground LV cables expenditure is shown in Figure 5-20.

5.5.4 Underground cables forecast

The projected underground HV and LV cables expenditure is shown in Figure 5-20.



Description	FY2021	FY2022	FY2023	FY2024	FY2025	FY2026	FY2027	FY2028	FY2029	FY2030
Capital Expenditure ($'000)										
Renewal-11kV Cables	335	210	210	210	292	292	382	300	300	300
Safety-11kV Cables	60	60	40	40	40	40	40	40	40	40
Renewal-400V Cables	40	40	40	40	40	40	40	40	40	40
Renewal-400V Pillars	228	228	228	228	228	228	228	228	228	228
Safety-400V Pillars	250	250	250	250	100	100	100	100	100	100
Total (Capex):	**913**	**788**	**768**	**768**	**700**	**700**	**790**	**708**	**708**	**708**
Operational Expenditure ($'000)										
Opex-400V Cables	23	23	23	23	23	23	23	23	23	23
Opex-400V Pillars	69	69	69	69	69	69	69	69	69	69
Total (Opex):	**92**	**92**	**92**	**92**	**92**	**92**	**92**	**92**	**92**	**92**

Figure 5-20: Projected underground cables expenditure

5.6 Zone substations

Electra has ten zone substations which transform energy from the 33kV sub-transmission network to the 11kV distribution network. All but the Paekakariki substation are dual transformer substations. Therefore, all substations have (n-1) security as shown in the following table except for Paekakariki where the transformer and 33 kV feeder are backed by 11 kV feeders apart for KiwiRail traction substation on 'n' security but backed by other KiwiRail supplies.

Zone substation	Description	Security	ICPs	Nature of load	Performance and risk concerns
Shannon	Dual transformer Indoor switchgear Built in 2010	(n-1)	1991	Mix of urban load in Shannon and rural load toward Tokomaru and Opiki	• No known issues • Performing within specification
Foxton	Dual transformer High-level steel structure outdoor Significantly rebuilt in 2004	(n-1)	3634	Predominantly urban load in Foxton with some rural load in all directions	• No known issues • Performing within specification
Levin East	Dual transformer High-level steel structure Built in 1990	(n-1)	6228	Predominantly urban, although with some rural load to the south and east of Levin	• No known issues • Performing within specification

Zone substation	Description	Security	ICPs	Nature of load	Performance and risk concerns
Levin West	Dual transformer High-level steel structure Built in 1974	(n-1)	5725	Predominantly the rural areas to the north and west of Levin, Waitarere Beach, some urban load in the western parts of Levin	• No known issues • Performing within specification
Otaki	Dual transformer Indoor substation Built in 1994	(n-1)	6292	Predominantly urban load in Otaki with some rural load in Otaki Gorge, Manakau, Te Horo and Waikawa Beach	• No known issues • Performing within specification
Waikanae	Dual transformer Indoor substation Built in 1996	(n-1)	7299	Dense urban load in and around Waikanae, some rural load to the north in Peka and to the east in Reikorangi	• No known issues • Performing within specification
Paraparaumu	Dual transformer High-level concrete pole outdoor Built in 1970, rebuilt in 2015	(n-1)	4456	Dense urban load in the eastern and central parts of Paraparaumu, some rural load on the immediate outskirts of Paraparaumu	• Performing within specification • Increased inspection frequency for 1 transformer
Paraparaumu West	Dual transformer Indoor substation Built in 2002	(n-1)	5381	Dense urban load in central and western parts of Paraparaumu	• No known issues • Performing within specification
Raumati	Dual transformer High-level steel structure outdoor substation Built in 1988	(n-1)	4083	Dense urban load in and around Raumati	• No known issues • Performing within specification
Paekakariki	Single transformer High-level outdoor substation Built 1982 *Single transformer and 33 kV feeder are backed up by 11 kV feeder except for KiwiRail traction substation on 'n' security and backed up by other KiwiRail supplies to the north and south	(n-1)*	917	Mix of light urban and semi-rural load around Paekakariki	• No known issues • Performing within specification

Appendix 5 contains the Commerce Commission's Schedule 12b, the report on forecast capacity which shows the security of supply and capacity of the zone transformers.

5.6.1 Zone transformers

Electra has 19 zone substation transformers, all 33/11kV. These range in capacity from 5 MVA to 11.5/18/23 MVA and have various levels of ONAN, ONAF and OFAF cooling.

There are three units of 5 MVA transformers and 16 units of 15.5 / 23 MVA transformers and details of these transformers follow:

Zone substation	Number and rating	Cooling	Year of manufacture		Utilisation of installed firm capacity	
			T1	T2	FY2019	FY2020
Shannon	Two 5 MVA	ONAN	1977	1974	84%	93%
Foxton	Two 11.5/23 MVA	ONAN, ONAF	2004	2004	28%	30%
Levin East	Two 11.5/23 MVA	ONAN, ONAF	1979	1973	56%	56%
Levin West	Two 11.5/23 MVA	ONAN, ONAF	2011	2000	57%	61%
Otaki	Two 11.5/23 MVA	ONAN, ONAF	1976	1976	51%	51%
Waikanae	Two 11.5/23 MVA	ONAN, ONAF	1996	1996	66%	66%
Paraparaumu	Two 11.5/18/23 MVA	ONAN, ONAF, OFAF	1970	1970	58%	56%
Paraparaumu West	Two 11.5/23 MVA	ONAN, ONAF	2001	2001	55%	55%
Raumati	Two 11.5/23 MVA	ONAN, ONAF	2011	1987	43%	43%
Paekakariki	One 5 MVA	ONAN	1960	-		

Shannon is the only substation close to being loaded to near its firm (n-1) capacity, in that case the 11kV load can be shifted to Foxton or Levin East if the constraint emerges.

The key design parameters are:

Parameter	Value
Durability	Expect a minimum life of 60 years
Rating	Design load to no more than 67% to enable load of faulted substation to be supplied by two neighbouring substations

The age profiles of these zone transformers are shown in Figure 5-21.

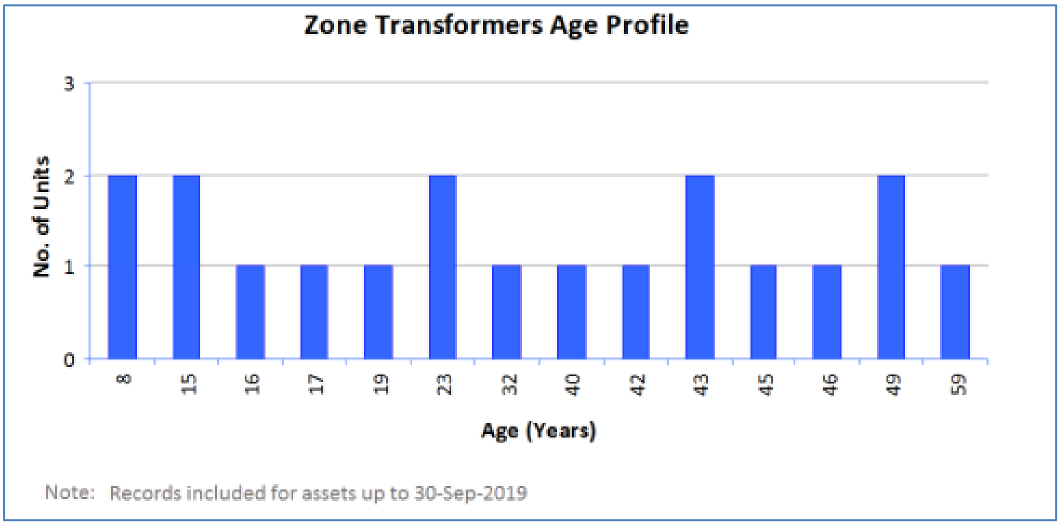


Figure 5-21: Zone transformers age profile

5.6.1.1 Condition and assessment

The condition of our power transformers is either at Grade 3 or Grade 4:

Condition:	Grade 1	Grade 2	Grade 3	Grade 4	Grade unknown	Data accuracy	Percent forecast for replacement over next 5 years
			89.5%	10.5%		4	10.52%

There are no known systemic issues with Electra's zone substation transformers and no known capacity, security nor reliability constraints too

5.6.1.2 Inspection and maintenance

Maintenance drivers include:

- Oil purity
- Integrity of gaskets and flexible seals on tank and fittings
- Chipping or cracking of bushings
- Oil leaks or staining on tank.

The criteria for maintenance cover the following:

- Key oil parameters such as acidity, gas content and moisture content exceed manufacturers' recommendations for main tank and tap changer compartment
- Tests such as partial discharge, Furans, paper sampling etc reveal out of specification
- Cabinets show evidence that gaskets and seals are failing
- Bushings are chipped, cracked or deteriorating to the point of imminent failure
- Oil leaks or staining suggests on-going leakage.

Assumptions made include:

- Declining oil condition will continue to decline rather than plateau
- Chipped or cracked bushings could result in sudden failure
- Corona discharge signals deteriorating component condition
- Oil rising into conservator tank suggests excessive heating, suggesting a localised hot spot in the absence of overloading.

Condition assessment techniques and methods include:

- Visual inspection of tank, bushings, gaskets, seals and instruments
- Regular testing of oil for dissolved gases and metals
- Regular impedance and insulation testing
- Lifecycle policies, criteria and activities.

Inspections are graded as follows and refurbishment or renewals applied as follows:

Grade	Inspection	Refurbishment	Renewal
1	Bi-monthly inspections but no further detailed monitoring, as it will be replaced within 12 to 18 months	Will not be refurbished	Renew with 1 year
2	Bi-monthly inspections and close monitoring, and is likely to be replaced within 3 years if repair or refurbish options are not cost effective	Minor repairs only	Renew within 3 years if repair and refurb options are not cost effective

Grade	Inspection	Refurbishment	Renewal
3 & 4	Continue to inspect, amend grade as required	Repair to extend life as considered appropriate by Planning & Development Manager	-

Defect corrections are carried out within the following time period:

- **Public safety defects**: correction within one week of identification
- **Significant structural integrity defects**: correction within one week of identification
- **Minor structural integrity defects**: repair by approved method within three months of identification.

Lifecycle decisions include:

- Oil filtration will be triggered by unacceptable acidity, gas or moisture levels
- Re-packing and re-bolting of core will be triggered by excessive vibration
- Major refurbishment of windings will typically occur after 35 years operation
- Consideration of lifetime loading
- Consideration of number and intensity of faults.

Life extension and investment deferral techniques include:

- Extra paint or galvanising may be applied if the transformer will be located in a coastal area
- Capacity margin may be deliberately planned to ensure light loading
- Major interventions such as oil filtration and re-packing the core may occur.

5.6.1.3 Major projects and programmes

The major projects, programmes and budget forecast follow:

No projects or programmes scheduled FY2021.

Projects and programmes FY2022-2025 follows:

Ref	Location	Type of work	Category	Cost
1	Levin East substation	Power transformer replacement	Renewal	$950,000
2	Paraparaumu substation	Power transformer replacement	Renewal	$900,000

Projects and programmes FY2026-2030 follows:

Ref	Location	Type of work	Category	Cost
1	Levin East substation	Power transformer replacement	Renewal	$950,000
2	Paekakariki substation	Power transformer replacement	Renewal	$1,000,000

The budget forecast for zone transformers is shown in Figure 5-23.

5.6.2 Zone switchgear

Electra has 56 separate 33kV circuit breakers and 78 separate 11kV circuit breakers in its zone substations, including associated protection:

Circuit breaker class	Number	Unit	Percent
33kV SF6 (indoor)	35	Each	26.12%
33kV SF6 (outdoor)	21	Each	15.67%
11kV oil	3	Each	2.24%
11kV vacuum	67	Each	50.00%
11kV SF6	8	Each	5.97%
Total	**134**		**100%**

Details of the incoming (33kV) switchgear follow:

Zone substation	Description and number	Year of manufacture	Typical loading	
			2018	**2019**
Shannon	10 indoor SF6 circuit breakers	2008 – all	3%	3%
Foxton	4 outdoor SF6 circuit breakers	2007: one circuit breaker 2003: three circuit breakers	9%	10%
Levin East	6 outdoor SF6 circuit breakers	2015: one circuit breaker 2009: two circuit breakers 2007: one circuit breaker 2003: one circuit breaker 1987: one circuit breaker	19%	20%
Levin West	5 outdoor SF6 circuit breakers	2012: two circuit breakers 2009: one circuit breaker 2007: one circuit breaker 2000 – one circuit breaker	19%	19%
Otaki	5 indoor SF6 circuit breakers	2003: one circuit breaker 1995: four circuit breakers	8%	8%
Waikanae	6 indoor SF6 circuit breakers	1996: all	11%	11%
Paraparaumu	8 indoor SF6 circuit breakers	2015: eight circuit breakers 2007: one circuit breaker	9%	9%
Paraparaumu West	5 indoor SF6 circuit breakers	2001: all	9%	9%
Raumati	5 outdoor SF6 circuit breakers	2009: one circuit breaker 2007: one circuit breaker 2005: one circuit breaker 1989: one circuit breaker 1988: one circuit breaker	7%	7%
Paekakariki	1 outdoor SF6 circuit breaker	2009: one circuit breaker	3%	3%

Some information and loadings of outgoing 11kV switchgear follow:

Zone substation	Description and number	Year of manufacture	Typical loading for feeder with highest load	
			2018	2019
Shannon	7 Reyrolle LMVP	2007	20%	20%
Foxton	7 Reyrolle LMVP	2004	23%	23%
Levin East	8 South Wales SF6 1 Reyrolle LMVP	2006: one circuit breaker 1989: eight circuit breakers	25%	25%
Levin West	9 Reyrolle LMVP	2012: one circuit breaker 2011: two circuit breakers 2000: six circuit breakers	34%	35%
Otaki	8 Reyrolle LMVP	1996: three circuit breakers 1995: five circuit breakers	31%	26%
Waikanae	9 Reyrolle LMVP	2010: one circuit breaker 1996: eight circuit breakers	35%	39%
Paraparaumu	10 Reyrolle LMVP	2015: all	33%	33%
Paraparaumu West	8 Reyrolle LMVP	2007: one circuit breaker 2002: seven circuit breakers	35%	35%
Raumati	7 Reyrolle LMVP	2018: four circuit breakers 2005: two circuit breakers 1997: one circuit breaker	31%	31%
Paekakariki	3 Reyrolle LMT oil 1 Reyrolle LMVP	2013: one circuit breaker 1982: three circuit breakers	15%	15%

The typical loading for the switchgear (630A capacity rating) is calculated based on the feeder with the highest load. We examine feeder loads regularly and actively carry out load transfers between feeders to balance loads.

The age profiles for the 33kV and 11kV zone switchgear are shown in Figure 5-22.

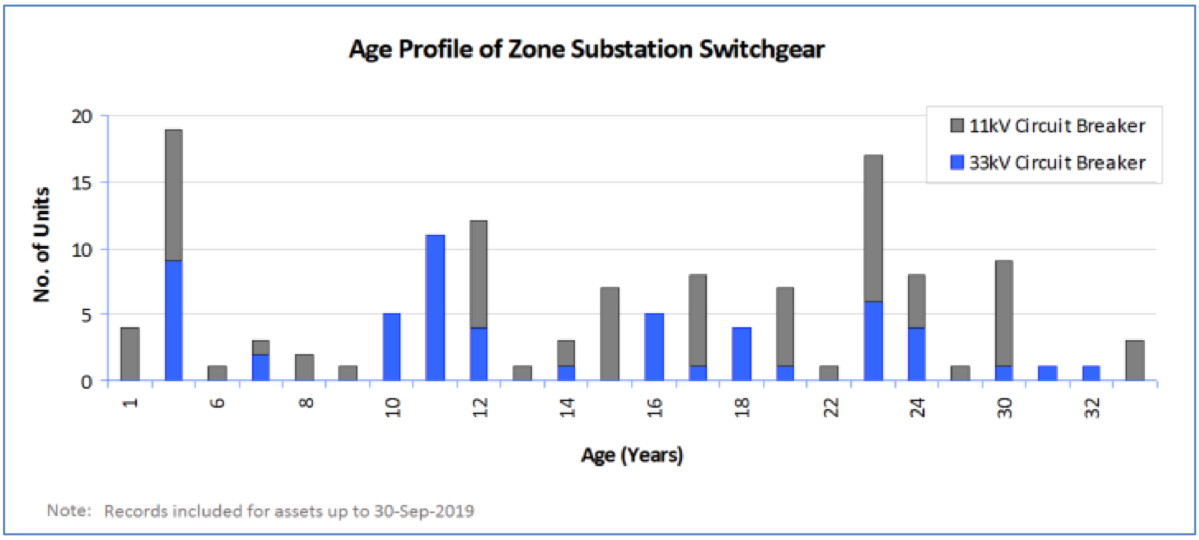


Figure 5-22: 11kV and 33kV zone switchgear age profile

The key design parameters are:

Parameter	Value
Durability	Expected life of 40 to 45 years
Load rating	Generally standard 630 A, which is often far in excess of likely load

5.6.2.1 Condition and assessment

The condition of zone switchgear follows:

Condition	Grade 1	Grade 2	Grade 3	Grade 4	Grade unknown	Data accuracy	Percent forecast for replacement over next 5 years
Indoor 22kV or 33kV			50.00%	50.00%		4	
Outdoor 22kv or 33kV			90.48%	9.52%		4	
3.3kV, 6.6kV, 11kV or 22kV		5.00%	75.00%	20.00%		3	5.0%

There are no known systemic issues and no capacity, security nor reliability constraints with Electra's zone substation switchgear.

5.6.2.2 Inspection and maintenance

Maintenance drivers include:

- The correct operation of mechanism, including remote functionality
- The correct pressure or level of arc-quenching medium
- The correct alignment of contacts, and timing of contact separation
- The integrity of interrupting chambers
- Surface rust on cabinets.

The criteria for maintenance include:

- The number of operations exceeds manufacturers maintenance recommendations
- Operating mechanism requires excessive force
- Remote functionality fails to operate correctly
- Pressure or level of arc-quenching medium below manufacturers recommendations
- Rust becomes more than surface deep
- Evidence that arc is not being correctly quenched.

The assumptions made for maintenance are the continuing decline in pressure or level of the arc-quenching medium and that surface rust will continue to deepen. Also, operating mechanisms which are stiff and require excessive force will require repairs.

Condition assessment techniques utilise a combination of visual inspections and regular checking of fluid levels and gas pressures as per OEM specifications.

Inspections, refurbishment or renewals are graded and applied as follows:

Grade	Inspection	Refurbishment	Renewal
1	No further inspections, will be replaced within 1 year	Will not be refurbished	Renew with 1 year
2	Bi-monthly inspections and close monitoring, and is likely to be replaced within 3 years if repair or refurbish options are not cost effective	Minor repairs only	Renew within 3 years if repair and refurb options are not cost effective
3 & 4	Continue to inspect, amend grade as required	Repair to extend life as considered appropriate by Planning & Development Manager	-

Public safety defects and significant structural defects are corrected within one week of identification while minor structural defects are repaired within three months of identification.

Electra is more likely to renew or replace assets rather than refurbish them due to safety reasons, increased fault levels or obsolescence of key components. If the sole issue is the fault rating, replacement of the interrupter heads with higher rated heads is undertaken to avoid replacing the whole switchboard.

5.6.2.3 Major projects and programmes

The projects and programmes as well as budget forecast follow:

Projects and programmes FY2021:

Ref	Location	Type of work	Category	Cost
1	All	Unplanned capital	Renewal	$130,579

Projects and programmes FY2022-2025:

Ref	Location	Type of work	Category	Cost
1	All	Unplanned capital	Renewal	$522,316
2	Foxton	Rebuild substation	Renewal	$400,000
3	Raumati	Rebuild substation	Renewal	$1,800,000
4	Paekakariki substation	11kV circuit breaker replacement	Renewal	$350,000

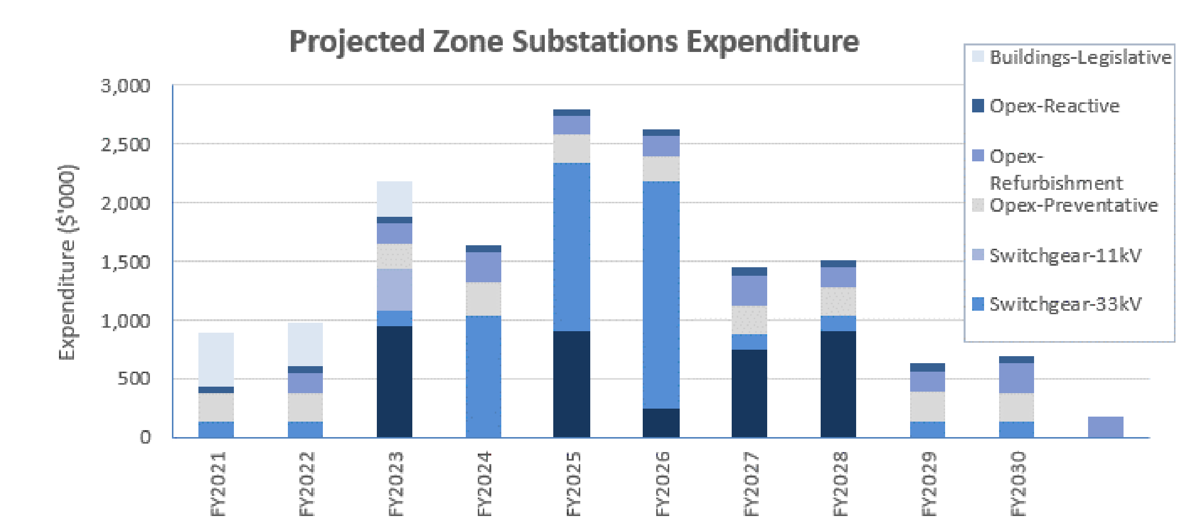
Projects and programmes FY2026-2030:

Ref	Location	Type of work	Category	Cost
1	All	Unplanned capital	Renewal	$652,895
2	Foxton	Rebuild substation	Renewal	$900,000
3	Raumati	Rebuild substation	Renewal	$900,000

The budget forecast for zone switchgear is shown in Figure 5-23.

5.6.3 Zone substations forecast

The projected zone substations expenditure for zone transformers and switchgear is shown in Figure 5-23.



Description	FY2021	FY2022	FY2023	FY2024	FY2025	FY2026	FY2027	FY2028	FY2029	FY2030
Capital Expenditure ($'000)										
Buildings-Legislative	450	375	300	0	0	0	0	0	0	0
Transformer-33kV	0	0	950	0	900	250	750	900	0	0
Switchgear-33kV	131	131	131	1,031	1,431	1,931	131	131	131	131
Switchgear-11kV	0	0	350	0	0	0	0	0	0	0
Total (Capex):	**581**	**506**	**1731**	**1031**	**2331**	**2181**	**881**	**1031**	**131**	**131**
Operational Expenditure ($'000)										
Opex-Preventative	245	245	216	295	245	216	245	245	266	245
Opex-Refurbishment	170	170	255	155	170	255	170	170	255	170
Opex-Reactive	61	61	61	61	61	61	61	61	61	61
Total (Opex):	**476**	**476**	**532**	**511**	**476**	**532**	**476**	**476**	**582**	**476**

Figure 5-23: Projected zone substations expenditure

5.6.4 Load control plant

Electra owns and operates the following load control plant:

- One Zellweger SFU-K/203 injection plant at Shannon rated at 80kVA and signalling to the northern area. This was installed in 2011 as part of the substation rebuild
- One Landis + Gyr SFU-K/403 injection plant rated at 200kVA in an Electra-owned building at Paraparaumu zone substation and signalling to the southern area. This was installed in 2016
- Two Zellweger SFU-K/203 injection plant controllers rated at 80kVA in storage as spares at Paraparaumu West and Shannon.

Both the Shannon and the Valley Road plants inject into the 33kV at 283Hz.

Most customer load control relays are owned by the energy retailer. Electra, does however, 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.

5.6.4.1 Condition and assessment

Condition:	Grade 1	Grade 2	Grade 3	Grade 4	Grade unknown	Data accuracy	Percent forecast for replacement over next 5 years
Centralised plant			50.0%	50.0%		4	
Relays					100.0%	2	10.0%

There are no known systemic issues with Electra's load control plant as well as no known capacity, security nor reliability constraints with Electra's load control plant.

Key design parameters include the following:

Parameter	Value
Durability	Expected life of 20 years
Load rating	About 50kVA to 100kVA
Frequency	283 Hz

5.6.4.2 Inspection and maintenance

The drivers for maintenance include the correct injection of required signals when instructed, the correct operation of relays as well as the integrity and isolation of coupling cells.

Maintenance is also required when injection fails, the relay fails to operate, or the coupling cell shows evidence of failure or insulation breakdown. The signal generator needs to be replaced as additional load is connected.

Condition assessment methods include visual inspections and regular testing to confirm signal frequency and strength.

Inspections, refurbishment and/or renewals are graded and applied as follows:

Grade	Inspection	Refurbishment	Renewal
1	No further inspections, as will be replaced within 1 year	Will not be refurbished	Renew with 1 year
2	No further inspections, as will be replaced within 3 years	Minor repairs only	Renew within 3 years if repair and refurb options are not cost effective
3 & 4	Continue to inspect, amend grade as required	Refurbish major components Functionality and signal penetration considered, as this may make replacement more feasible	

Defect correction is carried out based on the following timeline:

- **Public safety defects**: correction within one week of identification
- **Injection failure**: immediate correction in order to manage demand
- **Minor control defects**: repairs carried out within one month of identification.

Load control may be replaced rather than renewed if analysis reveals that improved functionality can be obtained by replacement. Insufficient signal penetration may require replacement with a more powerful signal generator.

There are no major load control or relay programmes nor forecast for the planning period.

5.6.5 Buildings

The general structure of zone substation buildings follows:

Zone substation	General description	Year built	Condition grade
Shannon	Timber framed	2008	Normal deterioration monitored in normal inspection cycle
Foxton	Masonry shear walls	1970	Normal deterioration monitored in normal inspection cycle
Levin East	Masonry shear walls	1973	Normal deterioration monitored in normal inspection cycle
Levin West	Masonry shear walls	1976	Normal deterioration monitored in normal inspection cycle
Otaki	Timber framed	1995	Normal deterioration monitored in normal inspection cycle
Waikanae	Timber framed	1982	Normal deterioration monitored in normal inspection cycle
Paraparaumu old	Masonry shear walls	1973	Normal deterioration monitored in normal inspection cycle
Paraparaumu new	Masonry shear walls	2016	Good or as new condition
Paraparaumu West	Timber framed	2002	Normal deterioration monitored in normal inspection cycle
Raumati	Masonry shear walls	1987	Normal deterioration monitored in normal inspection cycle
Paekakariki	Masonry shear walls	1982	Normal deterioration monitored in normal inspection cycle

Detailed seismic assessments were done for all zone substations in 2018. A further detailed seismic design was undertaken for Paraparaumu West substation in 2019 and a structural upgrade will be carried out this financial year in compliance with the Building Code, Section C5 of the Engineering Assessment Guidelines regarding the seismic assessment of existing buildings. In compliance with the Health and Safety (Asbestos) Regulations 2016, asbestos surveys by certified personnel are being programmed at our zone substations.

5.7 Distribution transformers

Electra's distribution transformers range from rural 1-phase 5kVA pole-mounted transformers with minimal fuse protection, to 3-phase 1,000kVA ground-mounted transformers with ring main unit and circuit breaker protection. Transformers may provide electricity to single large consumers, several large consumers or many small consumers.

Electra has 1,605 overhead distribution transformers and 955 ground-mounted distribution transformers of various kVA ratings as follows:

Substation rating	Pole mounted (quantity)	Ground mounted (quantity)	Total (quantity)
1-phase 5kVA	1	0	1
1-phase 10kVA	2	0	2
1-phase 15kVA	9	0	9
1-phase 30kVA	4	0	4
1-phase 50kVA	0	0	0
1-phase 100kVA	1	0	1
3-phase 5kVA	0	0	0

Substation rating	Pole mounted (quantity)	Ground mounted (quantity)	Total (quantity)
3-phase 7kVA	2	0	2
3-phase 10kVA	8	0	8
3-phase 15kVA	89	0	89
3-phase 25kVA	7	0	7
3-phase 30kVA	868	31	899
3-phase 50kVA	362	61	423
3-phase 75kVA	2	0	2
3-phase 100kVA	218	104	322
3-phase 150kVA	2	1	3
3-phase 200kVA	28	219	247
3-phase 250kVA	0	18	18
3-phase 300kVA	2	412	414
3-phase 500kVA	0	87	87
3-phase 750kVA	0	14	14
3-phase 1000kVA	0	8	8
Total:	1,605	955	2,560

The population and age profile of these transformers are shown in Figure 5-24.

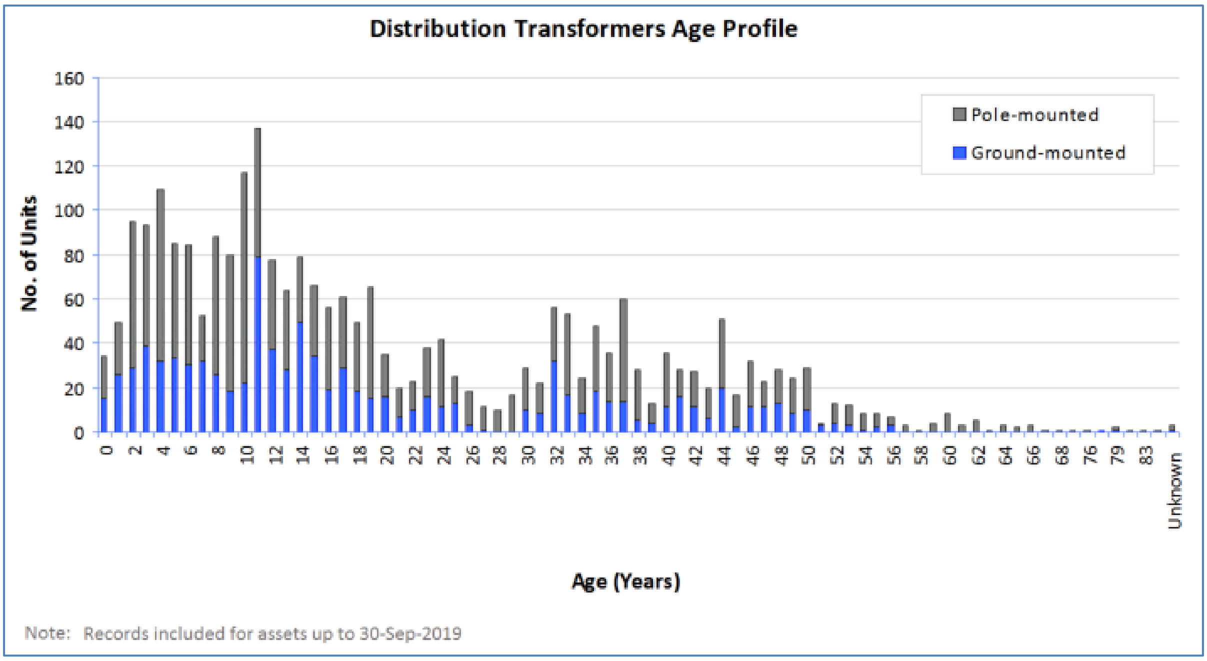


Figure 5-24: Distribution transformers age profile

Key design parameters are:

Parameter	Value
Rating	Design loading to 80% of manufacturer's rating subject to design ambient temperature and airflow
Durability	Expect to last 45 years

5.7.1 Condition

The condition of these transformers is as tabulated below:

Condition:	Grade 1	Grade 2	Grade 3	Grade 4	Grade unknown	Data accuracy	Percent forecast for replacement over next 5 years
Pole mounted	-	4.6%	74.%	22%	-	4	5%
Ground mounted	-	4%	55%	41%	-	4	4.0%

Identified systemic issues include:

- Corrosion of ground mounted transformer enclosures closer to coastal areas, these typically require replacement after 30-40 years of service
- Deck mounted transformers (on poles) requiring replacement due to declining structural integrity of the deck

5.7.1.1 Reliability

The failure rate for distribution transformers is indicated in Figure 5-25 for faults from FY2015 to FY2019 including the SAIDI-SAIFI impact. There were 14 transformer faults in FY2019 and investigations into these faults have been undertaken; besides inspections and mitigation measures identified, we are applying ARMM (Asset Risk Management Model) described in Section 8.4.1 into our process.

