Asset Management Plan

1 April 2016 – 31 March 2026

General Manager – Network
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1 Introduction

This Asset Management Plan ("AMP") applies to the electricity distribution network owned by Electra Limited and covers the period 1 April 2016 – 31 March 2026. It documents the network assets and describes plans for maintaining the existing assets and the investment in new assets for this period. Electra is committed to achieving service standards which meet our consumer's requirements. This AMP details the steps taken by Electra to meet these service levels.

We welcome comments on the AMP from interested parties and where appropriate these will be taken into consideration for future plans. Comments should be directed to:

General Manager – Network
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Disclaimer

The information and statements made in this Asset Management Plan are prepared in good faith, are based on assumptions and forecasts made by Electra Limited and represent Electra Limited's intentions and opinions at the date of issue. Circumstances will change, assumptions and forecasts may prove to be inaccurate, events may occur that were not predicted, and Electra Limited may, at a later date, decide to take different actions to those that it currently intends to take. Electra Limited does not give any assurance, explicitly or implicitly, about the accuracy of the information or whether Electra Limited will actually implement the plan or undertake any or all work mentioned in the document. Except for any statutory liability which cannot be excluded, Electra Limited, its Directors, office holders, shareholders and representatives will not accept any liability whatsoever by reason of, or in connection with, any information in this document or any actual or purported reliance on it by any person. Electra Limited may at any time change any information in this document. When considering any content of this Asset Management Plan, persons should take appropriate expert advice in relation to their own circumstances and must rely solely on their own judgment and expert advice obtained. All monetary values in this document are in constant price 2016 NZ dollars (ie no provision for inflation) unless stated otherwise.

2 Summary of the Plan

2.1 Introduction

This Asset Management Plan ("AMP") relates to the electricity distribution services supplied via the electricity distribution network owned by Electra Limited ("Electra") and covers the period 1 April 2016 – 31 March 2026. It documents the network assets and describes our plans for maintaining the existing assets and investing in new assets for this period. Electra is committed to achieving service standards which meet our consumers' requirements. This AMP details the steps taken by Electra to meet these service levels. It is reviewed on an annual basis.

2.2 Purpose of the plan

The purpose of this AMP is to provide a governance and management framework that ensures that Electra meets the requirements of its Asset Management Policy statements below

a. Electra will maintain and manage its network assets at defined levels to enable the safe, efficient and effective delivery of electricity to its consumers.
b. Electra will monitor standards and service levels to ensure that they meet/support consumer and Board goals and objectives.
c. Electra will develop and maintain asset inventories of its entire infrastructure.
d. Electra will establish infrastructure replacement strategies through the use of full life cycle costing principles.
e. Electra will plan financially for the appropriate level of maintenance and replacement of assets to deliver service levels and extend the useful life, of assets.
f. Electra will plan for and provide stable long term pricing/funding to replace and/or renew and/or decommission infrastructure assets.
g. Where appropriate, Electra will consider and incorporate asset management in its other corporate plans.

This purpose is consistent with Electra's overall business mission and goals. Electra's mission, as stated in our Statement of Corporate Intent ("SCI") is **"to enhance the region's development through the provision of 21st century infrastructure"** in the form of a safe, efficient and effective electricity delivery system.

This is reflected at the operational level by the network team with its own specific mission **"to maximise value for consumers and owners through competitive prices, quality services with safe and efficient operations."** This plan is about ensuring delivery of service targets on an ongoing basis – that is in the short term and over the next 10+ years.

Most importantly this AMP, along with Electra's other plans, demonstrates that Electra is responsibly managing its electricity network assets to best-practice levels. The AMP is set in context by asset condition, risk analysis, company policies and load projections. It provides a focus for continuous improvement in the management of the electricity assets and demonstrates responsible ownership of Electra's electricity distribution network on behalf of consumers, shareholders, retailers, government agencies, contractors, staff, financial institutions and the general public. The AMP is also a technical document which is used regularly by staff to manage Electra's assets. This year's AMP looks ahead for 10 years from 1 April 2016, with the main focus on the first five years – for this period specific projects have been identified and discussed. Beyond this period, analysis is more indicative.

Disclosure of this AMP in this format meets the provisions of clause 2.6 and Attachment A of the Electricity Distribution Information Disclosure Determination 2013. A summary of the links between this AMP and the Disclosure Requirements is included in Appendix B.

2.3 Our network

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

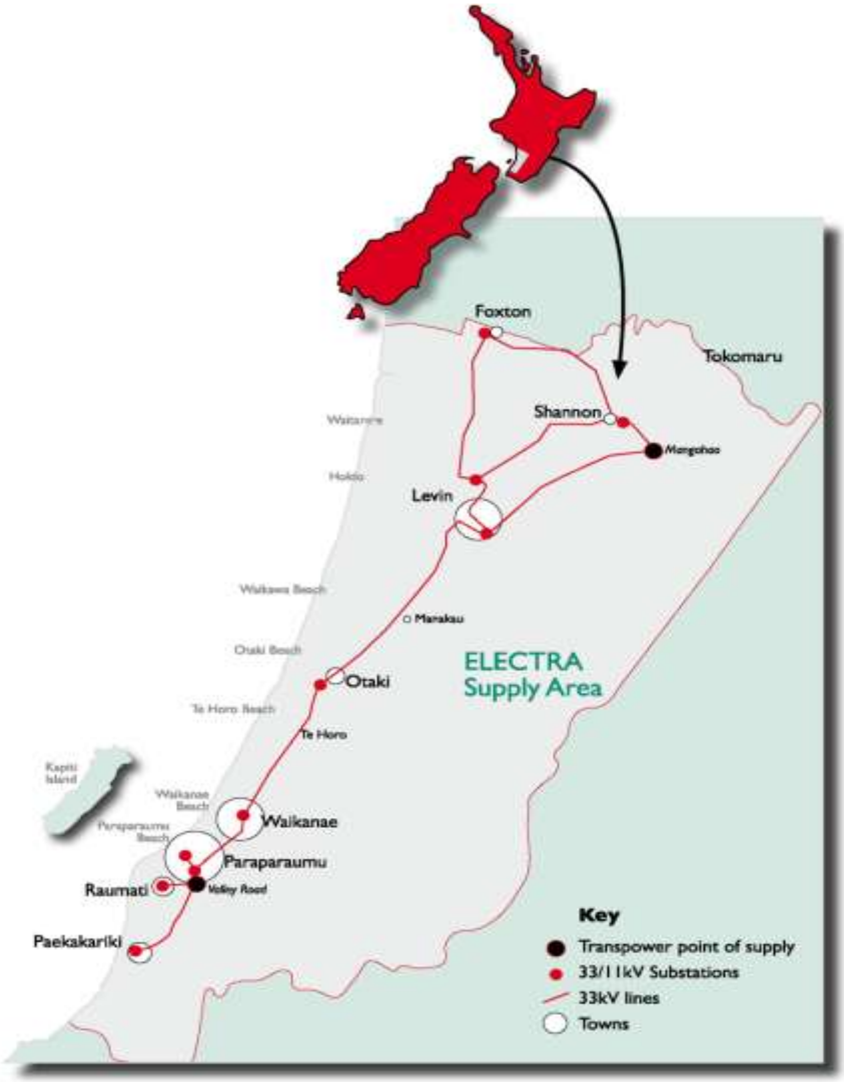


Figure 2.1: Network coverage area

The table below summarises the key statistics of Electra's network at 1 April 2015:

Description	Quantity
Number of Consumer Connections	43690
Network Maximum Demand (MW)	89MW
Electricity Delivered Annually	402GWh
Total kilometres of Lines and Cables	2256km
Number of Zone Substations	10
Number of Distribution Substations	2509
Value of Network Assets[1]	$143m

Table 2.1: Key statistics of Electra's network

2.4 Asset Management Plan Overview

To meet the objectives set by the Asset Management Policy, Electra's strategy is to maintain the existing capability of the network by providing measured and sustainable asset maintenance and renewal programmes. These programmes are based on known asset lifecycles specific to the local environment and monitored through regular inspection and systematic assessment.

This 2016 Asset Management Plan (AMP) continues to emphasise a sustained asset replacement programme in the medium to long term. This is consistent with the path of our previous plan. There continues to be less accent on growth, partly because we have little indication of any turn around in this area, but also simply because there are increasing numbers of ageing assets that need replacing in a timely fashion to prevent the network from aging further overall and to maintain system reliability.

While the focus is on renewal and replacement, we also expect the programme to result in a concurrent improvement in underlying reliability for our customers by installing devices that can provide and act on the increasing amount of data that is currently available. The increased availability and application of data and technology will also enhance our ability to respond to changing customer expectations.

Some projects such as the additional feeders at Waikanae and Otaki, while still included in the 10 year plan, have been deferred until later in the planning period as the trigger points for action will occur later than previously forecast. Some renewal and replacement work has been brought forward to create a consistent work flow and resource allocation.

Projected capital expenditure over the next 10 years is expected to be 6% for growth, 11% for reliability and 83% for renewal and replacement work.

Capital costs are expected to average $9.14m per year over the next 10 years while operational costs are expected to average $4.45m per year over the same period. Electra has the flexibility to modify this approach if growth accelerates beyond our expectations. This will require additional capital expenditure at the rate of approximately $1.1 million per percentage point of additional growth.

2.5 Asset management processes

The AMP is a key component of Electra's overall planning process which comprises:

1 Regulatory Asset Base as at 31 March 2015

- The Statement of Corporate Intent (SCI) – The SCI is agreed annually with shareholders and is a requirement of the Energy Companies Act. It sets out our objectives, the nature and scope of our activities, key policies and strategies, financial and operational performance targets and other related information;
- Annual Group Business Plan and Financial Budgets – Annually Electra prepares a Group Business Plan which outlines its detailed plans and budgets for the forthcoming year consistent with the SCI;
- Annual Network Business Plan – The Network Business Plan covers the operation and management of the network for the forthcoming year and includes targets, budgets and detailed project and operational plans. It is consistent with the Group Business Plan and the SCI;
- Consumer Consultation – Every year, Electra undertakes a formal consumer consultation process where consumers are surveyed for their views on Electra's service standards, prices and other topics such as energy efficiency. These, in addition to regular consultations with large consumers, are fed into the planning processes for the SCI, annual Group Business Plan and the AMP;
- Asset Management Plan – the AMP focuses on network assets and network service levels for a ten year forecast period, consistent with the SCI. Year one of the AMP is consistent with the annual group and network plans.

The following diagram shows how the planning processes interact with each other.

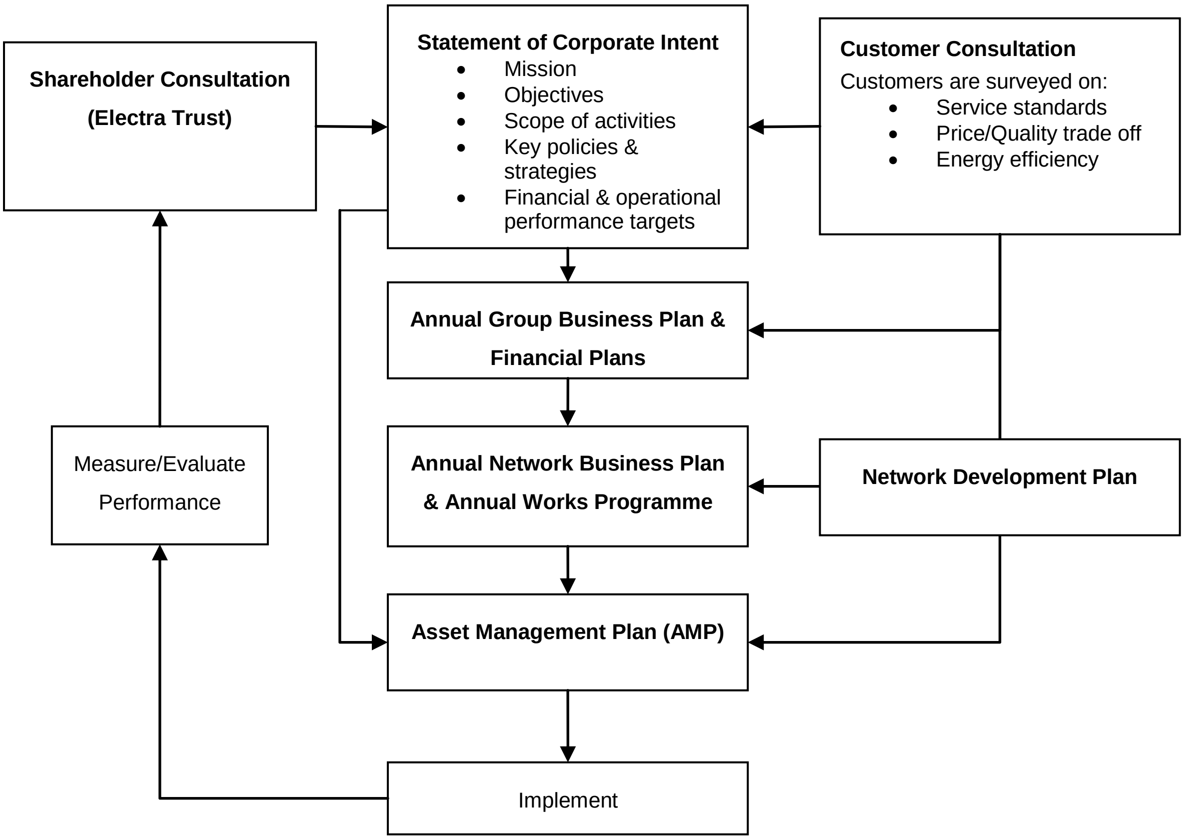


Figure 2.2: Interaction between planning processes

2.6 Levels of service

Electra's primary service levels are supply continuity and restoration. This is based on Electra's original five year average set by the Commerce Commission along with ongoing feedback provided from consumer surveys. These targets can be challenging to continually meet as reliability naturally decays when growth occurs as there are more components to fail and more customers affected when they do. To measure performance in this area the following three internationally accepted indices have been adopted:

- SAIDI – system average interruption duration index. This is a measure of how many system minutes of supply are interrupted per year;
- SAIFI – system average interruption frequency index. This is a measure of how many system interruptions occur per year;
- CAIDI – consumer average interruption duration index. This is a measure of how long the "average" consumer is without supply each year.

The target service levels illustrated overleaf reflect targets derived following Electra's planning and consultation processes, noted above. The forecast service performance levels are dependent on achieving the network maintenance and development plans outlined in Sections 6 and 7 of this AMP.

The following figure displays Electra's SAIFI for last 15 years, plus the targets until 2027:

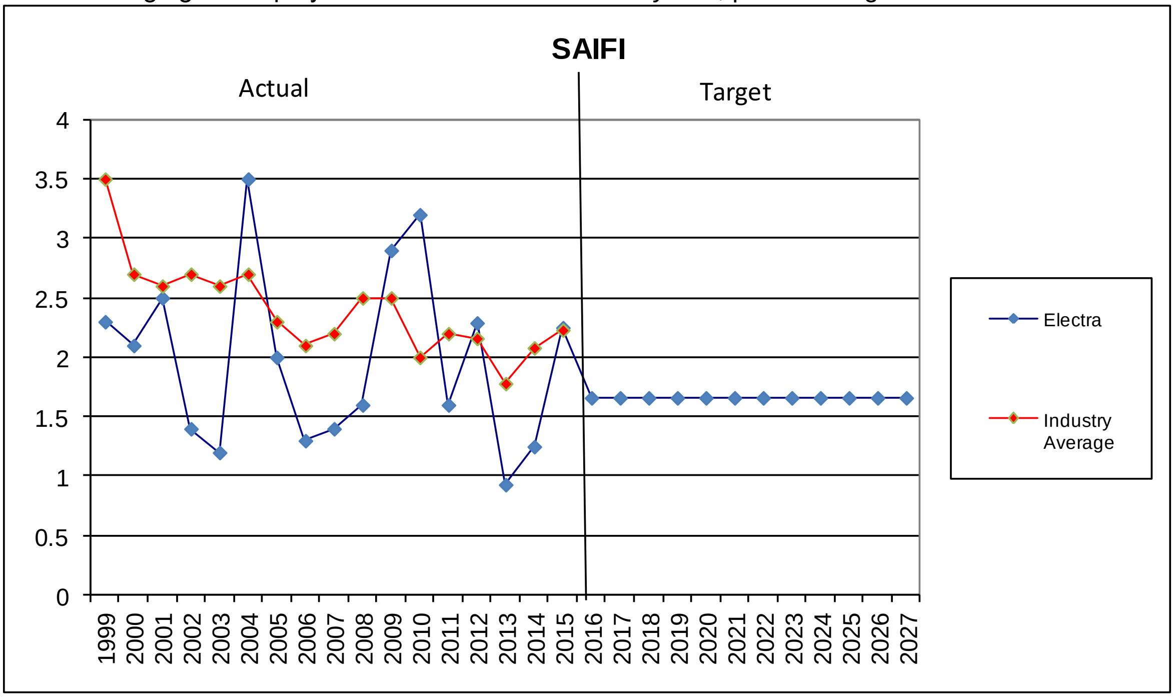


Figure 2.3: Electra's actual verses target SAIFI

The following figure displays Electra's SAIDI and CAIDI (in minutes) for last 15 years, plus the targets until 2027:

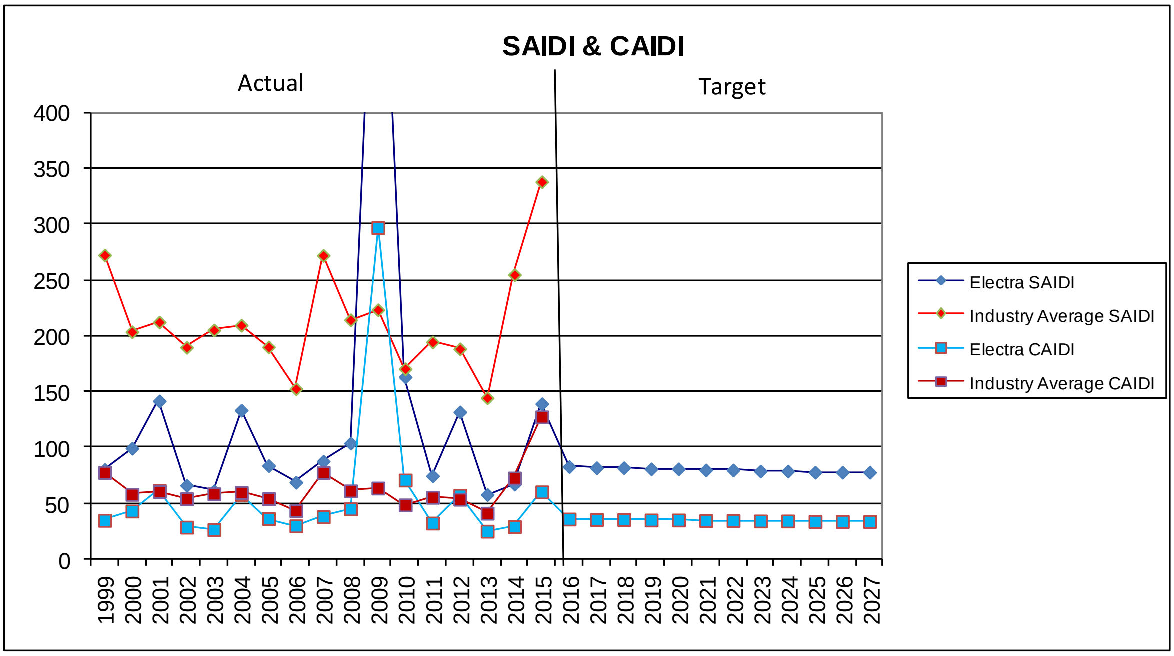


Figure 2.4: Electra's actual verses target SAIDI/CAIDI

Electra has other targets relating to asset performance, asset efficiency and effectiveness, and the efficiency of the line business activity. The following table shows these targets for the year ending 31 March 2017:

Attribute	Measure	2016/2017 Target	2025/2026 Target
Financial Efficiency	Network Operation expenditure per:		
	km circuit length	$1,939	$1,914
	Connection point	$97	$96
	Network Capital expenditure per:		
	km circuit length	$4,848	$4,200
	Connection point	$243	$210
Energy Delivery Efficiency	Load factor (average demand / maximum demand)	50%	50%
	Loss ratio (units lost / units entering network)	6.7%	6.7%
	Capacity utilisation (maximum demand / installed transformer capacity)	30%	33%

Table 2.2: Performance targets

Costs per km and per ICP are industry standard measures for assessing the efficiency of the lines business activity. Load factor, loss ratio and capacity utilisation are industry standard measures for assessing asset performance and efficiency. Using industry standard measures allows for easier benchmarking with other lines businesses.

2.7 Life cycle asset management

All physical assets have a lifecycle. Electra manages its assets through the asset lifecycle according to the process illustrated in the following diagram.

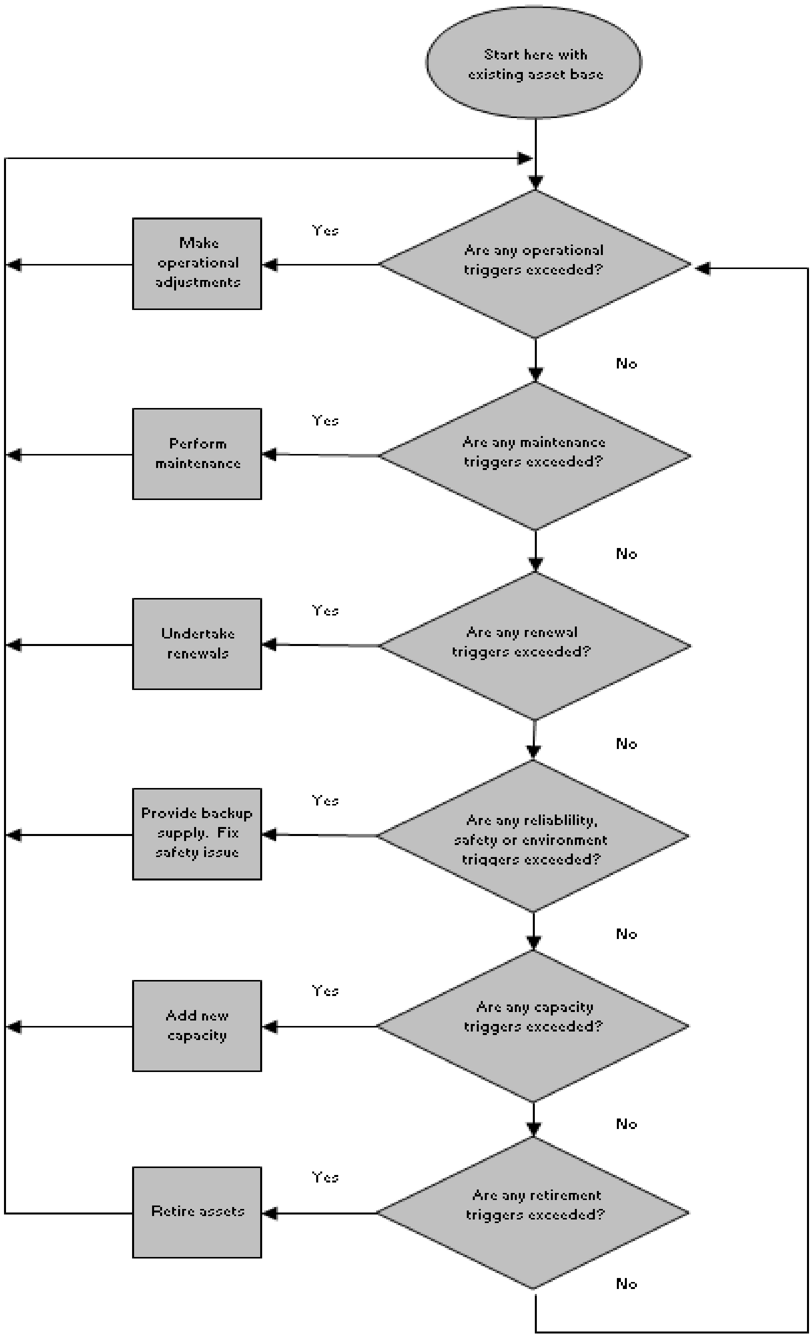


Figure 2.5: Management of the asset lifecycle

The triggers, criteria and assumptions for each of these lifecycle activities are discussed in detail in section 6. For a summary of forecast expenditure for these lifecycle activities refer to section 2.10 below.

2.8 Maintaining assets through the life cycle

Electra's maintenance strategy is based on regular monitoring of asset condition and performance. Inspections are carried out on all asset classes on a cyclical basis. Assets that affect a larger number of consumers are inspected more frequently. Most maintenance works arise from the inspection programme (e.g. crossarm and insulator renewals). Other maintenance works are completed on a cyclical basis (e.g. zone substation transformer oil replacements and tree trimming). Electra's maintenance expenditure ensures that the asset base is adequately maintained and renewed to maintain security of supply and ensure service targets are achieved.

2.9 Meeting demand

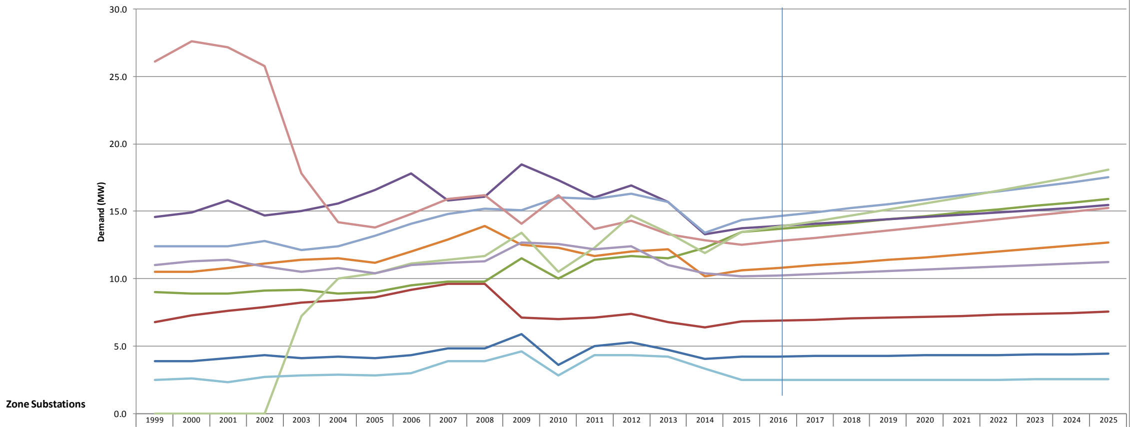
Meeting demand can be achieved by the following means (in a broad order of preference):

- Do nothing (accepting a certain level of calculated risk) ;
- Operational activities (e.g. switching activities on the distribution network to shift load from heavily-loaded to lightly-loaded feeders, etc);
- Influence consumers to alter their consumption patterns;
- Construct distributed generation;
- Modify an asset (e.g. by adding forced cooling);
- Retrofitting high-technology devices;
- Install new assets with a greater capacity.

In identifying solutions for meeting future demands for capacity, reliability, security and voltage, Electra considers the above options. The benefit-cost ratio of each option is considered (including estimates of the benefits of environmental compliance and public safety) and the option yielding the greatest benefit is adopted. The cost-benefit ratio is vital to ensure Electra maximises value for consumers and owners consistent with the mission statement stated in section 2.2.

Electra's network supplies two adjoining districts with distinct and different demographics. The southern area located around the towns of Paraparaumu and Waikanae is heavily urbanised. Demand growth has historically increased at approximately 2-3 percent per annum in this area, but since 2010 it has only been at around 1% per annum. This has reduced the need to increase capacity of existing assets due to high-density in-fill and increased load at existing installations. The northern area located around the towns of Levin, Shannon and Foxton is predominantly rural and is characterised by horticulture and by some agriculture related commercial load. Load growth in this area of the network has remained steady at around 1% per annum.

The following zone substation demand forecasts have been adopted for development planning. Based on these demand forecasts, some network constraints are expected to emerge over the ten year planning horizon.



Zone Substations	1999	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014
	Actuals															
Shannon	3.9	3.9	4.1	4.3	4.1	4.2	4.1	4.3	4.8	4.8	5.9	3.6	5.0	5.3	4.7	4.03
Foxton	6.8	7.3	7.6	7.9	8.2	8.4	8.6	9.2	9.6	9.6	7.1	7.0	7.1	7.4	6.8	6.41
Levin West	9.0	8.9	8.9	9.1	9.2	8.9	9.0	9.5	9.8	9.8	11.5	10.0	11.4	11.7	11.5	12.29
Levin East	14.6	14.9	15.8	14.7	15.0	15.6	16.6	17.8	15.8	16.1	18.5	17.3	16.0	16.9	15.7	13.3
Otaki	10.5	10.5	10.8	11.1	11.4	11.5	11.2	12.0	12.9	13.9	12.5	12.3	11.7	12.0	12.2	10.17
Waikanae	12.4	12.4	12.4	12.8	12.1	12.4	13.2	14.1	14.8	15.2	15.1	16.0	15.9	16.3	15.7	13.43
Paraparaumu	26.1	27.6	27.2	25.8	17.8	14.2	13.8	14.8	15.9	16.2	14.1	16.2	13.7	14.3	13.3	12.85
Paraparaumu West	0.0	0.0	0.0	0.0	7.2	10.0	10.4	11.1	11.4	11.7	13.4	10.5	12.3	14.7	13.4	11.89
Raumati	11.0	11.3	11.4	10.9	10.5	10.8	10.4	11.0	11.2	11.3	12.7	12.6	12.2	12.4	11	10.41
Paekakariki	2.5	2.6	2.3	2.7	2.8	2.9	2.8	3.0	3.9	3.9	4.6	2.8	4.3	4.3	4.2	3.31

Zone Substations	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025
	Forecast										
Shannon	4.2	4.2	4.2	4.3	4.3	4.3	4.3	4.3	4.4	4.4	4.4
Foxton	6.83	6.9	7.0	7.0	7.1	7.2	7.3	7.3	7.4	7.5	7.5
Levin West	13.46	13.7	13.9	14.2	14.4	14.6	14.9	15.1	15.4	15.7	15.9
Levin East	13.72	13.9	14.1	14.2	14.4	14.6	14.7	14.9	15.1	15.3	15.5
Otaki	10.6	10.8	11.0	11.2	11.4	11.6	11.8	12.0	12.2	12.4	12.7
Waikanae	14.36	14.6	14.9	15.2	15.5	15.9	16.2	16.5	16.8	17.2	17.5
Paraparaumu	12.53	12.8	13.0	13.3	13.6	13.8	14.1	14.4	14.7	15.0	15.3
Paraparaumu West	13.44	13.8	14.3	14.7	15.1	15.6	16.0	16.5	17.0	17.5	18.1
Raumati	10.15	10.3	10.4	10.5	10.6	10.7	10.8	10.9	11.0	11.1	11.2
Paekakariki	2.46	2.5	2.5	2.5	2.5	2.5	2.5	2.5	2.5	2.5	2.5

Figure 2.6: Maximum demand by zone substation (financial year)

The following table shows the main sub transmission circuits that are expected to become constrained within the planning horizon. It also contains a description of the constraint coupled with the intended action to remedy it. These projects constitute a significant portion of the extension and upsizing components of the development plan.

The constraints noted below while included in this developmental plan, may be affected by the outcomes of discussions with Transpower regarding development of the GXP's supplying the Electra network. This is discussed in more detail in section 7.4, Network Constraints.

Constraint	Description	Intended Remedy
Shannon & Mangahao – Levin East 600A circuits	Once the load at Mangahao GXP reaches 35MVA, there is the potential for overloading these circuits in an (n-1) outage.	Complete the separation of the Mangahao-Levin East 33kV line by installing a cable from Arapaepae Road to Levin East. (currently under construction)

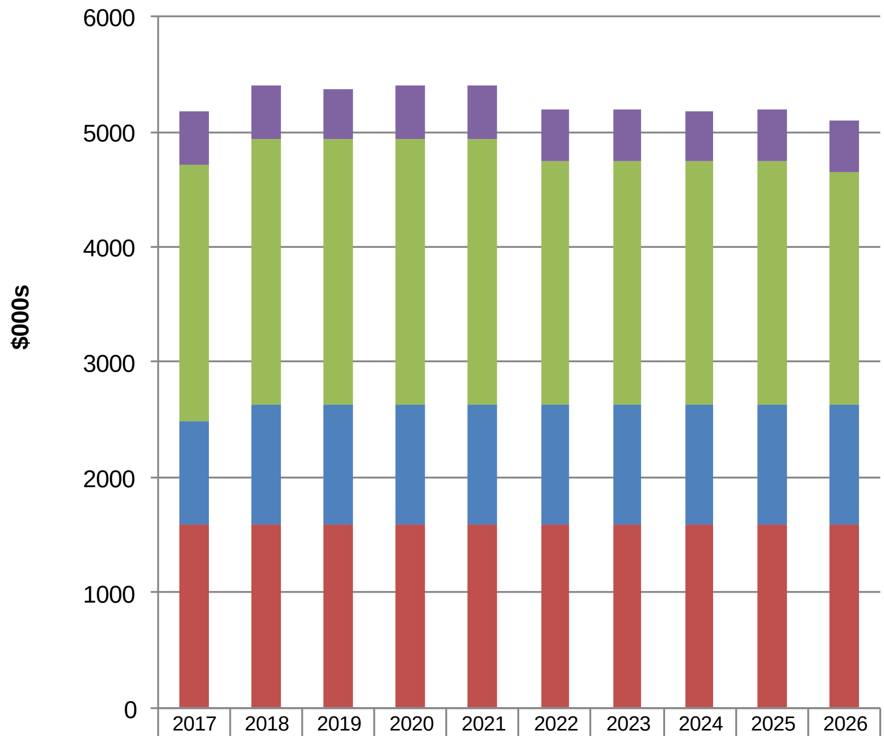
Table 2.3: Network constraints on the sub-transmission network

There are no known load or voltage constraints on the 11kV network over the forecast period. However, there are a number of developing beach settlements that are on single 11kV spur lines that over the planning period will require duplication due to the number of consumers that will be affected by any interruption and the consequential impact on system performance, SAIDI and SAIFI in particular.

2.10 Summary of forecast expenditure

We changed the criteria for budgeting in 2013/14 so that rather than differentiating by the financially based operational and capital expenditure we use asset based lifecycle and development expenditure. The primary difference in the two methods is that capital expenditure for replacement and renewal purpose is added to maintenance expenditure and becomes lifecycle expenditure. Development expenditure is effectively capital expenditure excluding replacement and renewal. Both systems have been included in this summary but only the lifecycle/development expenditure is shown in the body of the Asset Management Plan.

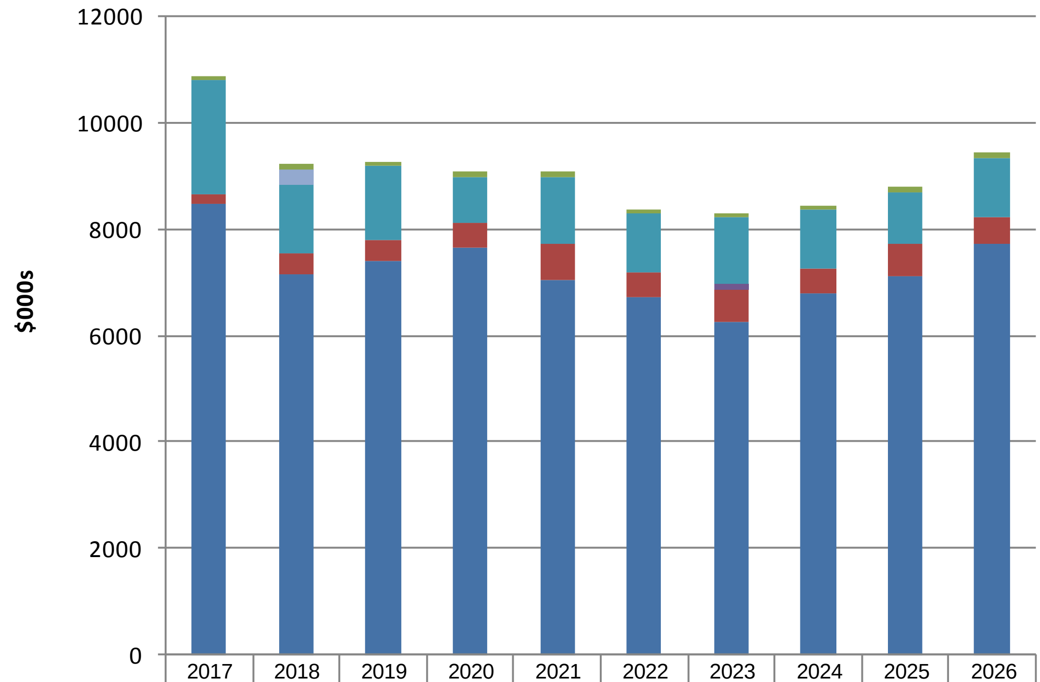
A summary of Electra's forecast maintenance expenditure in constant price NZ dollars is shown in the figure below.



	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026
Refurbishment & Renewal Maintenance	457	458	436	458	458	458	458	436	458	458
Fault & Emergency Maintenance	2226	2305	2305	2305	2305	2105	2105	2105	2105	2012
Routine & Preventative Maintenance	897	1043	1043	1043	1043	1043	1043	1043	1043	1043
Vegetation	1591	1591	1591	1591	1591	1591	1591	1591	1591	1591

Figure 2.7: Summary of Electra's forecast operating and maintenance expenditure

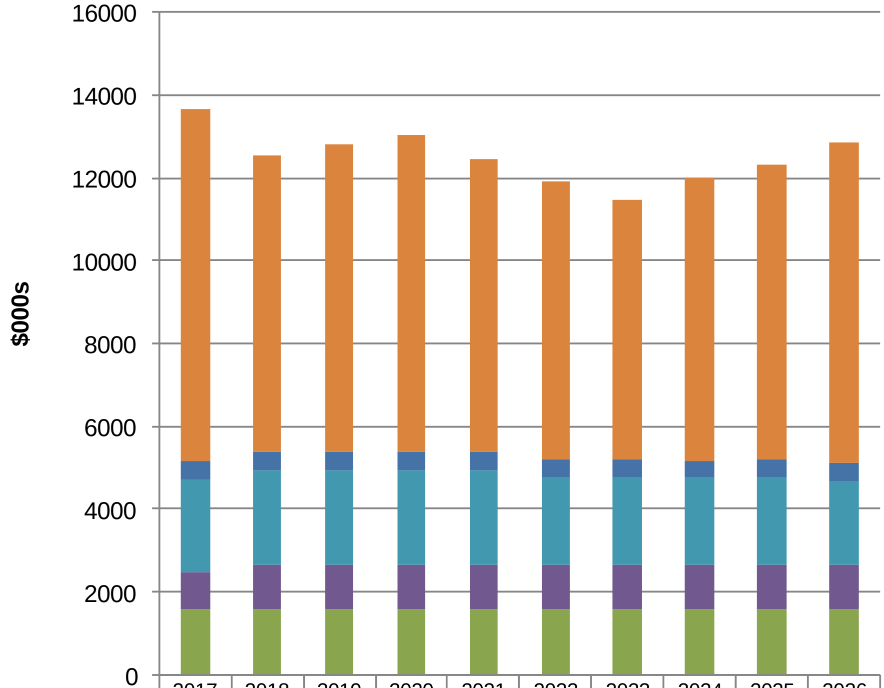
A summary of Electra's forecast capital expenditure over the next ten years is shown in the figure overleaf. These figures are in constant price NZ dollars (ie no provision for inflation). The majority of planned capital expenditure is aimed to maintain serviceability of the network and reduce the risk of declining network reliability using the average age as a proxy measurement. Other projects such as the installation of RMUs for network sectionalisation offset the natural degradation in reliability that occurs as the network grows both in customers and caused also improve reliability. The system growth projects included in the planned capital expenditure are to remedy the emerging demand constraints described in Section 2.9.



	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026
Customer Connection	95	95	95	95	95	95	95	95	95	95
Safety	0	303	0	0	0	0	0	0	0	0
Legislative	0	0	0	0	0	0	0	0	0	0
Quality	2135	1286	1387	886	1286	1094	1265	1100	946	1100
Relocation	0	0	0	0	0	0	102	0	0	0
Growth	204	409	388	460	664	460	583	460	613	511
Renewal	8466	7137	7414	7647	7047	6735	6272	6806	7131	7732

Figure 2.8: Summary of Electra's forecast capital expenditure

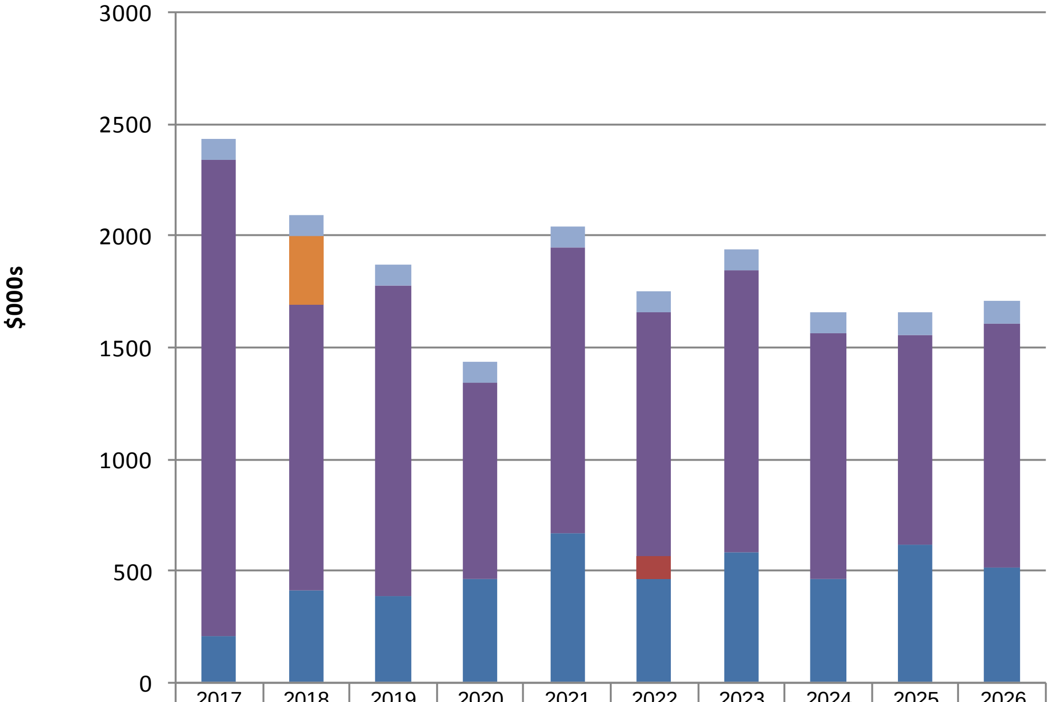
A summary of Electra's forecast lifecycle expenditure in constant price NZ dollars is shown in the figure below.



	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026
Renewal	8466	7137	7414	7647	7047	6735	6272	6806	7131	7732
Refurbishment & Renewal Maintenance	457	458	436	458	458	458	458	436	458	458
Fault & Emergency Maintenance	2226	2305	2305	2305	2305	2105	2105	2105	2105	2012
Routine & Preventative Maintenance	897	1043	1043	1043	1043	1043	1043	1043	1043	1043
Vegetation	1591	1591	1591	1591	1591	1591	1591	1591	1591	1591

Figure 2.9: Summary of Electra's forecast lifecycle expenditure

A summary of Electra’s forecast development expenditure in constant price NZ dollars is shown in the figure below.



	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026
Customer Connection	95	95	95	95	95	95	95	95	95	95
Safety	0	303	0	0	0	0	0	0	0	0
Legislative	0	0	0	0	0	0	0	0	0	0
Quality	2135	1286	1387	886	1286	1094	1265	1100	946	1100
Relocation	0	0	0	0	0	102	0	0	0	0
Growth	204	409	388	460	664	460	583	460	613	511

Figure 2.10: Summary of Electra’s forecast development expenditure

2.11 Risk management

Risk assessment and risk management strategies focus on the following areas:

Risk area	Summary of how Electra mitigates risk
Health and Safety	Electra has developed policies to mitigate risk relating to health and safety. Electra designs its network to meet relevant safety standards and is compliant with relevant regulation in relation to health and safety. Electra has developed a Safety Management System (SMS) which recognises the increased focus that distribution companies must have towards public safety. This SMS also covers contractor and employee safety along with requirements for new assets to be connected to the network.
Environmental Risks (Flooding, Wind, Earthquakes, etc)	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.
Asset Failure, Maintenance and/or Restoration of Supply	Electra has policies and procedures in place for all stages of the asset lifecycle. These policies and procedures are designed to reduce the risk of asset failure, and minimise the effect if assets do fail.
Network Records	Electra maintains offsite storage of computer backup tapes.
Regulatory Regime	Policies and procedures are in place for all stages of the asset lifecycle to reduce the likelihood that Electra will breach any quality thresholds set by the Commerce Commission.
Continuity of Key Business Processes	Electra has a backup Control Centre on the outskirts of Levin which has duplicates of all of the necessary software and templates to perform critical tasks.

Table 2.4: Electra's risk management

2.12 Performance evaluation

Feedback from our consumers and stakeholders helps us to determine how well we manage our network to meet agreed levels of service and quality. Regular price/quality consultation shows our consumers are generally happy with our service and reliability. We also measure our actual performance for operating and capital expenditure, and service levels against the targets identified in the previous AMP.

