Asset Management Plan
1st April 2017 – 31st March 2027

Approved by Electra Board: 31st March 2017
Direct enquiries to: General Manager - Lines Business

I am pleased to present our 2017 asset management plan. This version represents a significant update from our previous plans and outlines how we intend to manage our core electricity network assets to meet our vision to *enhance the region's development through the provision of 21st century infrastructure.*

Our asset management team have been considering how we can develop, maintain and operate the electricity network to meet this vision. We have included our direction and plans in this 2017 AMP.

You can expect that our plans will evolve as the needs of our customers change, however, for this plan the important themes are:

- Our network has adequate capacity to support further regional economic development. There is always work to do to ensure we continue to have adequate capacity. We have identified a small number of projects to enhance capacity. Our total spend on network development is $5.9 million over the next ten-years, which represent around 6.5% of our spend over that period;

- Communications with our customers will be enhanced.

- Customer's needs are changing and we are working on plans to ensure that our network can cater for the increasing use of electric vehicles and solar generation. We have acknowledged the impact these emerging technologies could have on the network and are developing plans to enable the network to facilitate their use.

  We have identified the need to implement an advanced distribution management system at a cost of $3.0 million. This system will allow us to better manage up to our low voltage network, where the impact of electric vehicles and solar generation will be seen. Our plans are in the early stages, and will become clearer in subsequent AMPs;

- Our network continues to perform reliably and is one of the most reliable networks in New Zealand. However, our network remains susceptible to severe weather events.

  We continue to pursue a significant program to replace ageing network assets, and this work comprises 77%, or $70 million of our capital expenditure over the next ten years. We are also planning to spend a further $13.1 million on reliability and safety and environment improvement initiatives.

This AMP is an important and evolving document and your feedback is welcome. Our General Manager – Lines Business would be happy to hear from you.

Kind regards
Neil Simmonds
Chief Executive"

0. Summary

0.1 Key themes of this AMP

The key themes of this AMP for the period 1st April 2017 to 31st March 2027 are

- A simplification of the AMP layout bringing outcomes and reasoning to the fore, while including supporting information on strategy and process in appendices.
- Retaining a focus on management of asset classes, while strengthening the presentation of managing assets for holistic network functionality and customer experience.
- A short-term focus on asset renewal and reliability improvement by feeder sectionalisation and improving 11kV interconnection.
- A medium to long-term focus on meeting isolated pockets of demand growth that are not expected to require zone substation or GXP reinforcement.
- Development of a vegetation management strategy focusing on reducing the SAIDI and SAIFI impact of vegetation hazards.
- Growth in electric vehicle charging as people respond to Government incentives.
- The implemention of an Advanced Distribution Management System during 2017/18 that will provide state estimation at an LV level and will provide insights on LV power flows, quality and interruptions.
- Further development of cost reflective price options.
- Issues on Electra's watch list include uptake of solar and batteries, and the impact of energy efficient street lighting on kWh revenue for that sector.

0.2 Material projects

Material projects for the planning period include

Description	Proposed timing	Expected cost
Raumati 11kV north half switchgear replacement	2018	$408,000
Levin East Zone Substation Protection Upgrade	2019	$582,000
Replace 11kV switchgear Paekakariki substation	2020	$327,000
33kV Levin East – Mangahao line renewal	2020-2024	$2,620,000
Rebuild Rumati zone substation	2020-2023	$2,650,000

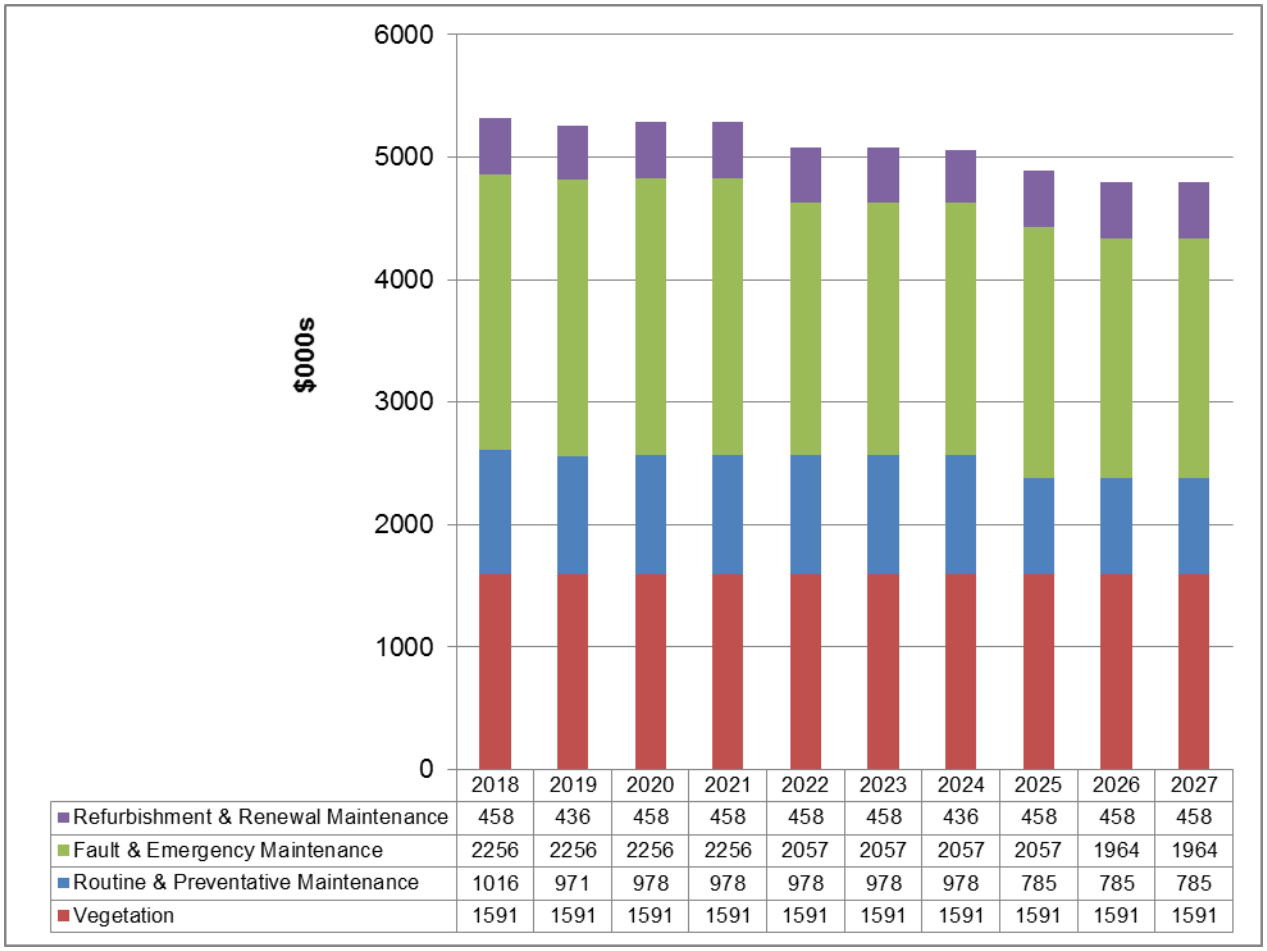
Foxton to Levin West line section upgrade	2021-2024	$1,830,000
Rebuild Foxton zone substation	2025-2026	$1,200,000
Levin West to Levin East 33kV line section upgrade	2025	$613,000
Build Waikawa rural substation	2026-2027	$1,270,000

0.3 Forecast expenditure

Projected capital expenditure over the next 10 years is expected to be 6.5% of total for growth, 16.5% of total for reliability and 77% of total for renewal and replacement work.

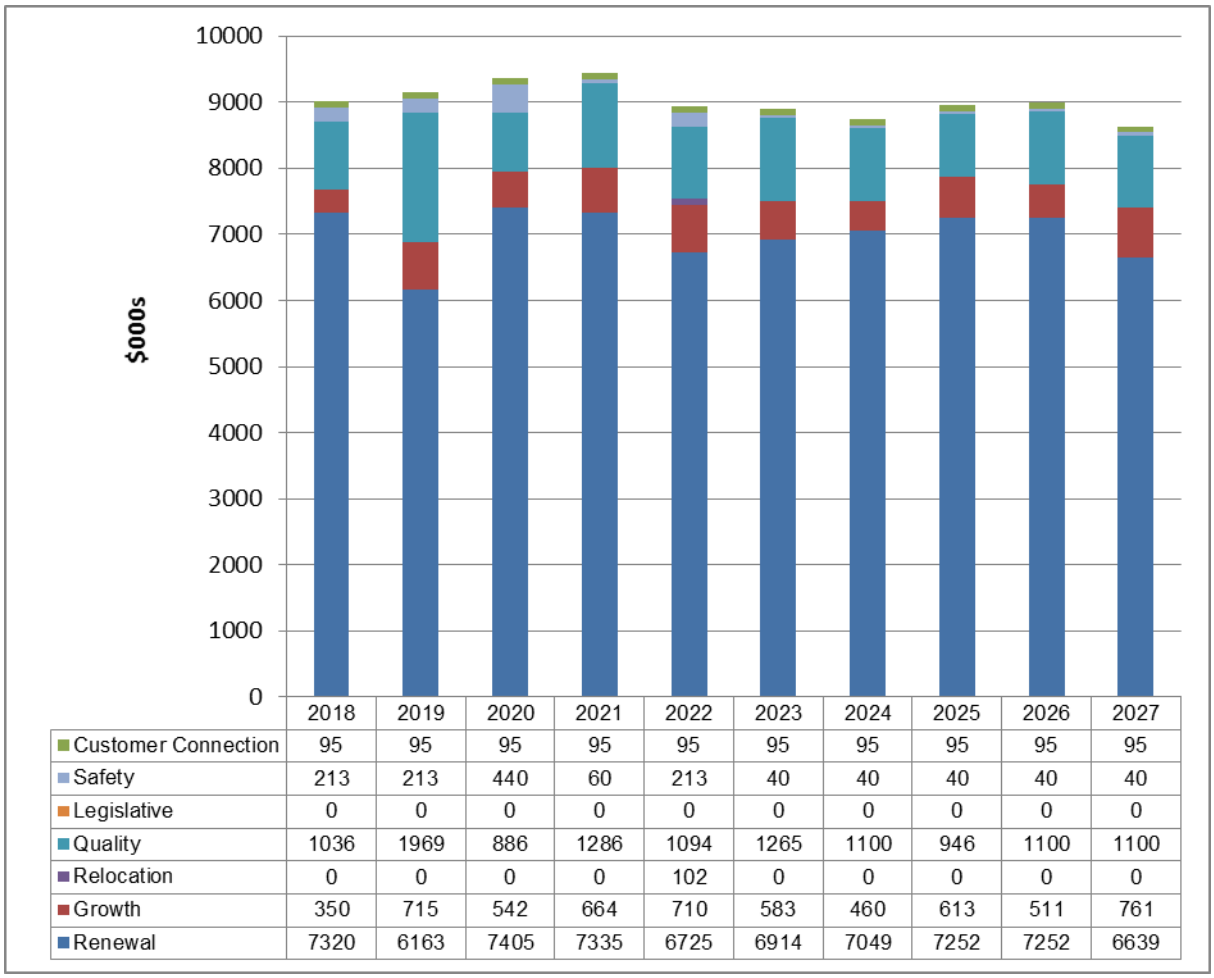
Capital costs are expected to average $9m per year over the next 10 years while operational costs are expected to average $5.1m per year over the same period. Electra has the flexibility to modify this approach if growth accelerates beyond our expectations.The expenditure forecast is based on 2017 constant dollars.

Summary OpEx forecast (year ending 31st March)



	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027
Refurbishment & Renewal Maintenance	458	436	458	458	458	458	436	458	458	458
Fault & Emergency Maintenance	2256	2256	2256	2256	2057	2057	2057	2057	1964	1964
Routine & Preventative Maintenance	1016	971	978	978	978	978	978	785	785	785
Vegetation	1591	1591	1591	1591	1591	1591	1591	1591	1591	1591

Summary CapEx forecast (year ending 31st March)



	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027
Customer Connection	95	95	95	95	95	95	95	95	95	95
Safety	213	213	440	60	213	40	40	40	40	40
Legislative	0	0	0	0	0	0	0	0	0	0
Quality	1036	1969	886	1286	1094	1265	1100	946	1100	1100
Relocation	0	0	0	0	102	0	0	0	0	0
Growth	350	715	542	664	710	583	460	613	511	761
Renewal	7320	6163	7405	7335	6725	6914	7049	7252	7252	6639

Contents

1. Background, context & objectives

1.1 Purpose statement

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

Additionally, the format and data content of this plan is presented to facilitate comparative and longitudinal benchmarking and is consistent with the requirements of the Electricity Distribution Information Disclosure Determination 2012.

1.2 Mission & vision

Electra's mission is to…

Enhance the region's development through the provision of 21st Century infrastructure.

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.

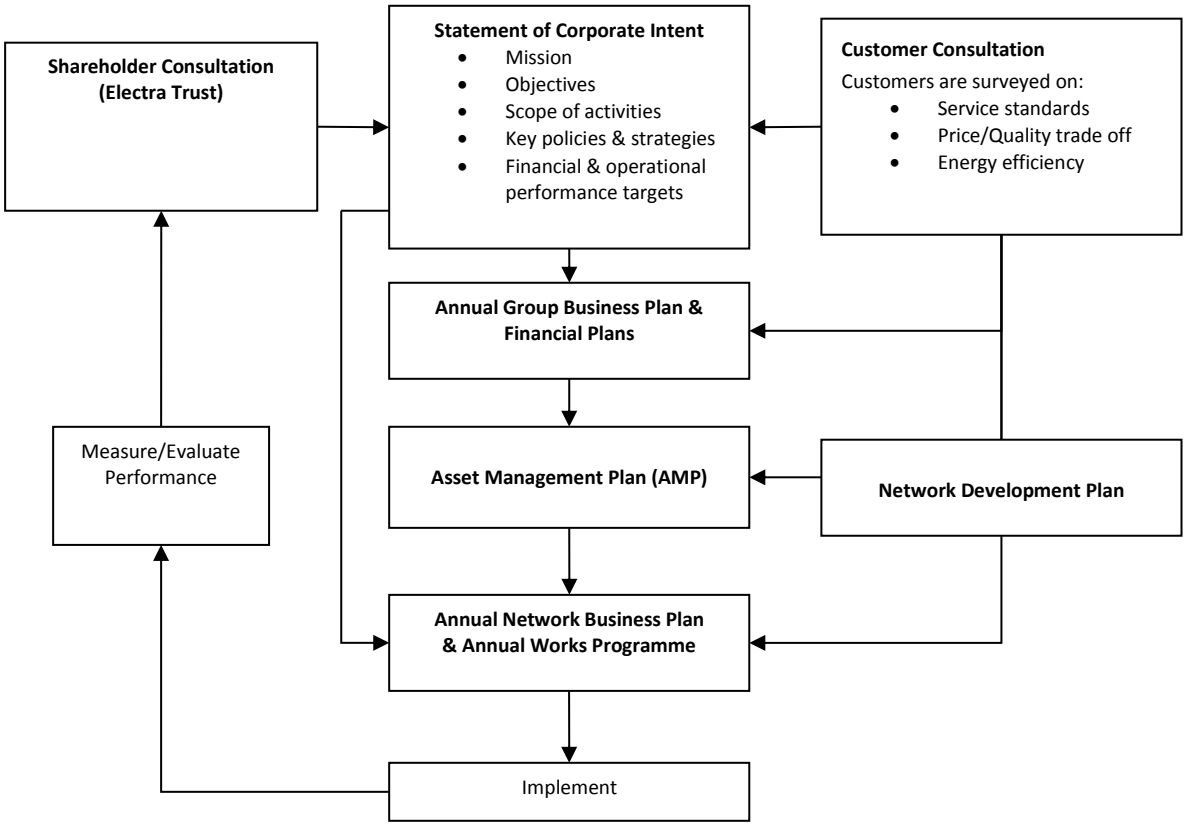
1.3 Key plans and documents

Electra's key plans and documents include…

Document title	Purpose
Statement of Corporate Intent	Articulates key strategies, governance philosophy, scope of activities and high level goals of business performance and customer experience.
Group strategic plan	Consolidates the strategic plans of Electras' subsidiaries into a coordinated Group plan.
Asset management plan	Connects management of long-life assets to Electras' 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 program	Define detail of specific works on a 12 month basis.

1.4 Relationships between plans and documents

The relationship between Electra's key plans and documents is as follows…



1.5 Linkages between planning goals

The above sub-chapters emphasise the line-of-sight and progressive refinement Electra's approach from strategic goals to tactical to operational plans. This is complemented by a small and close working environment.

1.6 Planning period

The planning period for this AMP is 1st April 2017 to 31st March 2018. The AMP embodies 3 levels of increasing certainty for nearer term plans.

Period	Scope	Cost	Timing
1st April 2017 – 31st March 2018	Firm, approved in principle	±5%	Quarter / month
1st April 2018 – 31st March 2022	Major components	±10%	Quarter
1st April 2022 – 31st March 2027	Indicative	±25%	Year

1.7 Board approval

This AMP was submitted in draft to the February Board meeting to allow for inclusion of the Board's comments before final approval on 31st March 2017.

1.8 Stakeholder interests

Electra defines its stakeholders as any person or organisation who effects or is effected by Electra's business.

1.8.1 Stakeholder interests and how they are identified

Electra defines its stakeholders as any person, class of persons or organisation 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 gossip • 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.

Industry representative groups	✓	✓			• Annually via meetings and conferences.
Staff & contractors	✓	✓	✓	✓	• Weekly staff meeting • Monthly contractor meetings • As required for specific projects • General workplace interactions • Performance appraisals.
Suppliers of goods & 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.
Land owners			✓	✓	• 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 Economic Development			✓	✓	• 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.
Electricity & Gas Complaints Commission		✓		✓	• 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.

1.8.2 Linking stakeholder interests to asset management practices

Electra's stakeholder interests are linked to its 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 its 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 its 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 (December 2015) indicated a general satisfaction with the present supply quality.
		• Electra will accommodate its 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

Viability	➔	deposit at the bank plus a margin to reflect the risks to capital in an increasingly regulated lines sector. • Price is the key to viability, but must be managed to be in line with similar network companies and to provide a satisfactory discount to Electra's consumer/owners.
Compliance	➔	• Electra ensure that all safety issues are adequately documented and available for inspection by authorised agencies as well as for learning by its own staff and contractors. • Electra discloses performance information in a timely and compliant fashion.

1.8.3 Managing conflicting stakeholder interests

Stakeholder interests will be managed in the following order of priority…

1. Safety of the public, Electra's 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 and hazard assessments during the assets operating life.

2. Customer's requirements for a reliable and efficient energy supply will be given second priority.

3. Viability.

4. Non-safety compliance.

1.9 Accountabilities for asset management

1.9.1 Accountability at governance level

Accountability at the governance level is by two mechanisms…

- Electra's Board are accountable to the Electra Trust via the Statement of Corporate Intent.

- The Electra Trust are accountable to the connected consumers through the Trustee elections.

1.9.2 Accountability at management level

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.

- The General Manager – Lines Business is accountable to the Chief Executive.

- There are four managers accountable to the General Manager – Lines Business.

1.9.3 Accountability at field operations level

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

1.9.4 Summary of roles, delegated authorities & reporting

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

Activity	Board	Chief Executive	GM – Lines Business
Preparing Statement Of Corporate Intent	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	Some input, key role is approving.	Preparation, submit to Board for approval.	Contributes together with the Executive Team.
Role with Asset Management Plan	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).
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 programs and significant projects	Responsible for detailed oversight of all works programs.
Reporting of outages	Summary included in monthly Board reports.	Summary included in monthly Board reports.	Receives a report of incidents, causes and follow up actions.

Delegated authorities are discussed more fully in Chapter 10.

1.9.5 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.
- 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 Ashhurst who are contracted to maintain SCADA and Control Centre radio communications. ICONA provide similar specialised support for a number of other EDB's
- Eagle Technology of Wellington for GIS support for the ESRI system used by a number of other EDB's and Local Authorities.
- Sandfield SQL database provisioning.
- Utility Consultants of Hamilton for asset management strategy and planning advice.
- 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 works.
- Tatanas and PEL for civil works and traffic management.

1.10 Significant assumptions

Significant assumptions for this AMP are…

- There will be no significant changes in national energy policy.
- Uptake of electric cars will increase in response to Government incentives.
- No significant changes in Council land use policy that will increase the cost of Electra doing work.
- No significant changes in land access policy by NZTA or by KiwiRail that will increase the cost of Electra doing work.
- The Wellington Northern Corridor roading development will continue as stated in the Roads of National Significance (the NZTA's website).
- The current Electricity Authority emphasis on cost reflective pricing will continue. To develop its' pricing options, Electra will apply more sophisticated analytics to demand and consumption data.
- The number of roof-top solar and battery installations will increase. Expected impact is small, thought customer attitude to the adoption of this technology will be monitored.
- Evolving application of device interconnectivity (the internet of things) will expand into energy transmission and network operations.
- The rate of inflation for the Planning Period will be 1.7%, which is based on the ANZ Bank forecasts.
- The Horowhenua District's resident population is forecast to increase by 8,600 people over the next 20 years, including an expected 4,900 houses and 3,000 jobs created.
- The Kapiti Coast District's resident population is forecast to increase by 6,300 people over the next 15 years.

Electra monitors and is adaptive to the rate of change in these characterisitcs of the business environment.

1.11 Causes of possible material difference

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

- Variations to the understood motorway development plans.
- An inability to manage electric car recharging to off-peak periods (whether through policy or otherwise).

- Variations from forecast labor and material costs.
- Increased health, safety and traffic management requirements that increase the cost of work.
- Increased requirements for access to land by NZTA or KiwiRail that increase the cost of work.
- A previously unknown widespread asset defect emerges that effects a large number of assets.
- Changes to the rate of customer adoption of new technologies.

1.12 Overview of asset strategy & delivery

Key features of Electra's asset strategy & delivery include…

- A demonstrable alignment with the Statement of Corporate Intent and the Group Strategic Plan.
- Visible inclusion of each phase of an assets lifecycle.
- Consideration of reliability, safety and lifecycle costs as an integral part of managing assets lifecycle (Safety in Design).

Refer to the individual asset lifecycle strategies in Chapter 6

1.13 Overview of systems & information

Electra uses a number of asset management systems to facilitate best practice asset management.

System	Data Held	What data is used for	Extent of integration
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.
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.
SCADA	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.
NIMS (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	Integral part of NIMS
Valuation Spreadsheets	Asset types, quantities, ages, expected total lives, remaining lives and values	Used for system fixed asset valuations	High (export from NIMS)
Paper & Electronic Documents	Miscellaneous records, design and operational files	Used to support GIS (NIMs) data	Highly manual

Reconciliation between the various data sets means that Electra now has improved data quality levels for its 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
	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 Chapter 6.

1.14 Limitations of this AMP

Compiling of this AMP has revealed the following possible limitations…

- For some classes of assets the condition data requires validation before it can be acted on. Electra plans to systematically cleanse and strengthen its asset condition data during 2017/18.

    - Demand forecasting methods have historically been linear extrapolations. Electra recognises that demand forecasting particularly for the southern network has become more complex, and it intends to develop a more comprehensive methodology during 2017/18 that will include consideration of emerging technologies, declining consumption and increasing demand .

Electra is confident that neither of these issues pose a significant risk to Electra's investment program or to public safety.

1.15 Overview of key processes

1.15.1 Routine inspections

Electra routinely inspects all classes of assets on a time basis. The timing and scope of inspections varies by asset class, asset criticality and public safety risk and are described in detail in chapter 6.

1.15.2 Maintenance

Electra uses the following range of maintenance strategies…

- 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.
- Individual low value, low risk components maybe managed on a run-to-breakdown basis.

These are described in detail in chapter 6.

1.15.3 Development projects

The key driver of all development projects is demand growth within existing network capacity (requiring a customer connection and minor network change), or demand growth in excess of existing network capacity or capability that requires capacity management, augmentation or 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 only be adopted after 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 eg. 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. Nett effect is minimal change in asset utilisation.	Ideally nil, probably minimal in practice.
Only after both of the above approaches have been determined to be unacceptable will Electra invest in new assets.	Ideally nil (capacity headroom maintain 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 Chapter 5.

1.15.4 Measuring performance

Electra measures its performance in 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).

Electra has 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.

1.16 Overview of documentation and controls

Electra manages its 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 the AMMAT section in Chapter 9.

1.17 Overview of communication processes

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

- Asset Planning & Development staff prepare the AMP and its associated work programs and budgets.
- The Finance team compile budgets for personnel, IT, AMP and non-network assets.
- Electra's Program 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 program.
- Electra has 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 Electra's priorities and work programs.

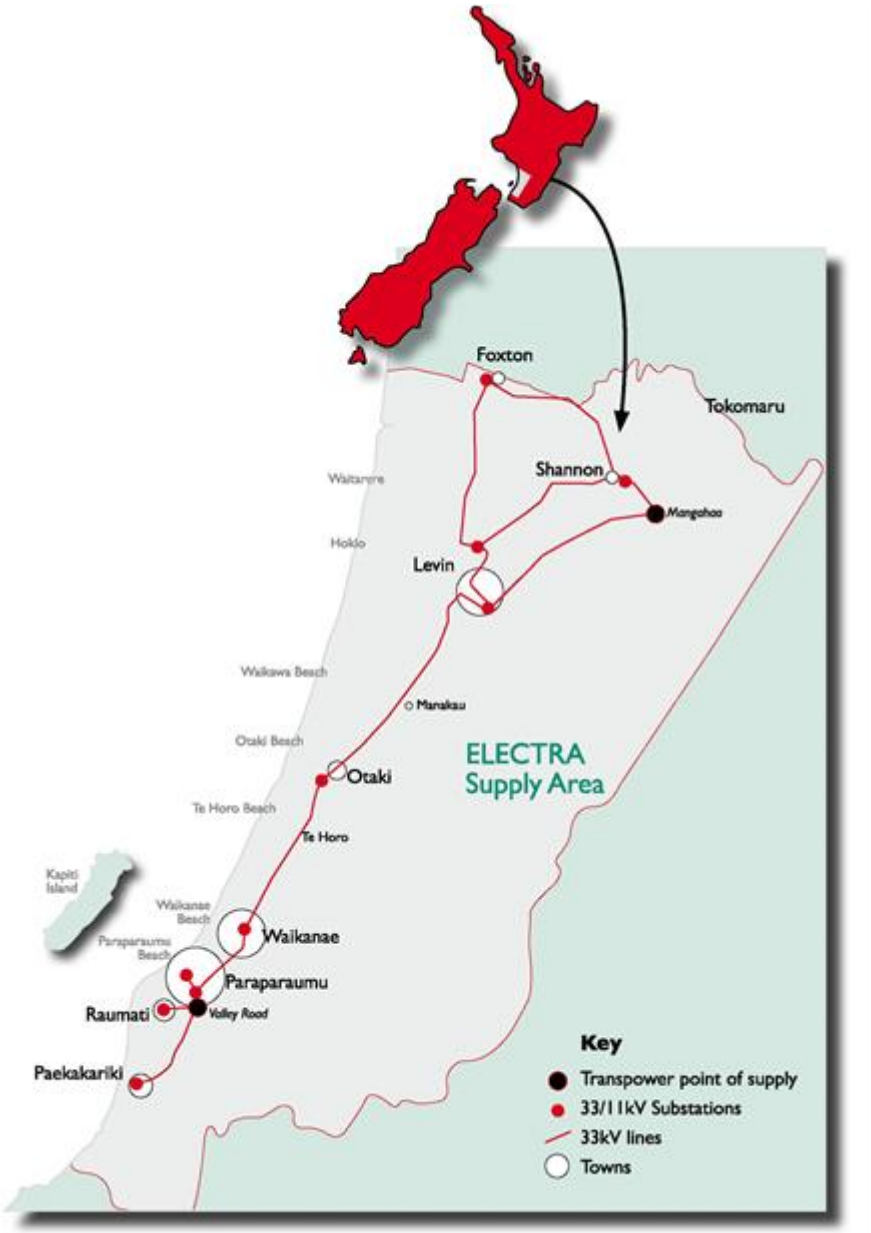
These communication processes are described in the AMMAT section in Chapter 9.

2. Assets covered by this AMP

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.



2.1.2 Large consumers

Electra's largest network customers are…

- Alliance Group, Levin (meat processing).
- Carter Holt Harvey, Levin (packaging manufacturer).
- Kapiti Coast District Council (sewage and water treatment).
- Pak n Save, Paraparaumu (supermarket).
- Unisys, Paraparaumu (data processing).
- KiwiRail, Kapiti Coast (rail transportation).

These consumers represent less than 5% of the energy conveyed through Electra's network. Accordingly, Electra faces a low revenue risk from its large industrial consumers' consumption trends.

Each of these consumers forecast demand and security requirements are discussed during Electra's consumer consultation process, 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 supplied predominantly from the Mangahao GXP, and supplying Levin, Foxton and Shannon. The economy of this market segment is strongly tied to root and leaf vegetable prices and to dairy prices, and has demonstrated low growth in both MW demand and ICP numbers along with declining kWh due to low economic growth and minimal growth in housing.

- A southern network supplied predominantly from Valley Road GXP, and supplying Paekakariki, Paraparaumu, Raumati, Waikanae and Otaki. 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 43% of the energy conveyed by Electra is though the northern network, and about 57% through the southern network.

2.1.4 Demand and energy

Key parameters of Electra's network as of 31st March 2016 are….

Parameters	Quantity
Number of connected customers	43,654
Maximum demand	107 MW
Annual electricity conveyance	439 GWh
Line and cable length	2,256 km
Number of zone substations	10
Number of distribution substations	2,546
Network asset valuation	$158m

2.2 Network configuration

Key "at a glance" features of Electra's network are as follows. Details of individual asset categories are set out in Chapter 3.

System level	Key features at a glance
Bulk supply & embedded generation	• 2 GXP's supplying a coincident maxium demand of 107 MW. • Embedded hydro station of 38 MW (Managaho). • About 300 rooftop solar installations.
Sub-transmission	• 4 zone substations supplied from Mangaho GXP. • 5 zone substations supplied from Valley Road GXP. • 1 zone substation that can be supplied from either Valley Road or Managahao.
Distribution network	• 854 km of overhead line • 234 km of underground cable.
Distribution substations	• 2,546 substations ranging in capacity from 5 kVA to 1,000 kVA.

3. Assets by category

3.1 Bulk supply assets

Electra takes bulk supply from two GXP's:

- Mangahao GXP, which supplies the northern area.
- Valley Road GXP, which supplies the southern area. Electra's Otaki zone substation may be supplied from either GXP, but is usually supplied from Valley Road.

Key features of these bulk supply points are….

GXP	Winter firm capacity (MVA)	Current peak demand (2016)
Mangahao	30	48.3
Valley Road	120	66.8

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.

3.2 Sub-transmission assets

Electra has 9 sub-transmission feeders as follows…

GXP	Feeder	Rating (A)	Typical loading (%)	Performance & risk concerns
Mangahao	Mangahao – Shannon 1	600	6%	Nil
	Mangahao – Shannon 2	600	6%	Nil
	Mangahao – Levin East 1	390	29%	Mangahao CB 332 will be replaced before its rating of 390 A is likely to be constrained by N-1 rating when feeding Otaki
	Mangahao – Levin East 2	390	29%	Mangahao CB 332 will be replaced before its rating of 390 A is likely to be constrained by N-1 rating when feeding Otaki.
Valley Road	Valley Road – Waikanae 1	530	24%	Nil
	Valley Road – Waikanae 2	600	21%	Nil.
	Valley Road – Para West	530	39%	Nil
	Valley Road - Paraparaumu	600	36%	Nil
	Valley Road - Paekakariki	600	7%	Nil

3.3 Zone substations

Electra has 10 zone substations which transform energy from the 33kV sub-transmission network to the 11kV distribution network. All but 1 are dual transformer substations.