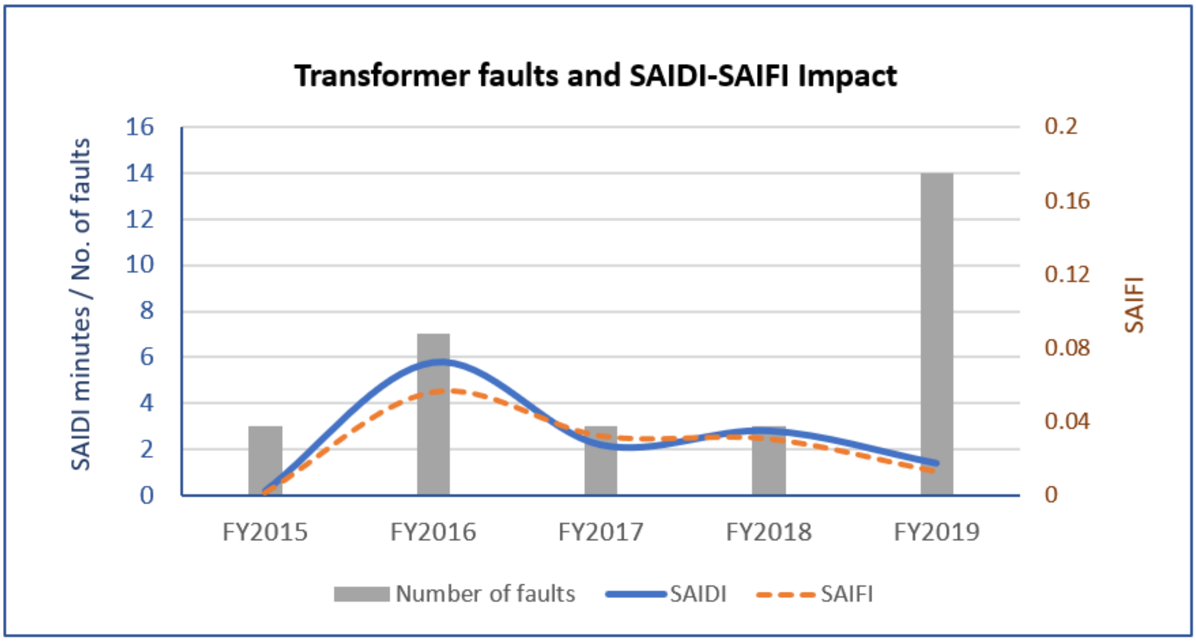


Figure 5-25: FY2015 to FY2019 - Distribution transformer faults with SAIDI-SAIFI impact

The mitigation measures for these issues follow:

Systemic issue	Mitigation	Magnitude of issue and impact on Electra
Corrosion of ground mount steel transformer enclosures	Replace corroded enclosure with more suitable type	Minimal, no significant impact
Safety concerns around structural integrity of deck mounted transformers	Replace with light weight overhead or ground mounted transformers	Minimal

There are no known distribution substation capacity, security nor reliability constraints.

5.7.2 Inspection and maintenance

The drivers for maintenance include the rusting or oil-staining of the tank, the colour of the silica gel breather where fitted, as well as excessive graffiti or evidence of interference or tampering including copper earthing (see Section 5.12).

Maintenance criteria include:

- Rusting of tank becomes more than surface deep
- Oil staining on tank suggests repeated internal overheating
- Silica gel breather remains blue
- Level of graffiti shows repeated attempts
- Evidence of attempts to force entry into cabinets.

The assumptions for maintenance are:

- Oil staining of tank suggests boiling of oil to the point of expulsion from around lid seal
- Once tank rust appears more than surface deep from ground level, tank perforations are likely.

Condition assessment techniques and methods are:

- Primarily visual, especially for oil leaks, breather colour, tank rust, chipped or broken bushings and perished seals or gaskets
- Oil sample tests only on 750kVA and above.

Inspections are graded as follows with refurbishment or renewals applied:

Grade	Inspection	Refurbishment	Renewal
1	No further inspections, will be replaced within 1 year	Will not be refurbished (generally scrapped as too expensive to refurbish	Renew within 1 year
2	No further inspections, will be replaced within 3 years	Will not be refurbished (generally scrapped as too expensive to refurbish	Renew within 3 years
3 & 4	Continue to inspect, amend grade as required	Minor repair to extend life as considered appropriate by Planning & Development Manager	-

Electra procedures ensure that transformers are maintained, transported and disposed in compliance with our environmental policy. Oil-related leaks are captured as an incident in our Health & Safety system and such events are monitored and audited.

Defect correction is carried out based on the following timeline:

- **Public safety defects**: correction within one week of identification
- **Significant structural integrity defects**: correction within one week of identification
- **Minor structural integrity defects**: repair by approved method within three months of identification.

Lifecycle decision criteria include:

- Replace when necessary repairs become more than minor
- Replace when MDI readings reveal regulator loading to more than 100% of design rating
- Life extension and investment deferral techniques
- Additional galvanising or paint for coastal areas.

5.7.3 Major projects and programmes

Projects and programmes for FY2021:

Ref	Location	Constraint description	Category	Cost
1	All	Ground transformer replacements	Renewal	$550,000
2	Kimberley Rd	Upgrade transformer room G97	Renewal	$100,000
3	All	Pole transformer replacements	Renewal	$182,000
4	All	Ground transformer faults	Renewal	$100,000
5	All	Pole transformer faults	Renewal	$55,000
6	Kirk St	Replace deck transformer M12	Renewal	$85,000
7	Tararua Rd	Replace deck transformer G326 with single pole 200kVA	Safety	$75,000

Projects and programmes for FY2022 to FY2025:

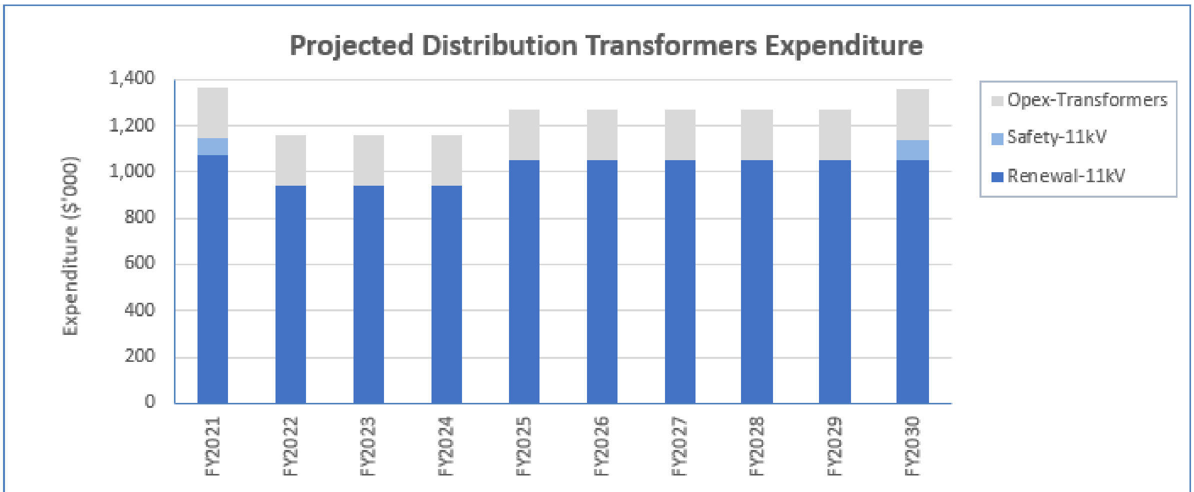
Ref	Location	Constraint description	Category	Cost
1	All	Ground transformer replacements	Renewal	$2,350,000
2	All	Pole transformer replacements	Renewal	$728,000
3	All	Ground transformer faults	Renewal	$400,000
4	All	Pole transformer faults	Renewal	$220,000
5	All	Indoor subs	Renewal	$163,538

Projects and programmes for FY2026 to FY2030:

#	Location	Constraint description	Category	Cost
1	All	Ground transformer replacements	Renewal	$2,750,000
2	All	Pole transformer replacements	Renewal	$910,000
3	All	Ground transformer faults	Renewal	$500,000
4	All	Pole transformer faults	Renewal	$275,000
5	All	Indoor subs	Renewal	$817,690
6	Whirokino Rd	Rebuild deck transformer C23	Safety	$90,000

5.7.4 Distribution transformers forecast

The projected distribution transformers expenditure is shown in Figure 5-26.



Description	FY2021	FY2022	FY2023	FY2024	FY2025	FY2026	FY2027	FY2028	FY2029	FY2030
Capital Expenditure ($'000)										
Renewal-11kV	1,072	937	937	937	1,051	1,051	1,051	1,051	1,051	1,051
Safety-11kV	75	0	0	0	0	0	0	0	0	90
Total (Capex):	**1,147**	**937**	**937**	**937**	**1,051**	**1,051**	**1,051**	**1,051**	**1,051**	**1,141**
Operational Expenditure ($'000)										
Opex-Transformers	221	221	221	221	221	221	221	221	221	221

Figure 5-26: Projected distribution transformers expenditure

5.8 Distribution switchgear

Electra has 2,599 individual items that are broadly classified as distribution switches are these are as tabulated below:

Sub-class	Number	Percent
Ground mount switches	149	6%
Auto reclosers	52	2%
Air break switches	346	13%
In-line drop-out fuses	2,052	79%
Total	**2,599**	**100%**

The age profiles of these switches are shown in Figure 5-27.

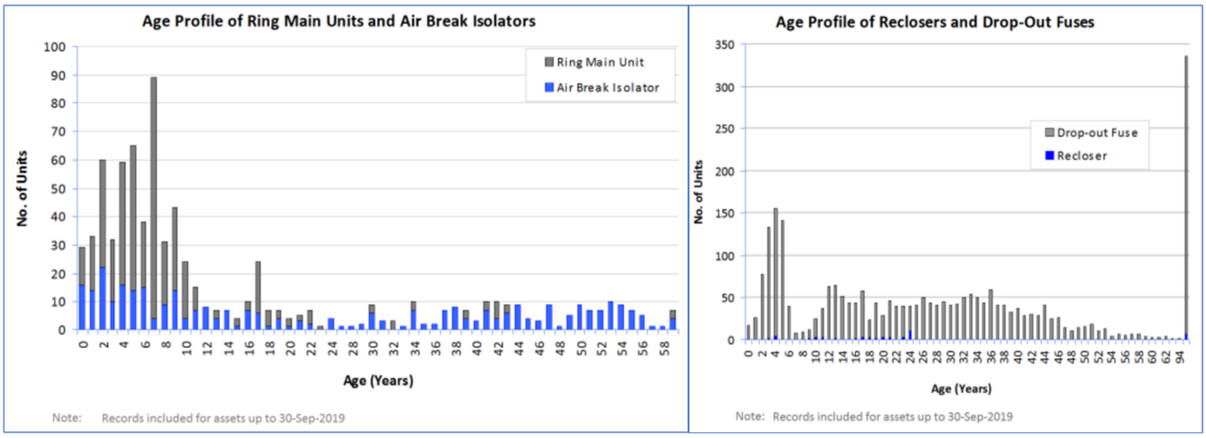


Figure 5-27: Distribution switchgear age profile

The key design parameters for the switchgear are tabulated below:

Parameter	Value
Durability	Expected life of 45 years
Load rating	Generally, the rating is based on minimum commercially available rating of 630A

SF_6 ring-main units and reclosers are deployed in the network and complies with our environmental policy. Our procurement policy includes considering alternatives such as vacuum - break switches which are being deployed where appropriate.

5.8.1 Condition

Condition:	Grade 1	Grade 2	Grade 3	Grade 4	Data accuracy	Percent forecast for replacement over next 5 years
Pole mounted circuit breakers (reclosers and sectionalisers)		2.50%	77.50%	20.00%	4	2.50%
Indoor circuit breakers		5.12%	76.88%	18.00%	4	5.20%
Pole mounted switches and fuses		3.50%	90.5%	6.00%	3	4.50%
Ring main units		6.0%	88.50%	5.5%	3	6.5%

We have identified a systematic issue with porcelain insulators on a particular brand for ABSs manufactured between 1996 to 2015.The total number affected is 104 units.

We have undertaken various operational and tactical measures to manage the risks involved with these ABSs including:

- Operational restrictions are placed on ABSs with additional Go-Pro inspections which are made mandatory before operation
- Drone inspections to be undertaken every year on the identified ABSs to determine any further deterioration
- Capex allocation have been increased to replace ABSs with integrated load break switches; these replacements will be risk ranked (such as presence of underbuilt LV and proximity to public places)
- Synergy with smart grid application will involve automation and replacing identified ABSs.

5.8.2 Inspection and maintenance

Maintenance drivers include:

- Interrupting medium levels or pressures
- Continued correct operation of mechanisms without excessive force
- Continue correct operation of remote capability
- Rusting of enclosures
- Stability of mounting, including slumping or subsidence of surrounding ground
- Manufacturers recommended overhaul intervals.

Maintenance criteria include:

- Number of operations exceeds manufacturers recommendations
- Oil levels drop below indicated minimum
- Gas or vacuum pressure varies outside of prescribed levels
- Failure to operate correctly, or with accepted level of force
- Timing test reveals contact separation times are outside of specification
- Testing reveals that trip coil is not operating within specified voltages
- Rust more than surface deep
- Slumping or movement of ground, particularly tilting that may expose live components above oil level.

Assumptions are:

- Stiff operating mechanism will eventually fail, rather than plateau
- Decline in insulating medium level or pressure will continue, rather than plateau.

Conditional assessment methods include:

- Visual, including public safety checks and checking of copper earthing (see Section 5.12);
- Regular checking of fluid levels, gas pressures etc as per OEM specifications.

Inspections are graded as follows with refurbishment or renewals applied:

Grade	Inspection	Refurbishment	Renewal
1	No further inspections, will be replaced within 1 year	Will not be refurbished (generally scrapped as too expensive to refurbish)	Renew within 1 year
2	No further inspections, will be replaced within 3 years	Will not be refurbished (generally scrapped as too expensive to refurbish)	Renew within 3 years
3 & 4	Continue to inspect, amend grade as required	Repair to extend life as considered appropriate by Planning & Development Manager	-

Correction of defects are carried out based on the following:

- **Public safety defects**: correction within 1 week of identification
- **Significant structural integrity defects**: correction within one week of identification
- **Minor structural integrity defects**: repair by approved method within three months of identification.

Criteria for lifecycle decisions and techniques include:

- Ground-mounted switches that are considered to have an unacceptably high public safety risk will be specifically marked for accelerated replacement. The precise order of replacement will include consideration of actual condition, known defects from industry experience, and proximity to sensitive locations like parks and schools
- Decision to renew rather than refurbish made on a case-by-case basis for ground-mounted distribution switches
- Decision to up-size or to replace single phase with three-phase based on load and fault level studies
- Electra may apply extra paint, galvanising or grease to individual switches near coastal areas.

5.8.3 Major projects and programmes

Projects and programmes FY2021:

Ref	Location	Description	Category	Cost
1	All	Replace ring main units	Renewal	$130,000
2	All	Urgent DDO/ABS replacement	Renewal	$30,000
3	All	ABS new and renewals	Safety	$325,000

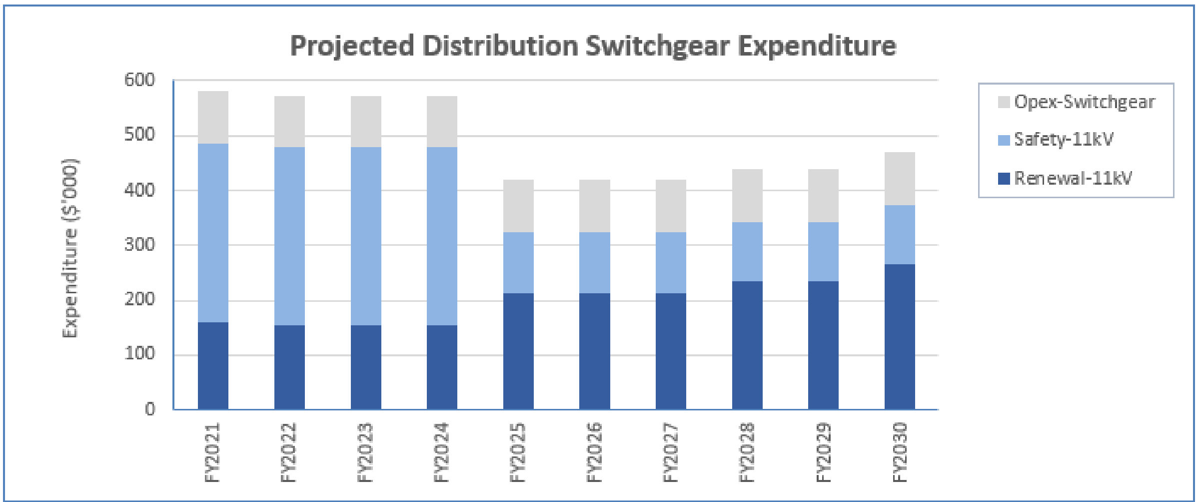
Projects and programmes FY2022to FY2025:

Ref	Location	Description	Category	Cost
1	All	Replace ring main units	Renewal	$551,939
2	All	ABS new and renewals	Safety	$1,085,000
3	All	Urgent DDO/ABS replacement	Renewal	$120,000

Projects and programmes FY2026 to FY2030:

Ref	Location	Description	Category	Cost
1	All	Replace ring main units	Renewal	$919,900
2	All	ABS new and renewals	Safety	$550,000
3	All	Urgent DDO/ABS replacement	Renewal	$240,000

The budget forecast for distribution switchgear is depicted in Figure 5-28.



Description	FY2021	FY2022	FY2023	FY2024	FY2025	FY2026	FY2027	FY2028	FY2029	FY2030
Capital Expenditure ($'000)										
Renewal-11kV	160	153	153	153	214	214	214	234	234	264
Safety-11kV	325	325	325	325	110	110	110	110	110	110
Total (Capex):	**485**	**478**	**478**	**478**	**324**	**324**	**324**	**344**	**344**	**374**
Operational Expenditure ($'000)										
Opex-Switchgear	95	95	95	95	95	95	95	95	95	95

Figure 5-28: Projected distribution switchgear expenditure

5.9 Secondary systems

5.9.1 Protection and control

Electra's network includes the following broad classes of protection and control equipment:

- Legacy protection relays (over current, earth fault, auto reclose functions)
- More recent digital protection (voltage, frequency, directional, distance, bus zone, and failure functionality)
- Transformer and tap changer temperature sensors including surge arrestors, explosion vents and oil level sensors
- Electra's main class of control assets are tap changer controls, for which Electra has standardised on the Eberle range.

Key features of Electra's protection and control include:

Asset	Directional	Over current	Earth fault	Auto reclose	Differential	Inter-trip	Fuse
Each 33kV circuit breaker	•	•	•				

Asset	Directional	Over current	Earth fault	Auto reclose	Differential	Inter-trip	Fuse
Each 11kV zone substation circuit breaker		•		•			
Each 33/11Kv transformer (bank)		•	•		•	•	
Each 11kV bank bus at zone substation		•	•				
Distribution feeder		•					•

Electra also owns a number of battery chargers, batteries and power supplies rated for a minimum of 6 hours continuous supply. All of these assets are in good serviceable condition.

There are 126 protection relays, with ages as shown in Figure 5-29.

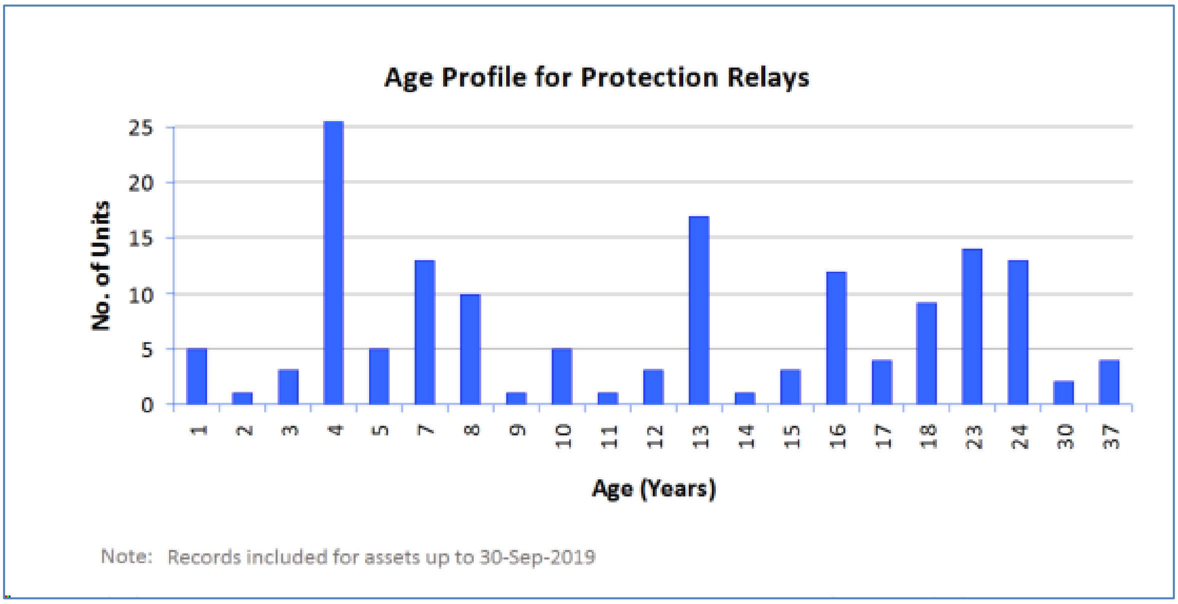


Figure 5-29: Protection relays age profile

5.9.1.1 Condition

Condition:	Grade 1	Grade 2	Grade 3	Grade 4	Data accuracy	Percent forecast for replacement over next 5 years
		10.0%	55.0%	35.0%	4	15.0%

There are no known systemic issues with Electra’s protection and control plants.

Due to a number of spurious 33kV trippings, a review of the protection settings at zone substations has been undertaken and the development of a strategy based on the following design parameters:

Parameter	Value
Functionality	Minimum as specified by Electra
Durability (relays)	Expected life of 15 to 20 years
Durability (batteries)	Expected life of 8 to 15 years
Capacity (batteries, UPS)	Minimum 6 hours full load

5.9.1.2 Inspection and maintenance

The maintenance drivers are:

- The correct operation of relays
- Battery chargers continue to charge at rated capacity
- Batteries' ability to hold the required charge.

Assumptions made include the failure to hold a charge indicates imminent failure, and a relay that has failed to correctly operate once will continue to fail.

The criteria for maintenance include:

- Relay fails to operate correctly
- Battery charger fails to maintain battery charge or voltage
- Battery fails to hold charge
- Battery age reaches design life
- Blown fuse.

Condition assessment methods include:

- Primarily visual for batteries, with fluid level checks for non-sealed batteries
- Regular testing of relay functionality and sensitivity where necessary
- Lifecycle policies, criteria and activities, including inspections.

Inspections are graded as follows and refurbishment or renewals applied as follows:

Grade	Inspection	Refurbishment	Renewal
1	No further inspections, as will be replaced within 1 year	Protection and control plant are normally replaced rather than refurbished	Renew with 1 year
2	No further inspections, as will be replaced within 3 years	Protection and control plant are normally replaced rather than refurbished	Renew within 3 years
3 & 4	Continue to inspect, amend grade as required	Protection and control plant are normally replaced rather than refurbished	

The correction of defects is carried out as follows:

- **Public safety defects**: correction within one week of identification
- **Relay fails to operate correctly**: investigate within one week, remedy within one month
- **Failure of battery charger**: replace within one month to reduce dependence on duplicate charger
- Failure of battery to hold charge: replace within one week.

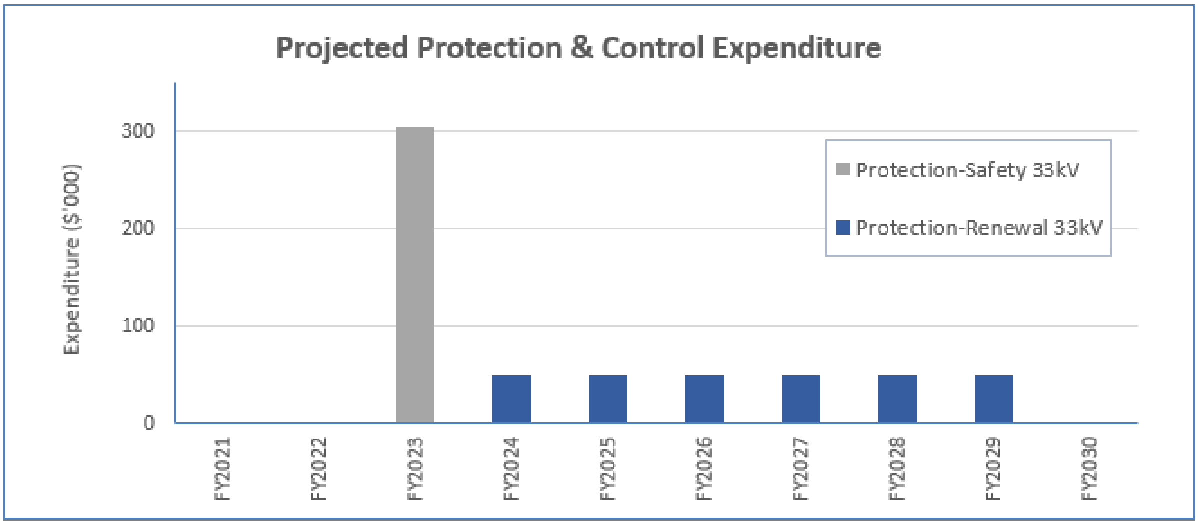
Due to the criticality and low value of individual protection and control plant, components are usually replaced rather than refurbished.

5.9.1.3 Major projects and programmes

The projects and programmes as well as budget forecast follow:

Year	Ref	Location	Description	Category	Cost
FY2021 to FY2024	1	All	33kV protection	Renewal	$100,000
	2	Zone substations	Arc flash protection	Safety	$305,000
FY2025 to FY2029	3	All	33kV protection	Renewal	$200,000

The projected protection and control expenditure are depicted in Figure 5-30.



Description	FY2021	FY2022	FY2023	FY2024	FY2025	FY2026	FY2027	FY2028	FY2029	FY2030
Capital Expenditure ($'000)										
Protection-Renewal 33kV	0	0	0	50	50	50	50	50	50	0
Protection-Safety 33kV	0	0	305	0	0	0	0	0	0	0

Figure 5-30: Projected protection and control expenditure

5.9.2 SCADA and communications

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

Microwave radio and voice connect all sites with a self-healing topology that includes the following repeater sites as shown in Figure 5-31:

- Forest Heights, Waikanae
- Mataihuka south of Paraparaumu Moutere Hill west of Levin
- Levin West substation
- Tunapo at Paekakariki.

The ages of remote terminal units or RTUs range from one to ten years.

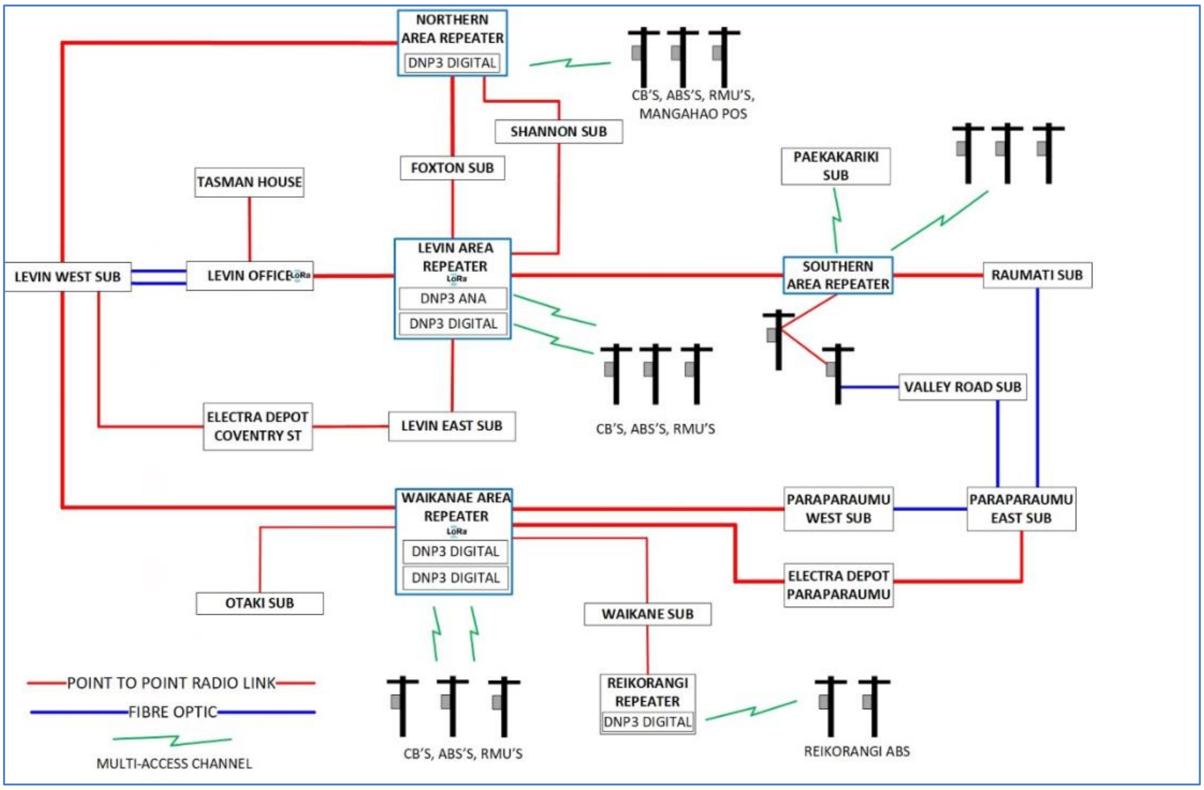


Figure 5-31: SCADA communications overview

5.9.2.1 Condition

The condition of the RTUs follow:

Condition:	Grade 1	Grade 2	Grade 3	Grade 4	Grade unknown	Data accuracy	Percent forecast for replacement over next 5 years
		10.0%	70.0%	20.0%		3	15.0%

There are no known systemic issues nor known constraints with Electra's SCADA. Functionality is a key design parameter and within minimum specifications for network operation.

5.9.2.2 Inspection and maintenance

The drivers for maintenance requirements are:

- The failure of core functionality
- The failure of RTUs during operation.

Assumptions made include:

- Faulty operation indicates imminent failure
- Replacement is preferred rather than refurbishment for new functionalities.

Condition assessment tends to be based on failure events.

Inspections, refurbishment or renewals are applied as follows:

Inspection	Refurbishment	Renewal
Review of system errors and alarm logs to identify faults	More likely to be replaced than refurbished	Tends to be driven by obsolescence or declining functionality rather than condition Lifecycle decision criteria

Defect correction is carried out as follows:

- **Immediate action**: for major loss of functionality or processing capacity, major input defects, or major RTU defects
- **Within three days**: minor input defect or minor RTU defects.

