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EA NETWORKS ASSET MANAGEMENT PLAN 2020-30

eanetworks.co.nz

Asset Management Plan for EA Networks' Electricity Network

Planning Period:	1 April 2020 to 31 March 2030
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The owner and custodian of this document is the Network Division of EA Networks, Ashburton. All comments, queries and suggestions should be forwarded to the Network Manager.

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EXECUTIVE SUMMARY

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EXECUTIVE SUMMARY

Key points to take from this plan are:

- The network is overall relatively new and in good condition.
- Fault frequency is better than the average of peer companies and generally better than the average of all companies. Fault restoration time is similar to the average of peer companies.
- Increased levels of SCADA distribution automation and control will occur over the next ten years.
- Customer satisfaction is good, based upon a recent survey.
- Urban underground conversion will conclude within the plan horizon but has been spread over several more years as overhead line condition permits.
- 11 to 22kV conversion will conclude within the plan horizon.
- 33 to 66kV conversion (to the extent intended) will be complete within 5 years.
- Irrigation load growth is static. Other load growth is modest.
- Rural zone substation and 66kV overhead line projects that rely on irrigation load growth to proceed have been delayed to the last two years of the planning period.
- Electric vehicles, batteries and solar PV have yet to make a measurable impact on demand.
- Capital expenditure is declining rapidly. Operational expenditure is slowly rising.
- Technology will play a greater role in future network management and operations.
- Rural distribution capacity will be sufficient for forecast load once 11 to 22kV conversion is complete.
- Urban 11kV distribution capacity will be sufficient for forecast load once the 11kV core network is complete.
- Reliability, resilience and load security increase during the plan period.
- The electricity network represents an acceptably low risk to staff and the public.
- The systems used to document and manage the electricity network are being constantly improved and upgraded.

1 Our Business

The Asset Management Plan is a cornerstone document, which guides the work of all EA Networks personnel.

This particular plan was completed on 12 March 2020 and covers a planning period from 1 April 2020 through to 31 March 2030. The next plan is due for release by 31 March 2021.

This summary is prepared for people who may not be involved within the business of electricity distribution networks and associated services, but who understand and have an interest in efficient management.

EA Networks Network:		
Maximum Demand	177 (Dec 2019)	MW
Annual Load Factor	42 (2019-20 estimate)	%
Delivered Energy	601 (2019-20 estimate)	GWh
Subtransmission Lines	431	km
MV Distribution Lines	2,194	km
LV Distribution Lines	473	km
Distribution Substations	6,505	
(Data as at January 2020		

EA Networks' Evolution

Starting life as a privately-owned generator based in Ashburton township, the Ashburton Electric Power Board was established in 1921 and took supply from the Government in 2023. After that time, the AEPB grew through a variety of operating voltages which included 230 volts dc, 3.3kV, 6.6kV, 11kV, and latterly, 33kV AC. During the 1970s, irrigation demand caused growth to accelerate dramatically, expanding the 33kV subtransmission network to all corners of the Ashburton District. A small hydro generator, Montalto, was also built during the early 1980s. EA Networks (as the AEPB became) has more recently introduced 22kV and 66kV as voltages on the network. A large capital works programme during the late 1990s and the early part of this century now has the majority of subtransmission lines operating at 66kV and a significant portion of the distribution network operating at 22kV. EA Networks relinquished the 33kV supply from Transpower in 2019.

EA Networks supply electricity line services to approximately 19,900 consumers using about 3,098km of lines in Mid-Canterbury (see plan cover) - both underground cables and overhead lines. Other pertinent statistics (As at January 2020) are shown above. EA Networks also develop and operate an open access fibre optic network in Mid-Central Canterbury (EA Networks Fibre).

Objectives of this Plan

This plan aims to document the approach EA Networks intends to take in managing EA Networks' electricity assets.

EA Networks has the following Asset Management Plan objective:

> ***To provide a systematic approach to asset management, which is intended to ensure that the condition and performance of the electricity network and associated assets are being effectively and efficiently maintained or improved to satisfy stakeholder requirements.***

This plan clearly defines the service objectives and gives a strong focus on life cycle management by presenting operations, maintenance and renewal policies and programmes by asset type. Asset management planning processes should effectively integrate best practice features. These establish the service standards and future demands to meet business, legislative and other needs, while developing optimum lifecycle asset management strategies and cash flow projections based on assessing non-asset solutions, failure modes, cost/benefits and risk.

The Asset Management Plan has been fashioned so that it meets the requirements for disclosure of AMP's outlined in the Commerce Act (Electricity Information Disclosure Requirements) Notice 2004 and amendments.

The disclosure regulations stipulate that the disclosed plan must include certain mandatory sections. This plan does not necessarily follow the order or grouping that the requirements are laid out in the regulations. An attempt has been made to flow the document through logical steps rather than the arbitrary nature of the regulation. It should however be noted that every effort has been made to permit simple identification of the mandatory sections.

It is hoped that the chosen layout and style allows the widest possible audience (including all stakeholders) to take advantage of the information it contains. The stakeholders in the plan include:

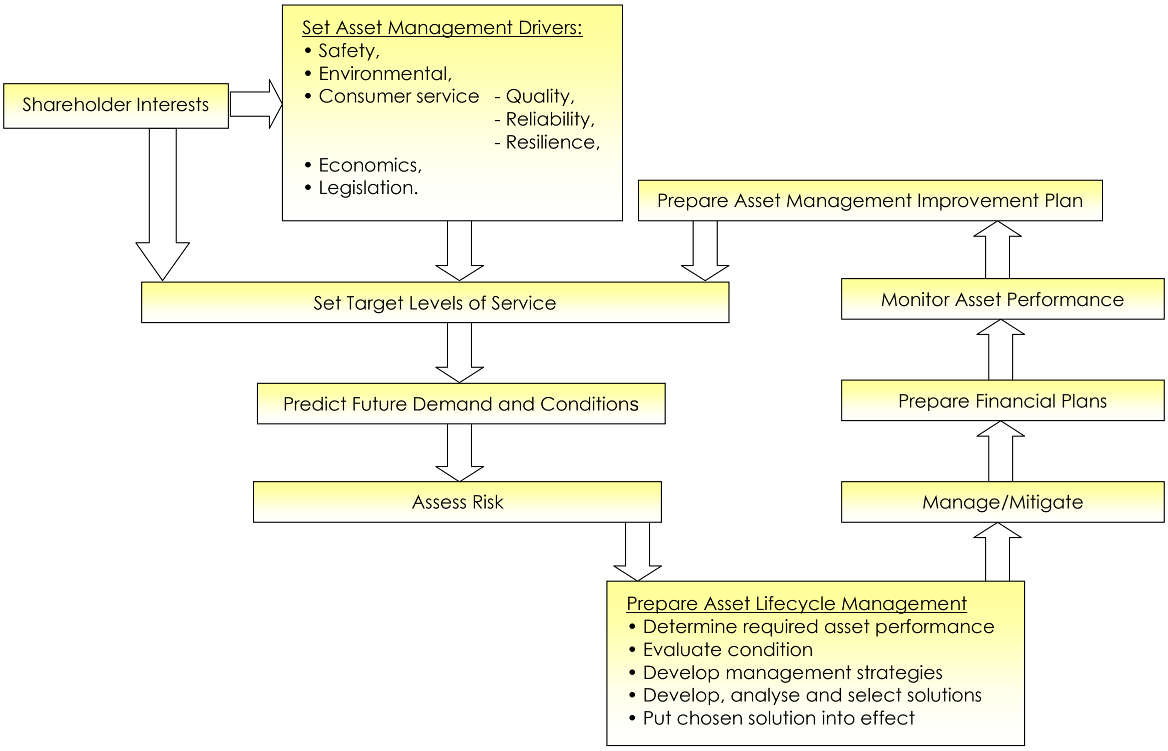
- EA Networks shareholder/consumers
- Energy retailers
- Embedded generation owners
- Ashburton District Council
- Employees and contractors
- Transpower
- Landowners
- Financial institutions
- Regulatory agencies
- Distributed generation proponents

Period Covered

This Asset Management Plan covers the management of EA Networks' electricity network assets for a period of 10 years from the financial year beginning on 1 April 2020 until the year ended 31 March 2030. The main focus of analysis is the first 5 years and for this period, most of the specific projects have been identified. Beyond this time, analysis tends to be more indicative based on long-term trends and it is possible that new development project requirements will arise in the latter half of the planning period that are not identified here.

The Planning Process

The process used to formulate the Asset Management Plan and other supporting documentation is as shown in the below diagram.



Asset Management Drivers

Drivers for this Asset Management Plan (set in consultation with stakeholders) include:

- Safety for staff and public
- Consumer service - reliability
- Consumer service - resilience
- Consumer service – power quality
- Corporate profile
- Environmental responsibility
- Legislative compliance
- Economic efficiency

Asset Management Practices

The management of an electricity network requires a broad range of information systems and applications to store, process and analyse the characteristics and location of electrical assets. EA Networks have a number of mature applications to facilitate some of this work. Some aspects of asset management are not so well served and improvements in systems and processes are occurring to bring these up to an acceptable standard.

Processes

Processes exist for most aspects of asset management in the EA Networks network division. A number of these processes require refinement to ensure optimal decision-making. One of the major processes still requiring additional documentation and formalisation is the design, inspection and testing regimes. Currently these are known and partially recorded but cannot be reproduced or easily modified. The risk management process requires revisiting and a feedback mechanism that triggers reassessment of risk before and after network changes.

The outstanding process documentation is being addressed as resources permit. Recent clarification of roles with specific asset responsibilities has focussed this effort. There are now systems in place that support progress (document management and asset management systems). While capital workloads are high, progress towards completion is likely to be incremental over the next few years.

Systems

EA Networks have a range of systems available for asset management and some are more capable than others. The main systems/applications that are in use are:

- Asset Management System
- SCADA System
- Financial/Accounting System
- Connection System
- Standards Documentation System
- GIS Asset Mapping System
- Work Management System
- Network Modelling and Analysis
- Fault Recording System
- Advanced Distribution Management System

An asset management system has been recently implemented and the data from the previous asset register is being progressively converted into it. This new system provides full asset lifecycle management (physical/financial) and will be maturing in functionality over the next few years. Inspection and testing regimes will be attached to assets so that these activities are rigorously adhered to. The GIS (Geographic Information System) is fully functional and the final capture of backlog data is complete. Functionality and integration will be progressively enhanced over the next three years. An emphasis on improving documentation of various processes will require extensive access to a document management system. The ADMS (Advanced Distribution Management System) will provide a significant increase in visibility of asset utilisation. Simple access to real-time, historical, and predictive loading and fault data will allow assets to be managed in a much more systematic fashion and machine intelligence will help to limit risk to both personnel and assets.

Other systems are also being updated or implemented and these include a customer relationship system, a billing system for handling network/retailer reconciliation, a system to handle co-operative shareholder management, and a data warehouse to provide an integrated repository of normalised data. These systems will all provide ancillary support to effective asset management.

EA Networks will continue to invest in systems that provide good benefit/cost and strengthen the ability of EA Networks to provide enhanced asset management, network management and risk management functions.

2 Managing Risk & Resilience

Introduction

The EA Networks network is periodically exposed to events or incidents that subject elements of the electrical network to a high risk of failure. If the location of these events coincides with a critical component of the electrical network, the result is a high risk to the integrity of the electrical network. This risk of failure can in turn lead to high risks for consumers, either as individuals or as larger collective groups.

EA Networks has assessed risk from four distinct perspectives.

- The first is risk to people and private property from the construction, and operation and condition-related failure of the electricity network.
- The second is the risk to the environment from the construction and operation of the electricity network.
- The third is the risk to the network from people, the environment, and High Impact Low Probability events.
- The fourth is commercial risk.

Risk Management Framework

A comprehensive risk assessment has been undertaken on both individual pieces of major equipment and categories of plant with common failure modes. These assessments have been entered into a risk register database for ease of update and prioritising. Some of the key risk factors that emerged, and the mitigation undertaken are:

Risk Factor	Actual/Proposed Mitigation
Design of seismic restraints of various network equipment	Adopted recommendations from seismic experts, especially improved restraint for ground mounted equipment.
Loss of 220/66kV GXP transformer leaving un-served load	Third 220/66kV transformer has been installed.
Security of Ashburton township load	Two substations now supply Ashburton, ensuring no on-going loss of supply. Reinforcement of 11kV network to increase transfer capacity is underway.
Lightning exposure of major plant	Assess each item for exposure and address in most effective manner for each item.
Oil spill management	Bund major oil volumes where possible and provide training and emergency response kits accessible from all locations.
SF_6 gas management	Acknowledge potential harm to the environment and manage according to industry best practices.
Weather exposure of overhead lines	Network design standards, underground conversion, network renewal, emergency stocks, closed subtransmission rings.
11kV switchgear failure	Affected model largely replaced and remaining unit disabled to prevent operation.
Distribution transformer failure	A universal spare distribution transformer (1 MVA, 22-11kV/415 V) with cables exists, along with a variety of other sizes.
Ripple plant failure	Configure plants so that loss of one plant does not prevent effective control.

Reassessment of risk occurs every day, and the adoption of sound procedures and minimum acceptable design standards provides mitigation from the conceptual design stages of all development or enhancement work.

High impact low probability events are treated by emergency contingency and response planning. The majority of these plans have been reviewed in the last 12 months.

Commercial risk is becoming an issue that will require consideration - largely due to the rise of disruptive technologies that could drive financial impacts, both in terms of revenue and stranding of historic assets. The risk of assets being under-utilised if widespread solar PV and battery technology occurs is real. The need to carefully consider the type of asset employed in new construction will be necessary to mitigate the risk of asset stranding. There is also some risk electric vehicles will become a major source of uncontrolled load that cannot be adequately supplied without additional assets and/or could cause network performance issues. To ensure adequate return over the assets' lifetime, the consumer pricing methodology may need to have a greater demand component to ensure economic viability and fair cost recovery.

3 Our Customers

Service is about satisfying all stakeholders, including safety aspects and environmental responsibilities.

It is EA Networks' goal to perform better in reliability indices than the industry median for comparable line companies and it is targeting an on-going quality improvement with a consistent price path.

Consumer Expectations

As a co-operative company, the vast majority of consumers are also shareholders and they directly elect a shareholders' committee who in turn appoint the directors. Also received/scrutinised by the Shareholders' Committee is the Statement of Corporate Intent, which identifies a range of financial and reliability performance targets. In conjunction with this form of consultation, EA Networks management liaises with the Energy Retailers to determine the expectations of their customers and quantify these in terms of desirable reliability indices.

EA Networks surveys their customers regularly. A recent telephone survey has concluded that only 4% of consumers are prepared to pay a slightly increased charge in order to ensure a timelier restoration of supply following an unexpected outage. Overall, the survey showed very good satisfaction with EA Networks performance.

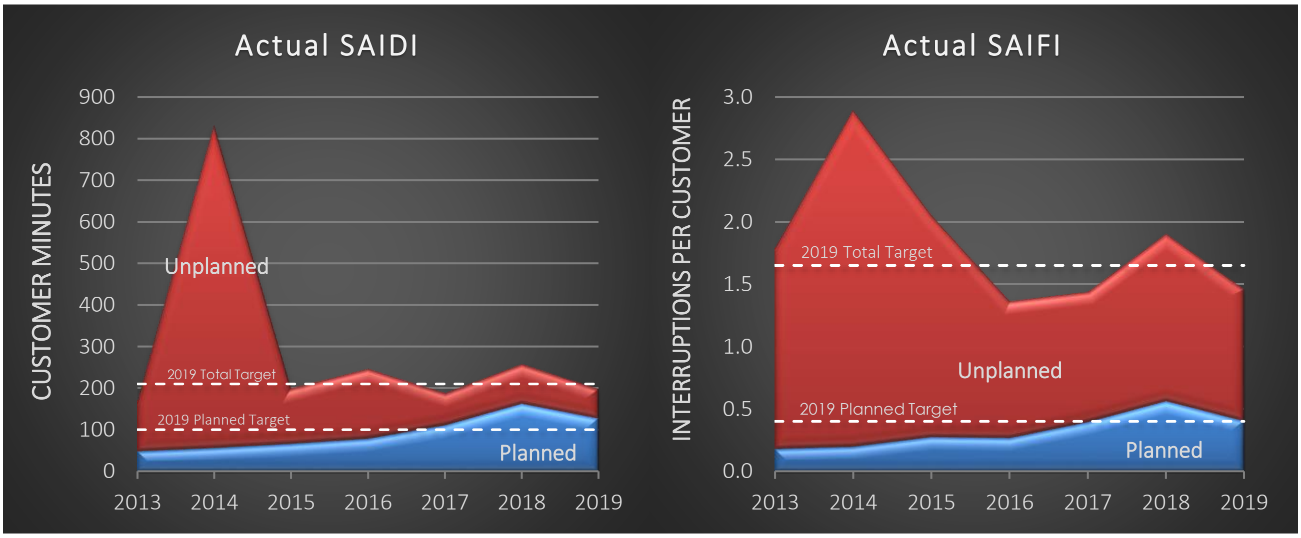
Future Performance Targets 2018-28											
Indicator	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	Default Quality Path Limit
SAIDI Total (mins)	230	215	210	180	173	168	168	168	168	168	151[1]
SAIFI Total (#/yr)	1.65	1.60	1.60	1.60	1.55	1.55	1.55	1.53	1.51	1.51	1.61[1]
Faults/100km	5	5	5	5	5	5	5	5	5	5	

[1] These are the Commerce Commission default quality path limits. The values are "Normalised" to remove aberrant events. The targets shown above are non-normalised and include all faults and planned outages.

Network Service Levels

Historically, EA Networks struggled to meet some of the service level targets it set. The targets have been revised in the last 36 months. As a consequence, the more realistic targets were met or only slightly exceeded in recent years.

When compared to other New Zealand lines companies the targets are almost all below the average forecast performance. What this information infers is that EA Networks (on average) target to have fewer, shorter outages than currently. Irrespective of the performance relative to other companies, on average, it is intended to outperform previous performance year by year. These targets assume "severe weather events" (admittedly undefined) are excluded from the averages.



The higher than target 2017-18 SAIDI and SAIFI was a consequence of the suspension of live line working causing many more planned outages. Live line work is now being undertaken again, but not at the same level as previously.

EA Networks are coming very close to breaching the Default Quality Path limit for 2019-20, largely as a result of a very intense lightning storm and the Rangitata River flooding event in December 2019 which collectvely caused at least 12 minutes of unplanned SAIDI (11% of unplanned SAIDI target). Planned outages were suspended from January 2020 to prevent a breach.

4 *Our Network*

The area EA Networks serves is largely rural land used for cropping and dairy farming. These two uses encourage a high level of irrigation in the district. The summer demand for irrigation water is in many cases served by electrically pumped systems. Irrigation represents the largest single group of loads that EA Networks supply. Other significant loads are vegetable and meat processing facilities and a ski-field.

There is a significant amount of distributed generation on the EA Networks network. The largest is Highbank at 26 MW. Several smaller ones also contribute, and they collectively provide about 20-25% of the energy needs of the district. Unfortunately, they are very seasonal and cannot be relied upon for back-up supply.

EA Networks has one geographic supply point from Transpower at 66kV. The 33kV supply was relinquished in 2019. An extensive 66kV subtransmission network (with some small 33kV spur lines) supplies 21 zone substations varying in size from 2.5 MVA to 40 MVA. The distribution network is a mixture of 22kV, 11kV and LV with both overhead and underground variants of each. Overall, the distribution system is about 26% underground cable by circuit length.

Distribution transformers and substations come in a variety of forms and EA Networks' modern ones are modular and flexible.

The LV network is extensive in urban areas but not so in rural areas. Underground conversion in urban areas is removing a lot of older overhead LV lines.

EA Networks have a range of secondary assets that perform critical functions in the network and range from ripple injection to protection and voice/data communications.

The 2019 closing Regulatory Asset Base (RAB) was $268.45 Million.

5 *Planning Our Network*

Dramatic load growth has occurred in the Mid-Canterbury region over the last two decades. The summer maximum demand has more than trebled since 1996 and more than doubled since 2003. The 2017-18 summer peak was 181MW. The previous maximum summer peak was 177MW in 2016. Irrigation load has doubled since 2005 and now is about 147MW. This growth has in turn driven very significant capital development on the EA Networks network. Annual peak demand is very dependent on rainfall and temperature driving irrigation diversity.

It is important to assess the future load as accurately as possible since network investment is required before the load arrives, not after. Incorrectly assessed, the absence of load can leave expensive assets under-utilised and conversely the presence of un-forecast load can leave it un-serviced. Future demand also comes in the form of security requirements that require additional or larger assets so that the network is more fault-tolerant.

A continuation of the historic high rates of load growth are unlikely. Irrigation load growth has markedly slowed to the point of no growth occurring for three consecutive years. A combination of gravity pressurised irrigation schemes, groundwater abstraction limits being reached, and potential new water storage schemes has influenced the attitudes of farmers. A cautious approach to electricity network capacity increases is warranted. An intelligence gathering exercise investigating future on-farm irrigation demand will be undertaken to minimise the risk of new underutilised assets. The international price for dairy products is also having an impact.