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

Category	2014/2015 Actual ($000)	2014/2015 Budget ($000)	Variance ($000)	Variance (%)
Operational Expenditure on Asset Management	10,629	7,015	3614	52%
Capital expenditure	8,464	7,879	585	7%

Table 2.5: Actual verses budgeted maintenance spend for year ending 31 March 2015

Operational expenditure was over budget as work contracted out in previous years was caught up. Capital expenditure was under budget was not achieved due to a combination of technical, resourcing and weather constraints. This issue has been addressed by a combination of additional staff recruitment and greater use of sub-contractors.

The following table presents our actual performance against target performance for key service level targets:

Attribute	Measure	2015 Target	2015 Actual
Network Reliability	SAIDI	83.0	149.2
	SAIFI	1.67	2.63
	CAIDI	49.7	56.7
Public Safety	Electricity (Safety) Regulations 2011	Compliant	Compliant
Industry performance	Electricity Information Disclosure Requirements 2004 and subsequent amendments	Compliant	Compliant
Financial Efficiency	Capital expenditure per: • total circuit length • connection point	 $2,834 $174	 $4039 $230
	Operational expenditure per: • total circuit length • connection point	 $2,614 $160	 $4711 $268
Energy Delivery Efficiency	Load factor (units entering network / maximum demand times hours in year)	54%	56%
	Loss ratio (units lost / units entering network)	6.6%	6.7%
	Capacity utilisation (maximum demand / installed transformer capacity)	33.7%	27.6

Table 2.6: Actual performance verses targets for year ending 31 March 2015

SAIDI was lower than target due mainly to less weather related outages within the period. The energy delivery efficiency measures all failed to meet target although load factor improved on the previous year. Losses are still higher than expected. We will continue to work with consumers to improve Power Factor to increase efficiencies across the northern network in order to help bring losses closer to target levels.

3 Background and Objectives

3.1 Purpose of the Plan

This AMP has been prepared by Electra to provide a governance and management framework that ensures that Electra:

- Sets service levels for its electricity network that will meet consumer, community and regulatory requirements;
- Understands the current and future network capacity, reliability and security of supply requirements, and the issues that drive these requirements;
- Has robust and transparent processes in place for managing all phases of the network life cycle, from conception to disposal;
- Considers the classes of risk its network business faces and has systematic processes in place to mitigate identified risks;
- Makes adequate provision for funding all phases of the network lifecycle;
- Makes decisions within systematic and structured frameworks across the business; and
- Builds knowledge of its asset's location, age and condition and the network's likely future behaviour and performance.

This purpose is consistent with Electra's overall business mission and strategic objectives, as demonstrated in section 3.2 below. Most importantly this AMP, along with Electra's other plans, demonstrates that Electra is responsibly managing its electricity network assets to best-practice levels. The AMP is set in context by risk analysis, company policies and load projections. It provides a focus for continuous improvement in the management of the electricity assets and demonstrates responsible ownership of Electra's electricity distribution network on behalf of consumers, shareholders, retailers, government agencies, contractors, staff, financial institutions and the general public. The AMP is also a technical document which is used regularly by our staff to manage our assets.

Disclosure of this AMP in this format meets the provisions of the Electricity Distribution Information Disclosure Determination 2013. A summary of the links between this AMP and the Disclosure Requirements is included in Appendix B*.*

3.2 Interaction with other goals, processes and plan

Electra is 100% owned by the Electra Trust whose beneficiaries are Electra's consumers.

Electra's mission, as stated in our Statement of Corporate Intent ("SCI") is **"to enhance the region's development through the provision of 21st century infrastructure, Electra will endeavour to maximise value for consumers and owners through competitive prices, quality services with safe and efficient operations."**

The following policies and strategies link directly to asset management:

- Electricity Line Services Pricing – "Electra will offer all its network customers the same price for similar electricity volumes and services. Future prices will continue to be competitive. They will reflect the costs associated with line services, including the cost of capital";
- Service and Operational Efficiency – "Electra will continue to invest in upgrading the quality, effectiveness and efficiency of network operations. It will continue to review opportunities to work with other line companies to minimise operating costs and benchmark performance, to ensure value to consumers and owners";
- Market Growth and Quality of Supply – "Electra will continue to invest in energy network assets to meet market growth and to maintain the quality of supply in the Kapiti/Horowhenua area, subject to normal investment criteria. It will continue to promote energy efficiency initiatives. The Company will, where necessary, develop and use electricity pricing options and other practical solutions that result in the best use of network capacity";
- Environmental Responsibility – "The Company will minimise the impact on the environment as much as practicable, and will comply with the spirit and letter of the Resource Management Act 1991 and any amendments to it".

The AMP is a key component of Electra's overall planning process which comprises the following:

- The SCI is agreed annually with shareholders and is a requirement of the Energy Companies Act. It sets out our objectives, the nature and scope of our activities, key policies and strategies, financial and operational performance targets and other related information;
- Annual Group Business Plan and Financial Budgets – Annually Electra prepares a group Business Plan which outlines its detailed plans and budgets for the forthcoming year consistent with the SCI;
- Annual Network Business Plan – The Network Business Plan covers the operation and management of the network for the forthcoming year and includes key performance indicators, budgets along with high level objectives, initiatives to achieve them along with the Annual Works Programme. The mission as previously noted in 2.2 is consistent with the Group Business Plan and the SCI;
- Consumer Consultation – Every year, Electra undertakes a formal consumer consultation process where consumers are surveyed for their views on Electra's service standards, prices and other topics such as energy efficiency. These, in addition to regular consultations with large consumers and feedback from the key contractor on the network, are fed into the planning processes for the SCI, annual Group Business Plan and the AMP;
- Asset Management Plan – the AMP focuses on network assets and network service levels for a ten year forecast period, consistent with the SCI. Year one of the AMP is consistent with the annual group and network plans/budgets and the Annual Works Programme.

The following diagram shows how the planning processes interact with each other.

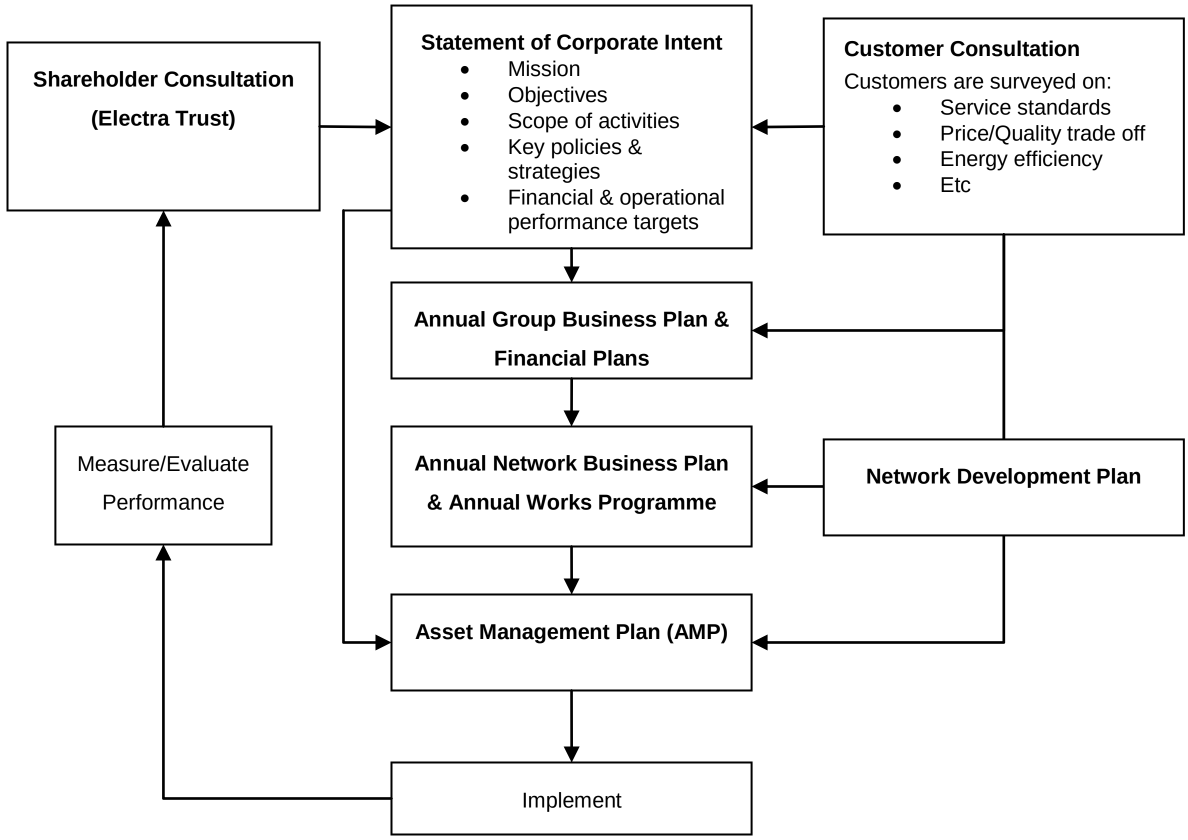


Figure 3.1: Interaction between planning processes

Thus, strategic policy flows directly into asset management, which is captured in the AMP for long term asset management. Each year Electra consolidates the first year of the AMP and any recent commercial, asset or operational issues into the annual business plan. An important component of the Annual Network Business Plan is the Annual Works Programme which scopes and costs each individual activity or project that is expected to be undertaken in the year ahead. A critical activity for Electra is to firstly ensure that this Annual Works Programme accurately reflects the projects scheduled for the current year in the AMP and secondly ensure that each project is implemented according to the scope prescribed in the works programme. All the planning documents above are approved at the Board level prior to implementation.

3.3 Planning period

This AMP covers the period 1 April 2016 – 31 March 2026. Maintenance and development plans are most specific for the initial five year period to 31 March 2021. Similar plans through to 31 March 2026 are more indicative and are provided for strategic direction. Proposed activities towards the end of this planning horizon are based on current views, trends and assumptions and may change as more accurate information emerges over time.

The AMP was approved by Electra's Board during the Board meeting held 31 March 2016.

3.4 Stakeholder interests

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

- has a financial interest in Electra (be it equity or debt);
- be physically connected to Electra's network (a consumer);
- 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 prices).

The interests of Electra's stakeholders are defined in Table 3.1 below. These are identified through consumer forums and surveys, relevant legislation and regulations, regular communications and meetings with the Electra Trust, retailers, Transpower, local authorities, developers, staff and contractors.

	Key Stakeholder Interests			
	Viability[2]	**Supply Quality**	**Safety**	**Compliance**
Electra Trust	✓	✓	✓	
Bankers	✓			
Connected consumers	✓	✓	✓	
Energy retailers	✓	✓		
Mass-market representative groups	✓	✓		
Industry representative groups	✓	✓		
Staff & contractors	✓	✓	✓	✓
Suppliers of goods & services	✓			
Public (as distinct from consumers)			✓	
Land owners			✓	✓
Councils (excluding as a consumer)			✓	✓
Land Transport			✓	✓
Ministry of Economic Development			✓	✓
Energy Safety Service			✓	✓
Commerce Commission	✓	✓		✓
Electricity Authority				✓
Electricity & Gas Complaints Commission		✓		✓
Ministry of Consumer Affairs		✓		✓
Transpower	✓	✓	✓	✓

Table 3.1: Key stakeholder interests

Table 3.2 below further describes these interests, and shows how these interests are accommodated in Electra's AMP.

[2] Price is related to this stakeholder interest.

Interest	Description	How Electra accommodate interests
Viability	Viability is necessary to ensure that the Trust and other providers of finance such as bankers have sufficient reason to keep investing in Electra.	• 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 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.
Supply Quality	Emphasis on supply continuity, restoration and reducing flicker is essential to minimising interruptions to consumers businesses.	• 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.
Safety	Staff, contractors and the public at large must be able to move around and work on Electra's network safely.	• Electra will ensure that the public at large are kept safe by ensuring that all above-ground assets are structurally sound, live conductors are well out of reach, all enclosures are kept locked, and all exposed metal is earthed. • Electra will also ensure that the public are kept safe via its Safety Management System (SMS). • Electra will ensure the safety of its staff and contractors by providing all necessary equipment, improving safe work practices, and ensuring that workers are stood down in unsafe conditions. • Motorists will be kept safe by ensuring that above-ground structures are kept as far as possible from the carriage way within the constraints Electra faces in regard to private land and road reserve.
Compliance	Electra needs to comply with many statutory requirements ranging from safety to information disclosure.	• Electra will 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 will disclose performance information in a timely and compliant fashion.

Table 3.2: Accommodating stakeholders interests

Table 3.2 below further describes the communication processes used between Electra and the various stakeholders identified above.

Stakeholder	Communication Plan
Electra Trust	Quarterly briefings
Bankers	Quarterly meetings
Connected consumers	As required via 0800 phone number and website enquiry section, Annual Review mail out, Annual General Meeting, annual customer survey.
Energy retailers	As required, at least annually
Mass-market representative groups	Annual General Meeting
Industry representative groups	Annually via meetings and conferences
Staff & contractors	Weekly Staff meeting, Monthly Contractor meeting, as required for specific projects
Suppliers of goods & services	As required
Public (as distinct from consumers)	As required via 0800 phone number and website enquiry section
Land owners	As required for specific projects
Councils (excluding as a consumer)	Monthly Emergency Management meeting, annual planning disclosure, as required for specific projects.
Land Transport	As required
Ministry of Economic Development	As required
Energy Safety Service	As required
Commerce Commission	Annually via Disclosures
Electricity Authority	As required
Electricity & Gas Complaints Commission	As required
Ministry of Consumer Affairs	As required
Transpower	Quarterly updates, annual planning meeting

Table 3.3: Stakeholder communications

Electra manages possible conflicting stakeholder interests by:

- Considering the needs of all stakeholders during planning;
- Undertaking cost/benefit analysis;
- Balancing security needs against the cost of non supply; and
- Considering our legislative requirements – including the requirement to operate as a successful business under the Energy Companies Act 1992.

Wherever possible, Electra will endeavour to resolve conflicts of interest in a responsible manner, and will follow due process in order to discharge its responsibilities in respect of its obligations for electricity supply. Our priorities for managing conflicting interests are:

- Safety - Electra will give top priority to safety. Even if it has to exceed budget or risk non-compliance, Electra will not compromise the safety of its staff, contractors or the public;
- Viability - Electra will give second priority to viability because without it Electra will cease to exist which makes supply quality and compliance irrelevant;
- Supply quality – Electra will give third priority to security of supply. Security of supply is important to consumers connected to Electra's Network;
- Compliance - Electra will give lower priority to compliance that is not safety related. Most aspects of compliance attempt to defend consumer interests in the face of supposed

monopoly power, however Electra reasons that if all stakeholders except the regulator are happy then the regulator is not reflecting stakeholder wishes.

These conflicting interests are taken into account in the prioritisation of jobs (if applicable). Section 7.2 provides more information about prioritisation of jobs.

3.5 Asset management accountabilities

All shares in Electra Limited are owned by the Electra Trust. Between the Trust and the Electra CEO sits a Board of Directors. The following diagram shows the organisational structure of the Electra Network. This is followed by a discussion of the roles and responsibilities held by each group.

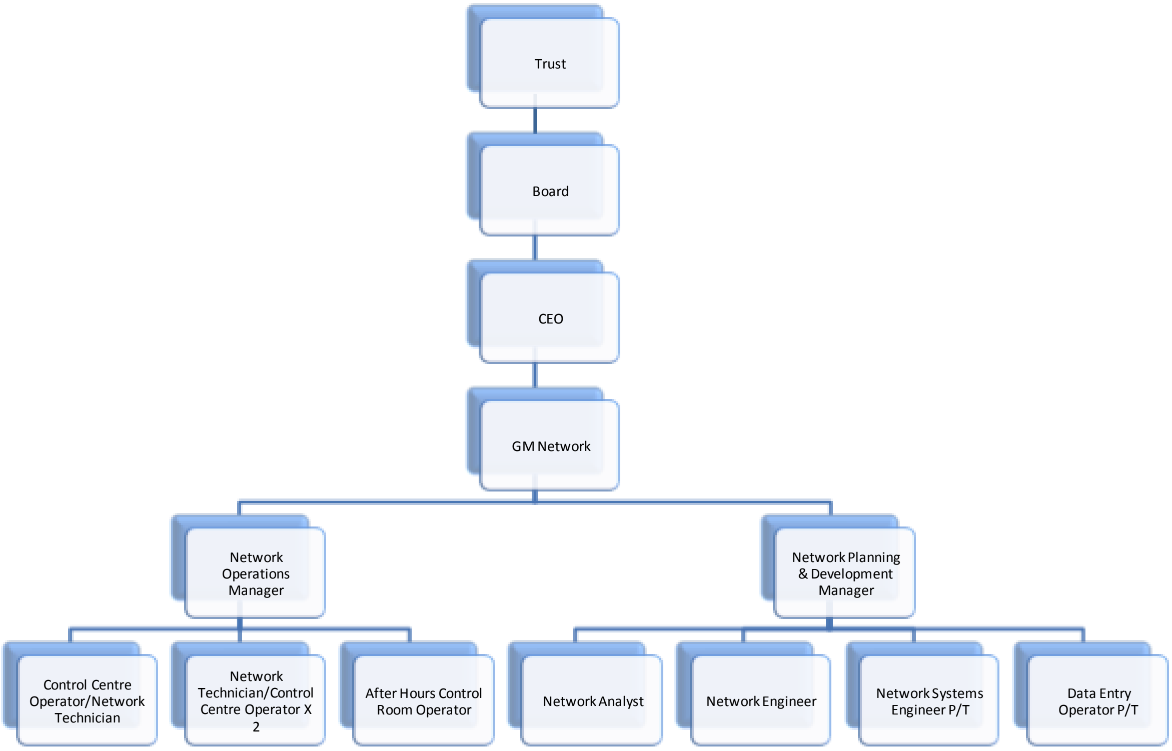


Figure 3.2: Organisational chart

The *Electra Trust* is elected by the consumers connected to the Electra network. They represent the interests of Electra's consumers and appoint the members of the *Electra Board*.

The *Electra Board* is responsible for the direction and control of the Company, including business plans and the AMP. Asset management performance (including capital and maintenance works completed, and progress against budget) and quality statistics are reported to the Board monthly.

The Board approves the annual development and maintenance plans during the annual budgeting process. Specifically they:

- Provide leadership, direction and governance including the Statement of Corporate Intent;
- Approve the overall strategic plan;
- Approve the overall Asset Management Plan
- Approve the Annual Network business Plan;
- Approve annual maintenance and capital budgets;
- Approve major work in excess of the CEO's authority ($500,000);
- Note works projects below the CEO's authority ($500,000); and
- Note/monitor expenditure against budget monthly.

The responsibility for the management of the network is through the *Chief Executive*. The day to day management is delegated via the *Chief Executive* to the *General Manager–Network and Commercial* who is responsible for network outcomes including capacity, security, reliability, voltage and safety. Specifically the CEO and GM – Network and Commercial:

- Develop the overall strategic plan;
- Review the AMP for Board approval
- Ensure the AMP's alignment with the Company's strategic direction;
- Review the Annual Network Business Plan for Board approval;
- Review the annual maintenance and capital budgets for Board approval;
- Approve major work in excess of the Network Team's delegated authority limit ($200,000);
- Note works projects below Network Team's delegated authority limit;
- Review expenditure against budget;
- Report progress of works programme to the Board monthly;
- Ensure disclosure requirements are complied with; and
- Approve any planned work exceeding a value of $50,000 and any unplanned work exceeding a value of $10,000.

The *Network Team* have the following responsibilities:

- Develop and manage the AMP including alignment with the Board's strategic direction;
- Develop and manage the Annual Network Business Plan, including the Annual Works Programme;
- Develop and manage annual maintenance and capital budgets;
- Develop and manage projects outlined in the AMP by ensuring timely delivery of Annual Works Programme to key contractor;
- Manage expenditure against budget by maintaining regular informal and formal contact with key contractor;
- Co-ordinate development and maintenance of Plans with the CEO and the Finance Team; and
- Maintain Plans to ensure they are up-to-date and relevant.
- Highlight operational and planning issues requiring action on a weekly basis

The above are supported by the *Finance Team*, who specifically:

- Develop the annual maintenance and capital budgets with the Network Team;

- Review expenditure against budget; and
- Maintain the financial models to ensure financial information is up-to-date for decision-making.

Electra has recently brought its former contracting subsidiary back in-house to enable a stronger focus on Electra work. Electra Distribution Operations is Electra's key contractor and the majority of works under this plan will be completed by Electra's Distribution Operations staff under performance based agreements.

Subcontractors are also engaged drawing from existing contractors already approved to carry out work on the network for third parties or from specialists approved on a contract by contract basis.

Other parties contracted for work directly by Electra are

- ICONA Ltd of Ashhurst who manage and maintain SCADA and Control Centre radio communications. ICONA provide similar specialised support for a number of other EDB's
- Callcare of Blenheim who provide Call Centre and minor fault management services to Electra and a number of other EDB's, effectively pooling the resources enabling greater flexibility and capacity to handle events.
- Eagle Technology of Wellington for GIS support for the ESRI system used by a number of other EDB's and Local Authorities.

3.6 Asset management systems and processes

Electra uses a number of asset management systems to facilitate best practice asset management. Table 3.3 below summarises Electra's asset information systems:

System	Data Held	What data is used for
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
iPad	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
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
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
Valuation Spreadsheets	Asset types, quantities, ages, expected total lives, remaining lives and values	Used for system fixed asset valuations
Paper & Electronic Documents	Miscellaneous records, design and operational files	Used to support GIS (NIMs) data

Table 3.3: Electra's asset information systems

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	Asset Information Held	Information Quality
33kV Lines	Size and Material	Accurate
	Age	Accurate to within 6 mths
33kV Cables	Size and Material	Accurate
	Age	Accurate to within 3 mths
11kV Lines	Size and Material	Accurate
	Age	Accurate to within 6 mths post 1995 Accurate to within 5 yrs pre 1995
11kV Cables	Size and Material	Accurate
	Age	Accurate to within 3 mths post 1995 Accurate to within 5 yrs pre 1995

400V Lines	Size and Material	Accurate post 1995 70% accurate pre 1995
	Age	Accurate to within 3 mths post 1995 Accurate to within 5 yrs pre 1995
400V Cables	Size and Material	Accurate
	Age	Accurate to within 3 mths post 1995 Accurate to within 5 yrs pre 1995
Poles	Size and Material	Accurate
	Age	Accurate to within 3 mths post 1995 Accurate to within 5 yrs pre 1995
Pillars	Type and Material	Accurate
	Age	Accurate to within 3 mths post 1995 Accurate to within 5 yrs pre 1995
Transformers	Rating, Manufacturer, Age	Accurate
RMU's	Rating, Manufacturer, Age	Accurate
Circuit Breakers	Rating, Manufacturer, Age	Accurate
Other Switches	Rating, Manufacturer	Accurate
	Age	Accurate to within 3 mths post 1995 Accurate to within 5 yrs pre 1995

Table 3.4: Electra's asset data

Asset condition information is recorded as part of the regular inspection cycle as described in section 6.2.Figure 3.5 shows how the various asset management systems that Electra uses interact with each other.

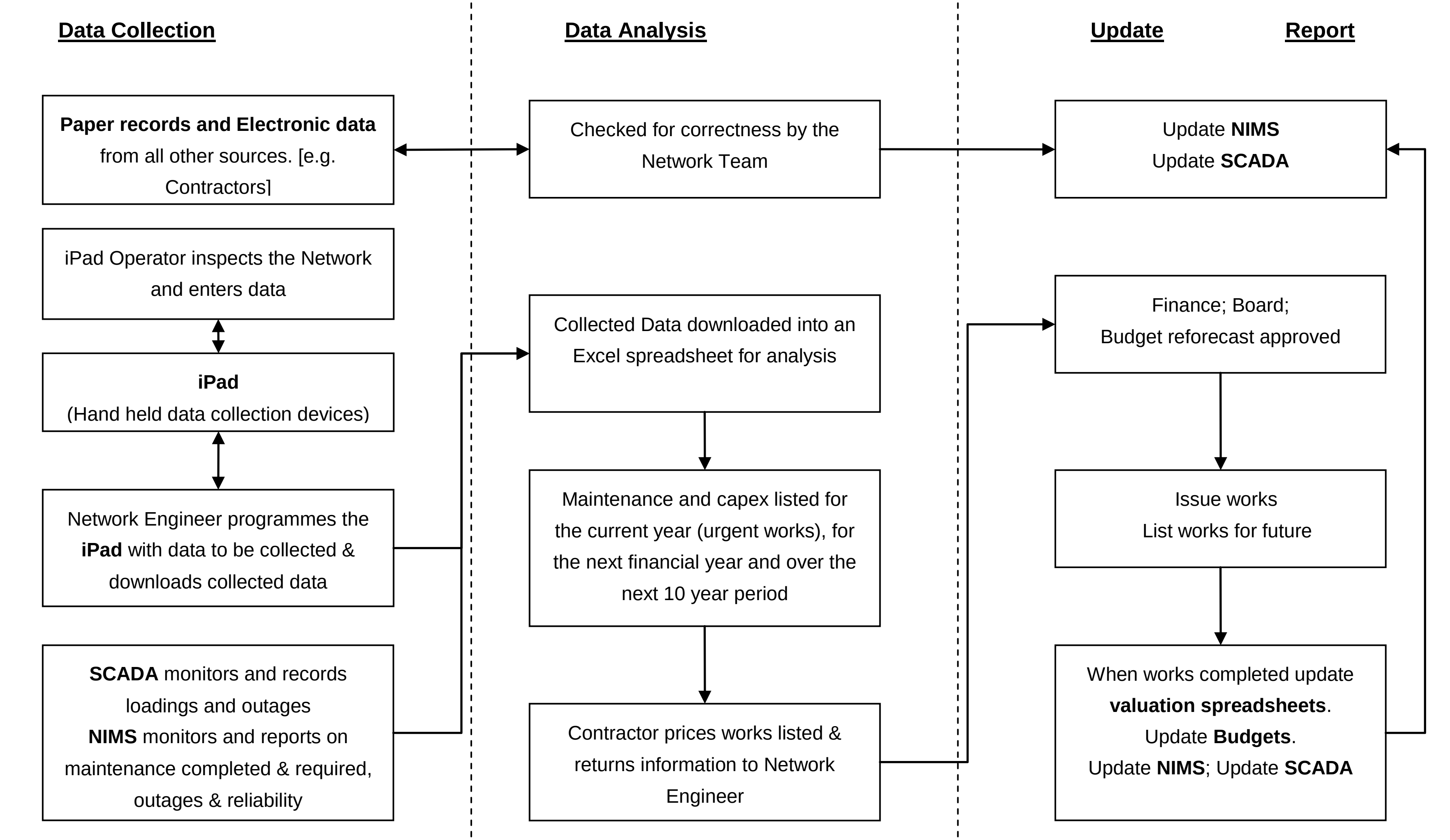


Figure 3.5: Interaction between asset management systems

Electra has identified that its asset age information for 11kV and 400V circuits is incomplete for assets that were installed prior to 1 April 1995. To overcome this, an average weighted age was applied to each asset based on the associated transformers. This is not ideal, as transformers and circuits are installed and replaced independently of each other. During 2010 Electra undertook re-estimating the age of each asset based on the type of line or cable in use and believes this has resulted in a more accurate age profile for circuits installed prior to 1 April 1995. All circuits installed or replaced since then have had installation dates recorded against each asset in NIMS. Over time this information will become accurate as old assets are replaced with new assets.

No other gaps in information have been identified. Any assets that do not match that recorded in Electra's systems will be identified (and records updated) as part of the inspection programme.

The processes for key network information tasks are described below:

3.6.1 Managing routine asset inspections and network maintenance

Annual asset information is stored electronically within the network management group. All individual equipment classes are contained within their own folders within the year of inspection. Inspections since 2005 have been captured electronically and stored for use with the GIS software. Previous inspection data is stored in spreadsheets. More specific detail about asset inspections and network maintenance policies and programmes are provided in section 6.2.

3.6.2 Planning and implementing network development processes

Development of the 11kV and 400V distribution network is usually driven by private development needs. These may in turn point to an area of the existing network which needs to be developed, strengthened or have additional 11kV feeders constructed from a zone substation to supply the expected forward demand.

System load analysis is undertaken to ensure that the expected forward load may be able to be supplied from the existing network after a simple reconfiguration (and for how long). If the analysis identifies that the system cannot meet the forward load, then Electra investigates whether the lines and/or cables need to be up-sized to cope with the additional load, or whether an additional 11kV supply is required from the nearest zone substation. At the same time, security of supply to the added area is explored. This applies to areas of the network including zone substations and the 33kV sub-transmission network.

All the possible and reasonable solutions are explored before a decision is made as to the final working solution. On large jobs such as zone substation rebuilds, external consultants are used to explore the various options. Projects are approved by staff with the appropriate delegated authority limit (refer to section 3.5 regarding accountabilities). Post job reviews are completed to ensure compliance with job specifications.

3.6.3 Measuring network performance (SAIDI etc)

All 33kV and 11kV outage information is entered in NIMS into the Incident Tracking programme. NIMS is able to produce reports on these incidents; one group of which are associated with SAIDI, SAIFI and CAIDI.

Data relating to the asset replacement is entered directly into the NIMS GIS data set. Reports are then able to be created showing progress against plan. This data is cross-checked against the accounting system asset register to provide quality assurance.

4 Assets Covered

4.1 High-level description of the distribution network

4.1.1 Distribution area

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

Figure 4.1: Network coverage area

The population of Electra's network area is about 79,500 up from 76,000 in 2007. The Horowhenua District has grown by 0.8% in the last 7 years while the Kapiti District has grown by 6.3% during the same period albeit at a slower rate over the past 3 years. This has been largely due to the impacts of slower economic growth.

Key energy and demand figures for the year ending 31 March 2015 are as follows:

Parameter	Value for Year Ending 31/3/15	Long-term trend
Energy conveyed	402 GWh	Decreasing
Coincident maximum demand	89.0 MW	Decrease over last year, overall trend is static but is dependent on temperature
Load factor	55.5%	Increased compared with prior years. Largely dependent on maximum demand
Distribution Transformer Capacity utilisation	27.0%	Lower than previous year - Largely dependent on maximum demand
ICPs	44,511	Increasing by 200-300 per annum

Table 4.1: Energy & demand statistics

4.1.2 Significant large consumers

Electra does not have large industrial consumers of the size typically found on many other networks. Electra's largest consumers in no particular order are:

- Alliance Group Limited, Levin (meat processors);
- Carter Holt Harvey, Levin (packaging manufacturer);
- Kapiti Coast District Council (sewage and water treatment);
- Pak'n'Save, Paraparaumu (supermarket);
- Unisys NZ, Paraparaumu (data processing).
- Kiwirail, Kapiti Coast (suburban transportation)

Together they represent less than 5% of the total usage on Electra's network. This presents a risk profile that is significantly less than the national average of 20% for the 5 largest connections for EDB's. Individually they do not significant impact on network operations or development. Each consumer's future demands and security needs are periodically discussed during Electra's normal consultative processes and where appropriate, specific needs are factored into the AMP.

4.1.3 Description of the load characteristics for different parts of the network

Electra's supply area, while contiguous, comprises of two distinct and different demographic and economic profiles along geographical lines as follows:

- The southern area located around the towns of Paraparaumu and Waikanae is heavily urbanised and relatively affluent, being the popular northern suburbs of Wellington that are within easy commuting distance of the capital. The southern area is essentially a dense suburban area that includes some light industry, an increasing number of big-box retailers, professional services and extensive growth of residential housing. This is evidenced by the lowest overall kWh consumption per consumer of all New Zealand networks. The key electrical characteristic of this area has formerly been the need for up-sizing existing assets due to high-density in-fill. This has now changed with reduced growth.
- The northern area located around the towns of Levin, Shannon and Foxton is predominantly rural and is characterised by horticulture and by some agriculture related commercial load. The urban areas have a strong rural services base. Some resurgence of niche services such as tourism and antiques is emerging in the smaller towns such as Shannon and Foxton. The northern area’s economy remains closely tied to vegetable and dairy prices.

4.1.4 Peak demand and total electricity delivered

Non coincident peak loads for the year ended 31 December 2015 for each GXP are shown by the following table:

GXP	Summer (Peak MW) October - March	Winter (Peak MW) April - September
Mangahao	31.164	32.538
Paraparaumu	44.986	61,092

Table 4.2: Peak demands by GXP

The electricity delivered for the year ending 31 March 2015 for Mangahao GXP was 175.5 GWh, and for Paraparaumu GXP was 266.9 GWh. The peak demand by zone substation for the year ended 31 December 2015 was:

Zone Substation	Peak MW
Shannon	4.2
Foxton	6.8
Levin East	13.7
Levin West	13.5
Otaki	10.6
Waikanae	14.4
Paraparaumu	12.5
Paraparaumu West	13.4
Raumati	10.2
Paekakariki	2.5

Table 4.3: Zone substation peak demands

4.2 Network configuration

4.2.1 GXP and 33kV embedded generation

The Electra network is supplied from two Transpower GXPs. Electra's northern network takes 33kV supply via four circuits at Mangahao GXP which is adjacent to the Mangahao hydro power station in the foothills of the Tararua Ranges, approximately 5km east of Shannon. Electra has concerns in the short to medium term about capacity, security, reliability and voltage when it is required to supply the Otaki zone substation from Mangahao. These will be addressed when the existing switchyard is rebuilt (expected 2020)

The Mangahao Power Station is the subject of a Generation Connection Agreement between Electra and the Joint Venture Partners Todd Energy and King Country Energy with the purpose of sharing transmission benefits resulting from the demand reduction at the Grid Exit Point. Operational control of the station has not changed except that generation is focused where possible around regional co-incident peaks.

Electra's southern area takes 33kV supply via five circuits from Paraparaumu GXP which is situated on the hillside above Paraparaumu. Due to the relatively high growth in this area of Electra's network, prudent and timely up-sizing of the GXP assets to maintain capacity, security, reliability and voltage has been seen as an on-going challenge for Electra and Transpower. The creation of a new highway access to Wellington has enabled the upgrading of this site to almost double the original capacity with direct connection to the 220kV transmission lines running between Manawatu and Wellington. This project was completed in the 2014/2015 financial year.

GXP	Winter Firm Capacity (MVA)	Current peak Load (MW - 2015)
Mangahao	30.00	32.54
Paraparaumu	120.00	61.09

Table 4.4: Firm capacity of GXP's

Electra's southern network load is predominantly domestic and shows a marked variation between summer and winter. Many Kapiti Coast residents commute to Wellington which adds to the evening peak as there is little commercial load during the day. This would result in the lowest load factor in New Zealand if the southern area were a standalone network.

In the northern area of the network there is a much more typical load pattern due to a higher portion of commercial load and domestic consumers living and working in the same geographical location. The variation between summer and winter loads is also less marked due to increased irrigation offsetting heating loads.

Typical daily load profiles for each GXP in both summer and winter are shown in the graph below.

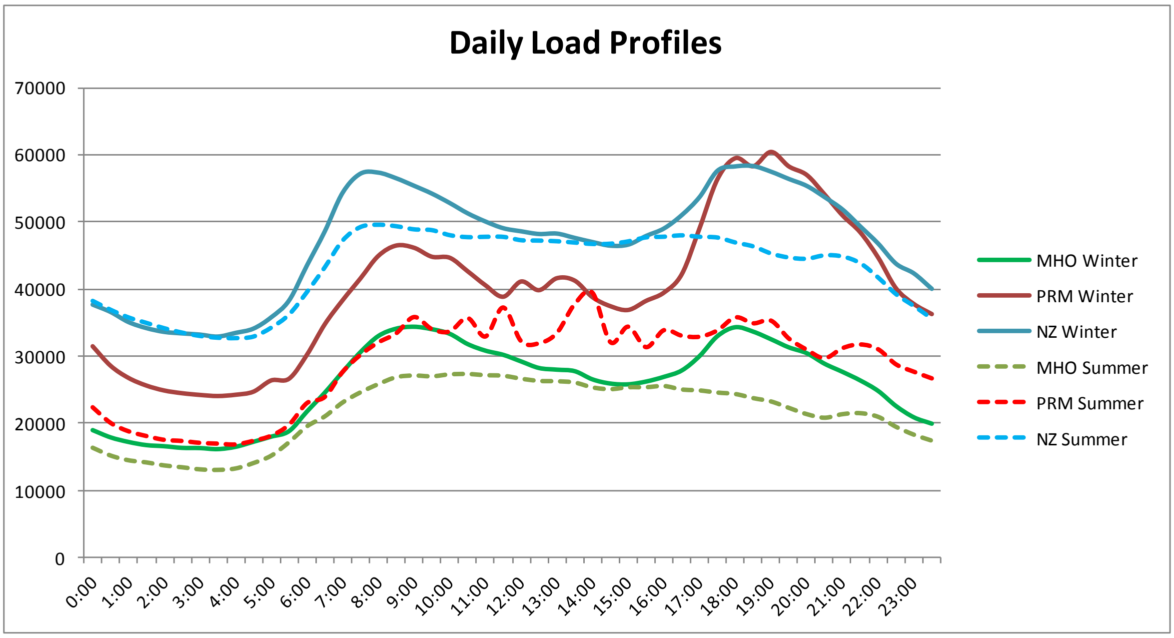


Figure 4.2: GXP Typical Daily Load Profiles

4.2.2 Description of the sub-transmission system

The 33kV sub-transmission network is based on a ring topology. The northern network (supplied from Transpower's Mangahao GXP) consists of four 33kV circuits. After heading west along a narrow gorge from Mangahao the four circuits spread out into an enmeshed network supplying Zone Substations at Shannon, Foxton, Levin East and Levin West. Each Zone Substation has 33kV connections to at least one other Zone Substation in addition to its normal supply from Mangahao GXP.

The southern network (supplied from Transpower's Paraparaumu GXP) consists of three 33kV overhead lines and two 33kV underground cables which form an enmeshed network supplying Zone Substations at Paraparaumu, Paraparaumu West, Raumati and Waikanae. A 33kV spur line runs south to supply Paekakariki.

Single 33kV lines between Levin East (northern network) and Waikanae (southern network) supply Otaki Zone Substation, with supply normally being taken from Waikanae for transmission efficiencies.

The network configuration ensures that Electra has continuous (n-1) security of supply at most of its substations barring Paekakariki which has an alternative 11kV supply from Raumati substation via automated switches. Switched (n-1) security of supply can be applied at all of these sites.

There are no known systemic issues with the 33kV network and assets are expected to operate for their full expected lifecycle.

Electra’s network includes the following ten zone substations:

Zone Substation	Description	n-1 Security	ICP’s Supplied	Nature of Load
Shannon	Substantial dual-transformer indoor substation built in 2010.	Y	1911	Mix of urban load in Shannon and rural load toward Tokomaru and Opiki.
Foxton	Substantial dual transformer high-level (steel structure) outdoor substation that was significantly rebuilt in 2004.	Y	3510	Predominantly urban load in Foxton with some rural load in all directions.
Levin East	Substantial dual transformer high-level (steel structure) substation built in 1990.	Y	5611	Predominantly urban, although with some rural load to the south and east of Levin.
Levin West	Substantial dual transformer high-level (steel structure) substation built in 1974.	Y	5958	Predominantly the rural areas to the north and west of Levin, Waitarere Beach, some urban load in the western parts of Levin.
Otaki	Substantial dual transformer indoor substation built in 1994	Y	6032	Predominantly urban load in Otaki with some rural load in Otaki Gorge, Manakau, Te Horo and Waikawa Beach.
Waikanae	Substantial dual-transformer indoor substation built in 1996	Y	6977	Dense urban load in and around Waikanae.
Paraparaumu	Substantial dual-transformer high-level (concrete pole) outdoor substation built in 1970.	Y	4469	Dense urban load in the eastern and central parts of Paraparaumu, some minor rural load on the immediate outskirts of Paraparaumu.
Paraparaumu West	Substantial dual-transformer indoor substation built in 2002.	Y	5271	Dense urban load in central and western parts of Paraparaumu.
Raumati	Substantial dual-transformer high-level (steel structure) outdoor substation built in 1988	Y	3860	Dense urban load in and around Raumati.
Paekakariki	Minimal single transformer high-level outdoor substation built 1982	N (Switched via 11kV)	912	Mix of light urban and semi-rural load around Paekakariki.

Table 4.5: Electra’s zone substations

Note that the total number of ICP's supplied as noted in this table may be different than the number identified elsewhere in this document.
The following systemic issues have been identified with Electra's zone substations:

- Exposure to salt-laden air at Raumati and Paekakariki.

4.2.3 11kV Distribution network

Electra's distribution network is all 11kV, operated in a radial configuration with extensive meshing in urban areas to allow restoration in the event of faults. 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 became compulsory around 1970. Cable tends to be PILC aluminium conductor, whilst lines tend to be a variety of conductors (Bee, 19/0.064 Copper and 7/0.083 Copper), predominantly on concrete poles;
- Rural areas are mostly line (but with increasing lengths of cable). These lines are Gopher or 7/0.064 Copper on a mix of wood and concrete poles.

Electra has identified the following systemic issues with its distribution network:

- 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.
- Wind-borne pollutants tracking on porcelain insulators. Electra has standardised on polymeric insulators from 2013.

The characteristics of the distribution network by zone substation as at 30 March 2016 are summarised below:

Zone Substation	11Kv Distribution Network Length (kms)		
	Overhead	Underground	Total
Levin East	127	29	156
Levin West	123	22	145
Shannon	177	8	185
Foxton	112	14	126
Paraparaumu	30	36	66
Paraparaumu West	6	33	39
Raumati	12	13	25
Waikanae	64	38	102
Paekakariki	16	6	22
Otaki	187	35	222
Total	**854**	**234**	**1,088**

Table 4.6: 11kV distribution network length

4.2.4 Distribution transformers

Electra's distribution transformers range from rural 1-phase 5kVA pole-mounted transformers with minimal fuse protection, to 3-phase 1,000kVA ground-mounted transformers with ring main unit and circuit breaker protection. Transformers may provide electricity to single consumers, several consumers or many consumers. The distribution transformers managed by Electra (excluding network spares) as at 31 December 2015 are as follows:

Substation Rating	Pole Mounted (Quantity)	Ground Mounted (Quantity)	Total (Quantity)
1-phase 5kVA	1	0	1
1-phase 10kVA	9	0	9
1-phase 15kVA	19	0	19
1-phase 30KVA	4	1	4
1-phase 100kVA	2	0	2
3-phase 7kVA	2	0	2
3-phase 10kVA	3	0	3
3-phase 15kVA	83	0	83
3-phase 25kVA	7	0	7
3-phase 30kVA	864	24	888
3-phase 50kVA	364	56	420
3-phase 75kVA	2	0	2
3-phase 100kVA	209	101	310
3-phase 150kVA	2	1	3
3-phase 200kVA	26	198	224
3-phase 250kVA	0	19	19
3-phase 300kVA	6	420	426
3-phase 500kVA	1	79	80
3-phase 750kVA	0	14	14
3-phase 1000kVA	0	7	7
Total	**1,604**	**920**	**2,523**

Table 4.7: Distribution transformer statistics

Electra has identified the following systemic issue for its distribution transformers;

- Electra continues to experience problems with corrosion of ground mounted transformer enclosures and as a consequence this asset type is often replaced after only 30-40 years of service

4.2.5 400V network

Electra's 400V coverage varies within the network. 400V tends to totally overlay the 11kV network in the central business districts (CBDs) and suburban areas. However, in rural areas the 400V tends to only cover about a 300m radius around each distribution transformer due to the issues associated with voltage drop.

In rural areas 400V is exclusively radial with no meshing. In urban areas the 400V network is similarly radial but the increased density of transformers means that many consumers are likely to be within the acceptable voltage drop distance of two transformers, hence limited meshing is possible at times. The limitation is usually related to distance rather than transformer loading.

Electra's 400V network construction is as follows:

- In CBD areas the 400V network is almost solely cable;
- In suburban areas the 400V network tends to be under-built overhead line in the older areas (original installation before 1960) of the network and underground cables in the newer areas (post 1960);
- In rural areas the 400V network has historically been solely overhead line, however it now increasingly includes underground cable laid in more recent lifestyle developments.

The following table shows the length of underground versus overhead installed for the 400V network as at 30 March 2016.

Zone Substation	400V Network Length (kms)		
	Overhead	Underground	Total
Levin East	91	57	148
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	109	154
Paekakariki	10	5	15
Otaki	99	58	157
Total	**507**	**480**	**987**

Table 4.8: 400V network length

Electra has identified the following systemic issues for its 400V network

- Early (pre 1970) 400V cables are experiencing failures in their underground tee joints. This results in entire sections of cable having to be replaced.
- Older (1960's & 1970's) steel pillars are corroding at ground level.

4.2.6 Consumer connections

The consumer connection assets connect Electra's 43,926 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 following systemic issue with consumer connections has been identified:

- Electra has had to replace some earlier generation pillars formed from thin grade steel and non UV stabilised polymers due to corrosion and material deterioration effects. The bulk of this work has been completed and normal lifecycle durations are expected from now on.

4.2.7 Load control

Electra currently owns and operates the following load control transmitter facilities for the control of ripple relays:

- 1 Zellweger SFU-K/203 80 KVA ripple injection plant located in the Shannon Zone Substation to cover the northern area. This plant was installed in 2011 as part of the substation rebuild.
- 1 Zellweger SFU-G/60 60 KVA ripple injection plant located in an Electra building on-site at the Transpower Paraparaumu GXP This plant was installed in 1994.
- 1 Zellweger SFU-K/203 80 KVA ripple injection plant in storage at Paraparaumu West Substation. This acts as a backup for the both plants

These plants are similar and based on the Zellweger MLC Local Controller and the SFU- static frequency converter. Low voltage supply to each plant is from the local 415 V AC station supply transformer. Injection from each plant is into the Electra 33 kV sub-transmission system at 283Hz. The majority of the individual ripple control receivers are owned by energy retailers with the exception of approximately 2,500 mounted in distribution transformers and on poles to control the streetlights, under veranda lighting and controlled load pilot systems. These are owned by Electra.