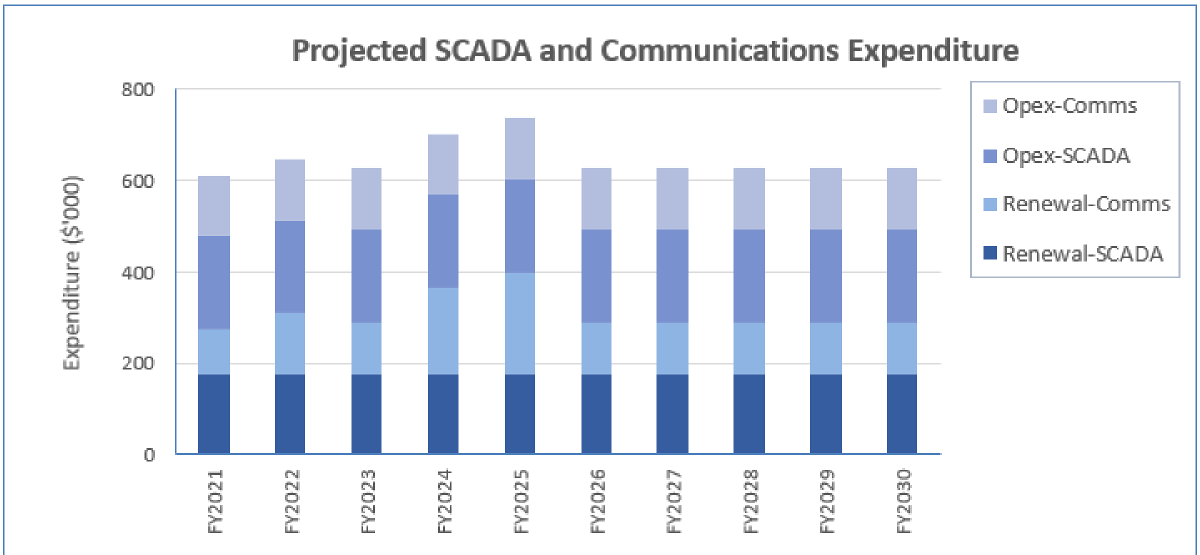
5.9.2.3 Major projects and programmes

The projects, programmes and budget forecast follow:

Year	Ref	Location	Description	Category	Cost
FY2021	1	Control Centre	SCADA upgrade	Renewal	$175,000
	2	All	Comms general - FMS	Renewal	$100,000
FY2022 to FY2025	1	Control Centre	SCADA upgrade	Renewal	$700,000
	2	All	Comms general - FMS	Renewal	$655,000
FY2026 to FY2030	1	Control Centre	SCADA upgrade	Renewal	$875,000
	2	All	Comms general - FMS	Renewal	$575,000

5.9.3 SCADA and communications forecast

The projected SCADA and communications expenditure are shown in Figure 5-32.



Description	FY2021	FY2022	FY2023	FY2024	FY2025	FY2026	FY2027	FY2028	FY2029	FY2030
Capital Expenditure ($'000)										
Renewal-SCADA	175	175	175	175	175	175	175	175	175	175
Renewal-Comms	100	135	115	190	225	115	115	115	115	115
Total (Capex):	**275**	**310**	**290**	**365**	**400**	**290**	**290**	**290**	**290**	**290**
Operational Expenditure ($'000)										
Opex-SCADA	203	203	203	203	203	203	203	203	203	203
Opex-Comms	133	133	133	133	133	133	133	133	133	133
Total (Opex):	**337**	**337**	**337**	**337**	**337**	**337**	**337**	**337**	**337**	**337**

Figure 5-32: Projected SCADA and communications expenditure

5.9.4 IoT communications and deployment

Electra also uses IoT (Industrial Internet of Things) communications technology to gather network status data to further improve network reliability, customer services and asset investment decisions.

Currently there are three Lora WAN gateways deployed in the Electra region:

- Electra Head Office, Levin
- Moutere Hill, west of Levin
- Forest Heights, Waikanae.

Additional gateways are planned at substation and repeater sites to provide full (Lora WAN) coverage of the Electra region:

- Tunapo, southern area repeater
- Te Paki, northern area repeater
- Mataihuka, Raumati substation
- Foxton, north western substation
- Pukehou
- Arko
- Paekakariki

The Electra IoT Communications framework is shown in Figure 4-2.

5.9.4.1 Condition

The LoRa gateways are recent additions to the Electra communications network. Only installed in the last year, their condition is Class 1 (new).

Gateways have an expected lifespan of 7 to 10 years; however, technology changes are more likely to drive upgrades prior to failure.

There are no known systemic issues nor known constraints with Electra's IoT platform. Resilience is a key design parameter in deployment.

5.9.4.2 Inspection and maintenance

The drivers for IoT Gateway maintenance requirements are:

- Failure of core functionality
- RF coverage.

Assumptions made include:

- Faulty operation indicates imminent failure
- Replacement is preferred rather than refurbishment due to unit cost.

Condition assessment tends to be based on failure events.

Inspections, refurbishment or renewals are applied as follows:

Inspection	Refurbishment	Renewal
Review of system errors and alarm logs to identify faults	Due to unit cost devices are likely to be replaced rather than refurbished	Driven by failure, obsolescence and declining functionality rather than condition Lifecycle decision criteria

Defect correction is carried out as follows:

- For major loss of functionality or processing capacity: immediate action
- Minor defects or signalling issues: within three days.

The details of the installation plan for IoT sensors as well as major programs and budget are detailed in Section 6.2.5.

5.9.5 ADMS

Historically Electra has operated a range of network ICT systems that have delivered basic functions well but have lacked interconnectivity and had few specific analysis capabilities. In 2015 Electra identified a range of barriers to improving its reliability / cost mix and implemented a number of isolated technology solutions. Those solutions provided some quick gains in fault restoration times, cost reductions and overall staff appreciation of technology, but still did not provide a unified ICT platform with advanced functionality.

Following an RFP process, Electra purchased the Milsoft ADMS, which was considered to provide the best functionality, scalability and cost for an EDB of up to 100,000 connections. Milsoft provides modules to integrate the previously separate functions of distribution management, SCADA, outage management, fault dispatching and various network engineering analysis functions. There are streams of work identified to improve the data quality to further enhance the Milsoft functions and improve customer experience overall through a combination of improved network reliability and lower costs.

Benefits have included:

- Quicker restoration of faults, including through quicker dispatch of fault crews
- Estimation of technical losses
- Improved demand and load flow analysis that is likely to allow deferral of asset upgrades
- Improved information available to customers
- Automated telephone and website updates during major events
- Reduced call volumes due to customers accessing the web outage viewer
- Enhanced data capture.

Current initiatives include:

- Re-engineering Electra’s as-built processes to a pre-build process enabling the ADMS model to reflect the real time network state
- Implementing a switching scheduler application
- Building an LV data model to reflect the customer phase connections and provide a building block to improved LV network management.

5.9.6 Mobile generator

Electra has owned a 500kVA mobile diesel generator since 2008. It is primarily used to maintain supply during planned and unplanned outages.

5.10 Strategic spares

In the event of network emergencies and high impact low probability events, it is important to keep adequate quantities of spares to enable the fast restoration of defects. Based on the quantities of transformers, switchgear and conductors installed on our network, Electra maintains spares for the following equipment at its depots:

Critical equipment type	Critical spare	Quantity	Location
Zone Transformer	5MVA 3 phase	1	Shannon Substation
Pole Mount Transformer	15kVA 1 phase	1	Levin East Substation
	30kVA 1 phase	1	Levin East Substation
	30kVA 3 phase	6	5 Levin East Substation, 3 Paraparaumu West Substation
	50kVA 3 phase	1	2 Levin East Substation, 2 Paraparaumu West Substation
	100kVA 3 phase	1	1 Levin East Substation, 1 Paraparaumu West Substation
	200kVA 3 phase	1	Levin East Substation
	500kVA 3 phase	1	Levin East Substation
Ground Mount Transformer	50kVA micro sub	2	1 Levin East Substation, 1 Paraparaumu West Substation
	100kVA 3 phase I tank	1	Levin East Substation
	200kVA 3 phase side by side	1	Paraparaumu West Substation
	200kVA 3 phase I tank	1	Levin East Substation
	300kVA 3 phase side by side	1	Levin East Substation
	300kVA 3 phase I tank	1	Levin East Substation
	500kVA 3 phase side by side	1	Paraparaumu West Substation
	500kVA 3 phase I tank	1	Paraparaumu West Substation
	1000kVA	1	Levin East Substation
	Transformer pad (75kVA-100kVA , 100kVA – 300kVA, 500kVA – 1000kVA)	1 of each	Levin East Substation
Switchgear/Fuses	Schneider RN62c	1	Levin Depot
	ABB (ccc, cfcc, cfc, cccc)	1 of each	Levin Depot
	ABS (load break)	4	2 Levin depot, 2 Paraparaumu depot
	DO Fuse sets	10 x 3-phase sets	Connectics
	Solid Link	19	Connectics

5.11 Trees

Electra doesn't own any trees, but it does 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. Electra, through the ENA, has submitted suggested changes to the Electricity (Hazards from trees) Regulations to reduce the current high cost of vegetation management.

5.11.1 Condition

Electra's overhead lines are surrounded by trees of varying heights, foliage types, growth rates and ownership classes. Section 8.4.5 contains our vegetation strategy which has moved to integrate a planned program where cyclic trimming is undertaken based on a risk-based assessment strategy.

Figure 5-33a shows a gradual increase in vegetation OPEX since FY2016 to FY2019 and a resulting decrease in vegetation SAIDI from FY2018 (7.8 min) to FY2019 (4.1 min). Comparing with other Electricity Lines Businesses in Figure 5-33b, our vegetation SAIDI is 64% below the industry median of 16.3 minutes over FY2018 to FY2019; the SAIDI performance versus vegetation OPEX is discussed further in Section 0.

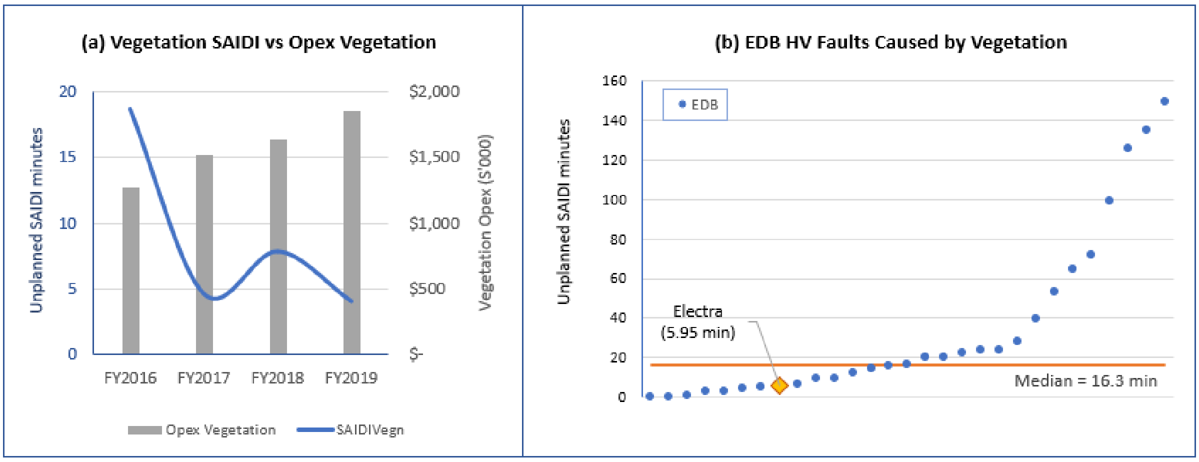


Figure 5-33: (a) Electra HV faults caused by vegetation, and (b) FY2018 -FY2019 EDB faults caused by vegetation

5.11.2 Inspection and maintenance

The maintenance drivers for tree management are the safety to the public, to customers, and to Electra personnel. Other drivers include the mitigation of risk of supply interruption, maintenance of minimum clearances specified in the Regulations, the fall zone for trees, and tree roots interfering with cables or ground level assets.

The criteria for maintenance include:

- Number of customers at risk of interruption from specific tree contacts
- Branches or leaves encroach into minimum clearances specified in the Regulations
- Roots observed to interfere with ground level assets
- Roots believed to interfere with cables
- Obviously unsafe tree within fall zone.

The assumptions made for these maintenance tactics are that most tree owners will accept the first cut at Electra's expense, but will prefer the tree to be removed rather than pay for second and subsequent cuts themselves. People usually give little thought to power lines when choosing the location or species of tree.

Our method for determining maintenance requirements are primarily visual, with a focus on major trunk splits or defects that could cause the tree to fall across a line.

Inspections are graded as follows and refurbishment or renewals applied as follows:

Inspection	Refurbishment	Renewal
Graded by encroachment and estimated time to reach encroachment zone; one year, three years	Not applicable	Customers are encouraged to replace fast growing species with slow growing natives Low growing species such as toitoi and flax that encroach on ground mounted assets will be removed

Defect corrections are carried out based on the following assessments:

- **Public safety defects**: mitigations established, and corrective action scheduled within one week of identification
- **Early engagement with customers:** early engagement during surveys encouraging proactive management prior to encroachment
- **Within notice zones**: these targets follow the timelines set out in Electricity (Hazards from Trees) Regulations 2013.

5.11.3 Major projects and programmes

Since 2018, we have investigated methods and specific technologies for migrating tree trimming from a responsive based approach to a risk-based approach, to systematically reduce tree-related SAIFI and SAIDI. Initial goals focus on vegetation on feeder sections closest to zone substations and out to the first automated switch. Feeder sections have been prioritised by the greatest improvement in vegetation-based risk. This programme has been enabled by insights developed from historical inspection data and Electra's geospatial network model.

The programmes for the indicated financial years follow and the tree or vegetation control operational budget is included in the following table as well as in Figure 5-34.

Year	Ref	Location	Type of work	Category	Cost
FY2021	1	All	Vegetation control (not faults)	Vegetation	$1,607,578
FY2022 to FY2025	2	All	Vegetation control (not faults)	Vegetation	$6,430,312
FY2026 to FY2030	3	All	Vegetation control (not faults)	Vegetation	$7,437,890

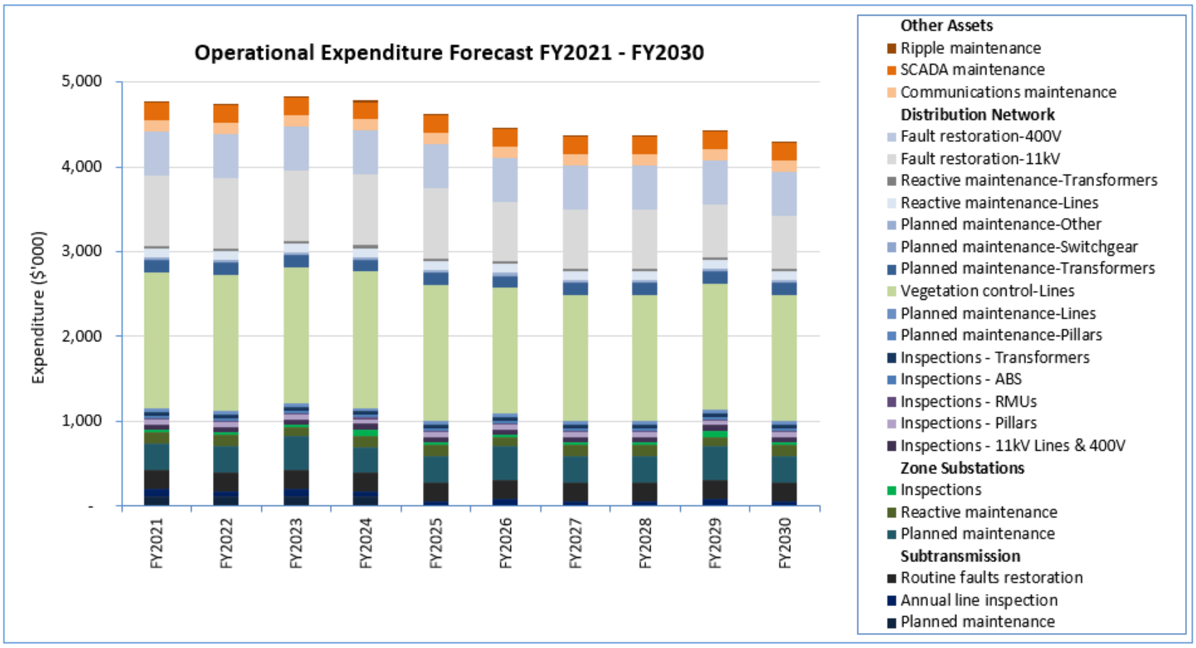
5.12 Copper thefts

Since August 2019, a total of 116 copper thefts affecting transformers and switchgear have been uncovered. Copper theft is an industry problem and Electra has engaged a consultancy company to study combat measures as well as working with enforcement authorities and recycling companies to stop these thefts. New guidelines have been released as countermeasures using alternative earthing installation methods and steel-reinforced copper for Electra's 11kV and 33kV distribution earthing requirements to ensure that safety standards are retained.

5.13 Summary of inspections and maintenance

Inspections and maintenance for all asset classes are summarised in the following chart and graph of Figure 5-34: Projected operational expenditure (OPEX) for FY2020 to FY2030.

These costs for OPEX are reflected in Schedule 11b Report of Forecast Operational Expenditure in Appendix 3.



Operations & Maintenance (Current $'000)	FY2021	FY2022	FY2023	FY2024	FY2025	FY2026	FY2027	FY2028	FY2029	FY2030
Subtransmission										
Planned maintenance	120	120	120	120	-	-	-	-	-	-
Annual line inspection	80	50	80	50	50	80	50	50	80	50
Routine faults restoration	227	227	227	227	227	227	227	227	227	227
Zone Substations										
Planned maintenance	312	312	397	297	312	397	312	312	397	312
Reactive maintenance	140	140	111	140	140	111	140	140	111	140
Inspections	24	24	24	74	24	24	24	24	74	24
Distribution Network										
Inspections - 11kV Lines & 400V	65	65	65	65	65	65	65	65	65	65
Inspections - Pillars	50	50	50	50	50	50	50	50	50	50
Inspections - RMUs	20	20	20	20	20	20	20	20	20	20
Inspections - ABS	30	30	30	30	30	30	30	30	30	30
Inspections - Transformers	45	45	45	45	45	45	45	45	45	45
Planned maintenance-Pillars	11	11	11	11	11	11	11	11	11	11
Planned maintenance-Lines	28	28	28	28	28	28	28	28	28	28
Vegetation control-Lines	1,608	1,608	1,608	1,608	1,608	1,488	1,488	1,488	1,488	1,488
Planned maintenance-Transformers	142	142	142	142	142	142	142	142	142	142
Planned maintenance-Switchgear	25	25	25	25	25	25	25	25	25	25
Planned maintenance-Other	8	8	8	8	8	8	8	8	8	8
Reactive maintenance-Lines	102	102	102	102	102	102	102	102	102	102
Reactive maintenance-Transformers	34	34	34	34	34	34	34	34	34	34
Fault restoration-11kV	828	828	828	828	828	697	697	697	622	622
Fault restoration-400V	523	523	523	523	523	523	523	523	523	523
Other Assets										
Communications maintenance	133	133	133	133	133	133	133	133	133	133
SCADA maintenance	203	203	203	203	203	203	203	203	203	203
Ripple maintenance	19	19	19	19	19	19	19	19	19	19
Total Operational Expenditure	**4,778**	**4,748**	**4,834**	**4,783**	**4,628**	**4,462**	**4,377**	**4,377**	**4,437**	**4,302**

Figure 5-34: Projected operational expenditure (OPEX) for FY2020 to FY2030

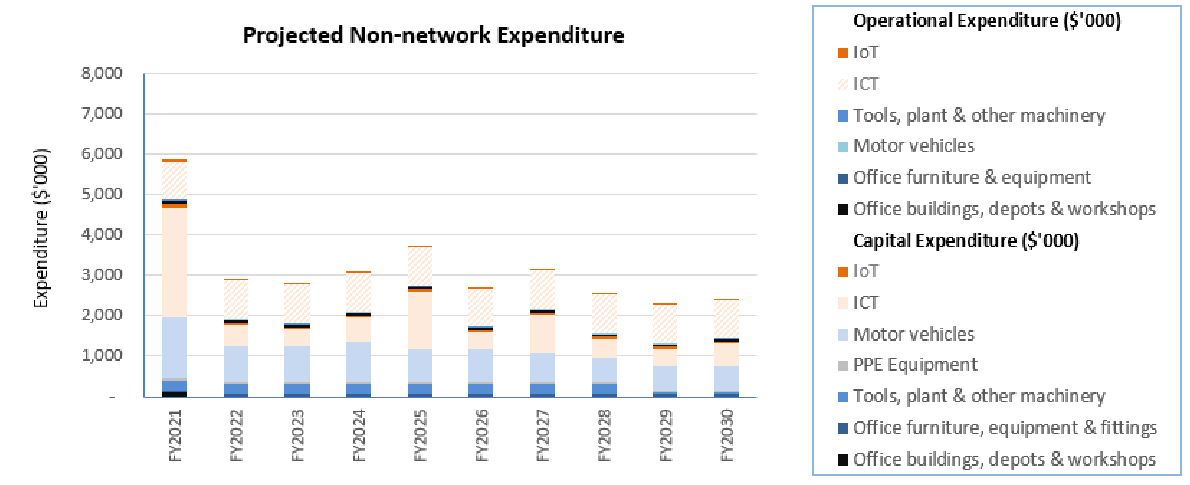
6 Non-network systems

6.1 Summary of non-network assets

Electra's non-network assets include:

Asset class	Description	Approx. value	Criticality to asset management
Non-network ICT and AMIS	Financial system - Microsoft Nav-Dynamics	About $1m total replacement cost	Financial reporting and purchasing would be disrupted. Criticality would be about 1 month unless a specific data extraction job was necessary
	Other corporate software	$504,024 (NBV)	
	In-house outage management and job dispatch system	$115,512 (NBV)	Fault dispatch work would be disrupted. Criticality is about 12 hours
	Customer Resource Management System (CRM)	$135,000 (NBV)	Existing work would continue, customer history for new jobs would need manual lookup. Criticality is about 30 days
	SCADA – iFix (Catapult, marketed by GE)	$1,866,000 (NBV)	Real-time operations would require manual HV switching. Criticality is minutes
AM systems	NIMS – based on ESRI GIS, but largely in-house	$1,357,000 (NBV)	Existing work could continue, but new jobs couldn't be created. Criticality is about 30 days
	Milsoft ADMS suite	$190,000 (NBV)	Outage resolution would be delayed increasing SAIDI
Buildings	Head office (Levin)	$1,388,000 (NBV)	Head office critical over the long-term, but short-term alternatives for control room and other critical work have been established
Photovoltaic (PV) and battery storage system	Head office (Levin)	$27,000 (NBV)	Not critical
Office furniture	Desks and workstations Chairs	$114,460 (NBV)	Not critical as easily replaced
Vehicles	Cars Vans 2WD Utes 4WD Utes Bucket Trucks	$4,011,000 (NBV)	Not critical as alternatives can be arranged
Tools, plant and machinery	Hand tools Test Equipment Power tools	$602,351 (NBV)	Not critical as easily replaced through local retailers or specialised suppliers

The overall projected non-network expenditure is shown in Figure 6-1.



Description	FY2021	FY2022	FY2023	FY2024	FY2025	FY2026	FY2027	FY2028	FY2029	FY2030
Capital Expenditure ($'000)										
Office buildings, depots & workshops	100	20	20	20	20	20	20	20	20	20
Office furniture, equipment & fittings	60	60	60	60	60	60	60	60	60	60
Tools, plant & other machinery	250	250	250	250	250	250	250	250	38	38
PPE Equipment	38	38	38	38	38	38	38	38	38	38
Motor vehicles	1,525	875	875	1,000	800	800	700	600	600	600
ICT	2,675	534	424	589	1,444	424	960	464	424	549
IoT	125	55	55	55	55	55	55	55	55	55
Total (Capex):	**4,773**	**1,832**	**1,722**	**2,012**	**2,667**	**1,647**	**2,083**	**1,487**	**1,235**	**1,360**
Operational Expenditure ($'000)										
Office buildings, depots & workshops	50	50	50	50	50	50	50	50	50	50
Office furniture & equipment	9	9	9	9	9	9	9	9	9	9
Motor vehicles	16	16	16	16	16	16	16	16	16	16
Tools, plant & other machinery	16	16	16	16	16	16	16	16	16	16
ICT	950	950	950	950	950	950	950	950	950	950
IoT	55	10	10	10	10	10	10	10	10	10
Total (Opex):	**1,096**	**1,051**	**1,051**	**1,051**	**1,051**	**1,051**	**1,051**	**1,051**	**1,051**	**1,051**

Figure 6-1: Projected non-network expenditure

6.2 Non-network ICT strategy

Electra maintains an Information System's Strategic Plan (ISSP) that provides clarity to Electra on the principles, approach and overall investment priorities for the business.

The ISSP is reviewed and updated annually to reflect the changing needs of the business. It aligns with the other strategic and operational plans of the company including this Asset Management Plan, the departmental business plans and associated budgets.

This section of the AMP refers to all technology centric operations and the development of systems to support the electricity distribution business, particularly, non-network ICT will support investment and operation via the following:

- Efficient works delivery
- Improved customer experience
- Improved supplier relationships
- Improved real-time operation
- Optimised network investment
- Integration of increasing data into Electra's wider businesses
- One and only one data item that is reliable ("Single Source of Truth")

6.2.1 Strategic context

Electra's Statement of Corporate Intent (SCI) identifies three Focus areas for the company. These are to provide a superior experience for customers and stakeholders, deliver best in class in the operation and management of the business, and to grow the business. These focus areas feature in Electra Group Business Plan and budgets. A summary of the relative position of the ICT systems and capabilities provides direction to the ISSP.

	Focus	Threat	ICT Initiatives in response
External Factors	Opportunities	Customers seek accurate and timely info. Reduce procurement and operational costs Growth potential in subsidiaries New business in technology centric business	CRM, Integrations and correct data Collaborate with CIO's in other ELB's Support and develop acquisitions Search and bring to the table
	Threats	Cyber and physical threats to operation Disruption of significant regional disasters Data Breach/Disclosure	Collaborate, strength, educate and test Plan and prepare and practice Controls, classification and education
Internal Factors	Strengths	ICT operation and management expertise Modern business information systems Progressive company strategy	Document and teach for succession Leverage and develop tools Research, innovate and learn
	Weaknesses	Limited business intelligence and analytics Phased ADMS implementation ICT dept lacking expertise in all systems	Investigate, select and develop Develop and extend Education and mentoring

Figure 6-2: Needs Analysis Survey. Source: Electra ISSP

Electra desires to serve its customers with better quality information by leveraging the new ADMS. The business expects the highest levels of service availability while being cognisant of the threats to our operation.

6.2.2 Electra's ICT assets

The operations and functions of each capability are integrated, and any business service often relies on one or more of these to operate at effective service levels.

The following model outlines Electra's approach to categorising our ICT assets and capabilities:

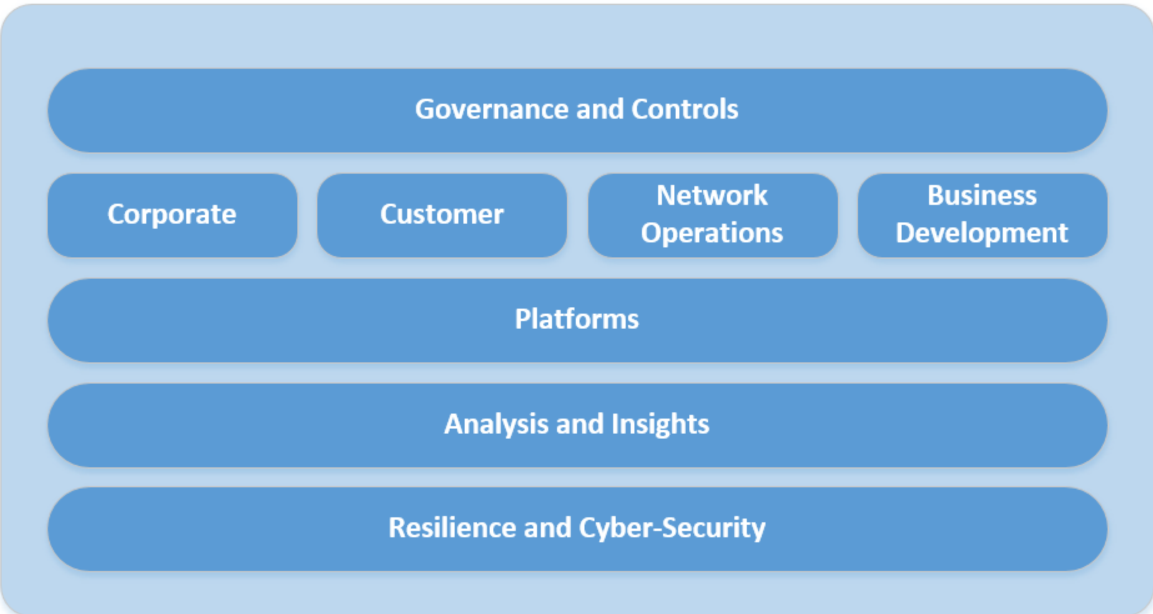


Figure 6-3: Electra ICT asset and capability framework

Each asset class provides business services, being:

ICT asset class	Business services
Governance and controls	Contributes to the overarching strategic direction of Electra. Aligns business decision making and ICT investment. Provides frameworks, planning and controls
Corporate	Supports the effective operation of business support functions, including finance, human resources and payroll, health & safety and knowledge management
Customer	Enables customers to interact with Electra – to understand outages, advise of concerns/incidents and to request new connections
Network operations	Supports the safe and effective operation of our electricity distribution network. Contributes to an integrated information sharing and efficient use of resources. ICT provides guidance on best practice
Business development	Support the operation and growth of existing businesses. Identify and drive creation of new businesses
Platforms	Underpins delivery and management of Electra's ICT services – both our Cloud and on-premise operating environments including hardware, software and services
Analysis and insights	Provide platform, expertise and training to enable the analysis of datasets and creation of performance graphs
Cyber security and resilience	Ensure our ICT services availability and enables response to threats and risks through establishing and maintaining internal controls

6.2.3 ISSP – planned ICT investments

The Electra ISSP addresses the financial years ending 31 March 2020 through to 2030. These plans fall into three horizons, each of which is approximately 12 months, with:

Horizon 1	Last 12 months
Horizon 2	Next 12 months, reasonably foreseeable, enables the known
Horizon 3	Following 12 months (months 13-24). Expected, foreseeable not proximate

The use of the 3 planning horizons, enables specific plans are in place for the first 12 months, with other less certain for the following 24 months. This ensures the ISSP can accommodate changes in both business needs and from rapidly evolving technology through annual business planning.