The impact of solar and electric vehicle charging is not significant, and it is likely that this will not be a major factor in peak demand for some time.

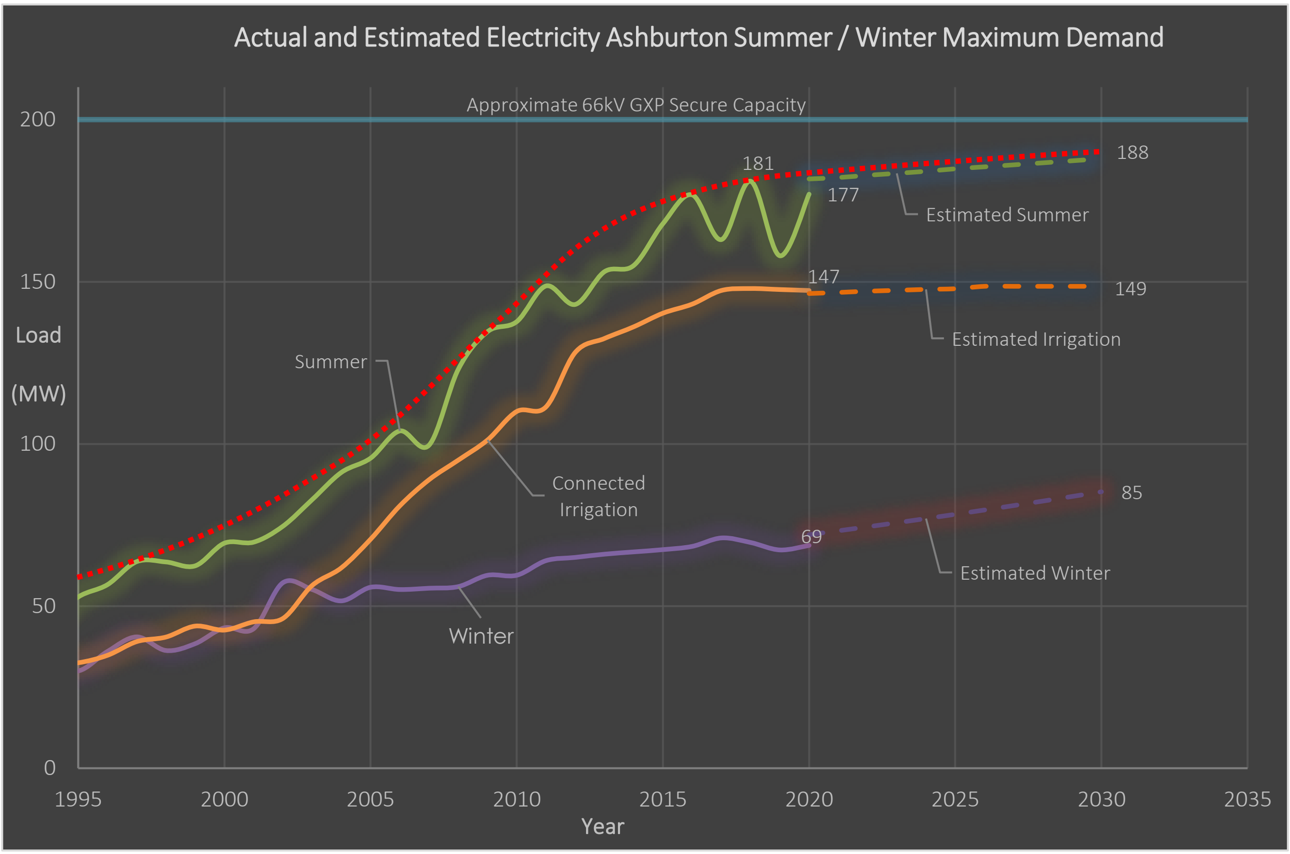
There are a broad range of assumptions that must be made when predicting future parameters. This makes confident prediction very challenging. The following is an incomplete set of assumptions that EA Networks have considered.

Uncertainty	Potential Effect of Uncertainty	Potential Impact
Load Growth	Timing change of projects. Funding risk.	Low
Irrigation Water	Increase in water availability. Load increase.	Medium – High
	Increase in gravity fed water. Load decrease.	Medium
Statute/Regulation	Change in statute/regulation. Business risk.	Low
Regional Demand	Regional peak demand summer. Pricing risk.	Medium to High
Consumer Expectations	Increase/decrease in consumer expectation. Risk of insufficient or excess asset investment.	Low

Natural Disaster	Widespread equipment damage. Funding, resourcing, and reputational risks.	Low – High severity dependent
Distributed Generation	Widespread and dense distributed generation. Power quality, capacity, commercial risk.	Low
Large Loads	Large new loads. Resource/timing risk.	Low
Electric Vehicles	Rapid/widespread uptake of electric vehicles. Power quality/capacity risk, then network reinforcement.	Low – Medium (add 15-20% CapEx)
District Plans	Rule changes restricting activity. Cost to business.	Low
Commodity Prices	Agricultural commodity price volatility. Project timing risk.	Low – Medium
Planning & Monitoring	Late stage AMP volatility. Funding and resource risks.	Low
Equipment Failure	Widespread/major equipment failure. Funding and reputational risk.	Low
Ownership	Altered ownership structure. Change of strategy.	Low – Medium

Load Forecasting

Future load projection is a difficult task and is based on a complex multivariate environment. A careful and rigorous approach must be taken to developing future load projections based on historical trends, available information and estimates on future changes.



Forecasts of maximum demand on the subtransmission system have been derived from internal modelling work. The forecast is based on estimating the future load likely to occur on each zone substation. Separate summer and winter demands are estimated for the next ten years. The results of this estimate are shown in the diagram above.

Extrapolating a moving four-year average growth linear regression line into the future for ten years is no longer valid. The results of this forecast have become hopelessly optimistic (it continues to show rapid growth) and cannot take account of changes to the environmental regulations and dairy market.

EA Networks are taking a cautious approach to the future summer system maximum demand. It will possibly exceed 188 MW by 2030, but that is the presumed system maximum demand.

Strategic (Development) Plans by Asset

Transpower Grid Exit Points

At Transpower's Ashburton substation 66kV GXP load has historically exceeded 180 MW on the 66kV bus (the only supply voltage – having relinquished 33kV in 2019). Three 220/66kV 100/120 MVA transformers are installed. It is unlikely further development will be required at this GXP. Any expansion would probably be at a new geographically remote 66kV GXP site.

Subtransmission Network

The subtransmission network will come under increased pressure if the load grows more than predicted. Most of the residual 33kV system will be converted to 66kV or 22kV for capacity and security reasons. By the end of the planning period it is possible that a second, geographically separate, 66kV GXP may supply some of the 66kV subtransmission network. This development depends upon significant load growth.

Zone Substations

Since the last Plan, two more zone substations have been converted to 66kV (Ashburton and Mt Somers). By the end of the planning period, only one zone substation (Mt Hutt) will be untouched by the 66kV developments.

Rural HV Distribution Network

Emphasis on conversion to 22kV as the best solution to capacity and voltage problems has already paid dividends for EA Networks. This approach will be followed wherever it makes commercial and engineering sense to do so. Increasing the conductor size of 11kV lines will still be an option for specific short-term problems that are not widespread. Some key 22kV lines on state highways have been placed underground in cooperation with NZTA. This is a programme that is continuing and should conclude within the planning period (2028). A programme to install rural ring main units is largely complete and assists safety and reliability by using remote control.

Urban HV Distribution

"Urban" distribution feeders are restricted to Ashburton, Methven, and Rakaia townships. Other townships are typically connected to a rural overhead feeder with additional network segregation using line reclosers to offer the township a more secure supply.

Urban reinforcement solutions are typically implemented by adding additional cable routes from a zone substation, although a point is reached when congestion makes this impractical. Ashburton substation was in this situation and the chosen solution introduced Northtown substation. The next phase of reinforcement is beginning, with an additional larger "11kV Core" cable network needed in Ashburton township.

The underground conversion programme has the widespread support of the consumers/shareholders, which lends additional weight to the other less obvious advantages that accrue from this work. The additional security, capacity, flexibility, quality of supply, and low maintenance characteristics all contribute to greater consumer/shareholder satisfaction. Other stakeholders are also encouraging of this work. The plan shows the urban underground conversion programme to be complete by 2029.

Urban LV Distribution

The urban underground LV network ranges in age from the 1960s to brand new. The majority has been installed since 1980. The urban overhead LV network is planned to all be replaced with underground cable by 2029. The relatively young age of the underground LV network has provided reasonable capacity for growth. Some early subdivisions may need reinforcement should demand from new loads such as electric vehicles arrive but provided slow-charging is off-peak then much of the underground LV network should be adequate for the duration of the planning period. Beyond the end of the planning period, additional reinforcement work may be required as electric vehicle battery capacity increases. Extensive solar PV may also cause some need for urban LV reinforcement.

SCADA

The SCADA system at zone substations is largely ubiquitous. Distribution automation is now being emphasised. Communications to zone substations has improved to allow data, voice and video communication. This communications development is largely complete, with some video cameras awaiting installation. Extra communication to distribution devices beyond the zone substation boundary has also been allowed for.

Distributed Generation

EA Networks already has significant distributed generation connected in the form of four hydroelectric generation plants, one at Barrhill (0.5MW), one at Cleardale (1.0 MW), one at Montalto (1.6 MW) and one at Highbank (26 MW). New distributed generation of any scale is encouraged and will be connected subject to suitable commercial and technical arrangements made according to industry rules and guidelines governing these activities.

A significant number of distributed generation proponents have had informal discussions with EA Networks. A range of generation projects are possible, and they vary from small to quite large over various fuel/energy sources. The economic environment for new generation investment is currently not particularly favourable. The possible projects are detailed in section 5.4.12.

EA Networks are always reviewing the feasibility of locally connected distributed generation that would enhance the security and profitability of both the company and the community. Several preliminary studies have been undertaken and this has identified some promising options that will be detailed in the Asset Management Plan if they become a commercial proposal.

6 *Managing Our Assets*

When considering the priorities for maintenance of a lines company network, it becomes apparent that the subtransmission level lines and substations require the highest priority. These represent the backbone of supply and the long-term loss of any one of these assets would have a potentially devastating effect on service levels. Lower voltage level assets are treated with the same rigour but slightly lower priority and less intensive diagnostic testing.

Overview

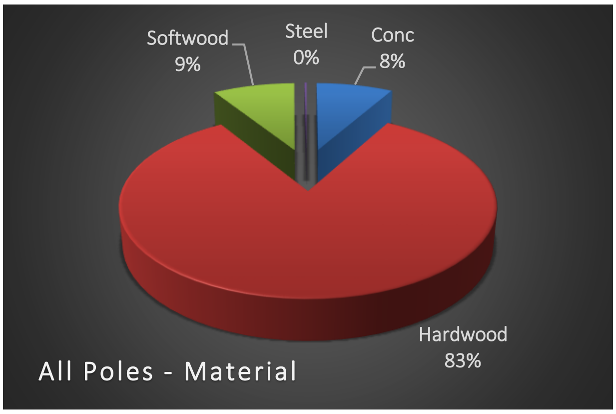
The management plans for each asset category detail how EA Networks intends to operate and manage the assets so that they meet the required performance standards. The focus on optimising lifecycle costs shapes all the processes involved.

Maintenance on all equipment is condition-based rather than time-based. The condition is measured by inspection, testing, and/or the duty a device has experienced (measured in operations or interrupted current).

Life Cycle Plans by Asset

Subtransmission Lines

This asset class is rapidly becoming younger as 66kV lines replace older 33kV lines. Little maintenance work is expected to be necessary during the planning period other than the rebuild of some old 33kV lines converted to 66kV in the 1990s. Development work will continue for security of supply reasons and if load growth increases.

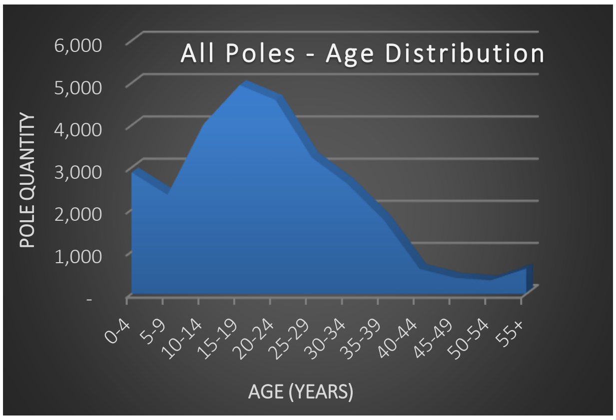


Zone Substations

The major electrical assets are almost all less than 20 years old. This asset category uses some of the most intensive diagnostic testing of all assets. Testing of oil, gases, mechanisms and insulation are all undertaken to ensure detailed knowledge of condition. Development of the subtransmission network requires redevelopment of one site and possibly construction of a new site.

Distribution Assets

The distribution network is predominantly in good condition with the vast majority of lines capable of withstanding moderate to strong wind and snow without damage. Condition assessment is on-going and as lines are examined they are either scheduled for maintenance or re-inspection at a later date. 22kV conversion is lightly refurbishing portions of the network as the line is reinsulated. It allows hardware to be examined and assessed for condition. The existing conductor is typically left in-situ.



The maintenance requirements of the network are not expected to increase significantly over the planning period despite the probable increase in line length.

7 Supporting Our Business

In late 2012, EA Networks relocated its operational base to a purpose-built complex. This site and buildings offer an integrated solution with IL4 seismic resistance and self-supporting storage infrastructure for diesel fuel, drinking water and on-site back-up power generation.

Other assets include vehicles, test equipment, LAN, radio-communications infrastructure, and various technical software systems. Some of these assets will incur significant expenditure during the planning period.

Most policies regarding non-network assets are understood but not formally documented. As opportunity permits, they will be recorded. The vehicle policy is documented and includes acceptable use and vehicle replacement criteria.

There will be continuing information technology investments in the next few years to ensure a solid footing for asset management, future customer engagement and improved service levels.

8 Financial Summary

The following chart and tables summarise the projected asset management expenditure over the next ten financial years on the EA Networks electricity network.

The amount of baseline capital and maintenance expenditure forecast in the plan has been revised to more accurately reflect the actual base levels that have been experienced over the last few years. Categorisation of expenditure is now more accurate and consistent than previous plans.

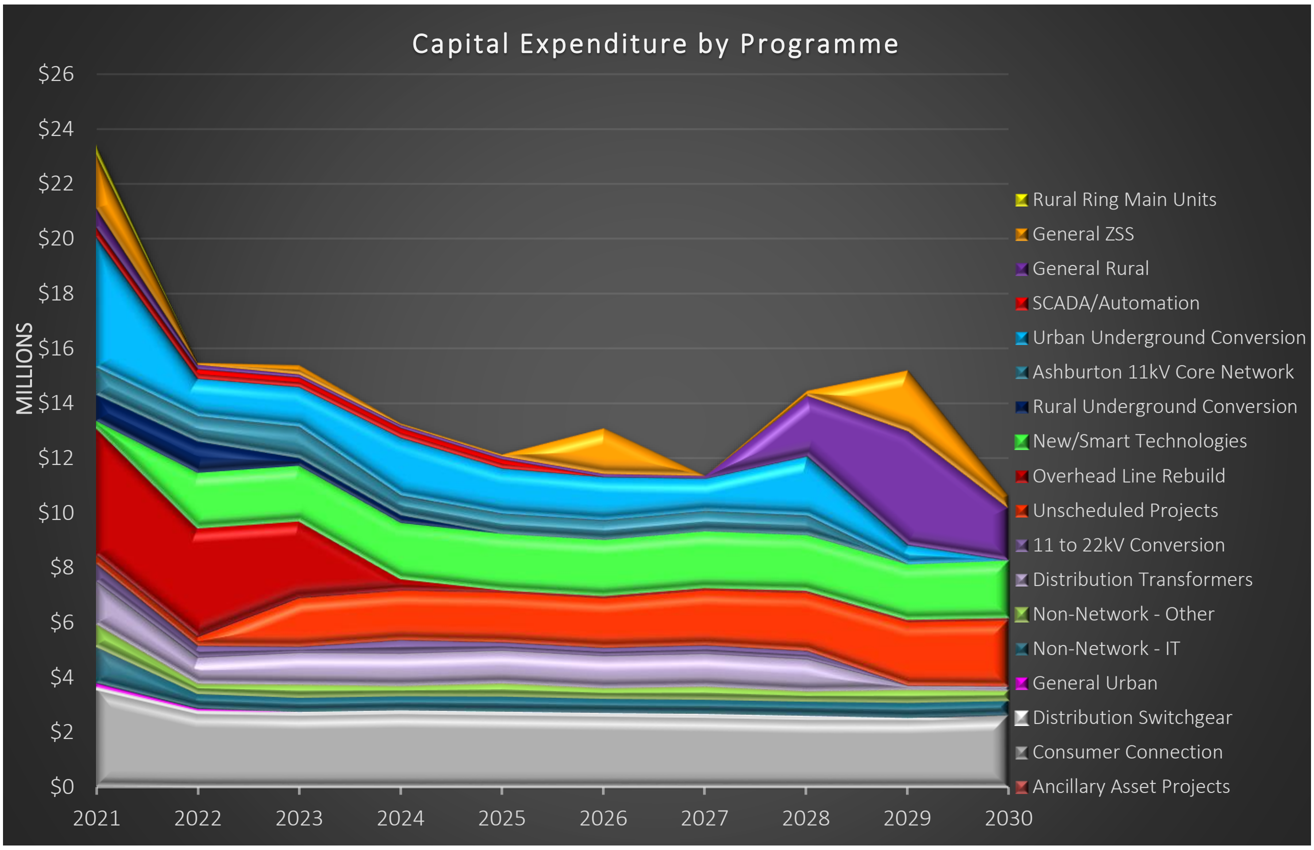
The costs stated here are in "constant" 2020-21 dollars (not adjusted for inflation).

Overall Network Capital	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
TOTAL	23,444	15,474	15,395	13,277	12,140	13,091	11,363	14,458	15,203	10,649

The first 3 years of the capital forecast are dominated by: backlog underground conversion, 66kV overhead rebuilding, some zone substation work, and by a series of development projects that are driven by security, condition, or information technology requirements. Please refer to the chart on the following page for a visual representation of the expenditure by asset grouping. During the following 5 years, the capital expenditure drops as various programmes run to their conclusion - particularly the underground conversion programmes (3 x blue) and 11 to 22kV conversion programme (2 x lilac). The level of baseline expenditure is in the range of $9-10M (which includes on-going routine activity associated with consumer connections). The red unscheduled projects category (post 2023) includes scheduled, but unidentified, overhead line rebuilds (dark red), which will be individually identified in future plans as resources allow reducing the unscheduled expense. The gold zone substation and purple rural subtransmission line expenditure will only happen if demand grows.

Overall Maintenance	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
TOTAL (exc. Non-Network)	3,900	3,936	3,913	3,991	3,944	3,969	3,950	3,940	3,944	3,949

The operational (maintenance) expenditure is shown as gently rising over the entire planning period. Random natural events will undoubtedly cause periods where significant repairs will be required. The planned operational expenditure will be more predictable as additional actual condition data is gathered (currently condition is inferred from age). The basis for the annual operational expenditure is historical performance combined with anticipated resourcing needs. Details of financial expenditure are available here.



9 Delivering On Our Plan

Improvements

EA Networks are always looking for opportunities to improve or refine our asset management systems, processes, and the supporting environment. EA Networks continue to look at industry best practice and actively engage in industry discussions in these areas. Where there is a business case for investing in improved asset management systems/processes, EA Networks look to commit investment to enable these system/process improvements. This approach is aligned with taking proactive responsibility for the management of the network with reference to all stakeholder objectives.

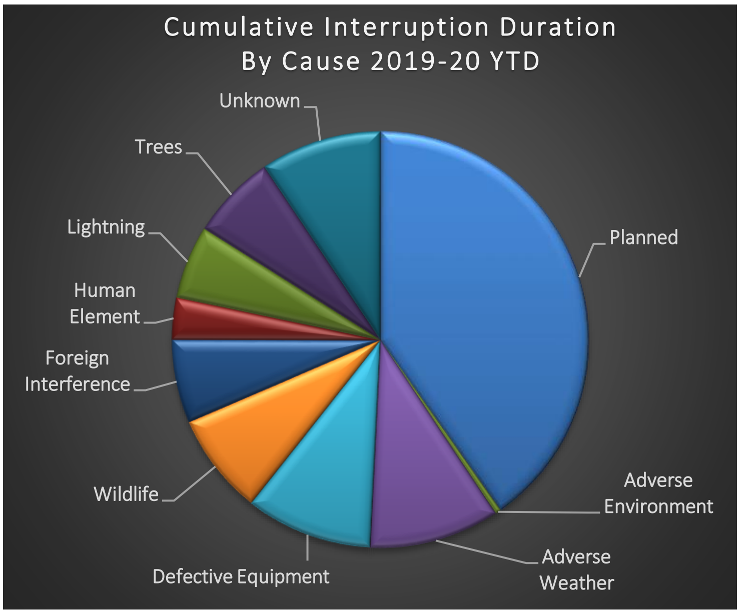
Examples of planned improvements over the AMP period are:

- advanced distribution management system implementation and development,
- risk management and detailed system security evaluation,
- data warehouse development,
- field-based systems to support accurate asset data capture/reporting.