4.2.8 Protection and control

Electra's network protection includes the following broad classifications of assets:

- CB protection relays including over-current, earth-fault, sensitive earth-fault and auto-reclose functions as well as more recent equipment which include voltage, frequency, directional, and distance, bus zone and CB fail functionality;
- Transformer and tap changer temperature sensors including surge arrestors, explosion vents and oil level sensors.

Batteries, battery chargers and battery monitors provide the DC supply systems for circuit breaker control, protection and SCADA functionality.

Electra has standardised on the Eberle range of tap change controllers. These allow software updating of settings and they provide all of the analogue and digital information required on site and by SCADA.

4.2.9 SCADA and communications

Electra uses an iSCADA system for control and monitoring of zone substations and remote switching devices and for activating load control plant. This system was installed during the year ended 31 March 2010. The SCADA master station is located in the Levin West zone substation. SCADA information is then broadcast to the main Electra office in which the main Network Operating Control Centre is located. At the Levin West zone substation an Emergency Control Centre which is identical in systems exists as a backup to the main one.

SCADA control and monitoring information is communicated via radio and micro-wave links. The following sites are located and interlinked so as to provide a “fail safe” information data path. These sites also provide voice repeater links.

- Forest Heights at Waikanae;
- Mataihuka south of Paraparaumu;
- Moutere Hill west of Levin; and
- Levin West zone substation Control Centre.
- Tunapo at Paekakariki

4.2.10 Other assets

Since 2008 Electra has owned a 500 kVA 3 phase mobile diesel generator set. This is primarily used to provide electricity within the Electra network during planned and unplanned outages.

4.3 Network assets

A more detailed description of the network assets, including voltage levels, quantities, age profiles, values and condition is provided in the following sections.

A summary of Electra's asset allocations as at 31 March 2015 is provided below:

5e(i): Regulated Service Asset Values

	Value allocated ($000s) Electricity distribution services
Subtransmission lines	
Directly attributable	8,859
Not directly attributable	
Total attributable to regulated service	8,859
Subtransmission cables	
Directly attributable	6,214
Not directly attributable	
Total attributable to regulated service	6,214
Zone substations	
Directly attributable	25,796
Not directly attributable	
Total attributable to regulated service	25,796
Distribution and LV lines	
Directly attributable	27,198
Not directly attributable	
Total attributable to regulated service	27,198
Distribution and LV cables	
Directly attributable	35,111
Not directly attributable	
Total attributable to regulated service	35,111
Distribution substations and transformers	
Directly attributable	22,751
Not directly attributable	
Total attributable to regulated service	22,751
Distribution switchgear	
Directly attributable	7,920
Not directly attributable	
Total attributable to regulated service	7,920
Other network assets	
Directly attributable	10,847
Not directly attributable	
Total attributable to regulated service	10,847
Non-network assets	
Directly attributable	1,975
Not directly attributable	
Total attributable to regulated service	1,975
Regulated service asset value directly attributable	146,671
Regulated service asset value not directly attributable	–
Total closing RAB value	146,671

Table 4.9: Regulatory asset allocations

4.3.1 Assets owned at bulk supply points

The two 110kV/33kV GXPs at Mangahao and Valley Road are connected to the 110kV transmission lines between Bunnythorpe (Palmerston North) and Takapu Road (Porirua). Transpower own, operate and maintain all transmission assets which lead to the GXPs and the GXPs themselves. Electra owns the 33kV cables and lines downstream of the 33kV circuit breakers at the GXPs. These are included in section 4.3.2 below. Electra also has one of its Ripple signal injection plants located at but not within Paraparaumu GXP. This is included in section 4.3.10 below. All other equipment at the Grid Exit Points such as circuit breakers and protection equipment are owned and maintained by Transpower.

4.3.2 Sub-transmission network

The ten zone substations owned by Electra are connected to the two Transpower GXPs through a backbone of two 33 kV closed ring circuits. For a diagram showing the location of the two GXPs, the 33kV subtransmission network and the zone substations refer to Figure 4.1.

The Horowhenua 33kV ring, which is mainly overhead, links Shannon, Levin East, Levin West, and Foxton zone substations to the Mangahao GXP. The Kapiti 33kV ring which is a mixture of overhead and underground circuits, links Waikanae, Paraparaumu, Paraparaumu West, Raumati and Paekakariki zone substations to the Valley Road GXP. The zone substation at Otaki links the two closed 33kV rings together. A summary of the sub transmission circuits is provided below:

Sub-transmission Line	Length (km)	Conductor	Rating (Amps) Summer/Winter	Condition
Foxton to Levin West	14.8	Bee	360/474	Good
Levin East to Otaki	22.3	Butterfly	600/830	Good
Levin to Shannon	15.4	Butterfly	600/830	Good
Levin West to Levin East	6.3	Bee	360/474	Good
Mangahao to Waihou Rd 1	13.8	95mm2 Cu	400/464	Good
Mangahao to Waihou Rd 2	13.8	95mm2 Cu	400/464	Good
Waihou Rd to Levin East	4.3	Butterfly	600/830	Good
Mangahao to Shannon Circuit 1	4.6	Butterfly	600/830	Fair
Mangahao to Shannon Circuit 2	4.6	Butterfly	600/830	Fair
Otaki to Waikanae	15.1	Butterfly	600/830	Good
PRM GXP to Paekakariki	10.6	Butterfly	600/830	Good
PRM GXP to Paraparaumu	1.0	Butterfly	600/830	Good
PRM GXP to Waikanae	7.1	Butterfly	600/830	Good
Shannon to Foxton	16.0	Butterfly	600/830	Good

Table 4.10: Summary of the overhead sub-transmission circuits

The age profile of sub transmission lines (33kV) as at 31 March 2015 is shown in Figure 4.3 below.

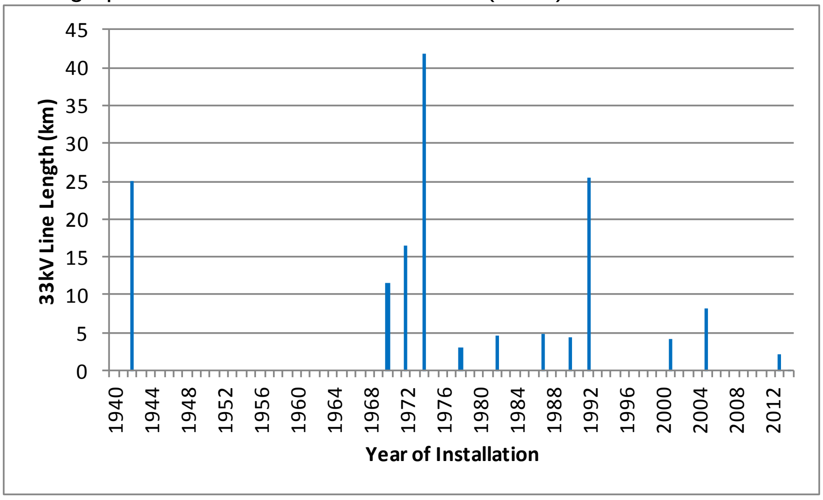


Figure 4.3: Age profile of sub-transmission circuits

Electra has assumed an average life expectancy of 52 years for this asset category. This means that using this assumed lifespan, some sections of the Mangahao to Levin East circuit have come to the end of their economic life. As such, based solely upon age, these spans would be overdue for replacement within the planning horizon. However, as discussed in section 6.2.2.1.1, the assets are subject to regular inspection and testing and are still regarded as in good condition. This condition will be reassessed once results from further samples sent for testing have been received. A summary of the main underground circuits is provided in the table below. Other circuits have small sections that are underground (usually coming in and out of GXP's or zone substations) however, are not included in this table.

Sub-transmission cable	Length (km)	Conductor	Installed	Rating (Amps)	Condition
Mangahao GXP to Shannon	4.0	630mm Al XLPE	2014	586A	Excellent
Mangahao GXP To Levin East	0.8	630mm Al XLPE	2014	586A	Excellent
Paraparaumu GXP to Waikanae (1)	1.2	630mm Al XLPE	1995	586A	Good
Paraparaumu GXP to Waikanae (2)	6.8 1.2	500mm Al XLPE and 630mm Al XLPE	1995	528A & 586A	Good
Paraparaumu GXP to Paraparaumu	1.1	630mm Al XLPE and	2015	586A	Excellent
Paraparaumu to Paraparaumu West	2.6	800mm Al XLPE	2003	586A	Excellent
Paraparaumu GXP to Paraparaumu West	1.1 2.6	630mm Al XLPE and 800mm Al XLPE	2003	586A	Excellent
Paraparaumu to Raumati	3.5	630mm Al XLPE	1998	586A	Good
Paraparaumu GXP to Raumati	1.3	630mm Al XLPE	1988	586A	Good

Table 4.11: 33kV cable summary information

The age profile of all 33kV cables as at 31 March 2015 is shown in Figure 4.4 below.

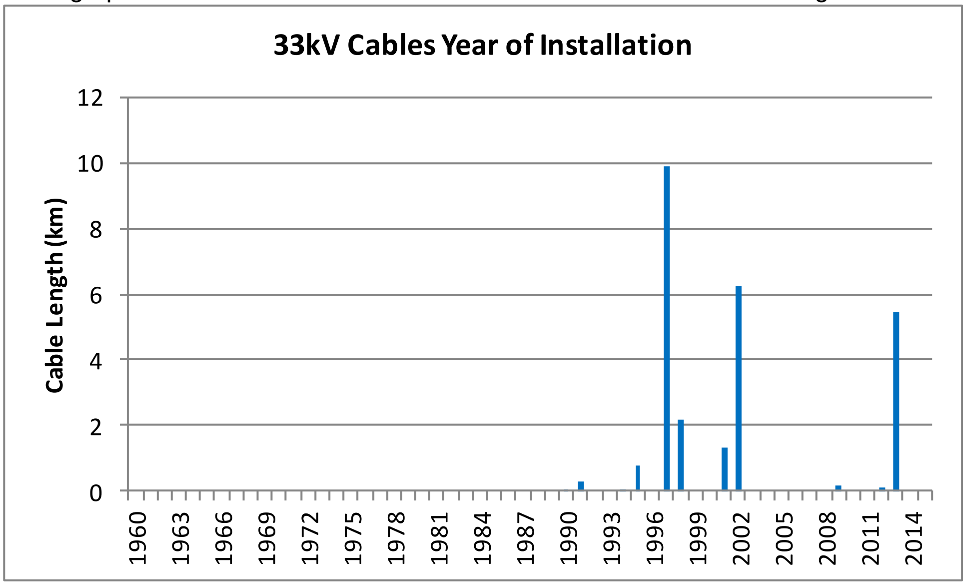


Figure 4.4: Age profile of the sub-transmission cables

Electra assumes an average life of 45 years for this asset. The figure shows that, solely based on age, no cable is due for replacement within the current planning horizon.

4.3.3 Zone substations

Zone substations have numerous and diverse range of individual assets. The major assets at any substation are the 33/11kV transformers, the 33kV and 11kV switchgear, the associated protection equipment and any installed load control injection plant.

All but one of the zone substations (Paekakariki), have dual transformer banks. The predominant transformer size on the Electra network is 11.5/23 MVA. (N-1) security of supply is provided to all consumers, although this may be achieved through automatic changeover schemes.

There are two spare units rated at 5/10MVA and 5MVA stored at Shannon substation.

Zone substation characteristics were presented earlier in Table 4.5. The following table provides more specific detail concerning the equipment contained in each substation.

Zone Substation	Transformer Capacity	33kV Circuit Breakers	11kV Circuit Breakers	Structure	Number of 11kV Feeders
Shannon	2 x 5 MVA ONAN	10 indoor SF6 circuit breakers	7 Reyrolle LMVP circuit breakers	Indoor 33kV switchboard	4
Foxton	2 x 11.5/23 MVA ONAN/ONAF	4 outdoor SF6 circuit breakers	7 Reyrolle LMVP circuit breakers	Outdoor 33kV structure	4
Levin West	2 x 11.5/23 MVA ONAN/ONAF	5 outdoor SF6 circuit breakers	9 Reyrolle LMVP circuit breakers	Outdoor 33kV structure	6
Levin East	2 x 11.5/23 MVA ONAN/ONAF	6 Outdoor SF6 circuit breakers	8 South Wales SF6 circuit breakers 1 Reyrolle LMVP circuit breaker	Outdoor 33kV structure	6
Otaki	2 x 11.5/23 MVA ONAN/ONAF	5 indoor SF6 circuit breakers	8 Reyrolle LMVP circuit breakers	Indoor 33kV switchboard	5
Waikanae	2 x 11.5/23 MVA ONAN/ONAF	6 indoor SF6 circuit breakers	9 Reyrolle LMVP circuit breakers	Indoor 33kV switchboard	6
Paraparaumu	2 x 11.5/18/23 MVA ONAN/ONAF/OFAF	5 outdoor SF6 circuit breakers 1 outdoor oil circuit breaker	9 Reyrolle LMT oil circuit breakers	Outdoor 33kV structure	6
Paraparaumu West	2 x 11.5/23 MVA ONAN/ONAF	5 indoor SF6 circuit breakers	8 Reyrolle LMVP circuit breakers	Indoor 33kV switchboard	5
Raumati	2 x 11.5/23 MVA ONAN/ONAF	5 outdoor SF6 circuit breakers	4 Yorkshire SF6 circuit breakers 3 Reyrolle LMVP circuit breakers	Outdoor 33kV structure	4
Paekakariki	1 x 5 ONAN	1 outdoor oil circuit breaker	4 Reyrolle LMT oil circuit breakers	Outdoor 33kV structure	3

Table 4.12: Summary of equipment in zone substations

4.3.4.1 Shannon substation

- Shannon substation, originally commissioned in 1924, was re-built in 1955 and again in 2011 although the two existing 5 MVA transformers were retained.
- The substation is in excellent condition.
- The scheduled three-yearly maintenance of transformers and circuit breakers is next due in the 2016/2017 financial year.

4.3.4.2 Foxton substation

- Foxton substation was originally built in 1970, extended in 1989 and extensively refurbished in 2005.
- The substation is generally in good condition.
- This refurbishment work included increasing the transformer capacity to two 11.5/23MVA ONAN/ONAF transformers

- The scheduled five-yearly maintenance of transformers, circuit breakers and structure is next due in the 2020/2021 financial year.

4.3.4.3 Levin West substation

- Levin West substation was built in 1976.
- The substation is generally in good condition.
- The 11kV feeder circuit breakers were frequently operated and these were retrofitted in 1998 with vacuum units to minimize maintenance costs and increase safety at the site.
- One 11.5/23MVA transformer was installed in 2000 and another 11.5/23MVA transformer was installed in 2011 to replace the second (5MVA) transformer.
- Routine five-yearly maintenance is next due in the 2017/2018 financial year.

4.3.4.4 Levin East substation

- Levin East substation was built in 1990.
- The substation is generally in good condition.
- In 2005, both 33kV/11kV transformers had a major tap changer overhaul and oil refurbishment on site.
- The scheduled five-yearly maintenance of transformers, circuit breakers and structure is next due in the 2019/2020 financial year.

4.3.4.5 Otaki substation

- Otaki substation was built in 1994.
- The substation is in good condition.
- Routine five-yearly maintenance of transformers and circuit breakers is next due in the 2018/2019 financial year

4.3.4.6 Waikanae substation

- Waikanae substation was built in 1996.
- The substation is in good condition.
- Routine five-yearly maintenance of transformers and circuit breakers is next due in the 2020/2021 financial year.

4.3.4.7 Paraparaumu substation

- Paraparaumu substation was originally built in 1970.
- The substation is generally in average condition.
- Routine maintenance of transformers, circuit breakers and the structure was last completed in the 2012/13 financial year.
- The two transformer OLTCs underwent a major overhaul in 2005 as a result of moisture and arcing compounds found during DGA analysis.
- A significant rebuilding of the substation is underway with expected commissioning in 2016. This includes removal of the old overhead structure and replacement of the outdoor 33kV SF6 circuit breakers and existing indoor 11kV oil circuit breakers with indoor vacuum types.

4.3.4.8 Paraparaumu West substation

- Paraparaumu West substation was built in 2003.
- The substation is in good condition.
- The substation is predominantly indoors barring the two transformers which are installed outside.
- Routine five-yearly maintenance of transformers and circuit breakers is next due in the 2017/2018 financial year.

4.3.4.9 Raumati substation

- Raumati substation was built in 1988.
- The substation is generally in good condition.
- Initially one 11.5/23MVA transformer was installed. A second 11.5/23MVA unit in 2012.
- A 33 kV bus protection scheme was installed during 2009/2010 to lessen the outage impact of any fault on the 33 kV outdoor busbar.
- The three yearly routine maintenance of the transformers, circuit breakers and structure is next due in the 2016/2017 financial year.
- Allowance has been made for the partial replacement (1/2 the 11kV switchboard and outdoor structure) of the substation toward the end of the planning period. The actual timetable will be determined by asset condition and ongoing maintenance costs.

4.3.4.10 Paekakariki substation

- Paekakariki substation was built in 1982.
- The substation is generally in good condition.
- Routine three yearly maintenance of transformers, circuit breakers and the structure is next due in the 2018/2019 financial year.

4.3.4.11 Zone substations in general

Zone capacity had previously been identified as nearing/exceeding present capabilities late in this decade. This coupled with the capacity restraints at the Transpower GXP'S led to Electra reviewing alternative transmission solutions to meet future growth needs. The works associated with the Transmission Gully highway upgrade have removed those constraints giving more certainty to Electra's future transmission and sub transmission arrangements. This will result in any growth being met by increased zone transformer capacity in the first instance, with increased sub transmission capacity attained in conjunction with the lifecycle replacement programme.

The following figure shows the age profile of the zone substation transformers.

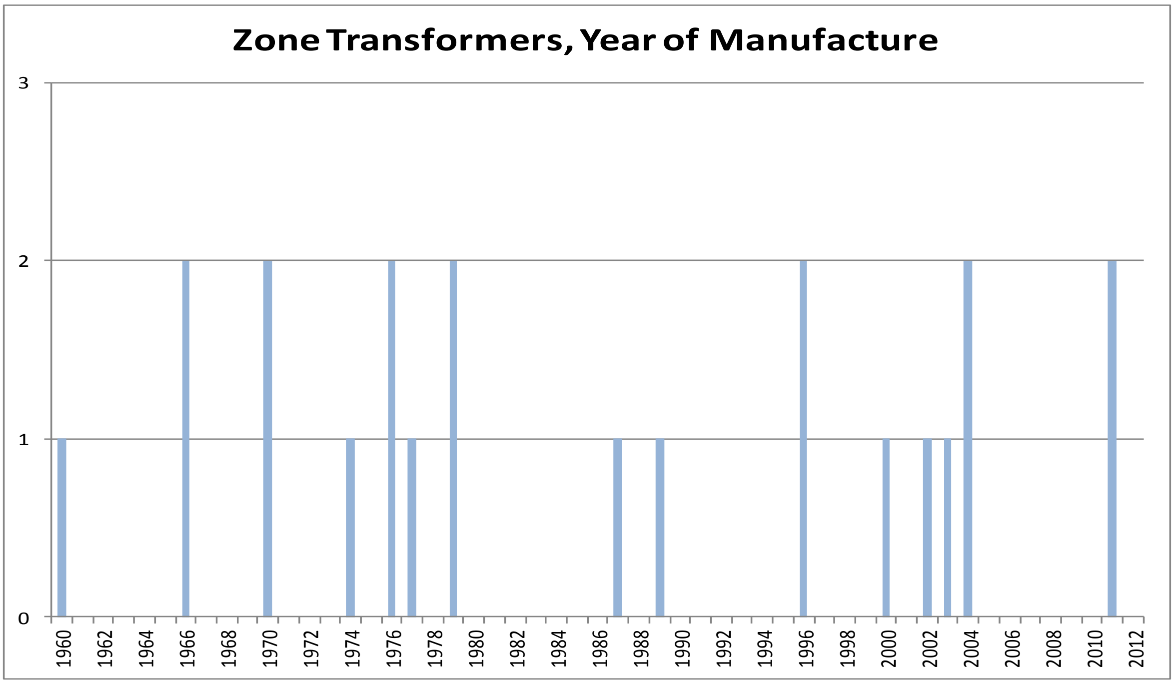


Figure 4.5: Age profile of zone substation transformers

The following diagram shows the age profile of the 33kV circuit breakers installed within zone substations.

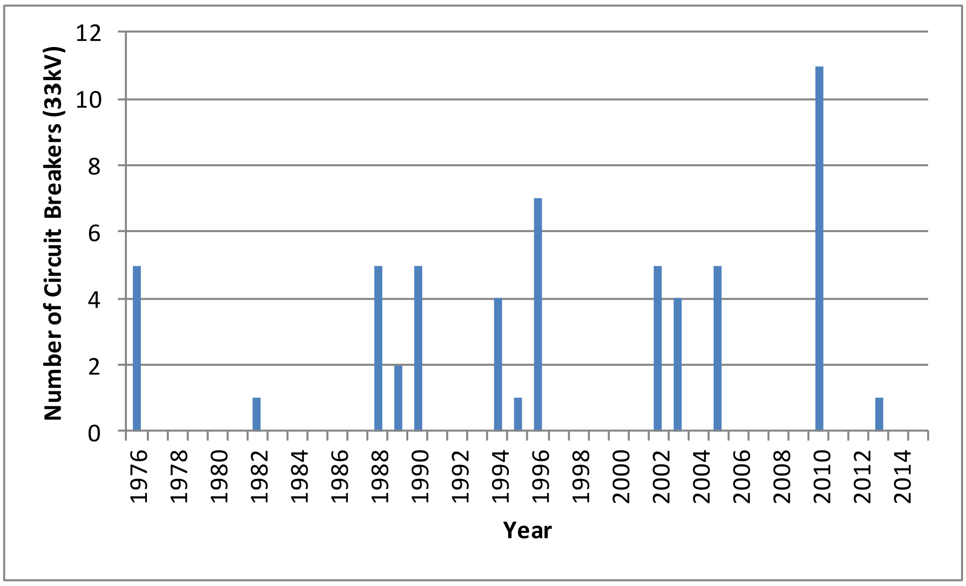


Figure 4.6: Age profile of 33kV circuit breakers

The following diagram shows the age profile of the 11kV circuit breakers installed within zone substations.

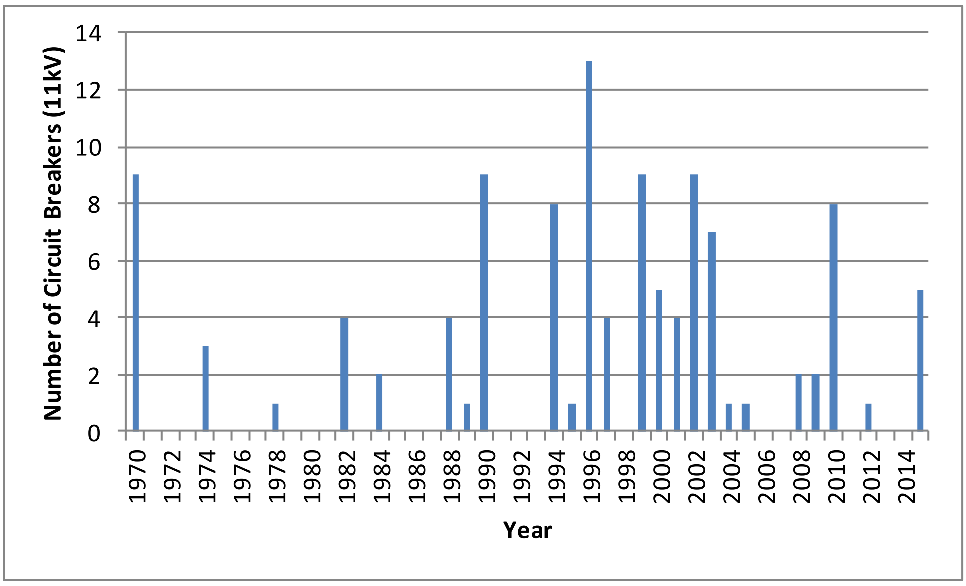


Figure 4.7: Age profile of 11kV circuit breakers

4.3.4 Distribution network

There are a total of 48 11kV feeders emanating from the zone substations, in clusters of three to six feeders from each zone substation, with the operating voltage set at 11.2kV at the zone substation busbars to compensate for voltage drop. Each circuit is a mix of overhead and underground circuits, depending on when the circuit was installed. All 11kV feeders are radial in operation, with interconnection to adjacent feeders, either on the same or adjacent zone substations. This aids in providing a secure supply to the majority of connected consumers.

4.3.4.1 <u>11kV Overhead lines</u>

Electra owns 786 kms of overhead 11kV lines. The overhead line construction is generally a three phase flat formation using hardwood crossarms on concrete poles with either aluminium or copper conductors. Prior to 1970, Electra extensively used copper conductors. Copper performs well in a windy coastal marine environment. Since then, Electra has used either AAC or ACSR aluminium conductors due to the additional costs of copper conductors and the corrosive resistant alloy aluminium conductors available. Over time, the backbone of the 11kV network will be completely replaced with AAC (Bee). All strain insulators are gradually being changed to polymers which have an improved performance.

Electra inspects 11kV circuits on a five yearly cycle, and considers that the 11kV overhead network is well built, well maintained and in good condition. A small number of poles and crossarms are replaced each year after inspection or to remedy third party damage.

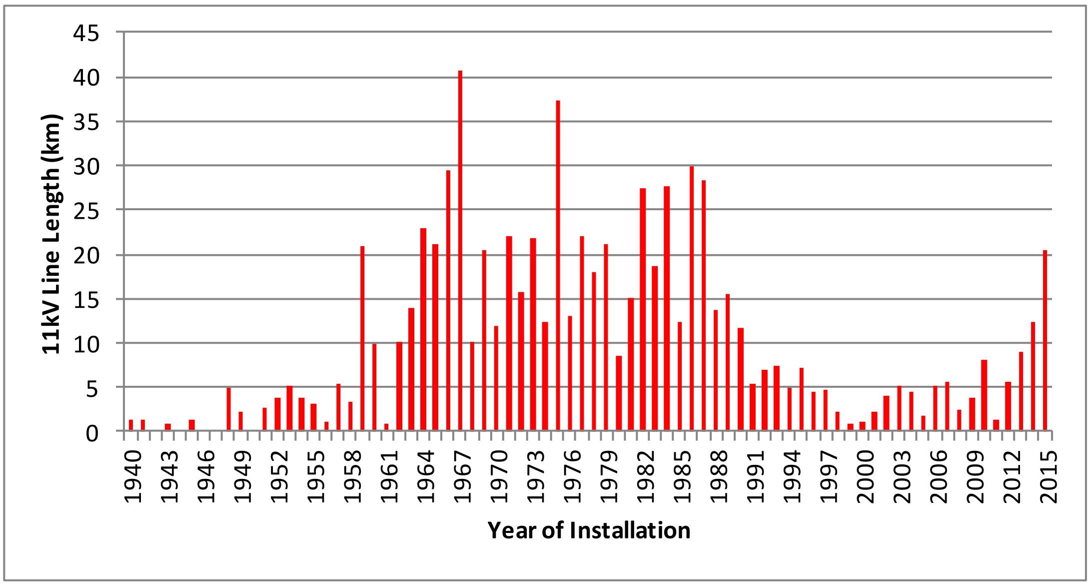


Figure 4.8: Age profile for 11kV lines

Electra assumes an economic life of 52 years for these assets.

4.3.4.2 <u>11kV Underground cables</u>

Electra has 239 kilometres of underground 11kV circuits. Cables are constructed as three-core cables, with a minimum cable size of 185mm^2 when feeding from zone substations. All 11kV feeder cables from zone substations are underground for at least some distance as all 11kV switchgear is indoor and this eliminates a potential source of conflict with 33kV circuits.

New 11kV and 400V circuits are generally installed underground.

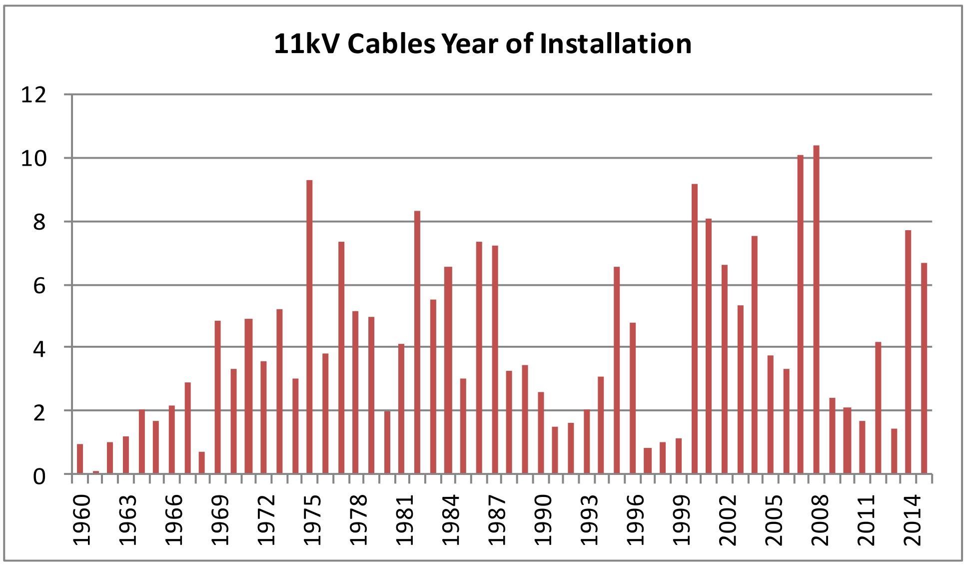


Figure 4.9: Age profile of 11kV cables

Electra assumes an economic life of 57 years for these assets.

4.3.5 Distribution transformers

These transformers are used to supply groups of up to 130 end use customers from the 11kV network. Details of transformer sizes and ratings were summarised earlier in Table 4.7.

All pole mounted transformers have a set of associated drop out fuses. Where these pole transformers are at the end of long spur lines, Electra installs a set of drop out fuses at the connection to the main 11kV line to improve fault location and isolation. Electra also aims to install a separate drop out fuse where access to the 11kV route is difficult.
Likewise, all ground transformers have either an associated drop out fuse or have local fuses installed in the 11kV cubicle.

Electra inspects all ground mounted transformers biannually. Pole mounted transformers are inspected as part of the 11kV network five yearly inspection cycle. The assets requiring replacement are identified from these inspections.

Electra generally does not undertake a structured refurbishment programme on distribution transformers which are less than 100kVA as this is not an economic option for these lower rated transformers.

The age profile of the distribution transformers by year of manufacture is shown below.

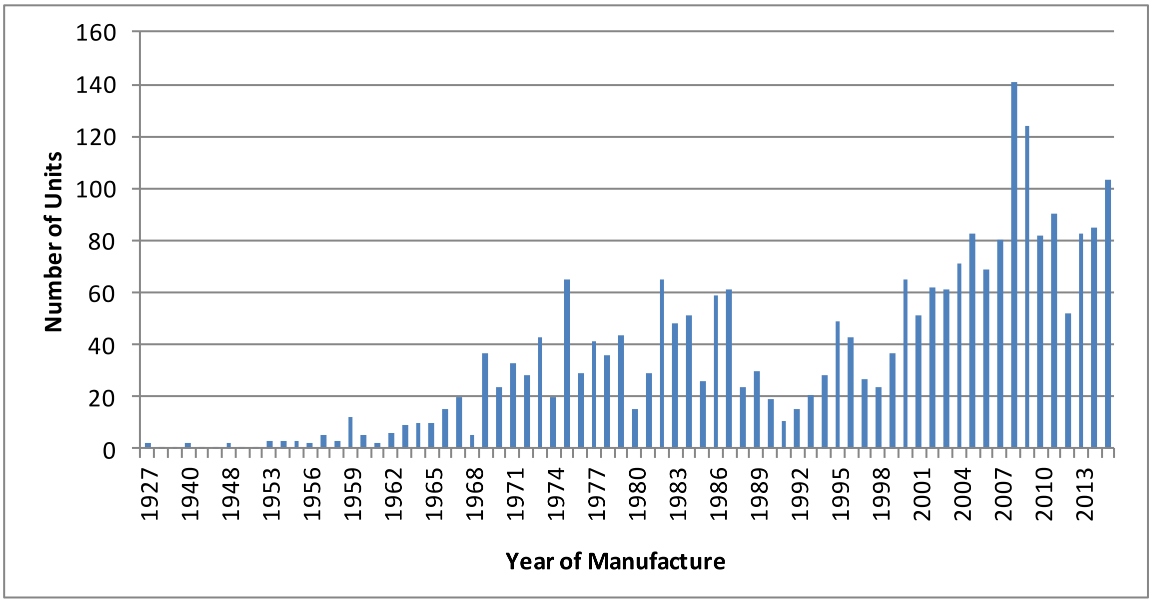


Figure 4.10: Age profile of 11kV/400V distribution transformers

Electra assumes an economic life of 45 years for transformers.

4.3.6 Distribution switchgear

In addition to the drop out fuses associated directly with a distribution transformer, Electra uses additional switchgear to provide isolation and automatic or manual sectionalising on the 11kV network. Total distribution switchgear on the network comprises:

Switchgear	Quantity
In line drop out fuses	668
Auto reclosers	35
Air break switches	345
Ground mounted switches	134
Total	1,112

Table 4.13: Distribution switchgear

Electra is reviewing the overhead and underground network in regards to sectionalisation and protection, in efforts to increase network reliability through greater flexibility in switching arrangements of the network.

Electra has not experienced any major issues with drop out fuses in recent years and efforts will be focused on installing more of these where spur lines connect to main through lines.

Electra visually inspects all ground-mounted switchgear and pole mounted equipment as part of the distribution transformer two year cycle.

Pole mounted switchgear is generally in good condition. However, there appears to be an increase in failures of air break switches which are inspected and maintained ‘live-line’ every three years. These tend to be either the older side swipe type or a certain ‘make’ of air break switches, in which water is causing metal to expand and break insulators. These account for many of the unplanned and preventative maintenance work being conducted this year. Replacements are now installed with polymeric insulators.

Due to failures in service of other networks ground mounted ring main units, and concerns raised by contractors, Electra undertook oil replacement and internal tank maintenance of all ground mounted oil filled ring main units on the network in the financial year ending 2010. This maintenance resulted in several outages for Electra consumers. Consequently, Electra expects to replace all oil filled switches with vacuum/gas types in the next 3 years.

The age profile of the distribution switchgear is shown below.

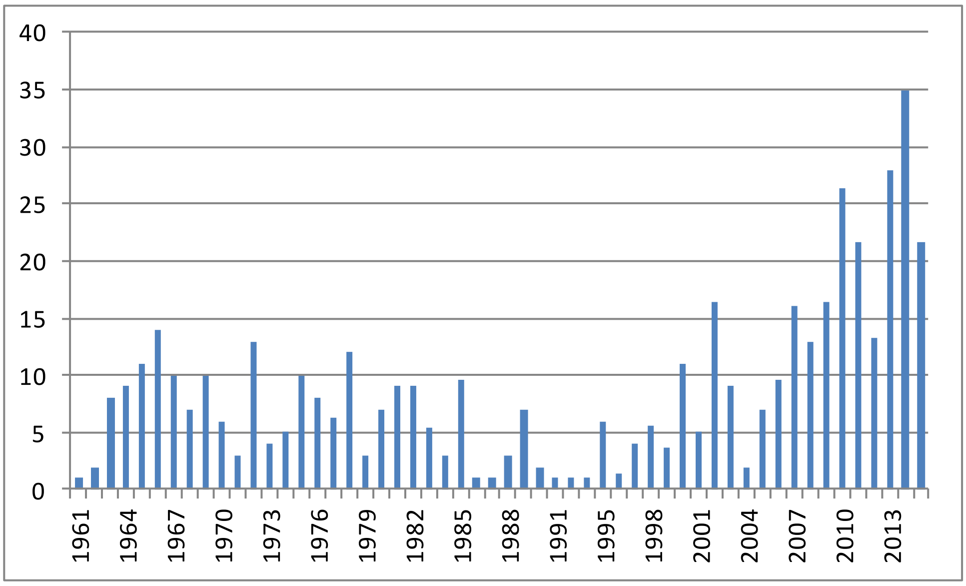


Figure 4.11: Age profile of 11kV distribution switchgear

4.3.7 400V network

The 400V network connects the transformers to the consumers through fuses located at service poles and pillars. Also included within this network are the street and community lighting circuits. Consumers are generally tapped off the 400V network, and fused at the boundary. There are 528km of overhead 400V lines and 479km of underground 400V cables, with 10,985 pillars and cabinets.

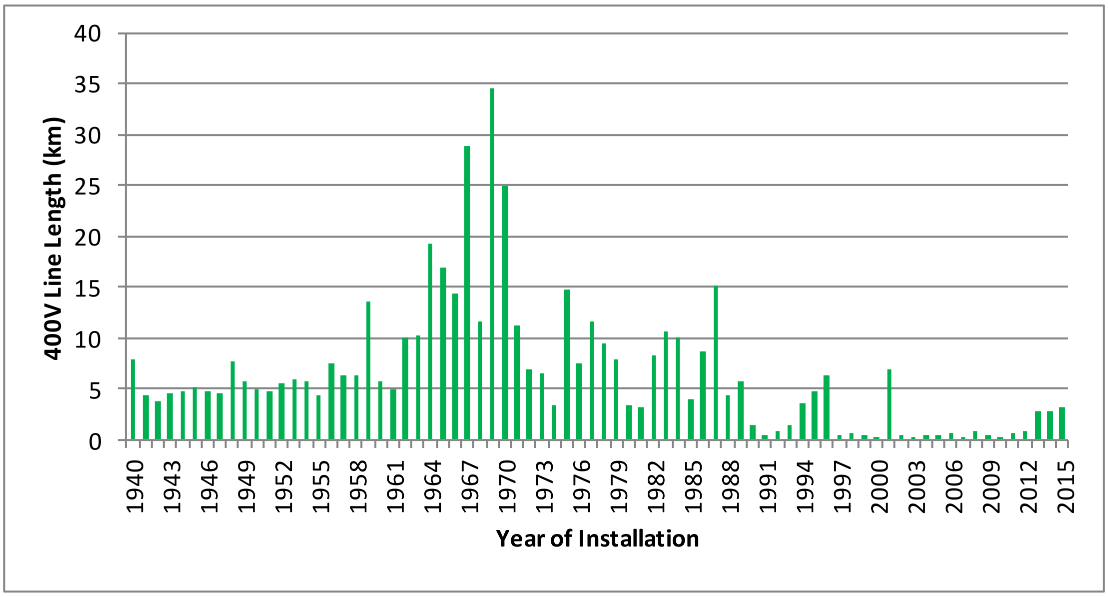


Figure 4.12: Age profile of 400V lines

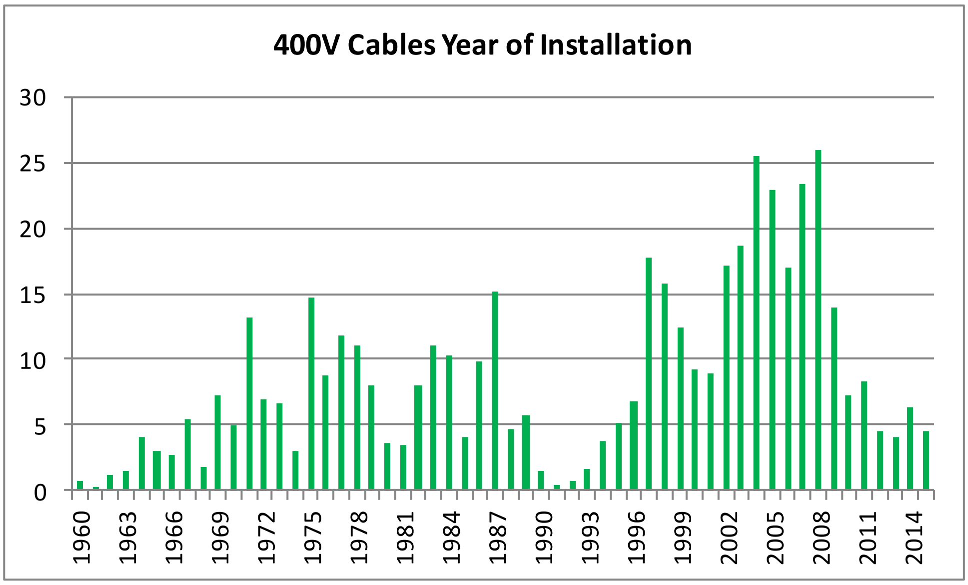


Figure 4.13: Age profile of 400V cables

All 400V pillars are inspected on a three year cycle and any damaged units replaced. The pillars need to be unobtrusive, have low initial costs and low maintenance costs. Generally installed as part of new subdivisions, most pillars are steel if installed prior to 1990 and PVC if installed after 1990.

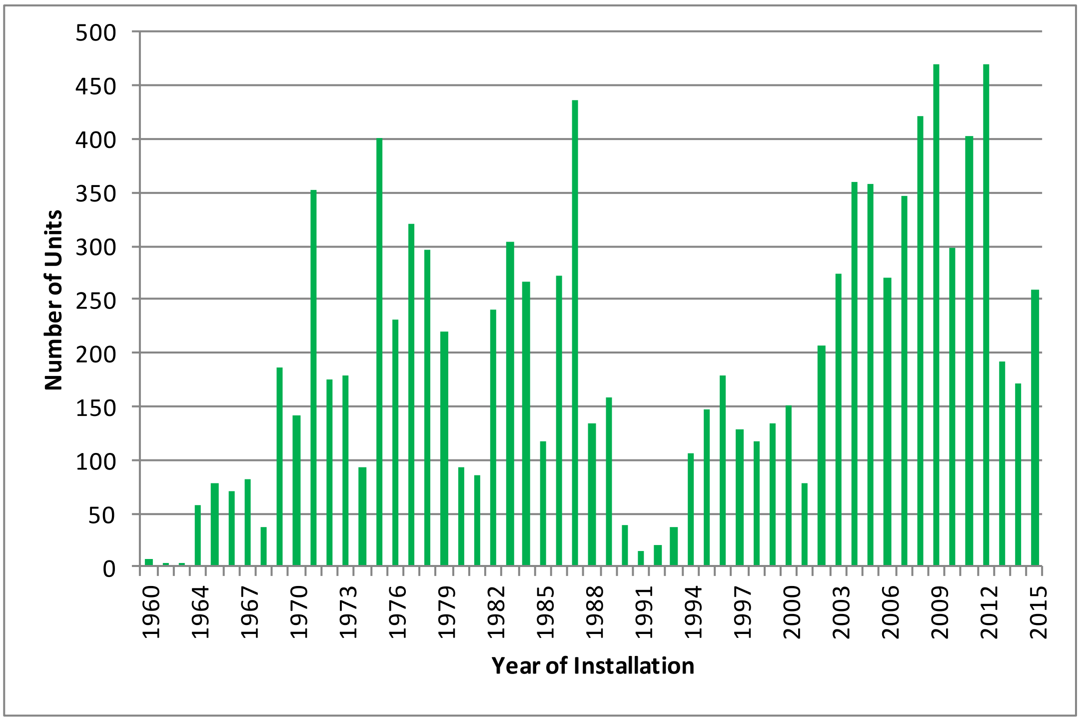


Figure 4.14: Age profile of 400V pillars

4.3.8 Consumer connections

There are approximately 44,000 connections with about half located on each of the overhead and underground networks. These are made up of three phase, single phase and pilot control connections. Electra owns and maintains all service fuses on the 400V network. Most fuses are HRC construction but rewireable types are still present on older overhead lines and load control circuits. Electra replaces fuses as they fail or when the equipment they are attached to is replaced.

4.3.9 Protection and control

The key protection systems comprise the following:

- Each 33 kV circuit from a zone substation is supplied from a circuit breaker fitted with directional, earth, over current protection;
- Each 11 kV circuit from a zone substation is supplied from a circuit breaker fitted with a minimum of earth, over current and auto re-close protection;
- Each transformer bank at each zone substation is supplied from a 33 kV circuit breaker fitted with a minimum of earth and over current protection;
- Each 11 kV bank bus at each zone substation is supplied from a circuit breaker fitted with a minimum of earth and over current protection;
- Differential protection is fitted to each transformer bank;
- Inter-trips are enabled on each transformer bank;
- Distribution network protection is, in the main, by way of 11 kV fuses;
- Many 11 kV circuits have a pole mounted circuit breaker fitted in line to reduce the number of consumers affected by any one outage.
- Eberle tap changer controllers have been selected as the modern standard for all zone substation transformers on the Electra network.