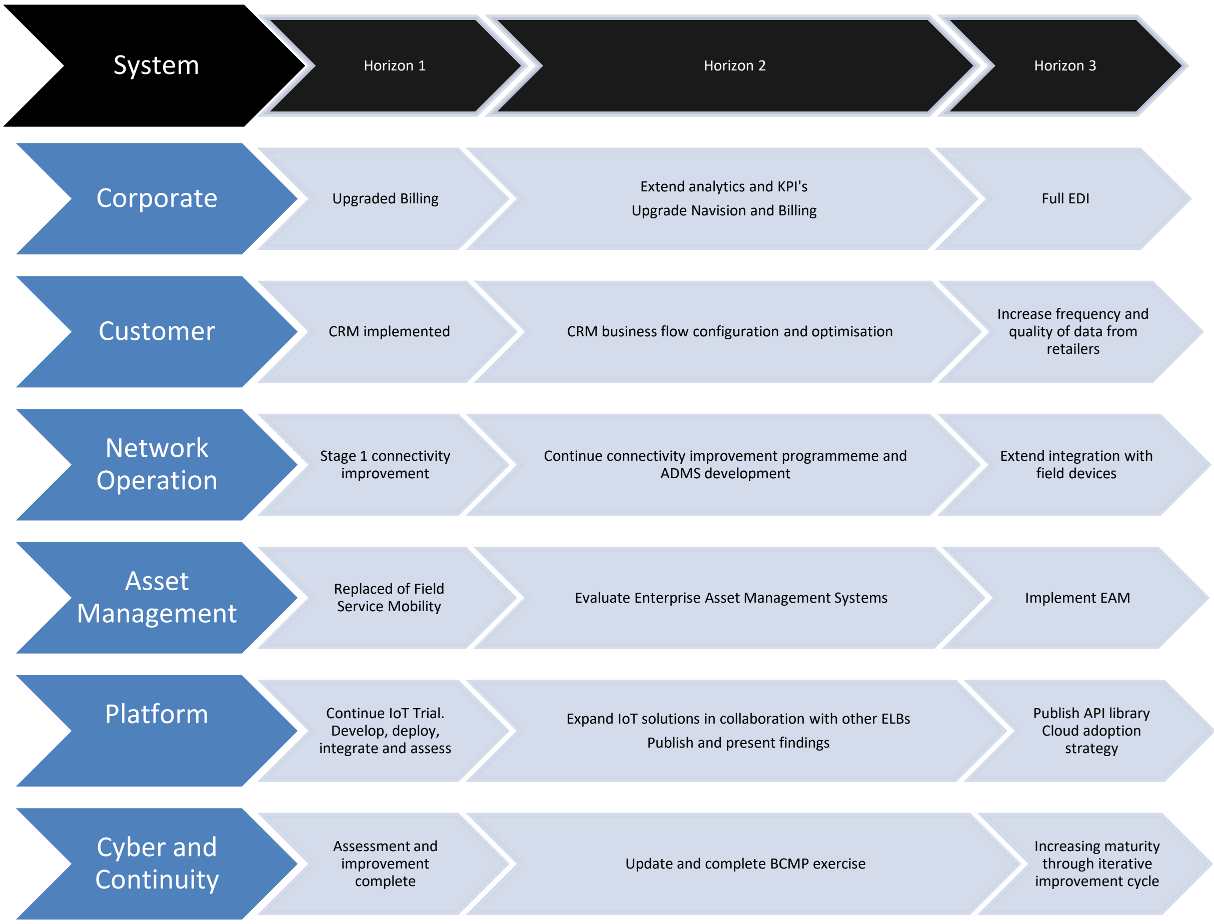


Figure 6-4: ISSP horizons (Source: Electra ISSP 2018)

6.2.4 Smart grid strategy - ADMS platform

In 2017 Electra began the implementation of the Advanced Distribution System (ADMS) from Milsoft Utility Solutions. This provides a suite of products for the design, analysis, operation and performance reporting of the distribution business.

Three key components are:

- Outage Management System that despatches jobs to field devices and provides visibility to electricity outages through a webpage and mobile application
- Design and Engineering analysis maintains the single-source-of-truth for the network design and provides the ability to edit and extend the network. This also provides load flow analysis
- Management of planned and unplanned outages including regulatory reporting.

We are already realising the benefits of improved communication with our customers and greater visibility of processes than span the company. A data quality improvement programme continues to improve the completeness of the underlying information. We have also implemented the Milsoft aligned Clevest Field Service Management platform providing field crews with greater visibility and the ability to update and restore customer outages.

We have also been trialling an IoT platform (Lora WAN) to leverage long range low bandwidth communication to collect (almost) real-time information on voltage, current and network status.

The advantages of these platforms are low cost, long range and easy deployment. The information collected is flowing into a central "data lake" for post analysis and is also presented to the control room operators for event notification and verification. This information improves network reliability, asset management, decision making and communication with the customer. This initiative involves deployment of a range of technologies within our electricity network and can only be achieved with the support of our vendors and customers.

6.2.5 ICT CAPEX forecast

The following Figure 6-5 has been produced by analysing our historic costs, then forecasting likely changes to the major systems. The costs have been estimated through consultation with solution providers.

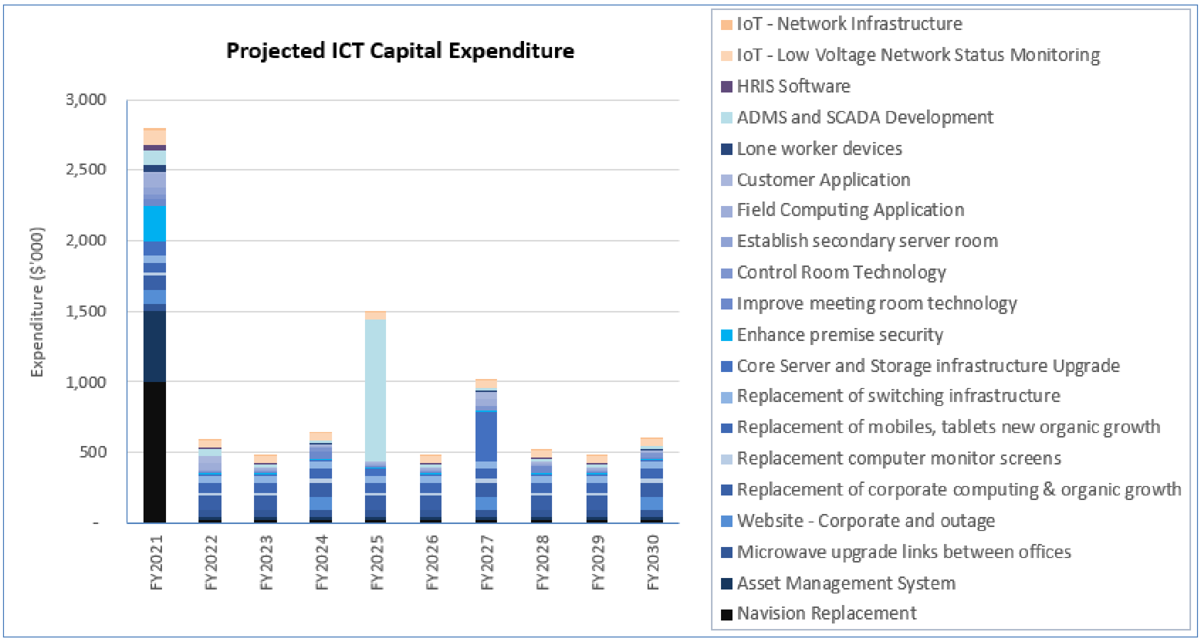


Figure 6-5: ICT CAPEX forecast

The investment in FY2021 reflects the anticipated implementation of the Microsoft Dynamics Navision financial system with the latest Cloud Computing version of Navision as well as an Asset management System. Provision has been made to replace our core digital information systems with a focus on increasing resilience, performance and capability. In the same financial year, we will continue to improve the resiliency and capability of our private Microwave WAN and public network connectivity solutions.

In 2022 provision has been made to replace or upgrade the SCADA Control system that has been in operation for over decade. This is an essential part of the ADMS solution that was not included in the upgrade in 2018.

The major IoT projects and programmes follow:

Year	Ref	Location	Description	Category	Cost
FY2021	1	Low voltage network: status sensing	Deployment of IoT sensors to monitor LV network	New	$100,000
	2	Network infrastructure	Installation of LoRa Gateways and antennas	New	$25,000

6.2.6 Cyber security plan

Electra has a mature Risk Management Framework that identifies the threat from regional natural disasters and cyber threats, amongst others. In 2018 the company undertook an extensive assessment and improvement programme with a New Zealand leading provider. This improved Electra's existing ICT controls to staff and customers. Initiatives carried out in 2019 included the use of Multi-Factor Authentication (MFA) when logging into one of our remote servers from anywhere except offices of the Electra Group. The product used is called ESET Secure Authentication which uses an application installed on your mobile phone which will prompt you to approve any attempt to log in to the Remote Access server using your username and password.

We continue to use leading hardware and software vendors when it comes to securing our infrastructure. This includes scheduled update and replacement of key architecture to support growth and resilience.

6.3 Buildings and property

Asset class	Key policies	Strategies and initiatives
Buildings	Head office (Levin) Depot (Levin) Depot (Paraparaumu)	No plans in the horizon for any additions

Buildings and property will support investment and operations by the deployment of:

- Safe, comfortable working environment
- Disaster resilience
- Ability to accommodate additional office and field staff
- Flexibility to rearrange staff as org structure evolves
- Specific plans for system control, especially back-up (cuts across ICT).

6.3.1 Photovoltaic (PV) and battery storage systems

This single-phase system was installed at Electra's Head office in 2019 and used to learn about domestic energy trading (Energy Arbitrage), how hybrid PV systems operate, and how users interact with these systems. This PV configuration is typical of a domestic dwelling with battery storage. A Sonnen 8kWh Lithium Iron Phosphate (LFP) Battery has been installed with ten 315-watt solar panels on the northern facing roof with room for another 89 panels. The black mono N-type solar panels each have an S230 micro inverter. N-type solar panels do not suffer from light-induced degradation (LID) which causes a decrease in efficiency over their lifetime.

6.4 Office furniture and fittings

Asset class	Key policies	Strategies and initiatives
Office furniture	Desks and workstations Chairs Cabinets and storage	No specific strategy, typically low value items that simply follow the need for staff work patterns and duties

Office furniture and fittings will support investment and operations through:

- Safe, comfortable working environment
- Disaster resilience

- Ability to accommodate additional office and field staff
- Flexibility to rearrange staff as org structure evolves.

6.5 Vehicles

Electra has two electric vehicles comprising of a Hyundai Ioniq and an LDV van, plus a hybrid Mitsubishi Outlander Plug-in Hybrid Electric Vehicle (PHEV), in our pool of vehicles.

The asset strategy for Electra's vehicles is tabulated below and our policy is based on the most fuel-efficient vehicle that meets the requirements of its use, and whether this meets fuel and emission requirements.

Asset class	Key policies	Strategies and initiatives
Electric vehicles and hybrids	Cars – electric vehicles and hybrids: EV batteries replacement as per manufacturer's recommendations	Evaluation on "fit for purpose" is undertaken by the team manager or supervisor, based on the distance the EV can be driven between recharging. If a fully Electric Vehicle is not fit for purpose, a Plug-in Hybrid Electric Vehicle (PHEV) is evaluated as such vehicles have no range limitation and have substantially lower emissions than a typical hybrid or fuel vehicle and will cost the same over its lifetime
Other Vehicles	Cars (petrol): replace after 130,000km or 4 years Cars (diesel): replace after 160,000km or 4 years Vans and Utes: replace after 160,000km or 6 years Trucks: determined by GM – Lines Business, but typically 10 years.	Key strategy is that the load capacity, terrain capability and range need to align with key network features as well as aspects of passenger or cargo or towing capacity or other requirement so that a fuel vehicle is justified e.g. extent of network footprint, length and weight of poles

Our vehicles contribute to our investment and operation by their ability to perform all required investment and operational activities including transport, lifting and digging.

6.6 Tools, plant and machinery

Electra's key policies for renewal and replacement of non-network assets include:

Asset class	Key policies	Strategies and initiatives
Tools, plant and machinery	Hand tools – replace when unsafe or insufficient functionality Power tools Generator - serviced every 250 hours including replacement of oil and filter. Electrical connections tested annually, COF for the trailer is renewed every 6 months	A replacement strategy based on the safe and efficient operation of our tools and equipment

The replacement policies aim to match the depreciation of the assets.

7 Risk management

Electra's network business is exposed to a wide range of risks. Aside from the obvious physical risks such as cars hitting poles, vandalism, public safety and storm damage, the network business is exposed to a wider range of risks that include regulatory commercial and technology uptake.

7.1 Risk analysis and methods

Electra has a comprehensive risk management framework as shown in Figure 7-1, this is regularly reviewed by the Board and by Management, in line with the requirements of the Health and Safety at Work Act 2015.

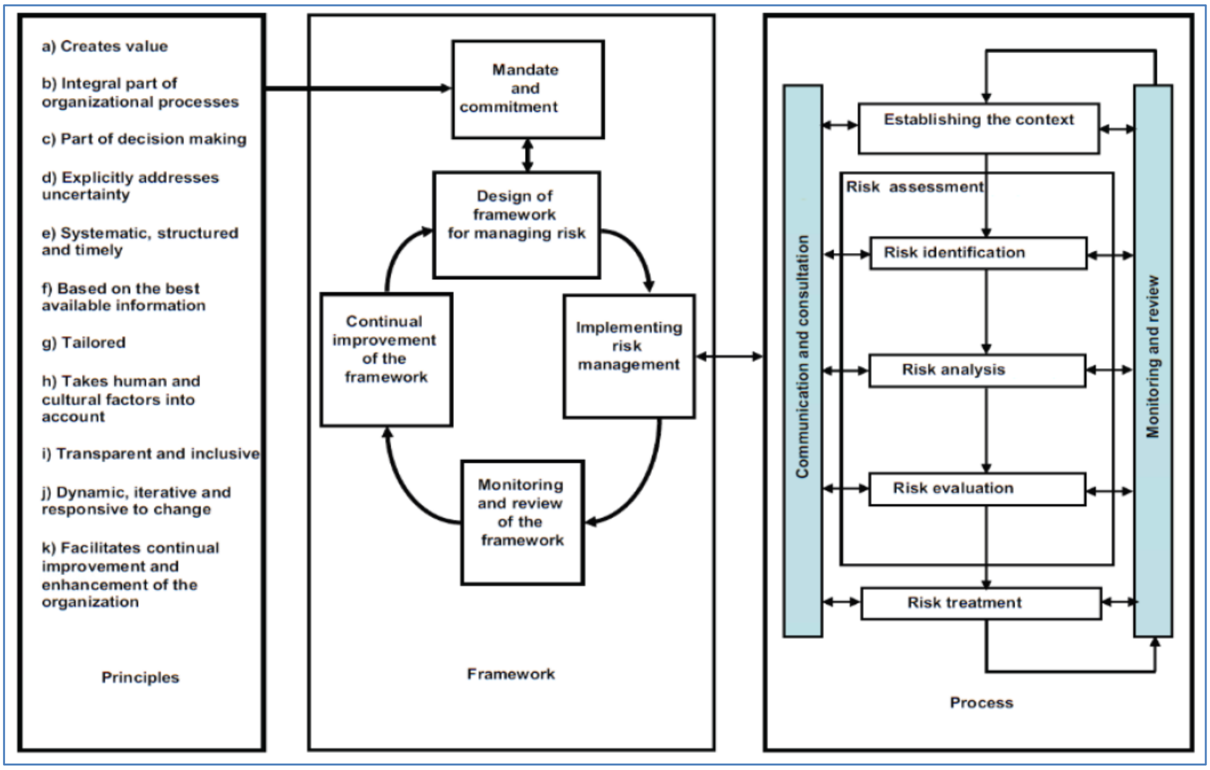


Figure 7-1: Risk management framework based on AS/NZS ISO 31000:2009

This uses an established process based on AS/NZS ISO 31000:2009 to:

- Identify risks that affect the business
- Assess the impact and likelihood of the risk occurring
- Identify existing controls that will mitigate the risk
- Identify the top five residual risks once the controls have been applied
- Produce and implement risk treatment plans to further minimise risks
- Assessments and plans will be fully documented to assist with the following year's review.

An essential part of this process is the identification of workplace hazards and the requirement to keep a register of accidents.

7.1.1 Risk management system

Electra uses the Vault risk management system to record and manage all risks for the company. Vault is a stand-alone risk management and incident reporting tool. Our H&S and organisations risks are recorded on this platform, and all events including incidents, injury, illness and near misses are reported (either via desktop or a mobile application). Incident investigations are also recorded on here.

The primary benefit is a common and consistent risk evaluation and scoring system shown in Figure 7-2. This enables the business to readily identify the greatest risks of the Electra Group.

Probability Scoring

Score	Scale	
5	Frequent	Certain to happen (i.e. at least once in 1 year)
4	Probable	Likely to happen (i.e. at least once in 5 years)
3	Occasional	Sometimes will happen (i.e. at least in 10 years)
2	Remote	Unlikely, probably won't happen (i.e. at least once in 50 years)
1	Improbable	Rarely happens, not expected to happen (i.e. once in 100 years)

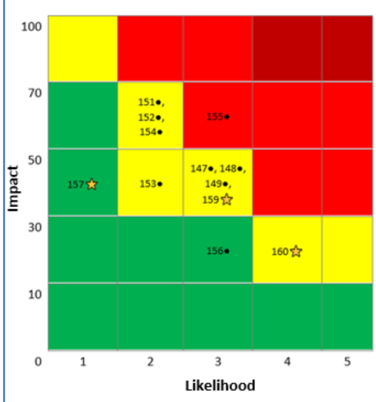
Consequence Scoring

Score	Scale	Human Lives or;	Environment or;	Assets / Profitability or;	Reputation
100	Catastrophe	Multiple fatalities	Permanent wide eco-damage	>7.0m	International coverage
70	Major	Single fatality	Significant damage, costly restoration	2.0m – 7.0m	National coverage
50	Serious	Extensive injuries	Locality damage, habitats affected	500k – 2.0m	Regional coverage
30	Moderate	Moderate injuries	Damage but no lasting or long-term effect	100k – 500k	Local media coverage
10	Minor	Single injury	Slight damage	<100k	Little media coverage

Figure 7-2: Scoring of risks

The tool is primarily intended to be used in an online environment.Figure 7-3a is a heatmap representing the 12 greatest buisiness risks identified as significant regardless of the current risk score (Figure 7-3b).

(a) Heat Map: Current Risk Scores



(b) Assessment of significant risks

Risk ID	Current Risk Score Movement	Subject	Raw Probability	Raw consequence	Raw Risk Score	Current probability	Current Consequence	Current Risk Score	Target Probability	Target Consequence	Target Risk Score
147	●	Regulatory change	4	70	280	3	50	150	3	50	150
148	●	Staff retention and recruitment	4	50	200	3	50	150	2	50	100
149	●	Failure to respond to change within our industries	3	70	210	3	50	150	2	50	100
151	●	Public: Serious injury or death	4	70	280	2	70	140	2	70	140
152	●	Adverse impact of significant disaster event	2	100	200	2	70	140	2	70	140
153	●	Electra's brand reputation	4	50	200	2	50	100	2	30	60
154	●	Erosion of Elctra financial	3	100	300	2	70	140	2	50	100
155	●	Worker: Serious injury/ Death	5	70	350	3	70	210	2	70	140
156	●	ICT Security Threats (cyber, internal & physical)	5	50	250	3	30	90	3	30	90
157	●	Theft/ Fraud	4	50	200	1	50	50	1	50	50
159	●	Mergers and Acquisitions	4	70	280	3	50	150	3	50	150
160	●	Delivering major projects well	5	50	250	4	50	120	4	30	120

Legend: New ☆ No Change ● Down ▼ Up ▲

Figure 7-3: (a) Heat map, and (b) Risk assessment of significant risks identified in October 2019

7.1.2 Risk register

The Group maintains a Risk Register which is reviewed on a quarterly basis by the Senior Leadership Team. Key risks are reported to the Risk and Audit Committee and the Board. Changes to the previously reported state are identified to support increased understanding of changing risk profiles and effectiveness of planned mitigation. Senior management are required to complete

Legal and Statutory Compliance certificates on a quarterly basis and actively support any ongoing compliance surveys such as Comply With.

The Group's Risk Register records identified risks, the methods of control, and the resultant residual risk (exposure to loss remaining after other known risks have been countered, factored in, or eliminated. Electra staff and management regularly complete a comprehensive risk analysis on the network and the supporting management structures. These risk analyses are reviewed by and agreed by the Risk and Audit committee comprised of Electra Directors. From this analysis, Electra identified the critical elements and plans required to manage these risks.

The Electra Group Risk and Controls Environment has been updated to reflect the progress of agreed actions (Figure 7-4).The key changes in movement of residual risk scores were:

- Lines business has greater Work in Progress (WIP) than desired but working on reducing this balance
- Reduced risk score for inventory management due to improved control in new Business Central implementation
- Recognised potential adverse impact of Transpower Transmission Price Methodology on the lines business
- Reduced the risk score for Regulatory Compliance risk to reflect relatively favourable Electricity Pricing Review (EPR) findings intended removal of Low Fixed Charge (LFC) tariff for domestic consumers
- Cyber controls considered effective result in a low risk score across the Electra Group except in Electra Generation where a control system application operates on a relatively vulnerable Windows XP machine
- Of the major projects, the CRM implementation in the lines business remains of greatest risk; significant training and ongoing support is required to ensure company-wide adoption.

Major Project Risks (as defined by the Electra Group Major Projects Policy)

Risk Description	Corporate	Network	Electra Services	Generation	Controls/Treatments	Comments
CRM implementation (Electra Services Limited)	LOW	~~LOW~~ N/A	~~N/A~~ LOW	N/A	Business Case. Project Manager and Steering Committee providing governance.	**Nov 2019**: Complete. 3CX integration will be considered 2020/21
CRM implementation in Lines Business	LOW	MEDIUM	MEDIUM	N/A	Business Case approved and project underway. Project Manager and Steering Committee providing governance. Variation Controls and Monthly report initiated	**Nov 2019**: Training complete. Working towards commissioning end of Oct, while recognising adoption will require sustained focus for 6 months
Microsoft Dynamics 365 (Electra Services Limited)	LOW	N/A	~~MEDIUM~~ LOW	N/A	Establishment of governance group (GM-ESL, CFO, CIO) Vendor led Design Document, Business Case, appointment of Project Manager and compliance to Electra Group Major Projects Policy.	**Nov 2019:** Complete. Post project review scheduled before Xmas.
Navision Upgrade (Head Office for Electra Ltd)	LOW	~~N/A~~ LOW	N/A	N/A	Establishment of governance group (CIO, CFO and GM-Lines) CIO providing project oversight with external project manager. Steering Committee established. Month progress reporting to Steering Committee	**Nov 2019:** Fujitsu completing detailed design during Sept and Oct to establish an agreed scope and a fixed price can be supplied.
New 33 kV Circuit Mangahao to Levin East (ex TP 110 kV line)	N/A	LOW	N/A	N/A		**Nov 2019**: Electra has proposed to HDC that Electra will underground once developer underground their component
Raumati 33 kV cable project	N/A	LOW	N/A	N/A	Project scope and estimates compiled to +/- 20% level and request to Board for delegation to CE for approval as estimates refined with contractor estimates	**Nov 2019:** Need to complete resurface remediation

Risk Assessment	
Not applicable	N/A
Low	LOW
Medium	MEDIUM
High	HIGH

~~ABC~~	Strikethrough denotes change
ABC	(changes since last report in red or crossed out)

Figure 7-4: Major project risks - Electra Group risk assessment and control environment

7.2 Specific risks

7.2.1 Operating safety risks

Operating and maintaining an electrical network involves hazardous situations that cannot entirely be eliminated. Electra is committed to providing a safe reliable network that does not place our staff, community or environment at risk. This has been underpinned with the implementation and incorporation of the Safety Management System (SMS) into the business. The SMS system is independently audited by Telarc and as a result a certificate verifying compliance with the standard has been issued.

Electra's strategies to mitigate risks relating to personal safety are:

- Development and maintenance of safety policies and manuals
- Giving the highest priorities to safety related network improvements
- Design, operate and develop a network in compliance with regulations and accepted industry practice
- Operation of a Safety Management System (SMS): This is a regulatory requirement focusing on public safety and certified to NZS7901 in 2012 and renewed in 2018.

Some of the key aspects of the health and safety policy are to:

- Identify and control hazards by eliminating, isolating or minimising them
- Work with team members in actively identifying, reporting and dealing with any potential hazard to himself or herself or any other person while at work
- Provide and maintain training and information to enable team members to fulfil their own and the Company's personal obligations for health and safety
- Any accident, health and safety incident, near miss or significant safety issue must be reported to the Company using the procedure explained in our health and safety manual
- Following investigation into causes and preventions of any accident, incident, near miss or significant safety issue identified Electra will, where practicable, action the recommendations arising to prevent a recurrence.

7.2.2 Natural disaster risks

Electra's distribution network area is exposed to a range of natural disaster risks. These are described more fully along with Electra's disaster response in the following sections.

7.2.3 Asset failure risk

The greatest probability of failure to any infrastructure utility is at any point where there is a concentration of assets, such as at a zone substation for an electricity distribution network. At zone substations, the highest risk equipment is the indoor 33kV and 11kV switchboards. A failure of these assets tends to be explosive and may cause subsequent damage to adjacent assets. This will increase the extent of any outage and the restoration time.

Assets are more likely to fail towards the end of their useful life. As discussed in Section 5, Electra inspects all its assets on a cyclical basis. Any assets that are of poor condition and are assessed to have a high likelihood of failure either have maintenance tasks performed to extend its asset life or are replaced with a new asset. Replacements are shown as renewals in the network development plan discussed in Section 4.

7.2.4 Network records risks

Electra records asset information electronically. The principal servers are located within Electra's head office. The inherent risk with this is reduced by both cloud and offsite storage of computer backups, including SCADA, and contracts with suppliers to provide temporary support if required.

7.2.5 Regulatory risk

The following regulatory risks are also noted:

- Uncertainty associated with a current government-initiated electricity pricing review
- Uncertainty of how regulators may interact with emerging energy technologies
- Uncertainty of the direction transmission pricing will take, particularly in relation to the impact of emerging technologies.

Electra is proactively collaborating and growing capabilities to adapt to the opportunities and risks presented by the above. By gaining experience in these new technologies and developing new products and services for our customers, Electra is acting rather than waiting for change to be imposed.

7.3 Mitigating network vulnerabilities

Electra manages risk through a combination of measures. These can include both physical and operational measures and will be focused on management and minimization of them.

Specific plans include both physical and operational mitigation measures ranging from replacing assets to insurance and access to financial reserves.

Physical risk management is part of Electra's overall legislative compliance programme. Electra, using the relevant electricity industry and building seismic codes, has a robust network.

Aspect of work	How risks are managed
Data integrity	As-built plans are required for all new extensions Asset data is required for all new extensions and all replacement or maintenance programmes
Easements	All new assets on private property are suitably protected by registered easements
Control of work	All work on the electricity assets – regardless of voltage – must be co-ordinated through the Control Centre Work must comply, as a minimum, with the Electricity Industry Safety Rules
Strength of works	As a minimum, all new extensions and all replacement or maintenance work must comply with relevant Electrical Codes of Practice and Electra's Network Construction standards

The following table summarises asset specific risk mitigation and management features of the network assets.

Activity	How risks are managed
Transformers and switchgear	Oil containment where located outside All zone transformers have individual oil containment with 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 VESDA sniffer systems for fire containment are installed at each zone substation's switchgear building All zone transformers and switchboards have annual diagnostic testing to locate potential faults before they occur

Activity	How risks are managed
Buildings and zone substations	All major projects, such as a new zone substation, are specifically designed for their location – electrically and structurally All buildings are built to the relevant building code Electra has seismically engineered bracing on all power transformers at zone substations, with seismic bracing for switchgear and other components as required Electra replaced all zone substation access locks with a tiered key system in 2002, distribution transformers completed in 2003 and all other 11kV equipment in 2004. Access keys are only provided to employees and contractors on a "need to have" basis – the need determined by Electra and not the contractor Electra completed security fences at the remaining zone substations in 2004 Electra undertakes bi-monthly visual inspections of all zone substations. Any necessary repairs are scheduled immediately
Network design	As a minimum, Electra uses the Electricity Act and associated Regulations as the basis for construction and maintenance of the network Electra, through the design process, ensures that, as the network develops, further interconnection is provided at 11kV.
Reticulation	Electra requires pole strength calculations for all new pole transformers and overhead extensions Underground cables are specified to withstand through short-circuit faults along with capacity requirements The annual network inspections identify any deterioration affecting physical strength, and safety clearances to ensure public safety
Network operation	Electra generally operates the 33kV network in two meshed networks to provide a high level of support for the zone substations Foxton, Otaki and Paekakariki are not on the closed 33kV rings; these substations are backed up by the 33kV and 11kV network through automatic changeover schemes Although the 11kV network is operated in a radial manner, all backbone feeders are interconnected with other feeders from the same zone substation and adjacent zone substations
Spares	Electra holds modern equivalent spares for all electrical assets on the network at their Paraparaumu and Levin depots Individual zone substations have site-specific spares stored at each site as appropriate

Electra also uses insurance as the basis for financial risk management, covering professional and director's indemnity, public liability, buildings and plant, loss of profit and vehicles. Except for zone substations, it is not possible for Electra to insure the electricity network for catastrophic damage. Electra requires insurance of its contractors to cover contract works, all project assets, public liability and liquidated damages.

7.4 Resilience framework

As per our asset management strategies, Electra has put in place a resilience framework to manage and mitigate events beyond normal circumstances and under emergency situations. The framework covers High Impact Low Probability Events, Climate Change, Emergency Response and contingency planning and Resilience Planning for Risk Preparedness.

7.4.1 High Impact Low Probability (HILP) Events

HILP Events are events that have a higher impact than that is allowed in normal system planning criteria. These include extended contingency events (greater than n-1) and domino-effect or cascading events causing the system to fail.

It is difficult to predict these events because there are multiple failure modes and some New Zealand examples of HILP events include:

- Sep 2010: Christchurch earthquake where electricity to 75% of the city was cut
- Oct 2014: Penrose cable trench fire causing blackouts to 85,000 Auckland customers.

HILP events can cause prolonged periods without power supply and customers have a low tolerance for prolonged outages. Our customers, the community and other lifelines utilities depend on electricity every day - during and after HILP events. To meet our responsibilities, we have set up an HILP and crisis risk management team. The Civil Defence Emergency Management Act 2002 (CDEM) also requires us to function to the fullest possible extent during and after these HILP events.

7.4.2 Climate change

Climate change is expected to cause a rise in sea levels and changing weather patterns may lead to more severe and frequent storms than previously experienced in New Zealand. Average temperatures, wind and rainfall may be impacted, and these changing weather effects may potentially affect assets and network operations. Continual improvement and efforts will be undertaken to monitor these changes to manage network reliability and improve network resilience.

7.4.3 Emergency response and contingency planning

The following strategies are applied to mitigate the impact of potential HILP events:

- **Identification**: understand the type and impact of the events the network could potentially experience
- **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 the use of contingency plans to invoke a staged and controlled restoration of the network.

7.4.4 Emergency response plans

Electra regularly responds to emergencies. Generally, these are outages on the network and are used as the basis for planning and training for large-scale emergencies. All emergency response is based at Electra’s Control Centre (supported by a UPS) through the toll-free fault service 0800 LOST POWER, web outage page and phone app.

7.4.4.1 General network faults

Electra Distribution Operation’s staff are available 24/7 in case of outages – with various levels of response to different fault types and widespread events such as storms. Electra’s Network staff are also available to provide assistance for contract and network operational issues.

Most faults are restored in less than three hours. As a guide, equipment failure, and the associated response can be summarised as follows:

Level of response	Means of response	Work required
Immediate (30 minutes to 3 hours)	SCADA or field switching Field repairs	No major work required (e.g. clearing tree branch off a line) Time depends on cause, available personnel, and extent of switching
Medium (3 hours to 12 hours)	SCADA or field switching (most consumers are restored by switching) Field repairs	Equipment damaged (e.g. pole hit by car, transformer needs changing, overhead line needs repairs or replacing) Time depends on cause, available personnel, and extent of switching
Long (12 hours to 48 hours)	SCADA or field switching (most consumers restored by switching) Field repairs	Major equipment damaged e.g. loss of a zone substation, replacing part or all of a damaged 33kV bus Time depends on cause, available personnel, and spares

7.4.4.2 Restoration of key component failures

Electra has considered the following network failure scenarios in order to assess its ability to promptly restore (n) security of supply:

- Busbar faults at each zone substation
- Loss of each sub-transmission circuit
- Loss of each zone substation transformer
- Loss of each communication hub
- Inability to access the Electra Head Office and associated systems.

The likely outcomes of each scenario have been considered, along with the tasks required to restore (n) security of supply and the resources required for each task. The list of major strategic spares including storage location is included in Section 5.10.