Zone Substation	Description	Security	ICP's	Nature of Load	Performance & risk concerns
Shannon	• Dual-transformer • Indoor switchgear • Built in 2010.	(n-1)	1,861	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)	3,424	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)	5,676	Predominantly urban, although with some rural load to the south and east of Levin.	• No known issues • Performing within specification
Levin West	• Dual transformer • High-level steel structure • Built in 1974.	(n-1)	5,832	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)	5,,881	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)	6,757	Dense urban load in and around Waikanae, some rural load to the north in Peka 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)	4,347	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)	5,164	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)	3,813	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 is backed up by 11 kV feeder except for NZR traction substation on n security and backed up by other NZR supplies to the north and south	(n-1)*	899	Mix of light urban and semi-rural load around Paekakariki.	• No known issues • Performing within specification

3.3.1 Incoming switchgear

Incoming (33kV) switch gear is as follows…

Zone Substation	Description & number	Age (years)	Typical loading
Shannon	10 indoor SF6 circuit breakers	Ten at 7 years	3%
Foxton	4 outdoor SF6 circuit breakers	One at 28 years Three at 14 years	9%
Levin East	6 outdoor SF6 circuit breakers	Three at 27 years Two at 8 years One at 4 years	18%
Levin West	5 outdoor SF6 circuit breakers	One at 41 years One at 10 years One at 8 years Two at 5 years	19%
Otaki	5 indoor SF6 circuit breakers	Four at 23 years One at 14 years	8%
Waikanae	6 indoor SF6 circuit breakers	Six at 21 years	10%
Paraparaumu	8 indoor SF6 circuit breakers	Eight at 2 years	9%
Paraparaumu West	5 indoor SF6 circuit breakers	Five at 15 years	8%
Raumati	5 outdoor SF6 circuit breakers	Four at 29 years One at 12 years	7%
Paekakariki	1 outdoor oil circuit breaker	One at 35	3%

3.3.2 Power transformers

Power transformers (33/11kV) are as follows…

Zone Substation	Number and rating	Cooling	T1 age	T2 age	Utilisation of Installed Firm Capacity
Shannon	Two 5 MVA	ONAN	40	43	92%
Foxton	Two 11.5/23 MVA	ONAN, ONAF	13	13	30%
Levin East	Two 11.5/23 MVA	ONAN, ONAF	38	44	62%
Levin West	Two 11.5/23 MVA	ONAN, ONAF	6	17	59%
Otaki	Two 11.5/23 MVA	ONAN, ONAF	41	41	53%
Waikanae	Two 11.5/23 MVA	ONAN, ONAF	21	21	63%
Paraparaumu	Two 11.5/18/23 MVA	ONAN, ONAF, OFAF	47	47	54%
Paraparaumu West	Two 11.5/23 MVA	ONAN, ONAF	15	14	52%
Raumati	Two 11.5/23 MVA	ONAN, ONAF	6	30	44%
Paekakariki	One 5 MVA ONAN	ONAN	57		-

Shannon is the only substation that comes close to being loaded to near its firm (n-1) capacity. Load growth at Shannon is static, and in any case load can transferred to other substation by switching on the 11kV.

3.3.3 Outgoing switchgear

Outgoing switchgear (11kV) is as follows…

Zone Substation	Description & number	Age	Typical loading
Shannon	7 Reyrolle LMVP	Seven at 7 years	14%
Foxton	7 Reyrolle LMVP	Seven at 14 years	17%
Levin East	8 South Wales SF6 1 Reyrolle LMVP	Nine at 27 years	22%
Levin West	9 Reyrolle LMVP	Three at 43 years Six at 18 years	22%
Otaki	8 Reyrolle LMVP	Eight at 23 years	21%
Waikanae	9 Reyrolle LMVP	Nine at 21 years	25%
Paraparaumu	10 Reyrolle LMVP	Ten at 2 years	23%
Paraparaumu West	8 Reyrolle LMVP	One at 9 years Seven at 15 years	23%
Raumati	4 Yorkshire SF6 3 Reyrolle LMVP	Four at 29 years Three at 20 years	24%
Paekakariki	4 Reyrolle LMT oil	Four at 35 years	8%

3.3.4 Buildings

Buildings are as follows…

Zone Substation	General description	Age	Condition grade
Shannon	Timber Framed	11	Normal deterioration monitored in normal inspection cycle.
Foxton	Masonry Shear Walls	27	Normal deterioration monitored in normal inspection cycle.
Levin East	Masonry Shear Walls	28	Normal deterioration monitored in normal inspection cycle.
Levin West	Masonry Shear Walls	43	Normal deterioration monitored in normal inspection cycle.
Otaki	Timber Framed	24	Normal deterioration monitored in normal inspection cycle.
Waikanae	Timber Framed	21	Normal deterioration monitored in normal inspection cycle.
Paraparaumu	Masonry Shear Walls	2	Good or as new condition, may have customised lengthened inspection cycle as defined in this AMP.
Paraparaumu West	Timber Framed	15	Normal deterioration monitored in normal inspection cycle.
Raumati	Masonry Shear Walls	29	Normal deterioration monitored in normal inspection cycle.
Paekakariki	Masonry Shear Walls	35	Normal deterioration monitored in normal inspection cycle.

3.4 Distribution lines & cables

Electra has 846km of 11kV overhead lines and 231km of 11kV cables connecting its zone substations to its distribution substations. It is constructed mainly as follows:

- CBD areas are almost exclusively cable. In older urban areas with low load growth such as Levin and Foxton these cables are PILC 185mm^2 Aluminium. New installations are constructed of XLPE cable.

- Suburban areas tend to be a mix of line and cable depending on whether the area was developed before or after undergrounding was adopted more widely around 1970. Cable tends to be PILC Aluminium conductor, whilst overhead conductor is a variety of Bee, 19/0.064 Copper and 7/0.083 Copper, almost totally on concrete poles.

- Rural areas are mostly line (but with increasing lengths of cable). These lines are Gopher or 7/0.064 Copper.

Line and cable length by zone substation area is as follows.

Zone Substation	Distribution network length (km)		
	Overhead	Underground	Total
Levin East	126	29	155
Levin West	106	22	128
Shannon	163	8	171
Foxton	140	15	155
Paraparaumu	29	32	61
Paraparaumu West	6	29	36
Raumati	11	13	24
Waikanae	64	40	104
Paekakariki	16	6	22
Otaki	186	35	221
Total	**846**	**231**	**1,077**

3.5 Distribution switchgear

Electra has 1,266 individual distribution switchs including ring main units, auto reclosers, air break switches and drop-out fuses. Precise numbers of each class of switches are in Chapter 6.

3.6 Distribution substations

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, and are detailed in Chapter 6. Transformers may provide electricity to single large consumers, several large consumers or many small consumers.
The key systemic issue with this asset class is corrosion of ground mounted transformer enclosures closer to coastal areas, which typically requires replacement after only 30-40 years of service.Electra also have issues with deck mounted transformers needing to be replaced due to safety concerns around structural integrity.

3.7 LV lines & cables

Electra has 507km of overhead LV (400V) and 483km of underground LV connecting its distribution substations to its customers, with an associated 10,863 pillars and cabinets.

LV line and cable length by zone substation area is as follows.

Zone Substation	LV network length (km)		
	Overhead	Underground	Total
Levin East	91	58	149
Levin West	74	46	120
Shannon	71	9	80
Foxton	64	16	80
Paraparaumu	21	67	88
Paraparaumu West	8	77	85
Raumati	24	36	60
Waikanae	45	110	155
Paekakariki	10	5	15
Otaki	99	59	158
Total	**507**	**483**	**990**

3.8 Customer connections

The consumer connection assets connect Electra's 43,654 consumers 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.

3.9 Other assets

3.9.1 Load control

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 at Electra-owned building at Paraparamu 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 at Paraparaumu West and Shannon, which are spares.

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 street lights, under verandah lighting and pilot-wire load control.

3.9.2 Protection & control

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

- 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.

3.9.3 SCADA & communications

Electra uses iSCADA for general control and monitoring. This was installed during 2010. The master station is located at Levin West. 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…

- Forest Heights, Waikanae.

- Mataihuka south of Paraparaumu.

- Moutere Hill west of Levin.

- Levin West substation.

- Tunapo at Paekakariki.

3.9.4 Mobile generator

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

3.10 Asset valuation (RAB) allocation

Allocation of asset valuation (RAB) across Electra's assets is as follows…

Asset class	Valuation (31st March 2016)	Percent of valuation *
Distribution and LV cables	$36,298,000	23.0%
Distribution and LV lines	$28,942,000	18.3%
Zone substations	$26,075,000	16.5%
Distribution substations and transformers	$25,204,000	15.9%
Other network assets	$12,525,000	7.9%
Subtransmission cables	$10,031,000	6.3%
Distribution switchgear	$9,742,000	6.1%
Subtransmission lines	$6,789,000	4.3%
Non-network assets	$2,424,000	1.5%
Total	**$158,039,000**	**100.0%**

* Percentages may not add due to rounding.

4. Proposed service levels

4.1 Customer service levels

4.1.1 Primary customer service levels

Electra's primary customer service level is supply continuity and restoration, as measured by SAIDI, SAIFI and CAIDI. Electra doesn't deliberately distinguish between customers in different geographical areas, but the radial configuration of its rural network will inevitably mean that while all customers will experience a similar frequency of interruptions, those in rural areas are likely to endure longer supply interruptions.

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

Measure	← Actual (historical)					Forecast →				
	2011/12	2012/13	2013/14	2014/15	2015/16	2017/18	2018/19	2019/20	2020/21	2021/22
SAIDI	74.7	131.8	58.0	67.3	139.3	83.0	83.0	83.0	83.0	83.0
SAIFI	1.62	2.29	0.93	1.25	2.25	1.66	1.66	1.66	1.66	1.66
CAIDI	46.2	57.6	75.2	53.7	61.9	50.0	50.0	50.0	50.0	50.0

* Actual for 2016/17 not available at time of writing.

Comments on the historical performance include…

- Storms in April 2014 and August 2014 meant the 2014/15 SAIDI exceeded target.
- An unplanned interruption on the back up supply to Levin whilst the main 33kV supply was out of service for maintenance meant the 2015/16 SAIDI exceeded target.

Customer consultation and community engagement reveals that Electra's customers prefer not to pay more for further improvements in reliability. However Electra has identified several strategies that have the potential to significantly improve reliability and safety, and deliver improved returns within the current cost base.

Initiative	Safety	Reliability	OpEx reduction
Take a more strategic view of tree trimming eg. cutting back trees near the growth zone.	●	●	
Planned removal of metallic pitch-filled pot heads that are of particular risk eg. sensitive sites, coastal corrosion areas etc.		●	
Review the effectiveness and efficiency of cross-arm and conductor replacement programs.		●	
Disaggregate fault response from reactive maintenance to better allocate costs to asset classes, and capitalise some of those costs			●

Electra will amend its forecasts once firm decisions on the above initiatives are made and credible estimates of the likely improvements are made.

4.1.2 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.

Customer survey 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, hence they can be manipulated more easily.

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

Attribute	Measure	Forecast →				
		2017/18	2018/19	2019/20	2020/21	2021/22
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

4.2 Asset performance levels

Electra's asset performance levels include…

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

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

Measure	← Actual (historical)					Forecast →				
	2011/12	2012/13	2013/14	2014/15	2015/16	2017/18	2018/19	2019/20	2020/21	2021/22
Load factor	49%	54%	53%	56%	47%	50%	50%	49%	49%	49%
Capacity utilisation	33%	26%	26%	25%	30%	30%	33%	33%	33%	33%
Network losses	7.3%	7.5%	7.4%	6.7%	6.8%	6.7%	6.7%	6.7%	6.7%	6.6%

* Actual for 2016/17 not available at time of writing.

4.3 Public safety performance levels

Electra's public safety performance includes the following measures…

- Compliance with the Electricity (Safety) Regulations 2011.
- Compliance with the Electricity (Hazards From Trees) Regulations 2003.

Electra's targets are nil non-compliances with both Regulations for every year.

4.4 Regulatory performance levels

Regulatory performance levels are generally set by statutory agencies, and include…

- Compliance with the Electricity Distribution Information Disclosure Determination 2012.
- Compliance with the Electricity Industry Participation Code.
- 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 NZTA 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.

4.5 Public good service levels

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

- Switching of controlled loads, including street lights and under verandah lighting.
- Ensuring voltage remains within statutory limits (which Electra expects to become more difficult if rooftop solar proliferates).
- Accomodating the highly variable and bi-directional power flows from rooftop solar generation, and ensuring that other consumers are not effected.

- Investigating and limiting harmonic interference.
- 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.

4.6 Justification for service levels

Electra has adopted it's current and planned future service levels as a result of the following…

- Customer surveys have repeatedly revealed a preference for paying about the same line charges to receive about the same reliability.
- Specific requests from customers to receive a different mix of reliability and pricing from what would otherwise be available.
- Decisions over many decades as to whether the 11kV network configuration should be radial or meshed, which strongly influences supply restoration times.
- Decisions over many decades that have influenced asset condition, and hence supply reliability.
- External agencies may impose either a service level (eg. public safety, AMP disclosure etc) or impose criteria that manifest as service levels (eg. a requirement to underground all new lines).

4.7 Translating stakeholder needs into service levels

Electra translates its stakeholder 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.

5. Network development plans

5.1 Planning context

Electra's development plans are driven primarily by capacity constraints, 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 multi-dimensional, along with the added overlay of disruptive technologies.

The following has been considered in regard to emerging technologies…

Specific technology	Mode of operation	Implications for Electra
Conventional, well understood loads	Consumption	• Increasing demand.
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. • Over voltages during periods of high generation and low demand. • Increased bi-directional power flows. • Reduced kWh sales if located behind the meter. • Peak shifting later into summer evenings.
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 cars	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 lighting interior	Consumption	• Reduced demand and consumption
Low energy streetligting	Consumption	• Reduced demand and consumption. Lower consumption based revenue will impact the value of this supply business

This demand at each connection aggregates up the network to the distribution transformer, then to the distribution feeder, to the zone substation, to the sub-transmission network back to the GXP and ultimately through the grid to a power station.

Electra has adopted the 11kV feeder as its fundamental planning unit which typically represents one or more of the following combinations of consumer connection.

- An aggregation of up to 1,500 urban domestic consumer connections (tends to be limited by the number of customers exposed to any one fault).
- An aggregation of about 5,000 kVA of urban commercial load (tends to be limited firstly by feeder loading, but also to limit the fraction of the CBD exposed to any one fault).
- A single large industrial consumer (tends to be driven by load, but also if that consumer is likely to create a lot of harmonics or flicker).

5.2 Planning criteria

Electra considers the following criteria for planning and developing its network.

- Capacity and voltage constraints.
- Reliability.
- Security of supply.

5.2.1 Capacity & 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 & 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 & 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 & 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
	• 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 & event history

5.2.2 Reliability triggers

In order to limit the load interrupted by any 1 fault, Electra will consider intervening when the following levels are reached.

- An aggregation of up to 1,500 urban domestic consumer connections on any 1 feeder.
- An aggregation of about 5,000 kVA of urban commercial load on any 1 feeder.

5.2.3 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

5.2.4 Actions when triggers are exceeded

Refer to Chapter 5.8.

5.3 Use of standards, codes etc

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	●			●

5.4 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.

- Optimisation of open points.

5.5 Asset capacity criteria

These are summarised in Chapter 5.2 above.

5.6 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 Chapter 1.8).

Prioritisation is also strongly linked to risk management (Chapter 8). 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 Chapter 5.8 provide potential solutions that are considered.

5.7 Demand forecasts

5.7.1 Demand forecasting methodology

Demand trends and challenges

Historically Electra has used a simple linear projection of recent zone substation demand growth rates to forecast demand, and supplemented by inclusion of localised factors eg. known industrial developments, observations of farm land being sold for residential development etc. It is acknowledged that this has probably led to a long-run over-investment in asset capacity, and also that many of the assumptions used in the past may no longer be valid.

Electra now recognises that demand is becoming more complex, viz….

- Installation of rooftop solar and other micro-generation technologies behind the meter are decoupling the relationship between demand supplied and demand seen by Electra's network and are expected to significantly alter the traditionally understood daily load cycle.

- Electric car recharging could significantly add to Electra's peak demand if not correctly managed.

- Improvement of motorways from Wellington could allow commuters to arrive home earlier, possibly concentrating the Kapiti zone substation peaks into narrower time periods.

- Publications by both the Kapiti Coast and Horowhenua District Councils indicating that increasing house prices in the Wellington metro area is encouraging people to move to Kapiti, in turn driving up house prices in Kapiti and encouraging people to move to Horowhenua.

- Increasing penetration of cheap heat pumps is making the load profile more peaky. This requires more capacity to be installed, but with minimal increase in kWh sales from which to recover the cost of that capacity.

However Electra believes that these issues are steady rather than sudden, and that there is sufficient capacity headroom (especially in the Northern network) to accommodate demand growth.

Demand issues specific to Electra

The annual planning process has revealed a low rate of demand growth in the Northern area, which combined with 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 the load projections are:

- Increasing air conditioning load is likely to over-lap into peak periods when demand is already high. 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.

Current approach to demand forecasting

Electra's demand forecasting methodology:

- Reviews external demographic, technology, economic and transport information (Councils, ANZ Bank, Reserve Bank, NZTA) for trends that are likely to alter current demand patterns at domestic, commercial, agricultural and industrial level.

- Aggregates the prospective effects of those trends up through the supply chain at 11kV feeder, zone substation and finally to GXP level.

Electra recognises that the following issues will need to be considered in future demand forecasts…

- Distruptive technologies, demand management and cost reflective distribution pricing.

- Bidirectional energy flows could complicate demand forecasting.

Electra recognises that the following previously held assumptions may also need to be re-assessed…

- The previously assumed demand diversity between zone substations may decline (ie. increase towards 1) as non-coincident demands converge in time.

- The previously assumed constant power factor throughout the planning period may decline as air conditioning load increases.

- The previously assumed constant asset utilisation may decline as air conditioning penetration increases.

- Harmonic interference may increase as inverter-drive air conditioners increase in number.

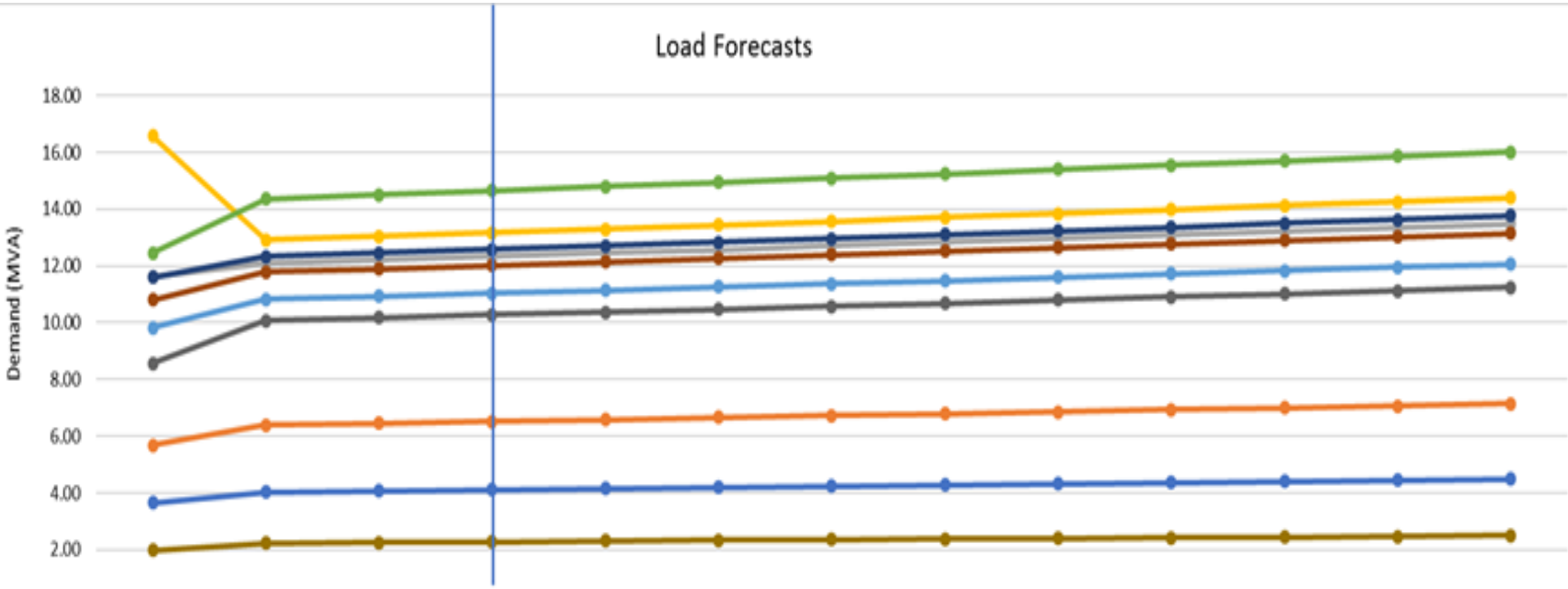
Assumptions that are expected to remain valid include…

- Based on a literature search, Electra has concluded that rooftop solar begins to cause power flow and voltage difficulties when the injected energy exceeds about 20% of prevailing demand. This is not expected to occur within the first 5 years of the planning period.

- New connections will continue to be predominately residential and increase at the historical average rate of 300-400 per year (at a diversified 2kW per connection this equates to increasing underlying peak demand of 600 to 800 kW per year).

5.7.2 Zone substation demand forecasts

Based on these assumptions, the following zone substation demand forecasts have been adopted for development planning. Historical demand has also been included for comparison purposes.



	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026
	Actuals				Forecast								
Shannon	3.66	4.03	4.07	4.11	4.15	4.19	4.23	4.28	4.32	4.36	4.41	4.45	4.49
Foxton	5.69	6.40	6.46	6.53	6.59	6.66	6.72	6.79	6.86	6.93	7.00	7.07	7.14
Levin West	11.63	12.08	12.20	12.32	12.45	12.57	12.70	12.82	12.95	13.08	13.21	13.34	13.48
Levin East	16.57	12.91	13.04	13.17	13.30	13.43	13.57	13.70	13.84	13.98	14.12	14.26	14.40
Otaki	9.83	10.82	10.93	11.03	11.15	11.26	11.37	11.48	11.60	11.71	11.83	11.95	12.07
Waikanae	12.46	14.36	14.50	14.65	14.79	14.94	15.09	15.24	15.39	15.55	15.70	15.86	16.02
Paraparaumu	11.60	12.34	12.46	12.58	12.71	12.84	12.97	13.09	13.23	13.36	13.49	13.63	13.76
Paraparaumu West	10.81	11.78	11.90	12.02	12.14	12.26	12.38	12.51	12.63	12.76	12.89	13.02	13.15
Raumati	8.58	10.07	10.17	10.27	10.37	10.48	10.58	10.69	10.79	10.90	11.01	11.12	11.23
Paekakariki	1.99	2.24	2.26	2.28	2.31	2.33	2.35	2.38	2.40	2.42	2.45	2.47	2.50

The following assumptions have been applied in deriving the zone substation demand forecasts:

Zone Substation	Rate and Nature of Growth	Provision for Growth
Shannon	About 0.5% per year, mainly lifestyle blocks around Tokomaru.	None required.
Foxton	About 1.0% per year, mainly residential development at Foxton Beach.	None required
Levin East	About 1.7% per year, mainly commercial and lifestyle blocks to the south and east of Levin. Possible large off-peak industrial load growth.	None required
Levin West	About 1.3% per year, mainly residential properties at Waitarere Beach and lifestyle properties to the north and west of Levin.	None required
Otaki	About 1.8% per year, mainly lifestyle blocks in Manakau and Te Horo.	Load is being managed by redistribution amongst existing feeders. An additional feeder is proposed within the planning period.
Waikanae	About 2.6% per year, mainly residential.	Capacity on existing feeders continues to be increased before end of life replacement. An additional feeder allowing full duplication if the main supply to Waikanae Beach is proposed within the planning period.
Paraparaumu	About 2.0% per year, mainly commercial and residential infill.	Increased utilisation of existing capacity. The construction of Paraparaumu West has allowed much of the former load to be transferred.
Paraparaumu West	About 3.0% per year, mainly commercial and residential infill.	An additional feeder will ultimately be needed with the ongoing development of Paraparaumu Airport. This will be factored into the development plan once a better understanding of development timing is known.
Raumati	About 1.0% per year, mainly residential infill.	An additional feeder could be required if there is land spare from the Kapiti Expressway development. This has not yet been factored into the development plan.
Paekakariki	About 0.3% per year, mainly residential infill.	No loading parameters are expected to be exceeded during the planning period, therefore no growth related projects are proposed either.

Many of the provisions for growth are aimed at maintaining reliability, security of supply from breakages and support from alternative zone substations. These are consistent with Electra's service level targets set out in Chapter 4.

The aggregated effect of the zone substation demand growth for a ten year planning horizon at both GXPs is shown below…

GXP	Rate and Nature of Growth	Provision for Growth
Mangahao	Average of 0.2MW per year	No provision for capacity or security growth will be possible until about 2020 when it is expected that the existing transformers will be upgraded to approximately 60MVA.
Paraparaumu	Average of 0.6MW per year	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.

5.7.3 Network 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 (provisionally timed for 2020).
Shannon - Foxton - Levin West 33kV circuit	When load is above 35MVA and the Managahao – Levin East 33kV circuit(s) trip, the Shannon – Foxton – Levin East 33kV circuit will overload.	Operate the soon-to-be purchased Transpower 110kV circuits at 33kV to duplicate the Mangahao – Levin East 33kV circuit(s).
Shannon - Foxton - Levin West 33kV circuit	If the Mangaho – 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 overloaded under N-1.	Operate the soon-to-be purchased Transpower 110kV circuits at 33kV to duplicate the Mangahao – Levin East 33kV circuit(s).

The impact of these constraints on specific asset classes are discussed in Chapter 6.

5.7.4 Impact of embedded generation

Apart from Mangahao (which is embedded at the GXP) there are about 300 known embedded generation sites on the Electra network with a combined capacity of about 1,100 kW. As noted above, there are likely to be few occasions when that 1,100kW will exceed 20% of the prevailing load. Electra will closely watch the number of applications and assess this impact, and will also closely watch the studies in South Australia, Queensland and Germany.

5.8 Approaches to development options

5.8.1 Criteria for selecting options

Exactly what is done to match the capacity of individual assets to forecast load is one of the following three classes of actions…

Do nothing

Where one or more parameters have exceeded a trigger point to formulate prospective development options, the do nothing option may be a “do nothing yet but watch more frequently” option. Essentially, do nothing is acceptable only when Electra and its stakeholders can continue to expect and experience adequate performance and acceptable risk.

Non-network (low or non-investment) solutions

Operational activities - in particular 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 can avoid new investment. The downside to this approach is that it may increase line losses, reduce security of supply, or compromise protection settings;

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 zones, negotiating interruptible 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;

Construct distributed generation – This allows adjacent assets to perform at levels below the trigger point. Distributed generation would be particularly useful where additional 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 is essentially a subset of the above approach, but generally involves less expenditure. This approach is more suited to larger classes of assets such as 33/11kV transformers;

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.

Network solutions

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 criteria are not exceeded.

How Electra applies these options in practice

In practice, Electra applies these options as follows…

- 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.

5.8.2 Development options

Refer to 5.9.1 and 5.9.2.

5.8.3 Innovations

These are described for individual asset classes in Chapter 6.

5.9 Forecast development projects

5.9.1 Development projects for 2017/18 year

Material projects for the 2017/18 are…

Ref.	Description	Category	Cost
1	Relieve constraint on Tararua Rd – Arapaepae Rd circuit	Quality	$615,000
2	Extend feeder 612 to offload feeder 652 from Waikanae	Growth	$350,000
3	Switchgear automation	Quality	$233,000

Ref.	Description and purpose of project	Category	Cost	Options considered			Option chosen and reason
				Do-Nothing	Non-Network	Network	
1	Provide duplicate circuit between Tararua Rd and Arapaepae Rd to relieve constraint on Levin East 33kV circuit.	Quality	$615,000	• Retain existing circuit configuration.	• Purchasing redundant Transpower 110kV circuits and operate at 33kV.	• Install new 33kV cables to duplicate existing circuits.	• Purchase redundant Transpower circuits. • This provides an equivalent level of security but at a lower cost than installing new 33kV cables. • Allowing the constraint to remain presents an unacceptable risk to security of supply.
2	Extend Feeder 612 to reduce both load and customer numbers on Feeder 652 from Waikanae.	Growth	$350,000	• Continue connecting customers to Feeder 652.	• Encourage customers to uptake solar and / or battery storage.	• Extend Feeder 612 to reduce load and customer numbers on Feeder 652.	• Extend Feeder 612. • As more customers are added to Feeder 652, the number of customers effected by a fault will also increase which is undesirable. Offloading customers will reduce the number of customers affected • Adding more customers to Feeder 652 will increase its asset utilisation and risk of in-service failure. This is inconsistent with Electra's policy on asset loading. • 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.
3	Automate switchgear on specified feeders to reduce restoration times.	Quality	$233,000	• 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.

Non-material projects for the 2017/18 are…

Ref.	Description	Category	Cost
4	Link between feeder L357 and L349 (between L213 & L394)	Quality	$195,000
5	Network sectionalisation	Quality	$153,000
6	Link between feeder 652 and 632 (between S186 & P285)	Quality	$127,000
7	Install a CFCF switch to improve sectionalisation W121 Te Kupe Rd	Quality	$90,000
8	Relocate access issues – S81	Quality	$82,000
9	Replace/Remove deck transformer H18	Safety	$77,000
10	Replace deck transformer Z13	Safety	$77,000
11	Replace pitchfilled potheads with Raychem terminations	Safety	$60,000
12	Install additional fault locators – Permanent	Quality	$51,000

Alternative options considered include

Ref.	Description and purpose of project	Category	Cost	Options considered			Option chosen and reason
				Do-Nothing	Non-Network	Network	
4	Link between feeder L357 and L349 (between L213 & L394) to provide alternative circuit.	Quality	$195,000	• Continue with existing unmeshed feeders.	• Encourage customers to uptake solar and / or battery storage	• Install link between L357 and L349.	• Install link between L357 and L349. • 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. • Being able to back-feed un-faulted sections of both feeders provides an opportunity to reduce restoration times which wouldn't necessarily occur with solar and / or batteries.
5	Install sectionalisers on specified feeders to reduce number of customers affected by faults.	Quality	$153,000	• Continue with existing feeder sections.		• Install line sectionlisers on specific feeder locations.	• Install line sectionlisers on specific feeder locations. • 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.
6	Link between Feeders 652 and 632 (between S186 & P285) to provide alternative circuit.	Quality	$127,000	• Continue with existing unmeshed feeders.		• Install link between Feeders 652 and 632.	• Install link between Feeders 652 and 632. • Being able to back-feed un-faulted sections of both feeders provides an opportunity to reduce restoration times.
7	Install a CFCF switch at W121 Te Kupe Rd to reduce number of customers affected by faults.	Quality	$90,000	• Continue with existing configuration.		• Install CFCF switch.	• Install CFCF switch. • As more customers are added to feeders, the number of customers effected by a fault will also increase, which is undesirable. Improving sectionalisation will reduce the number of customers affected.

8	Relocate S81 - access issues.	Quality	$82,000	• Leave assets in existing location.		• Relocate assets.	• Relocate assets. • Resolving access issues requires assets to be moved.
9	Replace / remove deck transformer H18 to eliminate safety hazard.	Safety	$77,000	• Leave existing transformer in place		• Replace with ground mount transformer.	• Replace with ground mount transformer. • Safety risk posed by deck transformers is becoming increasingly unacceptable. • Isolating or minimising this risk (eg. signs, guard rails, enclosures etc) is impractical.
10	Replace deck transformer Z13 to eliminate safety hazard.	Safety	$77,000	• Leave existing transformer in place		• Replace with ground mount transformer.	• Replace with ground mount transformer. • Safety risk posed by deck transformers is becoming increasingly unacceptable. • Isolating or minimising this risk (eg. signs, guard rails, enclosures etc) is impractical.
11	Replace pitch filled potheads with Raychem terminations to eliminate safety hazard.	Safety	$60,000	• Leave existing pot heads in place.		• Replace with Raychem terminations.	• Replace with Raychem terminations. • Safety risk posed by existing pitch filled pot heads is becoming increasingly unacceptable. • Raychem is an established approach, and can therefore be considered reasonably practicable.
12	Install additional permanent fault locators to allow quicker location of faults.	Quality	$51,000	• 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.