The following tables summarise the type and condition of the protection equipment:

GXP	GXP to Electra Feeder Protection (owned by Transpower)		
	Type	Quantity	Condition
Mangahao	GEC MCGG 82	4	Very good
Paraparaumu	SEL 351S	6	Very good

Table 4.14: 33kV feeder protection equipment

Zone Substation	Zone to Zone and Zone to GXP Protection			Zone Transformer Bank 33kV Protection		
	Type	Quantity	Condition	Type	Quantity	Condition
Shannon	SEL 351S	8	Very good Very good	SEL 387A SEL 351S	2 2	Very good Very good
Foxton	Nu-Lec ADVC	2	Very good	Nu-Lec PTCC SEL 587 SEL 551	1 2 1	Very good Very good Very good

Levin East	GEC KCEG 140 Nulec PTCC	1 2	Very good Very good	Nulec PTCC GEC MBCH12	2 2	Very good Very good
Levin West	Nulec ADVC	3	Very good	SEL 387A SEL 351S	2 1	Very good Very good
Otaki	GEC KCCG 140	2	Very good	GEC KCCG 140 REY Duobias-M	2 2	Very good Good
Waikanae	SEL 267-4 SEL 251	2 1	Good Good	SEL 587	2	Very good
Paraparaumu				REY 4C21/2B3 SEL387A	1 1	Good Very good
Paraparaumu West	SEL 351S	2	Very good	SEL 587	2	Very good
Raumati	SEL 351S SEL 311L SEL487B	1 1 1	Very good Very good Very good	SEL387A SEL351S	2 2	Very good Very good
Paekakariki	Nulec ADVC	1	Very good	REY TJM 11	1	Good

Table 4.15: Sub-transmission protection

Zone Substation	**Zone Transformer Bank 11kV Protection**			**11kV Feeder Protection**		
	Type	**Quantity**	**Condition**	**Type**	**Quantity**	**Condition**
Shannon	SEL 387A	2	Very good	SEL 351S	4	Very good
Foxton	SEL 551	2	Good	SEL 351S	4	Very good
Levin East	GEC MCGG 82	2	Average	GEC MCGG 82 SEL 351S	4 1	Average Very good
Levin West	SEL 387A GE SR760	1 1	Good Poor	SEL 751A SEL 351S	3 3	Very good Very good
Waikanae	SEL 251C	2	Good	SEL 251 SEL 751A	5 1	Good Very good
Otaki	GEC KCCG 140	2	Good	GEC KCGG 140	5	Good
Paraparaumu	REY TJM 10	2	Good	REY TJM 10 REY TJV SEL 751A	3 2 1	Good Good Very good
Paraparaumu West	SEL 351S	2	Very good	SEL 351S	5	Very good
Raumati	SEL 387A	2	Very good	SEL 351S	4	Very good
Paekakariki	REY TJM 11	1	Good	SEL 351S	3	Very good

Table 4.16: Zone substation protection equipment

Electra has a number of battery chargers and power supplies from a number of manufacturers. Although some are over fifteen years old, they are still in good serviceable condition because they have not been over-loaded or run at full load for any length of time. All batteries and UPSs are rated to give a minimum of six hours continuous standby load.

4.3.10 Load control and communications

Electra has several secondary networks that work in conjunction with the electricity network including two ripple injection plants, one central SCADA system (and Control Centre), one NIMS and the two radio (UHF and VHF) voice and data networks.

The ripple injection plants are used to control water-heating load, other storage heating loads, and street-lighting. These plants are virtually maintenance free and upgrades are generally limited to auxiliary equipment such as PLCs.

The SCADA master station and displays were replaced in 2009 with an iSCADA system supplied by Catapault Software. This has made SCADA accurate and easy to use and maintain (given it is New Zealand based support). Additionally, during 2011 iSCADA was made available on various desktops with the Electra office.

Due to the amount of high speed data required to ensure that SCADA and load management are working at maximum speed with the least amount of errors, the communication links were upgraded in 2005/06. Communication between substations in the Paraparaumu/Raumati area is via fibre optic cable with backup via radio links. The remainder of the network communicates by a combination of pure radio path data and microwave links. The system is rated “fail safe” in that if one of the repeater data paths fail these links will look for alternative paths to ensure the data gets through. The system is in good condition and well maintained in order to ensure radio spectrum compliance.

Electra is presently implementing an IP Network using DNP3 protocol as the communication method. This will continue to increase the reliability of the communications system. The following diagram shows the communication network associated with SCADA:

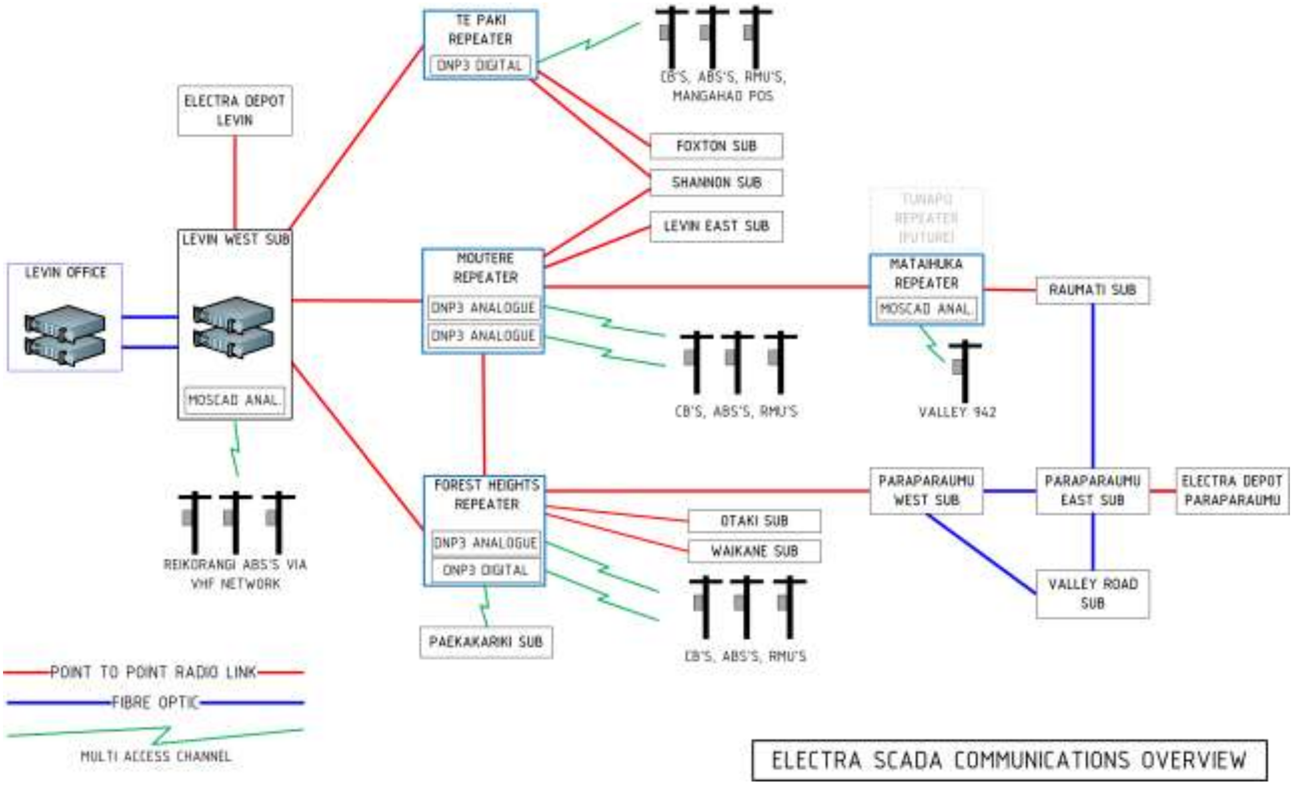


Figure 4.15: SCADA communications network

4.3.11 Office Buildings Depots and Workshops

Electra's main office building is located in Levin and was constructed in 2006. Electra has depots in Levin and Paraparaumu. The Levin depot has a small workshop for fitting out transformers and light engineering. Most engineering and structural work is contracted out to specialised businesses.

4.3.12 Office Furniture and Equipment

Electra's offices and depots have furniture to enable office and administrative functions to be carried out. In Electra's main office there are workstations for 19 staff and furnishings for two meeting rooms. In the Levin depot there are workstations for 4 staff and in Paraparaumu Depot there are workstations for 12 staff and two meeting rooms.

4.3.13 Motor Vehicles

Electra's vehicle fleet consists of the following:

- Nine heavy line construction trucks
- Five Elevated Platform Vehicles
- Four technician vans
- Twenty five light utility vehicles
- Thirteen cars

4.3.14 Tools, Plant and Other Machinery

Field staff are provided with tools to carry out the work necessary to provide Electra’s distribution services. These tools vary from hand tools to test and monitoring equipment to prove the safety of Electra’s assets.

4.4 Justification for the assets

All assets are justified by present or anticipated requirements to meet existing network standards and service levels. An engineering review undertaken of the network during the 2004 ODV valuation optimised out just $112,000 of assets or 0.06% of the value of the network. A review was undertaken of the network assets to ascertain their “Fair Value” in 2015 which will be used to highlight any additional optimisation requirements.

Electra designs and builds its network to meet the requirements of stakeholders. Stakeholders were discussed in section 3.4. Some assets need to deliver greater service levels than others (for example the Paraparaumu West zone substation supplying the rapidly growing beach area has a higher capacity and security level than the Paekakariki zone substation which supplies the small residential area located in southern Kapiti). Matching the level of investment in assets to the expected service levels requires consideration of the following issues:

- An intimate understanding of how asset ratings and configurations impact on service levels such as capacity, security, reliability and voltage stability;
- An understanding of the asymmetric nature of under-investment and over-investment i.e. over-investing creates service levels before they are needed, but under-investing can lead to service interruptions and in some cases catastrophic failure;
- Recognition of the discrete sizes of many classes of components (for example a 220kVA load will require a 300kVA transformer that is only 73% loaded). In some cases capacity can be staged through use of modular components;
- Recognition that Electra’s existing network has been built up over 80 years by a series of incremental investment decisions that may have been optimal at the time but when taken in aggregate at the present moment may well be sub-optimal; and
- The need to accommodate future demand growth.

In theory an asset would be justified if the service level it creates is equal to the service level required. In practice asymmetric risks, discrete component ratings, the non-linear behavior of materials and uncertain future growth rates combine to justify an asset if its service level is not significantly greater than that required, after allowing for demand growth and discrete component ratings. More information about service levels targets is provided in section 5. Further discussion of demand growth is provided in section 7.3.

At this time, Electra is not aware of any assets which are at risk of stranding. Electra consults with consumers (as shown in Figure 3.5) to find out future load requirements of consumers. Electra is not aware of any large load that may reduce or disconnect from the network which would leave assets stranded.

5 Service Levels

5.1 Consumer performance targets

The purpose of this section is to meet the AMP objective of setting service levels for its electricity network that will meet consumer, community and regulatory requirements as discussed in section 3.1. It also ties in with the following key policies and strategies of the SCI as noted in section 3.2:

- Service and Operational Efficiency - Electra will continue to invest in upgrading the quality, effectiveness and efficiency of network operations. It will continue to review opportunities to work with other line companies to minimise operating costs and benchmark performance, to ensure value to consumers and owners;
- Market Growth and Quality of Supply - Electra will continue to invest in energy network assets to meet customer led growth and to improve the quality of supply in the Kapiti/Horowhenua area, subject to normal investment criteria. It will continue to promote energy efficiency initiatives. Electra will, where necessary, develop and use electricity pricing options and other practical solutions that result in the best use of network capacity.

Consultation with consumers consistent with the process shown in Figure 3.1 is a vital ingredient to setting these service level targets.

This section firstly describes the service levels Electra expects to create for its consumers (which is what they pay for) and secondly the service levels Electra expects to create for other key stakeholder groups (which consumers are expected to subsidise).

Electra's annual research shows that both residential and commercial consumers value continuity of supply and prompt restoration of supply more highly than other attributes such as answering the phone quickly, quick processing of new connection applications etc. There is also an increasing value which consumers place on the absence of flicker, sags, surges and brown-outs. However, other research that Electra is aware of indicates that flicker is probably noticed more often than it is a problem. In addition there is only a tiny proportion of consumers who say they would be willing to pay in addition to what they are paying now in order to get a more reliable supply. Consistent with other sectors consumers are ever more likely to want greater reliability/quality for the same or a lesser price.

The challenge with these results is that the service levels valued by consumers depend in most situations on fixed asset solutions. Getting the power back on quickly at the 11kV and 33kV level through automated switching as opposed to an individual property which might rely more on the timing and skills of an individual person, fall into this category. Hence the tendency to require capital expenditure solutions (as opposed to training or process solutions) to address this. This raises the following issues:

- Limited substitutability between service levels i.e. prompt phone response will not compensate for frequent loss of power, but consumers do require and appreciate up to date and accurate information when they call as the result of a fault – for example likely restoration time;

- Averaging effect i.e. all consumers connected to an asset will receive about the same level of service; and
- Free-rider effect i.e. consumers who may not pay for improved service levels would still receive that improved service due to their common connection.

5.1.1 Primary service levels

Given the direction in 5.1, Electra's primary service levels are supply continuity and restoration. To measure performance in this area the following three internationally accepted indices have been adopted:

- SAIDI – system average interruption duration index. This is a measure of how many system minutes of supply are interrupted per year;
- SAIFI – system average interruption frequency index. This is a measure of how many system interruptions occur per year;
- CAIDI – consumer average interruption duration index. This is a measure of how long the "average" consumer is without supply each year.

Historical performance and targets of these measures for Electra's network are set out in table 5.1 below:

Y/End	Actual					Forecast											
31/Mar	**2011**	**2012**	**2013**	**2014**	**2015**	**2016**	**2017**	**2018**	**2019**	**2020**	**2021**	**2022**	**2023**	**2024**	**2025**	**2026**	**2027**
SAIDI	74.71	131.8	58.00	67.30	139.30	117.0	83.00	83.00	82.00	82.00	81.00	81.00	80.00	80.00	79.00	79.00	78.00
SAIFI	1.62	2.29	0.93	1.25	2.25	1.20	1.66	1.66	1.66	1.66	1.66	1.66	1.66	1.66	1.66	1.66	1.66
CAIDI	46.20	57.60	75.20	53.70	61.93	97.50	50.00	50.00	49.00	49.00	49.00	49.00	48.00	48.00	48.00	48.00	48.00

Table 5.1: Historical service statistics and forecast targets

The SAIDI and SAIFI actual figures for the year ended 31 March 2015 were above target levels. This was primarily the result of storms in April and August 2014.

For the year ending 31 March 2016 forecast SAIDI and SAIFI figures are trending lower than 2014/15 with SAIDI still above quality targets. The difference is due to a single incident on the main supply to Levin while the backup supply was out of service for maintenance.

Figure 5.1 below shows Electra's past SAIFI results and the forecast SAIFI level for the planning horizon until 2026:

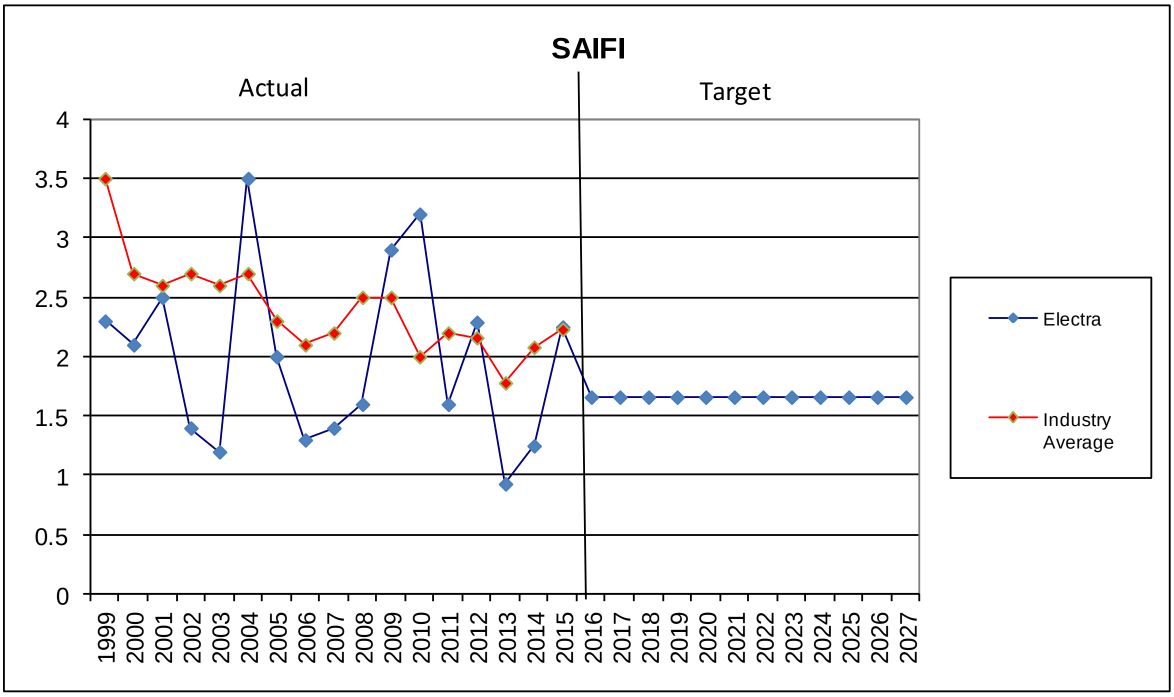


Figure 5.1: Electra's actual and target SAIFI

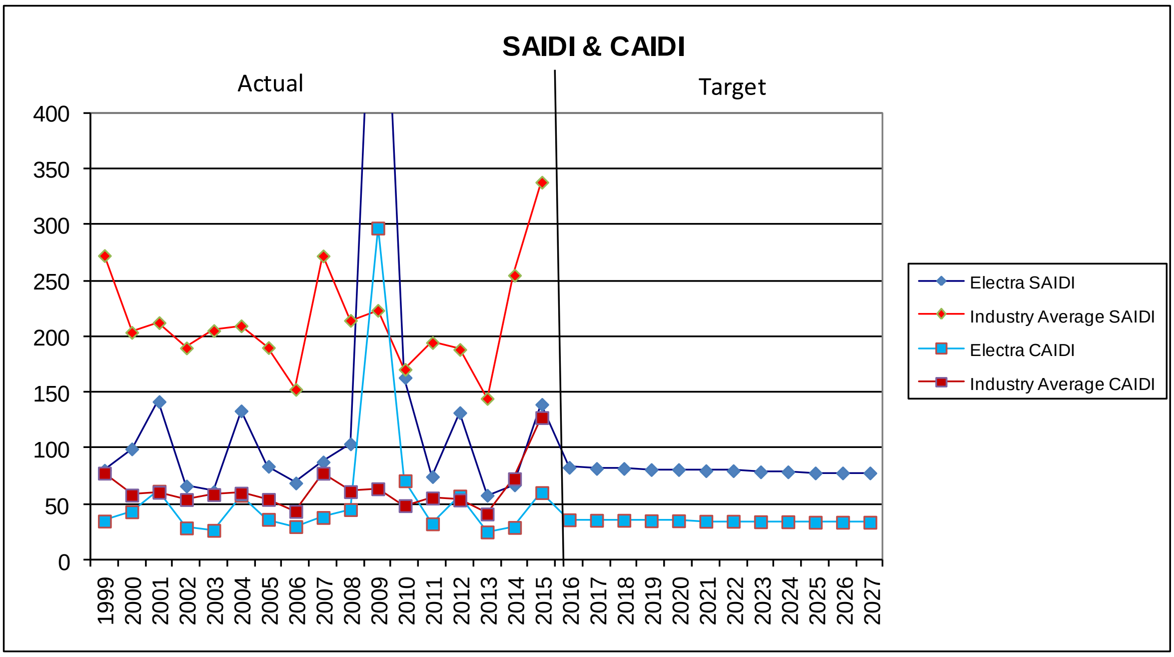


Figure 5.2: Electra's actual and target SAIDI/CAIDI

In practical terms this means Electra's consumers can broadly expect network reliability to remain reasonably constant. As noted in Table 3.2, Electra's most recent mass-market survey (carried out in December 2015) still indicates a general satisfaction with the present supply quality. Some variations to the network reliability may be caused by the following issues:

- The dead-line line maintenance that will need to be completed over the next ten year period (which is unable to be completed using live line techniques);
- The impact of extreme weather.

Dead-line works will be required where the distribution network is either under-hung or has other higher voltages located above the work sites. Every endeavour will continue to be made to reduce and minimise the impact of outages by the use of alternative routes or portable generators where it is practical to do so.

Generally, Electra does not differentiate service quality across different consumers although there are natural variations due to geographical location and network topology (eg customers located further away from main supply points are more likely to experience variations in service quality). Electra's philosophy is to keep things as uncomplicated as possible and this is reflected in there being no price differentiations within consumer groupings (i.e. any differentiation between urban and rural consumers would be arbitrary as the existence of lifestyle properties located on urban fringes removes any clear distinction between these property types.). All pricing is designed where possible to optimise asset utilisation on the network, no matter who the consumer is. Electra has a variety of pricing options based on how much and when electricity is being consumed. Consumers are able to choose the option that best suits them (dependant on how retailers repackage Electra's network prices).

Electra's consumer base is overwhelmingly residential and thus network capacity must meet the demands of high short-term morning and evening peaks, without the benefits of balancing daytime commercial and industrial load. Similarly, as any consumer is able to utilise a particular network tariff option Electra does not explicitly differentiate the level of service provided. This is reinforced by our relatively dense network (20% above the national average). In practice there are areas around the CBD's in Levin and Paraparaumu where there are concentrations of commercial consumers for whom we are able to keep service levels higher than average due to the proximity of alternative supply paths, but generally our restoration time in the event of a power outage is similar all consumers.

The network development plan (explained in detail in section 7) includes a number of renewal projects that aim to reduce the risk of equipment failure that would have an impact on SAIFI and SAIDI. There are some projects, such as the installation of RMUs for network sectionalisation which have the effect of improved reliability and reduced outage times. These projects are factored into the target service levels identified in section 5.1.1.

5.1.2 Secondary service levels

Secondary service levels are the attributes of service that consumers have ranked below supply continuity and restoration. Some of these service levels are process driven which implies:

- They tend to be cheaper than fixed asset solutions, for example: working overtime to process new connection application back logs, diverting over-loaded phones or improving the shut-down notification process; and

- They can be provided exclusively to consumers who are willing to pay more in contrast to fixed asset solutions which will equally benefit all consumers connected to an asset regardless of whether they pay.

Secondary service level attributes include:

- How promptly and how well technical advice is provided to Electra's consumers;
- The absence of flicker - which is a broad term encompassing a whole range of phenomena such as brown-outs, sags, surges and spikes; and
- Whether Electra gives its consumers sufficient notice of planned shutdowns.

Table 5.2 sets out Electra's target secondary service levels, for the AMP planning period:

Attribute	Measure	2016	2017	2018 - 2027
New Connections	Number of working days to process	3	3	3
Provision of Technical Advice	Number of working days to acknowledge inquiry: • Mail out • Telephone	 4 2	 4 2	 4 2
	Number of working days to investigate inquiry or validate complaint	5	5	5
	Number of working days to provide advice (other than in response to a complaint)	3	3	3
	Number of working days to resolve proven complaint (unless non minor asset modifications required)	10	10	10
Shutdown Notification	Number of consumers to whom 3 working days of a shutdown is not provided.	5	5	5
	Number of large consumers to whom 60 minutes advanced notice of an advised shutdown is not provided	1	1	1
	Number of large consumers whose preferred shutdown times cannot be accommodated	2	2	2

Table 5.2: Electra's secondary service level targets

5.2 Other performance targets

In addition to the service levels that are of primary and secondary importance to Electra's consumers who pay for electricity distribution services, Electra also generates a number of other service outcomes that benefit external stakeholders, for example safety, amenity value, absence of electrical interference and performance data. Many of these service levels are imposed on Electra by statute and, while they are public goods necessary for the proper functioning of a safe and orderly community, Electra must absorb the associated costs often with little or no ability to recover those costs.

Electra defines its performance in terms of the following Critical Success factors:

- Maintaining and growing a reputation for *Integrity, Quality and Excellence* within the electricity industry and in the Kapiti/Horowhenua area and in all other areas where we operate;
- *Exceeding Service Expectations* for our consumers (consistent with Electra's mission statement to provide 'quality services and efficient operations');
- Facilitating growing *Awareness and Pride* by consumers in their locally owned Electra Group of companies that return benefits to them by way of discounts;
- Asset efficiency/Energy delivery efficiency; and
- Financial efficiency of the lines business.

In this respect, a number of performance targets have been set for measuring Electra's success, as illustrated below:

Attribute	Measure	2016	2017	2018 - 2027
Marketing	Fault resolution service ratings (out of 5) Resolution Timeliness		 4.6 4.6	
Public Safety	Electricity (Safety) Regulations 2011		Compliant	
	Electricity (Hazards from Trees) Regulations 2004		Compliant	
Industry performance	Electricity Information Disclosure Requirements 2005 and subsequent amendments		Compliant	
Financial Efficiency	Capital expenditure per km	$3,031	$3,031	Annual planning adjustment
	Operational expenditure per km	$3,587	$3,587	Annual CPI adjustment
	Capital expenditure per connection point	$182	$182	Annual planning adjustment
	Operational expenditure per connection point	$216	$216	Annual CPI adjustment
Energy Delivery Efficiency	Load factor (units entering network / maximum demand multiplied by hours in year)	55%	50%	50%
	Loss ratio (units lost / units entering network)	6.6%	7.0%	6.7%
	Capacity utilisation (maximum demand / installed transformer capacity)	35.5%	30.0%	33.0%

Table 5.3: Performance targets

Electra's financial efficiency targets are set with an objective to maintain direct costs about the same as network companies with similar disclosed characteristics: Aurora Energy, Counties Power, Unison, Waipa Networks and WEL Networks.

5.3 Justification for service level targets

Electra primarily justifies its service levels in the following ways:

- On the basis that the majority of consumers have expressed a preference for similar levels of supply continuity and restoration in return for paying about the same line charges;

- By the physical characteristics and configuration of the network which embody an implicit level of reliability which is expensive to significantly alter (but which can be altered if a consumer or group of consumers agrees to pay for the alteration);
- Due to the diminishing returns of each dollar spent on reliability improvements;
- Through any consumers' specific request (and agreement to pay for) a particular service level;
- When an external agency imposes a service level or in some cases an unrelated condition or restriction that manifests as a service level such as a requirement to place all new lines underground or a requirement to maintain clearances.

Many of these justifications relate to the consumer consultation with consumers and stakeholders that Electra undertakes on a regular basis as identified in section 3.2. The results of the last survey (carried out in December 2015) are summarised below.

- 94% of residential and 88% of commercial customers agree that "Electra provides a reliable supply of electricity".
- 0% of residential and 2% of commercial customers would like Electra to provide a more reliable/better quality power supply.

Consequently Electra does not intend to substantially alter overall service levels for the duration of the planning period.

6 Lifecycle Asset Management Plan

6.1 Summary of the management of the asset lifecycle

This section describes the robust and transparent processes in place for managing all phases of the network life cycle, from conception to disposal. This is one of the objectives of the AMP listed in section 3.1. Electra manages its assets through the asset lifecycle according to the process illustrated in the following diagram:

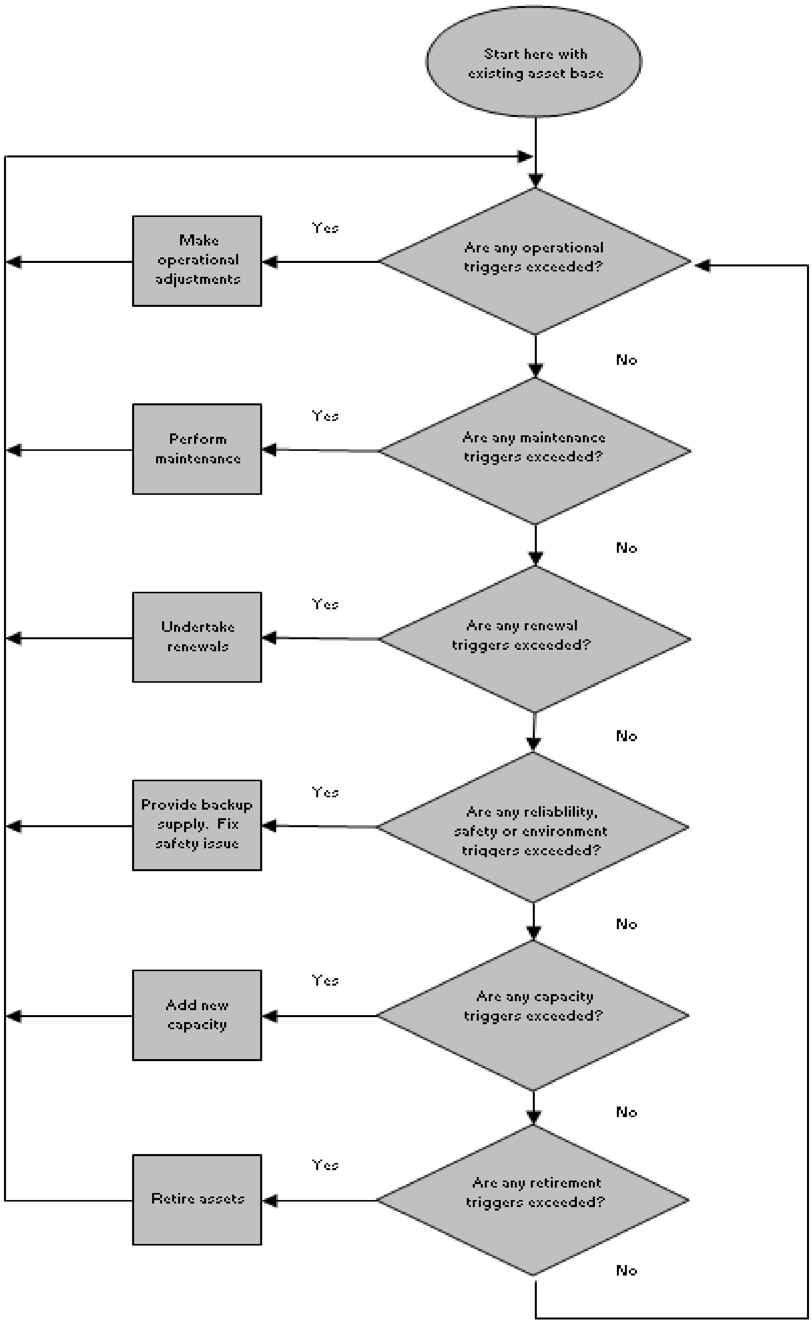


Figure 6.1: Management of the asset lifecycle

The key steps in the asset lifecycle are:

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

The following sections primarily discuss the first two key steps of the asset life cycle (Operations; and Inspection & Maintenance) in detail including policies, programmes and actions. However for completeness it also provides a summary of the renewal, reliability, system growth and retirement criteria. Section 7 contains Electra's detailed plans for these steps in the context of the Network Development Plan.

6.1.1 Asset operations criteria and assumptions

Actively operating electricity distribution assets predominantly involves doing nothing and simply letting the electricity flow from the GXPs to consumers' premises. However occasional intervention is required when a trigger point is exceeded.

Table 6.1 outlines the key operational triggers adopted by Electra for each class of assets. Note that whilst temperature triggers will usually follow demand triggers, this may not always be the case, for example an overhead conductor joint might get hot because it is loose or corroded rather than overloaded.

Asset Category	Voltage Trigger	Demand Trigger	Temperature Trigger
400V lines and cables	• Voltage routinely drops too low to maintain at least 94% of nominal voltage at the point of supply. • Voltage routinely rises too high to maintain no more than 106% of nominal voltage at the point of supply.	• Consumers' pole or pillar fuse blows repeatedly. • Transformer fuses blow repeatedly	• Signs of overheating on fittings • Infra-red survey reveals hot joint.

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

Table 6.1: Key operational triggers

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

- Operating a tap-changer to correct voltage excursions;
- Opening and closing ABSs or RMUs to relieve an over-loaded asset;
- Opening and closing ABSs or RMUs to shutdown or restore power either planned or fault related;
- Operating load control plant to reduce demand;
- Activating fans or pumps on transformers to increase the cooling rate.

6.1.2 Asset maintenance planning criteria and assumptions

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

Electricity networks are not only constrained electrically but also by the environment within which they are constructed. Electra's network is built within a coastal marine environment. This environment is hostile to most components used in an electricity network and is the principal driver of any accelerated maintenance programmes required to maintain service to consumers. Where possible, equipment designed for this environment is used. An example is the use of 15/22kV insulators that fit on the same spindle as the equivalent 11kV insulators – this extends the life between failure due to salt and dust contamination and improves service to consumers for very little additional cost.

Maintenance decisions are made on the basis of cost-benefit criteria with the principal benefits being avoiding supply interruption and minimising safety risks. Component condition is the key trigger for maintenance however the precise conditions that trigger maintenance are very broad, ranging from oil acidity to dry rot. Table 6.2 describes the maintenance triggers Electra has adopted for its lifecycle maintenance programme.

Asset Category	**Components**	**Maintenance Trigger**
400V, Distribution and Sub-Transmission Lines and Cables	Poles, arms, stays and bolts	• Evidence of dry-rot • Loose bolts, moving stays • Displaced arms.
	Pins, insulators and binders	• Obviously loose pins • Visibly chipped or broken insulators • Visibly loose binder • Missing nuts
	Conductor	• Visibly splaying or broken conductor • Low conductor • Evidence of heating • Oxidation
	Ground-mounted switches (distribution only)	• Visible signs of oil leaks • Corrosion • Visibly chipped or broken bushings • Cable damage
Distribution substations	Poles, arms and bolts	• Evidence of dry-rot • Loose bolts, moving stays • Displaced arms
	Enclosures	• Visibly splaying or broken conductor • Partial Discharge • Thermal Imaging
	Transformer	• Visible signs of oil leaks • Excessive moisture in breather • Visibly chipped or broken bushings
	Switches and fuses	• Evidence of heating and burning • Evidence of arcing • Insulation failure
Zone substations	Fences & enclosures	• Corroded wire and or posts • Damaged wire and or posts • Forced entry • Three yearly maintenance

	Buildings	• Build up of dirt / grime • Flaking paint • Damaged and or rotting boards • Leaks • Three yearly maintenance
	Bus work & conductors	• Damaged insulators • Evidence of heating • Splaying conductors • Oxidation • Three yearly maintenance
	33kV switchgear	• From oil and gas analysis results • Number of operations due to fault tripping or switching • Visible signs of oil leaks • Corrosion • Evidence of heating • Visibly chipped or broken bushings • Cable damage • Three yearly maintenance
	Transformer	• From oil and gas analysis results • Corrosion • Evidence of heating • Visibly chipped or broken bushings • Cable damage • Tap Changer number of operations • Three yearly maintenance
	11kV switchgear	• From oil and gas analysis results • Number of operations due to fault tripping or switching • Visible signs of oil leaks • Corrosion • Evidence of heating • Visibly chipped or broken bushings • Cable damage • Three yearly maintenance
	Bus work & conductors	• Evidence of heating • Splaying conductors • Oxidation • Three yearly maintenance
	Instrumentation	• Requirement of regulation • Failure to operate correctly • Three yearly maintenance

Table 6.2: Key maintenance triggers

6.1.3 Asset renewal and refurbishment criteria and assumptions

Electra classifies work as renewal if there is no change (usually an increase) in functionality i.e. the output of any asset does not change. A key criterion for renewing an asset is when the capitalised operating and maintenance costs exceed the renewal cost, and this can occur in a number of ways as follows:

- Operating costs become excessive for example: increasing level of inputs into a SCADA system requires an increasing level of manning;
- Maintenance costs begin to accelerate for example: a transformer needs more frequent oil changes as the seals and gaskets perish;

- Supply interruptions due to component failure become excessive as determined by the number and nature of consumers affected;
- Renewal costs decline, particularly where life time costs of new technologies decrease significantly.

Table 6.3 lists Electra's renewal triggers for key asset classes.

Asset Category	Components	Renewal Trigger
Sub-transmission, Distribution and LV lines and cables	Poles, arms, stays and bolts	• Rotting wooden poles • Concrete has spalled to the extent that it impacts on strength • Arms have rotted, broken or been damaged • Stays have severe corrosion affecting strength • Bolts are corroded beyond repair
	Pins, insulators and binders	• Affecting reliability • Affecting safety
	Conductor	• Over or at maximum load • Obviously beyond repair
	Ground-mounted switches	• Severe corrosion impacting on safety and or security • Beyond economic repair • Oil & gas tests indicate switch is under stress
Distribution substations	Poles, arms and bolts	• Wooden poles • Concrete has spalled to the extent that it impacts on strength • Arms have rotted, broken or been damaged • Stays have severe corrosion affecting strength • Bolts are corroded beyond repair
	Enclosures	• Severe corrosion impacting on safety and or security • Beyond economic repair
	Transformer	• Over 40 years old with associated impact on losses • Oil and gas tests indicate transformer is under stress.
	Switches and fuses	• Severe corrosion impacting on safety and or security • Beyond economic repair • Oil and gas tests indicate switch is under stress • Fuses are damaged or no longer available
Zone substations	Fences and enclosures	• Corroded beyond economic repair
	Buildings	• Damaged beyond economic repair
	Bus work and conductors	• Damaged or worn beyond economic repair
	33kV switchgear	• Damaged or worn beyond economic repair
	Transformers	• Damaged or worn beyond economic repair
	11kV switchgear	• Damaged or worn beyond economic repair
	Bus work and conductors	• Damaged or worn beyond economic repair
	Instrumentation	• Damaged or worn beyond economic repair

Table 6.3: Guidelines for renewal/replacement of assets

Details of the renewal or refurbishment programmes and associated expenditures are provided in Section 7.7 of the Network Development Plan.

6.1.4 Reliability, Safety and Environment criteria and assumptions

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

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

Details of the reliability, safety, and environmental programmes and associated expenditures are provided in Section 7.7 of the Network Development Plan.

6.1.5 System growth criteria and assumptions

If any of the triggers in Table 6.4 below are exceeded Electra will consider adding additional capacity to the network:

Asset category	System Growth (Add 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. • Conductor current exceeds 100% of thermal rating for more than 10 consecutive half-hours per year.	• Voltage at HV terminals of transformer consistently drops below 10.5kV and cannot be compensated by local tap setting.
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. • Conductor current exceeds 100% of thermal rating for more than 10 consecutive half-hours per year.	• 33kV voltage below 31.5kV at Zone substation supplied • Low volts alarms from Scada and reported in Scada Alarm & event history

Table 6.4: Guidelines for upgrading capacity of assets

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

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

Given the fairly simple nature of Electra's network, standard designs are generally adopted for all asset classes with minor site-specific alterations. These designs embody the wisdom and experience of current standards, industry guidelines and manufacturers recommendations. Work identified by Electra as needing to be done is almost solely carried out by Electra's Distribution Operations staff.

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

Details of the system growth programmes and associated expenditures are provided in Section 7.7 of the Network Development Plan.

6.1.6 Consumer connection criteria and assumptions

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

6.1.7 Retiring assets criteria and assumptions

Key criteria for retiring an asset include:

- Its physical presence is no longer required (usually because a consumer has reduced or ceased demand);
- It creates unacceptable risk exposure, either because its inherent risks have increased over time or because safe exposure levels have reduced. Assets retired for safety reasons are not re-deployed or sold for re-use;

- Where better options exist to deliver similar outcomes and there are no suitable opportunities for re-deployment, for example replacing lubricated bearings with high-impact nylon bushes;
- Where an asset has been up-sized and no suitable opportunities exist for re-deployment.

6.2 Asset Inspections and maintenance policies and programmes

The following sections describe the approach adopted by Electra to inspecting and maintaining for all asset categories. This includes a description of the inspections, tests, condition monitoring carried out, the intervals at which this is done, and the actions taken to address any systemic problems by asset category.

The following table summarises the planned inspection programme for the planning period to 2025:

Inspection	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026
Zone substations	Bi-monthly	Bi-monthly	Bi-monthy	Bi-monthly	Bi-monthly	Bi-monthly	Bi-monthly	Bi-monthly	Bi-monthly	Bi-monthly
33kV Overhead circuits	All	Aerial survey and thermography	All	All	Aerial survey and thermography	All	All	Aerial survey and thermography	All	All
Zone Transformers	All	All	All	All	All	All	All	All	All	All
Seismic	All zones			All zones			All zones			
11kV, 400V circuits	Foxton/Waitarere Beach to North Levin	Kapiti District south of Waikanae River	Horowhenua District, Levin and south	Shannon and Tokomaru	Kapiti District north of Waikanae River	Foxton/Waitarere Beach to North Levin	Kapiti District south of Waikanae River	Horowhenua District, Levin and south	Shannon and Tokomaru	Kapiti District north of Waikanae River
Pole mounted transformers and earths	Foxton/Waitarere Beach to North Levin	Kapiti District south of Waikanae River	Horowhenua District, Levin and south	Shannon and Tokomaru	Kapiti District north of Waikanae River	Foxton/Waitarere Beach to North Levin	Kapiti District south of Waikanae River	Horowhenua District, Levin and south	Shannon and Tokomaru	Kapiti District north of Waikanae River
Ground mounted transformers, switches and earths	South of Otaki River	North of Otaki River	South of Otaki River	North of Otaki River	South of Otaki River	North of Otaki River	South of Otaki River	North of Otaki River	South of Otaki River	North of Otaki River
ABS inspections	Horowhenua District, Levin and south	Shannon and Tokomaru	Kapiti District north of Waikanae River	Foxton/Waitarere Beach to North Levin	Kapiti District south of Waikanae River	Horowhenua District, Levin and south	Shannon and Tokomaru	Kapiti District north of Waikanae River	Foxton/Waitarere Beach to North Levin	Kapiti District south of Waikanae River
ABS servicing	Ohau, Manakau	Paraparaumu, Waikanae	Shannon, Foxton	Otaki, Te Horo	Levin	Ohau, Manakau	Paraparaumu, Waikanae	Shannon, Foxton	Otaki, Te Horo	Levin
33kV Partial Discharge		All underground circuits			All underground circuits			All underground circuits	All underground circuits	
33kV Temperature sensing		All underground circuits			All underground circuits			All underground circuits	All underground circuits	
400V Service Pillars and Cabinets	Paraparaumu, Raumati and Paekakariki	Levin	Between Otaki River and Waikanae River	Paraparaumu Beach and Otaihanga	North of Otaki River except Levin	Paraparaumu, Raumati and Paekakariki	Levin	Between Otaki River and Waikanae River	Paraparaumu Beach and Otaihanga	North of Otaki River except Levin

Table 6.5: Planned inspection programme for the planning period to 2026

6.2.1 Grid Exit Point (GXP) assets

These assets are owned, inspected and maintained by Transpower.

6.2.2 Sub-transmission assets

6.2.2.1 Overhead sub-transmission assets

6.2.2.1.1 Inspection policies and programmes on overhead sub-transmission assets

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

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

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

Table 6.6: Inspection guidelines for overhead lines

Electra's contractors record this information electronically and the information is stored in Electra's NIMS system. In some instances, paper recorded inspections means are also used. All inspection results are filtered by condition and purchase orders are raised for remedial or replacement works in the next financial year, urgent work is completed immediately. Electra’s contractors are relied upon to provide accurate and quantified condition assessments.

Electra has used Industrial Research Limited (IRL) to complete physical strength and remaining life tests on 33kV conductors removed from service. These test results are a critical part of condition assessment and are used to assist the development of the replacement programme for 33kV and 11kV circuits. In 2003, these tests were on two sections of the only copper conductors left on Electra's 33kV network (Mangahao – Levin East). The samples were taken from the section of 33kV circuit where most faults had been traced to and where the most exposure to adverse weather was. IRL determined that these two copper circuits had an effective remaining life until 2042.

Electra also carries out three yearly live line condition assessments of all 33kV and 11kV ABSs on a rotating basis as shown in Table 6.5. These inspections examine operation, contacts, vegetation and contamination.

6.2.2.1.2 Maintenance policies and programmes on overhead sub-transmission assets

Circuit faults, in particular overhead lines, are the largest contributor to SAIDI. Therefore maintenance of these circuits is essential to maintain the operating flexibility and capacity of the electricity network and minimise the risk of expensive failures and loss of supply to consumers. The maintenance plan includes vegetation control and any works required as a result of the routine inspections and tests and is allowed for in the Planned Inspection and Maintenance budget.

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

6.2.2.2 Subtransmission cables

6.2.2.2.1 Inspection policies and programmes on underground sub-transmission assets

Underground cables are generally not inspected except at terminations in zone substations, ground based transformers or switchgear. The sole exceptions are the 33kV underground cables where the route is visually inspected annually on a similar basis as to overhead lines. Further, partial discharge testing of these single core XLPE insulated cables is carried out every three years. A summary of the inspection programme for this asset class was shown in Table 6.5.

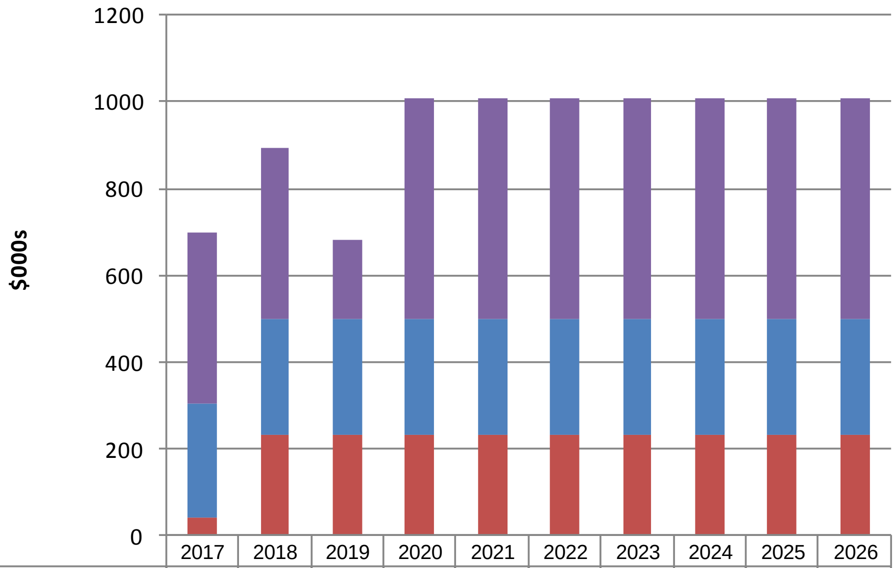
6.2.2.3 Maintenance policies and programmes on underground sub-transmission assets

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

Electra has six 33kV underground circuits; all of these are in the Kapiti Coast, each being single core XLPE cables laid in tre-foil. In 2008 Electra completed spot thermal resistivity studies around four underground circuits to confirm that the circuits were operating within the operating guidelines.