Network Service Improvements

A range of service improvement initiatives have been identified and either implemented or plan to be implemented. Areas that initiatives have targeted include:

- Subtransmission configuration
- Diagnostic inspections
- Protection upgrades
- Tree control
- Rural distribution switchgear
- Distribution management software
- 11 to 22kV conversion
- New equipment specifications
- Substation configurations
- Underground conversion
- Continuing SCADA development
- Harmonic limitation policy
- State Highway underground conversion



The main factors influencing the performance of the EA Networks network during 2018-19 were the gradual return of live-line working for most of 2018-19 after complete suspension in 2017-18. While live line working has returned it is still not at the levels used prior to 2017. This causes additional planned outages for work previously needing none. The only practical and affordable method to complete most essential planned work is by having interruptions. These outages are required to permanently repair or maintain assets after fault repairs, attend to regular condition-based maintenance work, or development work associated with load or security requirements. Planned work such as 11-22kV network conversion, new work, rebuilds, and maintenance combined contributed 95 minutes (51%) of the total SAIDI (to end Jan 2020) in 2019-20. In comparison, the unplanned SAIDI is 90 minutes (49%). Adverse weather has been a major contributor (Rangitata River flooding), as has lightning, defective equipment, and wildlife. Most other interruptions were the result of trees or unknown causes. The overall performance is quite satisfactory for this financial year and is comparable with some of the forecast targets. SCADA system expansion is continuing. It is expected that a new and expanded SCADA system will significantly improve fault restoration times (and to a lesser degree planned restoration times) in the future.

EA Networks performance compares favourably with peer companies on most measures over the last five years. Faults per 100km of line for the last two years is similar to peer companies but quite some way from the internal target.

Fault performance of the network was satisfactory in 2018-19, meeting both SAIDI and SAIFI targets. For 2019-20 it looks like a breach of the Default Quality Path will be avoided. There is still capability to improve reliability/resilience, and some of the initiatives in the plan will achieve that. Other than that, it appears to have been more distribution voltage faults affecting moderate numbers of consumers. Once the planned interruptions decrease, performance index totals will improve. The unplanned interruptions should also decrease in frequency and duration with asset improvements that are part of this plan.

Capability to Deliver

History has shown that the EA Networks business structure has provided a robust and resilient platform to implement the strategies outlined in the annual Asset Management Plan through times of unprecedented asset development and load growth.

In recent years, EA Networks has grown, and additional roles/skills have been employed to provide added rigour to a number of internal processes.

The next 5-10 years will require an increased focus on succession planning to ensure the personnel who will retire have mentored new staff to fill their role.

In future, it is planned to use the decrease in development workload to refine systems and processes that do not currently form part of a documented procedure.

OUR BUSINESS

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1 OUR BUSINESS

1.1 EA Networks' Evolution

In 1908 a private company, Craddock & Co, began supplying electricity to Ashburton township consumers at 220 volts DC. The source of this supply was a 30kW generator driven by a steam traction engine. 3.3kV AC was soon introduced and this was the distribution voltage of choice until around 1923.

In 1921, the Ashburton Electric Power Board came into existence and it took over the operation of the generators and began implementing one of the options for connecting to the national grid. The new Public Works Department Ashburton substation (the present Ashburton zone substation is on the same site) began supplying electricity to the Ashburton urban area in 1924. The AEPB initially had both 6.6kV and 11kV supplies from Ashburton substation (having quickly retired the 3.3kV and DC supplies). This system evolved gradually over the next twenty years until second and third 11kV points of supply from the national grid were established near Methven and Springfield Road. During this time (1932) Mr Kemp (the founding engineer at A.E.P.B.) devised an electric tractor. The photo at right shows the mobile substation used to supply the tractor. Six tractors were built and they each did over 4,000 hours of cultivation during an eight-year period.

During the post-war years the Power Board became the Power and Gas Board - supplying coal gas to a large percentage of Ashburton township. Gas production ceased in 1973 as it had become uneconomic.

As the load continued to increase, it became apparent in the early 1960s that a true subtransmission network would be required. Planning began and once 33kV had been settled upon as the correct subtransmission voltage, the first 33/11kV substations were commissioned in 1967. These substations were supplied from three AEPB owned 5 MVA step-up transformers (11/33kV) located at the Ashburton substation.

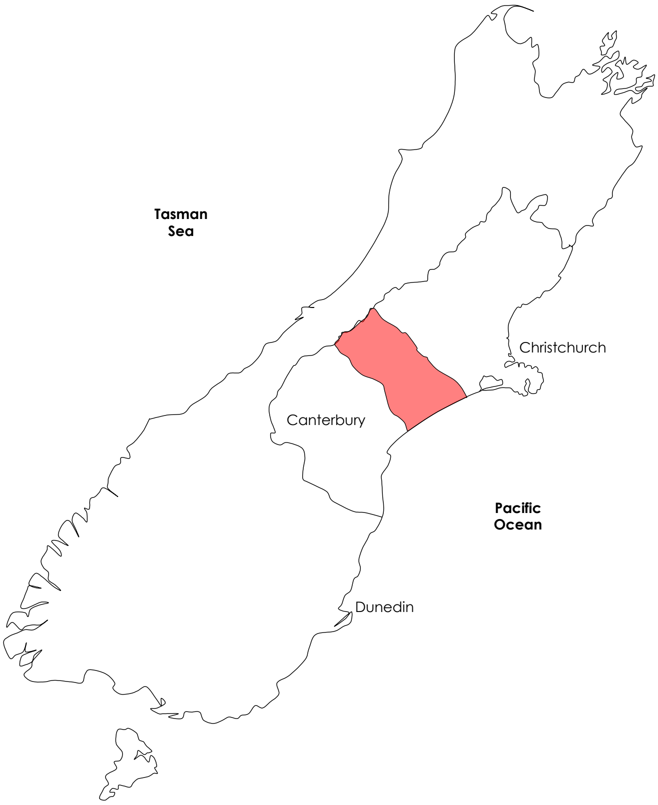
The final portion of 6.6kV distribution was converted to 11kV in 1971. The popularity of pumped irrigation began to increase, and general electricity use continued to rise. As a result of the increased irrigation load and other industrial loads such as snowmaking, animal processing plants and vegetable processing, the number of 33/11kV substations increased. By the early 1980s the three step-up transformers were overloaded, and relief came in the form of a 33kV point of supply at Ashburton and another at Cairnbrae (5km south-east of Methven). This arrangement allowed the creation of a 33kV ring network that initially allowed individual 33kV line faults to be tolerated without extended loss of supply.

A small (1.6 MW) hydro power station was constructed by the AEPB during the 1980s at Montalto. This induction generator continues to operate but is now owned by an electricity retailer.

During the late 1980s and early 1990s, Transpower proposed decommissioning the 110kV circuits between Timaru and Hororata. This required shifting one of the points of supply from the Ashburton township site to a site about 7km south-east of Ashburton. Once the two parties agreed on commercial arrangements, the new 220/33kV substation was built and EA Networks took 33kV supply from it in 1992.

Around 1995, what was the Ashburton Electric Power Board was transformed into the co-operatively owned company EA Networks Ltd. Options for this transition, from a quasi-governmental entity with undefined ownership to a limited liability company, were comprehensively researched and what was considered the fairest and most stable ownership option was instituted.

The subtransmission and point of supply rearrangement assisted in extending the life of portions of the 33kV ring network, but the huge increases in irrigation load were beginning to tax the rural 33kV network beyond its capacity. The same problem was facing the 11kV distribution network in places, so a bold decision was made to begin converting portions of the 33kV network to 66kV and some of the 11kV network to 22kV. The change to 66kV introduced an opportunity to provide a 66kV connection to the Highbank Power Station that had historically been connected to the Transpower network. This option was duly negotiated and a more extensive 66kV conversion undertaken to connect Highbank. The subtransmission development also enabled the Cairnbrae 66/33kV point of supply to be relinquished and there is now only one physical location for EA Networks' connection to the national grid.



Transpower's Ashburton substation (actually 7km from Ashburton) supplies an EA Networks substation called Elgin immediately adjacent to it. Elgin then connects to seven lines in the EA Networks 66kV subtransmission network. In 2019, EA Networks relinquished the 33kV connection to Transpower (leaving only the Elgin 66kV supply). Simultaneous with the subtransmission conversion was the conversion from 11kV to 22kV of some distribution lines. This was also very successful and offers much improved voltage regulation and capacity, thereby increasing power quality to those rural consumers supplied via 22kV. 22kV conversion has continued to progress in many rural 11kV areas where additional capacity is needed. The plan is now to convert the entire rural area to 22kV (excluding the Upper Rakaia Gorge – supplied at 11kV from the Orion network).

The area EA Networks directly services is approximately 3,500km². The extents of the area are the Rangitata River in the south, the Rakaia River in the north and the foothills of the Southern Alps in the west. Three distribution lines run up remote river valleys into the foothills, but these form a very small portion of the entire network.

The network comprises of some 28,339 poles, 2,329km of high voltage overhead lines, 296km of high voltage underground cable, 21 zone substations and switchyards, 6,505 distribution substations, one control room and a communications network.

There are four hydro generating stations embedded in the network. The newest generator is a 0.5MW unit near Barrhill, Cleardale is a 1MW station, Montalto is a 1.6MW station, and Highbank is a 26MW station. The Barrhill unit is owned by Barrhill Chertsey Irrigation, Cleardale is owned by Mainpower, while Montalto and Highbank are owned by Trustpower.

EA Networks' distribution lines have a variety of different capacities, dependent upon local demands and geographical considerations. Operating voltages include 66kV (66,000 volts), 33kV, 22kV, 11kV and 400V.

The rural distribution network configuration is predominantly long radial overhead feeders with some interconnection to adjacent feeders and substations. This arrangement is largely driven by economics and is the method of supplying rural consumers that offers best value at acceptable levels of reliability. Typically, the capacity of a rural feeder is limited by voltage drop and not the thermal rating of the conductors.

The urban 11kV distribution network is based upon a similar principle to the rural arrangement except the network is largely underground cable, the interconnections are more frequent, and the overall feeder lengths are significantly shorter. The capacity of urban feeders is thermally constrained by the maximum current rating of the underground cable.

EA Networks also operate and develop an open access fibre optic network in Mid-Central Canterbury (https://www.eafibre.co.nz).

Summary of Network Assets

(As at January 2020). Circuit voltage is rated voltage (operating voltage quantity in brackets).

Network Inputs and Outputs:

Connections	19,917	
Maximum Load Demand	171	MW (Dec 2019)
Delivered Energy	601	GWh (2019-20 estimate)
Annual Load Factor	42	% (2019-20 estimate)
Annual Loss Ratio	8.2	% (2019-20 estimate)

Network Components:

Overhead Lines (circuit km)	369 (318)	66kV Subtransmission
	54 (73)	33kV Subtransmission
	1,642 (1,443)	22kV Distribution
	264 (495)	11kV Distribution
	69	400 V Distribution
	23	Street Lighting
Poles	28,339	All types
Underground Cables (km)	4.2 (3.6)	66kV Subtransmission
	4.5 (4.4)	33kV Subtransmission
	167.1 (126.8)	22kV Distribution
	120.3 (155.3)	11kV Distribution
	403.9 (389.9)	400 V Distribution
	289.7 (288.2)	Street Lighting
Zone Substations	18	66/11kV or 66/22kV
	3	33/11kV
Distribution Substations	4,605	Pole Mounted
	1,900	Ground Mounted

The future of EA Networks will focus on a 66kV subtransmission network, a largely 22kV overhead line rural distribution network, and an 11kV urban underground cable distribution network in Ashburton and Methven townships. An additional layer of larger 11kV underground cable distribution will be added in Ashburton as many of the existing urban feeders have reached security or rating limits.

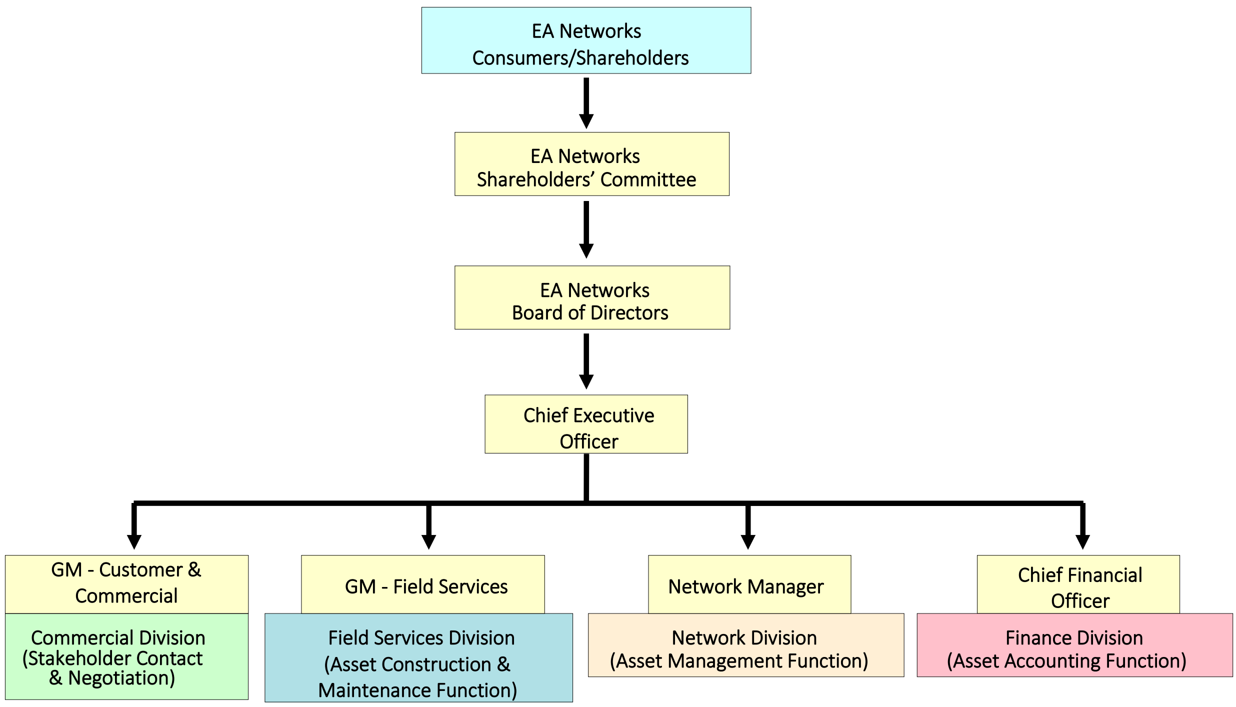
1.2 *Overview of EA Networks Organisation*

EA Networks operates as a stand-alone co-operatively owned lines business - EA Networks. This business incorporates an asset management function (the Network Division) and a contracting function (the Field Services Division). EA Networks owns, operates and maintains the infrastructure assets. The Network Division plans and controls the asset management function.

EA Networks offers network line services as its core activity. Ancillary to this function is the Field Services wing, which offers services to the Network Division, other line owners and the general public. Other business activities include a fibre optic data network.

There are 30,366,000 shares issued in EA Networks. The Ashburton District Council holds 28,750,000 of these shares in a non-rebate/non-voting form. The consumer/shareholders hold 1,326,535 rebate shares at 100 shares per consumer (some consumers have more than one connection). There are 289,465 unallocated rebate shares available for new consumers as they connect to the network. Existing consumer/shareholders who add additional connections are not entitled to additional shares.

The Asset Management Team in the Network Division holds the technical knowledge and is responsible for technical decisions concerning the asset. The Asset Management function remains associated with the Field Services function within one corporate body. The company oversees EA Networks assets and personnel - hence the requirements of equipment and personnel safety remain within one corporate body. The company structure is shown below.



The key functions and responsibilities of the groups are:

Consumers/Shareholders

The end users of electricity supplied over the EA Networks network. All new consumers are initially a shareholder in the cooperative company. Almost every new consumer chooses to retain the shareholding and only a handful of existing consumers are not shareholders. Each shareholder (consumer) has one vote to elect a shareholder committee. This is irrespective of the size/scale of their electrical connection(s) or contribution to the company's income or profit. The shareholders have the responsibility to consider their choice of committee member carefully to ensure they faithfully represent their views both in appointing directors and influencing the performance of the company. Ultimately, shareholder dissatisfaction with either the Shareholders' Committee or the Board will firstly result in changes to the Shareholders' Committee by the ballot and then a different emphasis in the Board members appointed by the Committee.

Shareholders' Committee

Representatives of all shareholders. Represent the interests of the shareholders/consumers (to be a shareholder one must be a consumer). Appointment of Directors, intense scrutiny of Statement of Corporate Intent (including performance targets) and monitoring and reporting of performance of the company and directors to the shareholders. The Shareholders' Committee also provide the principal means to resolve conflicts between asset management practices and large stakeholder interests. Three of the seven members of the Shareholders' Committee are appointed by the Ashburton District Council, the remainder are elected by a one vote per shareholder ballot.

Board of Directors

Review and approval of the Annual Budget and the Asset Management Plan as official company documents that accurately reflect the state and desired direction of EA Networks for the short and medium term.

Chief Executive Officer

Provision of company secretariat and attaining of revenue streams and a key contact point with electricity retailing companies wishing to use the EA Networks network for the distribution of electricity. Provides corporate policies that influence asset management philosophies. Monthly reporting of significant Asset Management Plan project progress and annual summary presentation of progress and plans for asset management to the Shareholder Committee and Board. The Safety and Quality Manager reports directly to the Chief Executive Officer, as does the Health, Safety & Risk Lead. The Chief Executive Officer has 127 staff under him.

Network Manager (Asset Management Function)

Managing the network including Subtransmission, Distribution, Services, LV Reticulation, Zone Substations, Distribution Substations, SCADA/Communications, Protection systems, and Distribution Transformers to maximise system availability. Develop maintenance strategies, set and manage priorities, set and manage standards, issue works orders to ensure target reliability is achieved at minimum cost. The Network Manager has 31 staff.

The Network Division completes almost all designs. Only when the scope of a project exceeds the capabilities of the internal staff in resource availability or expert knowledge is an external designer engaged.

General Manager - Field Services (Asset Construction and Maintenance Function)

Carry out the plans and works orders of the Network Manager satisfying the appropriate statutes, regulations, standards and industry guidelines. Additionally, the Field Services function offers suggestions for innovative work techniques to increase safety, security and reliability while minimising capital and on-going maintenance costs. The Field Services Manager has approximately 75 staff.

The maintenance of the network is primarily carried out by the EA Networks Field Services Division as the preferred contractor. They are contracted to undertake the servicing and testing, along with fault callout and fault repair work. Most line replacement, enhancement or development projects are also handled by the Field Services Division but when the scope of a project exceeds the capabilities of the Field Services Division, either sub-contractors will be sourced, or the Network Division will offer the complete construction project for competitive proposals from other contracting companies.

General Manager – Customer & Commercial (Stakeholder Contact and Negotiation)

Provides the interface between EA Networks and the external stakeholders – particularly major consumers. Facilitates discussions on changes to capacity and security with major consumers often assisted by technical personnel from the Network Division. The GM – Customer & Commercial has 5 staff.

Chief Financial Officer (Asset Accounting Function)

Financial accounting of network assets and management. Ensures compliance with relevant legislation governing financial activities of EA Networks including financial disclosures. The Chief Financial Officer has 10 staff.

1.3 Objectives of This Plan

This plan aims to document the intended approach EA Networks take in managing EA Networks' electricity assets. As a regulatory requirement, an Asset Management Plan must be published annually (with few exceptions). With this document, every effort has been made to comply with the requirements for disclosure of AMP's outlined in the most recently determined information disclosure requirements for Electricity Lines Companies set by the Commerce Commission under the Commerce Act 1986. To assist readers who have an interest in the regulatory aspect of this plan, Appendix D offers cross-reference to the mandatory disclosure items of the Electricity Distribution Information Disclosure Determination 2012.

This plan clearly defines the service objectives and gives a strong focus on life cycle management by presenting operations, maintenance and renewal policies and programmes by asset type. Asset management planning processes should effectively integrate best practice features. These establish the service standards and future demands to meet business, legislative and other needs, while developing optimum lifecycle asset management strategies and cash flow projections based on assessing non asset solutions, failure modes, cost/benefits and risk.