5.9.2 Development projects for 2018/19 to 2021/22

Development projects proposed for 2018/19 to 2021/22 include…

Ref.	Description	Category	Cost
1	Foxton to Levin West 33kV - Upgrade to Butterfly	Growth	$920,000
2	Automation of Switchgear	Quality	$852,000
3	Network Sectionalisation	Quality	$613,000
4	Waitarere Beach – Alternate Supply	Quality	$613,000
5	Protection Work-Levin East	Quality	$583,000
6	Alternative supply between W468 & Z50	Quality	$511,000
7	Additional Ripple Plant	Quality	$491,000
8	Install cable Sw gear close Ring (underground LV also)	Quality	$460,000
9	2nd Feeder – Beach	Growth	$460,000
10	6th Feeder – Parata St	Growth	$409,000
11	Additional feeder – Riverbank Rd	Growth	$307,000
12	Arc Flash Protection	Safety	$303,000
13	New feeder from Shannon Substation	Growth	$250,000
14	Replace pitchfilled potheads with raychem terminations	Safety	$240,000
15	Install additional fault locators – Permanent	Quality	$215,000
16	Install ring feed cable to back up L21 to L332	Quality	$204,000
17	Cable replacement between W97 & W98	Growth	$204,000
18	Link LV network where gaps exist	Quality	$163,000
19	Fault Locator Comm's	Quality	$113,000
20	2nd transformer (cold standby) – Paekakariki Substation	Quality	$102,000
21	Install 5th feeder – Matai Rd	Growth	$82,000
22	Replace deck transformer E58	Safety	$77,000
23	Replace deck transformer E64	Safety	$77,000
24	Rebuild deck transformer G76	Safety	$77,000
25	Rebuild deck transformer G334	Safety	$77,000
26	Replace deck transformer H1 with 200kVA	Safety	$77,000
27	Install cable Sw gear close Ring (underground Lv also)	Quality	$59,000
28	Replace W300 SW Gear and close ring W532	Quality	$59,000
29	Install new cable Sw gear close ring upgrade conductor to T180	Quality	$59,000

Alternative options considered include

Ref.	Description and purpose of project	Category	Cost	Options considered			Option chosen and reason
				Do-Nothing	Non-Network	Network	
1	Replace 3km section of Bee in the Foxton - Levin West 33kV with Butterfly to remove constraint if Levin East circuit trips.	Growth	$920,000	• Leave section of Bee in place.	• Install station class battery banks in substations to supply load during contingency.	• Replace 3km section of Bee with Butterfly.	• Replace section of Bee with Butterfly. • Leaving the 3km 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.
2	Automate switchgear on specified feeders to reduce restoration times.	Quality	$852,000	• 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.
3	Install sectionalisers on specified feeders to reduce number of customers affected by faults.	Quality	$613,000	• Continue with existing feeder sections.		• Install line sectionlisers 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	Install alternate supply to Waitarere Beach to allow quicker restoration of faults.	Quality	$613,000	• Continue with existing radial feeder configuration	• Encourage customers to uptake solar and / or battery storage	• Add second feeder to provide alternative supply.	• Add second feeder to provide alternative supply. • 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.
5	Protection work - Levin East.	Quality	$583,000	• 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.
6	Install alternative supply between W468 & Z50 to allow quicker restoration of faults.	Quality	$511,000	• 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.
7	Ripple Plant installation at Otaki to cover whole network if either of the existing plants are out of service.	Quality	$491,000	• Continue with existing plants.		• Purchase and install additional ripple plant	• Purchase and install additional ripple plant. • New plant will ensure that whole network will have ripple coverage. • Loss of ripple plant in either network could result in higher costs eg. failure to control load to within Transpower peaks.
8	Install cable and switchgear to close ring at specified locations and underground the LV to allow quicker restoration of faults.	Quality	$460,000	• 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

9	Install a second feeder to the Beach to supply existing load.	Growth	$460,000	• Allow load and customer numbers on existing feeder to increase.	• Encourage customers to uptake solar and / or battery storage	• Add second feeder.	• Add second feeder. • 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. • 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. • 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.
10	Install a sixth feeder to Parata St to supply increasing load.	Growth	$409,000	• Allow load and customer numbers on existing feeder to increase.	• Encourage customers to uptake solar and / or battery storage	• Add second feeder.	• Add second 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.
11	Install an additional feeder to Riverbank Rd to supply increasing load.	Growth	$307,000	• Allow load and customer numbers on existing feeder to increase.	• Encourage customers to uptake solar and / or battery storage.	• 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.
12	Arc Flash Protection	Safety	$303,000	• Continue with existing protection schemes.		• Install arc flash protection on specified equipment.	• Install arc flash protection on specified equipment. • Arc flash protection schemes reduces the risks to personnel in the event of a failure. • Arc flash protection is a well-established technology, and is therefore considered to be a reasonably practicable step.

13	New 11kV feeder from Shannon Substation to supply increasing load.	Growth	$250,000	• Allow load and customer numbers on existing feeder to increase.	• Encourage customers to uptake solar and / or battery storage.	• 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.
14	Replace pitch filled potheads with Raychem terminations to eliminate safety hazard.	Safety	$240,000	• Leave existing pot heads in place.		• Replace with Raychem terminations.	• Replace with Raychem terminations. • Safety risk posed by existing pitch filled pot heads is becoming increasingly unacceptable. • Raychem is an established approach, and can therefore be considered reasonably practicable.
15	Install additional permanent fault locators to allow quicker location of faults.	Quality	$215,000	• 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.
16	Install ring feed cable between L21 and L332 to allow meshing and reduce fault restoration time.	Quality	$204,000	• Retain existing spur configuration.		• Install ring feed cable.	• Install ring feed cable. • Meshing of circuits allows reduced restoration times.
17	Replace cable between W97 & W98 to allow load growth.	Growth	$204,000	• Retain existing cable.		• Replace existing cable with larger cable.	• Replace existing cable with larger cable. • Simply adding more load 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.
18	Link LV network where gaps exist to reduce fault restoration times.	Quality	$163,000	• 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.
19	Install comms on specified fault locators to allow remote indication.	Quality	$113,000	• 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.
20	Relocate a 33/11kV transformer to act as a cold standby at Paekakariki.	Quality	$102,000	• 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 Paekakriki 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.

21	Install a fifth feeder to Matai Rd to supply increasing load.	Growth	$82,000	• Allow load and customer numbers on existing feeders to increase.		• 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.
22	Replace deck transformer E58 to eliminate safety hazard.	Safety	$77,000	• Leave existing transformer in place		• Replace with ground mount transformer.	• Replace with ground mount transformer. • Safety risk posed by deck transformers is becoming increasingly unacceptable. • Isolating or minimising this risk (eg. signs, guard rails, enclosures etc) is impractical.
23	Replace deck transformer E64 to eliminate safety hazard.	Safety	$77,000	• Leave existing transformer in place		• Replace with ground mount transformer.	• Replace with ground mount transformer. • Safety risk posed by deck transformers is becoming increasingly unacceptable. • Isolating or minimising this risk (eg. signs, guard rails, enclosures etc) is impractical.
24	Rebuild deck transformer G76 to eliminate safety hazard.	Safety	$77,000	• Leave existing transformer in place		• Replace with ground mount transformer.	• Replace with ground mount transformer. • Safety risk posed by deck transformers is becoming increasingly unacceptable. • Isolating or minimising this risk (eg. signs, guard rails, enclosures etc) is impractical.
25	Rebuild deck transformer G334 to eliminate safety hazard.	Safety	$77,000	• Leave existing transformer in place		• Replace with ground mount transformer.	• Replace with ground mount transformer. • Safety risk posed by deck transformers is becoming increasingly unacceptable. • Isolating or minimising this risk (eg. signs, guard rails, enclosures etc) is impractical.
26	Rebuild deck transformer H1 to eliminate safety hazard.	Safety	$77,000	• Leave existing transformer in place		• Replace with ground mount transformer.	• Replace with ground mount transformer. • Safety risk posed by deck transformers is becoming increasingly unacceptable. • Isolating or minimising this risk (eg. signs, guard rails, enclosures etc) is impractical.
27	Install cable switchgear to close ring at specified locations and underground the LV to allow quicker restoration of faults.	Quality	$59,000	• Retain existing spur configuration.		• Install ring feed cable.	• Install ring feed cable. • Meshing of circuits allows reduced restoration times.
28	Replace W300 switchgear and close ring W532 to allow quicker restoration of faults.	Quality	$59,000	• Retain existing spur configuration.		• Install ring feed cable.	• Install ring feed cable. • Meshing of circuits allows reduced restoration times.

29	Install new cable and switchgear to close ring, and upgrade conductor to T180.	Quality	$59,000	• Retain existing spur configuration.		• Install ring feed cable.	• Install ring feed cable. • Meshing of circuits allows reduced restoration times.

5.9.3 Development projects for 2022/23 to 2026/27

Development projects proposed for 2022/23 to 2027/28 include…

Ref.	Description	Category	Cost
1	Rural Substation – Waikawa Beach Rd	Growth	$1,272,000
2	Automation of Switchgear	Quality	$1,065,000
3	Install conductor and close Ring – The Esplanade	Quality	$1,022,000
4	Foxton to Levin West 33kV - Upgrade to Butterfly	Growth	$920,000
5	Network sectionalisation	Quality	$767,000
6	Levin West to Levin East 33kV - Upgrade to Butterfly	Growth	$613,000
7	T106 to T57 install cable close Ring	Quality	$409,000
8	Install new cable Sw gear close ring upgrade conductor to T180	Quality	$358,000
9	Q91 to P271 Close up ring	Quality	$307,000
10	Alternative supply between W38 & W39	Quality	$307,000
11	Install additional fault locators – Permanent	Quality	$256,000
12	Install Sw Gear around M139, M143, M194, M149	Quality	$205,000
13	Run ht cable and join up ring – C315 to C317	Quality	$204,000
14	Link LV network where gaps exist	Quality	$203,000
15	Replace pitchfilled potheads with raychem terminations	Safety	$200,000
16	Install cable and Sw gear close Ring – Mill Rd	Quality	$153,000
17	Fault Locator Comm's	Quality	$142,000
18	Cable installation between W494 and W502	Growth	$122,000
19	Relocate access issues – S81	Quality	$102,000

5.10 Policies on embedded generation

Electra's policies for embedded generation are on its website. Key features of those policies are…

- Noting the Electricity Industry Participation Code requirements.
- Stating the requirement for exported electricity to be sold to a retailer.
- Setting out the application process.
- Setting out the safety, technical,operational, commercial and regulatory requirements.
- A list of approved inverters.

5.11 Policy on non-network solutions

5.11.1 Policies

Electra has long since recognised the need to minimise asset investment, and over many decades has used the following approaches….

- Confirming that the risk of in-service failure will not increase to an unacceptable level if load is allowed to increase (the "do-nothing" option).
- Opening and closing air-breaks to move load away from heavily-loaded assets.

- Installing forced cooling on zone substation transformers to defer capacity increases.

- Insisting on power factor correction

- Promoting controlled off-peak tariffs for water heating (demand management).

Electra hasn't specifically documented these approaches, but evidence of adoption is clear. Having said that Electra also recognises that opportunities for applying non-network solutions become exhausted over time and eventually additional asset investment is required

5.11.2 Expected application of non-network solutions

Electra expects to adopt the following non-network solutions to defer or avoid asset investment (refer to Chapter 5.7.3)…

Constraint or circumstance	Expected solution	Avoided investment
If Electra's load at Mangahao GXP reaches 35MVA and the Managahao – Levin East 33kV circuit(s) trip, the Shannon – Foxton – Levin East 33kV circuit will overload.	Operate the soon-to-be purchased Transpower 110kV circuits at 33kV to duplicate the Mangahao – Levin East 33kV circuit(s).	Up-sizing the 3km length of Bee in the Shannon – Foxton – Levin West circuit.
If the Mangaho – 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 soon-to-be purchased Transpower 110kV circuits at 33kV to duplicate the Mangahao – Levin East 33kV circuit(s).	Up-sizing the 3km length of Bee in the Shannon – Foxton – Levin West circuit.

6. Network lifecycle management plans

Electra manages its assets by asset type. The lifecycle plans for each asset type are set out below sections. The alignment of Electra's grades with the grades set out in the Determination is as follows…

Grade	Determination Definition	Electra's definition
0	Not used in the Determination	• Critical (make safe before leaving site. Secure and then repair within 1 week if can't be repaired immediately on site).
1	End of serviceable life, immediate intervention required.	• Urgent (repair or replace within 3 months).
2	Material deterioration but asset condition still within serviceable life parameters. Intervention likely to be required within 3 years.	• Material deterioration, planned replacement within next inspection cycle.
3	Normal deterioration requiring regular monitoring	• Normal deterioration monitored in normal inspection cycle.
4	Good or as new condition	• Good or as new condition, may have customised lengthened inspection cycle as defined in this AMP.
Unknown	Unknown or not yet assessed	• Unknown or not yet assessed. Crticality 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.

6.1 Concrete & steel poles

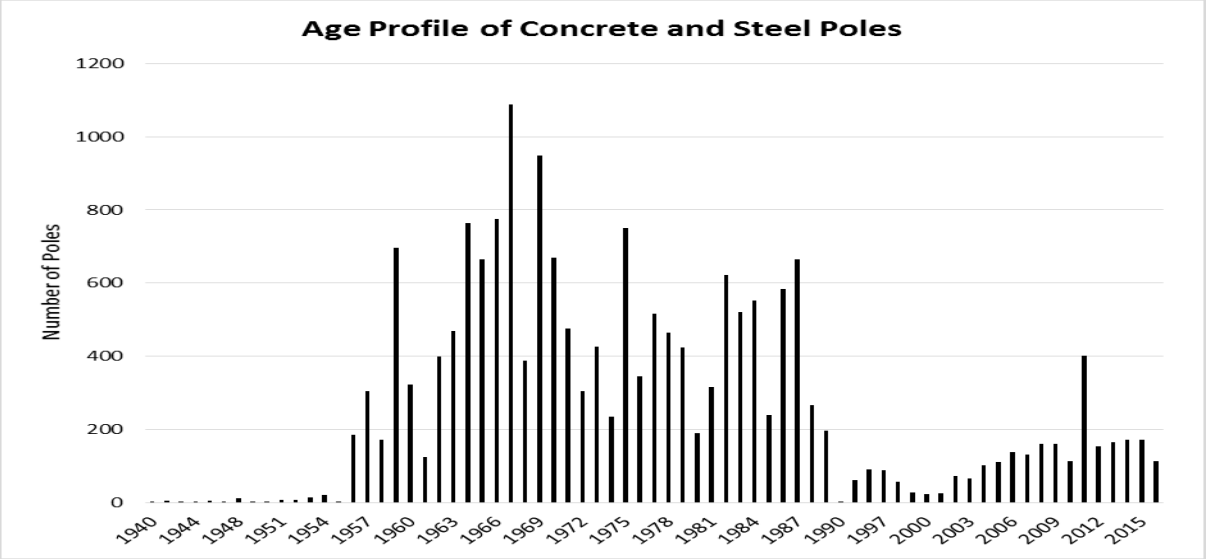
Key features of Electra's concrete & steel pole management are as follows.

Summary of asset class

Electra has 20,338 concrete poles and 96 steel poles on its network. These range in age from new to 77 years old, and have been sourced from a range of suppliers including the HEPB's own pole factory.

Population and age profile

Sub-class	Number	Unit	Percent	Key features of sub-class
Pre-stressed concrete	1,701	Each	8.32%	No known concerns, but observed that heavily loaded poles are deteriorating faster.
Solid concrete	18,635	Each	91.20%	No known concerns, but observed that heavily loaded poles are deteriorating faster.
Spun concrete	2	Each	0.01%	
Steel	64	Each	0.31%	
Oclyte	32	Each	0.16%	
Total	**20,434**	Each	**100%**	



Condition

Condition:	Grade 1	Grade 2	Grade 3	Grade 4	Grade unknown	Data accuracy	Percent forecast for replacement over next 5 years
		0.75%	94.25%	5.00%	-	3	1.00%

Systemic issues & mitigation

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

Key design parameters

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

Management tactics

Maintenance drivers

- 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.

Maintenance criteria

- Cracking or spalling of concrete becomes greater than hair-line or more than 250mm long.
- Reinforcing steel becomes exposed.
- Supporting ground shows evidence of erosion or subsidence eg. 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.

Assumptions

- 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.

Lifecycle policies, criteria and activities

Inspections

- Grade 1 – no further inspections, as it will be replaced within 1 year.
- Grade 2 – no further inspection, as it will be replaced within 3 years.
- Grades 3 and 4 – continue to inspect, amend grade as revealed by inspections.

Defect correction

- Public safety defects – correction within 1 week of identification.
- Significant structural integrity defects – correction within 1 week of identification.
- Minor structural integrity defects – repair by approved method within 3 months of identification.

Refurbishment

- Grade 1 – will not be refurbished.
- Grade 2 – will not be refurbished, may have minor repairs to lift from Grade 1.
- Grade 3 – repair to extend life as considered appropriate by Planning & Development Manager.

Renewal

- Grade 1 – renew within 3 months.
- Grade 2 – renew within inspection cycle.

Lifecycle decision criteria

- 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 program 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 & investment deferral techniques

- Electra views poles as safety-critical and therefore weights 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).

Major projects & programs

Projects & programs 2017/18

Ref.	Location	Description	Category	Cost
1	All	400V Pole Replacements - Inspection Driven	Renewal	$204,000
2	All	11kV Pole Replacements - Inspection Driven	Renewal	$194,000
3	All	33kV Pole Replacements - Inspection Driven	Renewal	$51,000

Projects & programs 2018/19 to 2021/22

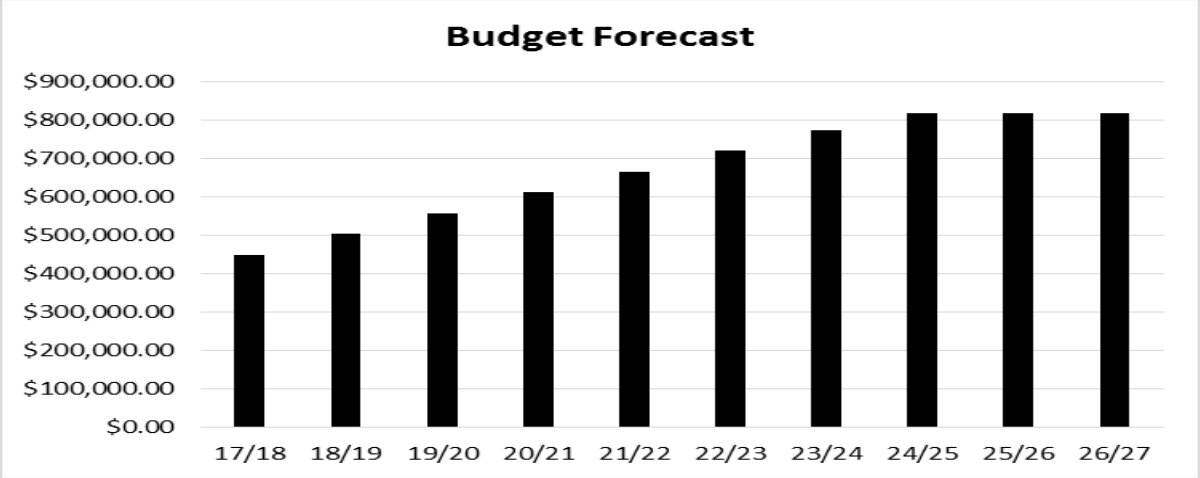
#	Location	Description	Category	Cost
1	All	400V Pole Replacements - Inspection Driven	Renewal	$815,000
2	All	11kV Pole Replacements - Inspection Driven	Renewal	$1,318,000
3	All	33kV Pole Replacements - Inspection Driven	Renewal	$204,000

Projects & programs 2022/23 to 2026/27

Ref	Location	Description	Category	Cost
1	All	400V Pole Replacements - Inspection Driven	Renewal	$1,019,000
2	All	11kV Pole Replacements - Inspection Driven	Renewal	$2,669,000
3	All	33kV Pole Replacements - Inspection Driven	Renewal	$255,000

Budget forecast

Budget	17/18	18/19	19/20	20/21	21/22	22/23	23/24	24/25	25/26	26/27
	$449.2k	$503.2k	$557.2k	$611.2k	$665.2k	$719.2k	$773.2k	$817k	$817k	$817k



6.2 Wood poles

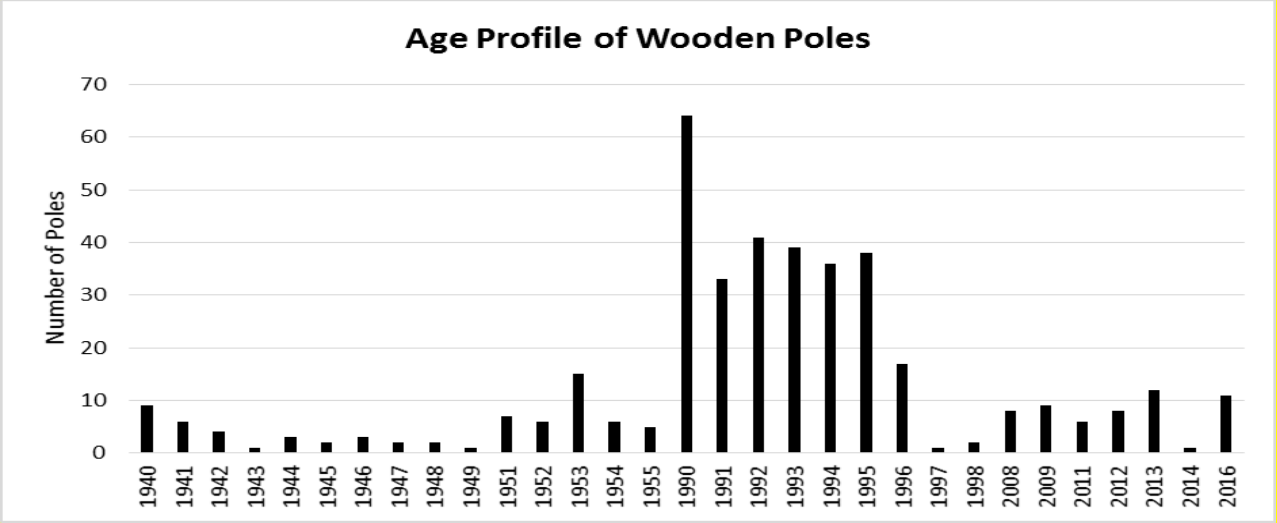
Key features of Electra's wood pole management are as follows.

Summary of asset class

Electra has 22 hardwood poles on its 11kV network, of which 4 are being replaced in early 2017. There are records of a further 1,180 service line poles for which ownership is unclear, and may include Electra, Chorus and customers. These range in age from new to 77 years old, and have been sourced from a range of suppliers.

Population and age profile

Sub-class	Number	Unit	Percent	Key features of sub-class
Soft wood	846	Each	70.6%	
Hard wood	352	Each	29.4%	
Total	**1,198**	**Each**	**100%**	



Condition

Condition:	Grade 1	Grade 2	Grade 3	Grade 4	Grade unknown	Data accuracy	Percent forecast for replacement over next 5 years
11kV hardwood distribution	-	37.78%	62.22%	-	-	3	44.00%

Systemic issues & mitigation

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

Electra has initiated a review of the risk and management practices for service line poles. It is expected that this review will lead to Electra developing a strategy during 2017/18 for management of service line poles.

Key design parameters

Parameter	Value
Durability	No longer applicable as Electra is no longer installing wooden poles.
Structural strength	No longer applicable as Electra is no longer installing wooden poles.

Management tactics

Maintenance drivers

- 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.

Maintenance criteria

- 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

- 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.

Lifecycle policies, criteria and activities

Inspections

- Grade 1 – no further inspections, as it will be replaced within 1 year.
- Grade 2 – no further inspection, as it will be replaced within 3 years.
- Grades 3 and 4 – continue to inspect, amend grade as revealed by inspections.

Defect correction

- Public safety defects – correction within 1 week of identification.
- Significant structural integrity defects – correction within 1 week of identification.
- Minor structural integrity defects – repair by approved method within 3 months of identification.

Refurbishment

- Grade 1 – will not be refurbished.
- Grade 2 – minor repairs only.
- Grades 3 and 4 – repair to extend life as considered appropriate by Planning & Development Manager.

Renewal

- Grade 1 – renew with 1 year.
- Grade 2 – renew within 3 years.

Lifecycle decision criteria

- 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 structural unsound, or placing undue load on other components including straining or slackening conductors.

Life extension & investment deferral techniques

- Not applicable as Electra no longer installs wood poles.

Major projects & programs

Wood poles are included with concrete poles at a program level, refer to Chapter 6.1.

As noted above, Electra will look towards developing a customer-owned wood pole management strategy during 2017/18.

Budget forecast

Wood poles are included with concrete poles at a program level, refer to Chapter 6.1.

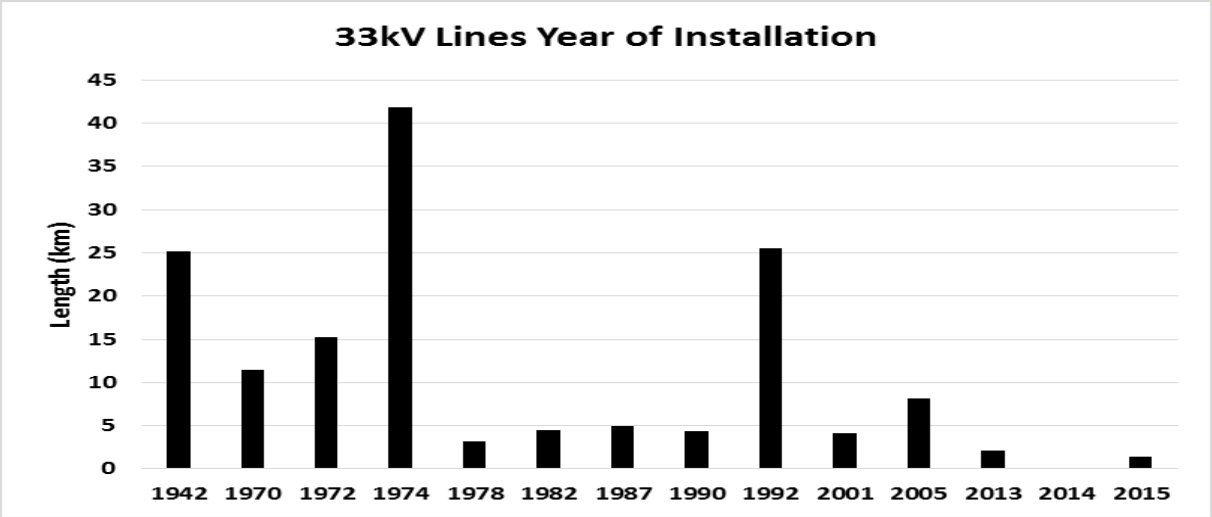
6.3 Overhead conductor

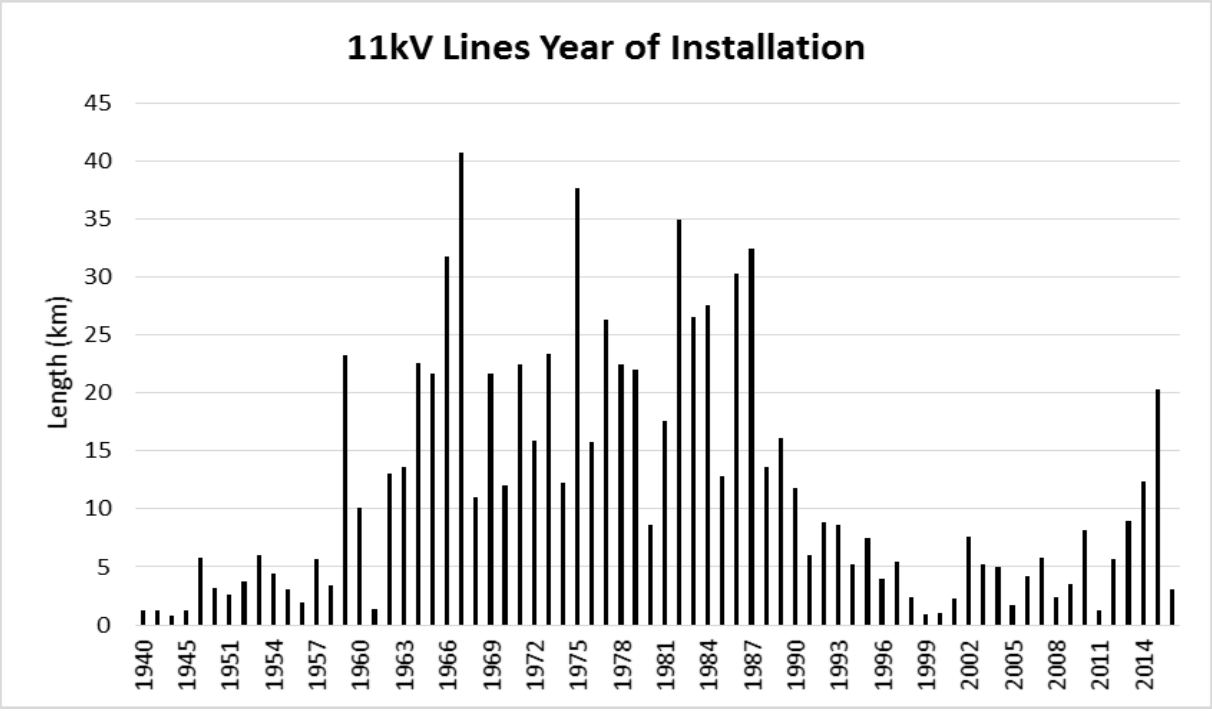
Key features of Electra's overhead conductor management are as follows.

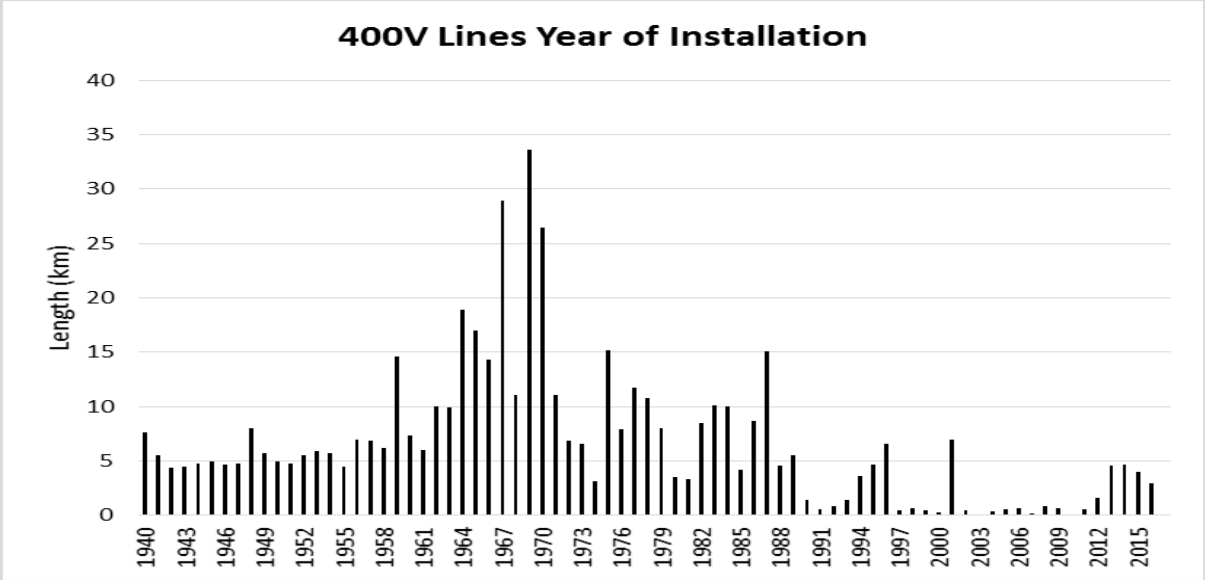
Summary of asset class

Electra has 152 km of 33kV overhead conductor, 849 km of 11kV overhead conductor, and 711 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.

Population and age profile







Condition

Condition:	Grade 1	Grade 2	Grade 3	Grade 4	Grade unknown	Data accuracy	Percent forecast for replacement over next 5 years
33kV conductor		9.00%	89.65%	1.35%		4	9.80%
11kV conductor		9.40%	85.10%	5.50%		3	9.40%
LV conductor		2.60%		1.20%	96.20%	3	4.00%

Key design parameters

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.

Capacity, security & reliability constraints

Refer to Chapter 5.7.3.