6.2.2.4 Expenditure projections for sub-transmission assets

The graph below shows the expected lifecycle expenditure on the sub-transmission network for the planning horizon:



	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026
Asset Replacement & Renewal	393	393	184	508	508	508	508	508	508	508
Refurbishment & Renewal Maintenance	0	0	0	0	0	0	0	0	0	0
Fault & Emergency Maintenance	265	265	265	265	265	265	265	265	265	265
Routine & Preventative Maintenance	40	233	233	233	233	233	233	233	233	233

Figure 6.2: Forecast sub-transmission expenditure

The expenditure for the 2018 year forward is based on the assumption that Transpower's existing 110kV lines between Mangahao and Levin are transferred to Electra.

6.2.3 Zone substations

6.2.3.1 Inspection policies and programmes on zone substation assets

Zone substations are essential to the supply of electricity to consumers. Electra carries out frequent visual inspections of these assets, with periodic intrusive inspections of assets as required. All zone substations are visually inspected every two months as follows:

Asset	Inspection Guideline
Structure	Rust and corrosion, concrete spalling, vermin nesting, contamination on insulators
Circuit breakers	Insulation leaks, rust and corrosion
Power transformers	Silica gel, oil containment, indicators, rust
Protection equipment	Alarm re-sets

Batteries	Voltages, condition
Perimeter fence and building security	Condition, holes, electric fences
Remote control	Confirm status and remote checks
Site security	Locks, debris in structures
Minor repairs	Blown light bulbs
Grounds	Vegetation, debris
Post earthquake	As required

Table 6.7: Visual inspection guidelines for zone substations

During the bi-monthly inspections, grounds maintenance is undertaken at each zone substation which includes mowing lawns, pruning trees, weed control, cleaning drains and gutters, washing walls and windows and other housekeeping tasks.

The inspection programme has several circuit breakers that will require maintenance and/or replacement within the time period of this plan. The work for this is shown as a renewal in the network development plan (refer Table *7.12*).

Additional equipment tests are also undertaken, typically as follows:

Asset	Test
33kV/11kV transformer	Annual vibration analysis, DGA, particle and Furans Analysis – main tank, tap changer
Earths	Annual earth tests including step and touch potentials
33kV oil filled VTs	Annual DGA, particle and Furans Analysis
Oil filled circuit breakers	Annual DGA, particle and Furans Analysis
SF6 filled circuit breakers	Annual particle and Furans Analysis
Indoor switchgear	Biennial partial discharge and thermography (Years 2017, 2019, 2021)
Oil Containment	Five yearly checks on integrity of oil containment

Table 6.8: Equipment test guidelines for zone substations

Electra also has an independent seismic inspection of all zone substations completed periodically. This inspection reviews the structure integrity of the buildings, switchgear, equipment racks, structures and transformer seismic tie-downs. The last inspection was completed in 2015 and did not indicate any significant issues with non-compliance with the relevant standard.

6.2.3.2 Maintenance policies and programmes on zone substation assets

Maintenance of zone substations is essential to maintain the operating capability of the electricity network and to minimise the risk of expensive failures. However, Electra does not undertake maintenance for the sake of maintaining equipment. All maintenance is based on either condition assessment arising from the inspection programme (for example overhaul of power transformers) or on manufacturer's recommendations.

Although development projects will influence the maintenance of individual zone substations (particularly those where replacement or refurbishment are imminent), no significant change to maintenance practices is anticipated at this stage.

As a minimum, Electra maintains zone substations, other than after faults, on a five yearly cycle. This five yearly routine maintenance includes:

- transformers and tap changers;
- minor repair work;
- maintaining oil within acceptable industry standards;
- correcting oil leaks;
- maintenance as recommended by the various manufacturers (IOMS manuals);
- painting (outdoor only);
- lubrication of moving parts;
- inspection, cleaning and replacements of insulators;
- corrosion control, cleaning off rust and other residues and replacing protective coatings;
- removal of debris;
- confirm operation of all switches;
- recalibration and confirmation of protection operation;
- test all lightning arrestors associated with the transformers and bus structures;
- test earth connections for physical deterioration on all above ground equipment;
- earth tests on the earth grid;
- water blasting of concrete;
- repairs to buildings and fences as required;
- landscaping as required.

A condition assessment of each zone substation is forwarded to Electra for review and inclusion within maintenance and development plans.

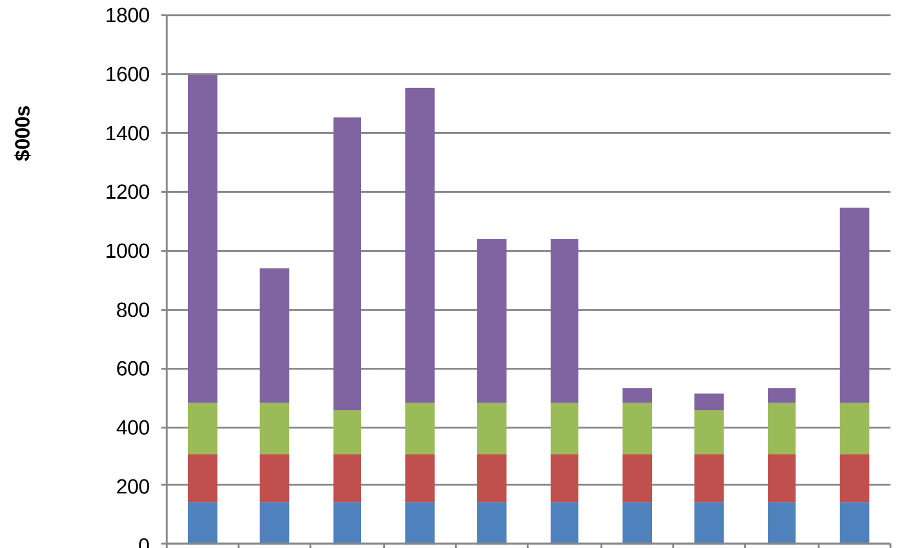
The zone substation five yearly maintenance cycle is illustrated below and the work is generally carried out over the summer months:

Year	Zone
2016/17	Raumati & Shannon
2017/18	Levin West & Paraparaumu West
2018/19	Otaki & Paekakariki
2019/20	Levin East & Paraparaumu
2020/21	Foxton & Waikanae

Table 6.9: Zone substation maintenance schedule

All maintenance and refurbishments are included in the maintenance budget. Replacements or upgrades are included in the capital budget.

6.2.3.3 Expenditure projections for zone substations



	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026
Asset Replacement & Renewal	1117	460	991	1073	562	562	51	51	51	664
Refurbishment & Renewal Maintenance	172	173	151	173	173	173	173	151	173	173
Fault & Emergency Maintenance	164	164	164	164	164	164	164	164	164	164
Routine & Preventative Maintenance	143	143	143	143	143	143	143	143	143	143

Figure 6.3: Forecast Zone Substation maintenance expenditure

6.2.4 Distribution Assets

6.2.4.1 Inspection policies and programmes on distribution assets

6.2.4.1.1 Distribution substations and hardware

The inspection cycle for distribution system equipment is as follows:

Asset	Inspection cycle
Ground transformers	Biennially
Pole mounted transformers	Five yearly as part of overhead line inspections
Ground switches	Biennially as part of the ground transformer inspections
Pole mounted switches	Five yearly as part of overhead line inspections
Earths – ground	Biennially as part of transformer or switchgear inspection
Earths – pole	Five yearly as part of overhead line inspections

Table 6.10: Inspection guidelines for distribution system equipment

All transformers are visually inspected as below:

Asset	Inspection
Overall	Rust and corrosion, cobwebs, vermin nesting, contamination on insulators, vegetation, grafitti
11kV fuses/joints	Insulation leaks, rust and corrosion
400V fuses/joints	Insulation leaks, rust and corrosion
Overall	Thermal imaging of equipment
Surrounds	Weeds, rubbish

Table 6.11: Inspection guidelines for transformers

All 11kV switches are visually inspected as below:

Asset	Inspection
Overall	Rust and corrosion, cob-webs, vermin nesting, contamination on insulators, vegetation, grafitti
11kV fuses and joints	Insulation leaks, rust and corrosion
Switchgear mechanism	Operation, insulation leaks, rust and corrosion
Surrounds	Weeds, rubbish

Table 6.12: Inspection guidelines for 11kV switches

Earth inspections cover the areas below:

Asset	Inspection
Overall	Rust and corrosion, cob-webs, contamination
Connections	Rust and corrosion, bonding of all assets at a location
Tests	Earth resistivity test within Regulations

Table 6.13: Guidelines for earth inspections

6.2.4.1.2 Distribution 11kV and 400V lines

The overhead network is inspected on a five yearly basis. These circuits are visually inspected as per Table 6.6 of section 6.2.2.1.1 for overhead lines.

6.2.4.1.3 Distribution 11kV and 400V Cables

The underground network is generally not inspected except at terminations in zone substations, ground based transformers or switchgear (at a frequency pertaining to those listed assets).

6.2.4.1.4 Consumer Connections

All service pillars are inspected for rust and corrosion, signs of overheating, vegetation, security and other damage. The surrounding areas is examined for weeds and rubbish, and sprayed and cleared if necessary.

6.2.4.2 Maintenance policies and programmes on distribution network assets

6.2.4.2.1 Distribution transformers and hardware

Electra maintains transformers, other than after faults, based on the condition inspections, as outlined above and annual MDI readings (where fitted) and analysis and annual thermograph scan of all terminations. In addition routine preventative maintenance includes:

- minor repair work on transformer, structures or associated 11kV or 400V fuses;
- maintaining oil within acceptable industry standards;
- correcting corrosion and oil leaks;
- inspections and repairs to tap changers;
- replacement of transformers, structures or associated 11kV or 400V fuses as required; and
- cleaning of site.

Buffalo grass is very prevalent in the Kapiti Coast and the transformers are regularly sprayed for weeds. Regular inspections and treatments are done to minimise the incidence of faults due to these. Cobwebs can also cause flashovers in 11kV and 400V transformer bays. Regular inspections and treatments are done to minimise the incidence of faults due to these.

Graffiti does not impact in the operation of the electricity network; however, it does have a social and environmental impact. Regular inspections and treatments are undertaken to remove it from ground mounted assets.

Equipment failures can occur randomly, without warning, and range from a simple drop out fuse operating or a simple mechanism fault on an ABS to a transformer or auto-recloser failing in service.

Electra maintains switchgear, other than after faults, based on the condition inspections outlined above and annual thermograph scans of all terminations. Routine maintenance includes:

- minor repair work on switchgear and structures;
- maintaining oil within acceptable industry standards;
- correcting corrosion and oil leaks;
- inspections and repairs to operating mechanisms;
- replacement of switchgear, structures or associated 11kV or 400V fuses;
- painting; and
- cleaning of site.

Replacements are completed as renewal capital projects, and are included in the development plans outlined in Section 7.7.

6.2.4.2.2 Distribution 11kV and 400V Lines

Circuit faults, in particular overhead lines, are the largest contributor to SAIDI. Therefore maintenance of these circuits is essential to maintain the operating flexibility and capacity of the electricity network and minimise the risk of expensive failures and loss of supply to consumers. The maintenance plan includes vegetation control and any works required as a result of the routine inspections and tests and is allowed for in the Planned Inspection and Maintenance budget.

Pole failures are rare and usually result from third party interference, damage caused by storms or wind borne debris, or age related conditions such as spalling of concrete. All damaged poles are replaced with prestressed concrete poles.

Cross-arms and insulators are replaced on all overhead circuits as required after condition assessment inspection. This expenditure is treated as maintenance.

Through routine inspections Electra has identified poles, cross-arms and insulators for replacement, these are classed as renewal cost in the capital budget of the network development plans (refer section 7.7.2).

Electra has approximately 300 hardwood poles remaining on the 11kV and 400V networks in total. Annual inspection results are indicating that many of these poles are approaching the end of their physical life. Electra plans to replace all hardwood poles on the network over the next 4 years with prestressed concrete poles as part of the annual pole replacement programme. Poles that Electra's contractors identify as being most at risk and/or in areas of other planned work will be replaced first.

Electra has in the past used kidney strain insulators on the 11kV tap off poles. The modern standard is polymer and the earlier insulators are beginning to fail. During preventative maintenance, Electra replaces these older kidney strain insulators with polymer insulators. Electra also replaces these older kidney strains when they are implicated in radio or television interference, as it is more economical than undertaking remedial works.

6.2.4.2.3 Distribution 11kV and 400V Cables

The majority of 11kV circuits are 3-core PILC cables, however more recent installations are XLPE. The 11kV cables are essentially maintenance free but faults occasionally occur due to damage by third parties. Electra replaces 11kV and 400V underground circuits on failure. These replacements are completed as capital projects.

In the past Electra used pitch filled cable terminations to connect 11kV underground circuits to overhead lines. These have been a cause of outages, particularly in beach areas. As such these potheads will be replaced as planned outages occur. They are generally completed as part of capital projects.

The maintenance plan includes vegetation control around terminations, partial discharge testing and any works arising from these inspections and tests. This is allowed for in the planned maintenance budget.

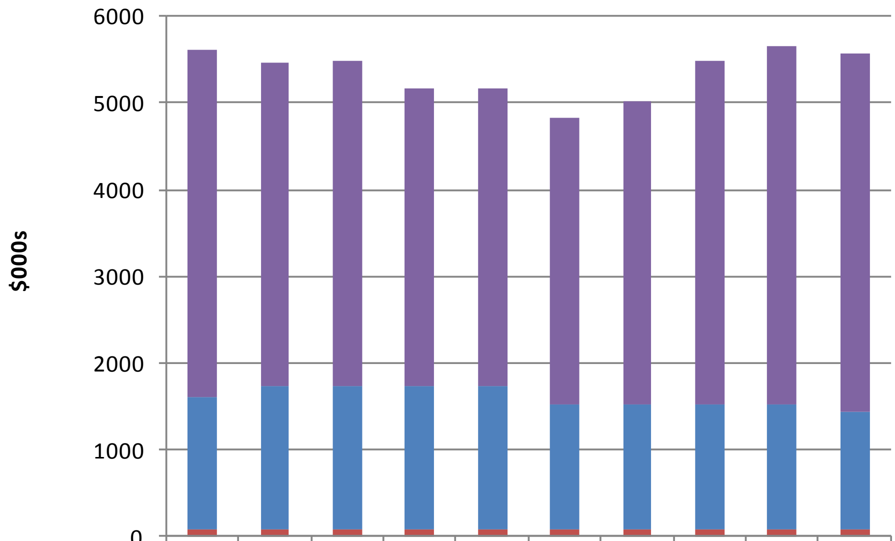
6.2.4.2.4 Pillars

Routine maintenance of service pillars includes minor repair work on the service pillar such as repairing fuses, tightening loose connections and improving access by clearing vegetation and debris.

Service pillar failures are rare and usually result from third party interference or damage. Replacements and repairs are generally due to corrosion in the case of metal service. Pillars installed during the late 1960's and early 1970's have proven to be particularly susceptible to this type of damage. Where a number of and metal pillar boxes in one street/road/etc need replacing, all pillar boxes will be replaced so as to have them all plastic.

6.2.4.3 <u>Expenditure projection for distribution 11kV and 400V lines</u>

The forecast lifecycle expenditure for distribution lines is shown below.

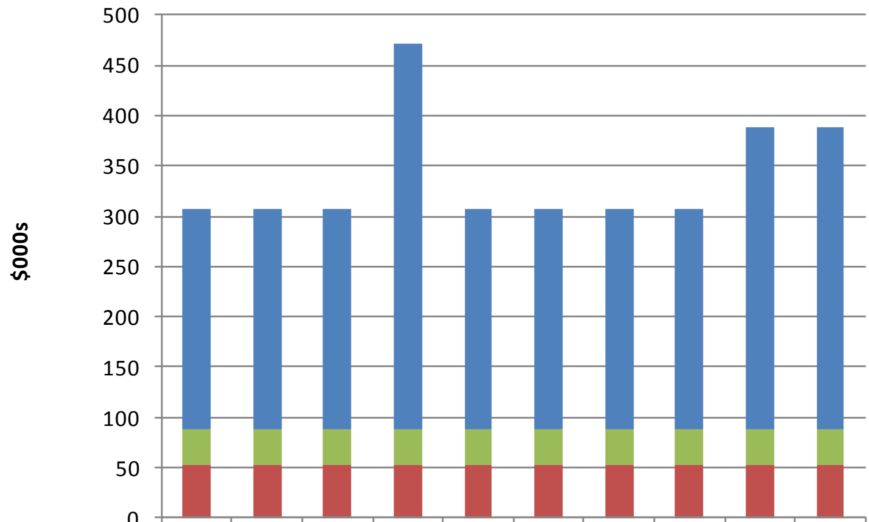


	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026
Asset Replacement & Renewal	4008	3731	3761	3450	3445	3298	3501	3956	4130	4130
Refurbishment & Renewal Maintenance	0	0	0	0	0	0	0	0	0	0
Fault & Emergency Maintenance	1541	1643	1643	1643	1643	1444	1444	1444	1444	1350
Routine & Preventative Maintenance	71	86	86	86	86	86	86	86	86	86

Figure 6.4: Forecast distribution line lifecycle expenditure

6.2.4.4 Expenditure projection for distribution 11kV and 400V cables

The expenditure forecast includes lifecycle expenses for distribution cables is shown below.

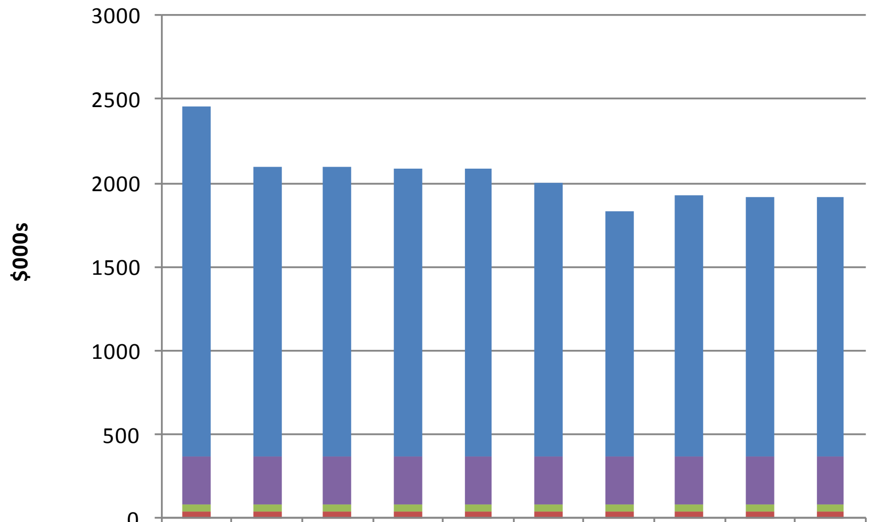


	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026
Asset Replacement & Renewal	218	218	218	382	218	218	218	218	300	300
Refurbishment & Renewal Maintenance	0	0	0	0	0	0	0	0	0	0
Fault & Emergency Maintenance	36	36	36	36	36	36	36	36	36	36
Routine & Preventative Maintenance	53	53	53	53	53	53	53	53	53	53

Figure 6.5: Forecast distribution cable lifecycle expenditure

6.2.4.5 Expenditure projection for distribution substations and transformers

The forecast lifecycle expenditure for distribution substations and transformers is shown below.

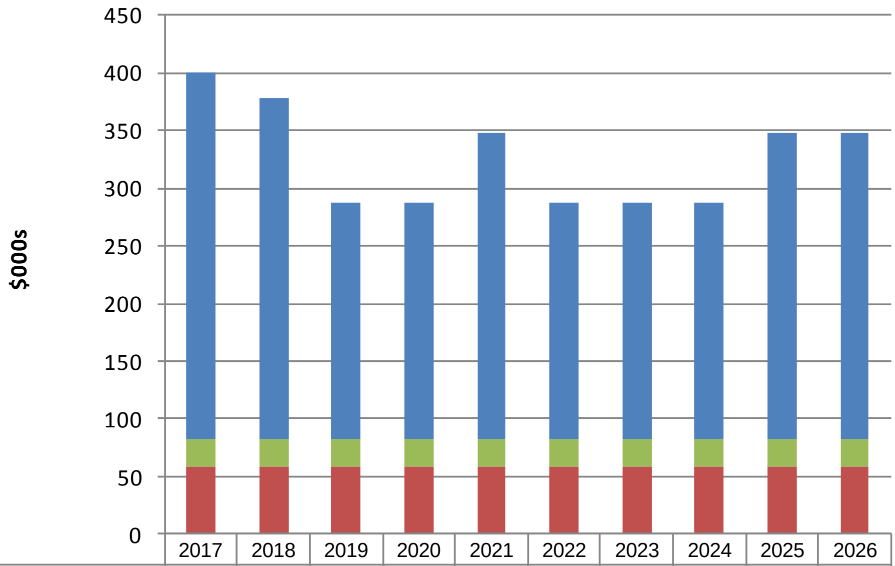


	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026
Asset Replacement & Renewal	2090	1729	1734	1721	1727	1636	1468	1559	1555	1555
Refurbishment & Renewal Maintenance	285	285	285	285	285	285	285	285	285	285
Fault & Emergency Maintenance	40	40	40	40	40	40	40	40	40	40
Routine & Preventative Maintenance	40	40	40	40	40	40	40	40	40	40

Figure 6.6: Forecast distribution substation and transformer lifecycle expenditure

6.2.4.6 Expenditure projection for distribution switchgear

The forecast lifecycle expenditure for distribution switchgear.



	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026
Asset Replacement & Renewal	319	296	205	205	266	205	205	205	266	266
Refurbishment & Renewal Maintenance	0	0	0	0	0	0	0	0	0	0
Fault & Emergency Maintenance	24	24	24	24	24	24	24	24	24	24
Routine & Preventative Maintenance	58	58	58	58	58	58	58	58	58	58

Figure 6.7: Forecast distribution switchgear expenditure

6.2.5 Other Network Assets (Ripple Injection, SCADA & GIS)

Electra has contracted Landis and Gyrr to undertake an annual inspection of the two ripple plants. This inspection includes signal strength measurements (both at the plant and at various locations in the electricity network) and confirmation of local timetables for the various ripple signals. LogicaCMG, Electra's SCADA support, undertakes routine inspections of the SCADA database remotely, as part of the SCADA support agreement. Electra has contracted Catapult Software to maintain the SCADA network.

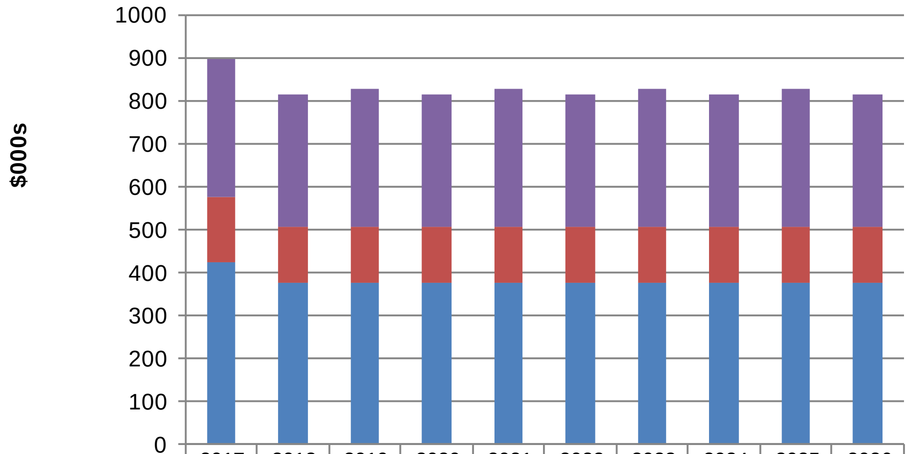
All field communication and SCADA equipment is maintained by Facilities Management under specific contracts. Facilities Management Ltd has a Service Level Agreement with Electra to inspect and service the radio hubs annually. As this inspection is intrusive, any adjustments that are required are completed at the time. Inspections include:

- All antennae support structures – including wood poles, towers and monopoles; and
- Antennae - for corrosion as well as electronic sweeps to ensure correct operation.

Electra has support agreements with Eagle Technology to monitor and maintain the NIMS (GIS) system.

6.2.5.1 Expenditure projection for other network assets

The forecast lifecycle expenditure for other network assets.



	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026
Asset Replacement & Renewal	320	308	320	308	320	308	320	308	320	308
Refurbishment & Renewal Maintenance	0	0	0	0	0	0	0	0	0	0
Fault & Emergency Maintenance	156	133	133	133	133	133	133	133	133	133
Routine & Preventative Maintenance	423	376	376	376	376	376	376	376	376	376

Axis Title

Figure 6.8: Forecast Other Network Asset lifecycle expenditure

6.2.6 Non-Network Assets

Electra policy regarding non network assets to allow for lifecycle replacement matching the rate of depreciation.

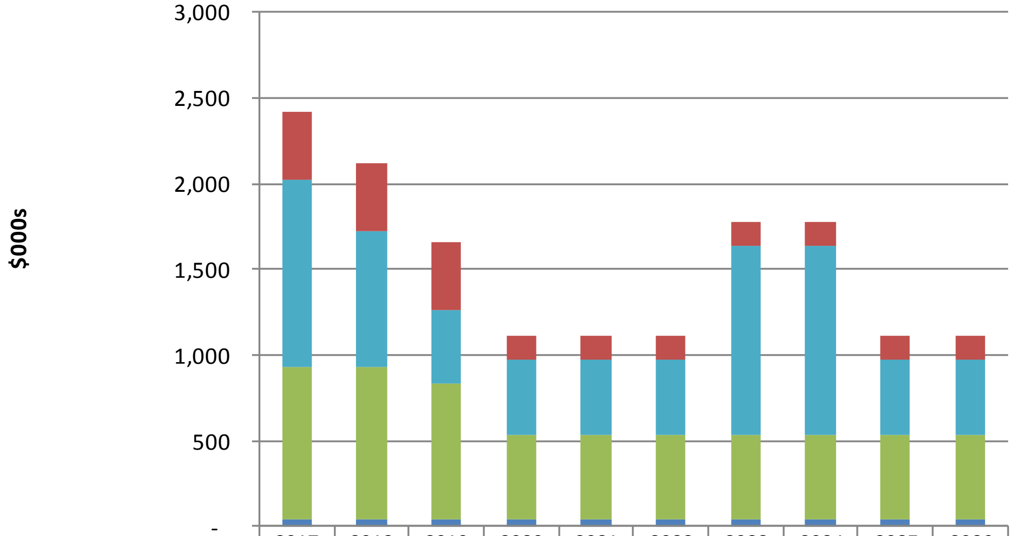
Electra's vehicle replacement policy is outlined below.

- Cars - Petrol – 4 years or 130,000kms
- Cars - Diesel – 4 years or 160,000kms
- Utes and Vans – 6 years or 160,000kms
- Trucks to be determined by the General Manager but average to be 10 years

Electra's Generator is serviced after every 250 hours of running time. This service includes replacement of filters, lubricants and coolants. The electrical connections including cables are tested annually. A Certificate of Fitness is obtained for the trailer at 6 monthly intervals.

6.2.6.1 Expenditure projection for non network assets

The expenditure forecast includes lifecycle expenditure for non network assets.



	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026
Tools, plant & other machinery	399	399	399	139	139	139	139	139	139	139
Motor vehicles	1,098	800	430	430	430	430	1,098	1,098	430	430
Office furniture & equipment	886	886	790	500	500	500	500	500	500	500
Office buildings, depots & workshops	39	39	39	39	39	39	39	39	39	39

Figure 6.9: Forecast non network asset lifecycle expenditure

6.2.7 Tree trimming and management

Trees provide shelter for overhead lines from wind borne debris; they are also one of the principal causes of unplanned interruptions. Trees can also damage underground circuits. This can be difficult to monitor, and as a result, damage is usually found after an outage. Tree management is important both in continuing to increase reliability and to focus on the environmental, legal and social impact of tree trimming.

Where possible and practical, fast growing trees are replaced with slow growing native trees. In addition where possible and practical, tree owners are encouraged to fell trees within the fall zone of all circuits.

6.2.7.1 Tree trimming inspections

From mid 2013 Electra's area was segmented into 10 areas based on the zone substations. Inspections will continue to be completed on a six monthly cycle. Vegetation control works will flow out of these inspections. Consumer initiated vegetation control is in addition to this contract. The following table summarises the annual tree inspection programme.

Area (Zone Substation)	Month to inspect and maintain
Shannon	April & October
Foxton & Levin East & Levin West	May & November
Otaki	June & December
Waikanae	July & January
Paraparaumu & Paraparaumu West	August & February
Raumati &Paekakariki	September & March

Table 6.14: Vegetation plan

The Electricity (Hazards from Trees) Regulations 2004 were issued in late December 2004. These regulations essentially outline the separation between trees and lines – both for existing installations/trees and for the planting of new trees near existing electricity circuits. The Regulations include the following separations between existing trees and overhead lines. These are not always sufficient to minimise or eliminate hazards between trees and electricity circuits.

Voltage	Minimum Separation
230V/400V	0.5 metres
11kV	1.6 metres
33kV	2.5 metres

Table 6.15: Minimum separation between trees and electricity circuits for spans 150 metres and less

Electra's contractor is compiling a database on trees near overhead lines allowing a planned approach to tree maintenance for future years.

Tree trimming maintenance

Electra's tree management plan is as follows:

- Electricity (Hazards from Trees) Regulations 2004 notifications will be complied with;
- All trees that have "no interest" will be reviewed balancing the aesthetic value of the tree to the local environment against the impact on consumers of probable faults being caused by that tree. Electra's default position is that the tree is removed. Electra may, at its own discretion, replace the tree with a slow growing native;
- All trees that have a declared "interest" will be recorded for future reference and application of the Electricity (Hazards from Trees) Regulations 2004. These regulations require the person declaring the "interest" to also take responsibility for the on-going costs associated with maintaining the tree;
- Other vegetation, such as toi toi and flaxes have been planted around ground mounted transformers by local residents. This can cause several problems including flashover faults due to vegetation growing inside the transformer. Any vegetation planted either within the transformer easement area (if on private property), or within one metre if the transformer is installed on a legal road, will be removed.

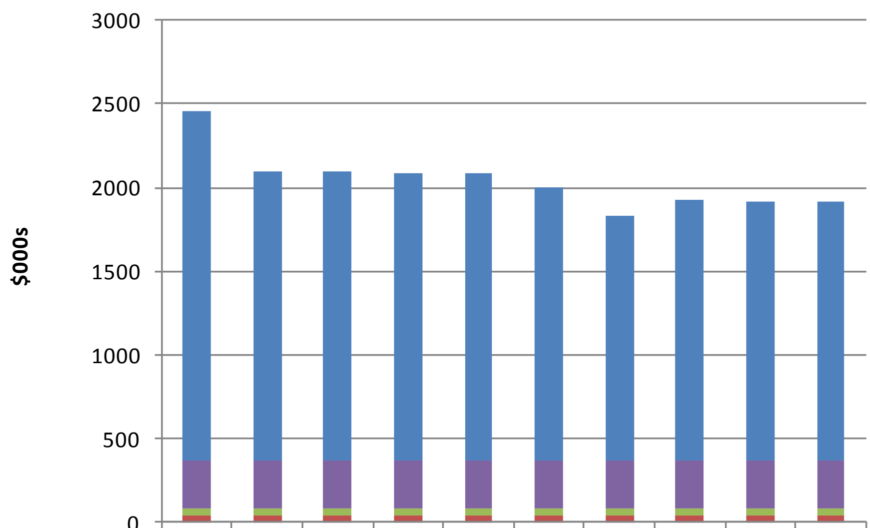
Electra will continue to:

- Remove vegetation within the minimum separation distances on the 33kV and backbone 11kV feeders;
- Re-inspect the 33kV networks, and concentrate on 20 areas of concern along with completing any minor trims as required
- Continually updating the database.
- Monitor tree-sourced interruptions closely to ensure that the budget is sufficient for long-term sustainability and that improvements in reliability are sustained;
- Ensure that tree owners, or others with declared interests in trees, maintain their trees clear of Electra's power lines.

Expenditure relating to tree trimming is included in the expenditure forecasts for distribution lines (refer Figure 6.5: ***Forecast distribution cable lifecycle expenditure***

6.2.4.5 Expenditure projection for distribution substations and transformers

The forecast lifecycle expenditure for distribution substations and transformers is shown below.



	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026
Asset Replacement & Renewal	2090	1729	1734	1721	1727	1636	1468	1559	1555	1555
Refurbishment & Renewal Maintenance	285	285	285	285	285	285	285	285	285	285
Fault & Emergency Maintenance	40	40	40	40	40	40	40	40	40	40
Routine & Preventative Maintenance	40	40	40	40	40	40	40	40	40	40

Figure 6.6: Forecast distribution substation and transformer lifecycle expenditure

6.2.8 Summary of maintenance expenditure

The following table summarises the total network maintenance expenditure forecast for planning period to 2025. No provision for inflation has been included in these figures.

Operations & Maintenance (Current $000)	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027
Subtransmission											
Routine faults restoration	265	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	-	193	193	193	193	193	193	193	193	193	193
Annual line inspection	40	40	40	40	40	40	40	40	40	40	40
Zone Substations											
Inspections	24	24	24	24	24	24	24	24	24	24	24
Planned Maintenance	292	292	271	292	292	292	292	271	292	292	292
Re-active Maintenance	164	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	53
Inspections - Pillars	40	40	40	40	40	40	40	40	40	40	40
Transformer inspections	40	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	- 17	- 17	- 17	- 17	- 17	- 17	- 17	- 17	- 17	- 17	- 17
Fault restoration	982	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	1,591
Planned Transformer maintenance	285	285	285	285	285	285	285	285	285	285	285
Re-Active Transformer maintenance	40	40	40	40	40	40	40	40	40	40	40
Planned Low Voltage maintenance	73	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	594
Planned Switchgear maintenance	58	58	58	58	58	58	58	58	58	58	58
Re-Active Switchgear maintenance	24	24	24	24	24	24	24	24	24	24	24
Other Assets											
Communications maintenance	314	314	314	314	314	314	314	314	314	314	314
SCADA maintenance	243	173	173	173	173	173	173	173	173	173	173
Ripple Maintenance	22	22	22	22	22	22	22	22	22	22	22
Total Operations & Maintenance	**5,127**	**5,353**	**5,332**	**5,353**	**5,353**	**5,153**	**5,153**	**5,132**	**5,153**	**5,060**	**5,060**

Table 6.16: Summary of forecast operations and maintenance expenditure

These forecasts exclude all capitalised expenditures associated with the renewal, system growth, consumer connection, reliability and retirement phases of the lifecycle asset management process. It should be noted that minor renewals associated with the replacement of the consumable components of an asset are included as maintenance above. Capital expenditure is included in the Network Development Plan (Section 7.7), which covers renewals, reliability projects, system growth, and consumer connections.

7 Network Development Plan

This section covers the following lifecycle activities shown in Figure 6.1:

- Asset replacement and renewal;
- Reliability, Safety and Environment projects;
- System growth.

In addition to the above lifecycle activities, the network development plan includes projects relating to asset relocations and forecast expenditure associated with new consumer connections.

7.1 Development planning criteria and assumptions

7.1.1 Planning approaches and criteria

Electra's development plans are driven primarily by demand (consumer led growth) or performance and service standards and targets. At its most fundamental level, demand is created by consumers drawing energy across their individual connections. The demand at each connection aggregates up the network to the distribution transformer, then to the distribution network, the zone substation, 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 1500 urban domestic consumer connections;
- An aggregation of up to 200 urban commercial consumer connections;
- An aggregation of up to 20 or 30 urban light industrial consumer connections;
- A single large industrial consumer especially if that consumer is likely to create a lot of harmonics or flicker.

Electra plans its assets in three different ways (strategically, tactically and operationally) as shown overleaf.

Attribute	Strategic	Tactical	Operational
Asset description	• Assets within GXP. • Sub-transmission lines & cables. • Major zone substation assets. • Load control injection plant. • Central SCADA & telemetry. • Distribution configuration eg. Decision to upgrade to 22kV.	• Minor zone substation assets. • All individual distribution lines (11kV). • All distribution line hardware. • All on-network telemetry and SCADA components. • All distribution transformers and associated switches. • All HV consumer connections.	• All 400V lines and cables. • All 400V consumer connections. • All consumer metering and load control assets.
Number of consumers supplied.	• Anywhere from 500 upwards.	• Anywhere from 1 to about 500.	• Anywhere from 1 to about 50.
Impact on balance sheet and asset valuation.	• Individual impact is low. • Aggregate impact is moderate.	• Individual impact is moderate. • Aggregate impact is significant.	• Individual impact is low. • Aggregate impact is moderate.
Degree of specificity in plans.	• Likely to be included in very specific terms, probably accompanied by an extensive narrative.	• Likely to be included in specific terms, and accompanied by a paragraph or two.	• Likely to be included in broad terms, with maybe a sentence describing each inclusion.
Level of approval required.	• Approved in principal in annual business plan. • Individual approval by board and possibly shareholder.	• Approved in principal in annual business plan. • Individual approval by authorised company officer.	• Approved in principal in annual business plan. • Individual approval by engineering manager.
Characteristics of analysis.	• Tends to use one-off models and analyses involving a significant number of parameters and extensive sensitivity analysis.	• Tend to use established models with some depth, a moderate range of parameters and possibly one or two sensitivity scenarios.	• Tends to use established models based on a few significant parameters that can often be embodied in a "rule of thumb".

Table 7.1: Network development planning approaches

As a further guide Electra has developed the following "investment strategy matrix" shown in Figure 7.1 which broadly defines the nature and level of investment and the level of investment risk implicit in different circumstances of growth rates and location of growth.

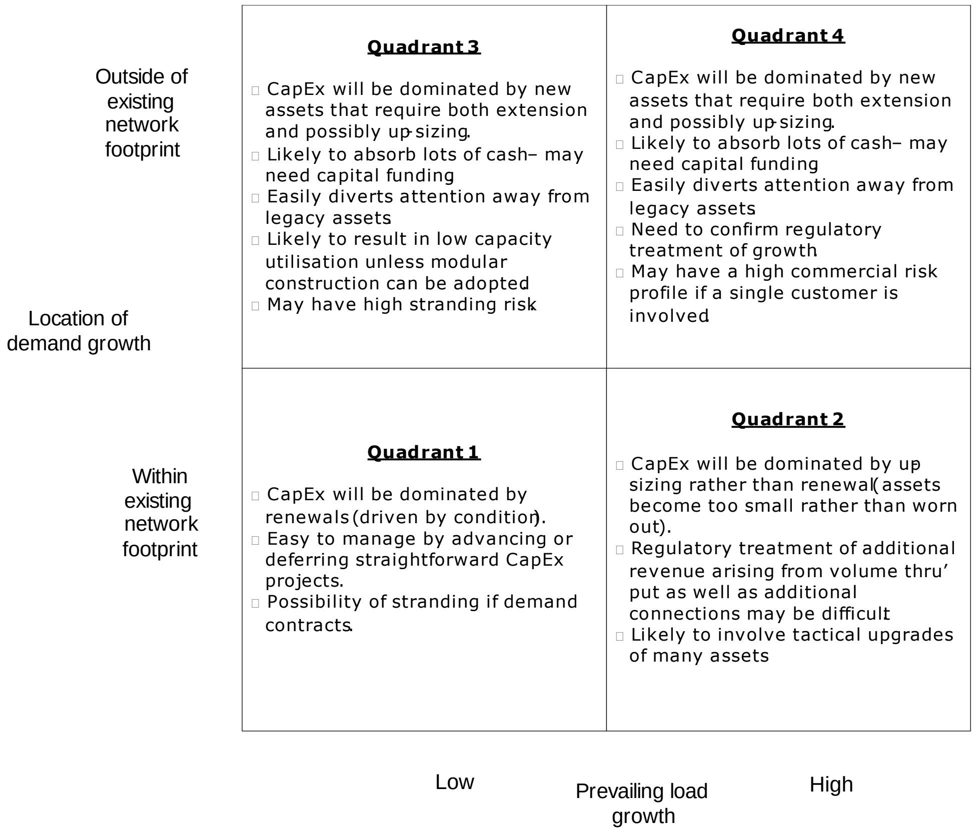


Figure 7.1: Investment strategy mix

Electra's predominant development modes are:

- Normally Quadrant 2 in the southern area because of the high density in-fill development that requires extensive up-sizing of existing assets but little in the way of extending the assets beyond the existing network footprint because of the Kapiti Coast District Council's preference for high-density infill rather than sprawl. This has moved to Quadrant 1 in recent years due to underlying economic conditions but is expected to return to Quadrant 2 later in the planning period;
- Quadrant 1 in most parts of the northern area because of the low level of load growth, and because what little growth there is generally occurs within or very close to the existing footprint. Apart from isolated occasions Electra does not expect the Development Plan mode in the northern area to migrate into other quadrants;
- Quadrant 4 in beach front settlements located in both the southern and northern areas.

7.1.1.1 Trigger points and criteria for planning new capacity.

The first step in meeting future demand is to determine if the projected demand will result in any triggers in relation to capacity, reliability, security or voltage. These points were outlined for each asset class in section 6.1.4 and in Table 6.4.

Zone power transformers are upsized to a twin bank of similar size transformers when the load reaches the normal 11 kV load rating of 11.5MVA (Electra's "standard" zone power transformers are 11.5/23.0 MVA).

Circuit breakers, all voltages, are either upsized or additional circuit breakers and circuits installed when normal load reaches 80 percent of the circuit breaker rating. This ensures that any fault currents do not cause "nuisance" trippings.

33 kV and 11 kV feeders are re-enforced when the normal load rating reaches 70 percent of the cable/line rating and . This ensures that any fault currents do not cause "nuisance" trippings and that plant arrives prior to any "over-load" occurring.

Because new capacity has valuation, depreciation, return and pricing implications, Electra will always try to meet demand by other, less investment-intensive means. If a trigger point is breached, Electra will then move to identify a range of options to bring the assets' operating parameters back to within the acceptable range of trigger points. These options are described in section 7.1.2.

7.1.2 Meeting demand

Table 6.4 defines the trigger points at which the capacity of each class of asset needs to be increased. Exactly what is done to increase the capacity of individual assets within these classes can take the following forms (in a broad order of preference):

- *Do nothing* - accept that one or more parameters have exceeded a trigger point. In reality, do nothing options would only be adopted if the benefit-cost ratio of all other reasonable options were unacceptably low and if assurance was provided to the Chief Executive and Board that the do nothing option did not represent an unacceptable increase in risk to Electra. An example of where a do nothing option might be adopted is where the voltage at the far end of an 11kV overhead line falls below the threshold for a few days per year – the benefits of correcting such a constraint may be too low;
- *Operational activities* - in particular switching activities on 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;
- *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.

In identifying solutions for meeting future demands for capacity, reliability, security and voltage Electra considers the above options. The benefit-cost ratio of each option is considered (including estimates of the benefits of environmental compliance and public safety) and the option yielding the greatest benefit is adopted. The benefit-cost ratio is vital to ensure Electra maximises value for consumers and owners as consistent with the mission statement. Environmental compliance is one of the key policies of the SCI. Figure 7.2 is used to broadly guide adoption of various approaches.

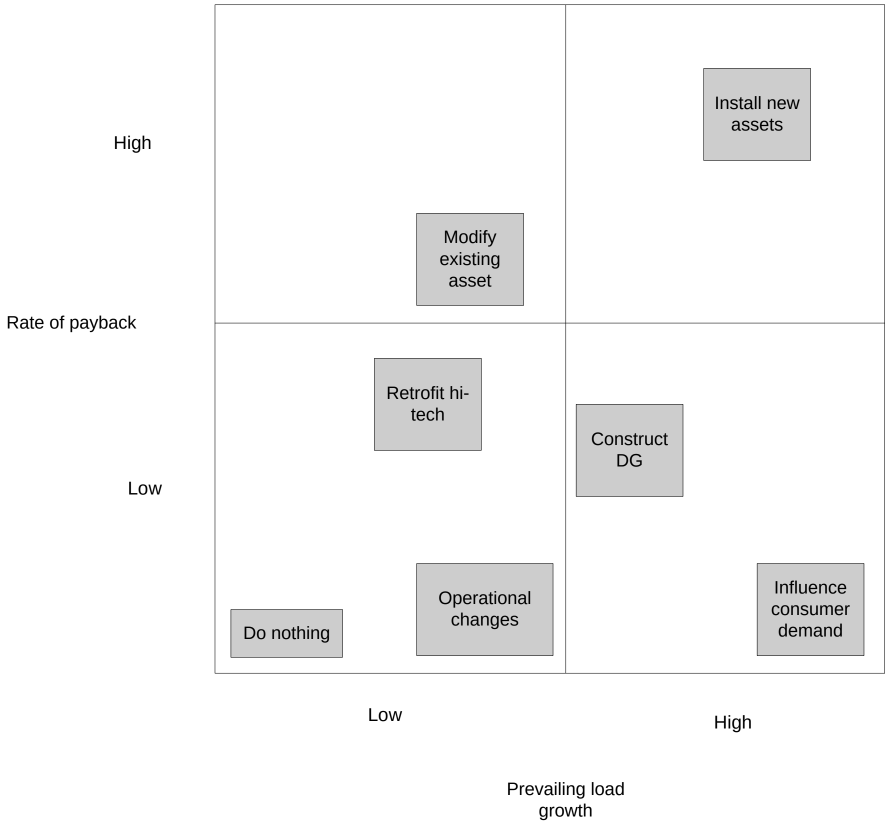


Figure 7.2: Options for meeting demand

7.1.3 Meeting security requirements

A key component of security is the level of redundancy that enables supply to be restored independently of repairing or replacing a faulty component. Typical approaches to providing security to a zone substation include:

- Provision of an alternative sub-transmission circuit into the substation, preferably separated from the principal supply by a 33kV bus-tie;
- Provision to back-feed on the 11kV network from adjacent substations where sufficient 11kV capacity and interconnection exists. This firstly requires those adjacent substations to be restricted to less than nominal rating and secondly requires a prevailing topography that enables interconnection;
- Use of local embedded generation.