Asset Management Plans must address growth. The EA Networks network has seen dramatic load growth over the last 20 years. This was predominantly caused by various types of rural irrigation. This growth appears to have subsided. A new framework for managing water in Canterbury has been established. The *Canterbury Water Management Strategy* is led by ECAN, Ngāi Tahu and Canterbury's District and City Councils. One of the phrases this organisation uses to describe the outcome they seek is *"It's about bringing to life a long-term vision to ensure we have clean, fresh water now and for generations to come".* One of the outcomes of this strategy is that there are no additional water use consents being issued in some areas which would cause unsustainable nutrient leaching into ground water. This directly affects the use of water for agriculture. The consequent decrease in forecast load growth is reflected in this plan.

EA Networks has the following Asset Management Plan objective:

> ***To provide a systematic approach to asset management, which is intended to ensure that the condition and performance of the electricity network and associated assets are being effectively and efficiently maintained or improved to satisfy stakeholder requirements.***

1.4 Stakeholders

Stakeholders are defined as those parties with interests in EA Networks' asset management from a financial or operational point of view. The principal stakeholders are:

Shareholders

EA Networks' shareholders (who, since EA Networks is a co-operative company, are all consumers) wish to ensure, as owners of the assets, that their financial capital is protected in the long term, by ensuring that the operating capability of the network is maintained, and that the system is maintained efficiently so that they earn a sufficient return on their investment

The interests of shareholders are actively sought by the Shareholders' Committee. As elected committee members (or Ashburton District Council appointed members as is the case for three of the seven), they are all members of the local community and they individually and collectively seek feedback from shareholders and shareholder/consumer groups.

The shareholders also have a direct interest in how EA Networks provides customer service and how it meets its obligations to other parties (as described below).

The shareholders elect a Shareholders' Committee and this group not only appoints the Board of Directors but also provides a consultative role for the Board and management. The Shareholders' Committee review the Statement of Corporate Intent, the Annual Report, the Asset Management Plan and other relevant company disclosures and statements. This process provides shareholder feedback and provides the principal means of managing conflicts between most stakeholder interests and asset management practices. The shareholders are also able to address any specific issues at the Annual General Meeting but more commonly they would use the

Shareholder's Committee as the conduit to resolve any issues of principle. Section 3.2 details the representative voice that the Shareholders' Committee provides between all shareholder/consumers and how this influences the asset management philosophy of EA Networks. Other stakeholders are typically consulted on an issue by issue basis as and when required.

Consumers

These are EA Networks' directly connected end-use consumers (more than 99% are shareholders).

The Shareholders' Committee actually serve as a de facto "Consumers' Committee" as all shareholders must be current consumers on the EA Networks network. They seek the opinions and balance the interests of the shareholders from a prudent financial management perspective as well as considering the level of network performance that is required to maintain a high level of satisfaction from the consumer/customer base.

EA Networks management also encourage individual consumers and representatives of groups of consumers to engage in constructive dialogue to further refine the focus of EA Networks in satisfying their needs and interests. A biennial consumer survey of 400 consumers takes place and they have been asked more than 30 questions ranging from preparedness to pay for additional reliability, ownership of on-property lines and satisfaction with advice and dialogue with EA Networks personnel. The survey is also provided to the Shareholders' Committee for their consideration. A selection of the larger consumers are interviewed as part of the survey to gauge their interests and concerns. These concerns can be addressed with individualised solutions in most circumstances and it generally comes down to presenting the price/quality trade-off options clearly and in a timely manner so that they can evaluate them objectively.

Generally, the consumers wish to receive a safe, adequate and suitably reliable network service and to be assured of being able to receive this over the long term, at minimum cost.

Customers (Retailers and Generators)

The retailers and generators (many of the larger ones are both and are colloquially called 'gentailers') active on EA Networks' network are relatively few in number (less than twenty but increasing) and are always prepared to share their opinion of EA Networks' business focus and methodologies. Regular meetings are held with representatives of some retailers while others (typically those with few customers on the EA Networks network) do not appear to seek regular engagement.

The EA Networks 'Use of System Agreement' provides the major vehicle for translating retailers' interests into the performance required of the EA Networks network. Equally, it provides a path to communicate the requirements EA Networks place on a retailer to use the electricity network. There is a review process available for the 'Use of System Agreement' and any significant changes in either party's interests can trigger that review process.

Among other things, the retailers want stable business practices, robust network performance and justifiable charges for use of the EA Networks network. Other issues of interest include timely responses to information requests and, where needed, follow-up actions.

Others

Other parties with a potential interest in EA Networks' asset management include:

- Transpower who have an interest in the existing and future utilisation of their assets. Management have regular meetings with Transpower representatives on various issues. Transpower have plans to encourage closer engagement with their customers such as EA Networks. This will entail much more direct discussion between peers in each organisation. Commercial negotiations tend to arrive at the most satisfactory resolution of any issues.
- Other lines companies in the region with whom common problems and solutions can be shared. This engagement takes place as a matter of course, and there are many examples of a unified approach to identifying, researching and resolving issues of common interest. These can be in the form of common equipment specifications, design standards or even principles of application of similar policies.
- Employees and contractors who design and build the system and have an interest in the future work

that is available and the safety of the assets. Every time a contractor is engaged, they are fully briefed on EA Networks' safety requirements and, although the level of work contracted out is less than many other lines companies, any request for information is answered promptly and candidly.

- The public on whose land the network may be built. EA Networks are fortunate not to have significant quantities of assets on private property. Whenever private land must be entered, permission is sought well in advance unless it is an emergency when all efforts are made to contact the owner and minimise the impact of any required work.
- Tree owners who have a requirement to keep their trees clear of power lines. A full-time employee actively manages the required dialogue with tree owners to minimise the conflict between trees and power lines. This process is typically amiable and very few dialogues become formal exchanges of letters. The tree owner typically has an interest in minimising the impact of tree control work on their tree and subsequently preventing any fiscal or reliability implications of the tree interfering with the line.
- Financial institutions who may be called upon to fund aspects of asset development or maintenance. The financial institutions that EA Networks both borrow money from and deposit money with have an interest in ensuring that EA Networks continues to be a viable and profitable business that can service any debt as contracted. These financial institutions always advertise their interests at an early stage and ensure they continue to be well known.
- Local Electrical Contractors who are required to comply with EA Networks' connection standards. These standards control a range of performance measures including, but not limited to: safety; the impact the connection has on the reliability of other consumers; the impact the connection's load has on the power quality of other consumers and on the EA Networks network; and the timing/advance notice needed to provide the connection.
- Interest groups such as Federated Farmers, Grey Power and electric vehicle owners. These groups are really consumer groups from whom EA Networks actively seek opinions on issues that will impact their members. Obviously, these groups are not the only consumer groups with whom EA Networks seek to engage and the vested interests of each group are balanced by presenting the Board and Shareholder Committee with both the interest group's opinions as well as the technical and fiscal implications for EA Networks should they choose to heed any or all of these opinions.
- Distributed generation (DG) proponents. These individuals and organisations are encouraged to communicate their interests to EA Networks at the earliest opportunity. As with all lines companies, EA Networks has a published policy and guidelines for the connection of DG to the network. The nature of potential DG connections is that they can be completely unknown to EA Networks and because of commercial sensitivity do not wish to engage in dialogue until the last stages of any development. This obviously makes it difficult to determine their interests in advance. EA Networks believe the DG policy in place satisfies most DG proponent's interests.
- Ashburton District Council as a major shareholder and the body that controls access to the road corridor. Many of the interests of a local body are enshrined in legislation and are therefore very transparent to EA Networks. Unique local interests that are specific to either district development or planning are typically dealt with in management to management dialogue and, on occasion, formal consultation for issues such as District Plan reviews and amendments. There are issues in the political domain that are discussed at Board, Shareholder Committee and District Councillor level. Asset management personnel are generally aware of the outcomes of these discussions rather than the content. While a significant shareholder, the Ashburton District Council has no greater power as a shareholder than any other shareholder.
- Regulatory agencies with which EA Networks comes into contact. The governmental agencies that EA Networks are required to deal with tend to make their interests quite clear by inviting comments on discussion papers or draft regulations that indicate the intent of any future regulation or legislation. Any interaction is typically very formal and open so that all interested third parties can gauge for themselves the validity of the opinions expressed by the regulatory body and EA Networks.

1.5 *Scope of This Plan*

This Asset Management Plan covers the management of EA Networks' electricity network assets for a period of 10 years from the financial year beginning on 1 April 2020 until the year ended 31 March 2030. The main focus of analysis is the first 5 years and, for this period, most of the specific projects have been identified. Beyond this time, analysis tends to be more indicative based on long-term trends. It is likely that new development project requirements will arise in the latter half of the planning period that are not identified here. Hopefully, most new projects would only affect the timing of development funds by displacing a project which has goals that can be mostly solved by the new project.

To provide a framework for asset management within the planning period, it is necessary to determine the longer-term direction in which the system should be developed. For example, it would not be prudent to invest heavily in enhancing a system at a particular voltage if, beyond the planning horizon but well within the life of those assets, it was likely that they would be overlaid by a new higher voltage system. A case in point is the augmentation of supply to the area bordering the foothills of the Southern Alps where currently 11kV is the distribution voltage, but 22kV is the voltage of choice for new lines/equipment. Further, strategic development planning must be responsive to a range of scenarios that might occur.

The regulated timing of Asset Management Plan disclosure coincides with the beginning of a new financial year. A consequence of this is that the data used for comparison with other Electricity Lines Companies is as of the date of the previous disclosure - exactly one year ago. The 'disclosed' full year data used in this plan is as of 31 March 2019. Where newer data is available it is used for forecasting/trending (such as power quality, load projections, asset quantities, asset ages, etc) or internal comparisons so that there is as little 'planning lag' incorporated as possible.

1.6 *Plan Structure and Approach*

This plan uses a consistent set of defined activities and asset types to categorise work programmes and their associated expenditure. Budgeting and financial reporting within EA Networks allows actual programme achievement and expenditure outcomes to be compared with the plan. Consistent use of this framework will facilitate comparisons over time.

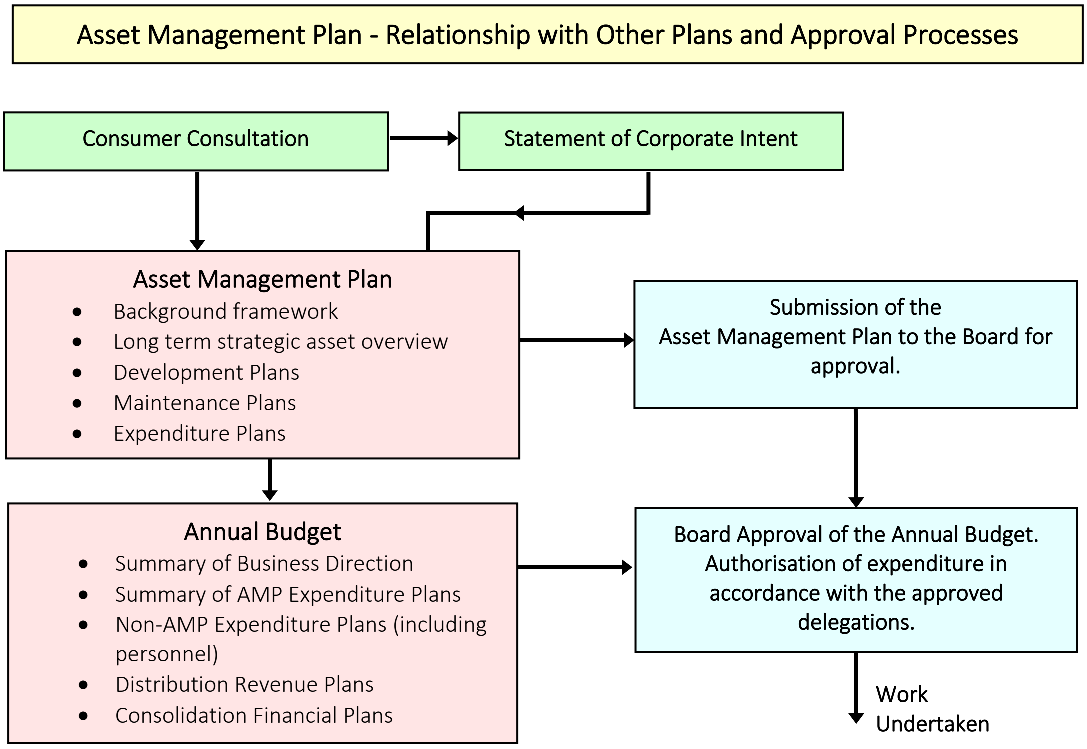
It should be noted that the activity and asset definitions are independent of accounting classifications of expenditure (i.e. between maintenance and capital expenditure). Therefore, trends over time should not be altered by any changes in the application of accounting policies regarding the accounting treatment of expenditure. However, it should be noted that, under the current application of accounting policies, all activities could be classified as either entirely revenue expenditure or entirely capital expenditure.

Similarly, the activity and asset type definitions are also independent of EA Networks' organisational structure and responsibilities, although closely aligned with the present structure. In the long run, adherence to the definitions will ensure that the plan remains meaningful despite any changes in organisational structure or responsibilities.

The asset and activity planning categories are defined in Appendix A. Asset Types and Activity categories, known as the Job Costing Tree Structure, are included. It should be noted that not all asset types and activity combinations are used. In addition, maintenance activities generally can be planned at the detailed asset level (e.g. servicing of transformers, of circuit-breakers etc), whereas development projects or programmes, which typically involve a combination of different asset types (e.g. lines, transformers, circuit-breakers, protection, communications and network management) are kept intact rather than attempting to allocate the expenditure against the component asset types. While no historical breakdown exists, the revised disclosure requirements will mean that this break down will occur in the future. Since the same workforce often does different tasks it is often a relatively arbitrary breakdown between asset classes. For example, in the process of laying cable for an underground conversion, the same staff lay two cables. Backfill and reseal applies to both cables along with additional works associated with installing pillar boxes and substations. It is not practical or cost efficient to expect field staff to split labour and common materials across asset classes.

One further definition distinction is made throughout this plan: between projects and programmes. The word **"programme"** is used to define a generic activity with a generic justification, but which may apply at several different sites. Replacement of defective insulators or fitting vibration dampers to lines are therefore classed as such programmes. On the other hand, "**projects**" are site (or asset) specific; for example, adding a second circuit to a particular line, or upgrading a particular transformer bank.

The process used to formulate the Asset Management Plan and other supporting documentation is as shown in the following diagram.



The plan interacts with other EA Networks working plans. Of particular importance are:

- The Statement of Corporate Intent, which is required by law and sets out the business intentions of EA Networks, and
- Annual budgets, which set out the specific resources required for asset management activities. Those parts of the annual estimates relating to the asset management of the electricity network are closely based on the annual Asset Management Plans.

Authorisation of expenditure results from approval of the annual estimates by the Board of Directors and from specific approvals. The Asset Management Plan does not represent an authorisation by EA Networks to commit expenditure, nor does it necessarily represent a commitment on the part of EA Networks to proceed with any specific projects or programmes.

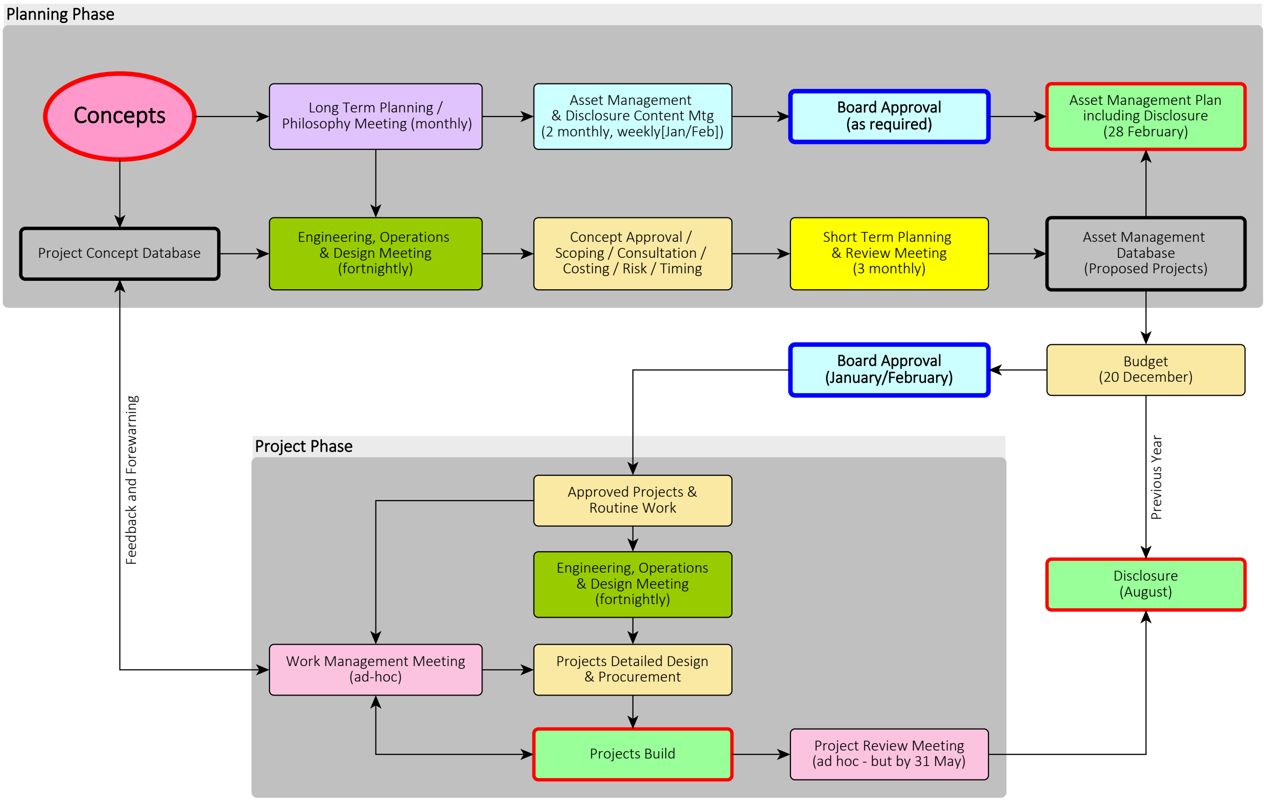
Governance

Any significant addition or alteration to the asset management philosophy of EA Networks is always thoroughly developed at management level using engineering focus groups before being tested for acceptability with the Board. If necessary, the Board will seek further clarification of the implications of any change and this may include workshops with management to permit less formal open exchanges of information and opinions in both directions. Once an understanding has been reached, the approach will be adopted and documented in Board motions or policy documents and this plan. Alternatively, it can be rejected and either another option is developed, or the status quo remains.

An example of this process is the policy to enforce all new connections to the network to be placed underground. This has significant implications for both EA Networks and the consumer. Once the proposal was instigated, management developed a draft policy that encompassed the philosophical background and rationale along with the necessary technical requirements. The fiscal implications were also assessed and together they were submitted to the Board for consideration. After consideration of the pros and cons of the proposal, the Board adopted it as policy and it now influences significant areas of the asset management philosophy at the distribution level.

The Board are provided with the schedule included as Appendix B of this plan (which individually identifies all significant projects) at the time of annual budget submission. This ensures that the Board can assess the complete evolution of any multi-stage project that they may be committing to in the budget they are considering. This was certainly the case when the initial conversion from 33kV subtransmission to 66kV subtransmission was proposed, as it committed the Board to more than a decade of expenditure with dozens of future projects worth tens of millions of dollars. This conversion process is nearing its end after more than 20 years. A similar consideration was made with the commitment to embrace 22kV as the preferred rural distribution voltage.

Asset Management Policy, Plan & Execute Processes



Large projects or programmes that are not part of a previously considered concept draw particular attention from the Board and the individual justification required is significantly more comprehensive than a project that fits into a pre-approved concept.

The Board take an active interest in the outcomes of all asset management decisions. This encompasses not only the direct financial cost of the projects and programmes triggered by the decision, but also the success at achieving the asset performance targets that were submitted as justification for the project or programme. An example of this interest was in the last few years a proposal was presented to rebuild as underground cable two rural overhead 11kV lines (which had reached the end of their useful lives). Both lines bordered State Highways. The positive decision was undoubtedly influenced by the previous decision to enforce new connections to be underground as well as a commitment to reliability, road/public safety and general aesthetic values of the Ashburton District. The Board made it clear that it would be a pilot project to examine the feasibility of more widespread use of underground cable in the rural area. The projects were studied, and further underground conversion projects have been completed. 2019-20 has seen more of these state highway conversions completed.

Moderate to minor asset management decisions are left in the hands of management. These decisions tend to be influenced more by technical knowledge than overarching fiscal or policy matters. As an example, these items include the preparation of methodologies to set internal performance criteria, the inclusion of new techniques and products (within approved budgets) that enhance the performance of the network, and any decision that has a low fiscal and/or reliability impact on the consumers and customers served by EA Networks.

EA Networks' management has responsibility for the day-to-day management of the company and its assets and for carrying out company policies. They are therefore the "owners" of the Plan - responsible for its creation and for using it as a tool for improving the efficiency and effectiveness of the management of EA Networks' assets.