Systemic issues & mitigation

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 reinforcing	This issue is of minimal magnitude, and doesn't significantly impact on Electra.

Management tactics

Maintenance drivers

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

Maintenance criteria

- More than 10% of strands frayed or broken.
- Corrosion appears more than surface for significant fractions of individual spans.
- Evidence of overheating.
- Excess tension (usually a pole leaning issue).
- Sag below minimum allowable distance (usually a pole leaning issue).

Assumptions

- 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.

Lifecycle policies, criteria and activities

Inspections

- Grade 1 – no further inspections, as it will be replaced within 1 year.
- Grade 2 – no further inspection, as it will be replaced within 3 years.
- Grades 3 and 4 – continue to inspect, amend grade as revealed by inspections.

Defect correction

- Public safety defects – correction within 1 week of identification.
- Significant structural integrity defects – correction within 1 week of identification.
- Minor structural integrity defects – repair by approved method within 3 months of identification.

Refurbishment

- Grade 1 – will not be refurbished.
- Grade 2 – minor repairs only.
- Grades 3 and 4 – repair to extend life as considered appropriate by Planning & Development Manager.

Renewal

- Grade 1 – renew with 1 year.
- Grade 2 – renew within 3 years.

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 about 10% of strands are visibly broken or splayed.

Life extension & investment deferral techniques

- Use of Aluminium coated steel reinforced ACSR rather than grease coated steel reinforcing.

Major projects & programs

Projects & programs 2017/18

Ref	Location	Description	Category	Cost
1	School Rd, Otaki	Replace 16mm Cu with Bee (3km)	Renewal	$245,000
2	Florida Rd, Levin	Replace Gopher with Bee (3km)	Renewal	$184,000
3	SH1 Waitarere Beach Rd to Koputaroa Rd, Waitarere Beach	Replace Mink with Bee (2.5km)	Renewal	$153,000
4	Nth of Oturoa Rd, Foxton	Replace 11kV line (1.5km)	Renewal	$128,000
5	Muhunoa East Rd, Levin	Replace 16mm Cu with Bee (2.0km)	Renewal	$123,000
6	C D Farm Rd, Levin	Replace 16mm Cu with Bee (2km)	Renewal	$123,000
7	Bath St East, Levin	Replace 16mm Cu with Bee (0.5km)	Renewal	$61,000
8	Parker Ave, Levin	Replace 16mm Cu with Bee (0.5km)	Renewal	$61,000

9	Meadowvale Dr, Levin	Replace poles and 25mm Cu with Bee (0.5km)	Renewal	$61,000
10	Parsons Ave, Levin	Replace poles and 25mm Cu with Bee (0.5km)	Renewal	$61,000
11	Glen Rd, Raumati	Replace 400V line	Renewal	$61,000
12	All	400V Reconductors	Renewal	$54,000
13	Spring St (possible underground), Foxton	Replace 400V line	Renewal	$51,000
14	Kings Dr, Levin	Replace 400V line	Renewal	$51,000
15	Oxford St North (do with Deck Transformer E58), Levin	Replace 400V line	Renewal	$51,000
16	Tilley Rd Sth, Paekakariki	Replace 400V line	Renewal	$51,000
17	All	Inspection Driven Conductor Replacements	Renewal	$51,000
18	Mako mako Rd (between McKenzie St and Mabel St), Levin	Replace 400V line	Renewal	$41,000
19	Karaka Gr, Waikanae	Replace 400V line	Renewal	$41,000
20	Ruahine St, Paraparaumu	Replace 400V line	Renewal	$41,000
21	Avenue Rd, Foxton	Replace 400V line	Renewal	$26,000
22	Ngarara Rd, Waikanae	Upgrade 3 spans on 11kV on Ngarara Road	Renewal	$18,000

Projects & programs 2018/19 to 2021/22

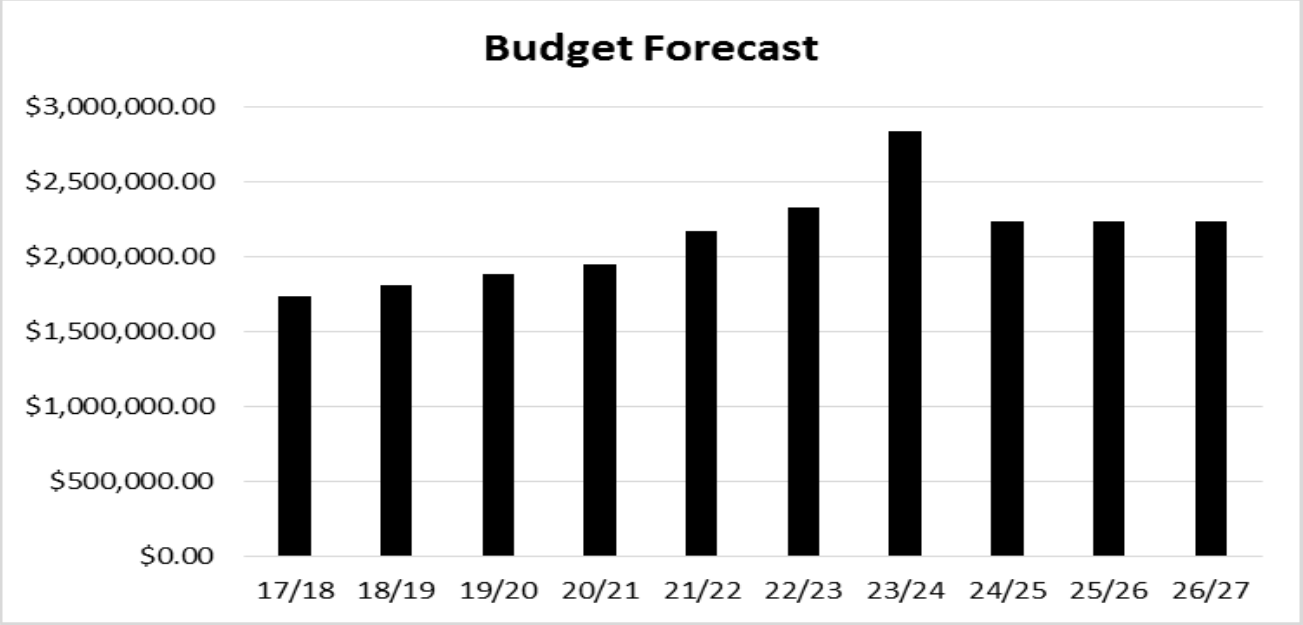
Ref	Location	Description	Category	Cost
1	All	400V Reconductors	Renewal	$1,635,000
2	All	Inspection Driven Conductor Replacements	Renewal	$204,000
3	Foxton Shannon Rd, Foxton	Replace 35mm Cu with Bee	Renewal	$1,227,000
4	SH1 South, Foxton	Replace 25mm Cu with Bee	Renewal	$511,000
5	Bergin Rd, Foxton	Replace 16mm Cu with Gopher (1.5km)	Renewal	$123,000
6	H219 to L224, Levin	Check conductor size upgrade to Bee	Renewal	$409,000
7	Queen St West, Levin	Replace 16mm Cu with Bee (1km)	Renewal	$82,000
8	Lindsay Rd, Levin	Replace 16mm Cu with Gopher (2km)	Renewal	$123,000
9	Kuku Beach Rd, Levin	Replace 16mm Cu with Gopher (4km)	Renewal	$245,000
10	Whakahoro Rd, Otaki	Replace 16mm Cu with Gopher (1km)	Renewal	$61,000
11	Domain Rd, Otaki	Replace 16mm Cu with Gopher (0.5km)	Renewal	$42,000
12	Convent Rd, Otaki	Replace 16mm Cu with Gopher (2km)	Renewal	$164,000
13	Waitohu Valley Rd, Otaki	Replace 16mm Cu with Bee (2.5km)	Renewal	$204,000
14	Te Manuao Rd, Otaki	Replace 16mm Cu with Bee (1km)	Renewal	$102,000
15	Manakau South Rd, Otaki	Replace 16mm Cu with Bee	Renewal	$204,000
16	Old Hautere Rd, Otaki	Replace 16mm Cu with Gopher (2km)	Renewal	$123,000
17	Valley Rd, Paraparaumu	Replace 16mm Cu with Gopher (1.5km)	Renewal	$123,000
18	Donovan Rd, Paraparaumu	Replace 25mm Cu with Gopher (0.3km)	Renewal	$133,000
19	Otaihanga Rd, Paraparaumu	Replace 16mm Cu with Gopher (1.5km)	Renewal	$92,000
20	Rata Rd, Raumati	Replace 16mm Cu with Gopher (1km)	Renewal	$82,000
21	Mangahao Rd, Shannon	Replace 16mm Cu with Gopher (4km)	Renewal	$327,000
22	Bryce St, Shannon	Replace 16mm Cu with Gopher (2km)	Renewal	$123,000
23	Seddon St, Waikanae	Replace 16mm Cu with Bee (1km)	Renewal	$82,000
24	Huia St, Waikanae	Replace 16mm Cu with Bee (1km)	Renewal	$82,000
25	Hadfield Rd, Waikanae	Replace 16mm Cu with Bee (0.5km)	Renewal	$41,000
26	Mangahao to Levin East 33kV, Levin	Upgrade to Butterfly double circuit	Renewal	$1,272,000

Projects & programs 2022/23 to 2026/27

Ref	Location	Description	Category	Cost
1	School Rd, Otaki	Replace 16mm Cu with Bee (3km)	Renewal	$307,000
2	SH1 Waitarere Beach Rd to Koputaroa Rd, Waitarere Beach	Replace Mink with Bee (2.5km)	Renewal	$153,000
3	All	400V Reconductors	Renewal	$2,044,000
4	All	Inspection Driven Conductor Replacements	Renewal	$6,605,000
5	Newth Rd, Foxton	Reconductor with Bee	Renewal	$511,000
6	Vista Rd, McLeavy Rd, Levin	Replace extension arms, reconductor and connect	Renewal	$153,000
7	Hautere Cross Rd, Otaki	Replace 16mm Cu with Bee (4km)	Renewal	$307,000
8	Ngaio Rd, Raumati	Replace 16mm Cu with Bee	Renewal	$123,000
9	Engles Rd, Shannon	Replace 16mm Cu with Gopher (2km)	Renewal	$123,000
10	Puriri St, Waikanae	Replace 16mm Cu with Gopher (1.5km)	Renewal	$123,000
11	Tui Cres, Waikanae	Replace 16mm Cu with Gopher (1km)	Renewal	$82,000
12	Mangahao to Levin East 33kV, Levin	Upgrade to Butterfly double circuit	Renewal	$1,348,000

Budget forecast

Budget	17/18	18/19	19/20	20/21	21/22	22/23	23/24	24/25	25/26	26/27
	$1.737m	$1.809m	$1.888m	$1.949m	$2.167m	$2.331m	$2.832m	$2.238m	$2.238m	$2.238m



6.4 Pole-top hardware

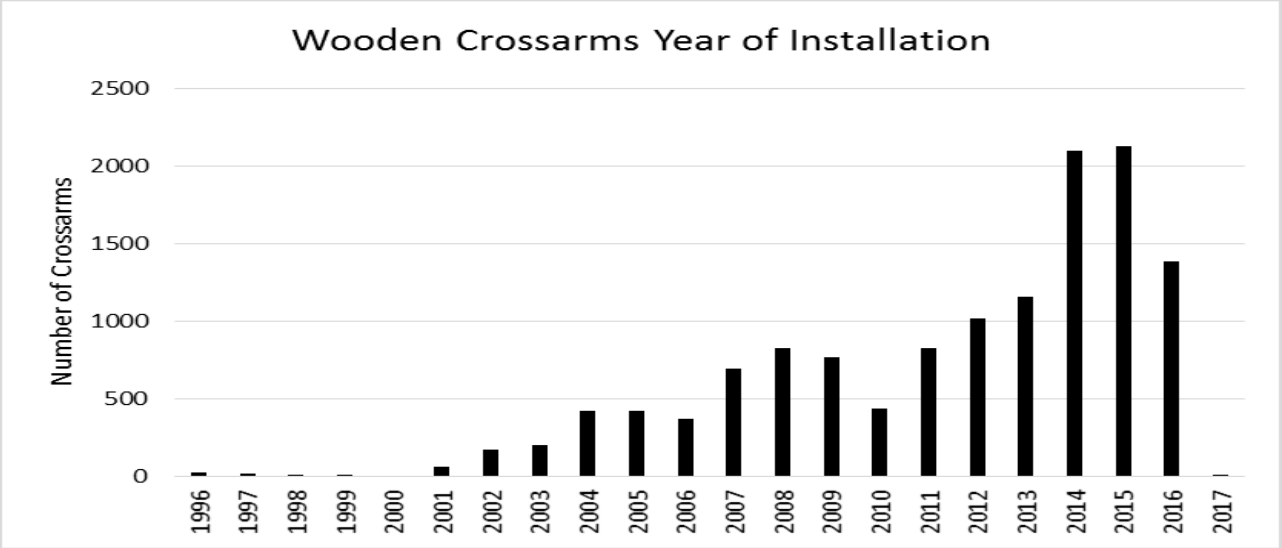
Key features of Electra's pole-top hardware management are as follows.

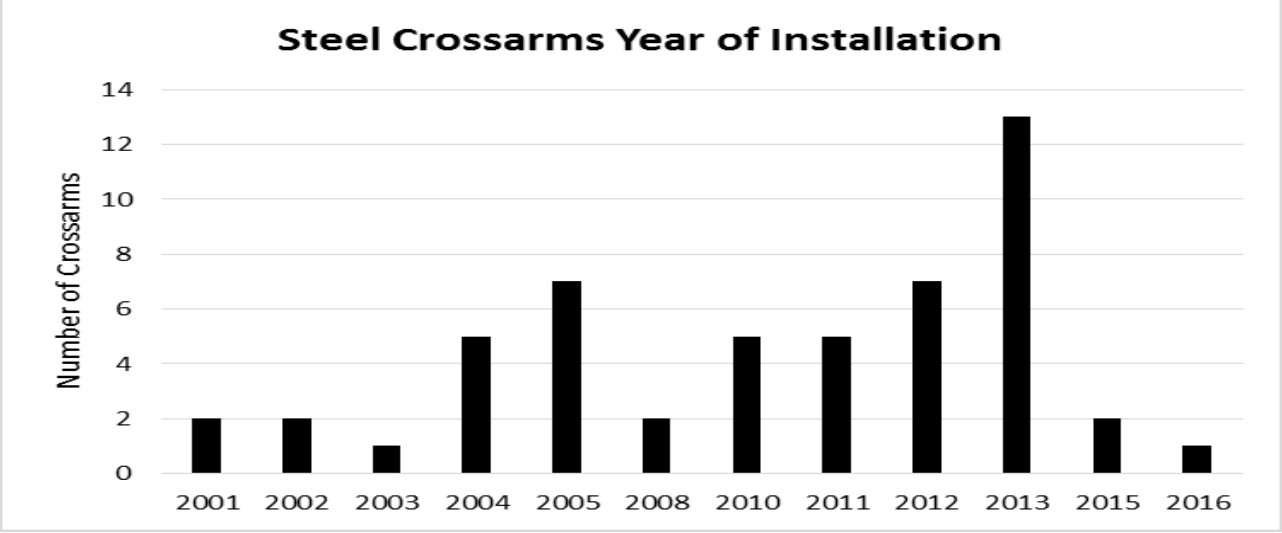
Summary of asset class

Electra has 40,892 wooden cross arms 4,046 galvanised steel cross arms.

Population and age profile

Sub-class	Number	Unit	Percent	Key features of sub-class
Hard wood	6,331	Each	14.1%	
Soft wood	71	Each	0.2%	
Tallow wood	34,490	Each	76.8%	
Steel	163	Each	0.4%	
Steel box section	3,883	Each	8.6%	
Total	**44,938**	**Each**	**100%**	





Condition

Condition:	Grade 1	Grade 2	Grade 3	Grade 4	Grade unknown	Data accuracy	Percent forecast for replacement over next 5 years
		8.9%	77.6%	13.5%	-	3	10%

Systemic issues & mitigation

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.

Key design parameters

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 (eg. 22kV instead of 11 kV).
Structural strength	Embodied in Electra's overhead line design standards, and includes consideration of static and wind loads.

Management tactics

Maintenance drivers

- Splitting, warping or bending of wooden arms.
- Rust on galv 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.

Maintenance criteria

- Splitting of wooden arms more than a finger width.
- 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

- Splitting of timber arms may lead to sudden failure.
- Warping or bending or timber arms may unevenly strain conductors, leading to excessive binding tension.
- 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.

Lifecycle policies, criteria and activities

Inspections

- Grade 1 – no further inspections, as it will be replaced within 1 year.
- Grade 2 – no further inspection, as it will be replaced within 3 years.
- Grades 3 and 4 – continue to inspect, amend grade as revealed by subsequent inspections.

Defect correction

- Public safety defects – correction within 1 week of identification.
- Significant defects that could lead to asset failure (eg. arm breaking) – correction within 1 week of identification.
- Minor defects – repair by approved method within 3 months of identification.

Refurbishment

- Pole top components are generally renewed rather than refurbished.
- General servicing of air break switchs on a 5 year cycle, starting with Ohau and Manakau in 2017.

Renewal

- Grade 1 – renew with 1 year.
- Grade 2 – renew within 3 years.
- Grade 3 – continue inspections.

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 or warping, in which case the arm would be renewed.

Life extension & investment deferral techniques

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

Major projects & programs

Projects & programs 2017/18

#	Location	Description	Category	Cost
1	All	Inspection Driven Crossarm Replacements from 2017 on	Renewal	$896,000
2	All	Inspection Driven Crossarm Replacements from 2017 on	Renewal	$717,000
3	All	Inspection Driven Crossarm Replacements from 2017 on	Renewal	$107,000
4	All	Fault/Urgent defect replacement of cross arms	Renewal	$82,000
5	Mangahao Line, Levin	Replace Poles and Crossarms	Renewal	$178,000

Projects & programs 2018/19 to 2021/22

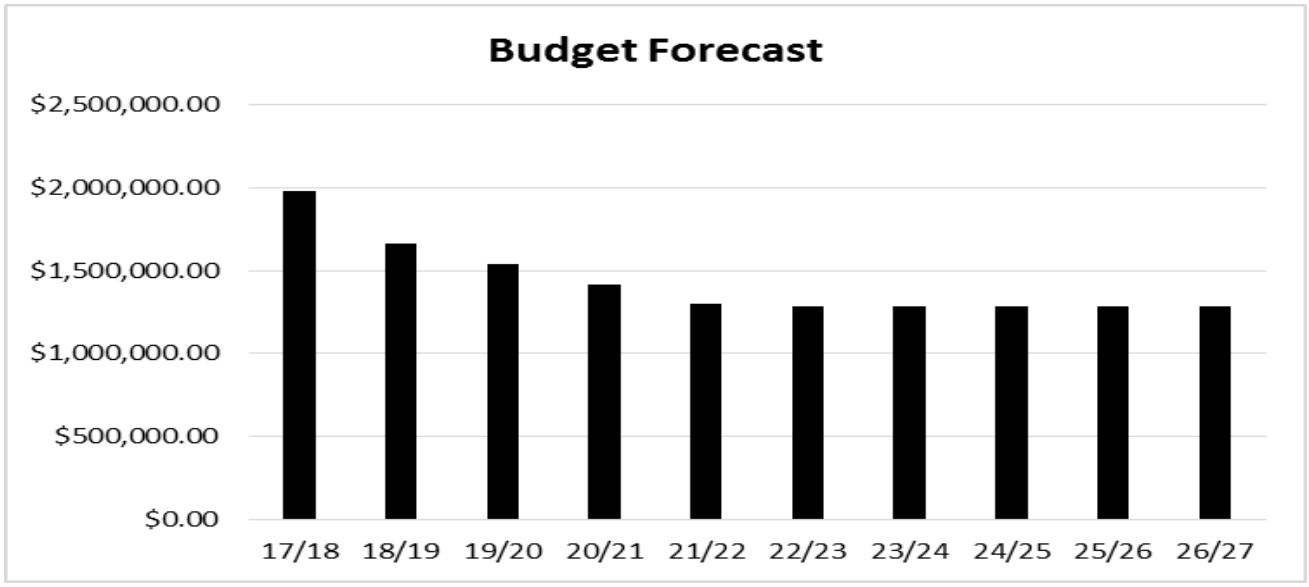
#	Location	Description	Category	Cost
1	All	Inspection Driven Crossarm Replacements from 2017 on	Renewal	$3,000,000
2	All	Inspection Driven Crossarm Replacements from 2017 on	Renewal	$2,280,000
3	All	Inspection Driven Crossarm Replacements from 2017 on	Renewal	$307,000
4	All	Fault/Urgent defect replacement of cross arms	Renewal	$326,000

Projects & programs 2022/23 to 2026/27

#	Location	Description	Category	Cost
1	All	Inspection Driven Crossarm Replacements from 2017 on	Renewal	$3,300,000
2	All	Inspection Driven Crossarm Replacements from 2017 on	Renewal	$2,328,000
3	All	Inspection Driven Crossarm Replacements from 2017 on	Renewal	$383,300
4	All	Fault/Urgent defect replacement of cross arms	Renewal	$408,000

Budget forecast

Budget	17/18	18/19	19/20	20/21	21/22	22/23	23/24	24/25	25/26	26/27
	$1.981m	$1.658m	$1.538m	$1.418m	$1.298m	$1.284m	$1.284m	$1.284m	$1.284m	$1.284m


Budget Forecast
$2,500,000.00
$2,000,000.00
$1,500,000.00
$1,000,000.00
$500,000.00
$0.00
17/18
18/19
19/20
20/21
21/22
22/23
23/24
24/25
25/26
26/27

6.5 33kV cable

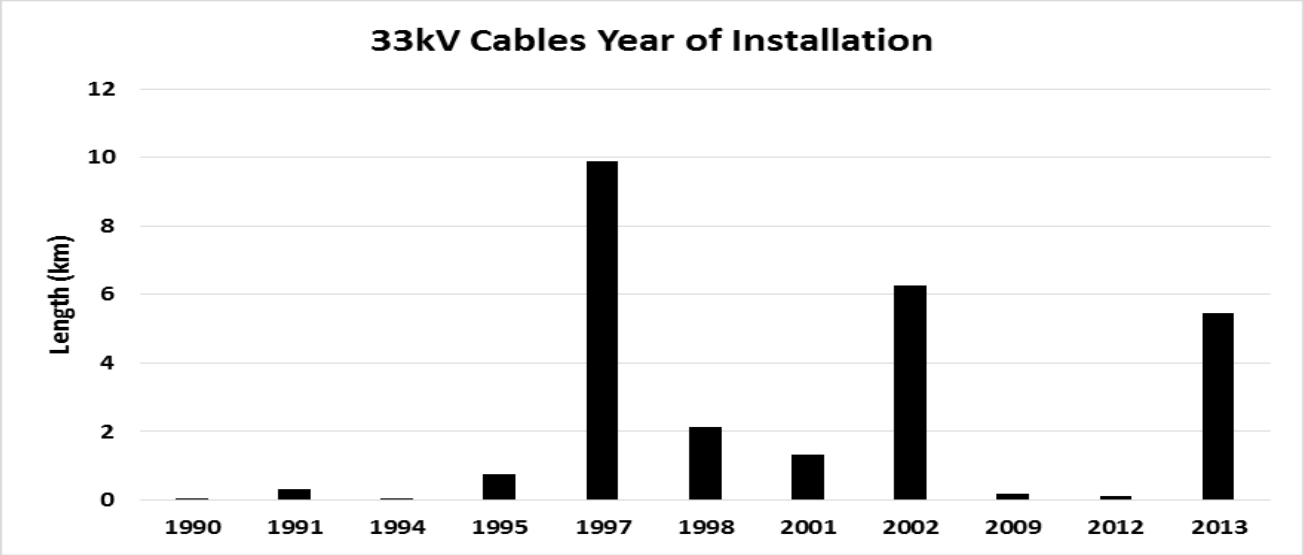
Key features of Electra's 33kV cable management are as follows.

Summary of asset class

Electra has 29.3 km of 33kV cable and associated terminations.

Population and age profile

Sub-class	Number	Unit	Percent	Key features of sub-class
500 mm² aluminium XLPE	6.1	km	20.8%	
630 mm² aluminium XLPE	17.7	km	60.4%	
800 mm² aluminium XLPE	5.5	km	18.8%	
Total	**29.3**	**km**	**100%**	



Condition

Condition:	Grade 1	Grade 2	Grade 3	Grade 4	Grade unknown	Data accuracy	Percent forecast for replacement over next 5 years
			79.70%	20.30%		4	

Systemic issues & mitigation

There are no known systemic issues with Electra's 33kV cables.

Capacity, security & reliability constraints

There are no 33kV cable constraints

Key design parameters

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

Management tactics

Maintenance drivers

- 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.

Maintenance criteria

- Tan Delta exceeds limits .
- Partial discharge test results exceed limits.
- Thermography of cable terminations reveals excessive temperatures.
- Spliting 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

- 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.

Lifecycle policies, criteria and activities

Inspections

- Grade 1 – no further inspections, as it will be replaced within 1 year.
- Grade 2 – no further inspection, as it will be replaced within 3 years.
- Grades 3 and 4 – continue to inspect, amend grade as required.

Defect correction

- Public safety defects – correction within 1 week of identification.
- Significant structural integrity defects – correction within 1 week of identification.
- Minor structural integrity defects – repair by approved method within 3 months of identification.

Refurbishment

- Grade 1 – will not be refurbished.
- Grade 2 – minor repairs only.
- Grades 3 and 4 – repair to extend life as considered appropriate by Planning & Development Manager.

Renewal

- Grade 1 – renew with 1 year.
- Grade 2 – renew within 3 years.

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 & 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.

Major projects & programs

No major 33kV cable projects or programs are planned.

6.6 11kV cable

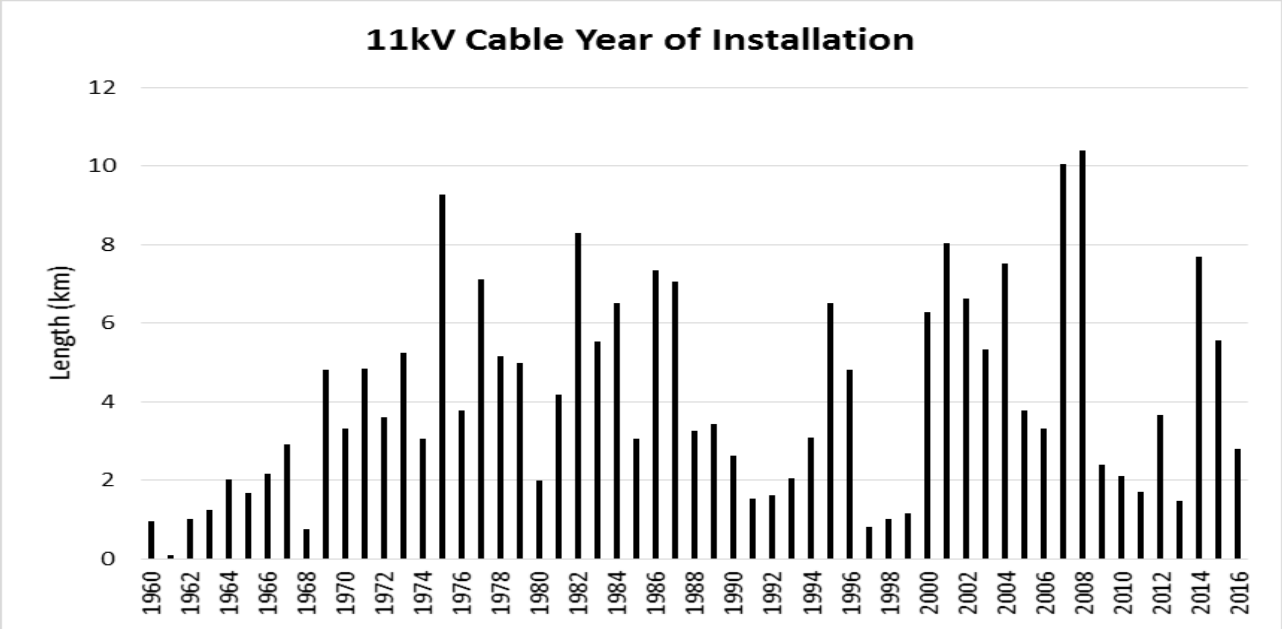
Key features of Electra's 11kV cable management are as follows.

Summary of asset class

Electra has 237 km of 11kV cable.

Population and age profile

Sub-class	Number	Unit	Percent	Key features of sub-class
PILC	122	km	51.48%	
XLPE, PVC or HDPE	115	km	48.52%	
Unknown	0.089	km	0.04%	
Total	**237**	**km**	**100%**	



Condition

Condition:	Grade 1	Grade 2	Grade 3	Grade 4	Grade unknown	Data accuracy	Percent forecast for replacement over next 5 years
XLPE, PVV or HDPE	-	-	61.30%	38.70%	-	3	-
PILC	-	1.63%	98.37%	-	-	3	2.00%

Systemic issues & mitigation

There are no known systemic issues with Electra's 11kV cable.

Capacity, security & reliability constraints

There are no known constraints with Electra's 11kV cable.

Key design parameters

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

Management tactics

Maintenance drivers

- 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.

Maintenance criteria

- Spliting 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.

Assumptions

- 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.

Lifecycle policies, criteria and activities

Inspections

- Grade 1 – no further inspections, as it will be replaced within 1 year.
- Grade 2 – no further inspection, as it will be replaced within 3 years.
- Grades 3 and 4 – continue to inspect, amend grade as required.

Defect correction

- Public safety defects – correction within 1 week of identification.
- Significant structural integrity defects – correction within 1 week of identification.
- Minor structural integrity defects – repair by approved method within 3 months of identification.

Refurbishment

- Grade 1 – will not be refurbished.
- Grade 2 – minor repairs only.
- Grades 3 and 4 – repair to extend life as considered appropriate by Planning & Development Manager.

Renewal

- Grade 1 – renew with 1 year.
- Grade 2 – renew within 3 years.

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 & 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.