The most difficult issue with security is that it involves a level of investment beyond what is required to meet demand, and over time demand growth can erode the security headroom.

The Electra sub-transmission is configured as a ring so that any one fault on any one line or cable does not cause a loss of supply to a zone substation and ensures that lines and cables left in service are able to handle the added loads. Any one sub-transmission line or cable under normal system configuration may only be carrying 150 Amps but under a fault condition this load may double or triple.

7.1.3.1 <u>Prevailing security standards</u>

The commonly adopted security standard in New Zealand is the EEA Guideline which reflects the UK standard P2/5 that was developed by the Chief Engineer's Council in the late 1970's. P2/5 is a strictly deterministic standard, that is, it prescribes a level of security for specific amounts and nature of load with no consideration of individual circumstances.

Deterministic standards are now beginning to give way to probabilistic standards in which the value of lost load and the failure rate of supply components is estimated to determine an upper limit of investment required to avoid interruption.

A key characteristic of deterministic standards such as P2/5 and the EEA Guidelines is that rigid adherence generally results in at least some degree of over investment. Accordingly the EEA Guidelines recommend that individual circumstances be considered.

From a security perspective, local generation would need to have 100% availability to contribute to permanent security. This is unlikely from a reliability perspective and even less likely from a primary energy perspective such as run-of-the-river hydro, wind or solar. For this reason the emerging UK standard P2/6 provides for minimal contribution of such generation to security.

7.1.3.2 Electra's security standards

Table 7.2 below describes the security standards Electra aims to achieve. In setting target security levels Electra's preferred means of providing security to urban zone substations will be by secondary sub-transmission assets with any available back-feeding on the 11kV providing a third tier of security.

Description	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	Between 0.5 and 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 240 minutes from adjacent feeders.
11kV Feeder	Between 0.5 and 2.0 MW	Loss of supply Supply restored within 30 minutes from adjacent feeders.	Fault repair time
11kV Feeder	Between 0 and 0.5 MW	Fault repair time	Fault repair time
400V Feeder	Between 0 and 0.5 MW	Fault repair time	Fault repair time

Table 7.2: Target security levels

These standards will help Electra to meet many of its service targets described in Section 5.

7.1.4 Standardisation practices

Electra standardises a range of practices, asset configurations and materials across its asset lifecycle as follows...

Lifecycle component	Standardisation	Benefits of standardisation
Detail design	• Standard design criteria eg. all poles will have a 2x factor of safety, voltage limits within the LV network. • Standard detail designs. It should be noted that the number of separate components involved results in several hundred component, however most assemblies fall within a few standardised designs.	• Longevity of design principles. • Minimises risk of unsafe or non-compliant assets (an ex-ante control mechanism). • Minimises risk of non-compliance with regulatory standards such as volt-drop, strength, clearances etc.

Construction	• Construction standards specify methods of installation and precise order of assembly. • Minimum competency requirements for installers.	• Minimise the risk of poor workmanship. • Minimise the breadth of competencies required. • Creates accountability of installers. • Establishes criteria for post-completion auditing of works.
Materials & supply	• A small number of alternative materials eg. transformers, cable fittings etc are approved. • Multiple suppliers are used to ensure market prices are obtained. New components will not be adopted unless more than 1 supplier can be identified.	• Minimse stock holdings. • Minimise breadth of asset specific skills required. • Minimises risk of non-compliance, especially safety. • Assists emergency sourcing of components.

7.2 Prioritising development projects

Section 3.4 outlines Electra's approach to managing possible conflicting stakeholder interests. This is applied when prioritising development projects.

Prioritisation is strongly linked to risk management (which is discussed further in section 8). Projects that reduce risks with high likelihood and high consequence are prioritised over projects with low likelihood and low consequence.

Prioritisation is also required where funds are constrained. Electra has a gearing of 21 percent, and therefore it has significant security to cover future funding needs. The Statement of Corporate Intent which is approved annually by the Trustees (Shareholders) includes a funding constraint. This ultimately limits the value of projects that can be funded in any one period. Currently the Capital Ratio Target is to "maintain shareholders funds at not less than 40% of total assets".

Each of the possible approaches to meeting demand that are outlined in Section 7.1.2 provide potential solutions that are considered. Electra's policies for the development aspects of the asset lifecycle management (renewal, reliability, upgrading and retirement) are outlined in Sections 6.1.3 and 6.1.7.

Provided that an operational activity such as switching the network to shift load did not increase the likelihood of loss of security of supply then this option is taken first. This option, in most cases, improves capacity utilisation at minimal cost. The longer term mitigation to meet future demand is logged as "future date" development projects in the capital expenditure budget. In addition, summer and winter load in the network area in question are also monitored to provide the information necessary to make informed decisions about future options and the timing for future investments. More than one development option is required to be considered by Electra's management and the Board. In this respect all options are:

- Subject to full financial cost benefit analysis;
- Fully justified as to the likely impact on SAIDI, SAIFI and CAIDI;
- Investigated as to the likely impact of the number of outages on residential and commercial consumers within the network area affected;
- For large projects (those above $500,000) such as a new zone substation, all of the potential options are reviewed by an external expert (Refer to the Shannon zone substation rebuild discussed in Electra's 2008 AMP in section 4.3.4.3). Then a recommendation is forwarded to the Board for consideration and expenditure approval.

7.3 Demand forecasts

Electra's individual non-coincident substation maximum demands are depicted in Table 7.3 below.

GXP	Substation	Max demand (MW)
Mangahao (35 MW)	Shannon	4.7
	Foxton	6.9
	Levin East	15.8
	Levin West	11.6
Paraparaumu (58 MW)	Otaki	12.2
	Paekakariki	4.4
	Paraparaumu	14.2
	Paraparaumu West	13.6
	Waikanae	17.0
	Raumati	11.6

Table 7.3: Maximum demand per substation

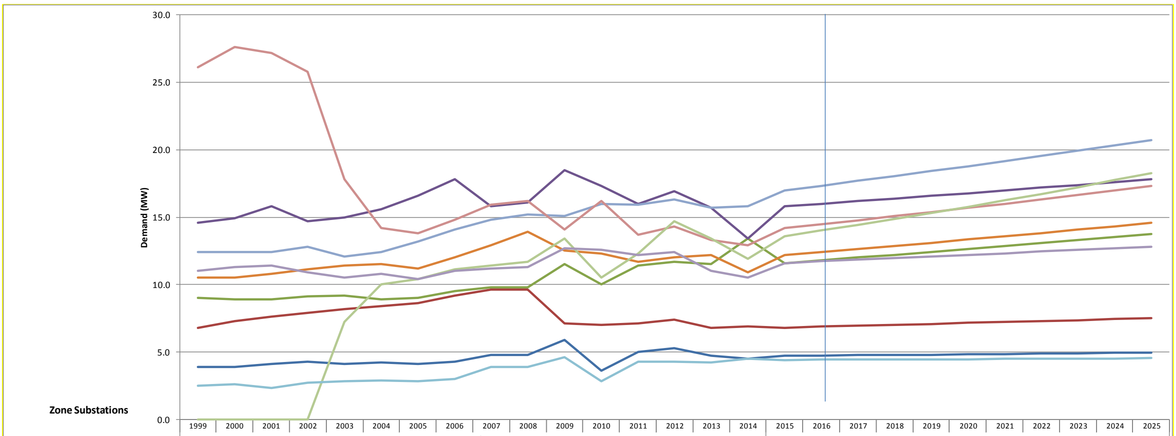
Individual zone substation maximum demands are non-coincident and cannot be summed to give the GXP or Electra system maximum demand.

In forecasting future demand, the following assumptions have been made:

- There will be no significant shifts in the underlying technology of electricity distribution in the next ten years;
- Demand diversity across each zone substation is assumed to be constant through the forecast period;
- There will be a constant load power factor throughout the forecast period. This is assumed to be the average for the winter period on each GXP;
- In contrast to the emerging industry trend of decreasing asset utilisation (i.e. a more "peaky" profile), Electra expects its asset utilisation to remain stable as the mix of consumer types remains the same;

- No additional demand management initiatives are likely to have a significant impact on the load profile. Electra already has a pricing structure that incentivises all consumer groups to reduce load at peak times on the system, and load control is utilised on the network;
- Embedded or standby generation will not be a significant factor until commercially viable energy storage systems are developed and uptake reaches 20% of Electra’s customers. This is not expected to occur before 2026 in either the southern or northern areas;
- 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 by 0.6-0.8MW/annum);
- A new major transportation corridor (Kapiti Expressway) due for completion in 2016 is likely to have an impact on electricity demand as a result of residential and commercial growth. This potential additional demand is unknown at this stage and has not been included in the demand forecast,

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.



Zone Substations	1999	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012
	Actuals													
Shannon	3.9	3.9	4.1	4.3	4.1	4.2	4.1	4.3	4.8	4.8	5.9	3.6	5.0	5.3
Foxton	6.8	7.3	7.6	7.9	8.2	8.4	8.6	9.2	9.6	9.6	7.1	7.0	7.1	7.4
Levin West	9.0	8.9	8.9	9.1	9.2	8.9	9.0	9.5	9.8	9.8	11.5	10.0	11.4	11.7
Levin East	14.6	14.9	15.8	14.7	15.0	15.6	16.6	17.8	15.8	16.1	18.5	17.3	16.0	16.9
Otaki	10.5	10.5	10.8	11.1	11.4	11.5	11.2	12.0	12.9	13.9	12.5	12.3	11.7	12.0
Waikanae	12.4	12.4	12.4	12.8	12.1	12.4	13.2	14.1	14.8	15.2	15.1	16.0	15.9	16.3
Paraparaumu	26.1	27.6	27.2	25.8	17.8	14.2	13.8	14.8	15.9	16.2	14.1	16.2	13.7	14.3
Paraparaumu West	0.0	0.0	0.0	0.0	7.2	10.0	10.4	11.1	11.4	11.7	13.4	10.5	12.3	14.7
Raumati	11.0	11.3	11.4	10.9	10.5	10.8	10.4	11.0	11.2	11.3	12.7	12.6	12.2	12.4
Paekakariki	2.5	2.6	2.3	2.7	2.8	2.9	2.8	3.0	3.9	3.9	4.6	2.8	4.3	4.3

Zone Substations	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025
	Actuals		Forecast										
Shannon	4.7	4.5	4.7	4.7	4.7	4.8	4.8	4.8	4.8	4.9	4.9	4.9	4.9
Foxton	6.8	6.9	6.8	6.9	6.9	7.0	7.1	7.1	7.2	7.3	7.4	7.4	7.5
Levin West	11.5	13.4	11.6	11.8	12.0	12.2	12.4	12.6	12.8	13.1	13.3	13.5	13.7
Levin East	15.7	13.4	15.8	16.0	16.2	16.4	16.6	16.8	17.0	17.2	17.4	17.6	17.8
Otaki	12.2	10.9	12.2	12.4	12.6	12.9	13.1	13.3	13.6	13.8	14.1	14.3	14.6
Waikanae	15.7	15.8	17.0	17.3	17.7	18.0	18.4	18.8	19.1	19.5	19.9	20.3	20.7
Paraparaumu	13.3	12.9	14.2	14.5	14.8	15.1	15.4	15.7	16.0	16.3	16.6	17.0	17.3
Paraparaumu West	13.4	11.9	13.6	14.0	14.4	14.9	15.3	15.8	16.2	16.7	17.2	17.7	18.3
Raumati	11	10.5	11.6	11.7	11.8	12.0	12.1	12.2	12.3	12.4	12.6	12.7	12.8
Paekakariki	4.2	4.5	4.4	4.4	4.4	4.4	4.5	4.5	4.5	4.5	4.5	4.5	4.5

Figure 7.3: Maximum demand by zone substation (financial year)

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.	End of life replacement of existing lines with greater capacity conductors is expected to cope with any growth for the remainder of the planning period
Foxton	About 1.0% per year, mainly residential development at Foxton Beach.	End of life replacement of existing lines with greater capacity conductors will satisfy growth demand off this zone substation for the planning period.
Levin East	About 1.7% per year, mainly commercial and lifestyle blocks to the south and east of Levin.	An additional feeder was constructed in 2015/15. This, combined with replacement of existing lines with greater capacity conductors, is expected to cope with any growth for the remainder of the planning period
Levin West	About 1.3% per year, mainly residential properties at Waitarere Beach and lifestyle properties to the north and west of Levin.	The additional feeder at Levin East will allow growth to be managed by load transfer to Levin East.
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 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.

Table 7.4: Zone substation growth forecast and planned actions

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 outlined in Section 5.1.1.

Table 7.5 shows the aggregated effect of the zone substation demand growth for a ten year planning horizon at both GXPs.

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 2017 when it is expected that the existing transformers will be upgraded to approximately 60MVA.
Paraparaumu	Average of 0.6MW per year	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.

Table 7.5: Aggregated effect of zone substation growth

For further discussion of these issues refer to section 7.4 Network Constraints.

7.3.1 Issues arising from demand projections

The relatively low rate of demand growth in the northern area 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 much higher (especially around Paraparaumu and Waikanae) and the time to react to unexpected demand may therefore be much shorter. Electra is confident that the relatively new zone substation at Paraparaumu West and the robustness of its planning processes will ensure that security of supply and sufficient capacity is always available. Demand forecasts are reviewed and updated annually as a result of work with Tesla and Transpower and Electra's own review processes where the Network Development Plan is continually being revised to accommodate changes in external factors.

Collective experience strongly indicates that confirmed changes in an existing or new major consumer's demand are only notified a few months (sometimes only weeks) before the change occurs. This is because most of the major consumers located on Electra's network operate in fast-moving consumer goods and service markets, often making capital investment decisions quickly and generally confidentially. Experience also shows that large consumers only minimally consider energy supply when making location decisions as they tend to be driven more by land-use restrictions, raw material supplies and transport infrastructure.

Specific issues which arise from the load projections are:

- Increasing air conditioning load is likely to over-lap into peak periods. 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 described in Section 5;
- Consumer expectations for increased reliability are likely to emerge in seaside locations as these settlements become permanent residences; The effects of electrification and double tracking of the main trunk rail from Paraparaumu to Waikanae has not been specifically factored into the demand forecasts as it has only recently been completed. Over time the demand effects will be fully assessed. It is not believed that the immediate effect is significant.

7.4 Network constraints

Major network constraints that Electra may face in the future occur at the two grid exit point connections (GXPs) on the network. For many years it has been suggested that a new GXP is required for this network. However, load has not grown at the rate predicted. With the increased number of actual and proposed transportation projects, it is possible that load growth within the area may increase more rapidly in the future. But this also must be seen in the context of continued patchy overall economic growth both nationally and internationally.

Mangahao GXP exceeded the transformers n-1 winter capacity by approximately 2.5MW in 2015. This is expected to increase to approximately 8MW by 2027. The supply transformer overload is managed operationally as Mangahao generation is contracted to be and is usually available at peak load periods. If Mangahao continues to generate at 13MW or more, this issue could be delayed beyond the forecast period. The expected end of life rebuilding of Mangahao’s switchyard provide a convenient opportunity to increase capacity.

The recent upgrading of Paraparaumu GXP (as a result of the Transmission Gully highway project) has increased its capacity and removed any transmission constraints in the Kapiti area.

Based on several small reports that were conducted in previous years, it was initially decided that an additional zone substation would be built at Manakau to ease the load at the Paraparaumu GXP. This zone substation would get supply via the existing 33kV from the Mangahao GXP. This however would continue to reduce the ability to transfer load during emergency conditions as well as increasing the load requirements at Mangahao GXP and has been deferred in preference to 11kV capacity upgrades for the time being.

The following table shows the main 33 kV circuits that are expected to become constrained, a description of the constraint, and the intended action to remedy the constraint. Note that the intended remedies are dependent upon the GXP (or alternative) solution that is developed and intended remedies will be finalized once this is known. These remedies are still the most likely scenario based on information to hand as at date of this document.

Network constraints within the Electra system have been identified as shown in table 2.3 and represented here for ease of reading. While these projects are included within the AMP budget, it is possible that as a result of the work being conducted by Transpower and Tesla, the constraints may change as a result of a proposed GXP or alternative transmission solution. When this is known more fully, these network constraints will be reassessed to establish if they remain valid.

Constraint	Description	Intended Remedy
Shannon & Mangahao – Levin East circuits	Once the load at Mangahao GXP reaches 35MVA, there is the potential for overloading these circuits in an (n-1) outage.	Complete the separation of the Mangahao-Levin East 33kV line by installing a cable from Arapaepae Road to Levin East.
Levin West – Levin East circuit	This forms part of the ring system from Mangahao, consequently constraints will manifest themselves in the Shannon & Mangahao to Levin East circuits.	Short term - Introducing Summer/Winter ratings Long term - Splitting the Mangahao – Levin East 33kV line at Arapaepae Rd.

Table 7.6: Network constraints on the sub-transmission network

There are a number of developing beach settlements (eg Waikawa Beach, Hokio Beach, Waitarere Beach) that are on single 11kV spur lines that may, over the planning period, require duplication due to the number of consumers that will be affected by any interruption. Duplication as opposed to up-sizing gives the added advantage of improved security and improved reliability, which means the impact of an outage has less impact on security targets discussed in Section 5.

7.5 Distributed generation

Electra recognises the potential value of distributed generation in the following ways:

- Reduction of peak demand at Transpower GXPs;
- Reducing the impact of existing network constraints;
- Avoiding investment in additional network capacity;
- Making a very minor contribution to supply security where consumers are prepared to accept that local generation is not as secure as network investment;
- Making better use of local primary energy resources thereby avoiding line losses;
- Avoiding the environmental impact associated with large scale power generation.

Electra also recognises that distributed generation can have the following less desirable effects:

- Increased fault levels, requiring protection and switchgear upgrades;
- Increased line losses if surplus energy is exported through a network constraint;
- Potential stranding of assets, or at least of part of an assets capacity.

Electra takes an active interest in the development of larger scale distributed generation that potentially benefits both the generator and Electra. A major benefit of this type of distributed generation is in reducing transmission charges.

This has been the case at Mangahao GXP where the existing hydro-electric power station is now treated as embedded for transmission purposes. Cooperative used of the generation has reduced our transmission charges significantly (approximately 40%) because these charges are based on the average of the 100 highest regional peaks. However this has only resulted in a reduction of the system peak load of 6% as the generation was not available at all times.

It should also be noted that photovoltaics (PV) without storage will contribute little or nothing to reducing peak demand on Electra’s network, particularly during the peak winter period.

Apart from Mangahao, which is notionally embedded at the grid exit point there are 263 distributed generation sites on the Electra network with a combined capacity of 680kW. This had been growing at a rate of 200% per annum (admittedly off a low base), but since feed in prices offered by retailers were reduced in 2014, new connections have been steady at approximately 100 per annum for the last two years. While we initially expected that it would not be until there several hundred distributed generation sites that a material impact may occur and warrant further attention in the Asset Management Plan, modelling has now shown that given the size and nature of most installations, 5000 sites (greater than 10% of connections) would be needed to materially impact the current operational assumptions of the business. Furthermore, it is expected that the limited availability of installers combined with market saturation will allow sufficient time to adjust our planning assumptions. Electra therefore, does not take into account the effect of distributed generation in its Asset Management Planning process at this stage.

The key requirements for those wishing to connect distributed generation to the network are contained in Electra’s Distributed Generation Policies:

Network Requirement	Policy or Condition
Connection Terms and Conditions	• An annual administration fee may be payable by the connecting party to Electra. • Installation of suitable metering (refer to technical standards below) shall be at the expense of the distributed generator and its associated energy retailer. • Electra is happy to recognise and share the benefits of distributed generation that arise from reducing costs (such as transmission costs, or deferred investment in the network) provided the distributed generation is of sufficient size to provide real benefits. • Those wishing to connect distributed generation must satisfy Electra that a contractual arrangement with a suitable party is in place
Safety Standards	• A party connecting distributed generation must comply with any and all safety requirements promulgated by Electra. • Electra reserves the right to physically disconnect any distributed generation that does not comply with such requirements.
Technical Standards	• Metering capable of recording both imported and exported energy must be installed. If the owner of the distributed generation wishes to share in any benefits accruing to Electra, such metering may need to be half-hourly. • Electra may require a distributed generator of greater than 10kW to demonstrate that operation of the distributed generation will not interfere with operational aspects of the network, particularly such aspects as protection and control. • All connection assets must be designed and constructed to technical standards not dissimilar to Electra's own prevailing standards. • Electra reserves the right to decline connection applications to a feeder that already has sufficient connected generation to destabilise operations.

Table 7.7: Key requirements for connecting distributed generation

Electra is not aware of any other firm distributed generation projects that are likely to emerge within the planning horizon. However, a number of projects have been discussed with various parties including opportunities for peak generation in Electra's southern area. This is at the early discussion phase and will be included in future planning if it looks like becoming a reality that will impact the network.

7.6 Non-asset solutions

As discussed in section 7.1.2 Electra routinely considers a range of non-asset solutions, and has a preference for solutions that avoid or defer new investment.

Electra's pricing structure has signals for all consumer groups to reduce load during peak periods. For example peak pricing is 42% higher than average pricing while off peak pricing is only 17% of average pricing. Approximately 60% of Electra customers have their peak loads managed using load control equipment already in use on the network. At this stage no other demand management initiatives are foreseen in the planning horizon, but any new initiative likely to have a significant impact would be considered. A pricing review was completed in 2012 to ensure that pricing signals are having the impact expected. One new pricing option was introduced in 2013 as a result.

Electra has a Generation Connection Agreement for Mangahao Power Station. This agreement has the purpose of sharing transmission benefits resulting from the demand reduction at the Grid Exit Point by generation being focused where possible around regional co-incident peaks.

Over recent years Electra has encouraged and subsidised the installation of a range of energy efficiency products including hot water cylinder wraps and thermostats, home insulation and energy efficient lighting within the Electra area. Research shows that in 2012 78% of consumer households had energy efficient lights in some or all of their fittings. That figure was 54% for commercial consumers. Electra continues to discuss other energy efficiency measures with end users including active engagement with larger consumers to improve load factor.

7.7 Network Development Plan including project descriptions

The network development plan has been disaggregated by the following asset groups:

- GXP and transmission development;
- Sub-transmission development;
- Zone Substation development;
- Distribution feeders (which includes all 11kV & 400V circuits and distribution switchgear);
- Other assets.

Each of these sections is further disaggregated to the following categories:

- Projects currently underway or planned to start in the next twelve months – for these projects a detailed description is provided, and the reasons for choosing the selected option is stated;
- Projects planned for the next four years – for these a summary description of the project is provided;
- Projects being considered for the remainder of the AMP period – these are discussed at high level, and it should be noted that this group of projects and associated costs are more speculative.

Each section includes separate identification of expenditure on all the main types of development projects as follows:

- Reliability, Safety and Environment;
- Asset Replacement and Renewal;
- System Growth (Up-sizing);
- Consumer Connection;
- Asset Relocations;

- Overhead to Underground (OHUG) conversion.

7.7.1 GXP and transmission development

GXP and transmission assets are owned by Transpower. The Mangahao GXP has two 30MVA 110/33kV transformers installed. The firm capacity of this GXP is 30MVA (summer/winter). The load is slowly increasing on this GXP, the transformers are predicted to reach 8MW overload by 2027. They are scheduled for end of life replacement in 2023 but may be replaced earlier in conjunction with other work at the Transpower site. At that point the opportunity will be taken to increase the capacity at the site to 60MVA enable Otaki to be supplied from Mangahao at any time if required..

The Paraparaumu GXP has recently been upgraded from two 60MVA 110/33kV transformers upgraded to two 120MVA 220/33kV transformers

On completion of the above projects no further development work is envisioned for the duration of the planning period.

7.7.1.1 Expenditure projections

Works associated with the Grid exit points is included in Transpower's Asset Management Plan. As there are no further development plans projected Electra has not set aside a budget for research associated with the GXP's or transmission system.

7.7.2 Sub-transmission development

Load growth will be catered for by upgrading capacity of existing circuits and zone substations and/or constructing new zone substations and 33kV circuits. Such projects are complementary to each other and to life-cycle maintenance plans.

The overall condition of the 33 kV sub-transmission overhead network is good. The IRL report on the two aged copper circuits between Mangahao and Levin East concluded that these circuits are generally in good condition and should, statistically, last until 2042. There is no proposal to renew any conductors within the ten year forecast period. The samples were removed from the area most prone to high winds and other sources of mechanical stress. Electra has, therefore, delayed the renewal of these circuits and routine annual inspections and maintenance will continue on them.

The double circuit line from Mangahao to Levin is currently operated as a single circuit as it is joined together approximately 5km north of Levin at Waihou Rd. Once capacity at Mangahao GXP is increased this will enable Otaki to transfer permanently from Paraparaumu. With Otaki connected via Levin it is considered prudent to duplicate the last 5km of line into Levin East substation. This will have the dual benefit of increasing capacity and reliability. In the long term full separation of the lines is planned when the line is scheduled for rebuilding (20 plus) years from now.

Electra's Foxton-Shannon 33kV circuit is built along the Foxton-Shannon Highway which crosses the flood plains of the Manawatu River. This can lessen the stability of the 33kV poles along this route, but there is no concern with the overall condition of the overhead line. Any poles that have increased their lean will continue to be re-guyed, a culvert installed behind them and, where necessary, re-blocked with gravel.

The over-all condition of the 33 kV sub-transmission underground cables is good and there is no proposal to renew the major cables within the ten year forecast period. The application of summer/winter ratings to defer replacement will mean that some of the short sections of cable connecting the substations with the overhead subtransmission system will need to be increased in capacity. This will be carried out on a case by case basis as individual load thresholds are reached.

7.7.2.1 Detailed description of projects currently underway or planned to start in the twelve months ending 31 March 2017

Table 7.8 below summarises the network development projects and projected costs for the year ending 31 March 2017:

Circuit	Expected Cost (2016 $000's)	Primary Purpose
Tararua Rd – Arapaepae Rd[i)]	615	Reliability

Table 7.8: Sub-transmission Network Development Budget Year Ending 2017

(i) Tararua Rd - Arapaepae Rd - Duplicate line with an underground cable. At described in 7.7.2 above the dual circuit from Mangahao to Levin combined into one line at Waihou Rd. This project involves installing cable in conjunction with the additional 11kV feeder described below along part of that route. This project will ensure an increased capacity n-1 system into this substation and the wider urban area. Costs were to be split over the 2014/15 and 2015/16 financial years but the impending availability of the existing Transpower 110kV lines means that any further expenditure will be deferred until final ownership is determined.

7.7.2.2 Projects planned for years ending 2018-2022

Table 7.9 below summarises the sub transmission network development projects and projected costs for the period 2018-2022:

Circuit	Timing	Expected Cost (2016 $000's)	Primary Purpose

Table 7.9: Sub-transmission Network Development Budget 2018-2022

7.7.2.3 Projects being considered for the remainder of the AMP planning period

The table below summarises the work planned for the sub transmission system for the period 2022 to 2026:

Circuit	Description	Expected Cost (2016 $000's)	Timing	Primary Purpose
Levin West – Foxton(i)	Increase Conductor size	1,704	2021-2024	Growth
Levin West – Levin East(ii)	Increase Conductor size	568	2025	Growth

Table 7.10: Sub-transmission Network Development budget 2022-2026

(i) Reconductor the Levin West to Foxton Line to allow operation as a closed ring all year round. Slower than expected growth means that existing criteria are now not expected to be met until 2022

(ii) Projected cost of increasing size of conductor to handle expected capacity growth.

7.7.2.4 Expenditure projections

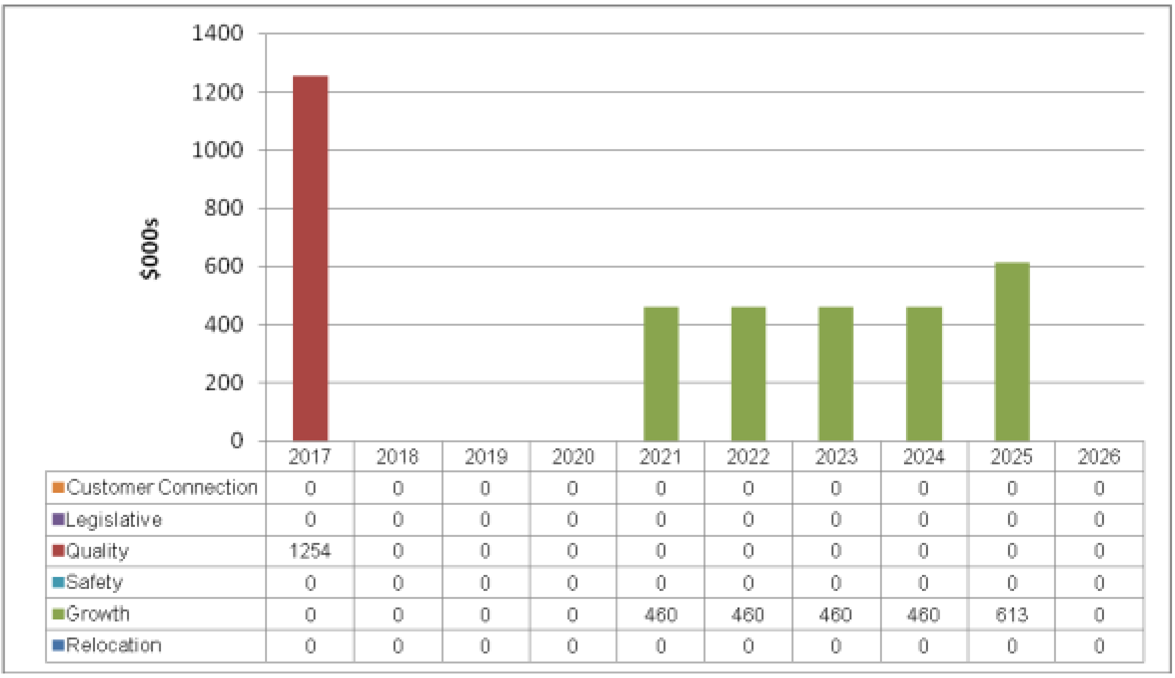


Figure 7.4: Development costs for sub-transmission development

7.7.3 Zone substation development

7.7.3.1 Detailed description of zone substation projects currently underway or planned to start in the year ending 31 March 2017

Zone Substation	Description	Expected Cost (2016 $000's)	Primary Purpose
All	Protection [i]	199	Reliability

Table 7.11: Development projects for zone substations 2017

(i) Replacement and reprogramming of protection systems for both distance and bus zone protection schemes.

7.7.3.2 Projects planned for years ending 2018-2022

Zone Substation	Description	Expected Cost (2015 $000's)	Timing	Primary Purpose
All [i]	Protection upgrades	539	2018	Reliability
All[ii]	Arc Flash Protection	303	2018	Safety
Paekakariki [ii]	2nd Transformer	95	2018	Reliability

Table 7.12: Development projects for zone substations 2018 – 2021

(i) All - Protection upgrades. This will be needed as the system loads increase and protection grading between feeders and zones becomes a problem with the existing relays. The work involves installing bus zone circuit breakers and associated modifications to the existing substation structures. Only those sites of concern will be completed at this time and will be based on feeder loads.

(ii) Installation of arc flash protection in substations to prevent injury to personnel in the event of a fault during operation. It is expected that this will become an industry standard practice by 2019.

(iii) Relocation of a spare zone transformer from Shannon to Paekakariki as a non-commissioned spare for future installation. Price is for transportation installation including oil retention system.

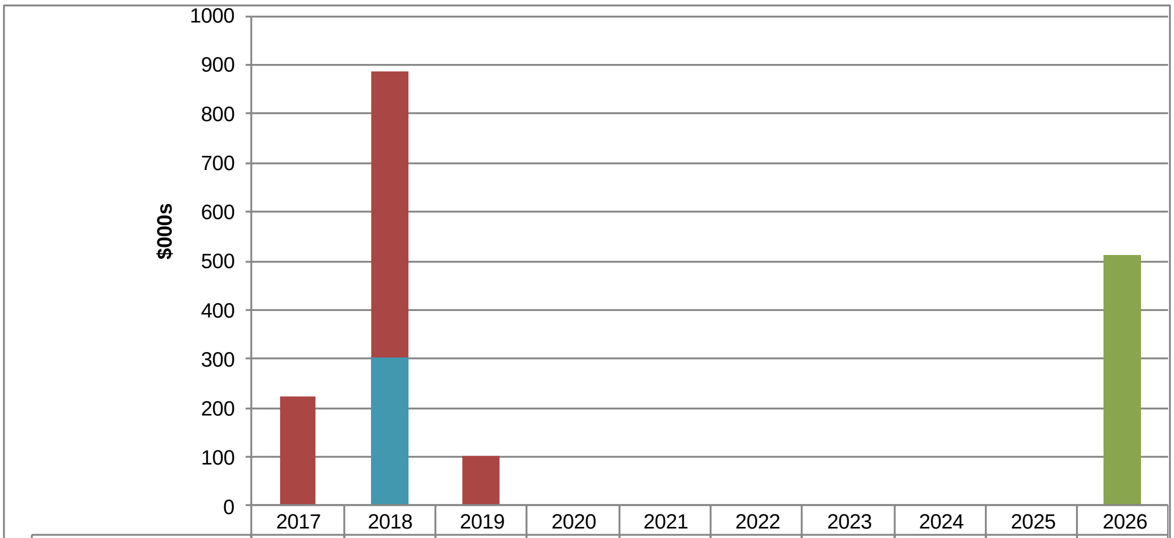
7.7.3.3 Projects being considered for the remainder of the AMP planning period

Zone Substation	Description	Expected Cost (2016 $000)	Timing	Primary Purpose
Manakau [ii]	Substation	946	2026-2027	Growth

Table 7.13: Development projects for zone substations 2022 - 2026

(i) Manakau - To meet additional demand for lifestyle blocks around Manakau and Te Horo, which are placing stress on the Otaki zone substation. At this stage installing a small rural substation north of Otaki still appears to be the most suitable option to meet the requirements for load centre, proximity to sub-transmission lines and distribution feeder route diversity. If the rate of growth in the area slows then it will become more economic the install extra capacity as part of the lifecycle replacement program of existing equipment rather than with additional specific assets.

7.7.3.4 Expenditure projections



	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026
Customer Connection	0	0	0	0	0	0	0	0	0	0
Legislative	0	0	0	0	0	0	0	0	0	0
Quality	225	583	102	0	0	0	0	0	0	0
Safety	0	303	0	0	0	0	0	0	0	0
Growth	0	0	0	0	0	0	0	0	0	511
Relocation	0	0	0	0	0	0	0	0	0	0

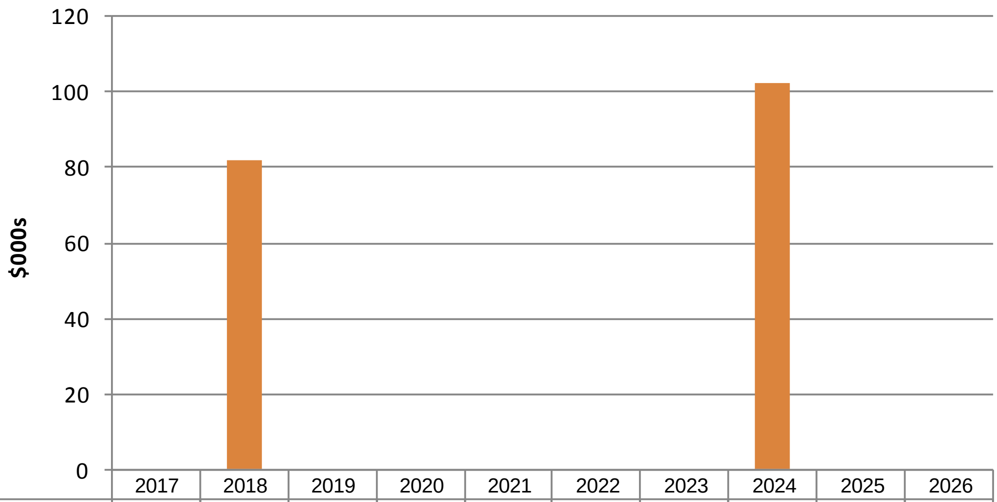
Figure 7.5: Development costs for zone substations

7.7.4 Distribution network

7.7.4.1 Distribution transformers

There are no specific development plans for individual distribution transformers and substations. Funds have been allocated for the installation of monitoring equipment to gather data for a "smart grid" trial and relocation of indoor sites when they are scheduled for renewal.

Equipment	Description	Expected Cost (2015 $000's)	Timing	Primary Purpose
Transformers	Smart Grids	75	2019	Quality
Transformers	Smart Grids	94	2024	Quality



	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026
Customer Connection	0	0	0	0	0	0	0	0	0	0
Legislative	0	0	0	0	0	0	0	0	0	0
Quality	0	82	0	0	0	0	0	102	0	0
Safety	0	0	0	0	0	0	0	0	0	0
Growth	0	0	0	0	0	0	0	0	0	0
Relocation	0	0	0	0	0	0	0	0	0	0

Figure 7.6: Development costs for distribution transformers

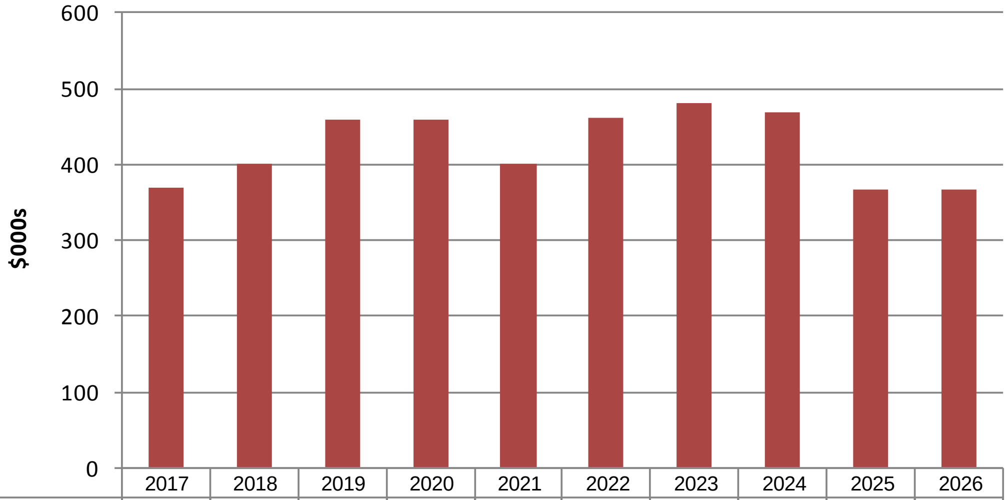
7.7.4.2 Distribution switchgear

The development plans for switchgear (circuit breakers, air break switches and ring main units) are driven primarily by the desire to improve reliability and reduce maintenance and operating costs. The following table summarises the network development programme for switchgear. It includes investments to improve system network reliability and network extensions.

Equipment	**Description**	**Expected Cost (2016 $000's)**	**Timing**	**Primary Purpose**
Switchgear	Additional Installations[i]	0 0 47	2017 2018-2021 2022-2026	Quality Quality Quality

Table 7.14: Development projects for distribution transformers & switchgear 2016-2026

(i) The additional network sectionalisation achieved through the installation of new switches will improve network reliability. Sites for 2016/17 include, Tokomaru Rd and Williams Rd, Tokomaru, Ballance St, Shannon, SH57 north of Levin, Seddon St, Waikanae, Cedar Dr & Manly St, Paraparaumu. Recently installed Ring Main Units will also be automated once we have completed converting of all existing automated equipment to the DNP3 communications protocol.



	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026
Customer Connection	0	0	0	0	0	0	0	0	0	0
Legislative	0	0	0	0	0	0	0	0	0	0
Quality	369	400	459	459	400	462	480	469	366	366
Safety	0	0	0	0	0	0	0	0	0	0
Growth	0	0	0	0	0	0	0	0	0	0
Relocation	0	0	0	0	0	0	0	0	0	0

Figure 7.6: Development costs for distribution switchgear

7.7.4.3 11kV and 400V network developments

Network extensions, at 11kV and 400V, are generally driven by new subdivisions and are underground or overhead, as required by Kapiti Coast and Horowhenua District Councils (and/or Electra requirements). As part of the approval of these extensions Electra may require an upgrade in circuit size or additional switchgear for future expansion of the 11kV network. These extensions are funded by the developer. Electra then purchases these assets at a standard economic value.

The following table summarises the network development programme for the 11kV and 400V distribution network for the years ending 2017 to 2026. It includes planned and inspection driven renewals, investments to improve system network reliability, network upsizing and network extensions.

Asset	Description	Expected Cost (2015 $000's)	Timing	Primary Purpose
Fault Locators	Additional installations	14 199 237	2017 2018-2022 2022-2026	Quality Quality Quality
11kV Conductor Development	Cedar Dr (i) Manly St, Ngapotiki St (ii)	189 142 3113 1353 4893 113	2017 2017 2018-2021 2018-2021 2022-2026 2022-2026	Growth Quality Quality Growth Quality Growth

400V Conductor Development	400V Upgrades(iii)	38 151 189	2017 2018-2021 2022-2026	Quality Quality Quality
Network Extensions	Subdivision extensions (iv)	95 379 473	2017 2018-2021 2022-2026	Connection Connection Connection
Total		**11,757**		

Table 7.15: Capital projects for 11kV/400V Network

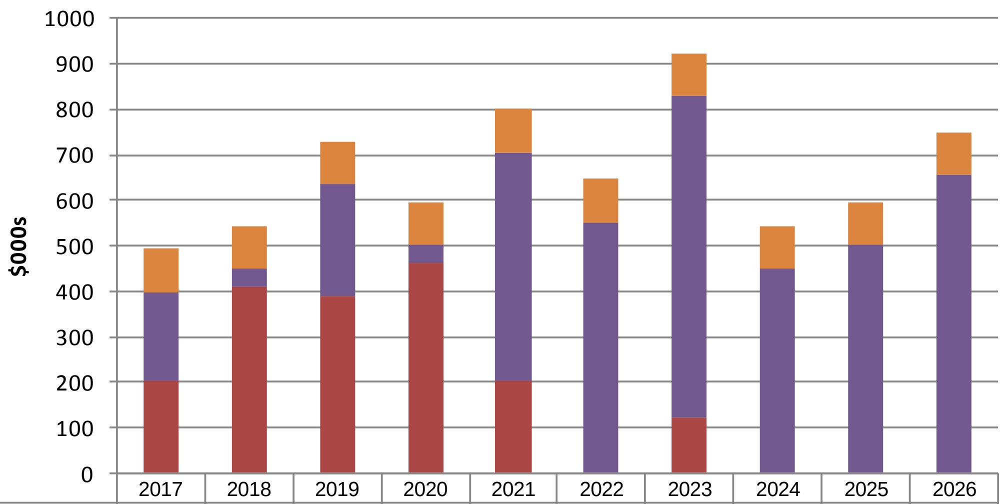
(i) Cedar Dr, Paraparaumu. Replacement of a 30 year old cable installed at the early stages of a subdivision that is no longer able to cope with expected demand.

(ii) Manly St, Ngapotiki St. Installation of a cable linking two parts of Paraparaumu Beach increasing network resilience and increase load transfer capacity in the area

(iii) Installation of short paralleling sections of cable to minimize outages for planned work such as transformer replacements.

(iv) Purchase of customer led network extensions. The majority of cost is paid for by the developer and a notional payment is made to transfer the newly created asset to Electra for future operation and maintenance.

The following figure summarises the projected capital costs for both 11kV and 400V lines and cables over the planning period.



	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026
Customer Connection	95	95	95	95	95	95	95	95	95	95
Legislative	0	0	0	0	0	0	0	0	0	0
Quality	194	41	245	41	501	552	705	450	501	654
Safety	0	0	0	0	0	0	0	0	0	0
Growth	204	409	388	460	204	0	123	0	0	0
Relocation	0	0	0	0	0	0	0	0	0	0

Figure 7.7: Development costs for 11kV and 400V distribution lines and cables

7.7.5 Other Network Assets

Table 7.16 below summarises the network development projects and projected costs for other network assets for the period 1 April 2016 to 31 March 2027.