7.4.4.3 Reinstating the network after a disaster or HILP event

Electra has developed a Major Network Event Guideline which outlines the broad tasks that Electra would need to undertake in HILP events of Section 7.4.1, to restore electricity supply to (n) security under the following publicly credible disaster scenarios:

- An earthquake of Richter magnitude 7.5 or greater on a major Wellington fault
- Volcanic activity at Ruapehu resulting in ash coverage of about 10mm throughout the Northern part of Electra's area
- A one in 100-year flood of the Otaki, Waikanae or Manawatu rivers, or
- A tsunami impacting on the West Coast that could inundate up to 2-km inland.

Preparation of the guideline has revealed that Electra has already put many recovery initiatives in place and has coordinated its likely responses with other agencies in both the Kapiti and Horowhenua districts.

7.4.4.4 Continuity of key business processes

Electra has used an external advisor to identify its key business processes and assess the vulnerability of those processes to a range of natural disasters, man-made events and deliberate interference. Mission critical processes are:

- Invoicing retailers for use of the network
- Receipting payments from retailers
- Maintaining sufficient business records of invoicing and receipting activities to compile compliant accounts and regulatory disclosures.

The key risks identified to these processes are:

- Unauthorised access to data
- Accidental fire or arson at Electra's offices or adjoining premises
- An earthquake of Richter magnitude 7.5.

Mitigating actions taken include:

- Maintaining a backup Control Centre off-site from the head office that contains all the necessary software and templates to perform critical tasks discussed above
- Review of the physical security of the principal server in regard to unauthorised physical interference, fire damage or earthquake damage
- Regular review of Electra's level of cyber security maturity and level of preparedness.

7.4.5 Resilience planning for risk preparedness

The procedures that relate to our network resilience cover the following:

No.	Documents	Description
1	Asset Management Policy and Strategies	Our asset management policy underpins out asset management plan, strategies and imperatives contained in our Asset Management Plan. Ensuring sustainability, network reliability as well as resilience is an important objective and this theme is being repeated throughout this AMP
2	Asset Risk Management Plan	Our asset risk plan for major incidents and/or emergencies which include risk treatment, prioritisation of risks, main contingency measures and location of emergency spares
3	Participant Rolling Outage Plan	This plan was written to comply with Part 9 Security of Supply of the Electricity Industry Participant Code 2010. The procedures outlined are in response to major generation shortages and/or significant transmission constraints. Typical scenarios include unusually low inflows into hydro-generation facilities, loss of multiple thermal generating stations or multiple transmission failures. The main energy saving measure deployed in response to such a scenario is the use of rolling outages. Our plan identifies how we will shed load when requested by Transpower (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
4	SMS Major Network Event (SMS Standard 47664), Escalation of a Major Risk Event (SMS Standard 57552)	The Major Network Event standard provides guidance around what needs to occur in the lead up to an event, at announcement of an event and during the event. It assists the team to ensure that they are aware of their responsibilities during such circumstances. The Escalation guidelines document is to assist the Electra Control Centre to identify when to escalate Electra's response to outages
5	Environmental Risks Policy and Plan	Environmental risks including sustainability requirements are included in the Electra Group's Environmental and Sustainability Policies, and our plans and activities are guided by these policies in environmental-related work

No.	Documents	Description
6	Business Unit Continuity Plans	Identifies the responsibilities of key roles and designations to ensure business continuity
7	Contingency Plans	Contingency plans are included in our standard documents concerning minimum critical spares; a double contingency risk analysis of Electra's Sub transmission Network has been carried out to evaluate the likelihood of a second contingency occurring while an existing event is occurring
8	Risk and Hazard Management (Standard 57517)	This plan details processes that are required and the actions undertaken in the identification, assessment, review and management of the risks that the Company is exposed
9	Minimum Critical Spares	This Safety Operating Procedure provides guidelines for the management of minimum critical spares necessary to ensure unplanned outages can be repaired in a timely manner; main strategic spares are listed in Section 5.10.

Figure 7-5: Key network resilience procedures

Line Mechanics competition, September 2019: Pole-top rescue underway

8 Performance evaluation

8.1 Works delivery performance

This section outlines Electra's progress against budgeted targets for the year ending 31 March 2019.

8.1.1 Maintenance plan

The following table presents a summary of actual spend against budgeted spend as well as the reasons for the variances of the key operational maintenance categories:

Category	FY2019 Budget ($'000)	FY2019 Actual ($'000)	Variance ($000)	Variance (%)	Reasons for variances
Fault and emergency maintenance	1,858	1,666	-192	-10%	This underspend is predominantly due to improved network reliability and lesser storm events
Vegetation management	1,358	1,852	+494	+36%	An additional analytical tool, over and above the requirements of the Electricity (Hazards from Trees) Regulations, to systematically identify the greatest risk to customer service and safety from trees close to network. This has led to a higher than budgeted spend to improve customer experience
Routine and corrective maintenance	1,121	1,053	-68	-6%	No material variation
Replacement and renewal maintenance	341	471	+130	+38%	Due to additional remedial work identified following additional condition monitoring inspections
System operations	3,111	2,599	-512	-16%	Less business support costs being attributed to the distribution business
Business support	4,625	4,509	-116	-3%	No material variation
Total	**12,414**	**12,150**	-264	-2%	No material variation

Overall, our operational expenditure was $264K under forecast or 2% below the forecast and the variances within the main categories are depicted in Figure 8-1a.

Electra applies a materiality threshold of $100K to identify material projects.

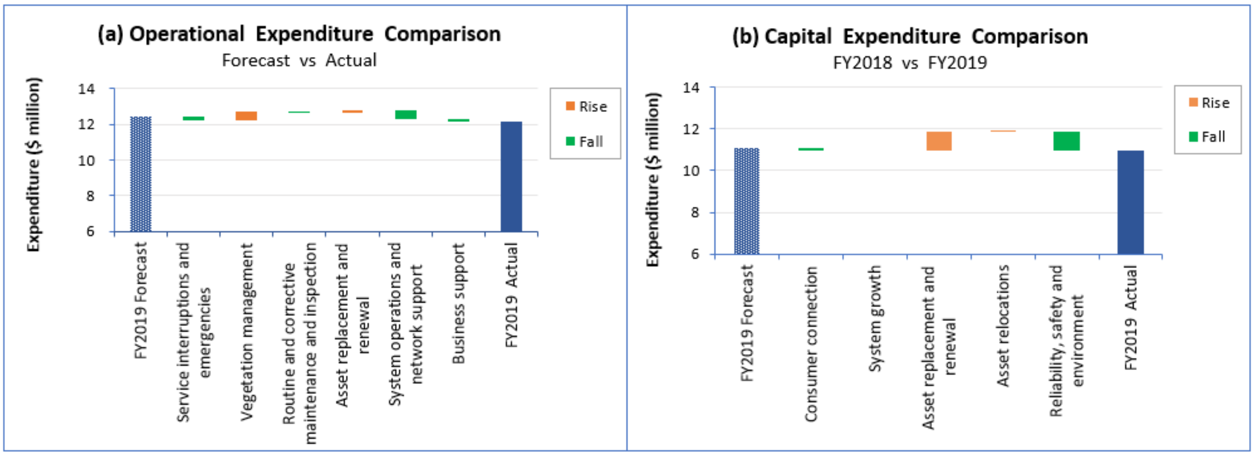


Figure 8-1: Variations between forecast and actual expenditures for: (a) Operational expenditure (OPEX), and (b) Capital expenditure (CAPEX)

8.1.2 Development plan

Overall expenditure on assets was $138k below forecast. The following table summarises the actual against budgeted spend for the key development categories as well as the main reasons for the variances.

Category	FY2019 Budget ($'000)	FY2019 Actual ($'000)	Variance ($000)	Variance (%)	Reasons for variances
Consumer connection	95	0	-95	-100%	Budgeted on a net basis for vested assets. Electra spent $0 on vested assets
System growth	0	0	0	0%	No system growth projects were planned
Asset replacement and renewal	7,589	8,468	+879	+12%	Overspend on 11kV reconductoring projects (Waitohu Valley link/upgrade and Convent Road) and additional switchgear replacements and pillars added to the work programme after the forecast was set
Reliability, safety and environment	3,398	2,457	-941	-28%	Under-forecast predominantly due to delay in obtaining specialist reports (external resource constraint) for sub transmission protection jobs and seismic assessment studies for substation buildings
Asset relocation	0	19	+19	0%	No planned relocations at time of forecasting. Actual costs incurred were for the relocation of duct and cable originally installed through stormwater drain
Total (ii)	**11,082**	**10,944**	**-138**	**-1%**	

Figure 8-1b shows the forecast, actual spend as well as variances for main categories.

8.2 Network reliability performance

8.2.1 Customer service performance (reliability)

Electra's actual performance against target performance for the FY2019 year for the key customer service attributes is shown in the following table and discussed in Section 3.1.

Attribute	Measure	FY2019 target	FY2019 actual	Comment
Network reliability: planned outages	SAIDI B	15	32.32	Non-compliant due to increased planned and renewal projects to improve network resilience identified in Section 4.7
	SAIFI B	0.06	0.10	
	CAIDI B	250	323	
Network reliability: unplanned outages	SAIDI C	68	57	Compliant
	SAIFI C	1.6	1.17	Compliant
	CAIDI C	42.5	48.7	Non-compliant attributed to several vehicle accidents and transformer faults (further analysis in Section 5.5)
Public safety	Electricity (Safety) Regulations 2011	Compliant	Compliant	Continued compliance to NZS 7901

Electra's performance for planned and unplanned outages is shown in Figure 8-2 for SAIDI and Figure 8-3 for CAIDI. The data is averaged for a two-year period (FY2018 to FY2019) and Electra is ranked fifth for SAIDI (planned and unplanned) and ranked second best amongst the 29 EDBs for CAIDI.

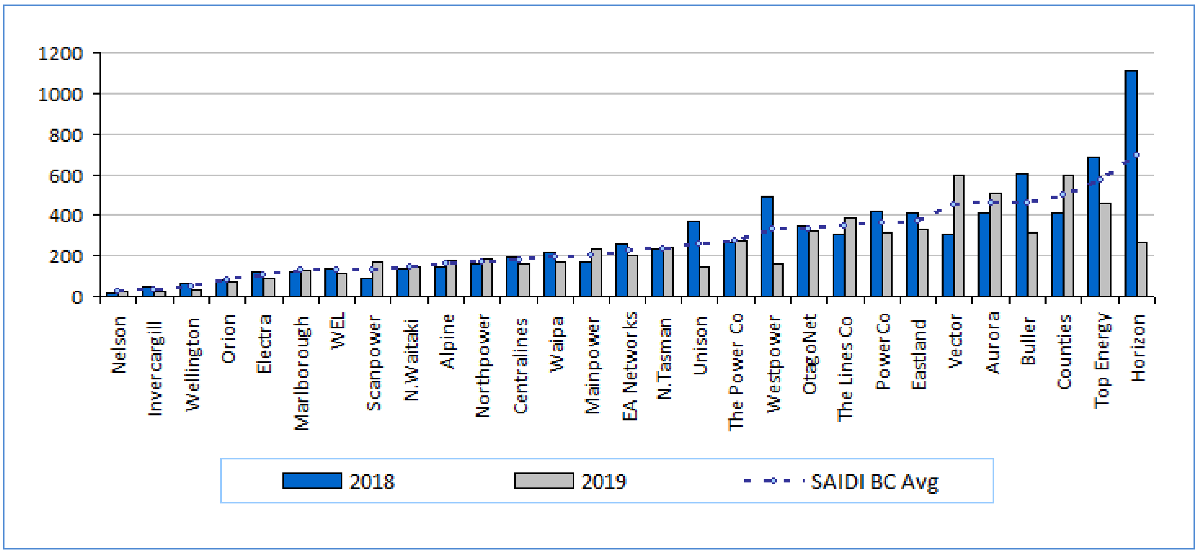


Figure 8-2: FY2018 to FY2019 SAIDI for planned B and unplanned C outages for electricity line businesses

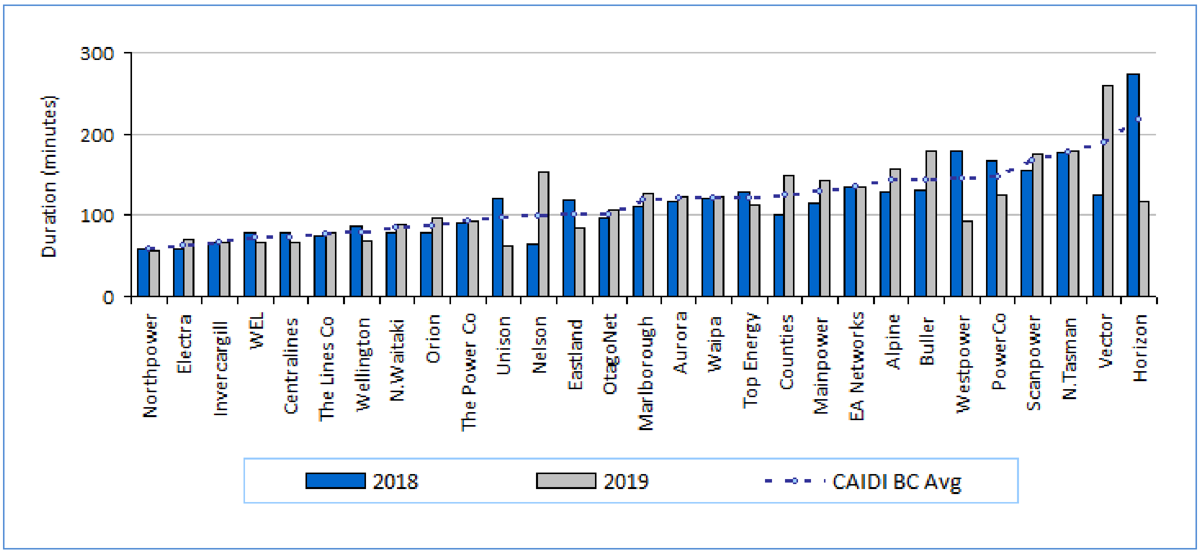


Figure 8-3: FY2018 to FY2019 CAIDI for planned B and unplanned C outages for electricity line businesses

8.2.2 Causes of faults

A cause analysis into our network reliability performance is depicted in Figure 8-4. The highest causes of faults impacting SAIDI in FY2019 (Figure 8-4a) is foreign interference (34%) followed by defective equipment (23%), wildlife (17%) and vegetation (12%). A further investigation based on the number of faults (Figure 8-4b) gave the highest fault contributor as defective equipment (34%), foreign interference (12%), wildlife (11%) and vegetation (9%). Other than unknown faults, other causes of faults include adverse weather/environmental factors and human error.

Besides faults on DDOs or drop-out fuses (21%), most defective equipment are attributed to transformers (19%), conductors (17%) and poles/crossarms (9%) where renewal programs and maintenance activities are undertaken to address and resolve such faults. Faults caused by trees or vegetation have been discussed in Section 5.11.

Fourteen out of a total of 25 faults caused by foreign interference are due to vehicle accidents, seven by contractors/others, two by vandals and another two due to fire.

The SAIDI impact and the number of HV faults between FY2015 to FY2019 are also shown in Figure 8-4. Although the number of faults has been increasing from FY2016 to FY2019, SAIDI has decreased from 95 minutes (FY2018) to 57 minutes (FY2019).

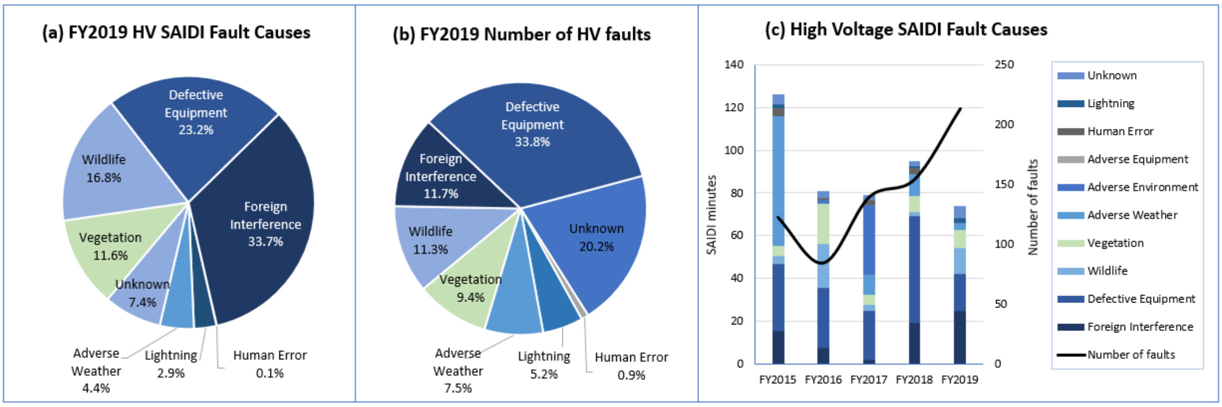


Figure 8-4: (a) FY2019 causes of HV faults, and (b) Comparison of HV faults from FY2015-FY2019

8.2.3 Restoration of faults

The information disclosure includes the performance indicator for faults restoration within a period of three hours. Figure 8-5b compares the performance of Electra against other EDBs from FY2018-FY2019 where our average performance of 54% is higher than the industry's median of 50%. Our performance between FY2015 to FY2019 is shown in Figure 8-5b where our performance peaked in FY2019 when we have restored 85% of faults within three hours.

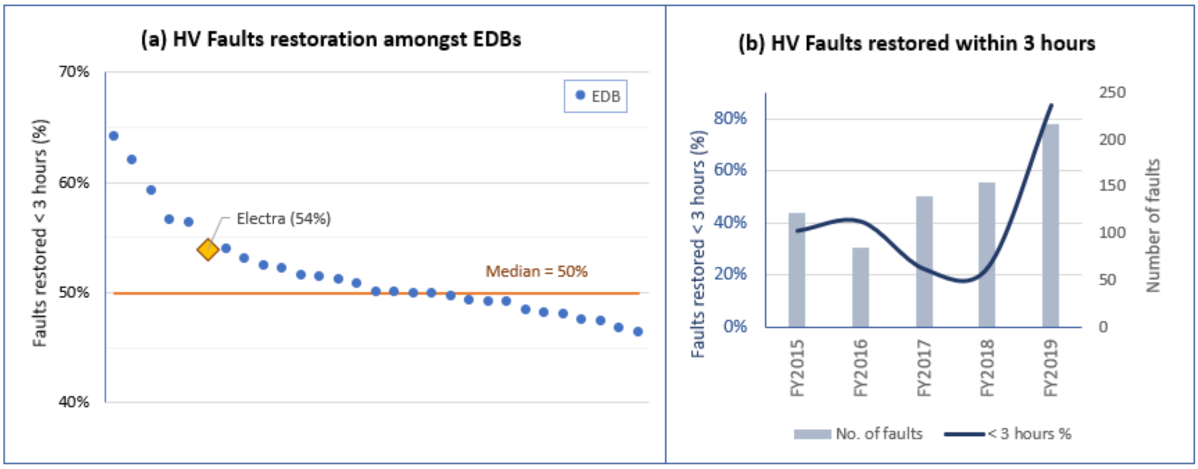


Figure 8-5: Faults restored within 3 hours: (a) EDB benchmarking from FY2018-FY2019, and (b) Electra FY2015-FY2019

8.2.4 Live-Line Works and Temporary Generation

To avoid outages and inconvenience to customers, Electra carries out live-line operations annually on the 11kV and 33kV networks based on risk assessment. Live-line work practices are stringently carried out according to safety operating procedures where the risks are first assessed including safety in design analysis, consideration of the ease of maintenance, operations and accessibility of the assets. These procedures are carried out in compliance with the New Zealand Code of Practice for High Voltage Live Line Work NZECP 46:2003 covering work practices, communications and safety equipment such as live-line gloves, insulating barriers and hot sticks.

Other SAIDI mitigation and customer-focus activities include the provision of temporary generation during planned outages. Planned schedules for outages estimated at least 50 SAIDI minutes saved since May 2019 covering 28 outages. The use of a generator is evaluated using a SAIDI-Generator Cost Impact calculator.

8.3 Asset performance

Electra's actual performance against target performance for the FY2019 year for the key asset and regulatory measures are as follows:

Attribute	Measure	FY2019 target	FY2019 actual	Comment
Industry performance	Electricity Distribution Information Disclosure Determination 2012 and subsequent amendments	Compliant	Compliant except in minor Risk preparedness[16] sectors	AMP assessed as generally compliant as per Appendix 1: Reconciliation of Asset Management Plan to Electricity Distribution Information Disclosure Determination 2012
Energy delivery efficiency	Load factor (units entering network/maximum demand * hours in year)	54%	50%	
	Loss ratio (units lost / units entering network)	6.6%	6.9%	Non-technical loss identification programme underway to address the issue
	Capacity utilisation (maximum demand/installed transformer capacity)	34%	30%	
Financial efficiency	Capital expenditure on assets (CAPEX) per: total circuit length (km) connection point	 $5,148 $268	 $5,065 $271	CAPEX/km has reduced by to $5,065 while CAPEX/ICP has increased slightly (1%) to $268
	Operational expenditure (OPEX) per: total circuit length (km) connection point	$5,306 $272	$5,308 $271	OPEX was kept constant with OPEX/km at $5,308 (1% increase) and OPEX/ICP at $271 decreased by 0.4%. Electra is committed to arrest increasing costs

8.3.1 Load factor

Figure 8-6 illustrates the historical trends for our load factor, derived from the energy (GWh) entering our network and maximum demand (MW). Our load factor in FY2019 is 50% - the low load factor is attributed to a historical legacy to over-design for system growth. The load factor is expected to rise in the coming years aligned with the forecasted increase of 1.6% and 0.8% of our consumption levels and maximum demand respectively.

[16] Commerce Commission (2019). AMP Review of EDB Risk Preparedness

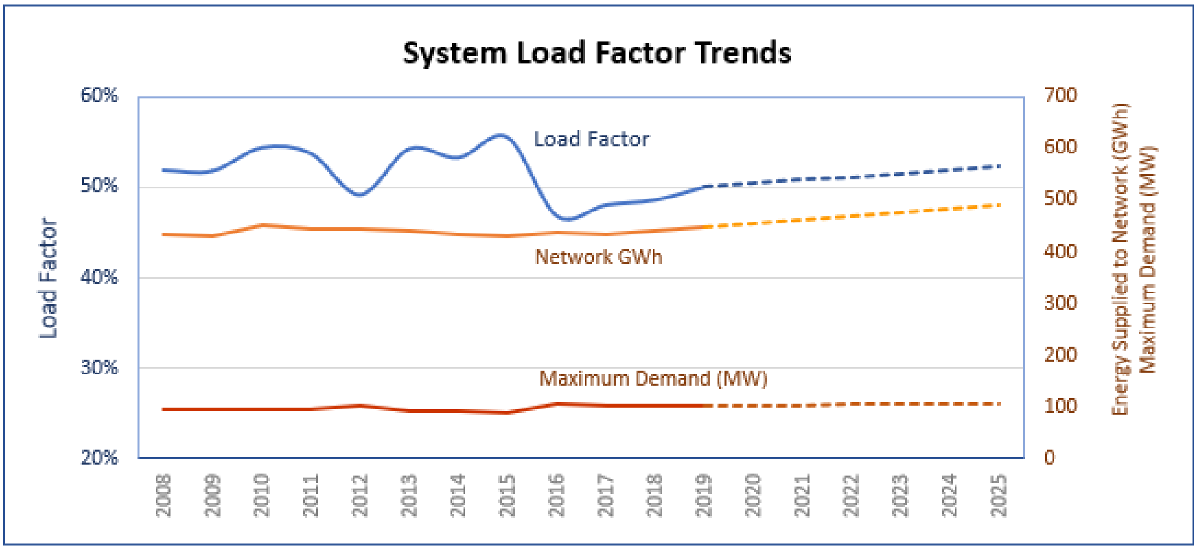


Figure 8-6: System load factor historical trends and forecast

8.3.2 Capacity utilisation

Figure 8-7 shows the industry's distribution transformer capacity utilisation against network load density. Electra sits well above the line of best fit at 30% utilisation, we use this relationship to set our utilisation target above 30%.

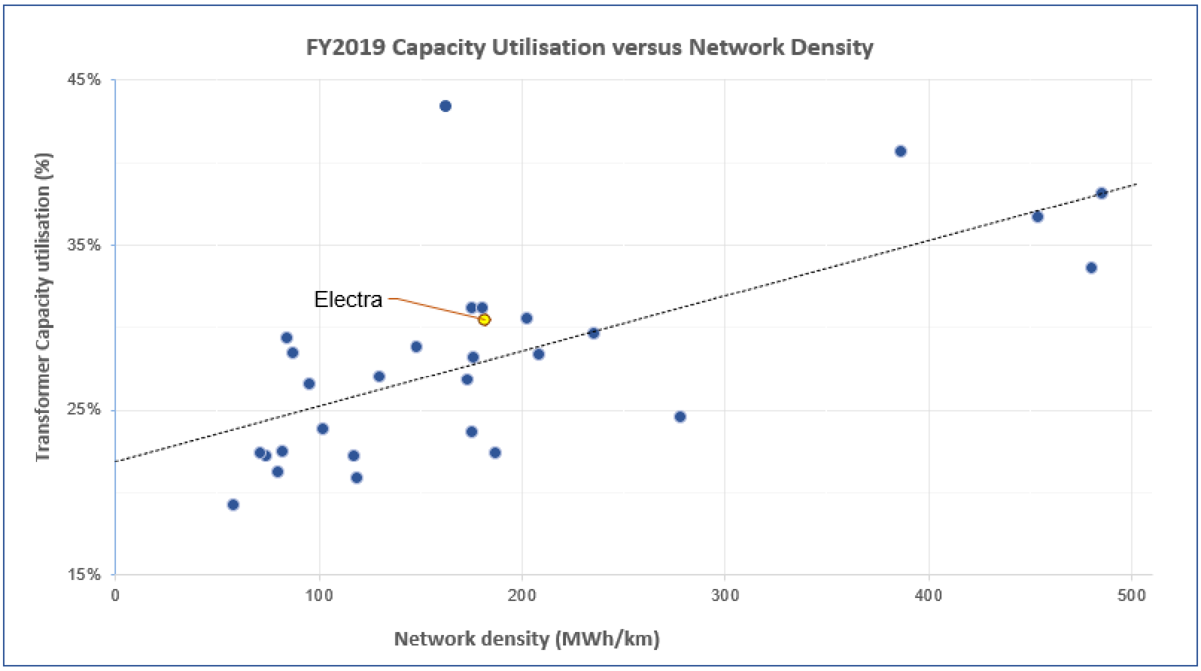


Figure 8-7: FY2019 transformer capacity utilisation versus network density

8.3.3 Loss ratio

We use the loss ratio for the purposes of information disclosure which is calculated based on electricity losses divided by the electricity (GWh) entering the system for supply to our customers. Figure 8-8 shows the historical trends for our losses and system GWh from FY2008 to FY2019 as well as our forecasts until FY2025. With the rise in the energy (GWh) supplied, our losses will increase slightly by less than 1%.

Due to limitations of the previous billing system, Electra moved in FY2019 to a new AXOS billing system which is able to provide added data validations to improve billing accuracy. An initiative is also underway to identify the composition of these losses and the project is expected to complete prior to FY2021.

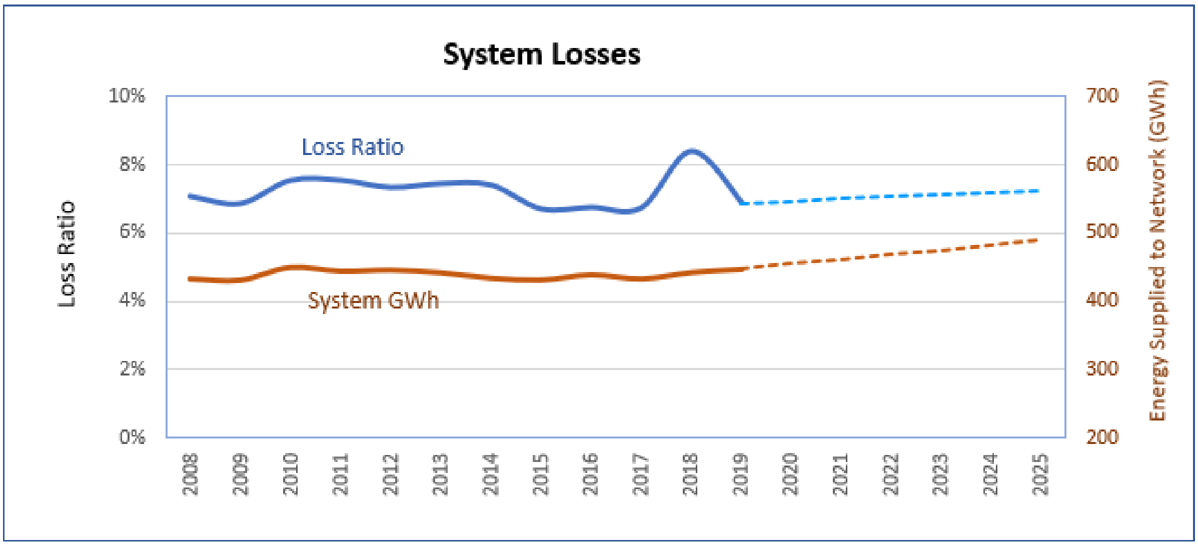


Figure 8-8: System losses historical trends and forecasts

8.3.4 Financial effectiveness

To examine our OPEX and CAPEX, Electra is compared with its peer group[17] of eight networks based on network characteristics, network density and customer size; these networks include Alpine, Aurora, Counties Power, Horizon, Network Tasman, The Lines Co and Top Energy.

Within the peer group, our financial performance was:

- OPEX/ICP at $272 is the second lowest and in the first quartile compared with the industry average of $408 and the peer median of $426 (Figure 8-9)
- Asset CAPEX/ICP at $259 is the second lowest and in the first quartile compared with the industry average of $501 and the peer median at $564 (Figure 8-9)
- Asset CAPEX/km at $5,065 is in the second quartile below the peer median of $5,082 and industry average of $5,308 (Figure 8-10a)
- Line charge revenue/ICP (Figure 8-10b), at $981 is also the second lowest, within the first quartile compared with the peer median and industry average of $1,256 and $1,409 respectively.

[17] 2019 data is extracted from Information Disclosure schedules from the relevant EDB's website.