Major projects & programs

Projects & programs 2017/18

Ref	Location	Type of Work	Category	Cost
1	SH1, Otaki	Upgrade the cable section feeding Manukau village – 11kV	Renewal	$75,000

Projects & programs 2018/19 to 2022/23

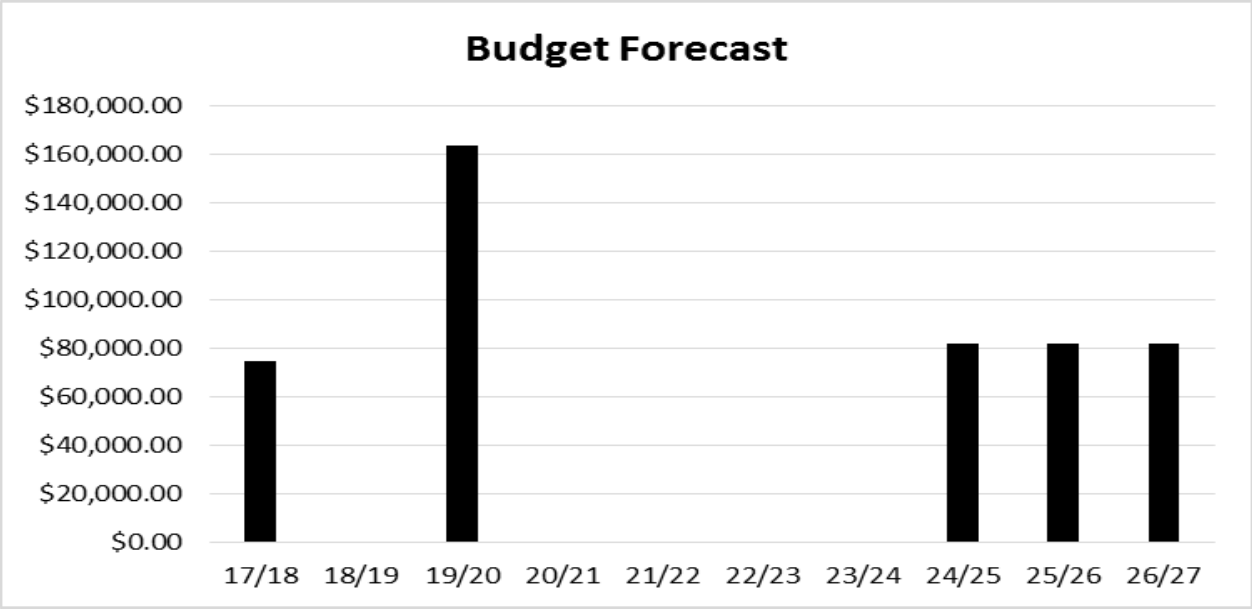
Ref	Location	Type of Work	Category	Cost
1	L21 to L332, Manakau	Replace HT cable and LV across road and rail to village – 11kV	Renewal	$82,000
2	Bath St, Levin	Replace 11kV cable E313-E83	Renewal	$82,000

Projects & programs 2023/24 to 2026/27

Ref	Location	Type of Work	Category	Cost
1	Tui Rd, Raumati	Replace cable between Z92 & Z103 – 11kV	Renewal	$245,000

Budget forecast

Budget	17/18	18/19	19/20	20/21	21/22	22/23	23/24	24/25	25/26	26/27
	$75k		$163.5k					$81.8k	$81.8k	$81.8k



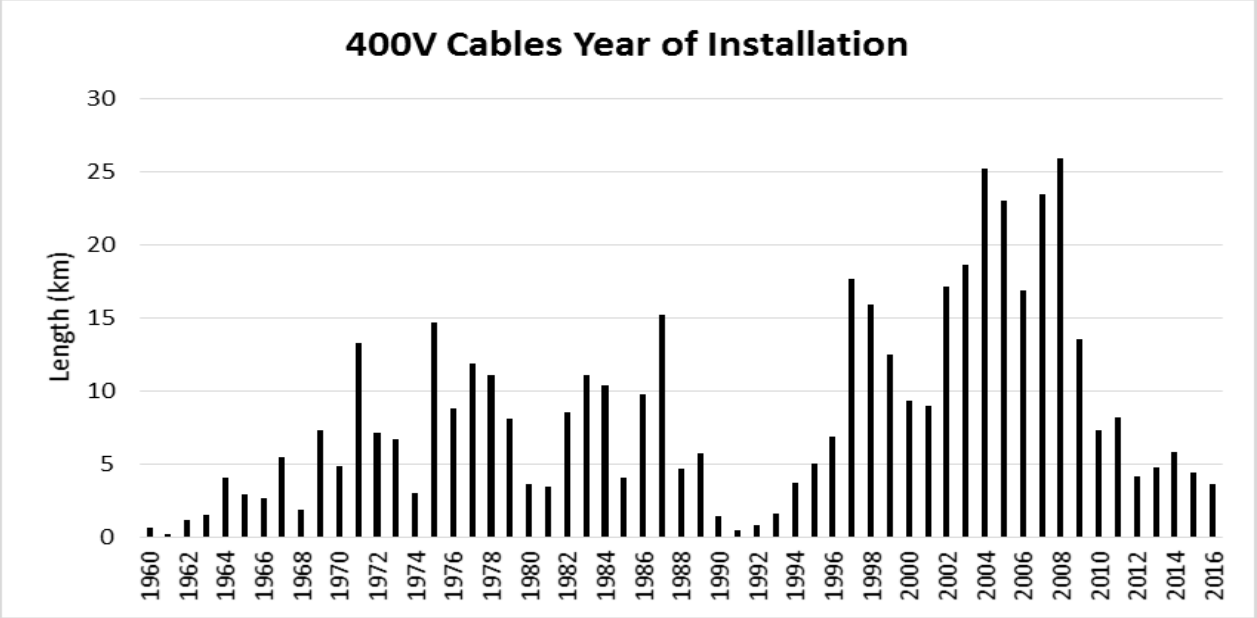
6.7 LV cable

Key features of Electra's LV cable management are as follows.

Summary of asset class

Electra has 775 km of LV cable and associated distribution pillars and fittings.

Population and age profile



Condition

Condition:	Grade 1	Grade 2	Grade 3	Grade 4	Grade unknown	Data accuracy	Percent forecast for replacement over next 5 years
				44.00%	56.00%	3	2.00%

Systemic issues & mitigation

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.

Capacity, security & reliability constraints

There are no known LV cable constraints. As constraints are discovered, they are managed by paralleling transformers at link pillars. These parallels are being confirmed in preparation for the ADMS implementation during 2017/18.

Key design parameters

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

Management tactics

Maintenance drivers

- 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.

Maintenance criteria

- Spliting 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.

Assumptions

- 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.

Lifecycle policies, criteria and activities

Inspections

- Grade 1 – no further inspections, as it will be replaced within 1 year.
- Grade 2 – no further inspection, as it will be replaced within 3 years.
- Grades 3 and 4 – continue to inspect, amend grade as required.

Defect correction

- Public safety defects – correction within 1 week of identification.
- Significant structural integrity defects – correction within 1 week of identification.
- Minor structural integrity defects – repair by approved method within 3 months of identification.

Refurbishment

- Grade 1 – will not be refurbished.
- Grade 2 – minor repairs only.
- Grades 3 and 4 – repair to extend life as considered appropriate by Planning & Development Manager.

Renewal

- Grade 1 – renew within 1 year.
- Grade 2 – renew within 3 years.

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 & 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.

Major projects & programs

There are no major LV cable projects planned.

6.8 Distribution transformers

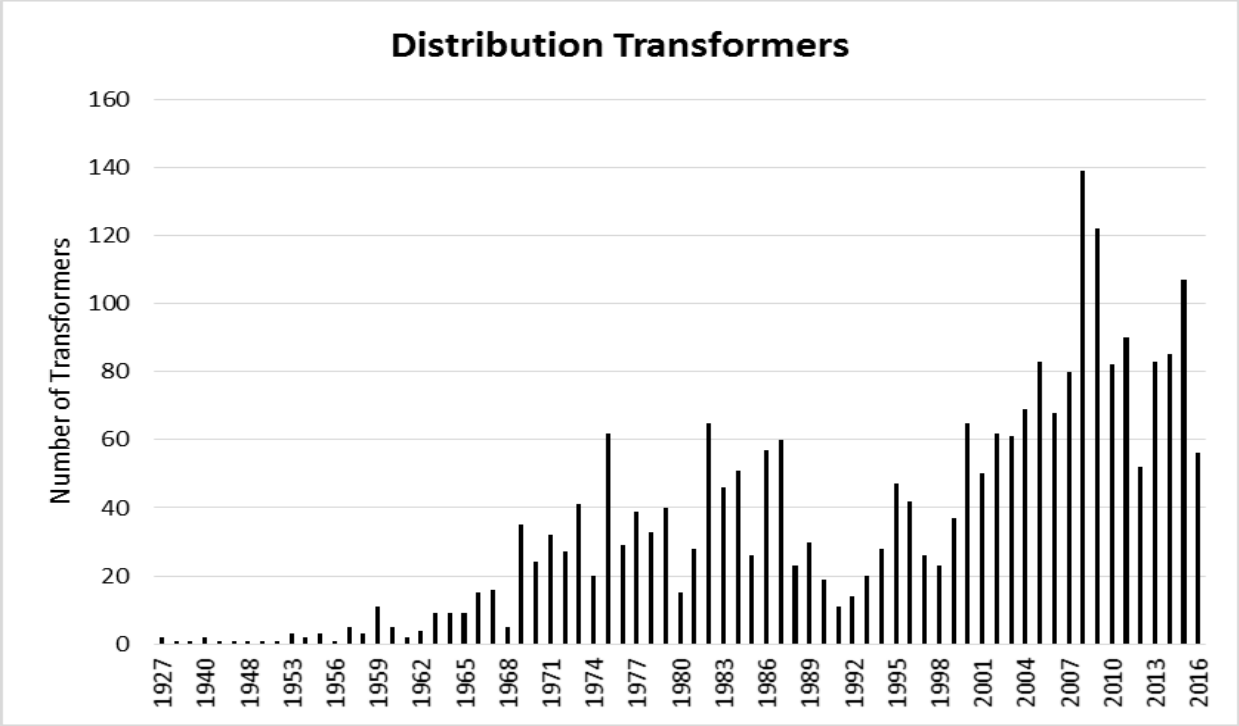
Key features of Electra's distribution substation management are as follows.

Summary of asset class

Electra has 1,599 overhead distribution transformers and 928 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	8	0	8
1-phase 15kVA	21	0	21
1-phase 30KVA	7	1	8
1-phase 100kVA	1	0	1
3-phase 5kVA	0	0	0
3-phase 7kVA	2	0	2
3-phase 10kVA	3	0	3
3-phase 15kVA	79	0	79
3-phase 25kVA	7	0	7
3-phase 30kVA	864	24	888
3-phase 50kVA	358	56	414
3-phase 75kVA	2	0	2
3-phase 100kVA	215	106	321
3-phase 150kVA	2	1	3
3-phase 200kVA	25	206	231
3-phase 250kVA	0	19	19
3-phase 300kVA	4	412	416
3-phase 500kVA	0	81	81
3-phase 750kVA	0	14	14
3-phase 1000kVA	0	8	8
Total	**1,599**	**928**	**2,527**

Population and age profile



Condition

Condition:	Grade 1	Grade 2	Grade 3	Grade 4	Grade unknown	Data accuracy	Percent forecast for replacement over next 5 years
Pole mounted	-	3.70%	63.30%	33.00%	-	4	6.15%
Ground mounted	-	4.50%	54.50%	41.00%	-	4	7.50%

Systemic issues & mitigation

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

Capacity, security & reliability constraints

There are no known distribution substation constraints.

Key design parameters

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

Management tactics

Maintenance drivers

- Rusting of tank.
- Oil staining of tank.
- Color of silica gel breather where fitted
- Excessive graffiti or evidence of interference or tampering.

Maintenance criteria

- 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.

Assumptions

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

Lifecycle policies, criteria and activities

Inspections

- Grade 1 – no further inspections, as it will be replaced within 1 year.
- Grade 2 – no further inspection, as it will be replaced within 3 years.
- Grades 3 and 4 – continue to inspect, amend grade as required.

Defect correction

- Public safety defects – correction within 1 week of identification.
- Significant structural integrity defects – correction within 1 week of identification.
- Minor structural integrity defects – repair by approved method within 3 months of identification.

Refurbishment

- Grades 1 and 2 – will not be refurbished (generally scrapped as too expensive to refurbish)
- Grades 3 and 4 – minor repair to maintain life as considered appropriate by Planning & Development Manager.

Renewal

- Grade 1 – renew with 1 year.
- Grade 2 – renew within 3 years.

Lifecycle decision criteria

- Replace when necessary repairs become more than minor.
- Replace when MDI readings reveal regulator loading to more than 100% of design rating.

Life extension & investment deferral techniques

- Additional galvanising or paint for coastal areas.

Major projects & programs

Projects & programs 2017/18

Ref	Location	Constraint Description	Category	Cost
1	All	Ground Transformer Replacements	Renewal	$650,000
2	All	Pole Transformer Replacements	Renewal	$260,000
3	All	Ground Transformer Faults	Renewal	$150,000
4	Buller Rd, Levin	Upgrade transformer room H104	Renewal	$91,000
5	SH1, Levin	Upgrade transformer room H25	Renewal	$91,000
6	All	Pole Transformer Faults	Renewal	$90,000

Projects & programs 2018/19 to 2022/23

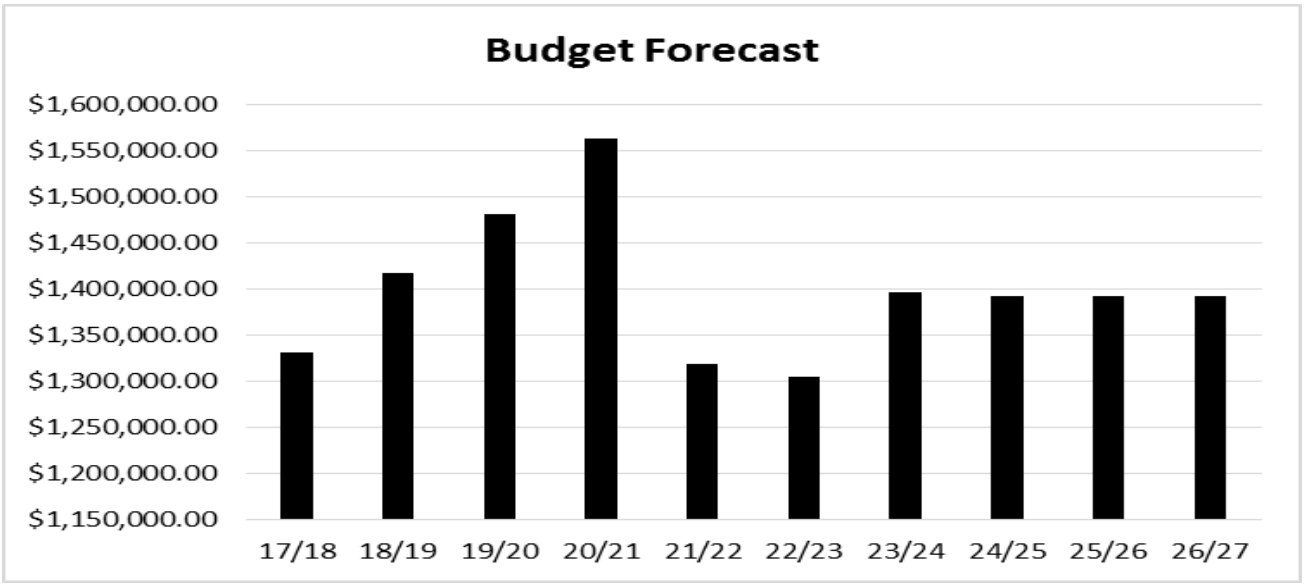
Ref	Location	Constraint Description	Category	Cost
1	All	Ground Transformer Replacements	Renewal	$3,004,000
2	All	Pole Transformer Replacements	Renewal	$972,000
3	All	Ground Transformer Faults	Renewal	$600,000
4	SH1, Levin	Upgrade transformer room H25	Renewal	$91,000
5	All	Pole Transformer Faults	Renewal	$360,000
6	H68, Levin	Remove H68 and run new service from H215 to feed Allied Concrete	Renewal	$77,000
7	Kimberley Rd, Levin	Upgrade transformer room G120	Renewal	$91,000
8	Bartholomew Rd, Levin	Upgrade transformer room G126	Renewal	$91,000
9	Totara St, Levin	Upgrade transformer room G177	Renewal	$91,000
10	Kimberley Rd, Levin	Upgrade transformer room G93	Renewal	$91,000
11	Hokio Beach Rd, Levin	Upgrade transformer room H174	Renewal	$91,000
12	Kirk St, Otaki	Replace deck transformer M12	Renewal	$77,000
13	Swamp Rd, Otaki	Replace deck transformer P65	Renewal	$77,000
14	S133, Waikanae	replace with ground mount Transformer Check	Renewal	$71,000

Projects & programs 2023/24 to 2026/27

#	Location	Constraint Description	Category	Cost
1	All	Ground Transformer Replacements	Renewal	$3,755,000
2	All	Pole Transformer Replacements	Renewal	$1,188,000
3	All	Ground Transformer Faults	Renewal	$750,000
4	All	Pole Transformer Faults	Renewal	$450,000
5	All	Indoor Subs	Renewal	$491,000
6	Whirokino Rd, Foxton	Rebuild deck transformer C23	Renewal	$77,000
7	Tararua Rd, Levin	Replace deck transformer G326 with single pole 200kVA	Renewal	$77,000
8	Kimberley Rd, Levin	Upgrade transformer room G97	Renewal	$91,000

Budget forecast

Budget	17/18	18/19	19/20	20/21	21/22	22/23	23/24	24/25	25/26	26/27
	$1.331m	$1.418m	$1.481m	$1.563m	$1.319m	$1.305m	1.396m	1.392m	1.392m	1.392m


Budget Forecast
$1,600,000.00
$1,550,000.00
$1,500,000.00
$1,450,000.00
$1,400,000.00
$1,350,000.00
$1,300,000.00
$1,250,000.00
$1,200,000.00
$1,150,000.00
17/18
18/19
19/20
20/21
21/22
22/23
23/24
24/25
25/26
26/27

6.9 Distribution switchgear

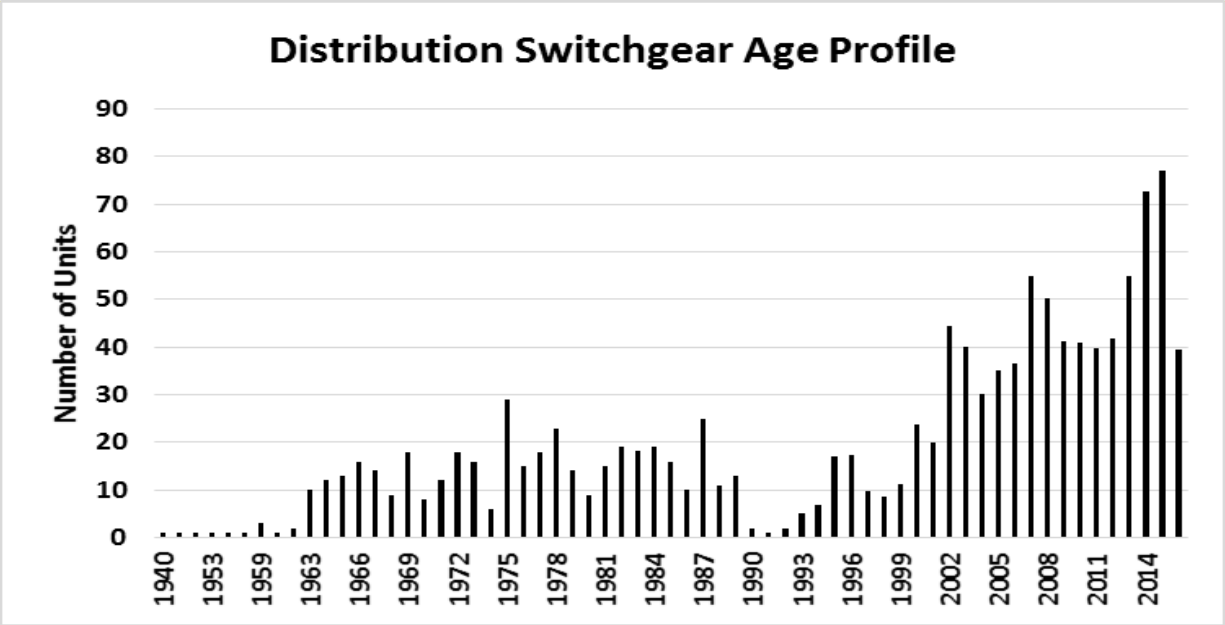
Key features of Electra's distribution switchgear management are as follows.

Summary of asset class

Electra has 1,266 individual items that are broadly classified as distribution switches.

Population and age profile

Sub-class	Number	Percent
Ground mount switches	135	11%
Auto reclosers	37	3%
Air break switches	342	27%
In-line drop-out fuses	752	59%
Total	**1,266**	**100%**



Condition

Condition:	Grade 1	Grade 2	Grade 3	Grade 4	Grade unknown	Data accuracy	Percent forecast for replacement over next 5 years
Pole mounted circuit breakers (reclosers and sectionalisers)		3.00%	85.00%	12.00%		4	3.00%
Indoor circuit breakers		12.00%	78.00%	10.00%		4	12.00%
Pole mounted switches & fuses		3.00%	66.00%	31.00%		3	5.00%
Ring main units		5.97%	54.03%	40.00%		3	7.00%

Systemic issues & mitigation

There are no known system issues with any class of distribution switchgear

Capacity, security & reliability constraints

There are no known constraints with any class of distribution switchgear

Key design parameters

Parameter	Value
Durability	Expected life of 45 years
Load rating	Generally use minimum commercially available rating of 630A.

Management tactics

Maintenance drivers

- Interupting 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

- 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

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

Lifecycle policies, criteria and activities

Inspections

- Grade 1 – no further inspections, as it will be replaced within 1 year.
- Grade 2 – no further inspection, as it will be replaced within 3 years.
- Grades 3 and 4 – continue to inspect, amend grade as required.

Defect correction

- Public safety defects – correction within 1 week of identification.
- Significant structural integrity defects – correction within 1 week of identification.
- Minor structural integrity defects – repair by approved method within 3 months of identification.

Refurbishment

- Grade 1 – will not be refurbished.
- Grade 2 – minor repairs only.
- Grades 3 and 4 – repair to extend life as considered appropriate by Planning & Development Manager.

Renewal

- Grade 1 – renew with 1 year.
- Grade 2 – renew within 3 years.

Lifecycle decision criteria

- 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.

Life extension & investment deferral techniques

- Electra may apply extra paint, galvanising or grease to individual switches near coastal areas.

Major projects & programs

Projects & programs 2017/18

Ref	Location	Description	Category	Cost
1	All	Replace Oil Switches	Renewal	$195,000
2	Bath St, Levin	Replace swgr E312-E314	Renewal	$90,000
3	All	ABS new & renewals	Renewal	$82,000
4	A45, Tokomaru	Replace with ABS 4+ Transformers	Renewal	$11,000

Projects & programs 2018/19 to 2021/22

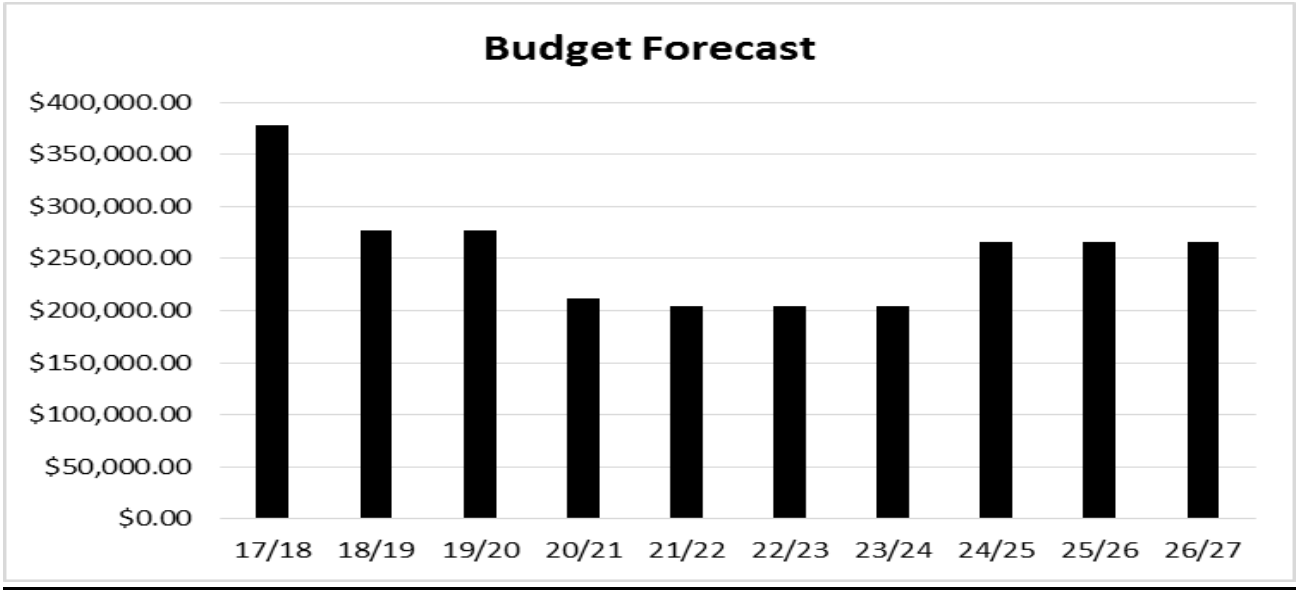
Ref	Location	Description	Category	Cost
1	All	Replace Oil Switches	Renewal	$643,000
2	All	ABS new & renewals	Renewal	$328,000

Projects & programs 2022/23 to 2026/27

Ref	Location	Description	Category	Cost
1	All	Replace Oil Switches	Renewal	$797,000
2	All	ABS new & renewals	Renewal	$410,000

Budget forecast

Budget	17/18	18/19	19/20	20/21	21/22	22/23	23/24	24/25	25/26	26/27
	$378.2k	$277.1k	$277.1k	$212.1k	$204.7k	$204.7k	$204.7k	$266.1k	$266.1k	$266.1k



6.10 Zone substation transformers

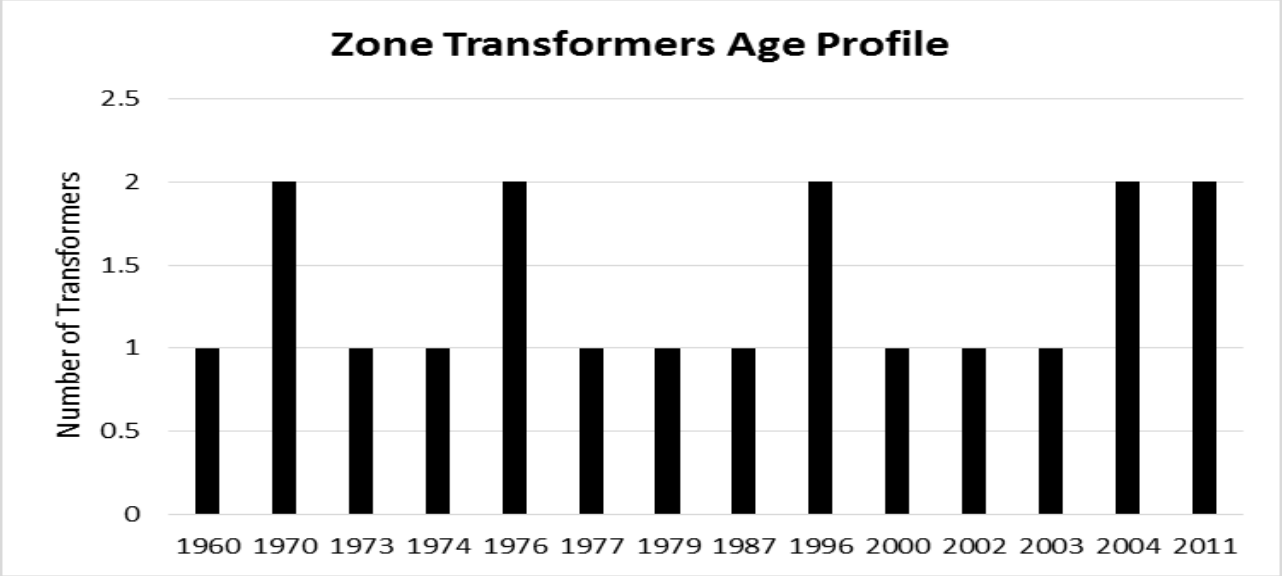
Key features of Electra's zone substation transformers management are as follows.

Summary of asset class

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.

Population and age profile

Sub-class	Number	Unit	Percent	Key features of sub-class
5 MVA	3	Each	18.75%	
11.5/23 MVA	16	Each	84.21%	
Total	**19**	**Each**	**100%**	



Condition

Condition:	Grade 1	Grade 2	Grade 3	Grade 4	Grade unknown	Data accuracy	Percent forecast for replacement over next 5 years
			90.00%	10.00%		4	

Systemic issues & mitigation

There are no known system issues with Electra's zone substation transformers.

Capacity, security & reliability constraints

There are no known constraints with Electra's zone substation transformers.

Key design parameters

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 supplied by 2 neighboring substations.

Management tactics

Maintenance drivers

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

Maintenance criteria

- 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

- Declining oil condition will continue 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.

Lifecycle policies, criteria and activities

Inspections

- Grade 1 – bi-monthly inspections but no further detailed monitoring, as it will be replaced within 12 to 18 months.
- Grade 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.
- Grades 3 and 4 – continue to inspect, amend grade as required.

Defect correction

- Public safety defects – correction within 1 week of identification.
- Significant structural integrity defects – correction within 1 week of identification.
- Minor structural integrity defects – repair by approved method within 3 months of identification.

Refurbishment

- Grade 1 – will not be refurbished.
- Grade 2 – minor repairs only.
- Grades 3 and 4 – repair to extend life as considered appropriate by Planning & Development Manager.

Renewal

- Grade 1 – renew with 1 year.
- Grade 2 – renew within 3 years if repair and refurb options are not cost effective.

Lifecycle decision criteria

- 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 & investment deferral techniques

- 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.

Major projects & programs

No major zone substation transformer projects are planned.

6.11 Zone substation switchgear

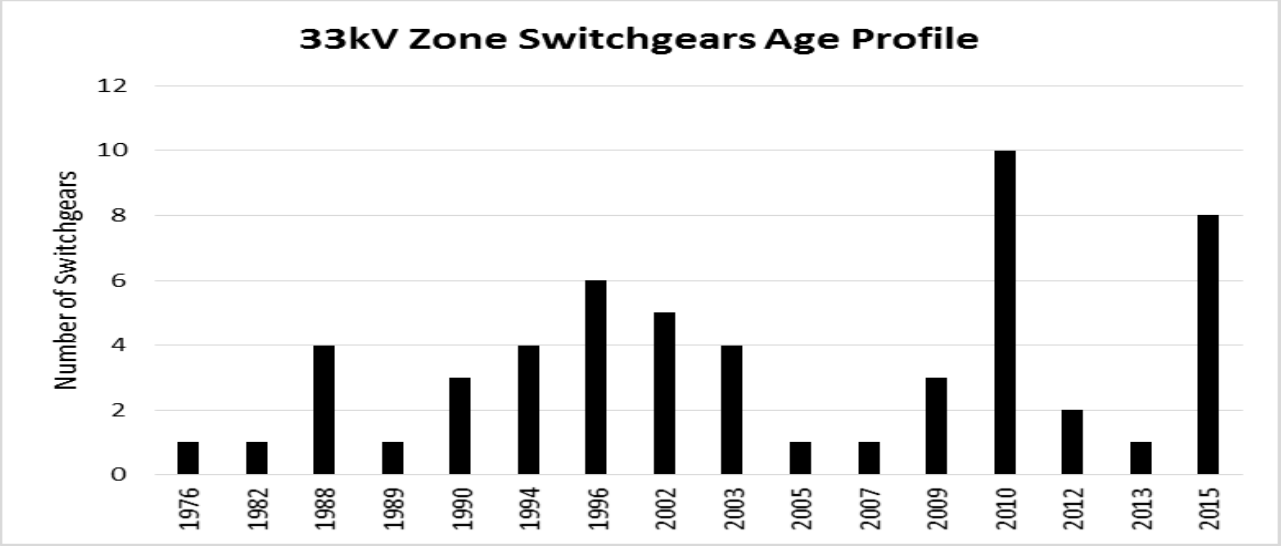
Key features of Electra's zone substation switchgear management are as follows.

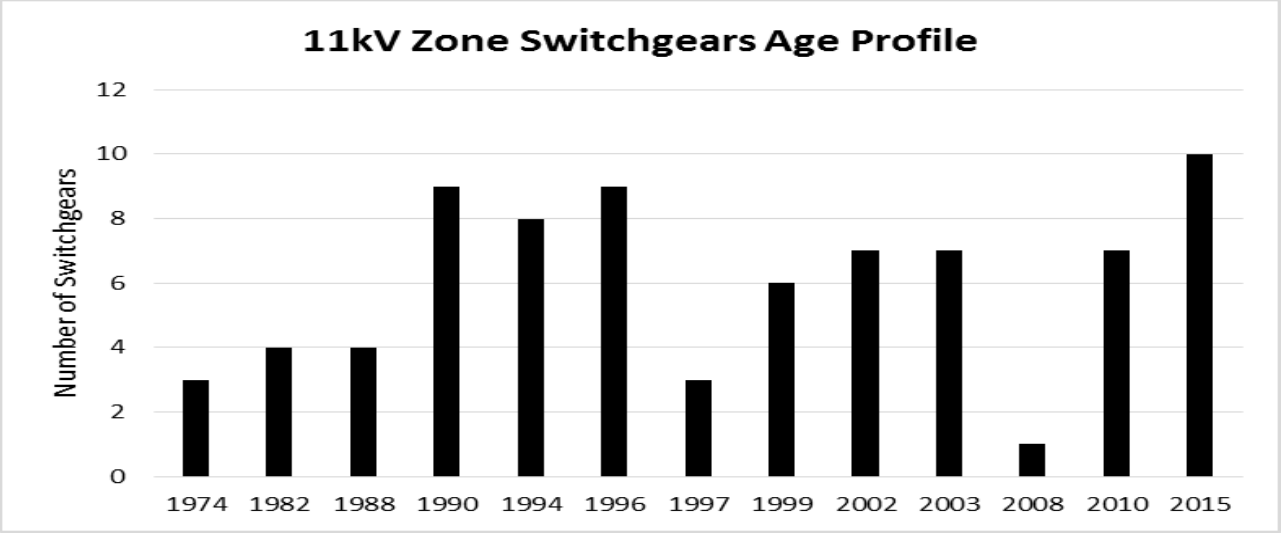
Summary of asset class

Electra has 55 separate 33kVcircuit breakers and 78 separate 11kV circuit breakers in its zone substations, including associated protection.