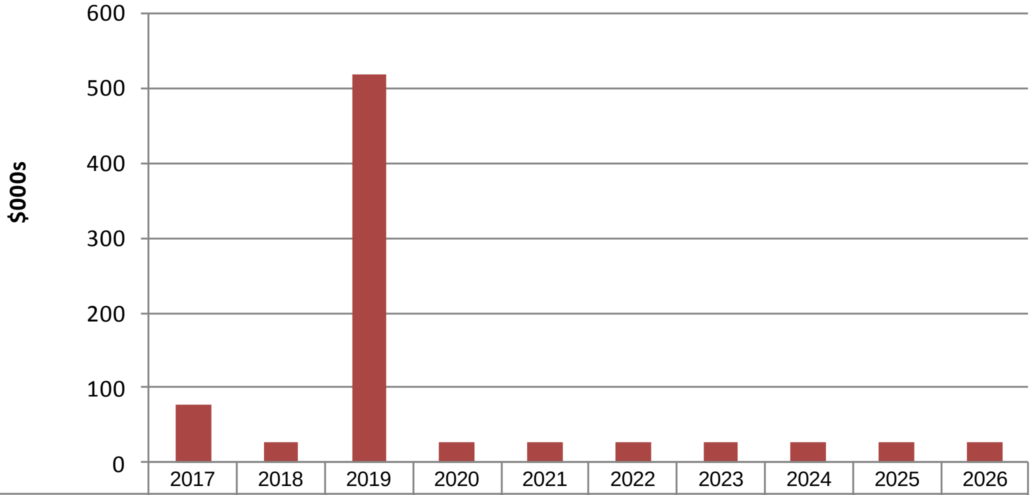
Asset	Description	Expected Cost (2016 $000)	Timing	Primary Purpose
Levin SCADA master station	Analog radio upgrades	12 24 24	2017 2018-2021 2022-2026	Renewals Renewals Renewals
	Scada upgrade	9 14 9 45	2017 2018 2019 2020-2024	Renewals Renewals Renewals Renewals
Fault Locators	Fault location communications	28 199	2017 2018-2026	Reliability Reliability
	Substation and Pole tops	4	2017-2024	Renewals
Ripple Plant	Otaki Ripple Plant	454	2019	Reliability
NIMS	NIMS programe updates	57	2017-2026	Renewals
Total for period		**4,566**		

Table 7.16: Development projects for other network assets

(i) Provision of a 3rd Ripple Relay Plant at Otaki Substation for peak load management. This would act as a backup to both Paraparaumu and Shannon Plants. Although able to be connected to both GXP's it would remain isolated except when one or other plant was out of service.

7.7.5.1 Expenditure forecast

The figure below shows the projected expenditure for other network assets for the planning period 1 April 2016 to 31 March 2027.



	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026
Customer Connection	0	0	0	0	0	0	0	0	0	0
Legislative	0	0	0	0	0	0	0	0	0	0
Quality	77	28	519	28	28	28	28	28	28	28
Safety	0	0	0	0	0	0	0	0	0	0
Growth	0	0	0	0	0	0	0	0	0	0
Relocation	0	0	0	0	0	0	0	0	0	0

Figure 7.9: Development costs for other assets

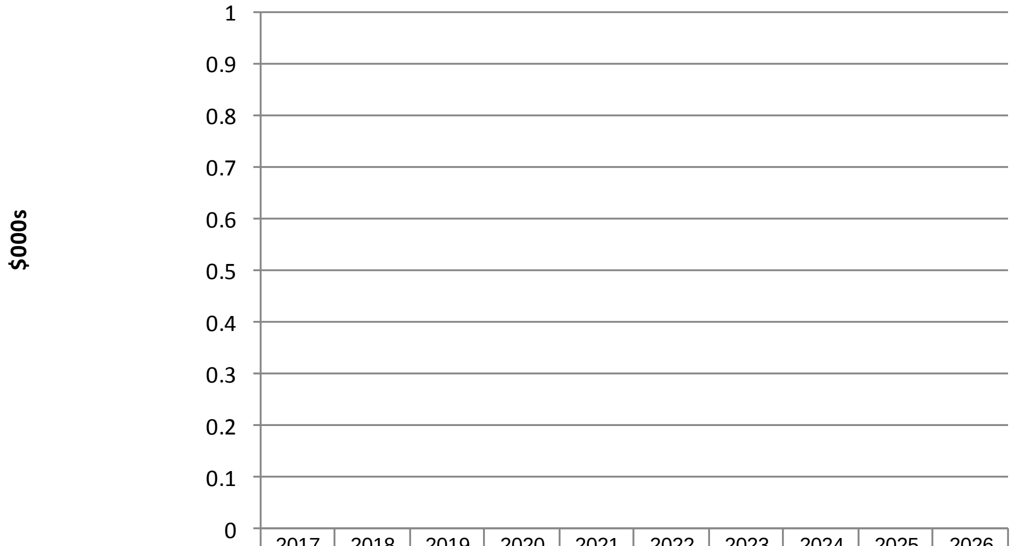
7.7.6 Non Network Assets

There are no development projects planned for non network assets for the period 1 April 2016 to 31 March 2027.

Asset	**Description**	**Expected Cost ($000)**	**Timing**	**Primary Purpose**

7.7.6.1 Expenditure forecast

The figure below shows the projected expenditure for non network assets for the planning period 1 April 2016 to 31 March 2027.

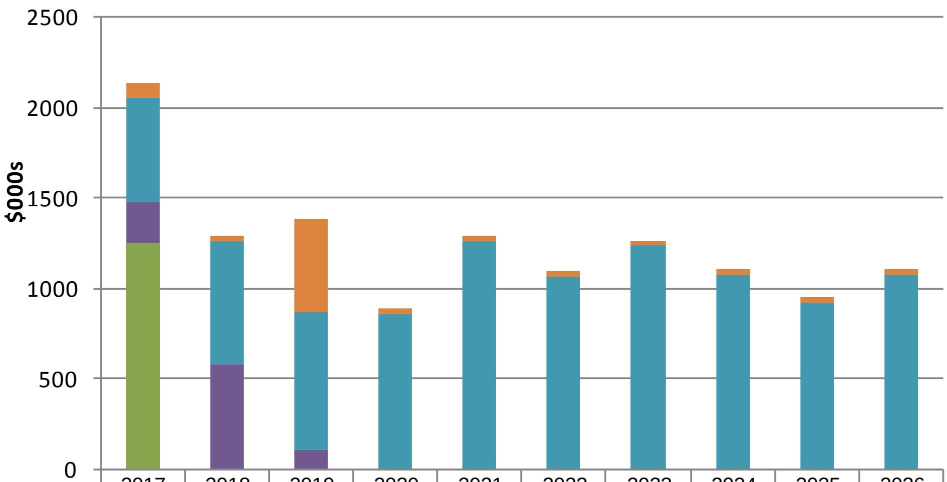


	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026
Tools, plant & other machinery	0	0	0	0	0	0	0	0	0	0
Motor vehicles	0	0	0	0	0	0	0	0	0	0
Office furniture & equipment	0	0	0	0	0	0	0	0	0	0
Office buildings, depots & workshops	0	0	0	0	0	0	0	0	0	0

Figure 7.7: Expected non network asset development costs

7.7.7 Summary of expenditure by cost category

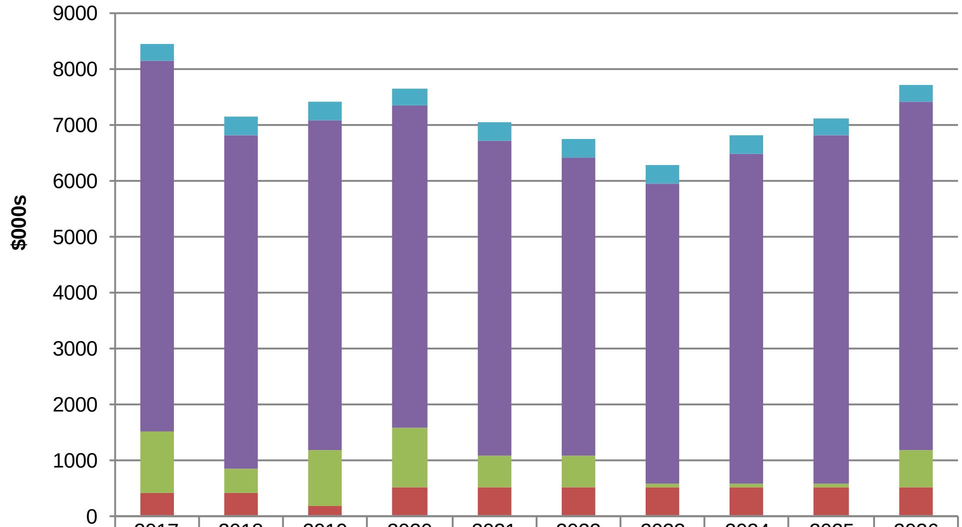
This section of the development plan shows the expenditure by life-cycle activity rather than by asset class. The following graph shows the projected costs for reliability, safety and environmental projects for the planning period 1 April 2016 to 31 March 2027.



	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026
Other Assets	77	28	519	28	28	28	28	28	28	28
Distribution Network	578	675	766	858	1258	1065	1236	1072	918	1071
Zone Substations	225	583	102	0	0	0	0	0	0	0
Subtransmission Network	1254	0	0	0	0	0	0	0	0	0
GXP Related Assets	0	0	0	0	0	0	0	0	0	0

Figure 7.9: Expected reliability costs by asset group

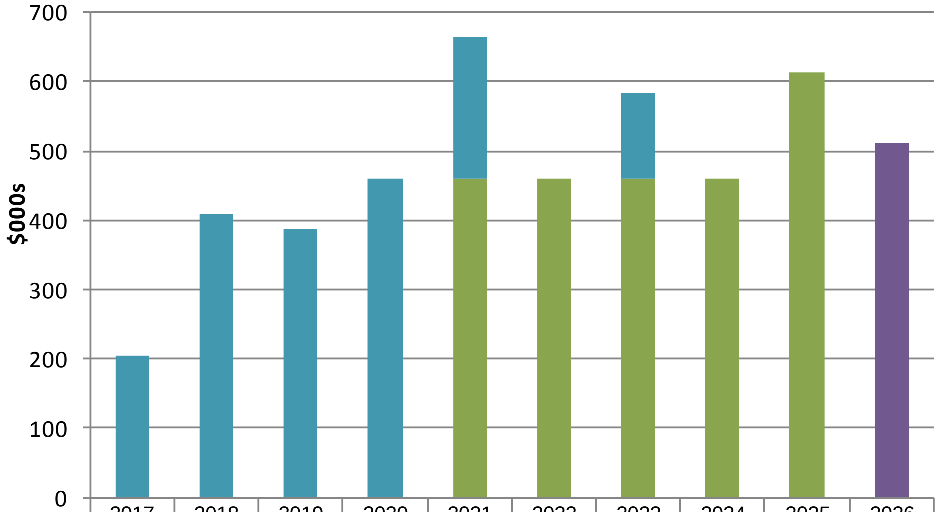
The following graph shows the projected costs for renewal projects for the planning period 1 April 2016 to 31 March 2027.



	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026
Other Assets	320	308	320	308	320	308	320	308	320	308
Distribution Network	6635	5975	5919	5758	5656	5357	5392	5938	6252	6252
Zone Substations	1117	460	991	1073	562	562	51	51	51	664
Subtransmission Network	393	393	184	508	508	508	508	508	508	508
GXP Related Assets	0	0	0	0	0	0	0	0	0	0

Figure 7.10: Expected renewal costs by asset group

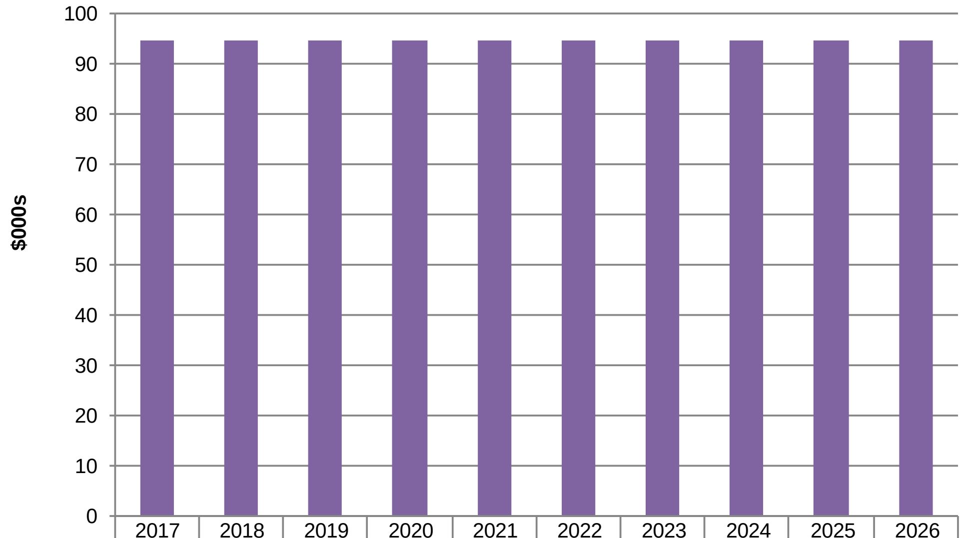
The following graph shows the projected costs for system growth projects for the planning period 1 April 2016 to 31 March 2027.



	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026
Other Assets	0	0	0	0	0	0	0	0	0	0
Distribution Network	204	409	388	460	204	0	123	0	0	0
Zone Substations	0	0	0	0	0	0	0	0	0	511
Subtransmission Network	0	0	0	0	460	460	460	460	613	0
GXP Related Assets	0	0	0	0	0	0	0	0	0	0

Figure 7.11: Expected system growth costs by asset group

The following graph shows the projected costs for customer connection projects for the planning period 1 April 2016 to 31 March 2027

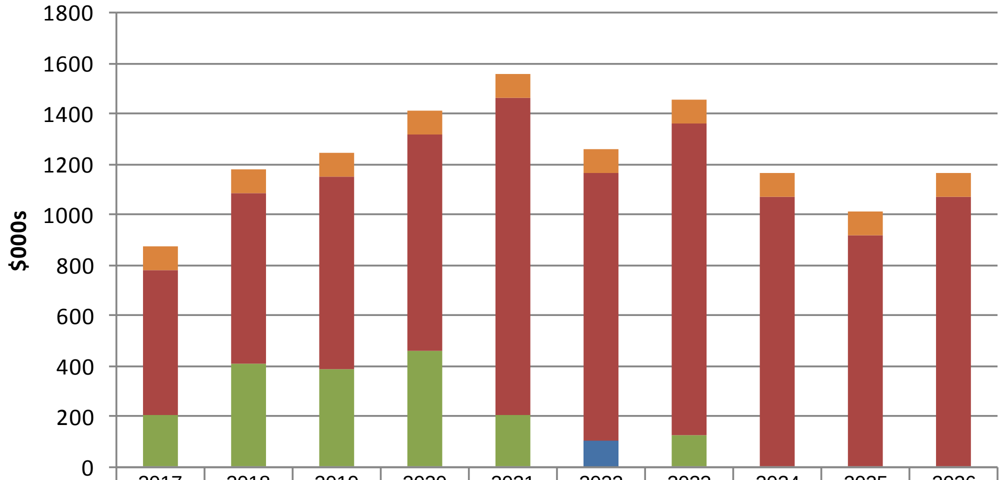


	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026
Other Assets	0	0	0	0	0	0	0	0	0	0
Distribution Network	95	95	95	95	95	95	95	95	95	95
Zone Substations	0	0	0	0	0	0	0	0	0	0
Subtransmission Network	0	0	0	0	0	0	0	0	0	0
GXP Related Assets	0	0	0	0	0	0	0	0	0	0

Figure 7.12: Expected consumer connection costs by asset group

7.7.8 Summary of development costs for all asset categories

The following graph shows the projected development expenditure for all network asset categories for the planning period 1 April 2016 to 31 March 2027 by activity.



	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026
Customer Connection	95	95	95	95	95	95	95	95	95	95
Legislative	0	0	0	0	0	0	0	0	0	0
Quality	578	675	766	858	1258	1065	1236	1072	918	1071
Safety	0	0	0	0	0	0	0	0	0	0
Growth	204	409	388	460	204	0	123	0	0	0
Relocation	0	0	0	0	0	102	0	0	0	0

Figure 7.8: Summary of development costs by activity

8 Risk Management

8.1 Risk analysis

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 that imposes new costs and distortions whilst restricting revenue. This section 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.

8.1.1 Electra Group's Policy – Risk Management

8.1.1.1 What is Risk Management?

There is risk involved in any business venture. The key to a successful business operation is assessing and managing those risks to ensure business continuity and success. Risk Management is not simply a compliance issue, but rather a way of viewing a company's operation for areas that could have a significant impact on long term viability. Risk can present either a hazard or an opportunity in terms of the company's objectives, therefore risk management activities should be closely monitored. The ultimate responsibility for risk management lies with the company's Board of Directors.

8.1.1.2 The policy

The Electra Limited Board of Directors has tasked management to monitor and manage risks to the company and formally report results to the Board in March each year. Risks to the Electra Group are to be managed in two distinct ways as follows:

- Insurance cover; and
- Risk management reviews.

8.1.2 Insurance

The company's insurances are reviewed for insurance required, adequacy of cover and marketed and renewed on an annual basis. The successful company is provided with an annual declaration which includes factors which may impact on the company's risk exposure. Risk exposure will be insured against wherever practicable. A risk committee comprising selected Board members, the Chief Executive and the Chief Finance Officer will assess annual proposals and present recommendations to the Electra Limited Board for approval.

8.1.3 Risk management reviews

Companies within the Electra Group will conduct an annual review of the risks relating to their operations. Risk management reviews are completed annually with results reported to the Electra Limited Board of Directors for acceptance. These reviews comprise:

- 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	August 2015 Final Score	December 2014 Final Score
G1	**Fatality or injury to staff, contractors or public**		
	Risks associated to people employees, contractors or public from work or infrastructure across the Electra Network	200	180
G2	**Inadequate business continuity and disaster recovery management**		
	Inefficient response, restoration and communication to stakeholders	154	165
	Inadequate and/or limited insurance cover for extreme events	115.5	165
	Unauthorised cyber access into ICT/SCADA systems	115.5	154
	Loss of data and company records	60	70
G3	**Inability to maintain economic return / discount contribution related to core business**		
	Historic pricing tariffs threaten medium-term economic return	80	154
	Continued reduced electricity consumption	80	154
	Exposure to avoidable peak demand costs	100	125
G4	**Failure to anticipate and plan for technological change**		
	Technological advances threaten businesses established markets	112	112
	Poor data management (access, analysis and decision making)	82.5	125
	Lack of timely investment in beneficial technological innovation	80	103.6
G5	**Failure to maintain stakeholder relationships**		
	Decline of company's reputation	70	78.4
	Lack of contract and contractor management	60	125
	Major customer disputes and litigation by our customers	50	50
	Inadequate skills and aptitude for the role (individual)	80	125
G6	**Poor long-term positioning and performance**		
	Failure of businesses to achieve profitability expectations	80	122
G7	**Inability to manage political and regulatory change**		
	Increased ComCom, EA costs and any potential industry reform	80	150
G8	**Inadequate commercial and financial management**		
	Inadequate group funding strategy leading to liquidity risk	80	105
	Risk of material fraud resulting in financial loss	70	112

(i) This risk has been mitigated somewhat by Electra's recent withdrawal from non-core business contracting to focus on the Electra network.

(ii) This risk has been reduced due to the lack of uptake for these technologies.

(iii) Upgraded as a result of the Canterbury earthquakes, this risk has now been mitigated by extended insurance cover.

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8.1.4 Identifying risks

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.

8.1.4.1 Safety risks

To operate and maintain an electrical network involves hazardous situations that cannot entirely be eliminated. 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 recently 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 section 3.4);
- 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 2015.

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.

8.1.4.2 Environmental risk

Although an earthquake would create more damage, 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 vegetation failures 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 relatively 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. 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

Table 8.1: Environmental risks

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.

8.1.4.3 Asset failure

The greatest probability of failure to a 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 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 section 6.2, 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 section 7.7.

8.1.4.4 Network records

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 backup tapes, including SCADA, and contracts with suppliers to provide temporary support if required.

8.1.4.5 Regulatory regime

As a Trust owned Electricity Distribution Business, Electra is no longer subject to the Commerce Commission's targeted control regime – where network prices and quality standards are monitored at specified levels. This is the most significant risk to a lines company and in particular investment within that network. While not subject to having prices regulated by the Commerce Commission, Electra is confident about being able to invest at a sensible level that allows delivery of an effective and efficient electricity supply to consumers and is still subject to the information disclosure regime. Further, Electra will also be closely observed by its consumers/owners in terms of both price and other key performance factors. Consumers are represented by the Electra Trust and as noted the company undertakes annual surveys around service levels and other attributes.

8.1.5 Risk and project prioritisation

As discussed in section 7.2, projects that reduce risks with high likelihood and high consequence are prioritised over projects with low likelihood and low consequence. The consequence criteria are shown in the table below. delete

		Economic	**Safety**	**Social and Environmental**	**Operational**
	Measure	$ Value	Degree of Harm	Level of Interest	SAIDI
0.1	**Minor**	<$100k	Minor incident, no medical attention required	Minimal interest	Less than 0.1 minute
5	**Moderate**	$100k to $500k	First Aid treatment on site	Local media coverage	0.1 to 1 minute

20	**Serious**	$500k to $2m	Incident requiring medical attention	Regional coverage.	1 to 5 minutes
40	**Major**	$2m to $7m	Hospitalisation.	National coverage	5 to 10 minutes
100	**Catastrophic**	>$7m	Fatality.	International coverage	10 or more minutes

Table 8.2: Consequence criteria

The following table discloses the frequency criteria:

Frequency Criteria	
1	**Rarely**
10	**Yearly/Seldom**
12	**Monthly/Occasional**
15	**Weekly/Frequent**
20	**Daily/Continuous**

Table 8.3: Likelihood criteria

The following table discloses the probability criteria:

Probability Criteria	
0.04	**Improbable**
0.2	**Remote**
0.4	**Occasional**
0.8	**Likely**
1.0	**Certain**

Table 8.4: Probability criteria

The combination of the consequence and frequency and probability criteria produces a risk rating. Projects are then ranked in priority based on this risk rating. The expected time to complete any project is then factored into scheduling work for the Asset Management Plan.

8.2 Management of risk

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.

Table 8.5: How risks are managed

The following table summarises asset specific risk mitigation and management features of the network assets.

Network Component	How risks are managed

Transformers and Switchgear	• Use of insulating oil • 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.

Table 8.6: How risks are managed for different network components

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.

8.3 Emergency response and contingency plans

Electra, as a lines company, 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. 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.

Table 8.7: Emergency response and contingency plans

8.3.1 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.

8.3.2 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.

8.3.3 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 subtransmission 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.

9 Performance Evaluation

9.1 Review of progress against plan

This section outlines Electra's progress against budgeted targets for the year ending 31 March 2015.

9.1.1 Maintenance Plan

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

Category	'15 Actual ($000)	'15 Budget ($000)	Variance ($000)	Variance (%)
Fault and emergency maintenance	1,453	1,510	(57)	(-4%)
Vegetation Management	980	1,224	(244)	(-20%)
Routine and corrective maintenance	573	821	(248)	(-30%)
Replacement and renewal Maintenance	2,599	1,234	1365	111%
System operations	1,305	1,938	(633)	(-33%)
Business support	3,719	288	2,431	1191
Total	**10,629**	**7,015**	**3,614**	**52%**

Table 9.1: Actual verses budgeted maintenance spend

Overall, Electra was over its maintenance budget by 52% for the 2014-2015 year. Individual categories show significant variation due to an accounting anomaly caused by the previously external contracting business being brought "in house". This resulted in reduced costs on all categories associated with asset maintenance at the expense of extra costs in the category of business support. Factors affecting individual categories are discussed below.

9.1.1.1 Fault and Emergency Maintenance

No material variation.

9.1.1.2 Vegetation Management

No material variation when the accounting adjustment discussed above is factored in.

9.1.1.3 Routine and Corrective Maintenance

Slightly under budget primarily due to cost savings associated with a move to electronic data capture for network inspections.

9.1.1.4 Replacement and Renewal Maintenance

Significantly overr budget as a result of catch up work from previous years using external contractors.

9.1.1.5 System Operations

No material variation when the accounting adjustment discussed above is factored in.

9.1.1.6 Business Support

No material variation when the accounting adjustment discussed above is factored in.

9.1.2 Development Plan

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

Category	'15 Actual ($000)	'15 Budget ($000)	Variance ($000)	Variance (%)
Consumer Connection(i)	-	94	(94)	(-100.0%)
System Growth(ii)	1	778	(777)	(-100.0%)
Reliability, Safety & Environment(iii)	2,305	1,639	666	41%
Asset Replacement/Renewal(iv)	5,954	5,180	774	15%
Asset Relocation(iii)	203	188	15	8%
Total(ii)	**8,464**	**7,879**	**585**	**7%**

Table 9.2: Actual verses budgeted spend

(i) Customer Connections are budgeted on a net basis for vested assets. Electra spent $0 on vested assets.
(ii) System Growth was under spent due to the late completion of a project in Paraparaumu Beach. This work has now been completed. Also some of the work completed on Shannon substation was classified as System Growth but had been budgeted under Reliability, Safety & Environment.
(iii) The late completion of the Paraparaumu GXP to Paraparaumu Zone Substation cables means these assets will now be commissioned in the 2015/16 year.
(iv) On budget.
(v) On budget.
(vi) Overall, Electra over spent its development budget by 7% for the 2014/15 year. This was a result of delays to two significant projects in Paraparaumu and Shannon from the 2013/14 year which was under spent by 23%, both of which are now complete.

9.1.3 Actual performance against target performance

The following table presents our actual performance against target performance for our key service level targets.

Attribute	Measure	’15 Target	’15 Actual	Comment
Network Reliability	SAIDI	83.0	149.2	
	SAIFI	1.67	2.63	
	CAIDI	49.7	56.7	
Public Safety	Electricity (Safety) Regulations 2011	Compliant	Compliant	Continued compliance to NZS 7901
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	 $4039 $230	
	Operational expenditure per: • total circuit length • connection point	 $2,614 $160	 $4711 $268	
Energy Delivery Efficiency	Load factor (units entering network / maximum demand * hours in year)	54%	56%	
	Loss ratio (units lost / units entering network)	6.6%	6.7%	
	Capacity utilisation (maximum demand / installed transformer capacity)	33.68%	27.63%	
Fault Response	Overall level of service from call centre	4.5	4.4	
	Overall level of service from faults persons	4.7	4.8	

Table 9.3: Actual performance verses targets for year ending 31 March 2015

9.2 Improvement initiatives

Three key areas for the Electra Network team to concentrate on over the next year are:

- Improved Asset Planning
  - Continued benchmarking with similar businesses using PAS 55 as a base document.
- 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 undertaken previously;
- 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.
- 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.

The following plans have been established to deal with the four key areas identified:

Improved Asset Planning

- Benchmarking with other Electricity Distribution Businesses using disclosed information.
- Develop quantifiable criteria for comparing one type of project against another (eg reliability vs growth) for prioritization purposes.
- 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)

Continue to maintain reliability

- 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.
- Increased installation of remote operated switches to enable faster restoration of supply.

Reduce re-active maintenance

- 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.

Planned and re-active works

Planned and re-active works processes in relation to the operation of the Control Centre has been improved. A document that directs what should occur and when has been developed. This is known as the 'Major Network Event (MNE)' document. Amongst other things, this requires that in the event of a district wide outage:

- Two control operators are present in the Control Centre with one operator dedicated to completing any network switching required.
- One operator will regularly update all records and call centre on the areas affected and progress to time. This operator will also update retailers, radio stations and emergency services on outage restoration progress.
- The Managers are present in the Control Centre area to ensure restoration is completed systematically and that records are being updated.
- The Operations Manager is present and co-ordinates works required with the contractors involved.

10 Expenditure reconciliation and forecasts

The following tables summarise the forecast of capital and operating expenditure for the year asset management planning period and shows a reconciliation of actual expenditure against forecast for the year ending 31 March 2015, which is the most recent financial year for which data is available. This disclosure is made consistent with Requirement 7(1) of the Electricity Distribution (Information Disclosure) Determination 2012.

11a(i): Expenditure on Assets Forecast

Row		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 16**	**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**
9	**11a(i): Expenditure on Assets Forecast**	**$000 (in nominal dollars)**										
10	Consumer connection	80	95	95	95	95	95	95	95	95	95	95
11	System growth	142	204	409	388	460	664	460	583	460	613	511
12	Asset replacement and renewal	9,593	8,466	7,137	7,414	7,647	7,047	6,735	6,272	6,806	7,131	7,732
13	Asset relocations	-	-	-	-	-	-	102	-	-	-	-
14	Reliability, safety and environment:											
15	Quality of supply	847	2,135	1,286	1,387	886	1,286	1,094	1,265	1,100	946	1,100
16	Legislative and regulatory	-	-	-	-	-	-	-	-	-	-	-
17	Other reliability, safety and environment	-	-	303	-	-	-	-	-	-	-	-
18	**Total reliability, safety and environment**	847	2,135	1,589	1,387	886	1,286	1,094	1,265	1,100	946	1,100
19	**Expenditure on network assets**	10,662	10,899	9,230	9,284	9,088	9,092	8,486	8,214	8,461	8,786	9,438
20	Non-network assets	-	-	-	-	-	-	-	-	-	-	-
21	**Expenditure on assets**	10,662	10,899	9,230	9,284	9,088	9,092	8,486	8,214	8,461	8,786	9,438
22												
23	*plus* Cost of financing	618	618	618	618	618	618	618	618	618	618	618
24	*less* Value of capital contributions	-	-	-	-	-	-	-	-	-	-	-
25	*plus* Value of vested assets	-	-	-	-	-	-	-	-	-	-	-
26												
27	**Capital expenditure forecast**	11,280	11,518	9,848	9,902	9,706	9,711	9,104	8,832	9,079	9,404	10,056
28												
29	Value of commissioned assets											

Row		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 16**	**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**
32		**$000 (in constant prices)**										
33	Consumer connection	80	95	95	95	95	95	95	95	95	95	95
34	System growth	142	204	409	388	460	664	460	583	460	613	511
35	Asset replacement and renewal	5,823	5,180	6,026	6,853	6,107	6,488	6,735	6,272	6,806	7,131	7,732
36	Asset relocations	450	188	-	-	-	-	102	-	-	-	-
37	Reliability, safety and environment:											
38	Quality of supply	1,258	1,604	1,589	1,230	1,209	394	1,094	1,265	1,100	946	1,100
39	Legislative and regulatory	35	35	35	35	35	35	-	-	-	-	-
40	Other reliability, safety and environment	30	-	-	300	-	-	-	-	-	-	-
41	**Total reliability, safety and environment**	1,323	1,639	1,624	1,565	1,244	429	1,094	1,265	1,100	946	1,100
42	**Expenditure on network assets**	7,817	7,306	8,154	8,902	7,905	7,676	8,486	8,214	8,461	8,786	9,438
43	Non-network assets	-	-	-	-	-	-					
44	**Expenditure on assets**	7,817	7,306	8,154	8,902	7,905	7,676	8,486	8,214	8,461	8,786	9,438
45												
46	**Subcomponents of expenditure on assets (where known)**											
47	Energy efficiency and demand side management, reduction of energy losses											
48	Overhead to underground conversion											
49	Research and development											

	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 16	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
Difference between nominal and constant price forecasts	**$000**										
Consumer connection	-	-	-	-	-	-	-	-	-	-	-
System growth	-	-	-	-	-	-	-	-	-	-	-
Asset replacement and renewal	3,771	3,286	1,111	561	1,540	559	-	-	-	-	-
Asset relocations	(450)	(188)	-	-	-	-	-	-	-	-	-
Reliability, safety and environment:											
Quality of supply	(411)	531	(303)	157	(323)	893	-	-	-	-	-
Legislative and regulatory	(35)	(35)	(35)	(35)	(35)	(35)	-	-	-	-	-
Other reliability, safety and environment	(30)	-	303	(300)	-	-	-	-	-	-	-
Total reliability, safety and environment	(476)	496	(35)	(178)	(358)	858	-	-	-	-	-
Expenditure on network assets	2,845	3,593	1,076	382	1,183	1,417	-	-	-	-	-
Non-network assets	-	-	-	-	-	-	-	-	-	-	-
Expenditure on assets	2,845	3,593	1,076	382	1,183	1,417	-	-	-	-	-

11a(ii): Consumer Connection

	Current Year CY	CY+1	CY+2	CY+3	CY+4	CY+5
for year ended	31 Mar 16	31 Mar 17	31 Mar 18	31 Mar 19	31 Mar 20	31 Mar 21
*Consumer types defined by EDB**	**$000 (in constant prices)**					
All	80	95	95	95	95	95
[EDB consumer type]						
[EDB consumer type]						
[EDB consumer type]						
[EDB consumer type]						
**include additional rows if needed*						
Consumer connection expenditure	80	95	95	95	95	95
less Capital contributions funding consumer connection						
Consumer connection less capital contributions	80	95	95	95	95	95

11a(iii): System Growth

	Current Year CY	CY+1	CY+2	CY+3	CY+4	CY+5
Subtransmission	-	-	-	-	-	460
Zone substations	-	-	-	-	-	
Distribution and LV lines	-	-	-	-	-	-
Distribution and LV cables	142	204	409	388	460	204
Distribution substations and transformers						-
Distribution switchgear						
Other network assets	-	-	-	-	-	-
System growth expenditure	142	204	409	388	460	664
less Capital contributions funding system growth	-	-	-	-	-	-
System growth less capital contributions	142	204	409	388	460	664

		Current Year CY	CY+1	CY+2	CY+3	CY+4	CY+5
	for year ended	31 Mar 16	31 Mar 17	31 Mar 18	31 Mar 19	31 Mar 20	31 Mar 21

11a(iv): Asset Replacement and Renewal

$000 (in constant prices)

	Subtransmission	50	47	47	375	47	47
	Zone substations	1,055	47	1,008	1,660	1,735	984
	Distribution and LV lines	1,860	1,946	1,847	1,622	1,125	2,110
	Distribution and LV cables	350	338	309	300	300	375
	Distribution substations and transformers	1,920	2,262	2,110	2,166	2,166	2,250
	Distribution switchgear	233	216	386	396	406	386
	Other network assets	355	326	319	335	328	335
	Asset replacement and renewal expenditure	5,823	5,180	6,026	6,853	6,107	6,488
less	Capital contributions funding asset replacement and renewal	-	-	-	-	-	-
	Asset replacement and renewal less capital contributions	5,823	5,180	6,026	6,853	6,107	6,488

11a(v):Asset Relocations

	*Project or programme**						
	Tilley Rd	150					
	Western Link Rd		188				
	Heights Rd	300					
	[Description of material project or programme]						
	[Description of material project or programme]						
	**include additional rows if needed*						
	All other asset relocations projects or programmes						
	Asset relocations expenditure	450	188	-	-	-	-
less	Capital contributions funding asset relocations						
	Asset relocations less capital contributions	450	188	-	-	-	-

11a(vi):Quality of Supply

	*Project or programme**						
	Subtransmission Line Separation	-	563	609	-	-	-
	Zone Substation Bus Zone Protection	280	516	638	291	-	-
	Alternative Supplies	720	272	225	694	403	225
	System Automation and Sectionalisation	240	244	117	216	216	169
	Ripple System and Load Control	18	10	-	30	590	-
	**include additional rows if needed*						
	All other quality of supply projects or programmes						
	Quality of supply expenditure	1,258	1,604	1,589	1,230	1,209	394
less	Capital contributions funding quality of supply						
	Quality of supply less capital contributions	1,258	1,604	1,589	1,230	1,209	394

11a(vii): Legislative and Regulatory

	*Project or programme**						
	All legislative and regulatory projects or programmes	35	35	35	35	35	35
	[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 legislative and regulatory projects or programmes						
	Legislative and regulatory expenditure	35	35	35	35	35	35
less	Capital contributions funding legislative and regulatory						
	Legislative and regulatory less capital contributions	35	35	35	35	35	35

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

for year ended	Current Year CY 31 Mar 16	CY+1 31 Mar 17	CY+2 31 Mar 18	CY+3 31 Mar 19	CY+4 31 Mar 20	CY+5 31 Mar 21
*Project or programme**	**$000 (in constant prices)**					
Arc Flash Protection	30	-	-	300	-	-
[Description of material project or programme]						
[Description of material project or programme]						
[Description of material project or programme]						
[Description of material project or programme]						
**include additional rows if needed*						
All other reliability, safety and environment projects or programmes						
Other reliability, safety and environment expenditure	30	-	-	300	-	-
less Capital contributions funding other reliability, safety and environment						
Other reliability, safety and environment less capital contributions	30	-	-	300	-	-

11a(ix): Non-Network Assets

Routine expenditure						
*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]						
[Description of material project or programme]						
**include additional rows if needed*						
All other routine expenditure projects or programmes						
Routine expenditure	-	-	-	-	-	-
Atypical expenditure						
*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]						
[Description of material project or programme]						
**include additional rows if needed*						
All other atypical projects or programmes						
Atypical expenditure	-	-	-	-	-	-
Non-network assets expenditure	-	-	-	-	-	-

Row		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 16	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
9	**Operational Expenditure Forecast**	**$000 (in nominal dollars)**										
10	Service interruptions and emergencies	1,480	1,510	1,547	1,584	1,628	1,672	1,724	1,776	1,835	1,894	1,954
11	Vegetation management	1,200	1,224	1,254	1,284	1,320	1,356	1,398	1,440	1,488	1,536	1,585
12	Routine and corrective maintenance and inspection	805	821	841	861	886	910	938	966	998	1,030	1,062
13	Asset replacement and renewal	1,210	1,234	1,291	1,295	1,331	1,396	1,410	1,452	1,531	1,549	1,591
14	**Network Opex**	4,695	4,789	4,932	5,024	5,165	5,334	5,470	5,634	5,853	6,010	6,192
15	System operations and network support	1,874	1,938	2,023	2,088	2,160	2,226	2,294	2,363	2,438	2,511	2,575
16	Business support	283	288	294	300	308	316	325	334	344	355	365
17	**Non-network opex**	2,157	2,226	2,317	2,388	2,468	2,542	2,619	2,697	2,782	2,866	2,940
18	**Operational expenditure**	6,852	7,015	7,249	7,412	7,633	7,876	8,089	8,331	8,635	8,876	9,132

Row		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 16	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
21		**$000 (in constant prices)**										
22	Service interruptions and emergencies	1,480	1,439	1,439	1,439	1,439	1,439	1,439	1,439	1,439	1,439	1,439
23	Vegetation management	1,200	1,125	1,125	1,125	1,125	1,125	1,125	1,125	1,125	1,125	1,125
24	Routine and corrective maintenance and inspection	795	764	764	764	764	764	764	764	764	764	764
25	Asset replacement and renewal	1,205	1,134	1,158	1,134	1,134	1,158	1,134	1,134	1,158	1,134	1,134
26	**Network Opex**	4,680	4,463	4,486	4,463	4,463	4,486	4,463	4,463	4,486	4,463	4,463
27	System operations and network support	1,767	1,820	1,830	1,845	1,860	1,875	1,890	1,905	1,920	1,940	1,960
28	Business support	277	277	277	277	277	277	277	277	277	277	277
29	**Non-network opex**	2,044	2,097	2,107	2,122	2,137	2,152	2,167	2,182	2,197	2,217	2,237
30	**Operational expenditure**	6,724	6,560	6,593	6,585	6,600	6,638	6,630	6,645	6,683	6,680	6,700
31	**Subcomponents of operational expenditure (where known)**											
32	Energy efficiency and demand side management, reduction of											
33	energy losses	20	20	20	20	20	20	20	20	20	20	20
34	Direct billing*	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
35	Research and Development	20	20	20	20	20	20	20	20	20	20	20
	Insurance	250	260	275	290	305	320	335	350	370	390	410

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

Row		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 16	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
41	**Difference between nominal and real forecasts**	**$000**										
42	Service interruptions and emergencies	-	70	107	144	189	233	285	337	396	455	515
43	Vegetation management	-	99	129	159	195	231	273	315	363	411	460
44	Routine and corrective maintenance and inspection	10	57	77	97	121	146	174	202	234	266	298
45	Asset replacement and renewal	5	100	133	160	197	238	275	318	373	414	457
46	**Network Opex**	15	326	446	561	702	847	1,007	1,171	1,366	1,547	1,729
47	System operations and network support	107	118	193	243	300	351	404	458	518	571	615
48	Business support	6	11	17	23	31	39	48	57	67	78	88
49	**Non-network opex**	113	129	210	266	331	390	452	515	585	649	703
50	**Operational expenditure**	128	455	656	827	1,033	1,237	1,459	1,686	1,951	2,196	2,432

	Voltage	Asset category	Asset class	Units	Asset condition at start of planning period (percentage of units by grade)						
9					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.		-	95.25%	4.75%		3	5.00%
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		16.43%	82.22%	1.35%		4	2.00%
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.		10.00%	50.00%	40.00%		4	10.00%
25	HV	Zone substation Buildings	Zone substations 110kV+	No.						N/A	
26	HV	Zone substation switchgear	22/33kV CB (Indoor)	No.			61.54%	38.46%		4	
27	HV	Zone substation switchgear	22/33kV CB (Outdoor)	No.		7.69%	92.31%			4	19.23%
28	HV	Zone substation switchgear	33kV Switch (Ground Mounted)	No.						N/A	
29	HV	Zone substation switchgear	33kV Switch (Pole Mounted)	No.				100.00%		3	13.64%
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.		10.34%	81.60%	8.06%		3	10.34%
34	HV	Zone substation switchgear	3.3/6.6/11/22kV CB (pole mounted)	No.						N/A	

	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
43											
44											
45	HV	Zone Substation Transformer	Zone Substation Transformers	No.			90.00%	10.00%		4	-
46	HV	Distribution Line	Distribution OH Open Wire Conductor	km		11.20%	83.30%	5.50%		3	7.00%
47	HV	Distribution Line	Distribution OH Aerial Cable Conductor	km						N/A	
48	HV	Distribution Line	SWER conductor	km						N/A	
49	HV	Distribution Cable	Distribution UG XLPE or PVC	km			61.30%	38.70%		3	-
50	HV	Distribution Cable	Distribution UG PILC	km			100.00%	-		3	2.50%
51	HV	Distribution Cable	Distribution Submarine Cable	km						N/A	
52	HV	Distribution switchgear	3.3/6.6/11/22kV CB (pole mounted) - reclosers and sectionalisers	No.		3.00%	85.00%	12.00%		4	6.00%
53	HV	Distribution switchgear	3.3/6.6/11/22kV CB (Indoor)	No.		12.00%	78.00%	10.00%		4	12.00%
54	HV	Distribution switchgear	3.3/6.6/11/22kV Switches and fuses (pole mounted)	No.		2.00%	67.00%	31.00%		3	10.00%
55	HV	Distribution switchgear	3.3/6.6/11/22kV Switch (ground mounted) - except RMU	No.						N/A	
56	HV	Distribution switchgear	3.3/6.6/11/22kV RMU	No.		2.00%	59.00%	39.00%		3	10.00%
57	HV	Distribution Transformer	Pole Mounted Transformer	No.		2.50%	65.20%	32.30%		4	10.00%
58	HV	Distribution Transformer	Ground Mounted Transformer	No.		10.90%	48.40%	40.70%		4	15.00%
59	HV	Distribution Transformer	Voltage regulators	No.						N/A	
60	HV	Distribution Substations	Ground Mounted Substation Housing	No.						N/A	
61	LV	LV Line	LV OH Conductor	km		2.60%		1.20%	96.20%	3	4.00%
62	LV	LV Cable	LV UG Cable	km		-		44.00%	56.00%	3	2.00%
63	LV	LV Streetlighting	LV OH/UG Streetlight circuit	km					100.00%	3	2.00%
64	LV	Connections	OH/UG consumer service connections	No.		10.80%	42.20%	15.00%	32.00%	2	12.00%
65	All	Protection	Protection relays (electromechanical, solid state and numeric)	No.		15.00%	55.00%	30.00%		4	20.00%
66	All	SCADA and communications	SCADA and communications equipment operating as a single system	Lot			80.00%	20.00%		3	20.00%
67	All	Capacitor Banks	Capacitors including controls	No.						N/A	
68	All	Load Control	Centralised plant	Lot			100.00%			4	-
69	All	Load Control	Relays	No.					100.00%	3	10.00%
70	All	Civils	Cable Tunnels	km						N/A	

7 **12b(i): System Growth - Zone Substations**

Row	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
8										
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	52%	23	57%	No constraint within +5 years	
14	Waikanae	17	23	N-1	12	73%	23	80%	No constraint within +5 years	
15	Paraparaumu	14	23	N-1	16	61%	23	67%	No constraint within +5 years	
16	Paraparaumu West	13	23	N-1	8	58%	23	67%	No constraint within +5 years	
17	Raumati	12	23	N-1	12	50%	23	53%	No constraint within +5 years	
18	Paekakariki	5	-	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*

30 **12b(ii): Transformer Capacity**

Row		(MVA)
31		
32	Distribution transformer capacity (EDB owned)	311
33	Distribution transformer capacity (Non-EDB owned)	13
34	**Total distribution transformer capacity**	325
35		
36	**Zone substation transformer capacity**	199

7 12c(i): Consumer Connections

		Current Year CY	CY+1	CY+2	CY+3	CY+4	CY+5
8	*Number of ICPs connected in year by consumer type*			**Number of connections**			
9		*Current Year CY*	*CY+1*	*CY+2*	*CY+3*	*CY+4*	*CY+5*
10	for year ended	**31 Mar 16**	**31 Mar 17**	**31 Mar 18**	**31 Mar 19**	**31 Mar 20**	**31 Mar 21**
11	*Consumer types defined by EDB**						
12	[EDB consumer type]						
13	[EDB consumer type]						
14	[EDB consumer type]						
15	[EDB consumer type]						
16	[EDB consumer type]						
17	**Connections total**	-	-	-	-	-	-
18	**include additional rows if needed*						
19	**Distributed generation**						
20	Number of connections	42	90	150	220	300	400
21	Installed connection capacity of distributed generation (MVA)	1	1	1	1	1	1