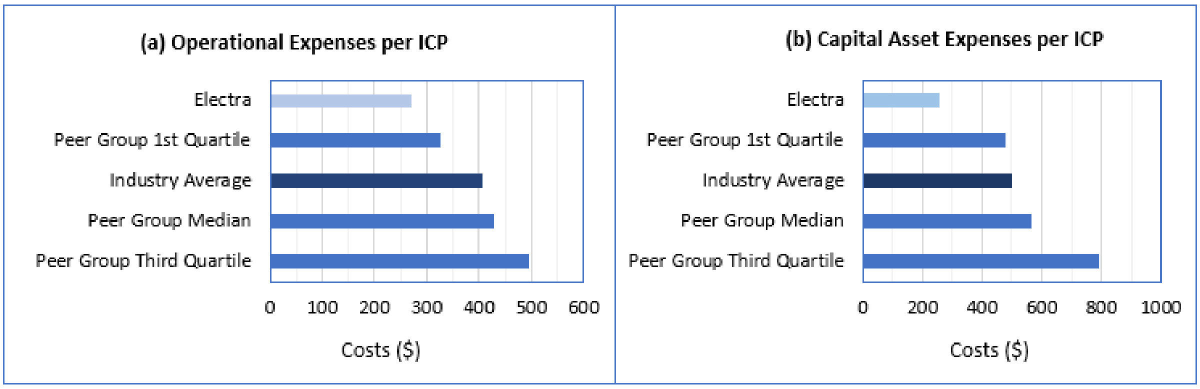


Figure 8-9: Peer group FY2019 OPEX and asset CAPEX per ICP

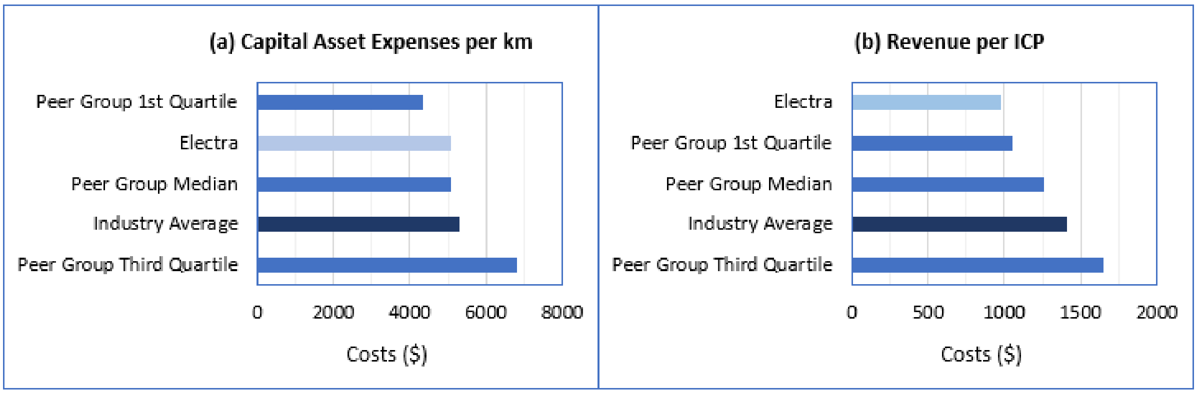


Figure 8-10: Peer group FY2019: (a) Asset expenditure per km, and (b) Line charge revenue per ICP

To study the operational expenses further, the OPEX per km of total circuit length is compared to reliability indicator SAIDI (unplanned) as shown in Figure 8-11 and compared with similar electricity distribution businesses (EDBs) in New Zealand. The input parameters are extracted from the 2019 Information Disclosures for the relevant EDBs. Electra is within a group of eight EDBs who's average OPEX/km is over the industry average of $3,970 but below the unplanned SAIDI average of 142 minutes.

Figure 8-12 compares the FY2019 OPEX per ICP versus unplanned SAIDI for all EDBs. Electra is one of nine EDBs whose OPEX/ICP and unplanned SAIDI are below the industry averages of $408 and 142 minutes respectively. Our OPEX/ICP at $271 is 34% below the industry average while unplanned SAIDI (57 minutes) is 60% below the said SAIDI average.

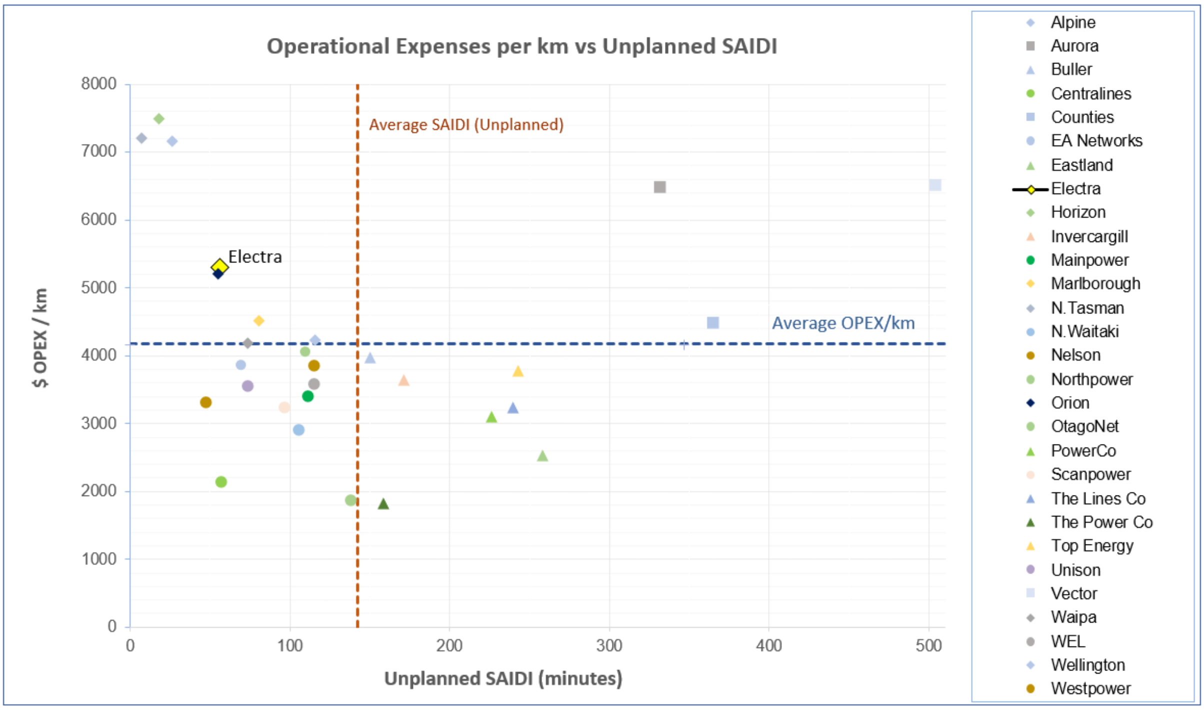


Figure 8-11: Operational expenses per circuit length (km) versus unplanned SAIDI for FY2019

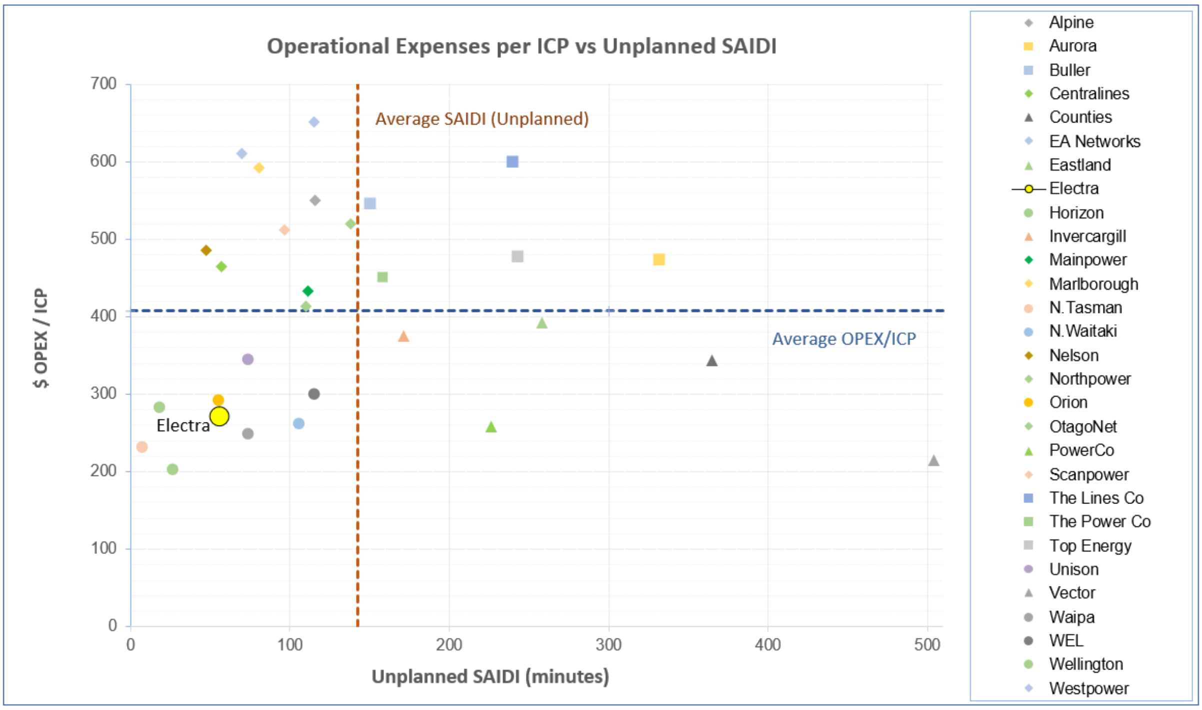


Figure 8-12: Operational expenses per ICP versus unplanned SAIDI for FY2019

8.3.4.1 System operations, network and business support expenditure

From FY2018 to FY2019, system operations and network support (SONS) costs increased by 11% while there was only a 2% increase in business support costs. In comparison with our peers in FY2019, we are below the SONS median by 15% and well below (53%) the industry average as shown in Figure 8-13a. For business support costs (Figure 8-13b), these are also below the peer group median and industry average by 17% and 42% respectively.

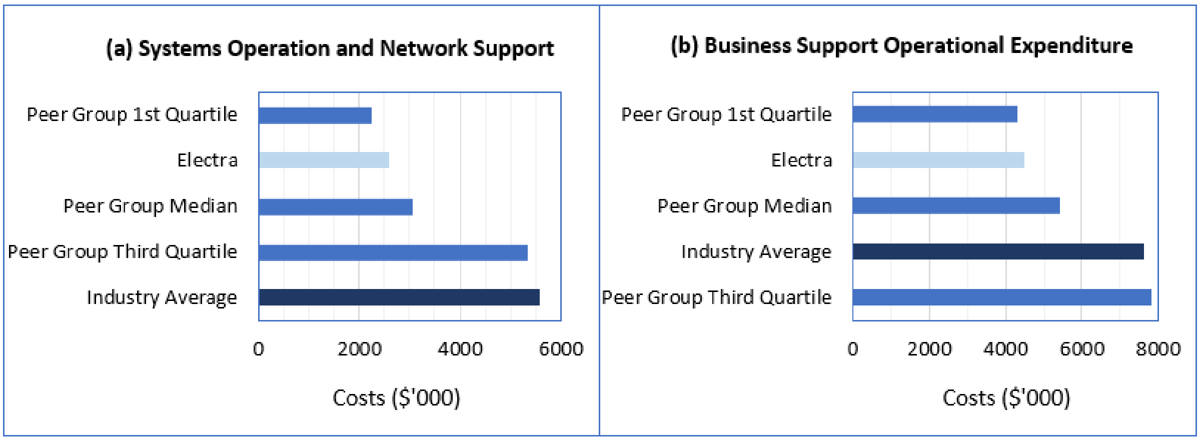


Figure 8-13: Peer group FY2019: (a) System operations and network support, and (b) Business support operating expenditure

8.3.4.2 Vegetation management performance

Our vegetation management operational expenditure increased from $1.64M (FY2018) to $1.85M in FY2019 with the addition of a second tree-trimming team as we moved from a responsive based approach to a risk-based/proactive approach to systematically reduce tree-related faults (Section 5.11).

Figure 8-14 portrays the industry's vegetation management operational expenditure per km-circuit requiring vegetation clearing versus SAIDI caused by vegetation faults for FY2019. Our expenditure of $1,215 per km is 12% below the industry average of $1,385 and the expenditure on vegetation management has reduced the SAIDI due to vegetation faults to only 4.05 minutes (from 7.85 minutes previously). The SAIDI value is also 88% below the industry average of 34.95 minutes.

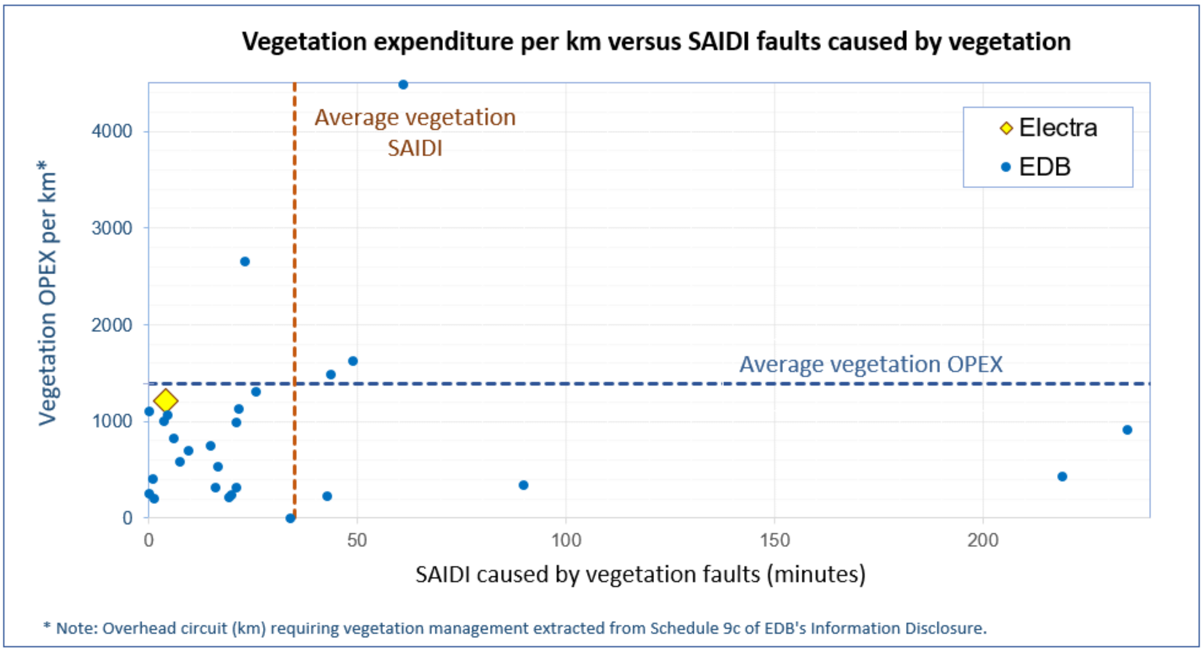


Figure 8-14: FY2019 vegetation management expenditure per km versus SAIDI caused by vegetation faults for EDBs

8.4 Asset management practice performance and improvement processes

The Report on Asset Management Maturity or Schedule 13 is included in Appendix 8 based on the Asset Management Maturity Assessment Tool (AMMAT), which was developed by the Commerce Commission to assess to develop the maturity if EDB asset management. The Electra AMMAT conducted in FY2019 and FY2020 are portrayed in Figure 8-15.

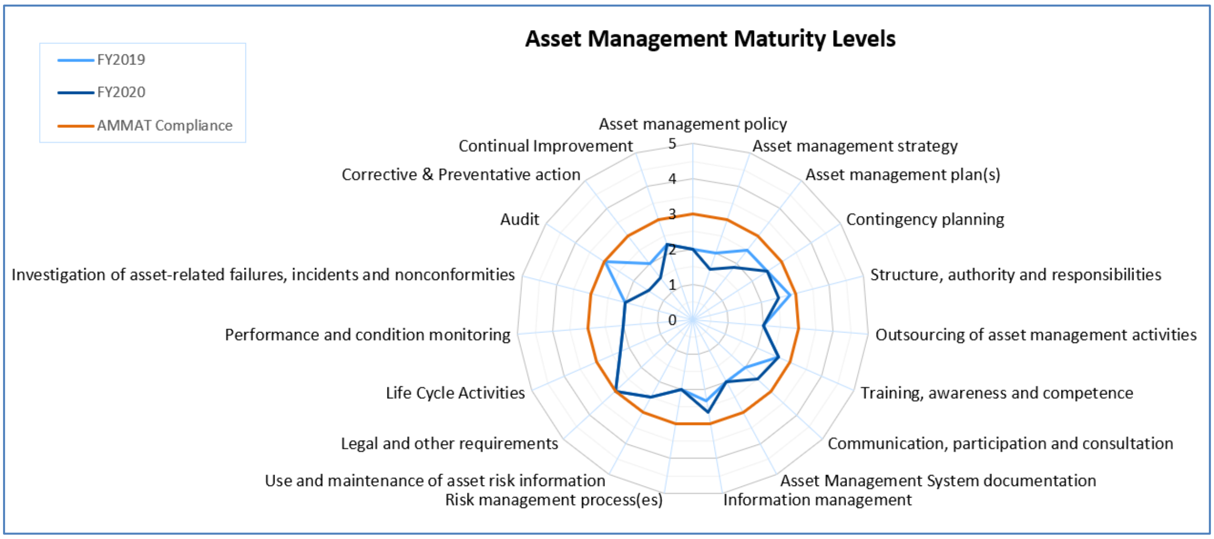


Figure 8-15: Electra's AMMAT scores for FY2019-FY2020

Significant aspects of the AMMAT Electra wishes to improve during the FY2021 year are:

Practice cluster	Proposed improvements
Asset management policy	Consider the revision of an updated AM policy to align with key asset management needs
Asset management strategy	Consider expanding a revised and approved AM Policy into specific asset management strategies for the core business that bridges the gap between the AM Policy and the AMP
Asset management plan	Continue to refine the lifecycle approach taken in Section 5 of the March 2020 AMP Formalise the communication of the AMP and its key themes not just at management level, but to all service delivery staff
Training, awareness and competence	Build on the concepts and models being developed to improve the long-term work force plans, particularly for service delivery staff
Communication, participation and consultation	Develop a strategy that ensures all critical asset management decisions are appropriately communicated to all key service delivery staff
AM system documentation	Improve the quality of AM information by developing a strategy that starts with identification of what information is needed for key AM activities and decisions

8.4.1 Asset risk management model

Electra currently uses asset condition (or asset health indicators) as the basis for most of its asset renewal and replacement decisions and is currently using an asset risk management model (ARMM) to better predict the health of its network assets covering sub-transmission and distribution lines, cables and poles as well as zone substation transformers and switchgear.

We are currently developing the tool for other assets such as pillars, transformers and switchgear. Asset criticality is one of the strategic themes that we have adopted within our condition-based risk management process.

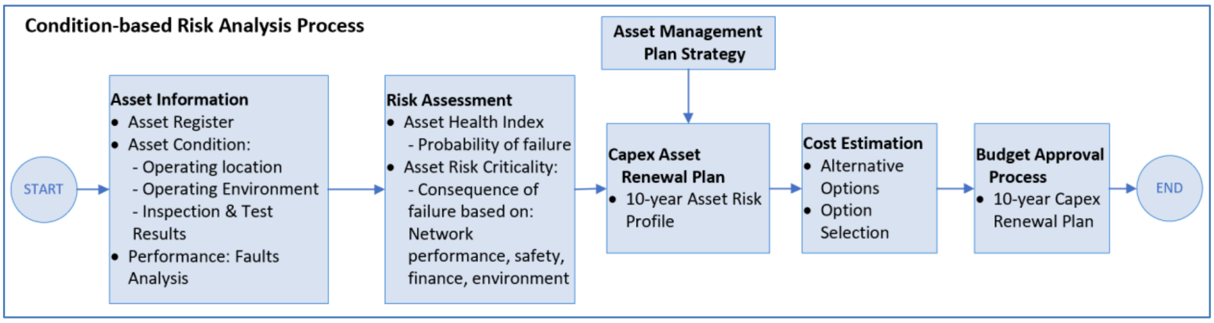


Figure 8-16: Asset risk management model

The criticality of an asset is a measure of its consequence of failure (CoF) based on network performance, safety, financial and environmental factors when compared with the average CoF for its asset type. The risk of failure for individual assets is based on the probability of failure (PoF) multiplied by the CoF. When an asset fails, there is an associated impact resulting from the failure.

The objective of this workstream is to have all network investment decisions driven by the asset health and criticality framework depicted in Figure 8-16.

8.4.2 Advanced distribution management system

The on-going adoption of the Milsoft Advanced Distribution Management System (ADMS) has provided Electra with leading grid management capabilities to improve outage response, optimise grid operations and better track the resolution of customer enquiries.

Figure 8-17 shows the as-built update process improvement where reticulation plans are keyed into the ADMS prior to the commencement of project works including a ten-day requirement for the submission of as-builts after project completion.

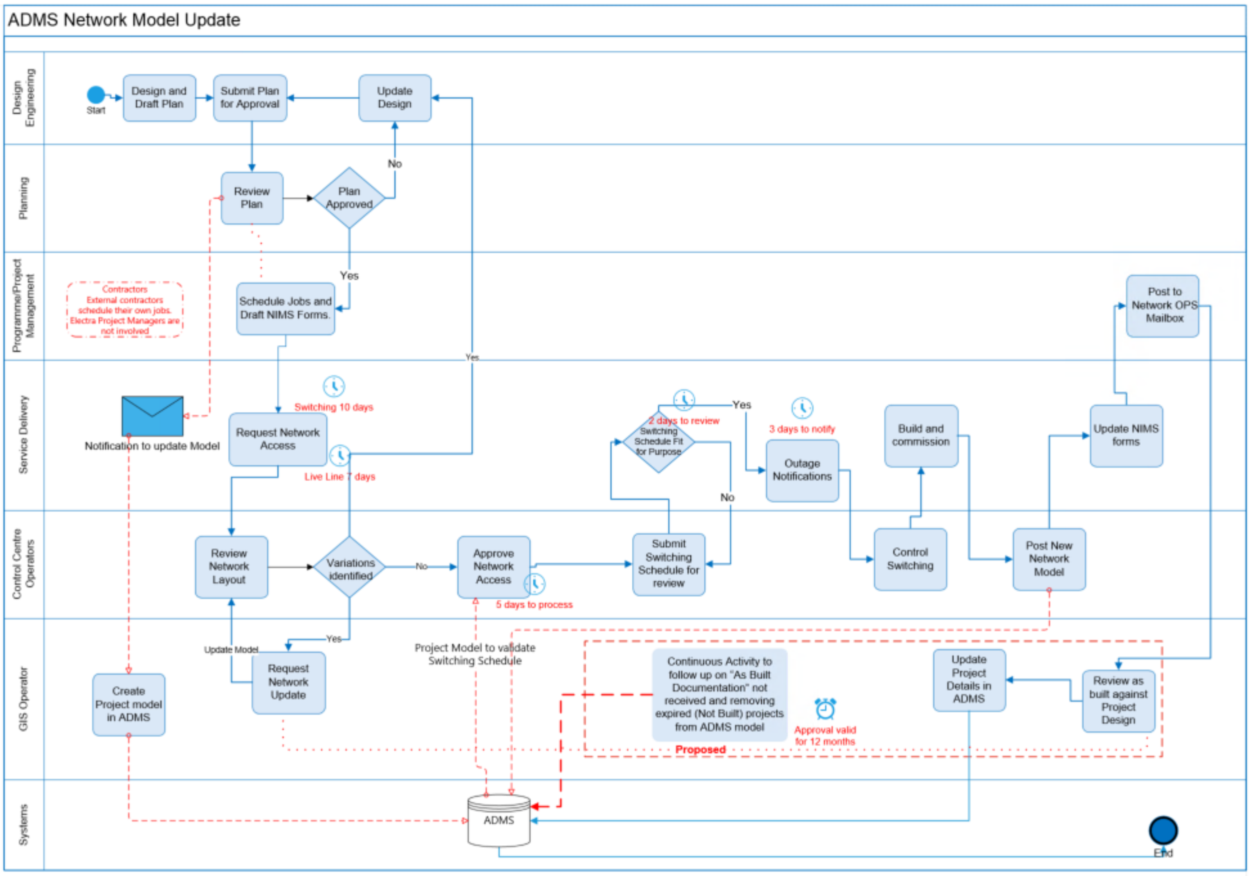


Figure 8-17: ADMS network process improvement

8.4.3 Implementation of Axos billing system

Axos billing system is an energy billing product tailored for the New Zealand electricity market. It supports the current and future billing requirements of network companies, retailers and major or complex consumers with standard or complex tariffs for time-of-use, smart meter, non-half hour and profiled sites.

Electra switched to this system as the previous bespoke system had minimal support available, limited features and was unable to handle Replacement Normalised billing methodology effectively. We looked for an off-the-shelf product, which was well supported with a development roadmap.

The potential enhancements of Axos are: exception reporting, unmetered load billing and transparent wash up process.

The enhancements observed since the system went live in October 2018 were:

- Improved data accuracy where network losses decreased from 8.4% in FY2018 to FY6.9% in FY2019
- Implementation of Axos Insights which is a dashboard to assist with Revenue Assurance.

8.4.4 Information disclosure compilation tool

Our information disclosure and asset management compilation processes are aided by the Information Disclosure Compilation Tool. The tool is a Microsoft Access program which links asset information, analyses the information via macros and filters the relevant asset data in accordance to asset classes set out in the Determination[18]. In line with our drive for continuous improvement and excellence in our operations, the tool assists us to ensure information consistency and accuracy for compliance. It also assists us in process efficiency as the tool also provides the age profiles and asset tables for the Asset Management Plan as depicted in Figure 8-18: (a) Information Disclosure Compilation Tool (IDT), and (b) Sample reports from IDT.

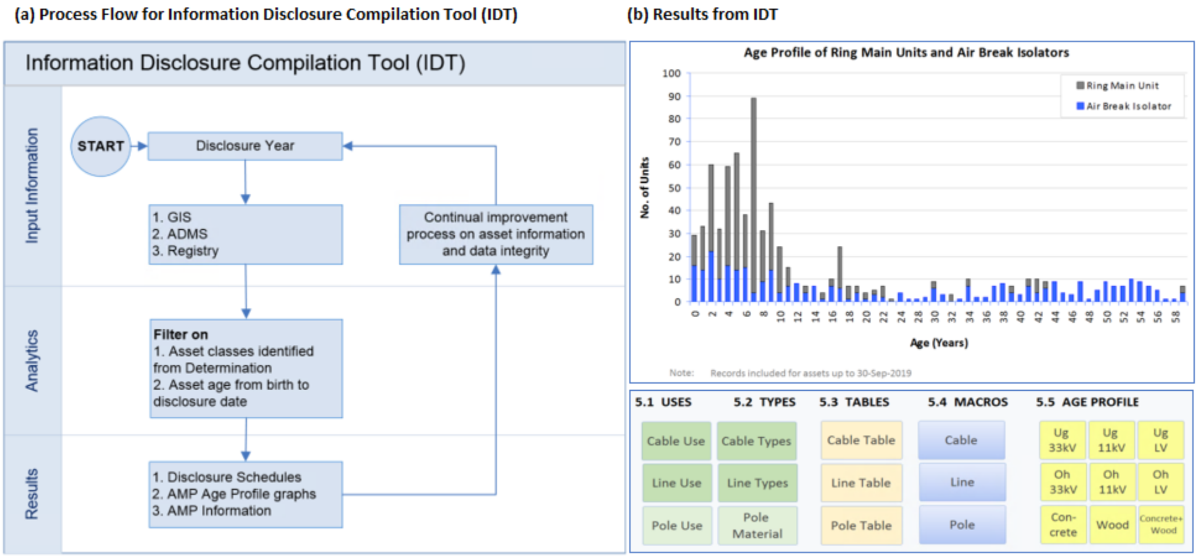


Figure 8-18: (a) Information Disclosure Compilation Tool (IDT), and (b) Sample reports from IDT

8.4.5 Strategic vegetation management improvement process

Another asset improvement process is within our vegetation management. As discussed in Section 3.9.6, we have moved from a responsive to a proactive planned tree-trimming risk-based process depicted in Figure 8-19. In order to improve our performance, we are using location and date information to forecast risk and develop trimming and removal plans by feeder section. For this work feeder sections are bounded by reclosers and remotely operable switches. Work is undertaken section by section and is prioritised based on the reduction of safety and SAIDI risk. Forecasts indicate a reducing OPEX from lower first cut and trim volumes, removal of trees on subsequent cuts and lower costs by proactive removal before trees reach the proximity requiring a safety observer.

[18] Commerce Commission, Electricity Distribution Information Disclosure Determination 2012

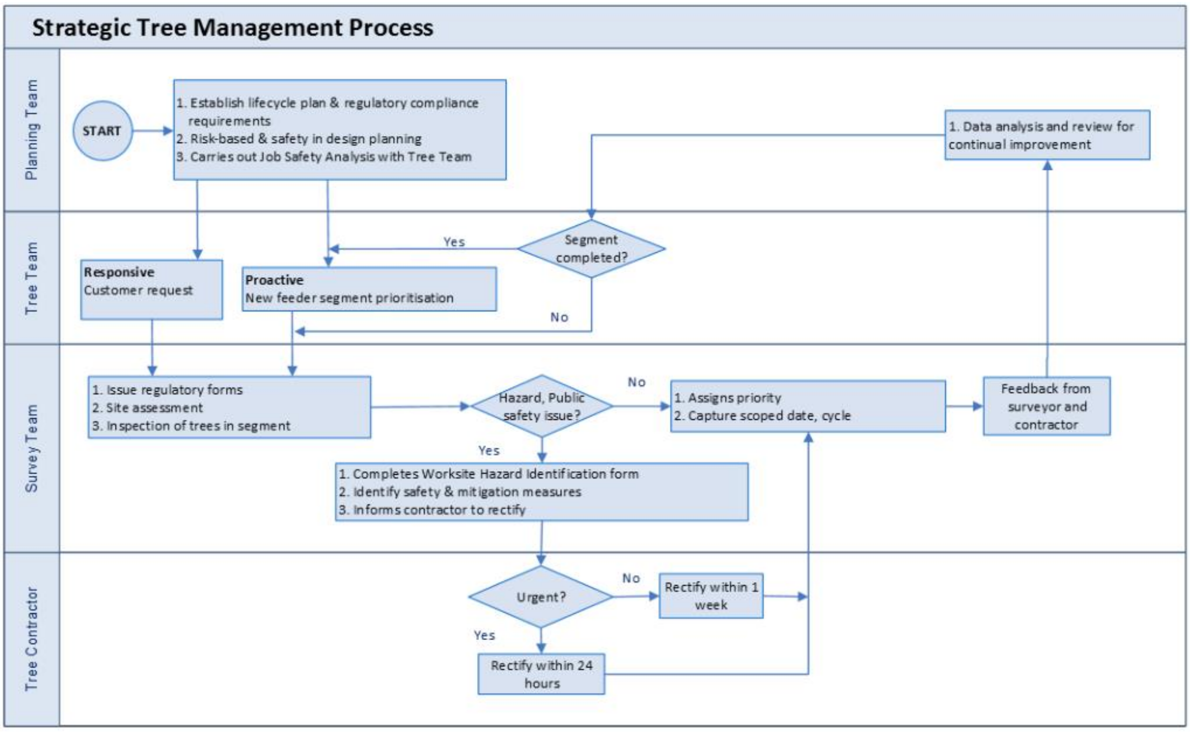
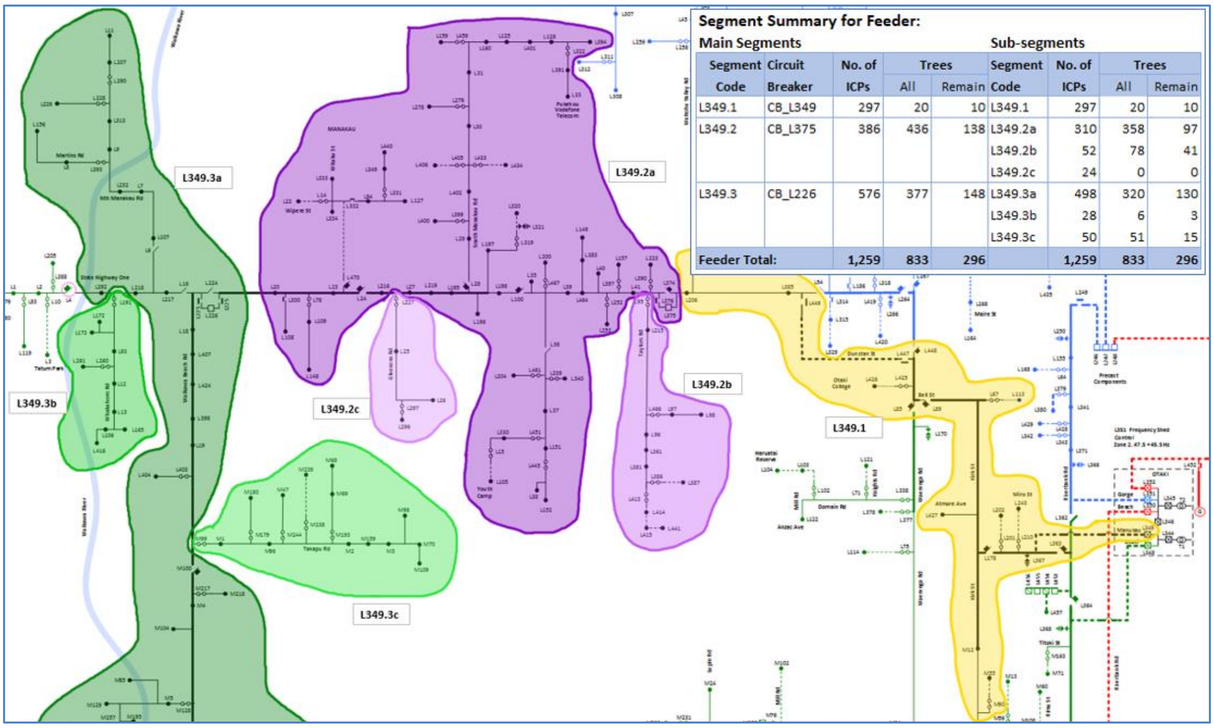


Figure 8-19: Tree-trimming planned process integration

Up to 150 segments were identified and analysed and the first hundred were prioritised for inspection and follow-up tree-trimming work in FY2020; a sample of the Otaki segment is shown in Figure 8-20. As of September 2019, 95% of these segments have been surveyed, and looking at the vegetation fault and cost management statistics in Section 8.3.4.2, we have made considerable progress in reducing our vegetation SAIDI as well as controlling vegetation costs.