Population and age profile

Sub-class	Number	Unit	Percent	Key features of sub-class
33kV SF6 (indoor)	35	Each	26.32%	
33kV SF6 (outdoor)	20	Each	15.04%	
11kV oil	4	Each	3.01%	
11kV vacuum	62	Each	46.62%	
11kV SF6	12	Each	9.02%	
Total	**133**		**100%**	





Condition

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		9.55%	90.45%			4	9.55%
3.3kV, 6.6kV, 11kV or 22kV		5.19%	82.31%	12.50%		3	10.38%

Systemic issues & mitigation

There are no known systemic issues with Electra's zone substation switchgear.

Capacity, security & reliability constraints

There are no known constraints with Electa's zone substation switchgear.

Key design parameters

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.

Management tactics

Maintenance drivers

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

Maintenance criteria

- 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.

Assumptions

- Decline in arc-quenching medium pressure or level will continue to decline rather than plateau.
- Increasingly stiff operating mechanism will require repairs.
- Surface rust will continue to deepen.

Lifecycle policies, criteria and activities

Inspections

- Grade 1 – no further inspections, as it will be replaced within 1 year.
- Grade 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.
- Grades 3 and 4 – continue to inspect, amend grade as required.

Defect correction

- Public safety defects – correction within 1 week of identification.
- Significant structural integrity defects – correction within 1 week of identification.
- Minor structural integrity defects – repair by approved method within 3 months of identification.

Refurbishment

- Grade 1 – will not be refurbished.
- Grade 2 – minor repairs only.
- Grades 3 and 4 – repair to extend life as considered appropriate by Planning & Development Manager.

Renewal

- Grade 1 – renew with 1 year.
- Grade 2 – renew within 3 years.

Lifecycle decision criteria

- Electra may refurbish when a majority of components require maintenance, but is more likely to renew (replace) due to other criteria such as safety, fault level or obsolescence of key components.

Life extension & investment deferral techniques

- If the sole issue is fault rating, an attempt will be made to replace the interruptor heads with higher rated heads to avoid replacing the whole switchboard.

Major projects & programs

Projects & programs 2017/18

Ref	Location	Description	Category	Cost
1	Raumati Substation	Replace north half of 11kV board	Renewal	$409,000
2	Levin East Substation	Replace 33kV breaker(rocket laucher)	Renewal	$65,000
3	Paekakariki Substation	CB replacement	Renewal	$65,000
4	All	33kV Protection	Renewal	$50,000
5	All	Unplanned Capital	Renewal	$31,000

Projects & programs 2018/19 to 2021/22

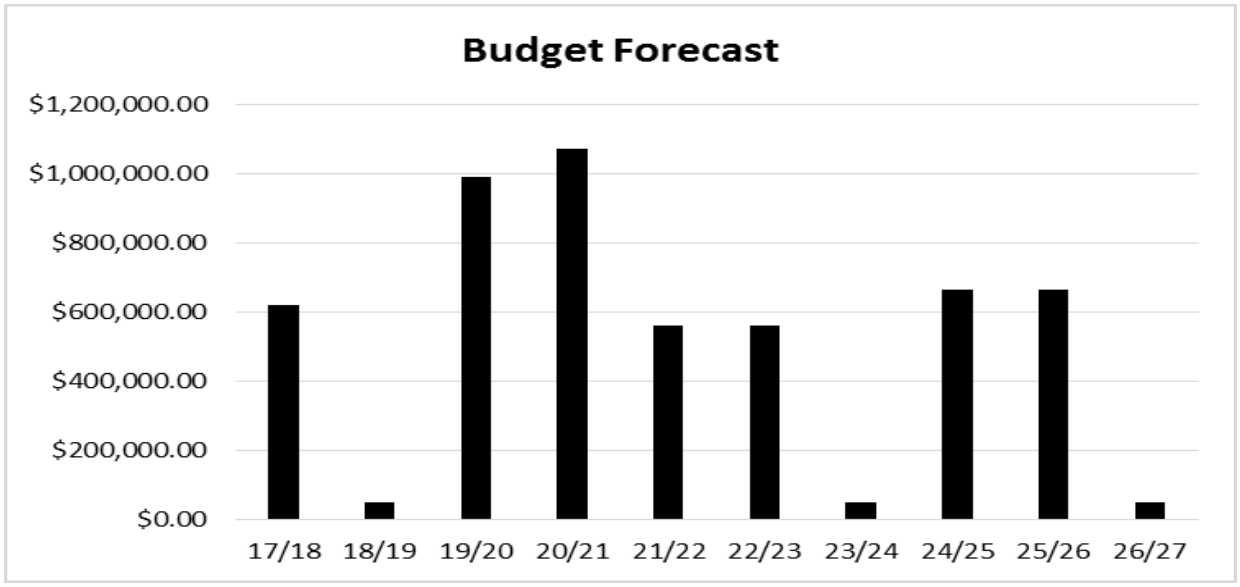
#	Location	Description	Category	Cost
1	All	33kV Protection	Renewal	$82,000
2	All	Unplanned Capital	Renewal	$122,000
3	Paekakariki Substation	CB replacement	Renewal	$327,000
4	Matai Rd, Raumati	Rebuild Substation	Renewal	$2,146,000

Projects & programs 2022/23 to 2026/27

#	Location	Constraint Description	Category	Cost
1	All	33kV Protection	Renewal	$102,000
2	All	Unplanned Capital	Renewal	$153,000
3	Union St, Foxton	Rebuild Substation	Renewal	$1,227,000
4	Matai Rd, Raumati	Rebuild Substation	Renewal	$511,000

Budget forecast

Budget	17/18	18/19	19/20	20/21	21/22	22/23	23/24	24/25	25/26	26/27
	$619.4k	$51k	$991.3k	$1.073m	$562k	$562k	$51k	$664.2k	$664.2k	$51k


Budget Forecast
$1,200,000.00
$1,000,000.00
$800,000.00
$600,000.00
$400,000.00
$200,000.00
$0.00
17/18
18/19
19/20
20/21
21/22
22/23
23/24
24/25
25/26
26/27

6.12 Load control plant

Key features of Electra's load control plant management are as follows.

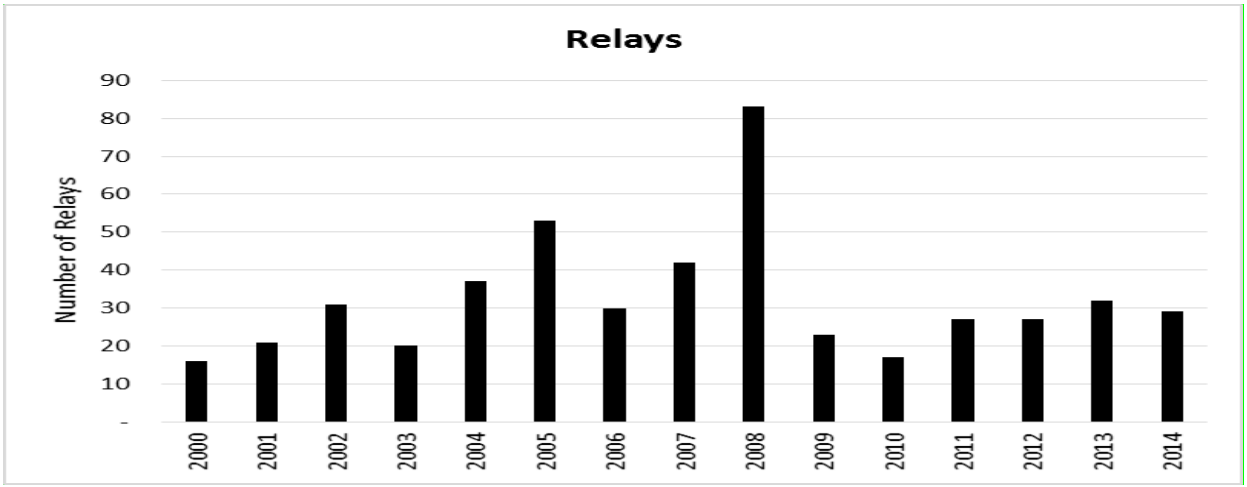
Summary of asset class

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 Paraparamu 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 at Paraparaumu West and Shannon, which are spares.

Both plants inject into the 33kV at 283Hz. Most customer load control relays are owned by the energy retailers however Electra does still own 1,924 relays for controlling street lights, under verandah lighting and pilot-wire load control.

Population and age profile



There are 1,436 relays of unknown age.

Condition

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%	3	10.0%

Systemic issues & mitigation

There are no known systemic issues with Electra's load control plant.

Capacity, security & reliability constraints

There are no known constraints with Electa's load control plant.

Key design parameters

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

Management tactics

Maintenance drivers

- Correct injection of required signals when instructed.
- Correct operation of relays.
- Integrity and isolation of coupling cells.

Maintenance criteria

- Injection fails.
- Relay fails to operates.
- Coupling cell shows evidence of failure or insulation breakdown.

Assumptions

- Signal generator will be need eventual replacement as more connected load absorbs signal.

Lifecycle policies, criteria and activities

Inspections

- Grade 1 – no further inspections, as it will be replaced within 1 year.
- Grade 2 – no further inspection, as it will be replaced within 3 years.
- Grades 3 and 4 – continue to inspect, amend grade as required.

Defect correction

- Public safety defects – correction within 1 week of identification.
- Injection failure – correct immediately (requirement to manage demand).
- Minor control defects – repair within 1 months of identification.

Refurbishment

- Grade 1 – will not be refurbished.
- Grade 2 – minor repairs only.
- Grades 3 and 4 – refurbish major components. Functionality and signal penetration considered, as this may make replacement more feasible.

Renewal

- Grade 1 – renew with 1 year.
- Grade 2 – renew within 3 years.

Lifecycle decision criteria

- 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.

Major projects & programs

There are no major load control or relay programs forecast for the planning period.

6.13 Protection and control

Key features of Electra's protection and control are as follows.

Summary of asset class

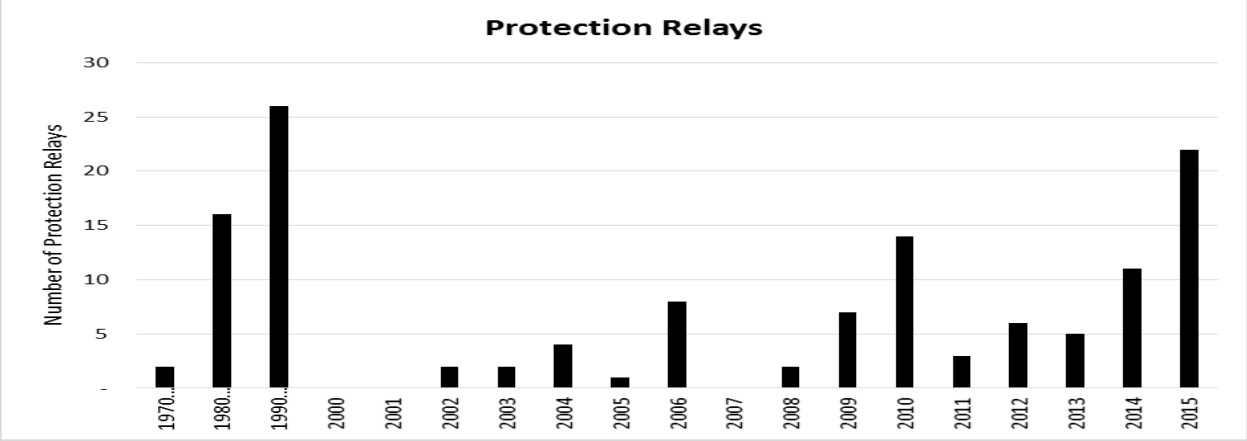
Electra's key protection systems include…

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

Population and age profile

There are 131 protection relays, with ages as follows.



Condition

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

Systemic issues & mitigation

There are no known systemic issues with Electra's protection and control plant.

Capacity, security & reliability constraints

There are no known constraints with Electa's protection and control plant.

Key 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

Management tactics

Maintenance drivers

- Correct operation of relays.
- Battery chargers continue to charge at rated capacity.
- Batteries hold charage.

Maintenance criteria

- 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.

Assumptions

- Failure to hold a charge indicates imminent failure.
- A relay that has failed to correctly operate once will continue to fail.

Lifecycle policies, criteria and activities

Inspections

- Grade 1 – no further inspections, as it will be replaced within 1 year.
- Grade 2 – no further inspection, as it will be replaced within 3 years.
- Grades 3 and 4 – continue to inspect, amend grade as required.

Defect correction

- Public safety defects – correction within 1 week of identification.
- Relay fails to operate correctly – investigate within 1 week, remedy within 1 month.
- Failure of battery charger – replace within 1 month to reduce dependence on duplicate charger.
- Failure of battery to hold charge – replace within 1 week.

Refurbishment

- Protection and control plant is normally replaced rather than refurbished.

Renewal

- Grade 1 – renew with 1 year.
- Grade 2 – renew within 3 years.

Lifecycle decision criteria

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

Major projects & programs

Projects & programs 2017/18

Ref	Location	Description	Category	Cost
1	All	33kV protection	Renewal	$50,000

Projects & programs 2018/19 to 2021/22

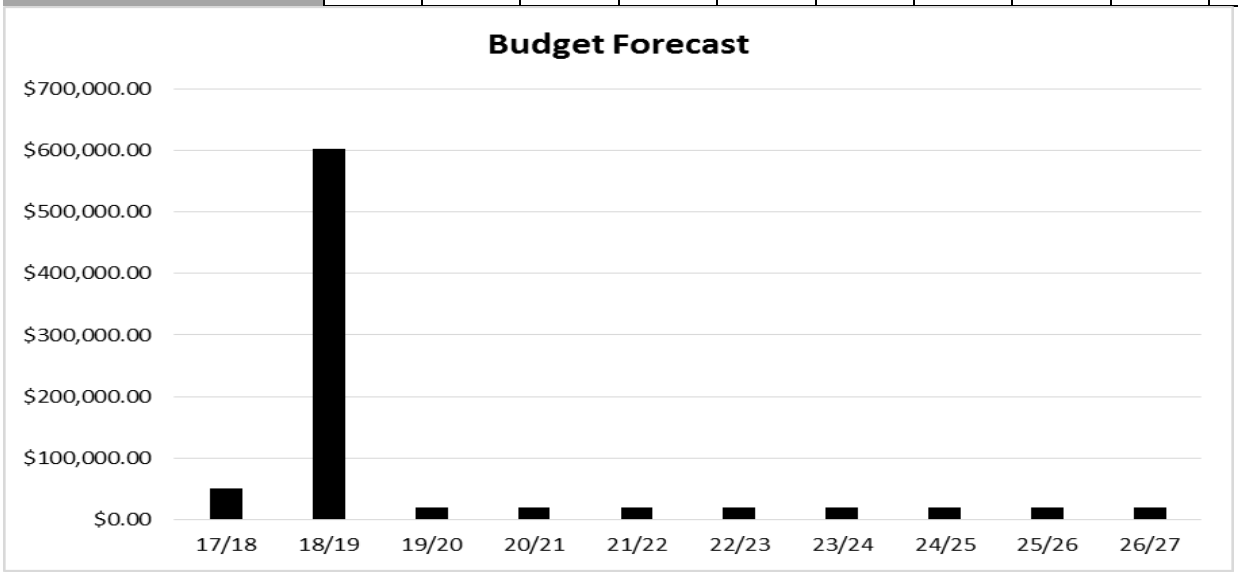
Ref	Location	Description	Category	Cost
1	Tararua Rd, Levin	Tesla protection Work	Quality	$583,000
2	All	33kV protection	Renewal	$81,500

Projects & programs 2022/23 to 2026/27

#	Location	Description	Category	Cost
1	All	33kV protection	Renewal	$102,000

Budget forecast

Budget	17/18	18/19	19/20	20/21	21/22	22/23	23/24	24/25	25/26	26/27
	$50k	$603k	$20.4k	$20.4k	$20.4k	$20.4k	$20.4k	$20.4k	$20.4k	$20.4k



6.14 SCADA and communications

Key features of Electra's SCADA and communications management are as follows.

Summary of asset class

Electra has 1 central SCADA.

Population and age profile

- The SCADA master station was installed in 2012 and has had progressive upgrades of software and hardware suffienct to keep within the requirements of vendor (Catapault) support.
- The age of RTU's ranges from 1 to 10 years.

Condition

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%

Systemic issues & mitigation

There are no known systemic issues with Electra's SCADA.

Capacity, security & reliability constraints

There are no known constraints with Electa's SCADA.

Key design parameters

Parameter	Value
Functionality	Minimum as specified by Electra

Management tactics

Maintenance drivers

- Increasing failure of core functionality.
- Failure of RTU's.

Assumptions

- Faulty operation indicates imminent failure.
- Generally better to replace than refurbish to capture new functionality.

Lifecycle policies, criteria and activities

Inspections

- Review of system errors and alarm logs to identify faults.

Defect correction

- Major loss of functionality or processing capacity – immediately.
- Major input or RTU - immediataley.
- Minor input or RTU – within 3 days.

Refurbishment

- More likely to be replaced than refurbished.

Renewal

- Tends to be driven by obsolescence or declining functionality rather than condition.

Lifecycle decision criteria

- Tends to be driven by obsolescence or declining functionality rather than condition.

Major projects & programs

Projects & programs 2017/18

#	Location	Description	Category	Cost
1	Control Centre	SCADA upgrade	Renewal	$186,000
2	All	Comms general- FMS	Renewal	$144,000

Projects & programs 2018/19 to 2021/22

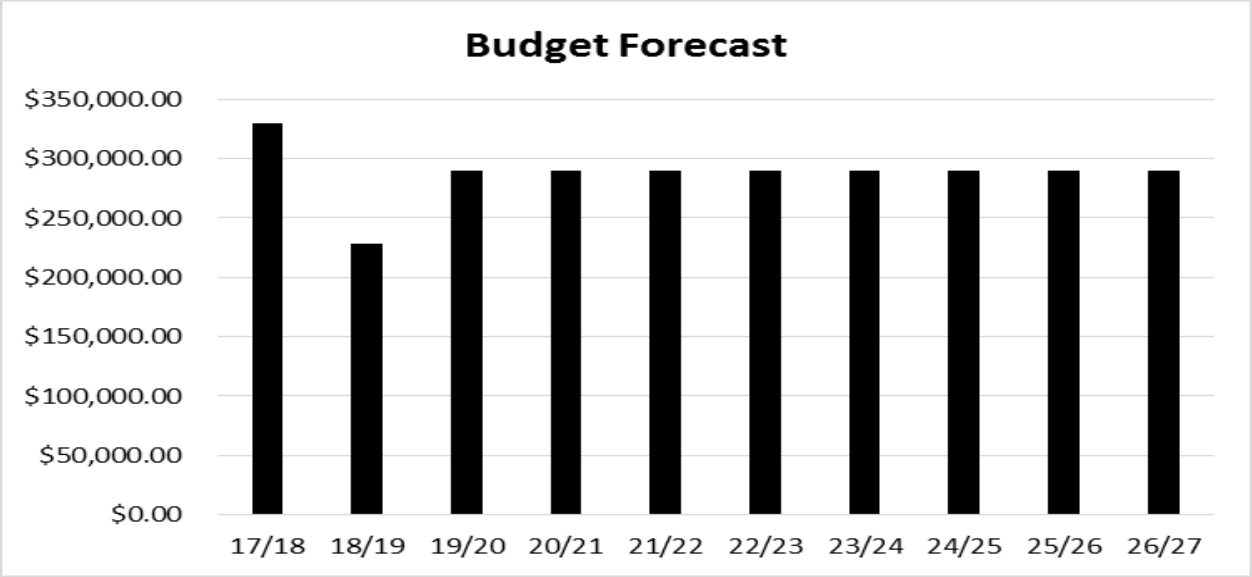
Ref	Location	Description	Category	Cost
1	Control Centre	Scada upgrade	Renewal	$645,000
2	All	Comms general- FMS	Renewal	$453,000

Projects & programs 2022/23 to 2026/27

Ref	Location	Constraint Description	Category	Cost
1	Control Centre	Scada upgrade	Renewal	$875,000
2	All	Comms general- FMS	Renewal	$575,000

Budget forecast

Budget	17/18	18/19	19/20	20/21	21/22	22/23	23/24	24/25	25/26	26/27
	$330k	$228k	$290k	$290k	$290k	$290k	$290k	$290k	$290k	$290k



6.15 Trees

Electra doesn't own any trees, but it does have 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.

Summary of asset class

Electra's overhead lines are surrounded by trees of varying heights, foliage types, growth rates and ownership classes.

Population and age profile

Not applicable.

Condition

Not applicable.

Systemic issues & mitigation

Not applicable.

Capacity, security & reliability constraints

Not applicable.

Key design parameters

Not applicable.

Management tactics

Maintenance drivers

- Minimum clearances specified in the Regulations.
- Fall zone.
- Roots interfering with cables or ground level assets.

Maintenance criteria

- 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.

Assumptions

- 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 give little thought to power lines when choosing the location or species of tree.

Lifecycle policies, criteria and activities

Inspections

- Grades not applicable.
- Six monthly inspection of entire network, based on zone substation areas.

Defect correction

- Public safety defects – correction within 1 week of identification.
- Tree condition determined to be unsafe – remove within 1 month subject to land owner approval.

Refurbishment

- Not applicable.

Renewal

- Efforts will be made to replace fast growing species with slow growing natives.
- Low growing specieis such as toi toi and flax that encroach on ground mounted assets will be removed.

Lifecycle decision criteria

- Not applicable.

Life extension & investment deferral techniques

- Not applicable.

Major projects & programs

During 2017/18 Electra will undertake a strategic inititiative aimed at developing a methodolodgy to systematically reduce tree related SAIFI and SAIDI in future years. Initial goals are to focus on vegetation on feeder sections electrically closest to zone substations and then progressively out to automated switching points further along the feeders. GIS will be used to aggregate risk from vegetation and tactically determine which areas to address in order to achieve the greatest risk improvement.

Projects & programs 2017/18

Ref	Location	Type of Work	Category	Cost
1	All	Vegetation control (not faults)	Vegetation	$1,591,081
2	All	Strategic initiative to reduce tree-rated SAIFI and SAIDI.	Vegetation	$100,00

Projects & programs 2018/19 to 2021/22

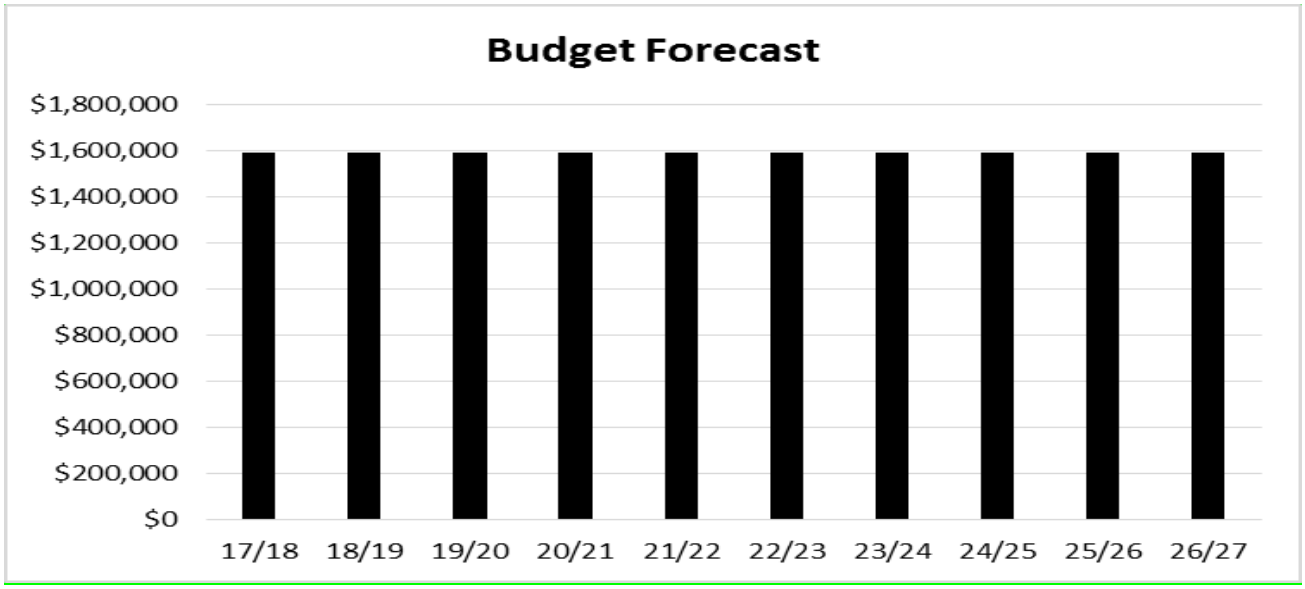
Ref	Location	Type of Work	Category	Cost
1	All	Vegetation control (not faults)	Vegetation	$6,364,326

Projects & programs 2022/23 to 2026/27

Ref	Location	Type of Work	Category	Cost
1	All	Vegetation control (not faults)	Vegetation	$7,955,407

Budget forecast

Budget	17/18	18/19	19/20	20/21	21/22	22/23	23/24	24/25	25/26	26/27
	$1,691	$1,591	$1,591	$1,591	$1,591	$1,591	$1,591	$1,591	$1,591	$1,591


Budget Forecast
$1,800,000
$1,600,000
$1,400,000
$1,200,000
$1,000,000
$800,000
$600,000
$400,000
$200,000
$0
17/18
18/19
19/20
20/21
21/22
22/23
23/24
24/25
25/26
26/27

6.16 Summary of inspections and maintenance

Inspections and maintenance for all asset classes are summarised below.

Operations & Maintenance (Current $000)	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027
Subtransmission										
Routine faults restoration	265	265	265	265	265	265	265	265	265	265
Planned Pole and cross arm renewals	-	-	-	-	-	-	-	-	-	-
Re-active Pole and cross arm renewals	-	-	-	-	-	-	-	-	-	-
Planned Maintenance	199	165	165	165	165	165	165	-	-	-
Annual line inspection	34	34	34	34	34	34	34	34	34	34
Zone Substations										
Inspections	24	24	24	24	24	24	24	24	24	24
Planned Maintenance	337	271	292	292	292	292	271	292	292	292
Re-active Maintenance	164	164	164	164	164	164	164	164	164	164
Distribution Network										
Inspections - 11kV & 400 O/H	53	53	53	53	53	53	53	53	53	53
Inspections - Pillars	40	40	40	40	40	40	40	40	40	40
Transformer inspections	40	40	40	40	40	40	40	40	40	40
Planned Pole and cross arm renewals	-	-	-	-	-	-	-	-	-	-
Re-active Pole and cross arm renewals	-	-	-	-	-	-	-	-	-	-
Planned Maintenance	- 16.71	- 16.71	- 16.71	- 16.71	- 16.71	- 16.71	- 16.71	- 16.71	- 16.71	- 16.71
Fault restoration	1,085	1,085	1,085	1,085	885	885	885	885	792	792
Vegetation control	1,591	1,591	1,591	1,591	1,591	1,591	1,591	1,591	1,591	1,591
Planned Transformer maintenance	285	285	285	285	285	285	285	285	285	285
Re-Active Transformer maintenance	40	40	40	40	40	40	40	40	40	40
Planned Low Voltage maintenance	73	73	73	73	73	73	73	73	73	73
Re-Active Low Voltage maintenance	594	594	594	594	594	594	594	594	594	594
Planned Switchgear maintenance	58	58	58	58	58	58	58	58	58	58
Re-Active Switchgear maintenance	24	24	24	24	24	24	24	24	24	24
Other Assets										
Communications maintenance	133	133	133	133	133	133	133	133	133	133
SCADA maintenance	206	206	213	213	213	213	213	213	213	213
Ripple Maintenance	19	19	19	19	19	19	19	19	19	19
Total Operations & Maintenance	5,321	5,255	5,283	5,283	5,084	5,084	5,062	4,890	4,797	4,797

7. Non-network management plans

7.1 Non-network assets

Electra's non-network assets include…

Asset class	Description	Approx. value	Criticality to asset management
IT and IS	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.
	A general work environment of 60 desk tops, 30 lap tops and 60 tablets and phones, plus CAD stations and minor applications such as payroll.	$469,900 (NBV)	Fault dispatch work would be disrupted Criticality would be about 12 hours.
	In-house outage management and job dispatch system.	$133,500 (NBV)	Fault dispatch work would be disrupted. Criticality is about 12 hours.
	SCADA – iFix (Catapult, marketed by GE).	$2,060,300 (NBV)	Real-time operations would require manual HV switching. Criticality is minutes.
AM systems	NIMS – based on ESRI GIS, but largely in-house.	$1,370,400 (NBV)	Existing work could continue, but new jobs couldn't be created. Criticality is about 30 days.
	Planned installation of Milsoft ADMS suite	About $3m over 3 years.	
Buildings	• Head office (Levin). • Depot (Levin) • Depot (Paraparaumu)	$1,465,700 (NBV)	• Head office critical over the long-term, but short-term alternatives for control room and other critical work have been established. • Each depot is critical for efficient works delivery over the long-term, but in the short-term work can be done from either depot (eg. after an earthquake).
Office furniture	• Desks & work stations • Chairs	$22,900 (NBV)	• Not critical as easily replaced.
Vehicles	• Cars • Vans • 2WD utes • 4WD utes	$188,400 (NBV)	• Not critical as alternatives can be arranged.
Tools, plant & machinery	• Hand tools • Power tools	$166,200 (NBV)	• Not critical as easily replaced through local retailers or specialised suppliers.

7.2 Policies

Electra's key policies for renewal and replacement of non-network assets include…

Asset class	Key policies	Strategies & initiatives
IT and IS	• ICT is seen as an enabler of the electricity business, and follows the electricity strategic plan rather than having a strategic direction of its own. • A standard range of operational policies cover use, access and security of ICT.	• A high level ISSP is being developed, and should be completed during the 2017/18 year. • A data mining platform is planned for installation during 2017/18, which will enable non-IT people to extract data. • A cyber security and disaster recovery program is underway to improve preparedness.
AM systems	•	• A review of AM systems and data is intended for 2017/18, with an anticipated purchase during 2018/19. Functionality is expected to include load flow, asset replacement analysis etc.
Buildings	• Head office (Levin). • Depot (Levin) • Depot (Paraparaumu)	• No plans in the horizon for any additions.
Office furniture	• Desks & work stations • Chairs • Cabinets & storage	• No specific strategy
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 eg. extent of network footprint, length and weight of poles etc.
Tools, plant & 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.	• No specific policy

These replacement policies aim to match the depreciation of the assets.

7.3 Material non-network capital projects

Electra's material non-network capital projects are as follows…

Asset class	2017/18	2018/19	2019/20	2020/21	2021/22
Office buildings, depots & workshops	$0	$0	$0	$0	$0
Office furniture & equipment	$0	$0	$0	$0	$0
Motor vehicles	$135,000	$0	$71,000	$119,000	$194,000
Tools, plant & other machinery	$38,000	$38,000	$38,000	$38,000	$38,000
IT, IS and AM systems	$1,651,000	$1,000,000	$800,000	$1,500,000	$600,000
Total	**$1,824,000**	**$1,038,000**	**$909,000**	**$1,657,000**	**$832,000**

7.4 Material maintenance & renewal projects

Electra's known material non-network maintenance and renewal projects are as follows…

Asset class	2017/18	2018/19	2019/20	2020/21	2021/22
Office buildings, depots & workshops	$0	$0	$0	$0	$0
Office furniture & equipment	$9,000	$9,000	$9,000	$9,000	$9,000
Motor vehicles	$69,000	$69,000	$69,000	$69,000	$69,000
Tools, plant & other machinery	$16,000	$16,000	$16,000	$16,000	$16,000
IT, IS and AM systems	$958,000	$1,008,000	$978,000	$988,000	$1,158,000
Total	**$1,052,000**	**$1,102,000**	**$1,072,000**	**$1,082,000**	**$1,522,000**

8. 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 ever increasing regulatory risk. This chapter examines Electra's physical risk exposures, describes what it has done and will do about these exposures, and what it will do when disaster inevitably strikes.