22 12c(ii) System Demand

			Current Year CY	CY+1	CY+2	CY+3	CY+4	CY+5
23			*Current Year CY*	*CY+1*	*CY+2*	*CY+3*	*CY+4*	*CY+5*
24		**Maximum coincident system demand (MW)** — for year ended	**31 Mar 16**	**31 Mar 17**	**31 Mar 18**	**31 Mar 19**	**31 Mar 20**	**31 Mar 21**
25		GXP demand	94	98	99	100	101	103
26	*plus*	Distributed generation output at HV and above	-	-	-	-	-	-
27		**Maximum coincident system demand**	94	98	99	100	101	103
28	*less*	Net transfers to (from) other EDBs at HV and above	-	-	-	-	-	-
29		**Demand on system for supply to consumers' connection points**	94	98	99	100	101	103
30		**Electricity volumes carried (GWh)**						
31		Electricity supplied from GXPs	434	439	441	443	445	448
32	*less*	Electricity exports to GXPs	138	138	138	138	138	138
33	*plus*	Electricity supplied from distributed generation	138	138	138	138	138	138
34	*less*	Net electricity supplied to (from) other EDBs	-	-	-	-	-	-
35		**Electricity entering system for supply to ICPs**	434	439	441	443	445	448
36	*less*	Total energy delivered to ICPs	404	409	411	413	415	418
37		**Losses**	30	30	30	30	30	30
38								
39		**Load factor**	53%	51%	51%	51%	50%	50%
40		**Loss ratio**	6.9%	6.8%	6.8%	6.8%	6.7%	6.7%

8			*Current Year CY*	*CY+1*	*CY+2*	*CY+3*	*CY+4*	*CY+5*
9		for year ended	**31 Mar 16**	**31 Mar 17**	**31 Mar 18**	**31 Mar 19**	**31 Mar 20**	**31 Mar 21**
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

Company Name	**Electra Ltd**
AMP Planning Period	**1 April 2016 – 31 March 2026**
Asset Management Standard Applied	**PAS 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—Summary	User Guidance	Why	Who	Record/documented Information
3	Asset management policy	To what extent has an asset management policy been documented, authorised and communicated?	3	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.		Widely used AM practice standards require an organisation to document, authorise and communicate its asset management policy (e.g., as required in PAS 55 para 4.2 i). A key pre-requisite of any robust policy is that the organisation's top management must be seen to endorse and fully support it. Also vital to the effective implementation of the policy, is to tell the appropriate people of its content and their obligations under it. Where an organisation outsources some of its asset-related activities, then these people and their organisations must equally be made aware of the policy's content. Also, there may be other stakeholders, such as regulatory authorities and shareholders who should be made aware of it.	Top management. The management team that has overall responsibility for asset management.	The organisation's asset management policy, its organisational strategic plan, documents indicating how the asset management policy was based upon the needs of the organisation and evidence of communication.
10	Asset management strategy	What has the organisation done to ensure that its asset management strategy is consistent with other appropriate organisational policies and strategies, and the needs of stakeholders?	3	The Asset Management Policy is signed off at Board level at the same time as Group Strategic Plan. A summary of the proposed Asset Management Plan is presented to the Consumer Trust for review prior to approval and issue. The Asset Management Strategy is now linked to both the Group and Network strategic plans.		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 (e.g., as required by PAS 55 para 4.3.1 b) and has taken account of stakeholder requirements as required by PAS 55 para 4.3.1 c). Generally, this will take into account the same polices, strategies and stakeholder requirements as covered in drafting the asset management policy but at a greater level of detail.	Top management. The organisation's strategic planning team. The management team that has overall responsibility for asset management.	The organisation's asset management strategy document and other related organisational policies and strategies. Other than the organisation's strategic plan, these could include those relating to health and safety, environmental, etc. Results of stakeholder consultation.
11	Asset management strategy	In what way does the organisation's asset management strategy take account of the lifecycle of the assets, asset types and asset systems over which the organisation has stewardship?	3	Asset life cycles and Planned Preventative Maintenance manual have been in place for 10+ years. Maintenance and budgets are allocated based on a sustainable schedule that accounts for the expected life of each asset.		Good asset stewardship is the hallmark of an organisation compliant with widely used AM standards. A key component of this is the need to take account of the lifecycle of the assets, asset types and asset systems. (For example, this requirement is recognised in 4.3.1 d) of PAS 55). This question explores what an organisation has done to take lifecycle into account in its asset management strategy.	Top management. People in the organisation with expert knowledge of the assets, asset types, asset systems and their associated life-cycles. The management team that has overall responsibility for asset management. Those responsible for developing and adopting methods and processes used in asset management	The organisation's documented asset management strategy and supporting working documents.
26	Asset management plan(s)	How does the organisation establish and document its asset management plan(s) across the life cycle activities of its assets and asset systems?	3	The Planned Preventative Maintenance manual identifies tasks and activities to be carried out through the life cycle of Electra's network assets. This has now been devolved into types specific plans for common equipment and individual plans for major/key components.		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 2016 – 31 March 2026	
	Asset Management Standard Applied	PAS 55	

SCHEDULE 13: REPORT ON ASSET MANAGEMENT MATURITY (cont)

Question No.	Function	Question	Score	Evidence—Summary	User Guidance	Why	Who	Record/documented Information
27	Asset management plan(s)	How has the organisation communicated its plan(s) to all relevant parties to a level of detail appropriate to the receiver's role in their delivery?	2	The full Asset Management plan is published on the Electra website along with a high level summary for the current years work. Detailed work lists and schedules are agreed and provided to Electra's main contractor at the start of each year so resources can be scheduled.		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	Roles and responsibilities have been defined and included in individual job descriptions. Delegated Authorities are reviewed and published each year. See section 3.5 of the Asset Management Plan.		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	The schedule and content of the works program is agreed with Electra's key service provider prior to the start of each year. Gap analysis of resource requirements identifies work to be subcontracted out and this subcontracting is subject to ongoing review.		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 Emergency management system has the following processes in place; Standard procedures for day to day situations; An event escalation procedure where additional resources are required; A Major Event document for large scale or widespread emergencies. These documents cover who is involved both internally and externally. Electra regularly (3-4 times per annum) participates in Emergency Management exercises with both districts supplied by its assets.		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 2016 – 31 March 2026**
	Asset Management Standard Applied	**PAS 55**

SCHEDULE 13: REPORT ON ASSET MANAGEMENT MATURITY (cont)

Question No.	Function	Question	Score	Evidence—Summary	User Guidance	Why	Who	Record/documented Information
37	Structure, authority and responsibilities	What has the organisation done to appoint member(s) of its management team to be responsible for ensuring that the organisation's assets deliver the requirements of the asset management strategy, objectives and plan(s)?	2	See section 3.5 of the Asset Management Plan. Roles and responsibilities have been defined and included in individual job descriptions. The Network Development Plan assigns responsibilities for initiatives to achieve objectives set. Annual targets are agreed with the relevant managers and they set specific objectives for their direct reports.		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 e.g., 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	Budgeted expenditure is approved at Board level. A resource requirement plan including man hours is prepared as part of the work schedule. A number of pre-approved contractors are available and have been used to supplement the main service providers.		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	Weekly meetings within the network team, including the GM, identify any issues. There are monthly contractor meetings. The monthly CEO report to the Board charts both physical and financial progress against the plan.		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	There is a contract with the key service provider including expected performance levels. There are monthly meetings with the key contractor . Authorisation limits are present in the job control system. Field audits are carried out to ensure compliance with Health and Safety and quality standards. Contractors failing to meet these standards have not had their contracts renewed.		Where an organisation chooses to outsource some of its asset management activities, the organisation must ensure that these outsourced process(es) are under appropriate control to ensure that all the requirements of widely used AM standards (eg, PAS 55) are in place, and the asset management policy, strategy objectives and plan(s) are delivered. This includes ensuring capabilities and resources across a time span aligned to life cycle management. The organisation must put arrangements in place to control the outsourced activities, whether it be to external providers or to other in-house departments. This question explores what the organisation does in this regard.	Top management. The management team that has overall responsibility for asset management. The manager(s) responsible for the monitoring and management of the outsourced activities. People involved with the procurement of outsourced activities. The people within the organisations that are performing the outsourced activities. The people impacted by the outsourced activity.	The organisation's arrangements that detail the compliance required of the outsourced activities. For example, this this could form part of a contract or service level agreement between the organisation and the suppliers of its outsourced activities. Evidence that the organisation has demonstrated to itself that it has assurance of compliance of outsourced activities.

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SCHEDULE 13: REPORT ON ASSET MANAGEMENT MATURITY (cont)

Question No.	Function	Question	Score	Evidence—Summary	User Guidance	Why	Who	Record/documented Information
48	Training, awareness and competence	How does the organisation develop plan(s) for the human resources required to undertake asset management activities - including the development and delivery of asset management strategy, process(es), objectives and plan(s)?	3	The resource chart for each year's plan identifies overall numbers and skill sets required for the current work schedule. The monthly meeting with the main service provider also discusses skills training and sucession planning. Resource shortages are highlighted to guide the use of subcontractors in the short term and independent consultants employed to verify identified long term requirements.		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	The contractor authorisation process identifies competencies for the various tasks to be carried out on the network. This forms part of the Safety Management System. Training records are kept for operators and field staff.		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	Our contractor authorisation process identifies competencies for the various tasks to be carried out on the network. This forms part of the Safety Management System. System audits ensure these records are kept up to date and field audits confirm that the appropriate staff carry out the tasks. The main contractor has an internal position of trainer/auditor which also carries out auditing of safety and compliance to required skill levels. In addition a skill matrix is in development that identifies the skills required for each role against network requirements and will be assessed against skills annually.		A critical success factor for the effective development and implementation of an asset management system is the competence of persons undertaking these activities. organisations should have effective means in place for ensuring the competence of employees to carry out their designated asset management function(s). Where an organisation has contracted service providers undertaking elements of its asset management system then the organisation shall assure itself that the outsourced service provider also has suitable arrangements in place to manage the competencies of its employees. The organisation should ensure that the individual and corporate competencies it requires are in place and actively monitor, develop and maintain an appropriate balance of these competencies.	Managers, supervisors, persons responsible for developing training programmes. Staff responsible for procurement and service agreements. HR staff and those responsible for recruitment.	Evidence of a competency assessment framework that aligns with established frameworks such as the asset management Competencies Requirements Framework (Version 2.0); National Occupational Standards for Management and Leadership; UK Standard for Professional Engineering Competence, Engineering Council, 2005.

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SCHEDULE 13: REPORT ON ASSET MANAGEMENT MATURITY (cont)

Question No.	Function	Question	Score	Evidence—Summary	User Guidance	Why	Who	Record/documented Information
53	Communication, participation and consultation	How does the organisation ensure that pertinent asset management information is effectively communicated to and from employees and other stakeholders, including contracted service providers?	3	The Annual Report and Review, Asset Management Plan, AMP Overview and Disclosures are all published on the Electra Website. The Trustees as both Owners and Customer Representatives are updated quarterly. Monthly reports and meetings are carried out with the Board and Service Providers. Asset management issues are the focus of weekly team meetings and meetings with Electra's key contractor.		Widely used AM practice standards require that pertinent asset management information is effectively communicated to and from employees and other stakeholders including contracted service providers. Pertinent information refers to information required in order to effectively and efficiently comply with and deliver asset management strategy, plan(s) and objectives. This will include for example the communication of the asset management policy, asset performance information, and planning information as appropriate to contractors.	Top management and senior management representative(s), employee's representative(s), employee's trade union representative(s); contracted service provider management and employee representative(s); representative(s) from the organisation's Health, Safety and Environmental team. Key stakeholder representative(s).	Asset management policy statement prominently displayed on notice boards, intranet and internet; use of organisation's website for displaying asset performance data; evidence of formal briefings to employees, stakeholders and contracted service providers; evidence of inclusion of asset management issues in team meetings and contracted service provider contract meetings; newsletters, etc.
59	Asset Management System documentation	What documentation has the organisation established to describe the main elements of its asset management system and interactions between them?	2	The main elements of the Asset Management System and the interactions between them are described in section 3 of the Asset Management Plan. Appropriate documents are contained within Electra's document management system.		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?	3	The original Asset Management Information System was specified and set up in the form of a process map up by a large team representing stakeholders, management and service providers. Further experience has resulted in additional information being stored in the system including inspection results and protection system details as well as links to other information systems such as financial records and asset registers. Data requirements are reviewed annually and the agreed changes made.		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	Asset information supplied by contractors is checked before importing to the system. Inspection results also are used to verify the accuracy of existing data. The information is also checked against the financial asset register annually.		The response to the questions is progressive. A higher scale cannot be awarded without achieving the requirements of the lower scale. This question explores how the organisation ensures that information management meets widely used AM practice requirements (eg, s 4.4.6 (a), (c) and (d) of PAS 55).	The management team that has overall responsibility for asset management. Users of the organisational information systems.	The asset management information system, together with the policies, procedure(s), improvement initiatives and audits regarding information controls.

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SCHEDULE 13: REPORT ON ASSET MANAGEMENT MATURITY (cont)

Question No.	Function	Question	Score	Evidence—Summary	User Guidance	Why	Who	Record/documented Information
64	Information management	How has the organisation's ensured its asset management information system is relevant to its needs?	2	Continual feedback is supplied by users of the asset information. Obsolete data is removed to streamline usage. Asset information is now available to field staff using mobile devices including the ability to annotate and send in changes identified on site.		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	Electra has Risk Committes at both management and Board level. They carry out an annual review and reassessment of all company risks. The Electra Safety Management System also has procedures for identifying physical risks on the network. Incident investigations are logged, including actions to be taken. These are followed up in the regular meetings.		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	The results of the risk assessments feed into objectives for Electra's strategic plan. This can include risks associated with resourcing and training particularly around specialist or key personnel. This has already resulted in safety being elevated to Electra's number one risk.		Widely used AM standards require that the output from risk assessments are considered and that adequate resource (including staff) and training is identified to match the requirements. It is a further requirement that the effects of the control measures are considered, as there may be implications in resources and training required to achieve other objectives.	Staff responsible for risk assessment and those responsible for developing and approving resource and training plan(s). There may also be input from the organisation's Safety, Health and Environment team.	The organisations risk management framework. The organisation's resourcing plan(s) and training and competency plan(s). The organisation should be able to demonstrate appropriate linkages between the content of resource plan(s) and training and competency plan(s) to the risk assessments and risk control measures that have been developed.
82	Legal and other requirements	What procedure does the organisation have to identify and provide access to its legal, regulatory, statutory and other asset management requirements, and how is requirements incorporated into the asset management system?	2	Electra subscribes to Brooker's for legal updates and is party to a number of industry groups such as ENA. Electra, along with a number of similar organisations, engages PWC to assess any legislative requirements or changes. Telarc carries out annual audits of Electra's Safety Management System. As an Electricity Distrubutor Electra is also subject to a number of compliance audits.		In order for an organisation to comply with its legal, regulatory, statutory and other asset management requirements, the organisation first needs to ensure that it knows what they are (eg, PAS 55 specifies this in s 4.4.8). It is necessary to have systematic and auditable mechanisms in place to identify new and changing requirements. Widely used AM standards also require that requirements are incorporated into the asset management system (e.g. procedure(s) and process(es))	Top management. The organisations regulatory team. The organisation's legal team or advisors. The management team with overall responsibility for the asset management system. The organisation's health and safety team or advisors. The organisation's policy making team.	The organisational processes and procedures for ensuring information of this type is identified, made accessible to those requiring the information and is incorporated into asset management strategy and objectives

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SCHEDULE 13: REPORT ON ASSET MANAGEMENT MATURITY (cont)

Question No.	Function	Question	Score	Evidence—Summary	User Guidance	Why	Who	Record/documented Information
88	Life Cycle Activities	How does the organisation establish implement and maintain process(es) for the implementation of its asset management plan(s) and control of activities across the creation, acquisition or enhancement of assets. This includes design, modification, procurement, construction and commissioning activities?	2	Electra's design approval process has standards and criteria for all new equipment to be connected to the network. Equipment standards and an approved equipment list are used for major components. Construction standards and audits are used to ensure that the construction is carried out properly. Standard tests are carried out prior to commissioning assets.		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	Maintenance tasks and inspection results are both audited. Work is clustered to minimise effect on customers and maximise resource utilisation and efficiency.		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	Standard network reliability data such as SAIFI, SAIDI and Faults/km are used as an overall guide. Electra also carries out post fault reporting and has a faults database which is used to analyse trends. The audit database is used to identify quality issues for constrcution and maintenance activities. Specific, targeted inspection and reporting cycles are followed.		Widely used AM standards require that organisations establish implement and maintain procedure(s) to monitor and measure the performance and/or condition of assets and asset systems. They further set out requirements in some detail for reactive and proactive monitoring, and leading/lagging performance indicators together with the monitoring or results to provide input to corrective actions and continual improvement. There is an expectation that performance and condition monitoring will provide input to improving asset management strategy, objectives and plan(s).	A broad cross-section of the people involved in the organisation's asset-related activities from data input to decision-makers, i.e. an end-to end assessment. This should include contactors and other relevant third parties as appropriate.	Functional policy and/or strategy documents for performance or condition monitoring and measurement. The organisation's performance monitoring frameworks, balanced scorecards etc. Evidence of the reviews of any appropriate performance indicators and the action lists resulting from these reviews. Reports and trend analysis using performance and condition information. Evidence of the use of performance and condition information shaping improvements and supporting asset management strategy, objectives and plan(s).
99	Investigation of asset-related failures, incidents and nonconformities	How does the organisation ensure responsibility and the authority for the handling, investigation and mitigation of asset-related failures, incidents and emergency situations and non conformances is clear, unambiguous, understood and communicated?	2	Electra employs specialised staff for investigations using a standardise investigation process which is audited as part of the Safety Management System. This information is kept in the audit database and in the post fault reports. Control Room operators are responsible for all issues under fault conditions, including managing contractor response.		Widely used AM standards require that the organisation establishes implements and maintains process(es) for the handling and investigation of failures incidents and non-conformities for assets and sets down a number of expectations. Specifically this question examines the requirement to define clearly responsibilities and authorities for these activities, and communicate these unambiguously to relevant people including external stakeholders if appropriate.	The organisation's safety and environment management team. The team with overall responsibility for the management of the assets. People who have appointed roles within the asset-related investigation procedure, from those who carry out the investigations to senior management who review the recommendations. Operational controllers responsible for managing the asset base under fault conditions and maintaining services to consumers. Contractors and other third parties as appropriate.	Process(es) and procedure(s) for the handling, investigation and mitigation of asset-related failures, incidents and emergency situations and non conformances. Documentation of assigned responsibilities and authority to employees. Job Descriptions, Audit reports. Common communication systems i.e. all Job Descriptions on Internet etc.

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SCHEDULE 13: REPORT ON ASSET MANAGEMENT MATURITY (cont)

Question No.	Function	Question	Score	Evidence—Summary	User Guidance	Why	Who	Record/documented Information
105	Audit	What has the organisation done to establish procedure(s) for the audit of its asset management system (process(es))?	2	The Commerce Commission carries out regular reviews of Electra's Asset Management Plan. The plan is subject to peer review using a variety of external consultants.		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	Results of safety and quality audits are fed back to all affected and potentially affected parties. This is carried out through direct reporting, Network General Advisory Notices and updates to standards. The Network Team addresses specific issues in its weekly meeting and will decide on necessary corrective action including changes to processes or equipment specification. It will also assign who is to be responsible.		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	Information from audits of previous work is incorporated into asset planning. Proposed projects are reviewed prior to committing to the current plan. Completed projects are reviewed to identify improvements. The network material standards are continually reviewed to include better products and remove poor performing ones, based on experience both on Electra's network and from feedback from other networks.		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	Electra's membership and participation of organisations such as the ENA and EEA means that improvements and innovations developed across similar businesses are accessed. Electra regularly meets with suppliers and hosts product demonstrations showing latest best practice. Professional forums are attended by staff where benefits are identified or where there is a fit with the direction of the AMP or Network Development Plan that year.		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 (e.g., by the PAS 55 s 4.6 standards) will be able to demonstrate that it continually seeks to expand its knowledge of all things affecting its asset management approach and capabilities. The organisation will be able to demonstrate that it identifies any such opportunities to improve, evaluates them for suitability to its own organisation and implements them as appropriate. This question explores an organisation's approach to this activity.	The top management of the organisation. The manager/team responsible for managing the organisation's asset management system, including its continual improvement. People who monitor the various items that require monitoring for 'change'. People that implement changes to the organisation's policy, strategy, etc. People within an organisation with responsibility for investigating, evaluating, recommending and implementing new tools and techniques, etc.	Research and development projects and records, benchmarking and participation knowledge exchange professional forums. Evidence of correspondence relating to knowledge acquisition. Examples of change implementation and evaluation of new tools, and techniques linked to asset management strategy and objectives.

Appendix A – Electricity Distribution (Information Disclosure) Requirements 2012 – Requirement 7(2)

The Electricity Distribution (Information Disclosure) Requirements 2012, gazetted in December 2012 introduced a new requirement in relation to AMP information. In addition to the information to be included in the AMP, as prescribed in the Electricity Information Disclosure Handbook, dated 31 March 2005 and amended 1 October 2012 and re determined in 24 March 2015, Electra is required to disclose the following information. This statement comprises Electra's disclosure in accordance with this Requirement.

(a) all significant assumptions, clearly identified in a manner that makes their significance understandable to electricity consumers, and quantified where possible;

- From 1 April 2010 Electra was exempt from the Commerce Commission Targeted Regulatory Control regime. However Electra plans throughout the AMP period to continue to use supply quality targets previously set by the Commerce Commission;
- Existing external regulatory and legislative requirements are assumed to remain unchanged throughout the planning period. Therefore the external drivers which influence reliability targets and design, environmental, health and safety standards and industry codes of practice are constant throughout the AMP period;
- It is unlikely that new technology will supersede the traditional methods of distributing electricity during the planning period and consequently the AMP is based on a "business as usual" model;
- The growth in electricity consumption may be reduced by alternative technologies in buildings such as solar panels and improved insulation. Additionally, due to rising retail electricity costs consumers may turn to alternative sources of heating or cut down in other areas during the planning period;
- All projections of expenditure are presented in real New Zealand dollar terms as at 1 January 2016. In reality over time input costs (including those sourced from outside of New Zealand) for asset management activities will change at rates greater or less than the rate of general inflation. As expenditure forecasts are updated annually, this approach is acceptable and consistent with that prescribed;
- Demand at each GXP is predicted to increase at a slightly lower rate compared to recent historical growth. However, it is expected during the planning period that the firm capacity of Electra's grid exit points will be exceeded and remedial action is taken as planned;
- Transpower continues to provide sufficient capacity to meet Electra's requirements at the existing GXPs and undertakes the additional investment required to meet additional future demand, as specified in the Development Plan section of this AMP;
- The existing Vision and Corporate Objectives and Policies of Electra continue for the planning period;
- Neither the Electra network nor the local transmission grid is exposed to a major natural disaster during the planning period;

- The Electra network is exposed to normal climatic variation over the planning period including temperature, wind, snow and rain variances consistent with its experiences since 1998;
- Seasonal load profiles remain consistent with recent historical trends, that is summer peaking GXPs are assumed to remain so, as are winter peaking GXPs;
- No new embedded generation is commissioned during the planning period;
- Zoning for land use purposes remains unchanged during the planning period;
- The demand diversity remains unchanged throughout the planning period.

(b) a description of changes proposed where the information is not based on the Distribution Business's existing business;

No changes are proposed to the existing business of Electra, and thus all prospective information has been prepared consistent with the existing Electra business ownership and structure.

(c) the basis on which significant assumptions have been prepared, including the principal sources of information from which they have been derived;

The basis on which the assumptions have been prepared is described in detail in Sections 5 and 7 of the AMP. The principal sources of information from which they have been derived are:

- Electra's Strategic Planning documents including the 2010 – 2015 Statement of Corporate Intent and the 2016 Network and Group Business Plans and Budgets;
- Consultation with stakeholders and consumers through surveys;
- Predictions based on historical demand and connections;
- Maximum electricity demand, at each GXP, for the period 1998 – 2015.

(d) the factors that may lead to a material difference between the prospective information disclosed and the corresponding actual information recorded in future disclosures;

Factors which may lead to a material difference between the AMP and future actual outcomes include:

- Regulatory requirements may change, requiring Electra to achieve different service standards or different design or security standards. This could also impact on the availability of funds for asset management;
- Electra's ownership could change, and different owners could have different service and expenditure objectives than those embodied in the AMP;
- Consumers could change their demands for reliability or their willingness to pay for different levels of service;
- The network could experience major natural disasters such as an earthquake, flood, tsunami or extreme wind, rain or snow storms;
- The rate of growth in demand could significantly accelerate or decelerate within the planning period;
- Within each region, load patterns could change resulting in a movement from summer to winter peaks and vice versa;

- Significant embedded generation capacity may be commissioned within the network supply area;
- Significant land zoning changes may be implemented within the region;
- Significant new loads may require supply or load diversity may increase significantly;
- There could be major unforeseen equipment failure requiring significant repair and possible replacement expenditure;
- More detailed asset management planning undertaken over the next 3 – 5 years may generate development and maintenance requirements which significantly differ from those currently provided for.

(e) the assumptions made in relation to these sources of uncertainty and the potential effect of the uncertainty on the prospective information.

The assumptions made in relation to these sources of uncertainty are listed in (a) above. The potential effect of each on the prospective information is:

Source of Uncertainty	**Potential Effect of Uncertainty**	**Potential Impact of the Uncertainty**
Regulatory Requirements	It is unlikely that any of the Requirements will reduce, thus the most likely impact is an increase in forecast expenditure to meet possible increased standards. It is not possible to quantify this potential impact.	Low
Ownership	Different owners could have different service and expenditure objectives than those embodied in the AMP, resulting in either higher or lower service targets and associated expenditures	Medium
Consumer Demands	Consumers could change their demands for service and willingness to pay resulting in either higher or lower service targets and associated expenditures	Medium
Natural Disaster	Equipment failure and major repairs and replacements required which are not currently provided for	Low, Medium, High depending on severity
Demand Growth	Higher or lower demands require greater or lesser capacity across the system as currently projected. Demand forecasts are contained in section 7 of the AMP. .	Low
Load Profile	Seasonal shifts in demand could require planned capacity upgrades to be accelerated or delayed. The magnitude of this potential shift is unlikely to be more than 3-5 years either way.	Low
Land Use Zoning	Zone changes will impact on demand growth. The implications of uncertainty for demand growth are noted above.	Low
New Loads	New loads will impact on demand growth. The implications of uncertainty for demand growth are noted above. Specific new investments may also be required to meet large new loads.	Low
Equipment Failure	Equipment failure and major repairs and replacements required which are not currently provided for.	Low due to Business Continuity Planning
Further Detailed	Development and maintenance requirements differ from those	Low (applies mainly

Planning	currently predicted for the later five years of the planning period, particularly for the 33kV, 11kV and 400V networks.	to years 6 – 10 of the AMP)

Appendix B – Summary of Compliance with Disclosure Requirements

As described in section 3.1 the purpose of Appendix A, is to assist readers with the compliance of Section 24 and Schedule 12 of the Electricity Information Disclosure Amendment Requirements 2012. The Commerce Commission has also provided a determination (NZCC 22, issued 24 March 2015) prescribing the information requirements that apply to electricity distribution businesses. The following table shows the determination reference, a description of the requirement, and the location in the AMP where compliance is achieved.

Determination Reference	Requirement	Location in AMP
3.1	A summary that provides a brief overview of the contents and highlights information that the **EDB** considers significant	Section 2
3.2	Details of the background and objectives of the **EDB**'s asset management and planning processes	Section 3
3.3	A purpose statement which	
3.3.1	makes clear the purpose and status of the **AMP** in the **EDB**'s asset management practices. The purpose statement must also include a statement of the objectives of the asset management and planning processes	3.1
3.3.2	states the corporate mission or vision as it relates to asset management	3.2
3.3.3	identifies the documented plans produced as outputs of the annual business planning process adopted by the **EDB**	3.2
3.3.4	states how the different documented plans relate to one another, with particular reference to any plans specifically dealing with asset management	3.2
3.3.5	includes a description of the interaction between the objectives of the **AMP** and other corporate goals, business planning processes, and plans	3.2
3.4	Details of the **AMP planning period**, which must cover at least a projected period of 10 years commencing with the **disclosure year** following the date on which the **AMP** is disclosed	3.3
3.5	The date that it was approved by the **directors**	3.3
3.6	A description of stakeholder interests (owners, **consumers** etc) which identifies important stakeholders and indicates-	3.4
3.6.1	how the interests of stakeholders are identified	3.4
3.6.2	what these interests are	3.4
3.6.3	how these interests are accommodated in asset management practices	3.4
3.6.4	how conflicting interests are managed	3.4
3.7	A description of the accountabilities and responsibilities for asset management on at least 3 levels, including-	

3.7.1	governance—a description of the extent of **director** approval required for key asset management decisions and the extent to which asset management outcomes are regularly reported to **directors**	3.5
3.7.2	executive—an indication of how the in-house asset management and planning organisation is structured	3.5
3.7.3	field operations—an overview of how field operations are managed, including a description of the extent to which field work is undertaken in-house and the areas where outsourced contractors are used	3.5
3.8	All significant assumptions must be-	
3.8.1	quantified where possible	Appendix A
3.8.2	clearly identified in a manner that makes their significance understandable to interested persons, including	Appendix A
3.8.3	a description of changes proposed where the information is not based on the **EDB**'s existing business	N/A
3.8.4	the sources of uncertainty and the potential effect of the uncertainty on the prospective information	Appendix A
3.8.5	the price inflator assumptions used to prepare the financial information disclosed in **nominal New Zealand dollars** in the Report on Forecast Capital Expenditure set out in Schedule 11a and the Report on Forecast Operational Expenditure set out in Schedule 11b.	Appendix A
3.9	A description of the factors that may lead to a material difference between the prospective information disclosed and the corresponding actual information recorded in future disclosures	Appendix A
3.10	An overview of asset management strategy and delivery	2.4
3.11	An overview of systems and information management data	3.6
3.12	A statement covering any limitations in the availability or completeness of asset management data and disclose any initiatives intended to improve the quality of this data	3.6
3.13	A description of the processes used within the **EDB** for-	
3.13.1	managing routine asset inspections and **network** maintenance	3.6.1
3.13.2	planning and implementing **network** development projects	3.6.2
3.13.3	measuring **network** performance.	3.6.3
3.14	An overview of asset management documentation, controls and review processes	Section 10
3.15	An overview of communication and participation processes	3.5
3.16	The **AMP** must present all financial values in **constant price New Zealand dollars** except where specified otherwise	Section 10
3.17	The **AMP** must be structured and presented in a way that the **EDB** considers will support the purposes of **AMP** disclosure set out in clause 2.6.2 of the determination.	
4	The **AMP** must provide details of the assets covered, including-	
4.1	a high-level description of the service areas covered by the **EDB** and the degree to which these are interlinked, including-	4.1

4.1.1	the region(s) covered	4.1.1
4.1.2	identification of large **consumers** that have a significant impact on network operations or asset management priorities	4.1.2
4.1.3	description of the load characteristics for different parts of the **network**	4.1.3
4.1.4	peak demand and total energy delivered in the previous year, broken down by **sub-network**, if any.	4.1.4
4.2	a description of the **network** configuration, including-	4.2
4.2.1	identifying bulk electricity supply points and any **distributed generation** with a capacity greater than 1 MW. State the existing firm supply capacity and current peak load of each bulk electricity supply point;	4.2.1
4.2.2	a description of the **subtransmission** system fed from the bulk electricity supply points, including the capacity of **zone substations** and the voltage(s) of the **subtransmission network**(s). The **AMP** must identify the supply security provided at individual **zone substations**, by describing the extent to which each has n-x **subtransmission** security or by providing alternative security class ratings;	4.2.2
4.2.3	a description of the distribution system, including the extent to which it is underground;	4.2.3
4.2.4	a brief description of the **network**'s distribution substation arrangements;	4.2.4
4.2.5	a description of the **low voltage network** including the extent to which it is underground	4.2.5
4.2.6	an overview of secondary assets such as protection relays, ripple injection systems, SCADA and telecommunications systems	4.2.7 to 4.2.9
4.3	If **sub-networks** exist, the **network** configuration information referred to in subclause 4.2 above must be disclosed for each **sub-network**	N/A
4.4	The **AMP** must describe the **network** assets by providing the following information for each asset category	4.3
4.4.1	voltage levels	4.3.1 to 4.3.10
4.4.2	description and quantity of assets	4.3.1 to 4.3.10
4.4.3	age profiles	4.3.1 to 4.3.10
4.4.4	a discussion of the condition of the assets, further broken down into more detailed categories as considered appropriate. Systemic issues leading to the premature replacement of assets or parts of assets should be discussed	4.3.1 to 4.3.10
4.5	The asset categories discussed in subclause 4.4 above should include at least the following	
4.5.1	Sub transmission	4.3.2
4.5.2	Zone substations	4.3.3
4.5.3	Distribution and LV lines	4.3.4 & 4.3.7
4.5.4	Distribution and LV cables	4.3.4 & 4.3.7
4.5.5	Distribution substations and transformers	4.3.5
4.5.6	Distribution switchgear	4.3.6
4.5.7	Other system fixed assets	4.3.9 & 4.3.10
4.5.8	Other assets	4.3.9 & 4.3.10

4.5.9	assets owned by the **EDB** but installed at bulk electricity supply points owned by others	4.3.1
4.5.10	**EDB** owned mobile substations and generators whose function is to increase supply reliability or reduce peak demand	4.2.10
4.5.11	other generation plant owned by the **EDB**	
5	The **AMP** must clearly identify or define a set of performance indicators for which annual performance targets have been defined. The annual performance targets must be consistent with business strategies and asset management objectives and be provided for each year of the **AMP planning period**. The targets should reflect what is practically achievable given the current **network** configuration, condition and planned expenditure levels. The targets should be disclosed for each year of the **AMP planning period**.	Section 5
6	Performance indicators for which targets have been defined in clause 5 above must include **SAIDI** and **SAIFI** values for the next 5 **disclosure years**.	5.1.1
7	Performance indicators for which targets have been defined in clause 5 above should also include	
7.1	**Consumer** oriented indicators that preferably differentiate between different consumer types	5.1
7.2	Indicators of asset performance, asset efficiency and effectiveness, and service efficiency, such as technical and financial performance indicators related to the efficiency of asset utilisation and operation.	5.2
8	The **AMP** must describe the basis on which the target level for each performance indicator was determined. Justification for target levels of service includes **consumer** expectations or demands, legislative, regulatory, and other stakeholders' requirements or considerations. The **AMP** should demonstrate how stakeholder needs were ascertained and translated into service level targets.	5.3
9	Targets should be compared to historic values where available to provide context and scale to the reader.	5.1 to 5.3
10	Where forecast expenditure is expected to materially affect performance against a target defined in clause 5 above, the target should be consistent with the expected change in the level of performance.	N/A
11	**AMP**s must provide a detailed description of **network** development plans, including—	Section 7
11.1	A description of the planning criteria and assumptions for **network** development;	7.1
11.2	Planning criteria for network developments should be described logically and succinctly. Where probabilistic or scenario-based planning techniques are used, this should be indicated and the methodology briefly described;	7.1
11.3	A description of strategies or processes (if any) used by the **EDB** that promote cost efficiency including through the use of standardised assets and designs	7.1
11.4	The use of standardised designs may lead to improved cost efficiencies. This section should discuss	Section 7
11.4.1	the categories of assets and designs that are standardised	Section 7
11.4.2	the approach used to identify standard designs.	Section 7
11.5	A description of strategies or processes (if any) used by the **EDB** that promote the energy efficient operation of the **network**	Section 7

11.6	A description of the criteria used to determine the capacity of equipment for different types of assets or different parts of the **network**	Section 7
11.7	A description of the process and criteria used to prioritise **network** development projects and how these processes and criteria align with the overall corporate goals and vision.	Section 7
11.8	Details of demand forecasts, the basis on which they are derived, and the specific **network** locations where constraints are expected due to forecast increases in demand	7.3
11.8.1	explain the load forecasting methodology and indicate all the factors used in preparing the load estimates	7.3
11.8.2	provide separate forecasts to at least the **zone substation** level covering at least a minimum five year forecast period. Discuss how uncertain but substantial individual projects/developments that affect load are taken into account in the forecasts, making clear the extent to which these uncertain increases in demand are reflected in the forecasts	7.3
11.8.3	identify any **network** or equipment constraints that may arise due to the anticipated growth in demand during the **AMP planning period**	7.4
11.8.4	discuss the impact on the load forecasts of any anticipated levels of **distributed generation** in a **network**, and the projected impact of any demand management initiatives	7.5
11.9	Analysis of the significant **network** level development options identified and details of the decisions made to satisfy and meet target levels of service, including-	7.7
11.9.1	the reasons for choosing a selected option for projects where decisions have been made	7.7
11.9.2	the alternative options considered for projects that are planned to start in the next five years and the potential for non-network solutions described	Section 7
11.9.3	consideration of planned innovations that improve efficiencies within the **network**, such as improved utilisation, extended asset lives, and deferred investment	Section 7
11.10	A description and identification of the **network** development programme including **distributed generation** and non-network solutions and actions to be taken, including associated expenditure projections. The **network** development plan must include-	Section 7
11.10.1	a detailed description of the material projects and a summary description of the non-material projects currently underway or planned to start within the next 12 months	7.7
11.10.2	a summary description of the programmes and projects planned for the following four years (where known)	7.7
11.10.3	an overview of the material projects being considered for the remainder of the **AMP planning period**	7.7
11.11	A description of the **EDB**'s policies on **distributed generation**, including the policies for connecting **distributed generation**. The impact of such generation on network development plans must also be stated.	7.5
11.12	description of the **EDB**'s policies on non-network solutions, including-	7.6
11.12.1	economically feasible and practical alternatives to conventional **network** augmentation. These are typically approaches that would reduce **network** demand and/or improve asset utilisation; and	7.6

11.12.2	the potential for non-network solutions to address **network** problems or constraints.	7.6
12	The **AMP** must provide a detailed description of the lifecycle asset management processes, including—	Section 6
12.1	The key drivers for maintenance planning and assumptions	6.1
12.2	Identification of **routine and corrective maintenance and inspection** policies and programmes and actions to be taken for each asset category, including associated expenditure projections. This must include-	6.1.1
12.2.1	the approach to inspecting and maintaining each category of assets, including a description of the types of inspections, tests and condition monitoring carried out and the intervals at which this is done	6.1.2
12.2.2	any systemic problems identified with any particular asset types and the proposed actions to address these problems	
12.2.3	budgets for maintenance activities broken down by asset category for the **AMP planning period**.	6.2.4 and 6.2.7
12.3	Identification of **asset replacement and renewal** policies and programmes and actions to be taken for each asset category, including associated expenditure projections. This must include-	6.2.4
12.3.1	the processes used to decide when and whether an asset is replaced or refurbished, including a description of the factors on which decisions are based, and consideration of future demands on the network and the optimum use of existing network assets	6.2.4
12.3.2	a description of innovations made that have deferred asset replacement	Section 7
12.3.3	a description of the projects currently underway or planned for the next 12 months	6.2
12.3.4	a summary of the projects planned for the following four years (where known)	7.7
12.3.5	an overview of other work being considered for the remainder of the **AMP planning period**	7.7
12.4	The asset categories discussed in subclauses 12.2 and 12.3 above should include at least the categories in subclause 4.5 above.	
13	**AMP**s must provide a summary description of material non-network development, maintenance and renewal plans, including—	Section 7
13.1	a description of non-network assets	4.2.10
13.2	development, maintenance and renewal policies that cover them	6.2.6 & 7.7.5
13.3	a description of material capital expenditure projects (where known) planned for the next five years	7.7
13.4	a description of material maintenance and renewal projects (where known) planned for the next five years	7.7
14	**AMP**s must provide details of risk policies, assessment, and mitigation, including—	Section 8
14.1	Methods, details and conclusions of risk analysis	8.1
14.2	Strategies used to identify areas of the **network** that are vulnerable to high impact low probability events and a description of the resilience of the **network** and asset management systems to such events	8.1.4
14.3	A description of the policies to mitigate or manage the risks of events identified in subclause 16.2	8.2
14.4	Details of emergency response and contingency plans	8.3

15	**AMP**s must provide details of performance measurement, evaluation, and improvement, including—	Section 9
15.1	A review of progress against plan, both physical and financial	9.1
15.2	An evaluation and comparison of actual service level performance against targeted performance	9.1.3
15.3	An evaluation and comparison of the results of the asset management maturity assessment disclosed in the Report on Asset Management Maturity set out in Schedule 13 against relevant objectives of the **EDB**'s asset management and planning processes	Section 10
15.4	An analysis of gaps identified in subclauses 15.2 and 15.3 above. Where significant gaps exist (not caused by one-off factors), the **AMP** must describe any planned initiatives to address the situation	8.1
16	**AMPs** must describe the processes used by the **EDB** to ensure that-	
16.1	The **AMP** is realistic and the objectives set out in the plan can be achieved	Section 10
16.2	The organisation structure and the processes for authorisation and business capabilities will support the implementation of the **AMP** plans	Section 10

Appendix C – Glossary of Terms

Term	Description
ABS	Air Break Switch
AMP	Asset Management Plan
CAIDI	Consumer Average Interruption Duration Index is the average total duration of interruption per interrupted consumer.
Capacity utilisation	A ratio which measures the utilisation of transformers in the system. Calculated as the maximum demand experienced on an electricity network in a year divided by the transformer capacity on that network.
CB	Circuit Breaker. A device which detects excessive power demands in a circuit and cuts off power when they occur.
CBD	Central Business District.
Conductor	Includes overhead lines which can be covered (insulated) or bare (not insulated), and underground cables which are insulated.
Continuous Rating	The constant load which a device can carry at rated primary voltage and frequency without damaging and/or adversely affecting its characteristics.
Current	The movement of electricity through a conductor, measured in amperes.
Distribution Substation	A kiosk, outdoor ground mounted substation or pole mounted substation taking its supply at 11kV and distributing at 400V.
Feeder	A physical grouping of conductors that originate from a district substation circuit breaker.
Frequency	On AC circuits, the designated number of times per second that polarity alternates from positive to negative and back again, expressed in Hertz (Hz)
GWh	Gigawatt hours.
GXP	Grid Exit Point - The point at which Electra Equipment is deemed to connect to the Transpower National Grid System.
Harmonics (wave for distortion)	A distortion to the supply voltage which can be caused by network equipment and equipment owned by consumers including electric motors or even computer equipment.
High voltage	Voltage exceeding 1,000 volts, generally 11,000 volts (known as 11kV)
Interruption	An electricity supply outage caused by either an unplanned event (e.g. Weather, trees) or a planned even (e.g. Planned maintenance).
kV	Kilovolt.
kW	Kilowatt.
kWh	Kilowatt hour.
kVA	Kilovolt amp. Output rating designates the output which a transformer can deliver for a specified time at rated secondary voltage and rated frequency.
Load Factor	The measure of annual load factor is calculated as the average load that passes through a network divided by the maximum load experienced in a given year.
Low Voltage	Voltage not exceeding 1,000 volts, generally 230 or 400 volts
Maximum Demand (peak demand)	The maximum demand for electricity during the course of the year.
MVA	Megavolt amp.
MW	Megawatt

MWh	Megawatt hours (one million watt hours)
N-1 Security	A load is said to have N-1 security if for the loss of any one item of equipment supply to that load is not interrupted or can be restored in the time taken to switch to alternate supplies.
NIMs	A Network Information Management System which contains geospatial information for all assets including asset description, location, age, electrical attributes, etc.
ODRC	Optimised Depreciated Replacement Cost.
ODV	Optimised Deprival Value.
ONAF	Oil Natural Air Forced
ONAN	Oil Natural Air Natural
PILC	Paper-insulated, lead-covered. A type of insulation.
Ripple Control system	A system used to control the electrical load on the network by, for example switching domestic water heaters, street lighting, etc.
RMU	Ring Main Unit.
RTU	Remote Terminal Unit. Communications device used for relaying data from the field.
SAIDI	System Average Interruption Duration Index is the average total duration of interruption per connected consumer.
SAIFI	System Average Interruption Frequency Index is the average number of interruptions per connected consumers.
SCADA	Electra's computerized System Control And Data Acquisition System being the primary tool for monitoring and controlling access and switching operations for Electra's Network.
SCI	Statement of Corporate Intent
SWER	Single Wire Earth Return
Transformer	A device that changes voltage up to a higher voltage or down to a lower voltage.
Transpower	The state owned enterprise that operates New Zealand's transmission network. Transpower delivers electricity from generators to various networks around the country.
Voltage	Electric pressure; the force which causes current to flow through an electrical conductor.
Voltage Regulator	An electrical device that keeps the voltage at which electricity is supplied to consumers at a constant level, regardless of load fluctuations.
XLPE	Cross linked Polyethylene. Type of insulation for cables.
Zone Substation	A major building substation and/or switchyard with associated high voltage structure where voltage is transformed from 33kV to 11kV.

Appendix D – Amendments to the plan for this version

Section	Amendment
4.3	Major maintenance cycle for zone substations extended to 5 yearly and sequence modified
All	Construction Business overhead costs allocated to the relevant Maintenance Category
All	Revised Capitalisation Policy results in crossarm renewals and replacements being re-categorised from Operational to Capital expenditure
6.2.2	Maintenance cost projections modified to allow for potential purchase and operation of Transpower 110kV lines between Mangahao & Levin