Segment Summary for Feeder:

Main Segments: Segment Code	Circuit Breaker	No. of ICPs	Trees: All	Trees: Remain	Sub-segments: Segment Code	No. of ICPs	Trees: All	Trees: Remain
L349.1	CB_L349	297	20	10	L349.1	297	20	10
L349.2	CB_L375	386	436	138	L349.2a	310	358	97
					L349.2b	52	78	41
					L349.2c	24	0	0
L349.3	CB_L226	576	377	148	L349.3a	498	320	130
					L349.3b	28	6	3
					L349.3c	50	51	15
Feeder Total:		1,259	833	296		1,259	833	296

Figure 8-20: Sample of an Otaki feeder segment analysis

8.4.6 Identification of worst 11kV feeders

The number of failures of 11kV feeders has been added into the computation of our worst performing feeders; this initiative has previously been referred to in Section 3.9.7. The prioritisation for reliability-improvement projects for the worst feeders identified are based on factors such as the condition-based risk assessment, asset criticality factors, number of customers affected and capacity constraints shown in Figure 8-21. The trade-off between cost and reliability are evaluated carefully where network analysis, circuit reconfiguration, automation and alternative methods are assessed while considering the SAIDI and cost impact. This process will reduce the number of repeated failures and improve the quality of supply and reliability for our customers.

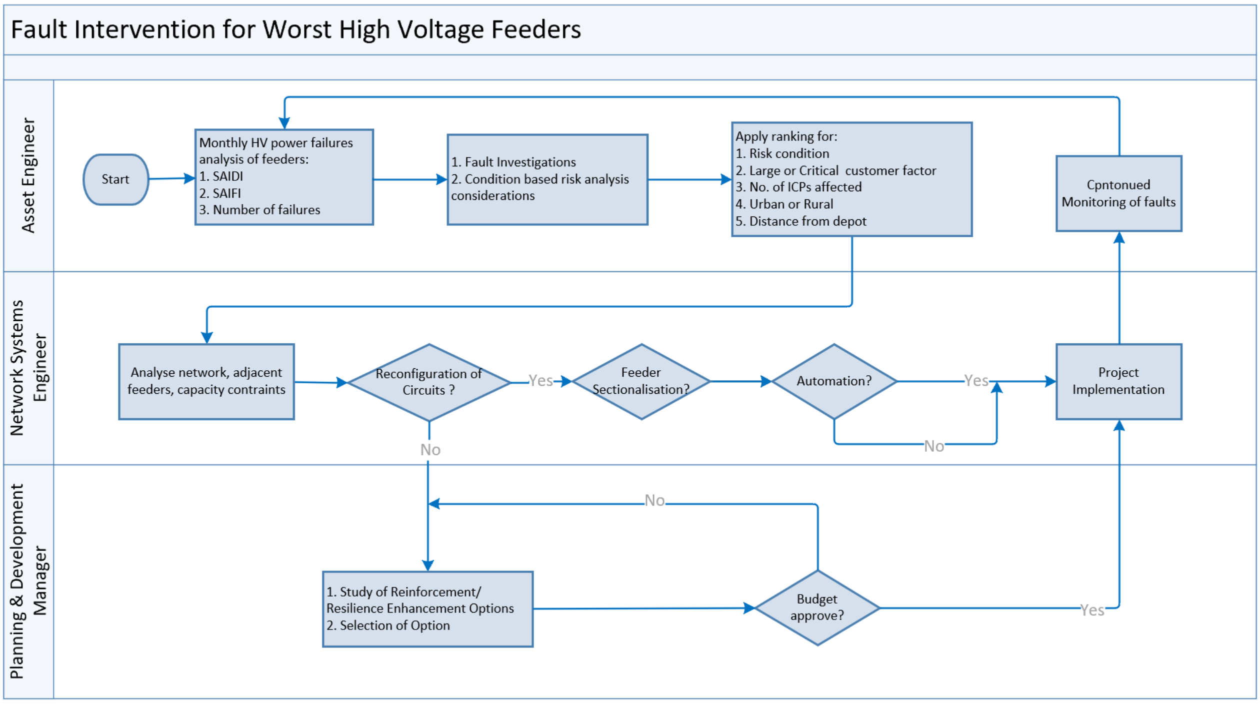


Figure 8-21: Fault intervention process for worst 11kV distribution feeders

8.4.7 Health and safety management system

Vault is a health, safety and risk management software tool commissioned in mid-2017. Public safety incidents recording started in Vault from September 2019, replacing a Microsoft Access database; legacy public safety data is being retrospectively included into Vault.

Vault is a stand-alone risk management and incident reporting tool administered by our Health & Safety Section. Our health and safety, and organisations risks are recorded on this platform. All events including incidents, injury, illness and near misses are reported (either via desktop or a mobile application) and recorded in this tool. Incident investigations are also recorded.

The system automatically notifies the senior management of critical events.

9 Works delivery

9.1 Resourcing policy and strategy

9.1.1 Resourcing approach

Key features of Electra's resourcing strategy include:

- Forecasting the annual hours required for the three key occupational classes of electrician/jointer, line mechanic, and arborist
- Identify the annual available man-hours for each of the three occupational classes, including new hires, apprentices, resignations and retirements.

Any shortfall of annual man-hours within each occupational class is identified and plans to meet those shortfalls are developed. Those plans can include multi-skilling of existing staff, improving productivity of existing work practices, training of apprentices, recruitment from the open market, or using contractors.

The competency requirements of staff and contractors deployed adhere to our SMS on competency requirements to ensure the safety of approved contractors' employees, staff and the public through effective training and the development of a highly competent work force.

9.1.2 Resourcing guidelines

Electra's resourcing is guided by the following principles:

- The majority of network construction, operation and maintenance will be performed by internal staff
- Contractors will be engaged for well-defined tasks such as trenching, directional drilling or concreting where their rates are cost competitive
- Infrequently required specialist skills will similarly be contracted when required.

Any transition from the use of contractors to in-house staff will include consideration of competency, likely work volumes, presence of contractors and the expected difference between wages and contract rates.

9.1.3 Strategic workforce issues

Electra recognises a range of strategic workforce issues that include:

- An increasing ICT content for its field work that includes programming and device interconnection
- Adjusting field crew makeup, leveraging the skills and experience of older people for works inspection and scoping while enabling younger workers to step up to work team leadership
- Forecast AMP spends by other EDB's is putting upward pressure on field services wages
- Retention of workers upon completion of training.

9.1.4 Specific resourcing plans

Current service delivery utilisation is about 76%, rising 2% in each of the last 2 years. Utilisation and productivity are areas of continued focus. Reporting, feedback and process developments aim to lift this to 85%.

Electra has a programme of annually recruiting new apprentices as part of its long-term succession planning, and it expects to continue this practice year-on-year over the next 10 years.

Part of the capability matrix is to upskill 30% of the workforce to be multiskilled in different disciplines to accommodate for peak periods.

9.2 Required resources to deliver works

9.2.1 Forecast resource requirements

Looking ahead Electra must recruit 16 replacement FTE's over the next 10 years due to 20% of the workforce approaching the age of National Superannuation entitlement. Capability and succession planning are in place to minimise that impact. Skillset capacity is set out in the next sub-section demonstrating both current FTE's and vacancies in the process of being filled.

YE 31 March	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
Electrician / jointer	15	13	13	12	13	13	15	14	13	13
Line Mechanics	28	30	32	32	29	29	26	26	26	26
Arborist	10	10	10	10	10	9	9	9	9	9
Total	**53**	**52**	**55**	**54**	**52**	**52**	**50**	**49**	**49**	**49**

Figure 9-1: Forecast FTE requirements

9.2.2 Forecast resource availability

YE 31 March	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
Electrician / jointers										
Opening number	11	12	12	12	13	12	12	13	12	12
Plus recruitments	0	1	0	0	0	1	0	0	1	1
Plus new apprentices	1	0	0	1	0	0	1	0	0	0
Less resignations and retirements	0	1	0	0	1	1	0	1	1	1
Closing number	12	12	12	13	12	12	13	12	12	12
Line mechanics										
Opening number	19	19	21	20	21	20	20	19	19	19
Plus recruitments	1	0	1	0	1	0	1	0	1	1
Plus new apprentices	0	2	0	2	0	2	0	2	0	0
Less resignations and retirements	1	0	2	1	2	2	2	2	2	2
Closing number	19	21	20	21	20	20	19	19	18	18
Live line mechanics										
Opening number	12	12	12	12	13	12	11	11	11	11
Plus recruitments	0	1	1	0	0	0	0	0	0	0
Plus new apprentices	1			1			1			
Less resignations and retirements	1	1	1	0	1	1	1	0	1	1
Closing number	12	12	12	13	12	11	11	11	10	10
Arborists										
Opening number	10	10	10	10	10	10	10	10	10	10

YE 31 March	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
Plus recruitments	0	0	0	0	0	0	0	0	0	0
Plus new apprentices	0	0	0	0	0	0	0	0	0	0
Less resignations and retirements	0	0	0	0	0	0	0	0	0	0
Closing number	10	10	10	10	10	10	10	10	10	10
Electrician/jointer	12	12	12	13	12	12	13	12	12	12
Line mechanics	31	33	32	34	32	31	30	30	28	28
Arborist	10	10	10	10	10	10	10	10	10	10

9.2.3 Expected resource surplus and shortfalls

The expected resource surplus and shortfalls for works delivery is tabulated in the following table and shown in Figure 9-2.

YE 31 March	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
Electrician/jointers										
Required	15	13	13	12	13	13	15	14	13	13
Available	11	12	12	12	13	12	12	13	12	12
Surplus/shortfall	-4	-1	-1	0	0	-1	-3	-1	-1	-1
Line mechanics										
Required	28	30	32	32	29	29	26	26	26	26
Available	31	31	33	32	34	32	31	30	30	30
Surplus/shortfall	3	1	1	0	5	3	5	4	4	4
Arborist										
Required	10	10	10	10	10	9	9	9	9	9
Available	10	10	10	10	10	10	10	10	10	10
Surplus/shortfall	0	0	0	0	0	1	1	1	1	1

The forecast shortfall of electrician/jointers can be offset by re-deploying multi-skilled line mechanics who can perform jointing work, and potentially also re-deploying the six FTE's allocated to third-party work to Electra jobs and projects.

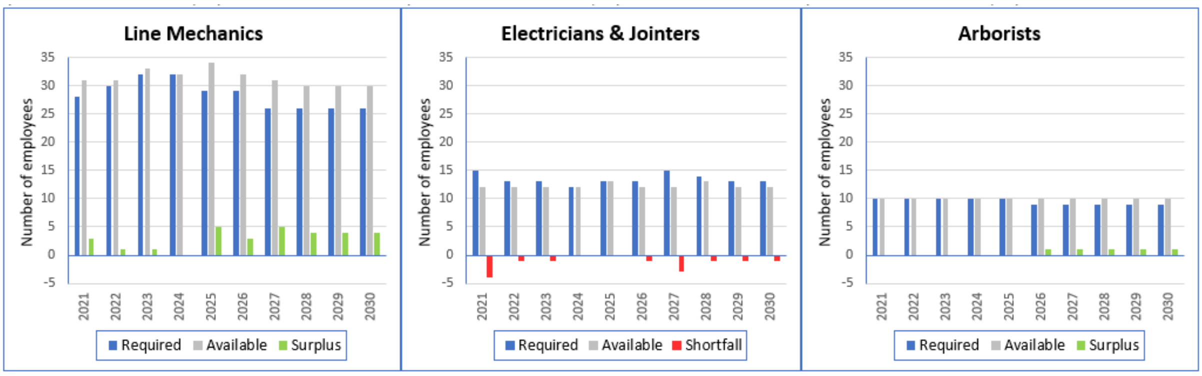


Figure 9-2: Works delivery projected resources

10 Appendices

10.1 List of Appendices

Appendix 1: Reconciliation of Asset Management Plan to Electricity Distribution Information Disclosure Determination 2012

The following table cross references the sections of this AMP to Attachment A of the Electricity Distribution Information Disclosure Determination 2012 (consolidated to 3 April 2018).

Determination Clause (Attachment A of Determination*)	AMP Section
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;	Executive Summary, 1
3.2 Details of the background and objectives of the EDB's asset management and planning processes;	1, 1.2. 1.7
3.3 A purpose statement which-	1
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;	1.14
3.3.2 states the corporate mission or vision as it relates to asset management;	1, 1.1.1
3.3.3 identifies the documented plans produced as outputs of the annual business planning process adopted by the EDB;	1.7.1
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	1.7.2
3.3.5 includes a description of the interaction between the objectives of the AMP and other corporate goals, business planning processes, and plans;	1.7.3
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;	1.8
3.5 The date that it was approved by the directors;	1.9
3.6 A description of stakeholder interests (owners, consumers etc) which identifies important stakeholders and indicates-	1.10
3.6.1 how the interests of stakeholders are identified	1.10.1
3.6.2 what these interests are;	1.10.2
3.6.3 how these interests are accommodated in asset management practices; and	1.10.2
3.6.4 how conflicting interests are managed;	1.10.3
3.7 A description of the accountabilities and responsibilities for asset management on at least 3 levels, including-	1.11
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;	1.11.1
3.7.2 executive—an indication of how the in-house asset management and planning organisation is structured; and	1.11.1
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;	1.11.2
3.8 All significant assumptions-	1.16
3.8.1 quantified where possible;	1.16
3.8.2 clearly identified in a manner that makes their significance understandable to interested persons, including-	1.16
3.8.3 a description of changes proposed where the information is not based on the EDB's existing business;	Not applicable
3.8.4 the sources of uncertainty and the potential effect of the uncertainty on the prospective information; and	1.16

Determination Clause (Attachment A of Determination*)	AMP Section
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;	1.16.2
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;	1.16.1
3.10 An overview of asset management strategy and delivery;	1.2.1, 1.2.2, 1.5, 1.6
3.11 An overview of systems and information management data;	1.12, 1.6
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;	1.12.1
3.13 A description of the processes used within the EDB for-	
3.13.1 managing routine asset inspections and network maintenance;	1.13.1, 1.13.2
3.13.2 planning and implementing network development projects; and	1.13.3
3.13.3 measuring network performance;	1.13.4
3.14 An overview of asset management documentation, controls and review processes.	1.14
3.15 An overview of communication and participation processes;	1.15
3.16 The AMP must present all financial values in constant price New Zealand dollars except where specified otherwise; and	1.16.2
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.	Table of Contents, 1
4. The AMP must provide details of the assets covered, including-	5
4.1 a high-level description of the service areas covered by the EDB and the degree to which these are interlinked, including-	2
4.1.1 the region(s) covered;	2.1.1
4.1.2 identification of large consumers that have a significant impact on network operations or asset management priorities;	2.1.2
4.1.3 description of the load characteristics for different parts of the network;	2.1.3, 2.2
4.1.4 peak demand and total energy delivered in the previous year, broken down by sub-network, if any.	2.1.4, 2.2
4.2 a description of the network configuration, including-	2.2
4.2.1 identifying bulk electricity supply points and any distributed generation with a capacity greater than 1 MW. State the existing firm supply capacity and current peak load of each bulk electricity supply point;	2.1.3, 2.2
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	2.1, 2.2
4.2.3 a description of the distribution system, including the extent to which it is underground;	2.2
4.2.4 a brief description of the network's distribution substation arrangements;	5.7
4.2.5 a description of the low voltage network including the extent to which it is underground; and	2.2, 2.3
4.2.6 an overview of secondary assets such as protection relays, ripple injection systems, SCADA and telecommunications systems.	5.9
4.3 If sub-networks exist, the network configuration information referred to in clause 4.2 must be disclosed for each sub-network.	
4.4 The AMP must describe the network assets by providing the following information for each asset category-	5
4.4.1 voltage levels;	5

Determination Clause (Attachment A of Determination*)	AMP Section
4.4.2 description and quantity of assets;	5
4.4.3 age profiles; and	5
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.	5
4.5 The asset categories discussed in clause 4.4 should include at least the following-	5
4.5.1 the categories listed in the Report on Forecast Capital Expenditure in Schedule 11a(iii);	5
4.5.2 assets owned by the EDB but installed at bulk electricity supply points owned by others;	5
4.5.3 EDB owned mobile substations and generators whose function is to increase supply reliability or reduce peak demand; and	5.9.6
4.5.4 other generation plant owned by the EDB.	
5. The AMP must clearly identify or define a set of performance indicators for which annual performance targets have been defined. The annual performance targets must be consistent with business strategies and asset management objectives and be provided for each year of the AMP planning period. The targets should reflect what is practically achievable given the current network configuration, condition and planned expenditure levels. The targets should be disclosed for each year of the AMP planning period.	3
6. Performance indicators for which targets have been defined in clause 5 must include SAIDI values and SAIFI values for the next 5 disclosure years.	3.1
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	3.1, 3.2
7.2 Indicators of asset performance, asset efficiency and effectiveness, and service efficiency, such as technical and financial performance indicators related to the efficiency of asset utilisation and operation.	3.3
8. The AMP must describe the basis on which the target level for each performance indicator was determined. Justification for target levels of service includes consumer expectations or demands, legislative, regulatory, and other stakeholders' requirements or considerations. The AMP should demonstrate how stakeholder needs were ascertained and translated into service level targets.	3.1.2, 3.7
9. Targets should be compared to historic values where available to provide context and scale to the reader.	3
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.	1.16.1, 1.16.2, 3.3.4
11. AMPs must provide a detailed description of network development plans, including—	4
11.1 A description of the planning criteria and assumptions for network development;	4.2
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;	4.2
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;	3.9, 4.3, 8.4
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	4.3.1
11.4.2 the approach used to identify standard designs;	4.3.1
11.5 A description of strategies or processes (if any) used by the EDB that promote the energy efficient operation of the network;	4.3.2
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;	4.3.5

Determination Clause (Attachment A of Determination*)	AMP Section
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;	4.3, 4.5
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;	4.4, 4.6
11.8.1 explain the load forecasting methodology and indicate all the factors used in preparing the load estimates;	4.6
11.8.2 provide separate forecasts to at least the zone substation level covering at least a minimum five-year forecast period. Discuss how uncertain but substantial individual projects/developments that affect load are taken into account in the forecasts, making clear the extent to which these uncertain increases in demand are reflected in the forecasts;	4.6.3, 4.6.4
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	4.4
11.8.4 discuss the impact on the load forecasts of any anticipated levels of distributed generation in a network, and the projected impact of any demand management initiatives;	4.3.4
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-	4.3.5, 4.7
11.9.1 the reasons for choosing a selected option for projects where decisions have been made;	4.3.5
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	4.3.5
11.9.3 consideration of planned innovations that improve efficiencies within the network, such as improved utilisation, extended asset lives, and deferred investment;	5, 5.1
11.10 A description and identification of the network development programme including distributed generation and non-network solutions and actions to be taken, including associated expenditure projections. The network development plan must include-	4.3
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;	4.7.1
11.10.2 a summary description of the programmes and projects planned for the following four years (where known); and	4.7.2
11.10.3 an overview of the material projects being considered for the remainder of the AMP planning period;	4.7.3
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	4.3.3, 4.3.4
11.12 A description of the EDB's policies on non-network solutions, including-	4.3.5, 4.3.6, 6
11.12.1 economically feasible and practical alternatives to conventional network augmentation. These are typically approaching that would reduce network demand and/or improve asset utilisation; and	4.3.5, 4.3.6
11.12.2 the potential for non-network solutions to address network problems or constraints.	4.3.5, 4.3.6
12. The AMP must provide a detailed description of the lifecycle asset management processes, including—	5
12.1 The key drivers for maintenance planning and assumptions;	5.1
12.2 Identification of routine and corrective maintenance and inspection policies and programmes and actions to be taken for each asset category, including associated expenditure projections. This must include-	5
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;	5
12.2.2 any systemic problems identified with any particular asset types and the proposed actions to address these problems; and	5

Determination Clause (Attachment A of Determination*)	AMP Section
12.2.3 budgets for maintenance activities broken down by asset category for the AMP planning period;	5
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-	5
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;	5
12.3.2 a description of innovations that have deferred asset replacements;	3.9
12.3.3 a description of the projects currently underway or planned for the next 12 months;	5
12.3.4 a summary of the projects planned for the following four years (where known); and	5
12.3.5 an overview of other work being considered for the remainder of the AMP planning period; and	5
12.4 The asset categories discussed in clauses 12.2 and 12.3 should include at least the categories in clause 4.5.	5
13. AMPs must provide a summary description of material non-network development, maintenance and renewal plans, including—	6
13.1 a description of non-network assets;	6.1
13.2 development, maintenance and renewal policies that cover them;	6.2
13.3 a description of material capital expenditure projects (where known) planned for the next five years; and	6.2.5
13.4 a description of material maintenance and renewal projects (where known) planned for the next five years.	6.2.5
14. AMPs must provide details of risk policies, assessment, and mitigation, including—	7
14.1 Methods, details and conclusions of risk analysis;	7.1
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;	7.1, 7.2, 7.2.2, 7.4, 7.4.1
14.3 A description of the policies to mitigate or manage the risks of events identified in clause 14.2; and	7.3, 7.4.3, 7.4.4, 7.4.5
14.4 Details of emergency response and contingency plans.	7.3, 7.4.3, 7.4.4, 7.4.5
15. AMPs must provide details of performance measurement, evaluation, and improvement, including—	8
15.1 A review of progress against plan, both physical and financial;	8.1, 8.2, 8.3, 8.3.4
15.2 An evaluation and comparison of actual service level performance against targeted performance;	8.1, 8.2, 8.3
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.	8.4
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.	3.9, 8.4
16. AMPs must describe the processes used by the EDB to ensure that-	
16.1 The AMP is realistic and the objectives set out in the plan can be achieved; and	1.11, 9.1
16.2 The organisation structure and the processes for authorisation and business capabilities will support the implementation of the AMP plans.	1.11, 1.11.1

Appendix 2: Schedule 11a - Report on Forecast Capital Expenditure

Company Name	Electra Ltd
AMP Planning Period	1 April 2020 – 31 March 2030

SCHEDULE 11a: REPORT ON FORECAST CAPITAL EXPENDITURE

This schedule requires a breakdown of forecast expenditure on assets for the current disclosure year and a 10 year planning period. The forecasts should be consistent with the supporting information set out in the AMP. The forecast is to be expressed in both constant price and nominal dollar terms. Also required is a forecast of the value of commissioned assets (i.e., the value of RAB additions)

EDBs must provide explanatory comment on the difference between constant price and nominal dollar forecasts of expenditure on assets in Schedule 14a (Mandatory Explanatory Notes).

This information is not part of audited disclosure information.

sch ref			*Current Year CY*	*CY+1*	*CY+2*	*CY+3*	*CY+4*	*CY+5*	*CY+6*	*CY+7*	*CY+8*	*CY+9*	*CY+10*
8		for year ended	**31 Mar 20**	**31 Mar 21**	**31 Mar 22**	**31 Mar 23**	**31 Mar 24**	**31 Mar 25**	**31 Mar 26**	**31 Mar 27**	**31 Mar 28**	**31 Mar 29**	**31 Mar 30**
9		**11a(i): Expenditure on Assets Forecast**	**$000 (in nominal dollars)**										
10		Consumer connection	95	95	96	98	100	101	103	105	106	108	110
11		System growth	950	1,450	797	439	1,799	1,658	1,066	1,660	1,463	2,244	1,426
12		Asset replacement and renewal	6,816	6,217	5,989	7,353	8,342	9,751	9,889	9,202	8,394	7,592	7,698
13		Asset relocations	-	-	104	-	-	-	-	-	-	-	-
14		Reliability, safety and environment:											
15		Quality of supply	3,150	2,002	2,040	1,666	3,028	2,387	2,757	2,504	1,598	1,854	1,853
16		Legislative and regulatory	275	450	381	310	-	-	-	-	-	-	-
17		Other reliability, safety and environment	360	895	646	952	647	267	272	277	281	286	396
18		**Total reliability, safety and environment**	3,785	3,347	3,067	2,928	3,675	2,654	3,029	2,781	1,879	2,140	2,248
19		**Expenditure on network assets**	11,646	11,109	10,054	10,818	13,915	14,165	14,087	13,747	11,842	12,085	11,482
20		Expenditure on non-network assets	2,875	4,773	1,832	1,722	2,012	2,667	1,647	2,083	1,487	1,235	1,360
21		**Expenditure on assets**	14,521	15,882	11,886	12,540	15,927	16,832	15,734	15,830	13,329	13,320	12,842
22													
23	*plus*	Cost of financing	109	100	100	100	100	100	100	100	100	100	100
24	*less*	Value of capital contributions	95	1,080	1,080	1,080	1,080	1,080	1,080	1,080	1,080	1,080	1,080
25	*plus*	Value of vested assets	1,200	1,200	1,200	1,200	1,200	1,200	1,200	1,200	1,200	1,200	1,200
26													
27		**Capital expenditure forecast**	15,735	16,102	12,106	12,760	16,147	17,052	15,954	16,050	13,549	13,540	13,062
28													
29		Assets commissioned											
30			*Current Year CY*	*CY+1*	*CY+2*	*CY+3*	*CY+4*	*CY+5*	*CY+6*	*CY+7*	*CY+8*	*CY+9*	*CY+10*
31		for year ended	**31 Mar 20**	**31 Mar 21**	**31 Mar 22**	**31 Mar 23**	**31 Mar 24**	**31 Mar 25**	**31 Mar 26**	**31 Mar 27**	**31 Mar 28**	**31 Mar 29**	**31 Mar 30**
32			**$000 (in constant prices)**										
33		Consumer connection	95	95	95	95	95	95	95	95	95	95	95
34		System growth	950	1,450	784	424	1,710	1,550	980	1,500	1,300	1,961	1,225
35		Asset replacement and renewal	6,816	6,217	5,889	7,109	7,931	9,116	9,090	8,317	7,459	6,634	6,614
36		Asset relocations	-	-	102	-	-	-	-	-	-	-	-
37		Reliability, safety and environment:											
38		Quality of supply	3,150	2,002	2,006	1,611	2,879	2,231	2,534	2,264	1,420	1,620	1,592
39		Legislative and regulatory	275	450	375	300	-	-	-	-	-	-	-
40		Other reliability, safety and environment	360	710	635	920	615	250	250	250	250	250	340
41		**Total reliability, safety and environment**	3,785	3,162	3,016	2,831	3,494	2,481	2,784	2,514	1,670	1,870	1,932
42		**Expenditure on network assets**	11,646	10,924	9,885	10,459	13,229	13,242	12,948	12,425	10,524	10,560	9,866
43		Expenditure on non-network assets	4,058	4,773	1,832	1,722	2,012	2,667	1,647	2,083	1,487	1,235	1,360
44		**Expenditure on assets**	15,704	15,697	11,717	12,181	15,241	15,909	14,595	14,508	12,011	11,795	11,226
45													
46		**Subcomponents of expenditure on assets (where known)**											
47		Energy efficiency and demand side management, reduction of energy losses											
48		Overhead to underground conversion											
49		Research and development											
50													

	Current Year CY	CY+1	CY+2	CY+3	CY+4	CY+5	CY+6	CY+7	CY+8	CY+9	CY+10
for year ended	31 Mar 20	31 Mar 21	31 Mar 22	31 Mar 23	31 Mar 24	31 Mar 25	31 Mar 26	31 Mar 27	31 Mar 28	31 Mar 29	31 Mar 30
Difference between nominal and constant price forecasts	$000										
Consumer connection	-	-	2	3	5	7	8	10	12	14	16
System growth	-	-	13	15	89	108	86	160	163	283	201
Asset replacement and renewal	-	-	100	244	411	636	799	885	934	958	1,084
Asset relocations	-	-	2	-	-	-	-	-	-	-	-
Reliability, safety and environment:											
Quality of supply	-	-	34	55	149	156	223	241	178	234	261
Legislative and regulatory	-	-	6	10	-	-	-	-	-	-	-
Other reliability, safety and environment	-	185	11	32	32	17	22	27	31	36	56
Total reliability, safety and environment	-	185	51	97	181	173	245	268	209	270	316
Expenditure on network assets	-	185	168	359	686	924	1,139	1,322	1,318	1,525	1,616
Expenditure on non-network assets	(1,183)	-	-	-	-	-	-	-	-	-	-
Expenditure on assets	(1,183)	185	168	359	686	924	1,139	1,322	1,318	1,525	1,616

11a(ii): Consumer Connection

	Current Year CY	CY+1	CY+2	CY+3	CY+4	CY+5
for year ended	31 Mar 20	31 Mar 21	31 Mar 22	31 Mar 23	31 Mar 24	31 Mar 25
*Consumer types defined by EDB**	$000 (in constant prices)					
All	95	95	95	95	95	95
[EDB consumer type]						
[EDB consumer type]						
[EDB consumer type]						
[EDB consumer type]						
**include additional rows if needed*						
Consumer connection expenditure	95	95	95	95	95	95
less Capital contributions funding consumer connection						
Consumer connection less capital contributions	95	95	95	95	95	95

11a(iii): System Growth

	Current Year CY	CY+1	CY+2	CY+3	CY+4	CY+5
Subtransmission	-	-	-	-	-	700
Zone substations	-	-	-	-	-	-
Distribution and LV lines	-	-	-	-	-	-
Distribution and LV cables	950	1,450	784	424	1,710	850
Distribution substations and transformers	-	-	-	-	-	-
Distribution switchgear	-	-	-	-	-	-
Other network assets	-	-	-	-	-	-
System growth expenditure	950	1,450	784	424	1,710	1,550
less Capital contributions funding system growth						
System growth less capital contributions	950	1,450	784	424	1,710	1,550

11a(iv): Asset Replacement and Renewal

	Current Year CY	CY+1	CY+2	CY+3	CY+4	CY+5
for year ended	31 Mar 20	31 Mar 21	31 Mar 22	31 Mar 23	31 Mar 24	31 Mar 25
	$000 (in constant prices)					
Subtransmission	682	360	360	360	1,360	1,360
Zone substations	131	131	131	1,431	1,081	2,381
Distribution and LV lines	3,734	4,027	3,521	3,331	3,557	3,151
Distribution and LV cables	478	378	478	608	478	560
Distribution substations and transformers	1,037	887	937	937	937	1,051
Distribution switchgear	280	160	153	153	153	214
Other network assets	475	275	310	290	365	400
Asset replacement and renewal expenditure	6,816	6,217	5,889	7,109	7,931	9,116
less Capital contributions funding asset replacement and renewal						
Asset replacement and renewal less capital contributions	6,816	6,217	5,889	7,109	7,931	9,116