8.1 Risk analysis & methods

Electra has a comprehensive risk management framework that is regularly reviewed by the Board and by Management. This uses an established process (ISO 31000) to…

- Identifying risks that affect the business;
- Assessing the impact and likelihood of the risk occurring;
- Identifying existing controls that will mitigate the risk;
- Identifying the top five residual risks once the controls have been applied;
- Producing and implementing risk treatment plans to further minimise risks; and
- All assessments and plans will be fully documented to assist with the following year's review.

The risk review process has highlighted 21 major risks to the group. Those relevant to the operation of the network are tabled below.

Master Risk	Risk Description	Jan 2017 Score	Aug 2015 Score
G1	**Fatality or serious harm to people**	**165**	**200**
	Risk associated with staff and contractors working on the Electra Network	165	200
	Risk to the public associated with the Electra Network	120	
	Risks to staff or the public from the use of vehicles or heavy mobile equipment	165	
G2	**Inadequate business continuity and disaster recovery management**	**115**	
	Inefficient response, restoration and communication to stakeholders	112	154
	Inadequate and/or limited insurance cover for extreme events	115	115
	Unauthorised cyber access, threat or misrepresentation into ICT/SCADA	115	115
	Loss of data and company records	60	60
G3	**Inability to maintain economic return / discount contribution related to core business**	**100**	**100**
	Historic pricing tariffs threaten medium-term economic return	80	80
	Continued reduced electricity consumption	80	80
	Exposure to avoidable peak demand costs	100	100
G4	**Failure to anticipate and plan for technological change**	**112**	**112**
	Technological advances threaten businesses established markets	112	112
	Poor data management (access, analysis and decision making)	82.5	82.5
	Lack of timely investment in beneficial technological innovation	80	80
G5	**Failure to maintain stakeholder relationships**	**80**	**80**
	Decline of company's reputation	70	70
	Lack of contract and contractor management	60	60
	Major customer disputes and litigation by our customers	50	50
	Inadequate skills and aptitude for the role (individual)	80	80
G6	**Poor long-term positioning and performance**	**80**	**80**
	Failure to maintain a portfolio of core and non-core businesses	70	70
	Failure of businesses to achieve profitability expectations	80	80
G7	**Inability to manage political and regulatory change**	**80**	**80**
	Increased ComCom, EA costs and any potential industry reform	80	80
G8	**Inadequate commercial and financial management**	**80**	**80**
	Inadequate group funding strategy leading to liquidity risk	80	**80**

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 Directors. From this analysis, Electra identified the critical elements and plans that were required to manage these risks. Key risks are listed below.

8.2 Specific risks

8.2.1 Safety risks

Operating and maintaining an electrical network involves hazardous situations that cannot entirely be eliminated. Having said that, Electra is committed to provide a safe reliable network that does not place our staff, community or environment at risk.

This has been underpinned with the implementation of the Safety Management System (SMS) that has been incorporated 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;
- Safety related network improvements have the highest priority (as discussed in Chapter 1);
- 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 that focuses on public safety and was certified to NZS7901 in 2012 and renewed in 2017.

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.

8.2.2 Natural disaster risks

Electra considers that severe storms and the associated flooding are the most probable damaging hazards that the electricity network is exposed to. The 2004 and 2009 storms and floods support this viewpoint. Although creating widespread damage through falling trees and localised flooding, the network was relatively easy to repair and electricity was restored to consumers once access was re-established and the weather conditions calmed sufficiently to provide a sufficiently safe working environment for contractors. The 33kV and 11kV networks were 98% repaired within 4 days of the worst part of the storm. The remaining 2% was restored after Civil Defence relaxed access restrictions.

It is worth noting, however, that the November 2016 Kaikoura earthquake caused 20 feeder trips and 4 material line breaks even though this earthquake was 250 km from the southern end of the network (and 320 km for the northern).

Specific environmental risks include:

Hazard	Location	Consequence
Flooding	Waikanae, Otaki and Manawatu rivers, Paekakariki drains	Flooded ground transformers, switchgear Pole failure due to flood waters or induced ground instability
Heavy rain	Swamp areas such as Koputaroa Road, Whirokino Road, Reikorangi and along rivers and drains	Pole failure due to induced ground instability or vegetation failure Access issues
Wind	Kapiti Coast and Horowhenua	Line failure due to vegetation failure Access issues
Earthquakes	All	Asset failures

Significant natural disasters have an impact far larger than just on Electra and its electricity assets. In such an event Electra will liaise with the relevant district and regional councils and their emergency management teams. Electra participates in Civil Defence emergency exercises through the Lifelines project. This helps identify physical risks to the network and enables the development of plans to deal with these risks.

Electra considers that, through its comprehensive inspection, maintenance, design and construction standards, the electricity network is able to survive major natural disasters in a repairable form. Repairs may take some days, weeks or even months depending on the exact nature of the disaster.

8.2.3 Asset failure risk

The greatest probability of failure to a 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. This is because a failure of these assets tends to be explosive, and will 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 Chapter 6, 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 on the asset to extend its

asset life, or are replaced with a new asset. These replacements are shown as renewals in the network development plan discussed in Chapter 5.

8.2.4 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 offsite storage of computer backups, including SCADA, and contracts with suppliers to provide temporary support if required.

8.2.5 Regulatory regime

As a Trust owned EDB, Electra is no longer subject to revenue regulation under Part of the Commerce Act 1986. However the costs associated with compiling the Disclosure (including the AMP) are considerable.

8.3 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.
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 has 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 a contractor's depot in Paraparaumu and Levin • 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.

8.4 Emergency response plans

Electra responds to emergencies regularly. 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.

8.4.1 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 3 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 – eg clearing tree branch off line • Time depends on cause and 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 – eg pole hit by car, transformer needs changing, overhead line needs repairs or replacing • Time depends on cause and 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 – eg loss of a zone substation, replacing part or all of a damaged 33kV bus. • Time depends on cause, available personnel and spares.

8.4.2 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.

8.4.3 Reinstating the network after a disaster

Electra has developed a disaster recovery plan which outlines the broad tasks that Electra would need to undertake 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 1 in 100 year flood of the Otaki, Waikanae or Manawatu rivers; or
- A tsunami impacting on the West Coast that could inundate up to 2km inland.

Preparation of this plan 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. Key recommendations of the plan are as follows:

- That the levels of spares outlined in Appendix 3 of the disaster recovery plan be regularly reviewed for on-going suitability and for correct storage;
- That the food stock outlined in Appendix 4 of the disaster recovery plan be regularly maintained and rotated.

8.4.4 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; and
- 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; and

- 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; and

- A review of Electra's vulnerability to being "hacked" over the web.

9. Performance evaluation

9.1 Works delivery performance

This section outlines Electra's progress against budgeted targets for the year ending 31st March 2016.

9.1.1 Maintenance Plan

The following table presents a summary of actual spend against budgeted spend for the key maintenance categories:

Category	2015/16 Actual ($000)	2015/16 Budget ($000)	Variance ($000)	Variance (%)	Reasons for variances
Fault and emergency maintenance	1,852	1,769	83	5%	No material variation.
Vegetation Management	1,273	1,331	-58	-4%	No material variation.
Routine and corrective maintenance	556	701	-145	-21%	Under budget primarily due to cost savings associated with a move to electronic data capture for network inspections.
Replacement and renewal Maintenance	1,210	1,595	-385	-24%	under budget due to the change in the accounting treatment of cross-arms (now recognised as capital rather than operational expenditure).
System operations	1,497	2,023	-526	-26%	Under budget due to forecast being optimistic
Business support	4,179	294	3,885	1321%	Over budget due to overhead management support costs not being forecasted.
Total	**10,567**	**7,712**	**2,855**	**37%**	

Overall, Electra was over its maintenance budget by 37% for the 2015-2016 year. Individual variances in different categories are shown above in the table. Material variation in business support was due to overhead management support costs not being forecasted.

A dollar value of $100,000 has been used as a threshold for material variation.

9.1.2 Development Plan

The following table presents a summary of actual spend against budgeted spend for the key development categories:

Category	2015/16 Actual ($000)	2015/16 Budget ($000)	Variance ($000)	Variance (%)	Reasons for variances
Consumer connection	0	111	-111	-100%	Budgeted on a net basis for vested assets. Electra spent $0 on vested assets.
System growth	20	166	-146	-88%	Under spent due to Paraparaumu substation not meeting the 75% capacity deemed to classify it as systems growth, and due to stalled growth in the region. This project was classified as Reliability, Safety & Environment instead. Also redefinition of the 11kV cable project from System Growth to Asset Replacement and Renewal.
Reliability, safety and environment	1,696	993	703	71%	Over forecast mainly due to the self-healing network with Schneider Electric in Opiki. Other contributors were various cabling projects that were brought forward for efficiency to tie in with cross-arm replacements.
Asset replacement and renewal	11,641	8,578	3063	36%	Over forecast mainly due to completion of prior year works for pole renewal, replacements and redefinition of 11kV cable project from system growth, and change in accounting recognition of cross-arms from OpEx to CapEx. Another contributing factor were the increased costs relating to zone substations, particularly the delays in the works at Paraparaumu substation delaying anticipated costs from the previous year.
Asset relocation	183	0	183	183%	Relocation of the switchgear on Weggery Drive and of the 33kV cables on Matai Road were not forecast.
Total[ii]	**13,540**	**9,849**	**3691**	**37%**	Overall Expenditure on Assets was $3.7m over forecast. This variance is largely due to the Tongariro substation being carried over and the change in accounting treatment of cross-arms. This was partially offset by lower system growth and customer connections.

9.2 Network business performance

9.2.1 Customer service performance (reliability)

Electra's actual performance against target performance for the 2015/16 year for the key customer service attributes is as follows.

Attribute	Measure	2015/16 Target	2016/16 Actual	Comment
Network Reliability	SAIDI	83.0	100.1	One major 33kV outage attributed towards SAIDI being higher than target.
	SAIFI	1.67	1.16	Compliant
	CAIDI	49.7	86.6	
Public Safety	Electricity (Safety) Regulations 2011	Compliant	Compliant	Continued compliance to NZS 7901

9.2.2 Asset performance

Electra's actual performance against target performance for the 2015/16 year for the key asset and regulatory measures are as follows.

Attribute	Measure	2015/16 Target	2015/16 Actual	Comment
Industry performance	Electricity Information Disclosure Requirements 2004 and subsequent amendments	Compliant	Compliant	AMP assessed as generally compliant and above industry average
Financial Efficiency	Capital expenditure per: • total circuit length • connection point	 $2,834 $174	 $6,351 $324	
	Operational expenditure per: • total circuit length • connection point	 $2,614 $160	 $4,684 $239	
Energy Delivery Efficiency	Load factor (units entering network / maximum demand * hours in year)	54%	47%	
	Loss ratio (units lost / units entering network)	6.6%	6.8%	
	Capacity utilisation (maximum demand / installed transformer capacity)	34%	30%	

9.3 Asset management practice performance

Significant aspects of the AMMAT which Electra wishes to improve during the 2017/18 year are as follows. Minor aspects may also be improved as Electra looks at this body of work more closely.

Practice cluster	Proposed improvements
Asset management policy	• Summarise the key features of the approved AM policy into the AMP and include a graphic that strengthens the line-of-sight principle.
Asset management strategy	• Consider expanding the approved AM Policy into a strategy as a specific document that bridges the gap between the AM Policy and the AMP.
Asset management plan	• Continue to refine the lifecycle approach taken in Chapter 6 of the March 2017 AMP. • Formalise the communication of the AMP and its key themes to service delivery staff.
Training, awareness & competence	• Build on the concepts and models being developed to improve the long-term work force plans, particularly for service delivery staff.
Communication, participation & consultation	• Develop a strategy that ensures all critical asset management decisions are appropriately communicated.
AM system documentation	• Improve the quality of AM information by developing a strategy that starts with identification of what information is actually needed for key AM activities and decisions.

9.4 Proposed improvement initiatives

Key areas for the Electra Network team to concentrate on over the 2017/18 year are:

Goal area	Focus of work	Specific strategies
Improved Asset Planning	Continued benchmarking with similar businesses using PAS 55 as a base document.	• Benchmarking with other Electricity Distribution Businesses using disclosed information. • Improved linking of datasets via NIMS to provide a single lookup source of information. • Upgrading of Fault and Incident Tracking database to allow reporting of individual 11kV Feeders (eg. FAIFI/FAIDI). • Asses the effectivenss versus efficiency of key programs such as conductor and cross arm renewals. • Improve understanding of how existing data might allow improved investment decisions. • Implement the Safety In Design principles.
Continue to maintain system reliability.	Increasing numbers of connected customers and length of the network will require improvements just to maintain the existing reliability levels. These will come at a higher cost per unit of SAIDI – SAIFI improvement simply due to the fact that the easier options to improve reliability have been exhausted.	• Requirements for additional 11kV feeders have been identified. This will reduce the number of consumers affected by any one fault. • Existing 11 kV feeders with an Urban/Rural mix have had pole mounted circuit breakers installed to protect the urban areas from faults originating in the rural area. • Existing long rural feeders will have additional pole circuit breakers or sectionalisers installed at strategic locations to reduce the number of consumers affected by any one fault. • An increased installation of ring main units (RMUs) at strategic locations within underground sections of the Electra network will aid in reducing outages areas and the need for generator usage in future planned work. • Taking a more proactive approach to tree cutting, including encouraging tree owners to allow trees to be cut back further than the statutory minimum. • Consider how the resilience of the 33kV network could be improved.

Goal area		Focus of work		Specific strategies
Reduce re-active maintenance.	➔	Reducing reactive maintenance will ensure a more efficient and reliable network. An increased focus on spending before asset failure will result in long term gains for the network.	➔	• Every effort will be made to ensure the root cause of a particular fault is clearly identified, recorded in NIMS for trend analysis and reported on monthly. • Experienced contract staff will be dedicated to all planned inspections. This will ensure consistency in the inspections and reporting. • Preventative maintenance will include partial discharge testing. It will also include minor maintenance such as re-shrinking or re-making off Raychem type cable terminations where discharges are detected and accurately locating possible cable/line faults for further investigation before they become a fault outage. • At present the majority of line and structure inspections are from ground level. Where appropriate this will change to a closer inspection either from a ladder, EPV or helicopter incorporating high resolution zoom camera.
Outages and fault repairs.	➔	The major concerns from our call centre are consumers' frustration in delay in advising them of outages and the associated details particularly details as to when the fault would be resolved.	➔	• Installation of distance to fault protection to allow quicker identification of faults. • Ensure that the full functionality of the planned Milsoft ADMS is used.

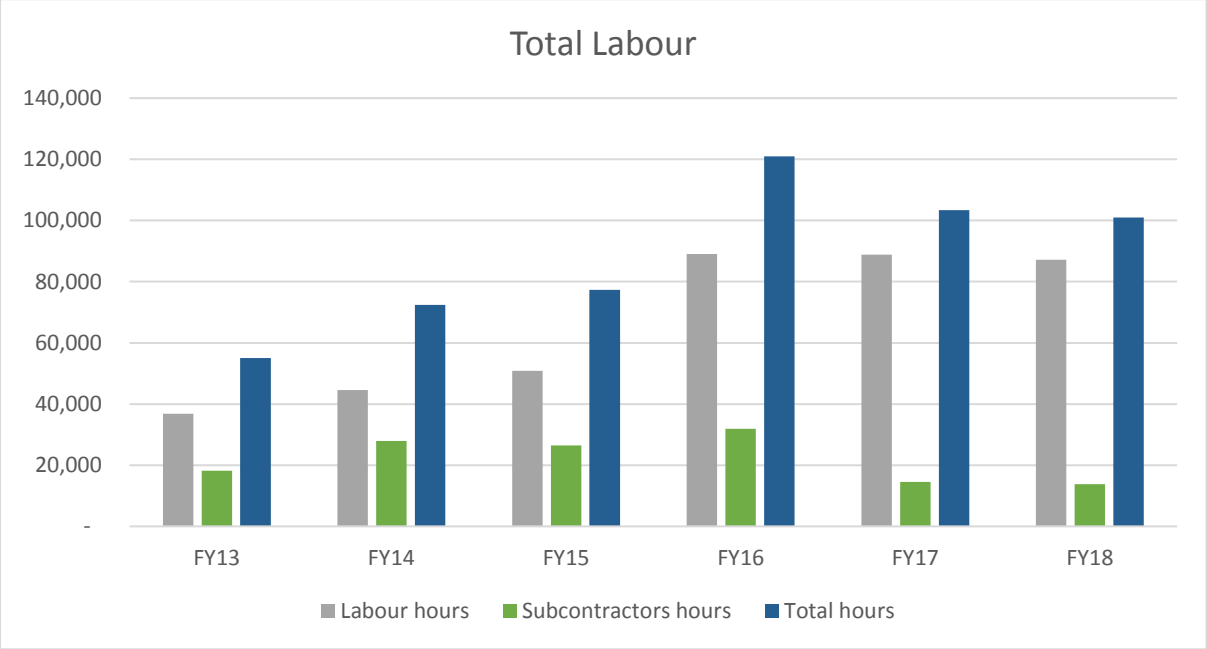
10. Works delivery

10.1 Resource planning methods

10.2 Required resources to deliver works

10.2.1 Forecast resource requirements

Over the past 5 financial years Electra has averaged 44 FTE's across the service delivery team with the last 3 years having an average of 54 FTE's.



Currently Electra has 55 FTE's and a further 11 vacancies in the process of being filled which will bring the FTE total to 66 for the 2017/18 year as there is an increase of third party work delivered on the network. Four of these new FTE's will be allocated to internal delivery of civil works to minimise the risk of utilising external subcontractors and to reduce the subcontractor hours to less than 8,000 hours per year.

Looking ahead Electra must recruit 12 replacement FTE's over the next 10 years due to 20% of the workforce approaching retirement age. Capability and succession planning is in place to minimise that impact. Skillset capacity is set out in Chapter 10.2.2 demonstrating both current FTE's and vacancies in the process of being filled.

10.2.2 Forecast resource availability

	FY17/18	FY18/19	FY19/20	FY20/21	FY21/22	FY22/23	FY23/24	FY24/25	FY25/26	FY26/27
Cable Jointers/Electricians	9	11	12	12	13	13	14	14	15	15
Recruitment Cable jointers/Electricians	3	0	0	1	0	0	1	0	0	1
New Apprentice Cable Jointer/Electrician	1	0	1	0	1	0	1	0	1	1
Leaving/Retiring Electrcians	1	0	0	1	0	0	1	0	0	1
Lineman	19	26	27	28	29	30	31	32	33	34
New Apprentice Lineman	4	2	2	2	2	2	2	2	2	2
Recruitment Lineman	6	4	2	2	2	2	2	2	2	2
Leaving/Retiring Lineman	3	3	3	3	3	3	3	3	3	3
Liveline Mechanic	10	11	11	11	11	11	11	11	11	11
Recruitment Liveline Mechanic	1	1	1	1	0	0	1	1	0	0
Leaving/Retiring Liveline Mechanic	0	0	1	1	0	0	1	1	0	0
Utility Arborists	6	8	8	8	8	8	8	8	8	8
Recruitment Utility Arborists	2	0	0	0	0	0	0	0	0	0
New Apprentice Utility Arborist	1	1	0	0	0	0	0	0	0	0
Leaving/Retiring Utility Arborists	0	0	0	0	0	0	0	0	0	0

10.2.3 Expected resource shortfalls

The ageing workforce will have an impact on long term delivery, especially as third party delivery appears to be growing year on year.

10.2.4 Strategies for addressing forecast shortfalls

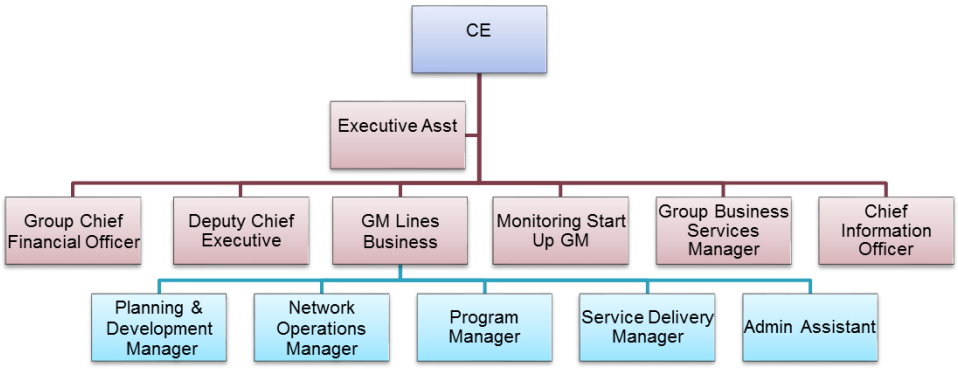
Current service delivery productivity is about 78%. It is proposed to lift this to about 86% by various process and work improvement improvements, which will create additional capacity to deal with the peak work loads.

Electra is also in the process of recruiting 6 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.

10.3 Organisation structure

Electra's staff structure emphasising the Lines Business is as follows..



This emphasises the short distance between the Lines Business managers (aiding line of sight), and also the logical alignment of the 4 Lines Business managers with the asset lifecycle.

10.4 Delegated authorities

Delegated authorities are set out in Chapter 1.9.

Appendix 1 – Determination references

The following table cross references the Chapters in this AMP to the Commerce Commission document; "The electricity distribution information disclosure detrermination 2012 (consolidated to March 2015).

Determination ref.	Chapter(s) in this AMP
3.1 Summary.	• Chapter 0.
3.2 Background and objectives.	• Chapter 1.
3.3.1 Purpose and status.	• Chapter 1.1
3.3.2 Corporate mission or vision.	• Chapter 1.2
3.3.3 Indentifies documented plans.	• Chapter 1.3
3.3.4 States how documented plans relate.	• Chapter 1.4
3.3.5 Description of interaction between objectives, goals and plans.	• Chapter 1.5
3.4 Details of planning period.	• Chapter 1.6
3.5 Date of approval by directors.	• Chapter 1.7
3.6.1 Describe how stakeholder interests are identified.	• Chapter 1.8.1
3.6.2 What these interests are.	• Chapter 1.8.1
3.6.3 How these interests are accommodated in asset management practices.	• Chapter 1.8.2
3.6.4 How conflicting interests are managed.	• Chapter 1.8.3
3.7.1 Governance accountability.	• Chapter 1.9.1 • Chapter 1.9.4
3.7.2 Executive organisation and structure.	• Chapter 1.9.2 • Chapter 1.9.4
3.7.3 How field operations are managed.	• Chapter 1.9.3 • Chapter 1.9.4 • Chapter 1.9.5
3.8 Significant assumptions	• Chapter 1.10
3.9 Description of the factors that may lead to a material difference	• Chapter 1.11
3.10 Overview of asset management strategy and delivery.	• Chapter 1.12 • Chapter 6 for each asset category
3.11 Overview of systems and information management	• Chapter 1.13
3.12 Statement covering any limitations	• Chapter 1.14
3.13.1 Description of processes used to manage routine inspections and maintenance.	• Chapter 1.15.1 • Chapter 1.15.2 • Chapter 6 for each asset category
3.13.2 Description of the processes used for planning and implementing development projects.	• Chapter 1.15.3 • Chapter 6 for each asset category
3.13.3 Description of the process used for measuring network performance.	• Chapter 1.15.4
3.14 Overview of asset management documentation, controls and review processes.	• Chapter 1.16
3.15 Overview of the communication and participation program.	• Chapter 1.17 • Chapter 9
4.1.1 Regions covered	• Chapter 2.1.1
4.1.2 Identification of large consumers.	• Chapter 2.1.2
4.1.3 Description of load characteristics.	• Chapter 2.1.4 • Chapter 3.1
4.1.4 Peak demand and energy delivered in the previous year.	• Chapter 2.1.4 • Chapter 3.1
4.2.1 Identify bulk supply points and embedded generation	• Chapter 3.1
4.2.2 Description of sub-transmission network.	• Chapter 3.2 • Chapter 3.3 • Chapter 6 for each asset class
4.2.3 Description of distribution system.	• Chapter 3.4 • Chapter 3.5 • Chapter 6 for each asset class
4.2.4 Description of distribution substations	• Chapter 3.6 • Chapter 6 for each asset class
4.2.5 Description of LV network.	• Chapter 3.7 • Chapter 3.8 • Chapter 6 for each asset class

4.2.6 Overview of secondary assets.	• Chapter 3.9
4.4 Describe network assets, including age and condition.	• Chapter 6 for each asset class
4.5 Asset categories	• Chapter 6 • Schedules
5. Identify and define a set of performance indicators.	• Chapter 4
6. Performance indicators must include SAIDI and SAIFI for the next 5 years.	• Chapter 4.1.1
7.1 Consumer oriented targets.	• Chapter 4.1.1
7.2 Indicators of asset performance etc.	• Chapter 4.2 • Chapter 4.3
8. Justification of target service levels.	• Chapter 4.6
9. Targets hould be compared to historic values.	• Chapter 4.1
10. Where forecast expenditure is expected to materially effect performance	•
11.1 Description of planning criteria and assumptions.	• Chapter 5.2
11.2 Described logically and succinctly.	• Chapter 5.2
11.3 Strategies used to promote efficiency.	• Chapter 5.3
11.4.1 Categories of assets and designs that are standardised.	• Chapter 5.3
11.4.2 Approach used to identify standard designs.	• Chapter 5.3
11.5 Description of strategies used to promote energy efficient operation.	• Chapter 5.4
11.6 Description of the criteria used to determine capacity	• Chapter 5.2
11.7 Description of the process used to prioritise development projects.	• Chapter 5.6
11.8.1 Explain load forecasting methodology.	• Chapter 5.7.1
11.8.2 Provide separate forecasts to at least zone substion level.	• Chapter 5.7.2
11.8.3 Identify any constraints.	• Chapter 5.7.3 • Chapter 6 for each asset class
11.8.4 Discuss the impact of distributed generation.	• Chapter 5.7.4
11.9.1 Reasons for choosing selected options.	• Chapter 5.2
11.9.2 Alternative options considered.	• Chapter 5.2.4
11.9.3 Consideration of planned innovations	• Chapter 6 for each asset class
11.10.1 Detailed description of material projects for next year.	• Chapter 5.9.1
11.10.2 Summary of project and programs for next 4 years.	• Chapter 5.9.2
11.10.3 Overview of projects for reminader of planning period.	• Chapter 5.9.3
11.11 Policies on distribution generation etc.	• Chapter 5.10
11.12.1 Policies on feasible or practical alternatives to network augmentation.	• Chapter 5.11.1
11.12.2 Potential for non-network solutions to address constraints.	• Chapter 5.11.2
12.1 Key drivers for maintenance planning and assumptions.	• Chapter 6 for each asset category
12.2.1 Approach to inspecting assets.	• Chapter 6 for each asset category
12.2.2 Identify any systemic problems.	• Chapter 6 for each asset category
12.2.3 Budgets broken down by asset category.	• Chapter 6 for each asset category
12.3.1 Process used to decide whether an asset is refurbished or replaced.	• Chapter 6 for each asset category
12.3.2 Description of innovations that have deferred asset replacements.	• Chapter 6 for each asset category
12.3.3 Description of projects for next 12 months.	• Chapter 6 for each asset category
12.3.4 Summary of projects planned for next 4 years.	• Chapter 6 for each asset category
12.3.5 Overview of work being considered for remainder of planning period.	• Chapter 6 for each asset category
12.4 Requirement to include asset categories set out in 4.5.	• Chapter 6
13.1 Description of non-netowrk assets.	• Chapter 7.1
13.2 Policies for those assets.	• Chapter 7.2
13.3 Material capital expenditure for next 5 years.	• Chapter 7.3
13.4 Material maintenance and renewal for next 5 years.	• Chapter 7.4
14.1 Methods, details and conclusions of risk analysis.	• Chapter 8.1
14.2 Strategies used to identify HILP events, and describe resilience.	• Chapter 8.1
14.3 Description of policies used to mitigate or manage risk	• Chapter 8.3
14.4 Emergency response plans	• Chapter 8.4
15.1 Review of progress aginst plan.	• Chapter 9.1
15.2 Evaluation and comparison of actual performance against target.	• Chapter 9.2
15.3 Evaluation of AMMAT	• Chapter 9.3
15.4 Analysis of gaps and initiatives.	• Chapter 9.4
16.1 Describe the processes used to ensure that the AMP is realistic.	• Chapter 10.1
16.2 Describe the organisation structure and the processes for authorisation.	• Chapter 10.2

Schedule 11a – CapEx forecast

Company Name	Electra Ltd
AMP Planning Period	1 April 2017 – 31 March 2027

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*
	for year ended	**31 Mar 17**	**31 Mar 18**	**31 Mar 19**	**31 Mar 20**	**31 Mar 21**	**31 Mar 22**	**31 Mar 23**	**31 Mar 24**	**31 Mar 25**	**31 Mar 26**	**31 Mar 27**
	11a(i): Expenditure on Assets Forecast	**$000 (in nominal dollars)**										
	Consumer connection	95	95	96	98	100	101	103	105	106	108	110
	System growth	204	350	728	560	699	759	634	509	690	585	886
	Asset replacement and renewal	8,522	7,320	6,267	7,658	7,716	7,194	7,522	7,799	8,160	8,299	7,726
	Asset relocations	-	-	-	-	-	109	-	-	-	-	-
	Reliability, safety and environment:											
	Quality of supply	2,142	1,036	2,003	916	1,353	1,170	1,376	1,217	1,065	1,259	1,280
	Legislative and regulatory	-	-	-	-	-	-	-	-	-	-	-
	Other reliability, safety and environment	76	213	217	455	63	228	44	44	45	46	47
	Total reliability, safety and environment	2,218	1,249	2,220	1,371	1,416	1,398	1,419	1,262	1,110	1,304	1,327
	Expenditure on network assets	11,039	9,014	9,311	9,688	9,931	9,563	9,679	9,675	10,067	10,296	10,049
	Expenditure on non-network assets	998	1,824	1,055	940	1,743	890	539	760	380	1,131	532
	Expenditure on assets	12,037	10,838	10,366	10,627	11,673	10,452	10,218	10,434	10,447	11,428	10,580
plus	Cost of financing		60	80	111	141	111	129	83	65	66	54
less	Value of capital contributions		137	137	137	137	137	137	137	137	137	137
plus	Value of vested assets	750	792	792	792	792	792	792	792	792	792	792
	Capital expenditure forecast	12,787	11,553	11,101	11,393	12,469	11,218	11,002	11,172	11,167	12,149	11,289
	Assets commissioned											

		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 17**	**31 Mar 18**	**31 Mar 19**	**31 Mar 20**	**31 Mar 21**	**31 Mar 22**	**31 Mar 23**	**31 Mar 24**	**31 Mar 25**	**31 Mar 26**	**31 Mar 27**
		$000 (in constant prices)										
	Consumer connection	95	95	95	95	95	95	95	95	95	95	95
	System growth	204	350	715	542	664	710	583	460	613	511	761
	Asset replacement and renewal	8,522	7,320	6,164	7,405	7,336	6,726	6,914	7,049	7,252	7,252	6,639
	Asset relocations	-	-	-	-	-	102	-	-	-	-	-
	Reliability, safety and environment:											
	Quality of supply	2,142	1,036	1,970	885	1,286	1,093	1,265	1,100	946	1,100	1,100
	Legislative and regulatory	-	-	-	-	-	-	-	-	-	-	-
	Other reliability, safety and environment	76	213	213	439	60	213	40	40	40	40	40
	Total reliability, safety and environment	2,218	1,249	2,183	1,324	1,346	1,306	1,305	1,140	986	1,140	1,140
	Expenditure on network assets	11,038	9,014	9,157	9,365	9,441	8,939	8,896	8,744	8,946	8,997	8,634
	Expenditure on non-network assets	998	1,824	1,038	909	1,657	832	496	687	338	989	457
	Expenditure on assets	12,036	10,837	10,195	10,274	11,098	9,770	9,392	9,431	9,284	9,986	9,091

Subcomponents of expenditure on assets (where known)

Energy efficiency and demand side management, reduction of energy losses										
Overhead to underground conversion										
Research and development										