1.7 Asset Management Drivers

The factors that drive asset management activities and their relationship to EA Networks' performance are derived from the external performance required of EA Networks by its consumers, staff (including contractors), shareholders and the public.

EA Networks' 2019 Statement of Corporate Intent identifies the following long-term objective:

> *"Provide infrastructure products and related services while adding value beyond the simple connection through innovation and customer focus"*
>
> *"The electricity division's meaning of value is the selection, location and operation of EA Networks' assets which leads to a safer, financially efficient, reliable electricity distribution network. Value extends to all classes of consumers in the Ashburton District while, subscribing at all times to the wider social, environmental, economic and cultural values of the Ashburton community."*

This statement encompasses all the drivers that have been determined for this plan which are in the following sections.

1.7.1 Safety

Safety is determined by a combination of asset design, asset location, maintaining the assets in a safe condition and the use of safe operating and work practices.

The Electricity Act 1992 (Reprinted 1 January 2014), section 61A sets out requirements for companies such as EA Networks to provide a public safety management system (PSMS).

The PSMS requires reasonably practicable steps to be taken to prevent the electricity supply network from presenting a significant risk of:

- Serious harm to any member of the public
- Significant damage to property owned by someone other than the electricity generator or distributor.

The Electricity Safety Regulations 2010 (reprinted 1 August 2014), Regulations 47 to 56 set out the application detail of the PSMS and that it shall comply with either NZS 7901 or Regulations 49 and 50. The regulations required that the PSMS was in place and audited by 1 April 2012. EA Networks has continued to fulfil this requirement annually with compliance to NZS 7901.

The Electricity Safety Regulations 2010, the Health and Safety at Work Act 2015 and the Health and Safety in Employment Regulations 1995 contain additional legal drivers for EA Networks' safety related asset management. These standards require EA Networks to operate as a reasonable and prudent operator.

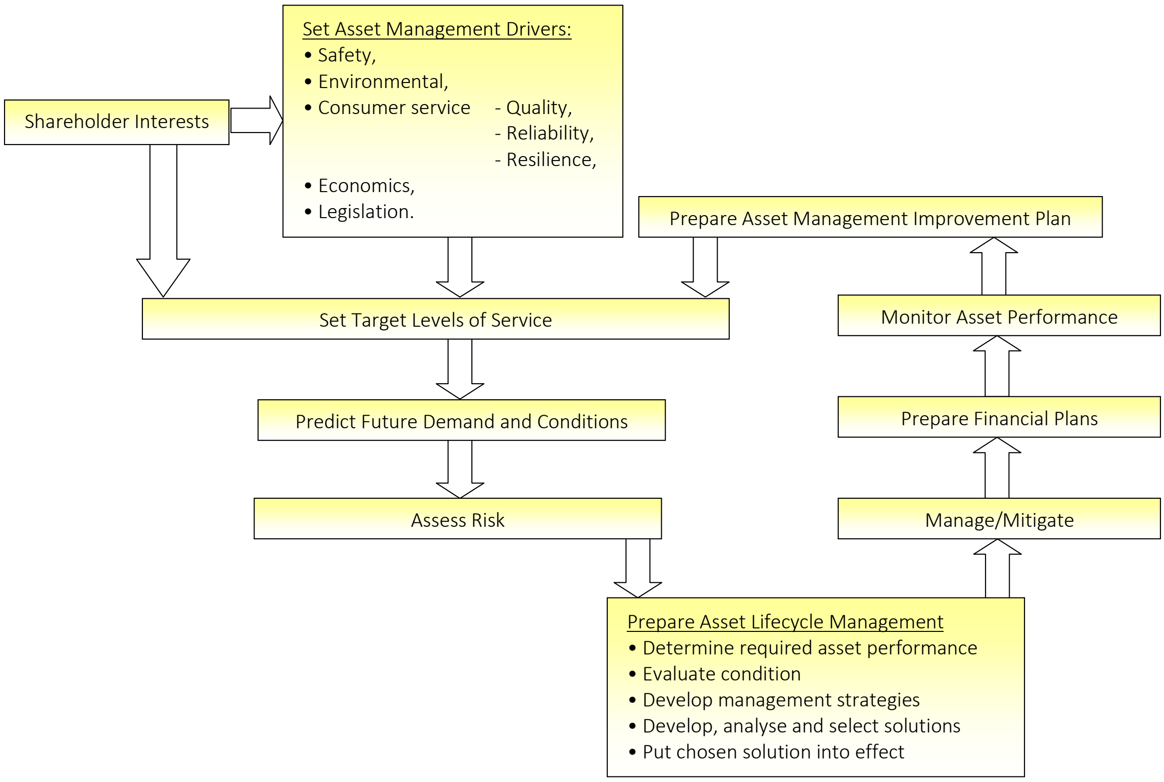
The Electricity Regulations 2010 have a realigned focus and are less prescriptive than previous versions. The emphasis is now on risk analysis for safe outcomes of design and operation rather than general technical requirements and considerations for new lines and substations are couched in language that reflects that.

The Regulations also require existing assets to be maintained in good order and repair to assure high immunity from danger.

The Building Act 1991 puts in place a building maintenance regime that is aimed at ensuring the existence of essential safeguards for the users of buildings; specifically, that buildings are safe, sanitary and offer adequate means of escape from fire.

The Health and Safety at Work Act 2015 and the Electricity Act 1992 (Electricity Amendment Act 1993 and Electricity Reform Act 1998) now dictate the legislative framework with a performance-based regime which puts the onus on EA Networks as the PCBU and the employer, to take control for ensuring the safety of workers and others in the work place.

The Health and Safety at Work Act's main objective is to provide for the prevention of harm to workers, contractor's workers, and the public. EA Networks has the responsibility for putting in place preventive measures.



1.7.2 Consumer Service

EA Networks' consumer service objective is to manage the network reliably, efficiently and economically to meet the needs of its consumers.

Capacity (i.e. Adequacy of Service)

EA Networks' policy is to provide sufficient capacity to meet current and future consumer's requirements, subject to satisfactory arrangements to cover the additional costs associated with any consequential capacity additions.

For asset management planning purposes, projected demands, security and capacity criteria are analysed assuming the additions and modifications to the network which have been projected in the plan take place.

Large step changes in load cannot always be accurately predicted, as these are often associated with large industrial projects whose promoters are notoriously loath to make firm commitments until the latest possible point in time. Nevertheless, EA Networks keeps up regular dialogue with these ventures whenever possible so that it can take potential changes into account when carrying out its regular planning activities.

Reliability (i.e. Continuity of Service)

Reliability is a function of:

Asset design, the most important mechanism being built-in equipment redundancy (referred to as the security level) so that, for example, failure of any one component does not lead to a supply outage.[1]

Asset condition, where this affects the likelihood of failure of a component.

[1] This is referred to as an **n-1** security level. Security in which failure of a single component causes a supply outage is referred to as **"n level"** security, while design which allows for any 2 components to fail without causing a supply outage is referred to as **n-2**.

- Efficient operation and maintenance practices (i.e. minimising the effects of planned equipment outages).

Within the network, EA Networks' policy is to focus expenditure on areas that give reliability improvements where the greatest benefits can be achieved for its consumers in the most economical manner. Generally, this involves focusing attention on distribution automation to reduce restoration times. This includes the installation of:

- Modern reclosers for automatic fault isolation; and
- Remote-controlled disconnectors, SF_6 gas switches and ring main units for fault indication and sectionalising.

Resilience

The resilience of a system characterises its ability to absorb or recover from a potentially damaging event. This event can stress the system or its components beyond the original design limits. The essence of creating a resilient system is to ensure that:

- there is sufficient redundancy built in to allow alternatives in the event of a component failure,
- there is no common-mode failure that will impact many components simultaneously,
- there is an adequate awareness of the risk sources that can cause component failure and the context in which that failure can compromise the system's resilience,
- the mode of failure is not catastrophic - repair is achievable in a modest timeframe without full replacement of the component (it may be possible to continue using the component),
- there is acceptance that non-system alternatives may be an effective means to provide resilience (a mobile generator may be adequate while repairs are undertaken).

The effect of having a resilient system is that consumers experience less disruption to the service provided (an improvement in reliability) during/after an event that is high impact, but low probability. A lot of the capital-intensive projects in this plan are included to help increase the resilience of the electricity network.

Power Quality

With the rapid development of modern irrigation systems incorporating variable speed drives, EA Networks experienced a rapid increase in harmonic levels on its network. This was accentuated in some areas where load growth occurred on relatively weak parts of the network with lower than current design fault levels. EA Networks has put in place a standard for connecting new loads which requires the limitation of harmonic current generation to acceptable international standard levels. EA Networks implemented a subsidy scheme (now ended) to encourage existing variable speed drive users to mitigate the harmonic distortion they created on the distribution network. A generous 50% subsidy of the cost of a suitable filter was available for the first year and this subsidy reduced to 25% over the following years in conjunction with the introduction of a differential (costlier) tariff for non-compliant installations. This scheme gave incentives which fairly and economically encouraged consumers to correct existing loads to acceptable levels. After this "grace" period, where consumers are incentivised to comply, EA Networks may require disconnection if the installation remains non-compliant after 1 October 2018. As of February 2020, 12 connections are non-compliant.

Transient Effects

Where problems are identified in relation to short-term voltage variations, EA Networks works with individual consumers to identify the best economic and engineering solution.

Voltage Profile

The present terms and conditions of supply specify voltage levels and tolerances at points of supply.

EA Networks generally adopts the policy that the supply bus voltage will not vary from the nominal voltage by more than +3/-4% for supplies at 11kV or 22kV. The maximum voltage variation at a consumer's LV connection point is $\pm$ 6%. Specific values are agreed with individual consumers where required.

1.7.3 Economic Efficiency

Economic efficiency is an important driver for maintenance and development work. A large proportion of repair work, refurbishment, and asset replacement work is undertaken only after economic analysis to determine the most cost-effective solution. This frequently involves the choice between a development option and continued maintenance.

With the increase in consumer choice of energy sources (solar PV and battery storage in particular) this driver will become more significant. If peak demand is going to decrease in some parts of the network, then consideration will need to be given to replacement asset design and whether the existing high level of network availability is required during the asset's lifetime as this may affect asset maintenance.

1.7.4 Environmental Responsibility

EA Networks' policy is to act in an environmentally responsible manner and as required under legislation.

The Resource Management Act 1991 is a major legal driver for EA Networks, which is supplemented by the Hazardous Substances and New Organisms Act 1996. The provisions relating to the discharge of contaminants into the environment, the duty to avoid unreasonable noise and the duty to avoid, remedy or mitigate any adverse effect on the environment are of particular relevance to EA Networks.

1.7.5 Corporate Profile

Many of EA Networks' network line assets, distribution substations and some zone substations are in high public profile areas and the design/condition of these assets reflects on the public perception of EA Networks as a responsible manager of local assets. Similarly, the condition of assets is readily observable by consumers who have a strong vested interest in their reliability. Owing to its co-operative structure, many customers have a sense of ownership of EA Networks and its assets.

Maintenance programmes recognise the need to preserve visual appearance in conjunction with economic and efficient management. For example, a review of the land around substations has shown that appearances are largely reasonable and only a few can be improved, reducing maintenance costs, by appropriate landscaping and/or revising the land usage.

EA Networks' policy is to develop and maintain assets in a way that reflects well on the organisation, and to adopt a socially responsible attitude towards community impacts. While this is not a major driver of asset management work, it is a consideration in all work.

1.7.6 Legislative Compliance

Although implicit in the philosophy of the company, the accomplishment of legislative compliance can be greatly assisted by documenting its interaction with the management of the assets of an electricity lines business. Achieving compliance with legal obligations under the following legislation (and all other legislation – the list is not exhaustive) is a driver for our asset management activities:

- Building Act 2004
- Civil Defence Emergency Management Act 2002 and Regulations 2003
- Commerce Act 1986
- Companies Act 1993
- Consumer Guarantees Act 1993
- Electricity Act 1992 & amendments 1993, 1997, 2000, 2001(1), 2001(2)
- Electricity Industry Act 2010
- Electricity (Safety) Regulations 2010
- Electricity (Hazards from trees) Regulations 2003
- Employment Relations Act 2000
- Fair Trading Act 1986

- Financial Reporting Act 2013 and Regulations 2015
- Fire Safety and Evacuation of Buildings Regulations 2006
- Fire and Emergency Act and Regulations 2017
- Hazardous Substances and New Organisms Act 1996 and Regulations (various)
- Health & Safety at Work Act 2015 and Regulations (various)
- Holidays Act 2003
- Human Rights Act 1993
- Injury Prevention, Rehabilitation and Compensation Act 2001 and Regulations (various)
- Local Government Act 2002
- Minimum Wage Act 1983
- NZ Electrical Codes of Practice
- Parental Leave and Employment Protection Act 1987 and Regulations 2016
- Privacy Act and Regulations1993
- Resource Management Act 1991
- Contract and Commercial Law Act 2017
- Smoke Free Environments Act 1990 and Regulations 2007 & 2017
- Taxation Legislation
- Wages Protection Act 1983

1.8 Asset Management Processes and Systems

The electricity distribution system is comprised of assets with long lives. The management of these assets (comprising maintenance of existing assets and development of new assets) is EA Networks' primary focus in providing an effective and efficient distribution service to its consumers. Further, because distribution is only one part of an integrated electricity system, consultation and co-ordination of plans is an essential ingredient for the effective functioning of that system.

This plan is an annually produced plan covering the next 10 years and documents likely or intended asset management requirements. The plan provides a focus for on-going analysis within EA Networks aimed at continuously improving the management of the distribution system and it provides a vehicle for communicating Asset Management Plans with consumers.

In many cases, particularly where asset development is involved, the work will be driven directly by consumer requirements and associated financial commitments. This plan is based on EA Networks' present understanding of its consumers' requirements. It is part of the process of communication with consumers and EA Networks will be responsive to consumer input, with regard both to actual expenditure commitment and to long term future planning.

Asset Management Processes Appraisal

Process	Current Business practice	Desired Business Practice
Level of service	• Most performance standards in place. • Consultation undertaken in association with specific developments and enhancements requested by consumers. • Shareholder/consumer input via Board and Shareholders' Committee.	• Complete range of performance measures. • Additional logic for service level review process implemented. • Regular consumer feedback & consultation. • Greater understanding of consumer preferences.
Knowledge of Assets	• New as-builts are captured by GIS for location and quantity after construction. • Some extra data capture for validation of RAB database occurs.	• Process for collection of maintenance data. • Proposed work documented in a way that permits as-built GIS records to be created without re-entry of data.

	• Attribute and condition information collection process from maintenance activities not comprehensive.	
Condition Assessment	• Minimal condition feedback requirement from contractors. • Routine maintenance inspection. • Testing of specific sites undertaken where performance is suspected to be outside targeted level of service.	• Enhance programme for condition assessment of critical assets. •Create, document and implement structured asset inspection and testing regimes for all significant assets.
Risk Management	• Fundamental Risk Analysis is concluded but not refreshed regularly. • Critical assets monitored, failure modes and effects understood and used for contingency planning and asset management prioritisation.	• Establish review process to monitor risk - closing the loop. • Complete risk management contingency plans. • Create resilience monitoring process that tracks changes over time.
Accounting/ Economics	• Financial systems record costs against maintenance activities. • Maintenance expenditure allocated against individual assets. • Valuation based on ODV principles.	• Forecast renewals used to measure the drop in service potential. • Robust process for tracking and reviewing projects and asset groupings. • Closed loop model of assets from initial budget proposal to end of life.
Operations	• Substantial documentation of operational processes. • On-going training of operators.	• On-going training/updating programme.
Maintenance	• No formal contractual relationship with in-house service providers. • Unit rates used for internal work.	• Develop target pricing for all maintenance work with contractors. • Process for on-going review of maintenance needs and delivery.
Performance Monitoring	• System faults recorded by controllers. • Power quality monitoring at individual installations at consumer request or complaint. • Feeder metering at all zone substations (including power quality). • Load loss monitoring at Grid entry points. • SCADA evolving beyond zone substations.	• Greater range of performance standards for service delivery contracts. • Process for monitoring compliance of contractors with performance standards established.
Optimised Life Cycle Strategy	• Replacement of assets based on assessment by experienced staff. • Formal risk management strategies. • Statistical failure modes not well understood.	• Develop rolling 10-year renewal programme with budgets based on predicting failure for critical assets, just-in-time replacement of non-critical assets. • Life cycle and risk costs considered in optimisation process.
Project Management	• Contract management process in place. • Project management procedures reasonably well documented.	• Document project management procedures to optimise lifecycle costs established.
Asset Utilisation	• Capacity of network assessed by load flow monitoring and computer modelling.	• Introduce real-time load flow analysis (state estimation).
QA / Continuous Improvement	• Some inspection of work undertaken, but no formal process for quality assurance of decision-making, management procedure and data.	• System of quality checks on all key asset management activities in place.

The plan is also intended to demonstrate responsible stewardship of assets by EA Networks to its consumers and shareholders. The plan shows the maintenance and replacement requirements which are intended to maintain the operating capability of the system over the long term. Each year an internal audit is carried out which reviews EA Networks' achievement with respect to this plan.

This section broadly outlines the current and desired asset management practices and specific improvement initiatives of EA Networks' Network Division. It then goes on to discuss proposed asset management improvements (section 9.6).

To identify and prioritise the asset management practices and needs of the Network Division, asset management improvement tasks are discussed under broad headings of **Processes, Information Systems** and **Data**.

Processes (above) are the business processes, analysis and evaluation techniques needed for life cycle asset management.

Information Systems are the information support systems used to store and manipulate the data.

Data is required for effective decision making (i.e. for manipulation using information systems).

The following tables broadly describe the current EA Networks asset management practices and possible future (desired) business practices it is intended to ultimately develop. The Asset Management Improvement Plan (section 9.6) discusses improvement priorities, timetables and resources for the next 3 years.

Asset Management Information Systems Appraisal

System	Current Business Practice	Desired Business Practice
Asset Registers	• Current database is an integrated financial/physical model with reasonable linkage to GIS. • Asset database system established and working.	• Close integration of Asset database and GIS database as there are strong relationships between financial, GIS, asset management and disclosure.
Financial System	• Financial system provider is the same as Asset system and adds financial transactions to assets. • Depreciation based on age of asset.	• Open financial system recording asset transactions and integrated well with other systems. • Maintenance costs always allocated against individual assets in Asset Management System.
Maintenance Management	• Maintenance history of major network equipment assets is being recorded. • Service Maintenance Management system in place.	• Critical and non-critical assets explicitly identified. • Service Maintenance Management system consistently used for cyclic/duty-based maintenance programmes.
Condition Monitoring	• Some basic condition monitoring systems for asset types. • New SCADA system being implemented, reporting is underdeveloped. • Condition data is loaded into asset management system database.	• Condition monitoring systems extended for key assets. • Predictive modelling capability available for critical assets. • SCADA system data fully integrated with other systems.
Consumer Enquiries	• New system being established to record consumer enquiries and relationships. • At the early stage of development.	• Electronic records of all consumer enquiries. • Asset links to consumer enquires. • Integrated with many other corporate systems.
Risk Management	• No risk component in the Asset Management System capability. • Stand-alone risk assessments.	• Failure modes, and probabilities and risk cost available from Asset Management System.
Optimised Renewal Strategy	• Renewal on systematic basis. • Life cycle costs considered in assessing renewal options.	• Comprehensive renewal strategy in place considering future technology and consumer needs.
Forward Works Programme	• 10-year forward maintenance and renewal programmes based on historical/condition data. • Development needs based on known future demands and IRR.	• Optimised future costs based on various scenarios for new technology and consumer needs.
Integration of Systems	• Limited integration of consumer database, Service Maintenance Management System or Asset Management System.	• Full interoperability between all systems to allow additional knowledge extraction from existing data.
Plans and records	• Overhead records all entered into GIS. • Geoschematic UG cable records in GIS. • UG cable location records scanned and being vectorised gradually (CAD).	• Fully digital record system allowing on-line access and linkages to other databases and systems.
Operations and Maintenance Manuals	• Some dependence on worker knowledge. • Operations well documented for access to network by others.	• Basic manuals available for all significant assets.

	• Maintenance manuals for limited number of zone substations.	
Document Management	• Primitive system available for capture of documents.	• Comprehensive document management system with integration to asset management system, Financials, Maintenance, and other corporate systems. • Faithful archiving and versioning of all documents that record an asset's lifecycle.
Levels of Service	• Reported continuously by "Faults" system but entered manually. • No non-electrical performance measures logged in real-time. • ADMS being implemented to provide integrated capture and reporting.	• More complete performance analysis from a real-time "Faults" system. • Automated entry into "Faults" system. • An integrated Distribution Management System superseding "Faults", SCADA, "Interruptions", and other discrete operational systems.
Contingency Management Plans	• Procedures for operational activities documented. • Some key contingency plans have been created.	• Complete procedures for high impact contingencies affecting system performance. • Maintain the currency and relevance of contingency plans in a changing electricity network.
Asset Management Plans	• Documented Asset Management Plan process but not sufficiently widely read.	• Mature Asset Management Plan used for all forward planning and stakeholder consultation.
Geographical Information System	• All major assets have been captured into the GIS. • Present GIS is an open system with full vendor support.	• Continuing development of GIS platform to increase productivity and integrate more closely with other corporate systems.