		Current Year CY	CY+1	CY+2	CY+3	CY+4	CY+5
	for year ended	31 Mar 20	31 Mar 21	31 Mar 22	31 Mar 23	31 Mar 24	31 Mar 25

11a(v): Asset Relocations

*Project or programme**	$000 (in constant prices)					
Alternative Supply - Waterfall Rd, Paekakariki			102			
[Description of material project or programme]						
[Description of material project or programme]						
[Description of material project or programme]						
[Description of material project or programme]						
**include additional rows if needed*						
All other project or programmes - asset relocations						
Asset relocations expenditure	-	-	102	-	-	-
less Capital contributions funding asset relocations						
Asset relocations less capital contributions	-	-	102	-	-	-

		Current Year CY	CY+1	CY+2	CY+3	CY+4	CY+5
	for year ended	31 Mar 20	31 Mar 21	31 Mar 22	31 Mar 23	31 Mar 24	31 Mar 25

11a(vi): Quality of Supply

*Project or programme**	$000 (in constant prices)					
Protection Work	625	850	850	375	-	-
Improving Network Interconnectivity	1,926	341	521	727	1,954	493
Network Automation and Sectionalisation	520	683	507	381	770	1,585
Fault Locator	79	128	128	128	154	153
**include additional rows if needed*						
All other projects or programmes - quality of supply						
Quality of supply expenditure	3,150	2,002	2,006	1,611	2,879	2,231
less Capital contributions funding quality of supply						
Quality of supply less capital contributions	3,150	2,002	2,006	1,611	2,879	2,231

		Current Year CY	CY+1	CY+2	CY+3	CY+4	CY+5
	for year ended	31 Mar 20	31 Mar 21	31 Mar 22	31 Mar 23	31 Mar 24	31 Mar 25

11a(vii): Legislative and Regulatory

*Project or programme**	$000 (in constant prices)					
Seismic Strengthening	275	450	375	300	-	-
[Description of material project or programme]						
[Description of material project or programme]						
[Description of material project or programme]						
[Description of material project or programme]						
**include additional rows if needed*						
All other projects or programmes - legislative and regulatory						
Legislative and regulatory expenditure	275	450	375	300	-	-
less Capital contributions funding legislative and regulatory						
Legislative and regulatory less capital contributions	275	450	375	300	-	-

Row		Current Year CY	CY+1	CY+2	CY+3	CY+4	CY+5
150	for year ended	31 Mar 20	31 Mar 21	31 Mar 22	31 Mar 23	31 Mar 24	31 Mar 25

151 **11a(viii): Other Reliability, Safety and Environment**

Row							
152	*Project or programme**	$000 (in constant prices)					
153	Arc Flash Protection	-	-	-	305	-	-
154	New ABS and renewals	110	325	325	325	325	110
155	Replacement of Deck Transformers	90	75	-	-	-	-
156	Replacement of Pitchfilled Potheads	60	60	60	40	40	40
157	Steel Link Pillar Removal	100	250	250	250	250	100
158	**include additional rows if needed*						
159	All other projects or programmes - other reliability, safety and environment	-					
160	**Other reliability, safety and environment expenditure**	360	710	635	920	615	250
161	*less* Capital contributions funding other reliability, safety and environment						
162	**Other reliability, safety and environment less capital contributions**	360	710	635	920	615	250
163							

Row		Current Year CY	CY+1	CY+2	CY+3	CY+4	CY+5
164							
165	for year ended	31 Mar 20	31 Mar 21	31 Mar 22	31 Mar 23	31 Mar 24	31 Mar 25

166 **11a(ix): Non-Network Assets**

Row							
167	**Routine expenditure**						
168	*Project or programme**	$000 (in constant prices)					
169	Office buildings, depots & workshops	100	100	20	20	20	20
170	Office furniture, fittings and equipment incl. PPE	98	98	98	98	98	98
171	Motor vehicles	100	1,525	875	875	1,000	800
172	Tools, plant & other machinery	250	250	250	250	250	250
173	ICT	2,277	725	534	424	589	444
174	IoT	50	25	55	55	55	55
175	**include additional rows if needed*						
176	All other projects or programmes - routine expenditure						
177	**Routine expenditure**	2,875	2,723	1,832	1,722	2,012	1,667
178	**Atypical expenditure**						
179	*Project or programme**						
180	Retailer Billing	123	-	-	-	-	-
181	ADMS and SCADA Development	200	100	-	-	-	1,000
182	Other IT Initiatives to Improve Asset Management	860	-	-	-	-	-
183	Navision Replacement	-	1,000	-	-	-	-
184	Asset Management System	-	500	-	-	-	-
185	Enhancement of premise security	-	250	-	-	-	-
	Field Computing Application	-	100	-	-	-	-
	IoT - Low Voltage Network Status Monitoring	-	100	-	-	-	-
186	**include additional rows if needed*						
187	All other projects or programmes - atypical expenditure						
188	**Atypical expenditure**	1,183	2,050	-	-	-	1,000
189							
190	**Expenditure on non-network assets**	4,058	4,773	1,832	1,722	2,012	2,667

Appendix 3: Schedule 11b - Report on Forecast Operational Expenditure

Company Name	Electra Ltd
AMP Planning Period	1 April 2020 – 31 March 2030

SCHEDULE 11b: REPORT ON FORECAST OPERATIONAL EXPENDITURE

This schedule requires a breakdown of forecast operational expenditure for the disclosure year and a 10 year planning period. The forecasts should be consistent with the supporting information set out in the AMP. The forecast is to be expressed in both constant price and nominal dollar terms.
EDBs must provide explanatory comment on the difference between constant price and nominal dollar operational expenditure forecasts in Schedule 14a (Mandatory Explanatory Notes).
This information is not part of audited disclosure information.

sch ref		*Current Year CY*	*CY+1*	*CY+2*	*CY+3*	*CY+4*	*CY+5*	*CY+6*	*CY+7*	*CY+8*	*CY+9*	*CY+10*
8	for year ended	**31 Mar 20**	**31 Mar 21**	**31 Mar 22**	**31 Mar 23**	**31 Mar 24**	**31 Mar 25**	**31 Mar 26**	**31 Mar 27**	**31 Mar 28**	**31 Mar 29**	**31 Mar 30**
9	**Operational Expenditure Forecast**	**$000 (in nominal dollars)**										
10	Service interruptions and emergencies	1,858	1,859	1,891	1,923	1,956	1,989	1,880	1,912	1,944	1,891	1,924
11	Vegetation management	1,538	1,608	1,635	1,663	1,691	1,720	1,618	1,646	1,674	1,702	1,731
12	Routine and corrective maintenance and inspection	911	999	986	1,003	1,072	909	925	940	956	1,030	988
13	Asset replacement and renewal	372	312	317	411	312	334	432	345	351	454	363
14	**Network Opex**	4,679	4,778	4,829	5,000	5,031	4,951	4,855	4,842	4,925	5,078	5,006
15	System operations and network support	3,111	3,901	3,849	3,935	4,002	4,070	4,139	4,209	4,281	4,354	4,428
16	Business support	4,625	4,439	4,609	4,702	4,782	4,863	4,946	5,030	5,115	5,202	5,291
17	**Non-network opex**	7,736	8,340	8,458	8,637	8,784	8,933	9,085	9,239	9,397	9,556	9,719
18	**Operational expenditure**	12,415	13,118	13,287	13,637	13,815	13,884	13,940	14,082	14,321	14,634	14,725
19		*Current Year CY*	*CY+1*	*CY+2*	*CY+3*	*CY+4*	*CY+5*	*CY+6*	*CY+7*	*CY+8*	*CY+9*	*CY+10*
20	for year ended	**31 Mar 20**	**31 Mar 21**	**31 Mar 22**	**31 Mar 23**	**31 Mar 24**	**31 Mar 25**	**31 Mar 26**	**31 Mar 27**	**31 Mar 28**	**31 Mar 29**	**31 Mar 30**
21		**$000 (in constant prices)**										
22	Service interruptions and emergencies	1,858	1,859	1,859	1,859	1,859	1,859	1,728	1,728	1,728	1,653	1,653
23	Vegetation management	1,538	1,608	1,608	1,608	1,608	1,608	1,488	1,488	1,488	1,488	1,488
24	Routine and corrective maintenance and inspection	911	999	969	970	1,019	849	850	849	849	900	849
25	Asset replacement and renewal	372	312	312	397	297	312	397	312	312	397	312
26	**Network Opex**	4,679	4,778	4,748	4,834	4,783	4,628	4,462	4,377	4,377	4,437	4,302
27	System operations and network support	3,111	3,901	3,849	3,935	3,935	3,935	3,935	3,935	3,935	3,935	3,935
28	Business support	4,625	4,439	4,609	4,702	4,702	4,702	4,702	4,702	4,702	4,702	4,702
29	**Non-network opex**	7,736	8,340	8,458	8,637	8,637	8,637	8,637	8,637	8,637	8,637	8,637
30	**Operational expenditure**	12,415	13,118	13,206	13,471	13,420	13,265	13,099	13,014	13,014	13,074	12,939
31	**Subcomponents of operational expenditure (where known)**											
32	Energy efficiency and demand side management, reduction of											
33	energy losses											
34	Direct billing*											
35	Research and Development											
36	Insurance											
37	** Direct billing expenditure by suppliers that direct bill the majority of their consumers*											
38												
39		*Current Year CY*	*CY+1*	*CY+2*	*CY+3*	*CY+4*	*CY+5*	*CY+6*	*CY+7*	*CY+8*	*CY+9*	*CY+10*
40	for year ended	**31 Mar 20**	**31 Mar 21**	**31 Mar 22**	**31 Mar 23**	**31 Mar 24**	**31 Mar 25**	**31 Mar 26**	**31 Mar 27**	**31 Mar 28**	**31 Mar 29**	**31 Mar 30**
41	**Difference between nominal and real forecasts**	**$000**										
42	Service interruptions and emergencies	-	-	32	64	96	130	152	184	216	239	271
43	Vegetation management	-	-	27	55	83	112	131	158	186	215	244
44	Routine and corrective maintenance and inspection	-	-	16	33	53	59	75	90	106	130	139
45	Asset replacement and renewal	-	-	5	14	15	22	35	33	39	57	51
46	**Network Opex**	-	-	81	166	248	323	392	466	548	641	705
47	System operations and network support	-	-	-	-	67	135	204	274	346	419	493
48	Business support	-	-	-	-	80	161	244	328	413	500	589
49	**Non-network opex**	-	-	-	-	147	296	448	602	760	919	1,082
50	**Operational expenditure**	-	-	81	166	395	619	840	1,068	1,308	1,560	1,786

Appendix 4: Schedule 12a – Report on Asset Condition

Company Name **Electra Ltd**
AMP Planning Period **1 April 2020 – 31 March 2030**

SCHEDULE 12a: REPORT ON ASSET CONDITION

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

sch ref					Asset condition at start of planning period (percentage of units by grade)							
7												
8												
	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
9												
10	All	Overhead Line	Concrete poles / steel structure	No.		2.30%	75.45%	17.25%	5.00%		3	2.50%
11	All	Overhead Line	Wood poles	No.		40.00%	60.00%	-		-	2	45.00%
12	All	Overhead Line	Other pole types	No.							N/A	
13	HV	Subtransmission Line	Subtransmission OH up to 66kV conductor	km		9.50%	62.74%	25.16%	2.60%		4	10.00%
14	HV	Subtransmission Line	Subtransmission OH 110kV+ conductor	km							N/A	
15	HV	Subtransmission Cable	Subtransmission UG up to 66kV (XLPE)	km			38.29%	30.71%	31.00%		4	-
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.			50.00%	30.00%	20.00%		4	-
25	HV	Zone substation Buildings	Zone substations 110kV+	No.							N/A	
26	HV	Zone substation switchgear	22/33kV CB (Indoor)	No.			40.00%	10.00%	50.00%		4	-
27	HV	Zone substation switchgear	22/33kV CB (Outdoor)	No.				90.48%	9.52%		4	-
28	HV	Zone substation switchgear	33kV Switch (Ground Mounted)	No.							N/A	
29	HV	Zone substation switchgear	33kV Switch (Pole Mounted)	No.			75.50%	15.00%	9.50%		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.		5.00%	35.00%	40.00%	20.00%		3	5.00%
34	HV	Zone substation switchgear	3.3/6.6/11/22kV CB (pole mounted)	No.							N/A	
39	HV	Zone Substation Transformer	Zone Substation Transformers	No.		5.20%	63.30%	21.00%	10.50%		4	10.52%
40	HV	Distribution Line	Distribution OH Open Wire Conductor	km		7.00%	76.15%	7.25%	9.60%		3	7.20%
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		-	61.70%	29.50%	8.80%		3	-
44	HV	Distribution Cable	Distribution UG PILC	km		2.00%	90.00%	8.00%			2	2.00%
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.		2.50%	62.50%	15.00%	20.00%		4	2.50%
47	HV	Distribution switchgear	3.3/6.6/11/22kV CB (Indoor)	No.		5.12%	52.88%	24.00%	18.00%		4	5.20%
48	HV	Distribution switchgear	3.3/6.6/11/22kV Switches and fuses (pole mounted)	No.		3.50%	78.80%	11.70%	6.00%		3	4.50%
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.		6.00%	48.50%	40.00%	5.50%		4	6.50%
51	HV	Distribution Transformer	Pole Mounted Transformer	No.		4.00%	20.00%	54.00%	22.00%		4	4.00%
52	HV	Distribution Transformer	Ground Mounted Transformer	No.		4.00%	45.00%	10.00%	41.00%		4	5.00%
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		4.00%	-	-	2.30%	94.70%	2	4.00%
56	LV	LV Cable	LV UG Cable	km				35.00%	9.00%	56.00%	2	2.00%
57	LV	LV Streetlighting	LV OH/UG Streetlight circuit	km						100.00%	2	1.00%
58	LV	Connections	OH/UG consumer service connections	No.		10.00%		42.00%	15.00%	33.00%	2	10.00%
59	All	Protection	Protection relays (electromechanical, solid state and numeric)	No.		10.00%	45.00%	10.00%	35.00%		4	15.00%
60	All	SCADA and communications	SCADA and communications equipment operating as a single system	Lot		10.00%	30.00%	30.00%	30.00%		3	12.00%
61	All	Capacitor Banks	Capacitors including controls	No.							N/A	
62	All	Load Control	Centralised plant	Lot				50.00%	50.00%		4	-
63	All	Load Control	Relays	No.					-	100.00%	2	10.00%
64	All	Civils	Cable Tunnels	km							N/A	

Appendix 5: Schedule 12b – Report on Forecast Capacity

Company Name	Electra Ltd
AMP Planning Period	1 April 2020 – 31 March 2030

SCHEDULE 12b: REPORT ON FORECAST CAPACITY

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

sch ref

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

sch ref	*Existing Zone Substations*	Current Peak Load (MVA)	Installed Firm Capacity (MVA)	Security of Supply Classification (type)	Transfer Capacity (MVA)	Utilisation of Installed Firm Capacity %	Installed Firm Capacity +5 years (MVA)	Utilisation of Installed Firm Capacity + 5yrs %	Installed Firm Capacity Constraint +5 years (cause)	Explanation
9	Shannon	4.6	5	N-1	6	92%	5	100%	No constraint within +5 years	
10	Foxton	6.8	23	N-1	4	30%	23	33%	No constraint within +5 years	
11	Levin West	12.9	23	N-1	12	56%	23	63%	No constraint within +5 years	
12	Levin East	14.4	23	N-1	12	63%	23	68%	No constraint within +5 years	Please enter text.
13	Otaki	11.7	23	N-1	4	51%	23	58%	No constraint within +5 years	
14	Waikanae	15.2	23	N-1	12	66%	23	78%	No constraint within +5 years	
15	Paraparaumu	12.9	23	N-1	16	56%	23	61%	No constraint within +5 years	
16	Paraparaumu West	12.7	23	N-1	8	55%	23	61%	No constraint within +5 years	
17	Raumati	9.9	23	N-1	12	43%	23	48%	No constraint within +5 years	
18	Paekakariki	2.3	-	N-1 (Switched)	6	-	-	-	No constraint within +5 years	Automatic changeover to Raumati using fault monitors and motorised switches
19										
20										
21										
22										
23										
24										
25										
26										
27										
28										

29 [1] *Extend forecast capacity table as necessary to disclose all capacity by each zone substation*

Appendix 6: Schedule 12c – Report on Forecast Network Demand

Company Name	Electra Ltd
AMP Planning Period	1 April 2020 – 31 March 2030

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

sch ref			Current Year CY	CY+1	CY+2	CY+3	CY+4	CY+5
7	**12c(i): Consumer Connections**							
8	*Number of ICPs connected in year by consumer type*				**Number of connections**			
9			*Current Year CY*	*CY+1*	*CY+2*	*CY+3*	*CY+4*	*CY+5*
10		for year ended	**31 Mar 20**	**31 Mar 21**	**31 Mar 22**	**31 Mar 23**	**31 Mar 24**	**31 Mar 25**
11	*Consumer types defined by EDB**							
12	All		400	425	450	475	500	525
13	[EDB consumer type]							
14	[EDB consumer type]							
15	[EDB consumer type]							
16	[EDB consumer type]							
17	**Connections total**		400	425	450	475	500	525
18	**include additional rows if needed*							
19	**Distributed generation**							
20	Number of connections		130	140	150	160	170	180
21	Capacity of distributed generation installed in year (MVA)		0.5	0.5	0.5	0.6	0.6	0.6
22	**12c(ii) System Demand**							
23			*Current Year CY*	*CY+1*	*CY+2*	*CY+3*	*CY+4*	*CY+5*
24	**Maximum coincident system demand (MW)**	for year ended	**31 Mar 20**	**31 Mar 21**	**31 Mar 22**	**31 Mar 23**	**31 Mar 24**	**31 Mar 25**
25	GXP demand		75	75	75	75	76	76
26	*plus* Distributed generation output at HV and above		26	27	27	27	27	27
27	**Maximum coincident system demand**		101	102	102	102	103	103
28	*less* Net transfers to (from) other EDBs at HV and above							
29	**Demand on system for supply to consumers' connection points**		101	102	102	102	103	103
30	**Electricity volumes carried (GWh)**							
31	Electricity supplied from GXPs		385	391	392	404	408	412
32	*less* Electricity exports to GXPs							
33	*plus* Electricity supplied from distributed generation		68	69	69	71	72	73
34	*less* Net electricity supplied to (from) other EDBs							
35	**Electricity entering system for supply to ICPs**		448	460	461	474	480	485
36	*less* Total energy delivered to ICPs		417	428	429	441	446	450
37	**Losses**		31	32	32	33	34	35
38								
39	**Load factor**		50%	51%	52%	53%	53%	54%
40	**Loss ratio**		6.9%	6.9%	6.9%	7.1%	7.1%	7.2%

Appendix 7: Schedule 12d – Report Forecast Interruptions and Duration

Company Name	Electra Ltd
AMP Planning Period	1 April 2020 – 31 March 2030
Network / Sub-network Name	Electra Ltd

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*
9	for year ended	**31 Mar 20**	**31 Mar 21**	**31 Mar 22**	**31 Mar 23**	**31 Mar 24**	**31 Mar 25**
10	**SAIDI**						
11	Class B (planned interruptions on the network)	15.0	15.0	15.0	15.0	15.0	15.0
12	Class C (unplanned interruptions on the network)	68.0	68.0	68.0	68.0	68.0	68.0
13	**SAIFI**						
14	Class B (planned interruptions on the network)	0.06	0.06	0.06	0.06	0.06	0.06
15	Class C (unplanned interruptions on the network)	1.60	1.60	1.60	1.60	1.60	1.60

Appendix 8: Schedule 13 – Report on Asset Management Maturity

Company Name	**Electra Ltd**
AMP Planning Period	**1 April 2020 – 31 March 2030**
Asset Management Standard Applied	**PAS 55; EEA Guide 2014**

SCHEDULE 13: REPORT ON ASSET MANAGEMENT MATURITY

This schedule requires information on the EDB'S self-assessment of the maturity of its asset management practices .

Question No.	Function	Question	Score	Evidence—Summary	User Guidance	Why	Who	Record/documented Information
3	Asset management policy	To what extent has an asset management policy been documented, authorised and communicated?	2	Policy exists dated 2013; has not been revised and designations and authorities are out of date. There is no version control on the document and no process for an update.		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?	1.5	The group strategy is current but it is a group business strategy with some references to asset management such as ISO 55000	Moving towards strategies and updating databases and information, developing the ARMM database for overhead lines, zone transformers, circuit breakers. Documentation needs to be formalised.	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?	1.5	The group strategy is current but does not have liftcycle strategies within it. Documentation for individual asset lifecycle strategies, procedures need to be formalised and records linked to conditional based risk assessment.		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	Asset management contain parts of lifecycle strategies.		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 Ltd**
AMP Planning Period	**1 April 2020 – 31 March 2030**
Asset Management Standard Applied	**PAS 55; EEA Guide 2014**

SCHEDULE 13: REPORT ON ASSET MANAGEMENT MATURITY (cont)

Question No.	Function	Question	Score	Evidence—Summary	User Guidance	Why	Who	Record/documented Information
27	Asset management plan(s)	How has the organisation communicated its plan(s) to all relevant parties to a level of detail appropriate to the receiver's role in their delivery?	2	Communicate the plan to the board at this stage, and through the EDMS and Intranet	There is a need to communicate to other stakeholders in the organization such as their customer servicesand construction teams	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	There is documentation but lacks accountabilities for asset management plan responsibities.		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)	1.5	Works delivery plan covers only construction team not engineers required to deliver the AMP		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	SMS standards for communication escalation for major events and strategic spares have been established.	Events need to be reviewed and monitored for improvement.	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 Ltd
AMP Planning Period	1 April 2020 – 31 March 2030
Asset Management Standard Applied	PAS 55; EEA Guide 2014

SCHEDULE 13: REPORT ON ASSET MANAGEMENT MATURITY (cont)

Question No.	Function	Question	Score	Evidence—Summary	User Guidance	Why	Who	Record/documented Information
37	Structure, authority and responsibilities	What has the organisation done to appoint member(s) of its management team to be responsible for ensuring that the organisation's assets deliver the requirements of the asset management strategy, objectives and plan(s)?	2.5	Organisation chart of responsibilities is in 1.7 of AMP but a RASCI matrix needs to be developed.		In order to ensure that the organisation's assets and asset systems deliver the requirements of the asset management policy, strategy and objectives responsibilities need to be allocated to appropriate people who have the necessary authority to fulfil their responsibilities. (This question, relates to the organisation's assets eg, para b), s 4.4.1 of PAS 55, making it therefore distinct from the requirement contained in para a), s 4.4.1 of PAS 55).	Top management. People with management responsibility for the delivery of asset management policy, strategy, objectives and plan(s). People working on asset-related activities.	Evidence that managers with responsibility for the delivery of asset management policy, strategy, objectives and plan(s) have been appointed and have assumed their responsibilities. Evidence may include the organisation's documents relating to its asset management system, organisational charts, job descriptions of post-holders, annual targets/objectives and personal development plan(s) of post-holders as appropriate.
40	Structure, authority and responsibilities	What evidence can the organisation's top management provide to demonstrate that sufficient resources are available for asset management?	2.5	Resource forecast and strategy are in Section 9 of AMP. Process documentation need to be developed with revision document control.		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?	2.5	Weekly team meetings to discuss asset events, complaints. Monthly depot meetings conducted and presentations given to field staff on new requirements such as earthing standards.		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	Contracts and policies need to be reviewed and aligned with asset management strategies.		Where an organisation chooses to outsource some of its asset management activities, the organisation must ensure that these outsourced process(es) are under appropriate control to ensure that all the requirements of widely used AM standards (eg, PAS 55) are in place, and the asset management policy, strategy objectives and plan(s) are delivered. This includes ensuring capabilities and resources across a time span aligned to life cycle management. The organisation must put arrangements in place to control the outsourced activities, whether it be to external providers or to other in-house departments. This question explores what the organisation does in this regard.	Top management. The management team that has overall responsibility for asset management. The manager(s) responsible for the monitoring and management of the outsourced activities. People involved with the procurement of outsourced activities. The people within the organisations that are performing the outsourced activities. The people impacted by the outsourced activity.	The organisation's arrangements that detail the compliance required of the outsourced activities. For example, this this could form part of a contract or service level agreement between the organisation and the suppliers of its outsourced activities. Evidence that the organisation has demonstrated to itself that it has assurance of compliance of outsourced activities.

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SCHEDULE 13: REPORT ON ASSET MANAGEMENT MATURITY (cont)

Question No.	Function	Question	Score	Evidence—Summary	User Guidance	Why	Who	Record/documented Information
48	Training, awareness and competence	How does the organisation develop plan(s) for the human resources required to undertake asset management activities - including the development and delivery of asset management strategy, process(es), objectives and plan(s)?	3	The job descriptions for Asset Management team members were reviewed.		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	Competency framework sighted previously.		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	Job descriptions sighted		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	Score	Evidence—Summary	User Guidance	Why	Who	Record/documented Information
53	Communication, participation and consultation	How does the organisation ensure that pertinent asset management information is effectively communicated to and from employees and other stakeholders, including contracted service providers?	2.5	There is evidence that there are meetings and feedback		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	There is evidence for the policy, strategies and standards are discussed in the AMP.		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	SMS standards have been sighted.		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 management information system should contain in order to support its asset management system. Evidence that this has been effectively implemented.
63	Information management	How does the organisation maintain its asset management information system(s) and ensure that the data held within it (them) is of the requisite quality and accuracy and is consistent?	3	Data available for age profiles and condition-based lifecycle management, assessment (for lines) sighted.		The response to the questions is progressive. A higher scale cannot be awarded without achieving the requirements of the lower scale. This question explores how the organisation ensures that information management meets widely used AM practice requirements (eg, s 4.4.6 (a), (c) and (d) of PAS 55).	The management team that has overall responsibility for asset management. Users of the organisational information systems.	The asset management information system, together with the policies, procedure(s), improvement initiatives and audits regarding information controls.

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Question No.	Function	Question	Score	Evidence—Summary	User Guidance	Why	Who	Record/documented Information
64	Information management	How has the organisation's ensured its asset management information system is relevant to its needs?	3	Company has evaluated and moved to ADMS and Axos systems to improve their processes.		Widely used AM standards need not be prescriptive about the form of the asset management information system, but simply require that the asset management information system is appropriate to the organisations needs, can be effectively used and can supply information which is consistent and of the requisite quality and accuracy.	The organisation's strategic planning team. The management team that has overall responsibility for asset management. Information management team. Users of the organisational information systems.	The documented process the organisation employs to ensure its asset management information system aligns with its asset management requirements. Minutes of information systems review meetings involving users.
69	Risk management process(es)	How has the organisation documented process(es) and/or procedure(s) for the identification and assessment of asset and asset management related risks throughout the asset life cycle?	2	PSMS is in place and improving its process with the use of the Vault software.		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	PSMS system developing into a better system for recording incidents validated by audits.		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?	3	Competent level (using ComplyWith).		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	Score	Evidence—Summary	User Guidance	Why	Who	Record/documented Information
88	Life Cycle Activities	How does the organisation establish implement and maintain process(es) for the implementation of its asset management plan(s) and control of activities across the creation, acquisition or enhancement of assets. This includes design, modification, procurement, construction and commissioning activities?	2	Procedures, processes and contruction standards to be periodically reviewed, formalised and version controlled.		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	2.5	Asset inspections and maintenance plans are budgeted and implemented.		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	ARMM for assets as well as fault analysis for 10 worst feeders done by SAIDI and SAIFI, and corrective action has room for improvement e.g. incorporating the ni=umber of repeated outages		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	NGAN process identified but RASCI matirx to be incorporated.		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	Score	Evidence—Summary	User Guidance	Why	Who	Record/documented Information
105	Audit	What has the organisation done to establish procedure(s) for the audit of its asset management system (process(es))?	1.5	Field activities are routinely scheduled and audited within the Public Safety Framework; these include internal and external audits. The SMS RIsk document as well as the Vault software also documents risks registers, hazards and risk assessments. The AMMAT review conducted	Electra appreciates that under PAS 55, there is a requirement to further lift the auditing process to drive continual improvement in asset management audit activities.	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?	1.5	Processes need to be established and formalised for corrective actions including version control.		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?	1.5	Documentation of processes need to be formalised and these activites documented.		Widely used AM standards have requirements to establish, implement and maintain process(es)/procedure(s) for identifying, assessing, prioritising and implementing actions to achieve continual improvement. Specifically there is a requirement to demonstrate continual improvement in optimisation of cost risk and performance/condition of assets across the life cycle. This question explores an organisation's capabilities in this area—looking for systematic improvement mechanisms rather that reviews and audit (which are separately examined).	The top management of the organisation. The manager/team responsible for managing the organisation's asset management system, including its continual improvement. Managers responsible for policy development and implementation.	Records showing systematic exploration of improvement. Evidence of new techniques being explored and implemented. Changes in procedure(s) and process(es) reflecting improved use of optimisation tools/techniques and available information. Evidence of working parties and research.
115	Continual Improvement	How does the organisation seek and acquire knowledge about new asset management related technology and practices, and evaluate their potential benefit to the organisation?	3	Business case documentation for improved software for reliability and billing as well as implementation of new - technology.		One important aspect of continual improvement is where an organisation looks beyond its existing boundaries and knowledge base to look at what 'new things are on the market'. These new things can include equipment, process(es), tools, etc. An organisation which does this (eg, by the PAS 55 s 4.6 standards) will be able to demonstrate that it continually seeks to expand its knowledge of all things affecting its asset management approach and capabilities. The organisation will be able to demonstrate that it identifies any such opportunities to improve, evaluates them for suitability to its own organisation and implements them as appropriate. This question explores an organisation's approach to this activity.	The top management of the organisation. The manager/team responsible for managing the organisation's asset management system, including its continual improvement. People who monitor the various items that require monitoring for 'change'. People that implement changes to the organisation's policy, strategy, etc. People within an organisation with responsibility for investigating, evaluating, recommending and implementing new tools and techniques, etc.	Research and development projects and records, benchmarking and participation knowledge exchange professional forums. Evidence of correspondence relating to knowledge acquisition. Examples of change implementation and evaluation of new tools, and techniques linked to asset management strategy and objectives.

Appendix 9: Glossary

Term	Description
ABS	Air Break Switch
ADMS	Advanced Distribution Management System
AMMAT	Asset Management Maturity Assessment Tool
AMP	Asset Management Plan
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
CBD	Central Business District.
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.
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.
DER	Distributed Energy Resource
Distribution Substation	A kiosk, outdoor ground mounted substation or pole mounted substation taking its supply at 11kV and distributing at 400V.
ECP	Electrical Code of Practice
EDB	Electricity Distribution Business
Feeder	A physical grouping of conductors that originate from a district substation circuit breaker.
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)
FY	Financial Year e.g. FY2021 is Financial Year 2019 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
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
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.

Term	Description
LCP	Load Control Plant
LED	Light-emitting diode
Load Factor	The measure of annual load factor is calculated as the average load that passes through a network divided by the maximum load experienced in a given year.
Low Voltage	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.
MVA	Megavolt amp.
MW	Megawatt
MWh	Megawatt hours (one million-watt hours)
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.
NIMs	A Network Information Management System which contains geospatial information for all assets including asset description, location, age, electrical attributes, etc.
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
PILC	Paper-insulated, lead-covered - a type of cable insulation.
Photovoltaic	The conversion of light into electricity using solar panels
Ripple Control system	A system used to control the electrical load on the network by, for example switching domestic water heaters, street lighting.
RMU	Ring Main Unit.
RTU	Remote Terminal Unit
SAIDI	System Average Interruption Duration Index is the average total duration of interruptions per connected customer
SAIFI	System Average Interruption Frequency Index is the average number of interruptions per connected customers
SCADA	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
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.
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.
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.

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