	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 17**	**31 Mar 18**	**31 Mar 19**	**31 Mar 20**	**31 Mar 21**	**31 Mar 22**	**31 Mar 23**	**31 Mar 24**	**31 Mar 25**	**31 Mar 26**	**31 Mar 27**
Difference between nominal and constant price forecasts	**$000**										
Consumer connection	-	-	2	3	5	7	8	10	12	14	16
System growth	-	-	12	19	34	50	51	49	77	74	125
Asset replacement and renewal	(0)	0	103	253	380	468	608	750	908	1,047	1,088
Asset relocations	-	-	-	-	-	7	-	-	-	-	-
Reliability, safety and environment:											
Quality of supply	(0)	(0)	33	31	67	77	111	117	119	159	180
Legislative and regulatory	-	-	-	-	-	-	-	-	-	-	-
Other reliability, safety and environment	0	0	4	16	3	15	4	4	5	6	7
Total reliability, safety and environment	0	0	37	47	70	92	115	121	124	165	187
Expenditure on network assets	0	1	154	322	490	624	782	931	1,120	1,299	1,415
Expenditure on non-network assets	-	-	18	31	86	58	44	73	42	143	75
Expenditure on assets	0	1	172	353	576	682	826	1,004	1,163	1,442	1,489

	Current Year CY	*CY+1*	*CY+2*	*CY+3*	*CY+4*	*CY+5*
for year ended	**31 Mar 17**	**31 Mar 18**	**31 Mar 19**	**31 Mar 20**	**31 Mar 21**	**31 Mar 22**

11a(ii): Consumer Connection

*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]						
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

*include additional rows if needed

11a(iii): System Growth

Subtransmission	-	-	-	-	460	460
Zone substations	-	-	-	-	-	-
Distribution and LV lines	-	-	-	-	-	-
Distribution and LV cables	204	350	715	542	204	250
Distribution substations and transformers	-	-	-	-	-	-
Distribution switchgear	-	-	-	-	-	-
Other network assets	-	-	-	-	-	-
System growth expenditure	204	350	715	542	664	710
less Capital contributions funding system growth						
System growth less capital contributions	204	350	715	542	664	710

		Current Year CY	CY+1	CY+2	CY+3	CY+4	CY+5
	for year ended	31 Mar 17	31 Mar 18	31 Mar 19	31 Mar 20	31 Mar 21	31 Mar 22

11a(iv): Asset Replacement and Renewal

	$000 (in constant prices)					
Subtransmission	337	337	128	452	452	752
Zone substations	1,117	619	51	991	1,073	562
Distribution and LV lines	3,516	3,433	3,391	3,025	2,967	2,765
Distribution and LV cables		75		164		
Distribution substations and transformers	2,014	1,331	1,418	1,481	1,563	1,319
Distribution switchgear	465	378	277	277	212	205
Other network assets	1,073	1,147	899	1,015	1,069	1,123
Asset replacement and renewal expenditure	8,522	7,320	6,164	7,405	7,336	6,726
less Capital contributions funding asset replacement and renewal						
Asset replacement and renewal less capital contributions	8,522	7,320	6,164	7,405	7,336	6,726

	Current Year CY	CY+1	CY+2	CY+3	CY+4	CY+5
for year ended	31 Mar 17	31 Mar 18	31 Mar 19	31 Mar 20	31 Mar 21	31 Mar 22

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 17	31 Mar 18	31 Mar 19	31 Mar 20	31 Mar 21	31 Mar 22

11a(vi):Quality of Supply

*Project or programme**	$000 (in constant prices)					
Protection Work	225		583			
Improving Network Interconnectivity	471	363	245	347	347	552
Network Automation and Sectionalisation	578	510	1,052	459	860	462
Fault Locator	44	81	90	79	79	79
Duplicate line from Waihou Rd	824					
include additional rows if needed						
All other projects or programmes - quality of supply		82				
Quality of supply expenditure	2,142	1,036	1,970	885	1,286	1,093
less Capital contributions funding quality of supply						
Quality of supply less capital contributions	2,142	1,036	1,970	885	1,286	1,093

11a(vii): Legislative and Regulatory

	Current Year CY	CY+1	CY+2	CY+3	CY+4	CY+5
for year ended	31 Mar 17	31 Mar 18	31 Mar 19	31 Mar 20	31 Mar 21	31 Mar 22
*Project or programme**	$000 (in constant prices)					
[Description of material project or programme]						
[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	-	-	-	-	-	-
less Capital contributions funding legislative and regulatory						
Legislative and regulatory less capital contributions	-	-	-	-	-	-

11a(viii): Other Reliability, Safety and Environment

	Current Year CY	CY+1	CY+2	CY+3	CY+4	CY+5
for year ended	31 Mar 17	31 Mar 18	31 Mar 19	31 Mar 20	31 Mar 21	31 Mar 22
*Project or programme**	$000 (in constant prices)					
Arc Flash Protection				303		
Replacement of deck transformers	76	153	153	76		153
Replacement of pitchfilled potheads		60	60	60	60	60
[Description of material project or programme]						
[Description of material project or programme]						
*include additional rows if needed						
All other projects or programmes - other reliability, safety and environment						
Other reliability, safety and environment expenditure	76	213	213	439	60	213
less Capital contributions funding other reliability, safety and environment						
Other reliability, safety and environment less capital contributions	76	213	213	439	60	213

11a(ix): Non-Network Assets

	Current Year CY	CY+1	CY+2	CY+3	CY+4	CY+5
for year ended	31 Mar 17	31 Mar 18	31 Mar 19	31 Mar 20	31 Mar 21	31 Mar 22
Routine expenditure						
*Project or programme**	$000 (in constant prices)					
Vehicles	70	135	-	71	119	194
Tools, Plant & Other machinery	85	38	38	38	38	38
[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 - routine expenditure						
Routine expenditure	155	173	38	109	157	232
Atypical expenditure						
*Project or programme**						
Retailer Billing		120				
ADMS		427				
Other IT initiatives to improve asset management	843	1,104			1,500	600
Analytic platform in cloud + ADMS			1,000			
Asset Management System in cloud + Upgrade of ERP Platform				800		
*include additional rows if needed						
All other projects or programmes - atypical expenditure						
Atypical expenditure	843	1,651	1,000	800	1,500	600
Expenditure on non-network assets	998	1,824	1,038	909	1,657	832

Schedule 11b – OpEx forecast

Company Name	Electra Ltd
AMP Planning Period	1 April 2017 – 31 March 2027

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												
7		*Current Year CY*	*CY+1*	*CY+2*	*CY+3*	*CY+4*	*CY+5*	*CY+6*	*CY+7*	*CY+8*	*CY+9*	*CY+10*
8	for year ended	**31 Mar 17**	**31 Mar 18**	**31 Mar 19**	**31 Mar 20**	**31 Mar 21**	**31 Mar 22**	**31 Mar 23**	**31 Mar 24**	**31 Mar 25**	**31 Mar 26**	**31 Mar 27**
9	**Operational Expenditure Forecast**	**$000 (in nominal dollars)**										
10	Service interruptions and emergencies	2,084	2,256	2,295	2,334	2,374	2,200	2,238	2,276	2,314	2,247	2,285
11	Vegetation management	1,591	1,591	1,618	1,646	1,674	1,702	1,731	1,760	1,790	1,821	1,852
12	Routine and corrective maintenance and inspection	801	1,016	987	1,011	1,029	1,046	1,064	1,082	883	898	913
13	Asset replacement and renewal	457	458	444	473	482	490	498	483	515	524	533
14	**Network Opex**	4,934	5,321	5,344	5,464	5,557	5,438	5,531	5,601	5,503	5,490	5,583
15	System operations and network support	1,531	2,438	2,479	2,523	2,569	2,617	2,668	2,722	2,779	2,839	2,903
16	Business support	4,833	3,968	4,292	4,367	4,447	4,530	4,619	4,712	4,810	4,915	5,025
17	**Non-network opex**	6,365	6,406	6,771	6,890	7,016	7,148	7,287	7,434	7,589	7,754	7,929
18	**Operational expenditure**	11,298	11,727	12,115	12,355	12,573	12,586	12,817	13,035	13,092	13,244	13,512

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 17**	**31 Mar 18**	**31 Mar 19**	**31 Mar 20**	**31 Mar 21**	**31 Mar 22**	**31 Mar 23**	**31 Mar 24**	**31 Mar 25**	**31 Mar 26**	**31 Mar 27**
21		**$000 (in constant prices)**										
22	Service interruptions and emergencies	2,084	2,256	2,256	2,256	2,256	2,057	2,057	2,057	2,057	1,964	1,964
23	Vegetation management	1,591	1,591	1,591	1,591	1,591	1,591	1,591	1,591	1,591	1,591	1,591
24	Routine and corrective maintenance and inspection	801	1,016	971	978	978	978	978	978	785	785	785
25	Asset replacement and renewal	457	458	436	458	458	458	458	436	458	458	458
26	**Network Opex**	4,934	5,321	5,255	5,283	5,283	5,084	5,084	5,062	4,890	4,797	4,797
27	System operations and network support	1,531	2,438	2,438	2,438	2,438	2,438	2,438	2,438	2,438	2,438	2,438
28	Business support	4,584	3,968	3,968	3,968	3,968	3,968	3,968	3,968	3,968	3,968	3,968
29	**Non-network opex**	6,116	6,406	6,406	6,406	6,406	6,406	6,406	6,406	6,406	6,406	6,406
30	**Operational expenditure**	11,049	11,727	11,660	11,689	11,689	11,489	11,489	11,468	11,296	11,203	11,203
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 17**	**31 Mar 18**	**31 Mar 19**	**31 Mar 20**	**31 Mar 21**	**31 Mar 22**	**31 Mar 23**	**31 Mar 24**	**31 Mar 25**	**31 Mar 26**	**31 Mar 27**
41	**Difference between nominal and real forecasts**	**$000**										
42	Service interruptions and emergencies	-	-	38	77	117	143	181	219	258	283	322
43	Vegetation management	-	-	27	55	83	111	140	169	199	230	261
44	Routine and corrective maintenance and inspection	-	-	17	34	51	68	86	104	98	113	129
45	Asset replacement and renewal	-	-	7	16	24	32	40	46	57	66	75
46	**Network Opex**	-	-	89	181	274	355	447	539	612	693	786
47	System operations and network support	-	-	41	85	131	179	230	284	341	401	465
48	Business support	249	0	324	400	479	563	651	744	843	947	1,058
49	**Non-network opex**	249	0	366	485	610	742	881	1,028	1,184	1,348	1,523
50	**Operational expenditure**	249	0	455	666	884	1,097	1,328	1,567	1,796	2,041	2,309

Schedule 12a – Asset condition

Company Name	Electra Ltd
AMP Planning Period	1 April 2017 – 31 March 2027

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)						
	Voltage	Asset category	Asset class	Units	Grade 1	Grade 2	Grade 3	Grade 4	Grade unknown	Data accuracy (1–4)	% of asset forecast to be replaced in next 5 years
10	All	Overhead Line	Concrete poles / steel structure	No.		0.75%	94.25%	5.00%		3	1.00%
11	All	Overhead Line	Wood poles	No.	-	37.78%	62.22%	-		3	44.00%
12	All	Overhead Line	Other pole types	No.						N/A	
13	HV	Subtransmission Line	Subtransmission OH up to 66kV conductor	km		9.00%	89.65%	1.35%		4	9.80%
14	HV	Subtransmission Line	Subtransmission OH 110kV+ conductor	km						N/A	
15	HV	Subtransmission Cable	Subtransmission UG up to 66kV (XLPE)	km			79.70%	20.30%		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%	50.00%		4	-
25	HV	Zone substation Buildings	Zone substations 110kV+	No.						N/A	
26	HV	Zone substation switchgear	22/33kV CB (Indoor)	No.			50.00%	50.00%		4	-
27	HV	Zone substation switchgear	22/33kV CB (Outdoor)	No.		9.55%	90.45%	-		4	9.55%
28	HV	Zone substation switchgear	33kV Switch (Ground Mounted)	No.						N/A	
29	HV	Zone substation switchgear	33kV Switch (Pole Mounted)	No.		7.00%	45.00%	48.00%		3	10.00%
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.		5.19%	82.31%	12.50%		3	10.38%
34	HV	Zone substation switchgear	3.3/6.6/11/22kV CB (pole mounted)	No.						N/A	

					Asset condition at start of planning period (percentage of units by grade)						
	Voltage	Asset category	Asset class	Units	Grade 1	Grade 2	Grade 3	Grade 4	Grade unknown	Data accuracy (1–4)	% of asset forecast to be replaced in next 5 years
39	HV	Zone Substation Transformer	Zone Substation Transformers	No.			90.00%	10.00%		4	-
40	HV	Distribution Line	Distribution OH Open Wire Conductor	km		9.40%	85.10%	5.50%		3	9.40%
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			61.30%	38.70%		3	-
44	HV	Distribution Cable	Distribution UG PILC	km		1.63%	98.37%	-		3	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.		3.00%	85.00%	12.00%		4	3.00%
47	HV	Distribution switchgear	3.3/6.6/11/22kV CB (Indoor)	No.		12.00%	78.00%	10.00%		4	12.00%
48	HV	Distribution switchgear	3.3/6.6/11/22kV Switches and fuses (pole mounted)	No.		3.00%	66.00%	31.00%		3	5.00%
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.		5.97%	54.03%	40.00%		3	7.00%
51	HV	Distribution Transformer	Pole Mounted Transformer	No.		3.70%	63.30%	33.00%		4	6.15%
52	HV	Distribution Transformer	Ground Mounted Transformer	No.		4.50%	54.50%	41.00%		4	7.50%
53	HV	Distribution Transformer	Voltage regulators	No.						N/A	
54	HV	Distribution Substations	Ground Mounted Substation Housing	No.						N/A	
55	LV	LV Line	LV OH Conductor	km		2.60%		1.20%	96.20%	3	4.00%
56	LV	LV Cable	LV UG Cable	km		-		44.00%	56.00%	3	2.00%
57	LV	LV Streetlighting	LV OH/UG Streetlight circuit	km					100.00%	3	2.00%
58	LV	Connections	OH/UG consumer service connections	No.		10.80%	42.20%	15.00%	32.00%	2	12.00%
59	All	Protection	Protection relays (electromechanical, solid state and numeric)	No.		10.00%	55.00%	35.00%		4	15.00%
60	All	SCADA and communications	SCADA and communications equipment operating as a single system	Lot		10.00%	70.00%	20.00%		3	15.00%
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%	3	10.00%
64	All	Civils	Cable Tunnels	km						N/A	

Schedule 12b – Capacity forecast

Company Name	Electra Ltd
AMP Planning Period	1 April 2017 – 31 March 2027

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

12b(i): System Growth - Zone Substations

	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	5	5	N-1	6	92%	5	96%	No constraint within +5 years	
10	Foxton	7	23	N-1	4	30%	23	31%	No constraint within +5 years	
11	Levin West	14	23	N-1	12	59%	23	54%	No constraint within +5 years	
12	Levin East	14	23	N-1	12	62%	23	72%	No constraint within +5 years	
13	Otaki	12	23	N-1	4	53%	23	57%	No constraint within +5 years	
14	Waikanae	15	23	N-1	12	63%	23	80%	No constraint within +5 years	
15	Paraparaumu	13	23	N-1	16	54%	23	67%	No constraint within +5 years	
16	Paraparaumu West	12	23	N-1	8	52%	23	67%	No constraint within +5 years	
17	Raumati	10	23	N-1	12	44%	23	53%	No constraint within +5 years	
18	Paekakariki	2	-	N-1 (Switched)	6	-	-	-	No constraint within +5 years	Automatic changeover to Raumati using fault monitors and motorised switches
19	[Zone Substation_11]					-			[Select one]	
20	[Zone Substation_12]					-			[Select one]	
21	[Zone Substation_13]					-			[Select one]	
22	[Zone Substation_14]					-			[Select one]	
23	[Zone Substation_15]					-			[Select one]	
24	[Zone Substation_16]					-			[Select one]	
25	[Zone Substation_17]					-			[Select one]	
26	[Zone Substation_18]					-			[Select one]	
27	[Zone Substation_19]					-			[Select one]	
28	[Zone Substation_20]					-			[Select one]	

29 *[1] Extend forecast capacity table as necessary to disclose all capacity by each zone substation*

Schedule 12c – Demand forecast

Company Name	Electra Ltd
AMP Planning Period	1 April 2017 – 31 March 2027

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

12c(i): Consumer Connections

Number of ICPs connected in year by consumer type

Number of connections

for year ended	*Current Year CY* **31 Mar 17**	*CY+1* **31 Mar 18**	*CY+2* **31 Mar 19**	*CY+3* **31 Mar 20**	*CY+4* **31 Mar 21**	*CY+5* **31 Mar 22**
*Consumer types defined by EDB**						
All	380	350	350	350	400	400
[EDB consumer type]						
[EDB consumer type]						
[EDB consumer type]						
[EDB consumer type]						
Connections total	380	350	350	350	400	400

**include additional rows if needed*

Distributed generation

	Current Year CY **31 Mar 17**	*CY+1* **31 Mar 18**	*CY+2* **31 Mar 19**	*CY+3* **31 Mar 20**	*CY+4* **31 Mar 21**	*CY+5* **31 Mar 22**
Number of connections	61	80	100	110	120	120
Capacity of distributed generation installed in year (MVA)	0.2	0.2	0.3	0.3	0.4	0.4

12c(ii) System Demand

	for year ended	*Current Year CY* **31 Mar 17**	*CY+1* **31 Mar 18**	*CY+2* **31 Mar 19**	*CY+3* **31 Mar 20**	*CY+4* **31 Mar 21**	*CY+5* **31 Mar 22**
Maximum coincident system demand (MW)							
GXP demand		103	102	103	104	105	106
plus Distributed generation output at HV and above							
Maximum coincident system demand		103	102	103	104	105	106
less Net transfers to (from) other EDBs at HV and above							
Demand on system for supply to consumers' connection points		103	102	103	104	105	106
Electricity volumes carried (GWh)							
Electricity supplied from GXPs		445	445	448	450	451	452
less Electricity exports to GXPs							
plus Electricity supplied from distributed generation							
less Net electricity supplied to (from) other EDBs							
Electricity entering system for supply to ICPs		445	445	448	450	451	452
less Total energy delivered to ICPs		414	415	418	420	421	422
Losses		31	30	30	30	30	30
Load factor		49%	50%	50%	49%	49%	49%
Loss ratio		6.9%	6.7%	6.7%	6.7%	6.7%	6.6%

Schedule 12d – Reliability forecast

Company Name	**Electra Ltd**
AMP Planning Period	**1 April 2017 – 31 March 2027**
Network / Sub-network Name	

SCHEDULE 12d: REPORT FORECAST INTERRUPTIONS AND DURATION

This schedule requires a forecast of SAIFI and SAIDI for disclosure and a 5 year planning period. The forecasts should be consistent with the supporting information set out in the AMP as well as the assumed impact of planned and unplanned SAIFI and SAIDI on the expenditures forecast provided in Schedule 11a and Schedule 11b.

sch ref		*Current Year CY*	*CY+1*	*CY+2*	*CY+3*	*CY+4*	*CY+5*
9	for year ended	**31 Mar 17**	**31 Mar 18**	**31 Mar 19**	**31 Mar 20**	**31 Mar 21**	**31 Mar 22**
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

Schedule 13 – Asset management maturity

Company Name	Electra Ltd
AMP Planning Period	1 April 2017 – 31 March 2027
Asset Management Standard Applied	PASS 55

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 inspected	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	A specific Asset Management Policy was prepared and signed off by the Board of Directors in the 2012/13 year. It has been included as part of both the Network and Group Strategic Plans.Electra's Strategic Plan was examined,it embodies good line-of-sight, and includes SWOT and PESTLE analyses.		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	There is no obvious AM Strategy, however the strategic plan and the AMP clearly embody a cohesive set of strategies that link to the goal areas.		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?	2	The strategy for each asset class described in Chapter 6 of the AMP explicitly considers condition, age and systemic issues. Refer to Q26 below.		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	Chapter 6 of the 2017 AMP clearly shows that the condition and life cycle of major asset classes are considered. There is direct line-of-sight from the asset age and condition to the policies, the management tactics and the resulting work program.		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 2017 – 31 March 2027
Asset Management Standard Applied	PASS 55

SCHEDULE 13: REPORT ON ASSET MANAGEMENT MATURITY (cont)

Question No.	Function	Question	Score	Evidence inspected	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			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?	2.5	Chapter 1.9 of the 2017 AMP documents the responsibilities for AM.		The implementation of asset management plan(s) relies on (1) actions being clearly identified, (2) an owner allocated and (3) that owner having sufficient delegated responsibility and authority to carry out the work required. It also requires alignment of actions across the organisation. This question explores how well the plan(s) set out responsibility for delivery of asset plan actions.	The management team with overall responsibility for the asset management system. Operations, maintenance and engineering managers. If appropriate, the performance management team.	The organisation's asset management plan(s). Documentation defining roles and responsibilities of individuals and organisational departments.
31	Asset management plan(s)	What has the organisation done to ensure that appropriate arrangements are made available for the efficient and cost effective implementation of the plan(s)? (Note this is about resources and enabling support)	2	Refer to Q40 also.		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?	3	Electra has various guidelines for Escalation Of Events and Major Network Events that define escalation actions, key roles and communication requirements. Evidence of supply restoration after the November 2016 earthquake was examined, noting repairs.		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 2017 – 31 March 2027
Asset Management Standard Applied	PASS 55

SCHEDULE 13: REPORT ON ASSET MANAGEMENT MATURITY (cont)

Question No.	Function	Question	Score	Evidence inspected	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)?	3	Chapter 1.9 of the 2017 AMP shows the current structure, demonstrating alignment to the asset life cycle.		In order to ensure that the organisation's assets and asset systems deliver the requirements of the asset management policy, strategy and objectives responsibilities need to be allocated to appropriate people who have the necessary authority to fulfil their responsibilities. (This question, relates to the organisation's assets eg, para b), s 4.4.1 of PAS 55, making it therefore distinct from the requirement contained in para a), s 4.4.1 of PAS 55).	Top management. People with management responsibility for the delivery of asset management policy, strategy, objectives and plan(s). People working on asset-related activities.	Evidence that managers with responsibility for the delivery of asset management policy, strategy, objectives and plan(s) have been appointed and have assumed their responsibilities. Evidence may include the organisation's documents relating to its asset management system, organisational charts, job descriptions of post-holders, annual targets/objectives and personal development plan(s) of post-holders as appropriate.
40	Structure, authority and responsibilities	What evidence can the organisation's top management provide to demonstrate that sufficient resources are available for asset management?	3	A sucession planning model and a talent matrix were examined (HRs database), however this stops short of a specific numbers of each staff category required over the timeframe.For asset mangagemnt work a process is established and followed by contracting division by forecasting labour requirement over the AMP period.		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	There is a fortnightly Progress To Plan meeting to ensure that works are completed to target. There is also a monthly Lines business unit meeting that includes field staff that deals with operational issues (eg. issuing of latest schematics), safety, quality and some works		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	The Undergound Line Construction Standard was examined.		Where an organisation chooses to outsource some of its asset management activities, the organisation must ensure that these outsourced process(es) are under appropriate control to ensure that all the requirements of widely used AM standards (eg, PAS 55) are in place, and the asset management policy, strategy objectives and plan(s) are delivered. This includes ensuring capabilities and resources across a time span aligned to life cycle management. The organisation must put arrangements in place to control the outsourced activities, whether it be to external providers or to other in-house departments. This question explores what the organisation does in this regard.	Top management. The management team that has overall responsibility for asset management. The manager(s) responsible for the monitoring and management of the outsourced activities. People involved with the procurement of outsourced activities. The people within the organisations that are performing the outsourced activities. The people impacted by the outsourced activity.	The organisation's arrangements that detail the compliance required of the outsourced activities. For example, this this could form part of a contract or service level agreement between the organisation and the suppliers of its outsourced activities. Evidence that the organisation has demonstrated to itself that it has assurance of compliance of outsourced activities.

Company Name	Electra Ltd
AMP Planning Period	1 April 2017 – 31 March 2027
Asset Management Standard Applied	PASS 55

SCHEDULE 13: REPORT ON ASSET MANAGEMENT MATURITY (cont)

Question No.	Function	Question	Score	Evidence inspected	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	KPA Review documents for the Contract Supervisor and for the Field Staff were inspected. These clearly link performance requirements to Electra's values and specific competency requirements. The documents inspected were drafts, and show evidence of review.		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	The Competency Framework (on HR's database) was inspected.		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	Refer to Q48. The KPA Review documents for the Contract Supervisor and for the Field Staff inspected clearly link performance requirements to Electra's values and specific job competencies, and then assess actual performance against those values and required competencies.		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.

Company Name	Electra Ltd
AMP Planning Period	1 April 2017 – 31 March 2027
Asset Management Standard Applied	PASS 55

SCHEDULE 13: REPORT ON ASSET MANAGEMENT MATURITY (cont)

Question No.	Function	Question	Score	Evidence inspected	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	Refer to Q42. This meeting ensures that the importance of the works program staying on time and on budget is clearly emphasised. Operational "red flag" issues are communicated to all staff and contractors via a Network Group Advisory Notice (NGAN #64 was inspected, and demonstrated a high level of document control).		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?	1			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	In regard to critical or dangerous situations, Network Group Advisory Notice #64A advising of potentially dangerous substation, and NGAN #64B advising of remediation were inspected.		Effective asset management requires appropriate information to be available. Widely used AM standards therefore require the organisation to identify the asset management information it requires in order to support its asset management system. Some of the information required may be held by suppliers. The maintenance and development of asset management information systems is a poorly understood specialist activity that is akin to IT management but different from IT management. This group of questions provides some indications as to whether the capability is available and applied. Note: To be effective, an asset information management system requires the mobilisation of technology, people and process(es) that create, secure, make available and destroy the information required to support the asset management system.	The organisation's strategic planning team. The management team that has overall responsibility for asset management. Information management team. Operations, maintenance and engineering managers	Details of the process the organisation has employed to determine what its asset information system should contain in order to support its asset management system. Evidence that this has been effectively implemented.
63	Information management	How does the organisation maintain its asset management information system(s) and ensure that the data held within it (them) is of the requisite quality and accuracy and is consistent?	3			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.

Company Name	Electra Ltd
AMP Planning Period	1 April 2017 – 31 March 2027
Asset Management Standard Applied	PASS 55

SCHEDULE 13: REPORT ON ASSET MANAGEMENT MATURITY (cont)

Question No.	Function	Question	Score	Evidence inspected	User Guidance	Why	Who	Record/documented Information
64	Information management	How has the organisation's ensured its asset management information system is relevant to its needs?	2			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	The PSMS Policy was examined, and it is noted that this policy references a wide range of policies aimed at ensuring conformance and minimising risks at the design, construction, commissioning and operating phases of the asset life cycle. The PSMS Internal Audit and external Revalidation are key processes for identifying asset and asset management risks, and are performed in accordance with auditing standards. The PSMS Internal Audit from December 2016 noted the risk of oil-filled		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	The TELARC Revalidation of January 2016 included an assessment of 2 contractors skills and competencies, and noted that Electra has also performed further contractor competency 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	Electra uses Comply With to maximise its legal and regulatory compliance. The draft report from November 2016 was inspected, and various corrective actions were noted. People and Capability Manager confirmed that these are being actioned.		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

Company Name	Electra Ltd
AMP Planning Period	1 April 2017 – 31 March 2027
Asset Management Standard Applied	PASS 55

SCHEDULE 13: REPORT ON ASSET MANAGEMENT MATURITY (cont)

Question No.	Function	Question	Score	Evidence inspected	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?	2.5	Electra has Standards for design and construction of works to minimise non-conformance. A wide range of operating policies ensure compliant operation.		Life cycle activities are about the implementation of asset management plan(s) i.e. they are the "doing" phase. They need to be done effectively and well in order for asset management to have any practical meaning. As a consequence, widely used standards (eg, PAS 55 s 4.5.1) require organisations to have in place appropriate process(es) and procedure(s) for the implementation of asset management plan(s) and control of lifecycle activities. This question explores those aspects relevant to asset creation.	Asset managers, design staff, construction staff and project managers from other impacted areas of the business, e.g. Procurement	Documented process(es) and procedure(s) which are relevant to demonstrating the effective management and control of life cycle activities during asset creation, acquisition, enhancement including design, modification, procurement, construction and commissioning.
91	Life Cycle Activities	How does the organisation ensure that process(es) and/or procedure(s) for the implementation of asset management plan(s) and control of activities during maintenance (and inspection) of assets are sufficient to ensure activities are carried out under specified conditions, are consistent with asset management strategy and control cost, risk and performance?	2	The Underground Line Construction Standard was examined.		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	The first step in managing asset performance is through the use of design and construction standards, material specifications and auditing of completed works.		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?	1.5	NGAN's 64A and 64B (Totara St transformer station safety issue) were examined. The Process For Investigation Of Network Incidents Involving Public Safety was examined.		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.

Company Name	Electra Ltd
AMP Planning Period	1 April 2017 – 31 March 2027
Asset Management Standard Applied	PASS 55

SCHEDULE 13: REPORT ON ASSET MANAGEMENT MATURITY (cont)

Question No.	Function	Question	Score	Evidence inspected	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))?	3	The PSMS Internal Audit and the TELARC Revalidation have been inspected. The AMMAT was refreshed in January 2017. Various consultants have been engaged to assess various aspects of Electra's AM activity, and recommend improvements.		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?	2	The Undergound Line Construction Standard was examined. The Process For Investigation Of Network Incidents Involving Public Safety from the PSMS was examined.		Having investigated asset related failures, incidents and non-conformances, and taken action to mitigate their consequences, an organisation is required to implement preventative and corrective actions to address root causes. Incident and failure investigations are only useful if appropriate actions are taken as a result to assess changes to a businesses risk profile and ensure that appropriate arrangements are in place should a recurrence of the incident happen. Widely used AM standards also require that necessary changes arising from preventive or corrective action are made to the asset management system.	The management team responsible for its asset management procedure(s). The team with overall responsibility for the management of the assets. Audit and incident investigation teams. Staff responsible for planning and managing corrective and preventive actions.	Analysis records, meeting notes and minutes, modification records. Asset management plan(s), investigation reports, audit reports, improvement programmes and projects. Recorded changes to asset management procedure(s) and process(es). Condition and performance reviews. Maintenance reviews
113	Continual Improvement	How does the organisation achieve continual improvement in the optimal combination of costs, asset related risks and the performance and condition of assets and asset systems across the whole life cycle?	2	The memo from GM Lines Business in December 2016 includes a commitment to investigate several safety, reliability and resiliance improvements within the existing cost base.		Widely used AM standards have requirements to establish, implement and maintain process(es)/procedure(s) for identifying, assessing, prioritising and implementing actions to achieve continual improvement. Specifically there is a requirement to demonstrate continual improvement in optimisation of cost risk and performance/condition of assets across the life cycle. This question explores an organisation's capabilities in this area—looking for systematic improvement mechanisms rather that reviews and audit (which are separately examined).	The top management of the organisation. The manager/team responsible for managing the organisation's asset management system, including its continual improvement. Managers responsible for policy development and implementation.	Records showing systematic exploration of improvement. Evidence of new techniques being explored and implemented. Changes in procedure(s) and process(es) reflecting improved use of optimisation tools/techniques and available information. Evidence of working parties and research.
115	Continual Improvement	How does the organisation seek and acquire knowledge about new asset management related technology and practices, and evaluate their potential benefit to the organisation?	2.5	Presence of external contractors was noted on various occassions. Attendance of Electra staff at industry events has been observed. Comparative analysis work was examined.		One important aspect of continual improvement is where an organisation looks beyond its existing boundaries and knowledge base to look at what 'new things are on the market'. These new things can include equipment, process(es), tools, etc. An organisation which does this (eg, by the PAS 55 s 4.6 standards) will be able to demonstrate that it continually seeks to expand its knowledge of all things affecting its asset management approach and capabilities. The organisation will be able to demonstrate that it identifies any such opportunities to improve, evaluates them for suitability to its own organisation and implements them as appropriate. This question explores an organisation's approach to this activity.	The top management of the organisation. The manager/team responsible for managing the organisation's asset management system, including its continual improvement. People who monitor the various items that require monitoring for 'change'. People that implement changes to the organisation's policy, strategy, etc. People within an organisation with responsibility for investigating, evaluating, recommending and implementing new tools and techniques, etc.	Research and development projects and records, benchmarking and participation knowledge exchange professional forums. Evidence of correspondence relating to knowledge acquisition. Examples of change implementation and evaluation of new tools, and techniques linked to asset management strategy and objectives.