Asset Management Data Appraisal

Data	Current Business Practice	Desired Business Practice
Asset Classification	• Network asset hierarchy established. • Asset categories identified for asset cost records.	• Coherent multiple-use categorisation established to satisfy Disclosure, Valuation, AMP, Tax, and other uses.
Asset Identification	• Unique ID numbers allocated in Asset database and/or GIS system for all major network assets. • Comprehensive asset register being implemented.	• Asset register data complete and comprehensive. • Asset data correlates to that held in other corporate systems.
Asset Textual/ Spatial Data	• Quality and completeness satisfactory.	• Appropriate spatial/textual data available on GIS/plans via direct storage or system integration.
Maintenance Tasks	• Check sheets for Zone Substations and other major assets.	• Documented maintenance tasks for network. • Documented maintenance programmes for Zone Substations.
Historical Condition & Maintenance Data	• Limited history available for some assets, but asset management system now storing all available data.	• Full maintenance data history in Asset Management System used for maintenance scheduling.
Future Prediction Data	• Predicted future growth data limited. • Simulated future load flows from computer model based on theoretical growth.	• Simulated future load flows from computer model based on growth predictions. • More authoritative future load growth data.
Life Cycle Costs	• Life cycle costs not collected per asset.	• Life cycle cost data used for renewal decision-making.

Network Operational Support

EA Networks uses the internal Field Services division as its preferred maintenance contractor for all network associated inspection, servicing and testing, faults response, fault repair, maintenance, replacement and network enhancement. Some development and maintenance work is put out to external tender where internal capacity or expertise is insufficient or alternatively the Field Services division may arrange sub-contractors to assist.

Information Systems Development

A recently implemented asset management system is in the process of being fully commissioned. This system is used to record and manage all significant assets. This system will form the core data repository for current and historical data. The new asset management system shows much more promise as a partner for asset management than the previous legacy system. These advances should help track expenditure by activity, asset type and other categories.

The capture of asset information has been carefully considered and EA Networks are content that the level of detail and accuracy presently stored is close to optimal. Additional information could be gathered, but the cost/benefit ratio for doing so is not particularly favourable. Some additional asset types will be captured as time permits.

The asset management system records information about a range of equipment including poles, cables, transformers, substations, switchgear (HV and LV), miscellaneous assets such as battery chargers and relays etc. Ancillary to the asset management system is a "Faults" system that records interruptions, and a "Competency" register that records an individual's competency for tasks that need to be performed on the network. An ADMS (Advanced Distribution Management System) is currently being implemented. This system will supersede the Faults, Competency, and SCADA and several other ad-hoc systems to form an integrated system. The chosen ADMS is from OSI (Open Systems International) and called monarch™ (multi-platform open network architecture).

The GIS system installed at EA Networks is called G/Technology. This system is very "open" (stored in Oracle™ RDBMS) and all its data is accessible by other applications (including the asset management system). EA Networks have converted all data held in the previous GIS into this system and are now capturing new data. The previous GIS was used to capture all primary asset information from paper and digital work-plans and maps. The data is being used for RAB and asset management. In conjunction with the asset management system, G/Technology keeps information on types of equipment installed at a site. The asset management system records engineering and financial details of assets and tracks maintenance history of those assets and other associated equipment. The G/Technology and asset management system databases are continually expanding to accommodate new sources of information. EA Networks can geographically locate any uniquely identifiable asset via G/Technology and the asset management system can provide all available data on that asset.

GIS viewing software provides users information which is drawn from data stored in many different systems. Information from external agencies, the asset management system, GIS, GPS units, and other open data sources can be drawn together for a spatial view of data that can reveal previously hidden relationships. It is hoped to integrate the ADMS data to the new GIS so that improved spatial analysis can be performed on fault statistics and other real-time data can be visualised/analysed.

The linking together of GIS, asset management and the financial system enables data concerning network assets to be accessed in a multitude of ways and from multiple applications, resulting in better decision-making processes.

EA Networks have a range of in-service systems available for asset management and some are more capable than others. The main systems/applications that are in use are:

Network Information Systems Description

System/Application	Capabilities
Asset Management System	Supplied by Technology One. It offers an integrated solution for storing and analysing asset information. Financial, engineering and maintenance data is all stored in the one database. Due to the multitude of corporate systems being implemented, integration with other key decision software is not complete.
GIS Asset Mapping System	G/Technology is a very capable modelling tool for the maintenance of spatial and electrical data. Open data storage enables access by many other GIS tools for detailed analysis. Data linking and exchange with other systems is achieved through connections to the Oracle RDBMS. Data is complete, consistent and spatially fit for purpose. High performance electrical connectivity analysis tools have vastly increased the value and use of the data.

	Continued development of this system will occur to provide enhanced functionality and productivity.
SCADA System	The QTech Datran SCADA system has been in use for approximately 20 years and while it is serviceable, there are some aspects that are less robust than required. The transition to a new SCADA system within the OSI ADMS in underway.
Work Management System	System is part of enterprise resource planning system which includes the financial system. The asset management system integrates with the work management system at the work order level (assets are assigned to the work order for either creation or maintenance). Data is captured for all projects and permits reporting in multifaceted ways.
Financial/Accounting System	System is in place and detailed reporting permits useful insights. The use of an industry standard database engine can potentially lead to better availability of data. The potential for close integration of GIS with asset management and financials should now provide significant analytical benefits.
Network Modelling and Analysis	DIgSILENT and ETAP Powerstation software are easy to use and provide for day-to-day analysis of network fault levels and power load flows. Future prospects for real-time analysis exists by integrating/linking with ADMS and GIS. This would make interruption planning and fault restoration more structured and precise. DigSILENT network models are prepared as required. The overhead of maintaining a complete model in an accurate state cannot be justified. In the future, GIS may allow direct linkage and provide a useable model without additional data entry. The ADMS has built-in network modelling (using the GIS network model) and analysis (using an internal calculation engine) that is updated in real-time - giving alarms for loading and voltage violations in un-metered locations. Many of the routine engineering needs will be satisfied by the data output of this ADMS analysis.
Connection System	All connections are recorded and linked via unique identifier to the GIS. History of connection changes and occupation are available as is the interruption history, which is integrated with the Faults system. Data is complete and as accurate as required. Access is readily available and widely used. A replacement Customer Relationship Management system (called *Stream* internally) is being implemented to provide a platform for recording and reporting all customer interactions. It will also form the repository for data about, or related to, connections.
Fault Recording System	All interruptions, both planned and unplanned, are recorded in this system and a full history is available that permits anytime calculation of performance indices and any other parameter of interest. Data is reasonably complete. Additional benefit would derive from data capture of fault location to the nearest pole or faulted asset. It is anticipated that the ADMS will fully replace this system within a year.
Standards Documentation System	There is a minimal intranet based system for storing documentary standards. A more robust and substantial system is needed to provide a framework for storing and accessing documentation as it is developed. Once a system is installed that allows storage and access to a wide range of documentation, the desire to commit more information to standards will grow.
Public Safety Management System	As required by legislation, a safety management system has been implemented. The supporting processes and systems for the PSMS help underpin other necessary systems that have historically lacked robust structure.

Specification, Procedures and Manuals

EA Networks has spent considerable effort in preparing a set of drawings which provides information to staff and contractors on EA Networks standard overhead line and underground cabling construction techniques. Further work is still required to extend these publications into documented design standards. Documentation for levels of competency, Network Releases and access to sites is now complete but additional work is still required to provide a completely integrated approach.

Procedures have also been completed which are deemed to be mandatory for contractors who wish to carry out work for EA Networks or on EA Networks' network.

EA Networks licensed a set of procedures and standards from PowerCo which assisted in initially developing the significant quantity of documentation required to support asset management and a Public Safety Management System (PSMS). This initiative helped overcome the historic difficulties EA Networks have experienced with high load growth causing rapid network development which prevented adequate resource being available to develop documentation. EA Networks have begun to transition away from the purely PowerCo documents and, as time allows, staff are developing standards that better suit EA Networks.

1.9 Responsibilities

Within the network division of EA Networks, staff are allocated distinct responsibilities for asset management functions. The Network Manager oversees the process and takes direct responsibility for the asset decisions which are made. The smaller size of EA Networks asset management team requires multiple responsibilities by all staff and this helps to provide perspective on many tasks and assets that would otherwise quickly become foreign.

The modest scale of EA Networks means that planning/analysis/asset management/design/ procurement/standards are all managed by a small core team of personnel. There are no 'departments' that separately handle these functions and consequently there is no distinct structural separation.

The entire network group work in close proximity in an open plan environment. This working arrangement encourages the free flow of information and ideas between members of the group and encourages the dissemination of information. A monthly "Engineering Meeting" is an open forum for discussing all aspects of asset management, work processes, ideas and the general dissemination of information. The communication paths established, and the relatively small number of people involved in the asset management process, alleviates the need for some of the more formal documentation that would be required in a larger organisation.

The key staff have the following responsibilities specific to asset management, although these are also shared to some extent:

Network Manager:

- Electricity network information systems - development and maintenance
- Network valuations - preparation and maintenance
- Overall responsibility for asset management and asset performance
- Preparation of documented standards for areas of responsibility

Engineering Services Manager:

- Graduate engineer management
- SCADA – development, maintenance, operation, enhancement and expansion
- As-built records – capture, documentation and recording of records as they are returned
- Geographic Information Systems – operation and maintenance
- Electrical protection – detailed design, settings, maintenance planning and test plans on various equipment and procurement of some equipment
- Performance monitoring and analysis of network
- Reporting and analysis of network and planning options using engineering software (load-flow and fault analysis)
- Power quality – investigation and analysis

Operations Manager:

- Network operations – day to day network control and performance
- Vegetation control management
- Network performance – capture, analysis and disclosure of faults statistics and consequently offering engineering recommendations for improvement or investigation of assets
- Zone substation construction – scheduling and project management
- Zone substation - major equipment specification and procurement
- Zone and distribution substations – maintenance planning and management
- Distribution transformers – specification and procurement

Overhead Manager:

- Overhead lines – detailed design and maintenance
- Overhead line construction and maintenance projects - scheduling and management
- 11kV to 22kV conversion – design, scheduling and management
- Rural new connection interface – network design and specification
- Network stores management
- Overhead distribution equipment – procurement and specification

Planning Engineer:

- Network planning – preparation, analysis and documentation of medium-long term and medium-large scale network development concepts
- Preparation of Asset Management Plan
- Geographic Information Systems – oversight of architecture & development
- Electrical protection - architecture, specification, design oversight, and some procurement of major equipment
- Zone substation – conceptual & aspects of detailed design
- Engineering analysis – incidental load-flow and fault analysis (shared responsibility)
- New technology – investigation and analysis

Underground Manager:

- Underground cables – detailed planning, design and maintenance
- Underground cable construction and maintenance projects - scheduling and management
- Underground distribution equipment – specification
- Subdivision development - electrical reticulation negotiations and design
- Urban new connection interface – network design and specification
- Land interests and requirements – negotiation, procurement and maintenance

Health & Safety, Environmental Management Team:

- Personnel competency – documentation of individual competencies
- Safety and Training – management of the safety and training regimes run by EA Networks
- Public Safety Management System (PSMS) – coordination of implementation
- Environmental Management – Oversight of normal business practices

1.10 Information Sources, Assumptions and Uncertainty

As a forward-looking planning document, this publication relies on a considerable pool of information sources, assumptions, opinions and known facts. Other than facts, these considerations have a degree of uncertainty associated with them which needs to be at least described and wherever possible quantified.

1.10.1 Information Sources

It is impractical to list every source of information used to prepare this document. The items listed below represent the principal foundations upon which this plan is built. They are:

- EA Networks' 2019 Statement of Corporate Intent.
- EA Networks' 2020-21 Business Plan and Budget.
- EA Networks' Use of System Agreement.
- EA Networks' New or Modified Connections and Extensions Policy (17 April 2018).
- EA Networks' 2019 Shareholders Committee Report.
- EA Networks' December 2019 Customer Survey Report.
- EA Networks' large user consumer interviews.
- EA Networks' asset database.
- EA Networks' Consumer Connections database.
- EA Networks' equipment loading records.
- Retailers' generation and energy consumption data.
- Retailers' reports on EA Networks performance.
- Transpower's and EA Networks' GXP energy data.
- Transpower's disclosed development documents.
- Ashburton District Council's District Plan.
- Ashburton District Council population projections.
- Environment Canterbury's strategy and policy documents as they relate to home heating and water availability for irrigation. Resource consent data (water) is also supplied from this source.
- Environment Canterbury's flood risk modelling documents.
- EA Networks' internal discussions regarding commercial and technical options for managing security, reliability, increased load and the value of these considerations.
- External discussions with existing and prospective consumers regarding new electrical load and/or security requirements.
- Correspondence with shareholders (consumers) regarding issues that can be addressed within the scope of asset management techniques.
- Documents by The Treasury such as "Half Year Economic and Fiscal Update 2019".

1.10.2 Significant Assumptions

It is important for stakeholders that the manner and the basis upon which the Asset Management Plan is intended to operate is clearly understood. For the purposes of clarity, and in order to avoid any confusion, the following underlying assumptions need to be taken into account by the stakeholders in dealing with the Asset Management Plan:

- As a Lines Business, EA Networks will continue to be a going concern under the regulatory regime in place now or in the future.
- Asset Management, System Control and Corporate Services functions will be provided internally and be based in Ashburton.

- EA Networks will have access to skilled and experienced staff.
- The Lines Business will continue to operate an internal Field Services Division.
- The Lines Business must satisfy the twin constraints of providing a risk-adjusted normal profit for its shareholders sufficient to retain investment, while performing within the regulatory limits set by government regulations.
- As a non-exempt entity, the EDB will continue to meet the requirements of the price quality determination.
- The Lines Business will continue to meet the requirements of its consumers/shareholders as a co-operative.
- The prevailing regulatory and legislative requirements mandated by central and local government remain unchanged for the duration of the planning period. This ensures that the environment which influences reliability targets, as well as governing industry codes of practice, health and safety, design and environmental standards is stable.
- The predictions and estimates of load growth are timely, and of reasonable and prudent scale. This ensures that the level of investment to cope with additional load is not unreasonably small or large and occurs in advance of the additional demand occurring.
- The availability of ground water for irrigation will not increase above that presently consented in ECAN 'red-zoned' aquifers, but significant water will continue to be available for irrigators.
- There are no significant unidentified uncertainties, errors, or omissions in the internal records and databases (they contain suitably accurate information).
- The focus, policies and key business strategies of EA Networks remain consistent for the duration of the planning period.
- The value of future projects and programmes is not affected by the value of the New Zealand Dollar or the cost of constituent raw materials (particularly copper, aluminium, steel and oil) by more than the official rate of CPI. In reality, these costs will change. The impact of these changes will be reflected within 12 months when a subsequent plan is issued with updated cost projections.
- Wage rate movements are not significantly greater than the prevailing CPI. Skill shortages and wage/availability pressures around the Christchurch rebuild were an issue, but this is now abating. Significant expenditure has been approved by the Commerce Commission via Customised Price Paths and this may put pressure back on resources and therefore wages. Wage rate movements continue to be manageable within EA Networks allowable revenue.
- The availability of sufficient capacity (as described by projected load growth in this plan) from both the existing Ashburton GXP and any new Transpower Grid Exit Point will not be unreasonably constrained by 220kV operational limits. This applies under steady state and fault conditions.
- The Transpower charging methodology of regional coincident maximum demand remains and the peak occurs during winter. Consequently, load management of summer peaking consumers (such as irrigation pumps) has not been a necessary commercial consideration. Some peaks are now in summer and this is causing annual swings in network pricing.
- The consistent pattern of responses exhibited by consumers surveyed annually by EA Networks continues in future surveys. This will ensure satisfaction, expectations and willingness to fund improved reliability remain within narrow bounds and do not fundamentally change the current asset management strategies.
- The EA Networks network is not exposed to extraordinary natural disasters during the planning period. In particular, events such as a major earthquake caused by a rupture of the Alpine Fault, further Canterbury earthquakes, a massive flood of record proportions, a snowstorm of record proportions, or a windstorm with sustained speeds exceeding 140 km/h (900 Pa). Any of these events is outside the reasonable design parameters for the electricity network to survive without significant damage.
- The impact of electric cars on peak demand is not significant during the planning period. The moderate initial uptake of electric cars due to high cost is likely to dampen the initial impact on the network. It is also inevitable that they will be subject to some form of load control. The option to source stored energy from electric cars into the network has not been considered as consequential during the planning period.

- A review of any of the District Plans covering the EA Networks network does not materially affect the ability of EA Networks to manage the network assets using the strategies outlined in this plan.
- Any distributed generation that is commissioned during the planning period is of sufficiently small scale as to not materially affect the demand estimates or permit the postponement or cancellation of any planned projects or programmes.
- The climate during the planning period is within the normal range of precipitation, temperature, wind speed and humidity. Significant changes in any of these parameters could not only affect the assets but also the characteristics of electricity demand placed on those assets.
- The changing retail cost of electricity does not materially affect the rate or pattern of consumption exhibited by consumers or groups of consumers representing significant demand on the EA Networks network.
- The international price of agricultural commodities remains close to current values. This is particularly relevant to dairy products and irrigated crops. A major drop in price could see less irrigation demand and a major increase in price could see a dramatic increase in irrigation demand.
- No significant agricultural event, such as an outbreak of foot and mouth disease occurs, which could materially affect the value of agricultural production in Mid-Canterbury. An outbreak of Mycoplasma bovis has occurred, and there are several farms in Mid-Canterbury with infected cattle. The current strategy appears to be containment with the ultimate goal of elimination.
- A global pandemic does not cause a long-term (multiple year) significant downturn in economic activity.
- The performance characteristics of technologies and equipment types new to the EA Networks network are as represented to EA Networks during the equipment approval process. History has shown that on rare occasions vendors have misrepresented the products they sell (generally unknowingly). EA Networks have an expectation that any such technology or equipment performs as specified.
- The consumer uptake of solar photovoltaic generation and battery storage is not sufficient to cause widespread disconnection from the distribution network. If prices for this technology fall sufficiently, then the commercial risk of network earnings being insufficient to earn an acceptable return may exist.
- That the load growth and new connections forecasts will be met.

1.10.3 Future Changes to the Distribution Business

Any change in the scale, scope, structure or focus of EA Networks as an electricity lines company could considerably affect the validity of many information sources and assumptions used to prepare this plan.

There is no intention to change the ownership or structure of the electricity lines company that is EA Networks. As such, the prospective information and assumptions used here are consistent with the current scale, scope and structure of EA Networks.

For completeness, it should be noted that EA Networks are currently involved in one other utility activity:

- A fibre optic communications network. Initially for EA Networks' use as inter-substation communication, but also built with the intent of provision of broadband services to other users.

The primary focus of EA Networks for the foreseeable future remains the electricity lines function.

During 2017, Electricity Ashburton divested itself of an interest in a piped and gravity pressurised water distribution network for irrigation from the Rangitata Diversion Race.

1.10.4 Factors Affecting Information Uncertainty

The information sources that have been used in this plan are all subject to a greater or lesser degree of uncertainty. A high level of uncertainty in a parameter is not necessarily problematic unless the plan exhibits a high degree of sensitivity to that parameter. What follows is a description of the information sources that do have a moderate to high degree of sensitivity on the plan's projections and outcomes. Should the uncertainty prove to be significant, it could materially affect any comparison of predictions with future actual outcomes. The factors are as follows:

- The load growth is significantly greater or less than predicted in the plan.

- Water availability for irrigation significantly increases from either ground or storage sources.
- No significant agricultural event, such as an outbreak of foot and mouth disease occurs, which could materially affect the value of agricultural production in Mid-Canterbury.
- The regulatory environment changes, requiring EA Networks to achieve different service standards or different design or security standards. This could also affect the availability of funds for asset management.
- The regional coincident maximum demand occurs in summer. This could drive further investment in piped irrigation schemes as the increased cost of Transpower summer peaks discourages rural electricity usage.
- Consumer expectations change, and/or they are prepared to pay a different amount for a significantly different level of electricity network reliability.
- A significant natural disaster occurs.
- Significant amounts of distributed generation and/or battery storage are commissioned.
- Large and unforeseen loads require connection to the network.
- The uptake of electric vehicles is much faster and widespread than anticipated.
- The District Plans covering the EA Networks network introduce significant new restrictions or requirements on new or existing network.
- International markets for agricultural commodities boom or collapse causing changes in irrigation or processing industry demand.
- Advances in condition assessment and research in network planning generate additional development and maintenance requirements that are significantly different from current strategies.
- A major item of equipment may fail without warning requiring significant repair or replacement expenditure.
- The ownership of EA Networks may change with new owners requiring different service, design or security standards to meet business objectives not embodied in this plan.

1.10.5 Assumptions Surrounding Sources of Uncertainty

It is possible to subjectively quantify uncertainty and, in some cases, even objectively quantify uncertainty. Even if the actual degree of uncertainty is open to debate, the effect of the uncertainty can often be evaluated in a much more rigorous manner that establishes the sensitivity of the assumption to uncertainty and ultimately its impact on any information based on the assumption. What follows is a generalised description of the effects of uncertainty on the assumptions of section 1.10.2.

Source of Uncertainty	Potential Effect of Uncertainty	Potential Impact of the Uncertainty
Load Growth	A general acceleration or deceleration in load growth would (as has happened in previous plans) advance or retard the enhancement and development project(s) that had been earmarked to accommodate it.	Low
Irrigation Water	If significant additional irrigation water sources were made available, the projected demand could increase well above the level expected during the planning period. The rate of increase could also be dramatic as the allocation is likely to be prioritised by the sequence of application. Significant additional network reinforcement (capital expenditure) would be necessary to support the extra load.	Medium – High (estimated 10-25% increase in capital expenditure depending on water quantity and location).

	Alternatively, a significant move from deep well pumped irrigation to gravity fed/surface water could result in significant load reductions. Retention of the deep well water consent and electrical connection could cause very large peaks in drought years (hidden/unused load in average years).	Medium
Regulatory Environment	While most network lines companies remain natural monopolies, it is highly likely that the level of regulation will persist at current levels or increase. Regulatory compliance costs are therefore likely to increase. The Regulator is best placed to quantify the likely impact.	Low
Regional Demand	If the regional demand peak period changes to mostly summer, pressure would come on to control that peak. Presently the irrigation consumers have indicated they prefer to pay the peak penalty than accept load control. If peak charges increase, irrigators may accept control capping peak load. This could defer some scheduled capital expenditure.	Medium to High
Consumer Expectations	If the annual consumer survey reveals a change in service quality expectations and/or a preparedness to fund this change, the altered service levels would result in variations in capital expenditure.	Low
Natural Disaster	Widespread equipment damage (potentially irreparable) would require significant funding for repairs and replacements not allowed for in cost projections.	Low – Medium – High severity dependent
Distributed Generation	Widespread small-scale distributed generation could cause localised issues that would need resolution as well as network wide issues. Depending upon generation availability it could defer some development costs. Small quantities of medium-large (0.5 – 5.0MW) individual distributed generators can generally be accommodated without major service level or network development cost implications.	Low
Large Loads	Large new loads (typically industrial) will change the load growth estimates by step amounts. Beyond the GXP, additional dedicated investment required to service a new load is typically borne by the new load. This funding can be in the form of a long-term contract requiring EA Networks to initially find the capital. This would change the capital cash-flow projected in the plan.	Low
Electric Vehicles	Rapid and widespread uptake of electric vehicles could require significant network development in dense urban areas. This would be new capital expenditure not allowed for in the plan.	Low – Medium (estimated 15-20% increase in capital expenditure)
District Plans	A dramatic change in the District plan rules or land zoning would typically only impact on new network (existing use rights would protect existing network). A tightened set of controls would increase new network capital cost.	Low
Commodity Prices	A significant rise or fall in agricultural commodity prices would raise or lower existing and new irrigation demand. This would in turn advance or defer planned network capital projects and programmes.	Low – Medium

Planning & Monitoring	The development and maintenance requirements differ from those currently projected, particularly for years 6-10 of the planning period and generally involving the 22kV, 11kV and LV networks.	Low
Equipment Failure	Widespread or major equipment failure and subsequent repairs or replacement are not factored into current projections. Largest individual item does not exceed 1% of network value.	Low
Ownership	An altered ownership structure or new owners outright could alter the business objectives of the company and therefore the drivers of this plan. This could result in significant changes to service levels and expenditure.	Low – Medium

Weather affects the fault expenditure through the level of storm damage experienced. As it is very difficult to predict weather patterns over a 12-month period, the budget for fault expenditure can only be an estimate based on historical averages and general knowledge of the asset condition.

The sensitivity of the network to storm damage has greatly reduced over the last 10 years as major subtransmission and distribution feeders have been progressively upgraded with better quality materials. A continuing distribution automation programme is reducing the amount of time and effort required for fault location and repair. The Canterbury and Kaikoura earthquakes have shown the unpredictability of major events and the extent of damage that can occur in a significant earthquake.

EA Networks is regulated using a default price-quality path under Part 4A of the Commerce Act 1986 that applies to 17 electricity distribution business in NZ. The price-quality path reset for a five-year period from 1 April 2015 to 31 March 2020 has the following components:

- The maximum prices/revenues that are allowed at the start of the regulatory period.
- The annual rate at which maximum allowed prices can increase – expressed in the form of CPI-X
- The minimum service quality standards (SAIDI&SAIFI) that must be met.

Penalties may be incurred for breaches of the price-quality path.

If prices are forced downward, costs will have to be reduced accordingly through reduced maintenance expenditure. The most likely area for attention would be that of Inspection, Servicing and Testing, as this has little immediate effect on system performance and can be deferred for short periods to smooth out expenditure.

GDP in the Mid-Canterbury area has a direct effect on EA Networks' revenue stream through increased demand from large consumers. It also has an indirect effect as secondary and tertiary level consumers in the commercial and domestic area expand. As for price control, any reduction in revenue must be reflected in cost savings or deferred maintenance if profitability is to be maintained.

Several major projects have been mooted for Mid-Canterbury over recent years involving irrigation, agricultural processing and industrial processing. Any large additional loads could require major system reinforcement with associated increased expenditure on development and enhancement projects. This activity would also highlight the potential shortage of skilled labour which could either delay or price-escalate projects. This expenditure will have to be at least partially funded by the end user, either as a capital contribution or through a longer-term contractual arrangement. Maintenance expenditure will not be directly affected except insofar as competition for resources may slightly reduce the level of non-critical work carried out.

1.10.6 Price Inflator Assumptions

The majority of costs quoted in this plan are in 'constant price' 2020 calendar year New Zealand dollars (2020-21 financial year). There are some disclosures associated with the plan that require 'nominal dollar' values. To convert forecasts made in 'constant price' dollars to 'nominal dollar' values, a set of assumptions must be made about future economic conditions. The obvious factors that would influence future costs include:

- The consumer price index (CPI)
- NZD/Foreign currency exchanges rates

- New Zealand labour rates
- International commodity prices (aluminium, copper, steel, oil, plastic etc)
- Export/import tariffs and taxes

Although all of these factors are valid, there are very few authoritative forecasts freely available for periods exceeding a few months to a year. The CPI includes most of the other factors to some degree. Consequently, EA Networks have decided that the only price inflator that will be factored into the 'nominal dollar' multiplier is the CPI forecast issued by the New Zealand Government Treasury at:

https://treasury.govt.nz/publications/efu/half-year-economic-and-fiscal-update-2019-html

This "Half Year Economic and Fiscal Update 2019" published in December 2019 includes a CPI forecast (June years/quarter) to 2024 and EA Networks will use the 2024 value of CPI for the following 6 years, extending the forecast to 2030. The values are as follows:

Financial Year (ending March)	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
Treasury CPI Forecast (%)	1.9	2.0	2.0	2.0	2.0	2.0	2.0	2.0	2.0	N/A
Cumulative CPI Price Inflator	1.000	1.019	1.0394	1.0602	1.0813	1.103	1.1251	1.1476	1.1705	1.1939

MANAGING RISK AND RESILIENCE

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2 MANAGING RISK & RESILIENCE

2.1 *Introduction*

This section of the plan will consider the risks that EA Networks' electrical network faces from all sources and the risks it presents to people and the environment.

EA Networks explicitly recognises that the company must take some risks in undertaking its core functions and pursuing opportunities.

EA Networks manages risk by anticipating reasonably foreseeable risk, understanding risk criteria, analysing and evaluating risk,

- determining risk tolerance,
- implementing risk controls and mitigation, and
- ongoing monitoring and review of effectiveness.

Throughout this process EA Networks communicates and consults with affected stakeholders.

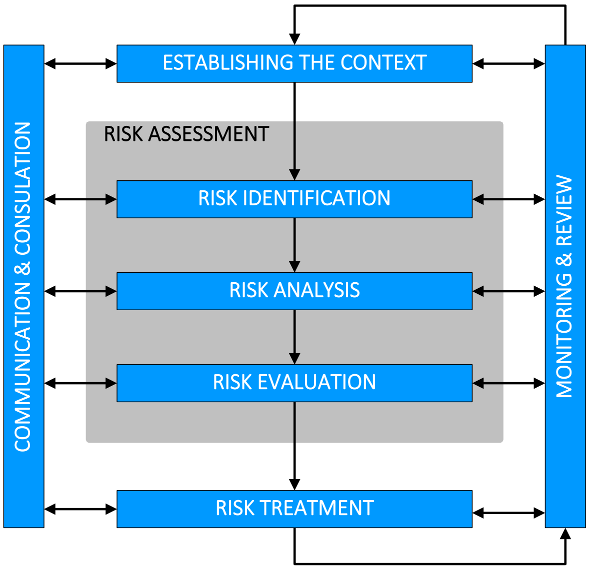
High impact low probability (HILP) events such as catastrophic events, complete failure of critical infrastructure, natural disasters, pandemics or cyber-attacks necessitate situation specific reporting and responsibility structures. Each HILP event will be different, so EA Networks use a high-level planning framework rather than event-specific plans.

2.2 *Risk Management Framework*

The purpose of risk assessment is to provide empirical knowledge and analysis to make informed decisions on the treatment and method of resolution of particular risks.

EA Networks's risk management processes use the methodology outlined in International Standard *AS/NZS/ISO 31000:2009 Risk Management – Principles and guidelines for use*.

Establishing the context: This considers company objectives, key drivers, the operating parameters, external environment, and risk criteria.



Risk identification: This is the process of finding, recognising, and identifying risks, which is undertaken by a variety of methods including (but not limited to the following):

- Engineering assessment
- Inspection and Maintenance outcomes
- Defect reports
- Accident/near miss reports
- External advice
- Audits and safety observations

Risk analysis: This is undertaken using both qualitative and quantitative assessment to produce a risk score.

The risk score is calculated by multiplying the Likelihood (Frequency x Exposure) by Consequence. The established risk score is an indication of the severity of the risk, which, in turn, assists in the evaluation and treatment of the risk.

Recognising that risk analysis is a subjective process, EA Networks encourage staff to seek support in performing initial risk assessments before registering a risk on the register. All registered perceived risks are evaluated by a selection of staff experienced in performing such assessments.

			Consequence Weighting				
			Minor	Important	Serious	Major	Catastrophic
			0.5	1	1.5	4	5
Likelihood level	Almost Certain	5	Moderate	High	High	Extreme	Extreme
	Likely	4	Moderate	Moderate	High	Very High	Extreme
	Possible	3	Low	Moderate	High	Very High	Very High
	Unlikely	2	Low	Moderate	Moderate	High	Very High
	Rare	1	Low	Low	Low	Moderate	High

Risk evaluation: This is used to determine the most effective methods of treating risk, as well as setting priority of execution.

A number of dimensions must be satisfied to meet EA Networks Statement of Corporate Intent's objectives of "the selection, location and operation of EA Networks' assets which leads to a safer, financially efficient, reliable electricity distribution network".

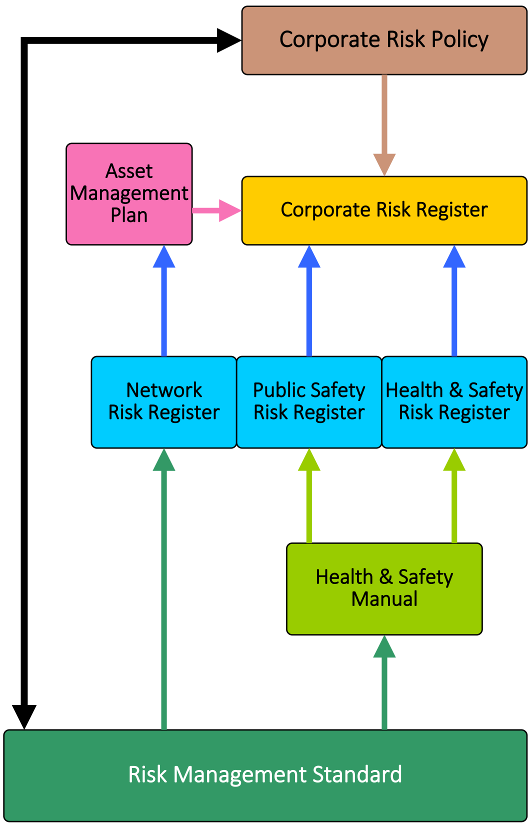
Risk treatment: This is the process to modify risk by either avoidance, reduction by implementing controls, or mitigating the outcome.

A series of comprehensive risk registers feed into the corporate Risk Management Policy, which provides EA Networks' philosophy to risk management and risk appetite at a Governance and Corporate level.

The purpose of the Policy is to explain EA Networks' underlying approach to risk and risk management and ensures that a systematic and strategic approach to identifying and managing risk and meeting business objectives is taken.

- The identification and management of risk is linked to the achievement of EA Networks' strategic goals.
- Risk management is embedded in normal business processes.
- Everyone is held accountable for considering risk in all decisions
- Delegated authority for accepting risk is defined.
- A risk capability appetite and tolerance statement is maintained and reviewed annually by the Board Audit and Risk Committee

Risk Management Interconnectivity



The EA Networks network is periodically exposed to events or incidents that subject elements of the electrical network to a high risk of failure. If the location of these events coincides with a critical component of the electrical network, the result is a high risk to the integrity of the electrical network. This risk of failure can in turn lead to high risks for consumers, either as individuals or as larger collective groups.

The range of events that can place the network at risk are extensive and range from a mouse entering a protection panel in a substation to a 747 aircraft crashing into a Transpower substation. These two examples could have similar immediate effects (loss of supply to a wide area) but the likelihood of each one happening is particularly disparate.

Natural disasters will be assessed by evaluating the risk cost for each event (probability times the consequences of failure cost) and developing appropriate contingency plans and procedures to ensure business continuation and mitigation of impacts respectively.

Note that the risk of non-supply of electricity is managed by way of service agreements/insurance cover and is outside the scope of this plan

Network risk assessment identifies:

- the category or specific equipment at risk,
- the supply at risk,
- the risk elements and the likelihood of each element depriving the network of the equipment,
- the initial deprival time and quantity delayed (initial consequences of the risk event),
- the delayed deprival time and quantity (repair time or delayed consequences of the risk event).

This information is then used to form a maximum risk score, which combines the maximum risk element score with the duration and quantities of deprival.

The network risk register details:

- the risk treatment decisions that have been made,
- who is responsible for acting on them, the risk score after treatment,
- the year for treatment action,
- the monitoring technique, and
- the date of the most recent review.

A site summary details the risks facing the site overall and any co-ordinated mitigation that is necessary to reduce the risk to an acceptable level.

Widespread (common-mode) risks to a particular type of equipment that could be affected by an area-wide event are assessed without reference to any particular site.

The recent rapid rate of network development has resolved some of the most critical historical risks that have been identified in the past.

2.3 Environmental

Some level of adverse environmental effects needs to be accepted to recognise the necessity for electricity supply. It is also recognised that EA Networks may have limited choice in locating assets and facilities, given logistical or technical practicalities.

The objective is to provide for the construction, installation, operation, maintenance and decommission of electricity infrastructure where adverse effects on the surrounding environment can be appropriately avoided, remedied or mitigated

Network assets are mainly situated on land that has been previously modified. EA Networks do not have any highly significant ecological, archaeological or environmental areas within their network footprint.

Fortunately, most of EA Networks' technical infrastructure has been either renewed or upgraded to modern requirements so legacy environmental issues such as PCBs and Asbestos are minimal.

The EA Networks Environmental Management Standard (last reviewed October 2019) specifies how environmental assessments are undertaken, manage possible environmental impacts arising as a result of electricity network activities, and provides detailed information to support the EA Networks' Environmental Policy.

This is supported by Standards relating to:

- Sulphur Hexafluoride management (last reviewed November 2019),
- Legacy Asbestos management (last reviewed October 2019), and
- Specific spillage procedures (last reviewed September 2019).

The three most critical environmental risks are as follows:

2.3.1 Sulphur Hexafluoride (SF_6) gas

SF6 has unique physical and electrical properties making it a very efficient dielectric and arc-quenching gas. It has mainly replaced oil-filled circuit breakers (which contained PCBs) and reclosers in some 33kV and all 66kV switchgear. Only four oil-filled 33kV circuit breakers remain on the network.

EA Networks is committed to adopting best practice with respect to minimising SF_6 emissions when installing new equipment, during maintenance and during retirement of old equipment

- EA Networks voluntarily follow the International Standard IEC 60694 requirement of less than 1% leakage from equipment per annum
- SF_6 reserves are stored in an approved and secure purpose-built storage bunker. EA Networks are participating in the Emissions Trading Scheme due to holding more than 1,000 kg of SF_6.

At this time, there is no intention to remove SF_6 from the network. Switchgear containing SF_6 is still actively being purchased.

However, techniques to decrease the volume of SF_6 held in reserve are being actively pursued.

2.3.2 Oil

The majority of zone substations have been built or rebuilt in the last decade, and they are subject to stringent contemporary Resource Consent conditions.

Due to our zone substation transformers holding between 14,000 and 19,000 litres each, the risk to the environment is from the volume of oil that could be released in the case of an accidental spillage, rather than the likelihood of that spill occurring.

2.3.3 Fire

One of the most common effects any electricity network has on the rural environment is initiating small brush or grass fires. To date, any fires caused by the network have been very infrequent, small volume, and very localised. The fire is often out by the time FENZ arrive.

It is normally external factors such as airborne debris, vegetation, farm machinery etc. hitting live lines, which causes either drop out fuses to operate or live wires to contact the ground.

Both hot fuse elements and sparks from live contact are a common source of ignition in dry conditions.

Every effort is made to ensure the network is as fault resistant as possible.

Active network mitigation methods include:

- Permanently configuring the reclose function on the automatic circuit reclosers to permit only one reclose attempt before lockout (from the default setting of three attempts).
- During dry weather disabling the reclose function on the automatic circuit reclosers using meteorological data from FENZ and NIWA as trigger points.

Other network projects that benefits fire mitigation include:

- Ongoing overhead to underground conversion projects decreasing the likelihood of live lines or hot fuse elements falling to the ground.
- Bird-proofing the pole-top SF_6 Gas switches.
- Installation of Neutral Earthing Resistors in the zone substations, which limits earth fault current to 300 Amps maximum (decreasing the amount of energy available when live wires contact the ground).

To completely eliminate these fire risks would be extremely costly and could not be justified by the reduction in likelihood of environmental harm.

2.4 Commercial

There is a wide spectrum of commercial risk that EA Networks face. Many of them are the same risks faced and addressed by businesses everywhere. These risks tend to be at the lower consequence end of the scale and will not be directly addressed in the AMP. The areas that are of note tend to be around the risk to income from both changes in seasonal load and, over time, changes in consumer choice of energy source.

EA Networks has already seen some of the 100 highest regional peaks shift to summer and this has caused dramatic swings in the charges received from Transpower. Ultimately, these charges are passed onto the consumer, but the following year can see the situation reversed and the charges are then dropped.

Large yearly changes in the cost of supply do not allow robust economic analysis of energy options and can discourage consumers from using electricity as the preferred energy source reducing the income available to EA Networks.

The conversion of some irrigation schemes to gravity-pressurised pipe networks has allowed farmers to consider whether they can forego the deep well electric pump. In many cases, this is retained only for back-up in case of a very dry year or to retain the water-use resource consent. If farmers decide it is not worth retaining the electric pump, then rural load could decrease, risking the income used to earn a return on relatively new rural electrical assets. To date, there have been relatively few disconnections, but some have chosen to reduce the pump size.

The world-wide electricity industry is entering a new era where the end-user has more choice. The choice between retailers of energy has existed for many years and energy consumers choose between energy sources (gas, electricity, wood, coal, etc) and within that energy source they have choice of provider (Contact, Meridian, Trustpower, etc). Consumers can now generate their own electricity using solar PV and, once generated, can store this in batteries within their premises. The batteries can also be used stand-alone to store off-peak energy. This give consumers choice over their provider of not only electrical energy but also electrical power (capacity). If they wish, they can decide to completely self-generate and disconnect from the network.

At this time, it is not economic to completely disconnect from the existing electricity network, and it may never be truly economic, but that opportunity still exists.

Assuming most consumers choose to retain a network connection, the complexity of power flow through the distribution network is going to increase over time and there will be a need to manage that complexity with additional assets and resources. These assets and resources (along with the existing assets) will require a financial return on them, and the mechanism to charge for the facilities provided to consumers needs to be simple and transparent. The existing energy-based charging is unlikely to be adequate in that regard. Some form of demand/capacity charge is necessary to signal the consumer their fair contribution to charges that will be imposed upon EA Networks by Transpower and reflect the use they make of the shared distribution network.

EA Networks is investigating options for providing data capture and control options for charging, monitoring and controlling the capacity required by each connection. This would be one piece of the wider puzzle to allow the distribution network to facilitate bi-directional power flow and localised energy trading. It is still not clear how it will be possible to properly coordinate the myriad appliances that generate into, store energy from, and load the network (an "AC" battery does all three). As the way becomes clearer, EA Networks will look to provide the necessary infrastructure to remove barriers to economic and efficient use of the distribution network.

One of the risks to the distribution network owner is that sufficient consumers choose the self-generation/disconnection option and the return on fixed assets must then be recovered from the remaining consumers. The price of capacity will increase to the connected consumers and this will encourage more to disconnect leading to a spiral of cost to those that remain. This may seem unlikely as asset write-downs would undoubtedly occur, but ultimately the viability of the business is then put at risk.

There are a range of options for mitigating this risk, some of which are within the control of EA Networks while others lie in the hands of government agencies and some are unknown. One option already provided for is an accelerated depreciation recovery, allowing up to 15% reduction in asset lives. EA Networks are not able to provide sufficient evidence of asset underutilisation at this time. However, there has been some evidence that even energy efficient appliances have started to reduce individual household energy consumption (but not necessarily peak demand).

2.5 *Network Risk*

2.5.1 Equipment Risks

Risk assessment has identified a number of pieces of equipment that have a sufficiently critical place in the EA Networks network that the consequences of failure is seen as worthy of further investigation. In most cases, the risk had been informally identified prior to the risk assessment exercise and consideration was already being given to appropriate mitigation.

The following table gives a summary of the highest scoring risks for critical pieces of major equipment which would have implicitly high consequences if they were unavailable.

Summary of highest risk type and severity for major substations			
Site	Building & Contents	Power Transformers	Switchyard Equipment
Ashburton 66/11	Seismic = Low	Equipment = Low	Lightning = Low
Carew 66/22	Seismic = Low	Equipment = Low	Lightning = Low
Coldstream 66/22	Seismic = Low	Equipment = Low	Lightning = Low
Dorie 66/22	Seismic = Moderate	Equipment = Low	Lightning = Low
Eiffelton 66/11	Seismic = Low	Equipment = Low	Lightning = Low
Elgin 66/33	Seismic = Low	Seismic = Low	Lightning = Low
Fairton 66/22/11	Seismic = Low	Equipment = Low	Lightning = Low
Hackthorne 66/22	Seismic = Low	Equipment = Low	Lightning = Low
Lagmhor 66/22	Seismic = Low	Equipment = Moderate	Lightning = Low
Lauriston 66/22	Seismic = Low	Equipment = Moderate	Lightning = Low
Methven 33/11	Seismic = Low	Equipment = Low	Seismic = Low
Mt Hutt 33/11	Seismic = Moderate	Equipment = Moderate	Seismic = Moderate
Mt Somers 66/22	Seismic = Moderate	Equipment = Moderate	Seismic = Moderate
Methven 66/11	Seismic = Low	Equipment = Low	Lightning = Low
Methven 66/33	Seismic = Low	Equipment = Low	Lightning = Low
Montalto 33/11	N/A	Equipment = Low	Seismic = Moderate
Northtown 66/11	Seismic = Low	Equipment = Low	Lightning = Low
Overdale 66/22	Seismic = Moderate	Equipment = Low	Lightning = Low
Pendarves 66/22	Seismic = Low	Equipment = Low	Lightning = Low
Seafield 22/11	Seismic = Low	N/A	Lightning = Low
Seafield 66/11	Seismic = Low	Equipment = Moderate	Lightning = Low
Tinwald 66/22-11	Seismic = Low	N/A	Lightning = Low
Wakanui 66/22	Seismic = Low	Equipment = Low	Lightning = Low

"Equipment" refers to the risks involved in equipment failure.

2.5.2 External Risks

Seismic events, flooding, snowfalls, high wind and wildlife are the key natural risks faced by the road-side electricity network. A consequence of typically being by the roadside means that vehicles, vandalism and fire are the significant man-made risks to the electricity network.

Different items of plant will respond in different ways to the same risk. A flood is unlikely to cause major problems for a pole-mounted transformer, but a kiosk-mounted unit will undoubtedly have a higher risk of failure during a flood.

The following table identifies the risks facing different parts of the network and the consequences of being exposed to that risk.

Summary of highest risk type and severity for major asset categories			
Category	Highest Risk	Consequences	Treatment
UG 66kV & 33kV	Seismic	High	Emergency Spares
UG 11kV Cable	Seismic	Medium	Emergency Spares
UG LV Cable	Seismic	Low	Accept & Design
OH 66kV Line	Wind/Snow	Medium	Emergency Spares & Design
OH 33kV Line	Wind/Snow	Medium	Emergency Spares & Contingency Plan
OH 22kV Line	Wind/Snow	Medium	Normal Spares & Design
OH 11kV Line	Wind/Snow	Medium	Normal Spares & Design
OH LV Line	Snow	Low	Normal Spares & Design
Circuit-Breakers	Seismic	Medium	Emergency Spares
Ring Main Units	Seismic/Flood	Low	Normal Spares & Contingency Plan
Disconnectors	Seismic	Low	Normal Spares & Contingency Plan
HV Fuses	Lightning/Seismic	Low	Normal Spares
Pole Mount Transformer	Wind/Snow Lightning/Seismic	Medium	Normal Spares & Revise Design
Kiosk Transformer	Seismic/Flood	Medium	Normal Spares & Revise Design
LV Boxes	Vehicle/Flood	Low	Accept

Design = Ensure Adequate Design

Accept = Accept the risk and repair any damage in a routine fashion

Emergency Spares = Spares set aside for emergency use only

Ashburton District Council's Civil Defence Emergency Management defines a major earthquake as one which closes road access into the Ashburton District for up to 72 hours and severely disrupts Lifeline Utilities within the district. This equates to a 1 in 300-year event[1].

External consultants reviewed the seismic risk to our network five years ago. Since then, their recommendations have been adopted - in particular, improved seismic restraint for ground-mounted equipment.

Recent flood protection works to Ashburton's major stop banks (to prevent a 1 in 100-year inundation event) have reduced the risk of major flooding to Ashburton township during the design life of our network assets to a very low percentage[2].

2.6 Risk Mitigation Proposals

2.6.1 Procedural Responses

EA Networks can control some aspects of risk. Gathering information about potential risks and proactively planning responses to it can alleviate the likelihood of an event occurring in some cases or, alternatively, lower

[1] Ashburton District Earthquake Initial Response Plan

[2] Environment Canterbury - Ashburton River (Hakatere) Flood Hazard Management Strategy.

the consequences to EA Networks if the event does occur.

The following procedures will be adopted to assist in managing risk:

- Minimise critical equipment failure risks by early identification of issues and subsequent prudent management and maintenance to ensure equipment availability.
- Liaise closely with regulatory agencies and neighbouring electricity companies to compare preparedness and co-operate with technical information
- Ensure design standards are compatible with a risk profile deemed acceptable by the community
- Safety aspects of risk have been addressed in section 2.2 and section 3.7.
- Risk to the environment has been addressed in section 2.3 and section 3.8.
- Development of a range of emergency response plans has been addressed in section 2.8. The majority of these plans have been reviewed in the last 12 months.

2.6.2 Engineering Responses

A certain amount of physical work can be undertaken that helps mitigate the risk faced by EA Networks if that is an element of the chosen treatment for those risks. The following items are engineering responses to distributed risks that are significantly mitigated by this treatment.

- Emergency stocks: Specific items have been reserved in the stores system for use in emergencies. These items are typically items that are long delivery or potentially difficult to transport in the aftermath of a natural disaster
- Emergency spare distribution transformer: A universal emergency distribution transformer has been established. It is 1,000kVA and can be connected to 22kV or 11kV, overhead line or underground cable. This is useful for covering critical individual transformers for failure (hospital, water supply, etc).
- Distribution transformer restraint: Revision of the mounting arrangements for all distribution transformer mechanical restraint has ensured lower risks for people as well as lower risk of interruption during an earthquake.
- All new transformers larger than 100kVA are now ground mounted on seismically secure precast foundations. A standard holding down arrangement has been established that offers high seismic security.
- Staff awareness: Education of staff has heightened awareness of risk and solutions are now becoming part of the way of working.
- Network renewal: By renewing the network (for other reasons) a lot of the riskiest network components are being removed or replaced.
- Containerised autotransformers: The portable 5 MVA autotransformers that are required at the junction of 11kV and 22kV distribution are housed in lined shipping containers to ensure no oil spill risk.

2.6.3 Specific Solutions

Some of the risks that scored the highest in the risk register have been specifically treated by engineering a solution to minimise the likelihood and/or consequences. The following items are the most relevant responses.

- Northtown: The security of Northtown substation has been further enhanced by the addition of the EGN-FTN 66kV circuit in 2019-20. In conjunction with FTN 66/22/11kV substation, this provides two full capacity in-feed 66kV lines.
- Closed Subtransmission Rings: The risk of spur lines failing in adverse weather and then not being accessible for repair has caused the fundamental design requirement of virtually all zone substations to be on a closed subtransmission ring. Those sites that are not on a ring must have alternative HV distribution voltage alternatives available that do not share the same pole line as the subtransmission supply. Sections 5.4.2 and 5.4.3 outline a variety of projects that advance this objective.
- Ripple plant configuration: The possibility of ripple plant failure allowing an uncontrolled system peak has significant risks for EA Networks both - economically and electrically. The configuration of the two

ripple plants has been engineered to allow the GXP to be covered by another plant in the event of a failure. This was relatively inexpensive to achieve and has reused 33kV ripple plants when the 66kV GXP was introduced. The commissioning of a new 220/66kV transformer (T9) has reduced the ability to cover for ripple plant failure. Future projects will ensure the security of load control signalling (see section 5.4.11).

2.7 Health and Safety

Electricity is a familiar and necessary part of everyday life, however failure of our infrastructure or uncontrolled release of electricity can kill or severely injure people and cause significant damage to property.

All participants in the electricity supply industry have an obligation to ensure their workers, contractors and the public are kept safe, and are well informed of potential hazards and how to avoid them.

2.7.1 Health and Safety Management

With many work practices underpinned by relevant legislation, standards and industry best practice health and safety cannot simply be a matter of compliance.

EA Networks equips its workers with the necessary equipment tools, and plant to undertake their work tasks safely.

Worker competency is a fundamental requirement for all work on and associated with the network. EA Networks as a member of the Electricity Networks Association has committed to the common competency framework (CCF). The CCF is intended to provide a nationally transportable competency standard across the New Zealand electricity supply industry. The commitment to increasing both knowledge, skills by education and training of all staff is a core obligation of EA Networks' approach to safety.

An ongoing culture of continuous improvement is practiced by EA Networks considering new technologies and human factors.

2.7.2 Public Safety Management

The Electricity (Safety) Regulations 2010 require electricity network companies to implement and maintain a Safety Management System for public safety. EA Networks is fully committed to this requirement by achieving compliance with annual external audits conducted by TELARC to verify compliance with NZS 7901.

The EA Networks Public Safety Management System (PSMS) covers all aspects of asset management including:

- management of risk, hazards and change,
- equipment specification,
- procurement,
- network design,
- network construction,
- network operation,
- public awareness including:
  a) regular radio and newspaper advertising of electrical hazards.
  b) safety presentations to emergency services personnel and other targeted audiences.
  c) extensive warning labelling of EA Networks equipment.

EA Networks provide a free condition assessment to owners of HV service lines connected to the network, highlighting any problems to them in writing. If these recommendations are ignored a copy of the letter is then forwarded to the Energy Safety Service.

Regular investigations and review of all public incidents are undertaken including, but not limited to the following incident types.

- Vehicles hitting poles or ground-mounted equipment.
- Mobile plant, irrigators or equipment contacting overhead conductors.
- Excavation damage to underground cables.
- Operation of network assets causing damage to private property.

Where network assets have materially contributed to a public incident, consideration is undertaken to either reconfigure, relocate, or remove the asset.

As a means of further improving supply security, reliability, and public safety, EA Networks has adopted the following policies and initiatives.

- Policy: New Connection and Extensions; As from February 2009 all new installation connections to the EA Networks distribution network have been by underground cable.
- An industry-leading undergrounding initiative across the EA Networks distribution network has led to improvements not only in reliability but also in public safety.

This ongoing programme of removal of overhead lines and power poles has led to improvements in public safety by decreasing the likelihood of contact with overhead assets (less mobile plant and equipment contact with overhead conductors, or vehicles hitting poles) as well as decreasing the likelihood of outages from weather, vegetation, or wildlife impacting overhead conductors.

EA Networks regularly collaborate and cooperate with other stake holders to work together to improve safety. Examples of this are:

- Partnering with NZ Transport Agency to remove overhead lines and poles from State Highways 1 and 77.
- Canterbury based Electrical Networks undertaking joint public safety messaging campaigns via multiple channels including print, radio and online. The focus is to increase the effectiveness of all joint public safety campaigns through the provision of consistent messages, irrelevant of consumer location.

2.8 Resilience and Emergency Response

It is recognised that the local economy depends on a secure and reliable supply of electricity, and that a catastrophic event such as an earthquake, landslide, tsunami, flood, wind and snowstorms, and terminal failure of key assets can have a significant impact on both the network and the local economy.

Resilience is the ability to withstand, respond to, and recover from significant emergency events.

EA Networks have developed emergency response plans for dealing with widespread abnormal situations created by either asset failure or catastrophic natural events. All emergency response plans are regularly reviewed to ensure that unique risks arising from emergency response have been identified.

Mutual Assistance Agreements have been signed with peer electricity distribution networks. These agreements were successfully implemented when aiding Orion during the Canterbury earthquakes in September 2010 and February 2011, and to Westpower in the aftermath of 2018’s cyclones Gita and Fehi.

2.8.1 Business Continuity Planning

The EA Networks building at J B Cullen Drive is constructed to Importance Level 4 standards.

The site is well provisioned with standby generation, water tanks, and our own radio communications pathways to support critical infrastructure.

Regular electronic backups of mission critical records for retailer billing and consumer identification are carried out. The backup copies are securely stored offsite by EA Networks’ web host.

All ICT servers are virtually hosted across the Ashburton substation data centre.

SCADA is also duplicated at Ashburton substation data centre.

A 20,000 litre bulk diesel fuel tank and pump in the J B Cullen Drive yard decreases reliance on external fuel sites. 200 litres of petrol are held for portable plant and generators.

Non-perishable food and water has been provisioned for essential staff.

For further details refer to:

- Emergency Preparedness Standards (last reviewed January 2020)
- Pandemic Planning Standard (last reviewed November 2019)
- Critical Infrastructure - Ancillary Services Standard (last reviewed December 2019)

2.8.2 Emergency Contingency Planning

Emergency contingency planning covers any emergency event situation that is the result of any:

- earthquake, eruption, tsunami, landslide, flood, storm, tornado, cyclone,
- explosion, fire, leakage or spillage of any hazardous gas or substance,
- infestation, plague, epidemic, or
- technological failure, complete failure or major disruption to an emergency service or lifeline utility

which cannot be dealt with by emergency services as business as usual, or otherwise requires a significant and coordinated response.

For further details refer to:

- Health & Safety Manual Section 7: Emergency Management
- Emergency Preparedness Standards (last reviewed January 2020)
- Building Evacuation (last reviewed November 2019)
- Pandemic Plan (last reviewed October 2019)

2.8.3 Specific Network Contingency Plans

Specific contingency plans for the restoration of supply to essential services and individual major industrial and commercial consumers exist to complement and supplement the Participant Rolling Outage Plan. The majority of EA Networks' contingency plans have been reviewed in the last 12 months.

These include, but are not limited to the following:

- Network isolation and reconnection of embedded Hydro-stations (Highbank, Montalto, and Cleardale).
- Alternate network supply pathways after complete failure of a Zone Substation.
- Identification of critical third-party infrastructure, and alternate supply pathways.

2.8.4 Participant Rolling Outage Plans

The Electricity Industry Participation Code 2010 Part 9 requires all specified Electrical Distribution Businesses to prepare and publish a Participant Rolling Outage Plan (PROP) for audit and approval by Transpower's System Operator.

The PROP is required to conform with the requirements set out in the System Operator Rolling Outage Plan (latest version 19 June 2016), and details how electricity distributors will assist the System Operator in managing either a total outage or rolling outages of up to 25% of normal load if there is a national or regional electricity shortage.

EA Network's most current PROP was approved by the System Operator on 17 October 2019. A copy of the current Plan can be found on the EA Networks website: https://www.eanetworks.co.nz/Participant-Rolling-Outage-Plan-October-2019.pdf .

2.8.5 Civil Defence Emergency Management

EA Networks are a member of the Canterbury Lifelines Utilities Group which promotes resilience to risks and develops contingency measures for Civil Defence Emergencies arising from disasters.

As a lifeline utility, EA Networks participates in the development of both regional and local Civil Defence Emergency Management plans, and provide technical advice to local authorities and other lifeline utilities as requested

In the event of a Civil Defence Emergency, nominated staff members are sent to liaise with the local district council's Civil Defence Emergency Operations Centre.

Delegated senior management staff have also attended recent workshops where the South Island regional preparedness for a magnitude 8 Alpine Fault earthquake was discussed.

Designated staff will be trained in Coordinated Incident Management System (CIMS) protocols to improve our interaction with Civil Defence Emergency Management.

2.8.6 Post Critical Event Reviews

A post-critical review is carried out after every major emergency event – however, the event may not necessarily impact directly on EA Networks (e.g. the Canterbury earthquakes).

The post-critical review process acts as an effective tool to identify areas of improvement, and lessons learnt from the post-critical review are incorporated into EA Networks' operations.

The most recent review was undertaken after the Rangitata River flooding and lightning storm event 6th-8th December 2019.

OUR CUSTOMERS

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3.1 Introduction

EA Networks is required by statute to take all reasonable precautions to secure continuity of service. A certain level of outages is inevitable, and they occur in all utilities. As a predominantly rural electricity supplier with several townships, it is not always reasonable to compare EA Networks directly with a predominantly urban supplier. It is EA Networks' goal to ensure that it continues to perform above the industry average for comparable line companies and it is targeting an on-going quality improvement with a consistent price path.

Service is about satisfying all stakeholders, and this includes safety aspects and environmental responsibilities as well.

This section outlines stakeholder expectations, current, past and desired network performance, and goes on to detail service improvement solutions that are either proposed or have already been implemented.

3.2 Consumer Research and Expectations

To set reasonable security standard targets that are compatible with end user expectations, appropriate research must be carried out.

The needs of electricity users have changed greatly over the last decade or so with the rapid introduction of technology into the domestic market. Appliances from DVD players and personal computers to security and fire alarm systems are now commonplace in most homes and have greatly increased the sensitivity of householders to power outages and minor interruptions.

The degree to which modern society has come to be reliant on a secure supply of electricity was clearly demonstrated during outages in the Auckland area in recent years. While EA Networks' area cannot boast a similar level or density of critical business users, this perception is merely a matter of degree. The small gift shop owner in Ashburton, running on small margins and high overheads, is just as reliant on electricity to power cash registers and EFTPOS terminals as the largest multinational company is for power to its multi-storey tower office block. There is of course an argument that they both should have some degree of backup for critical systems (a UPS for the cash register, EFTPOS terminal and phone system would be sensible in the case of the small retailer).

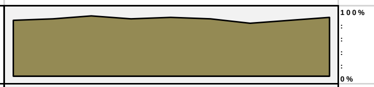
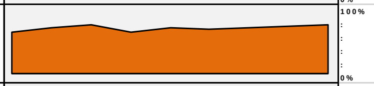
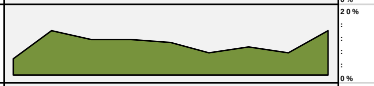
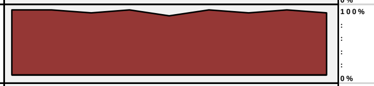
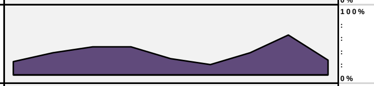
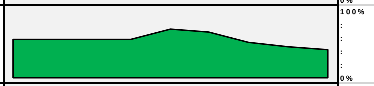
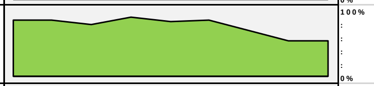
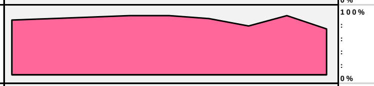
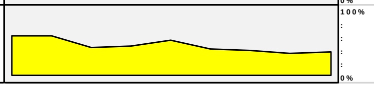
EA Networks' 2019 Statement of Corporate Intent Objective (see section 1.7) details the governance philosophy of the business. This approach has been crafted by embracing the feedback received from the community of consumers that the company serves.

Words used in the Statement of Corporate Intent such as "efficient" and "reliable" are relative terms that are subject to personal perceptions. In turn, these perceptions must be viewed from the consumer's perspective, which must be actively sought.

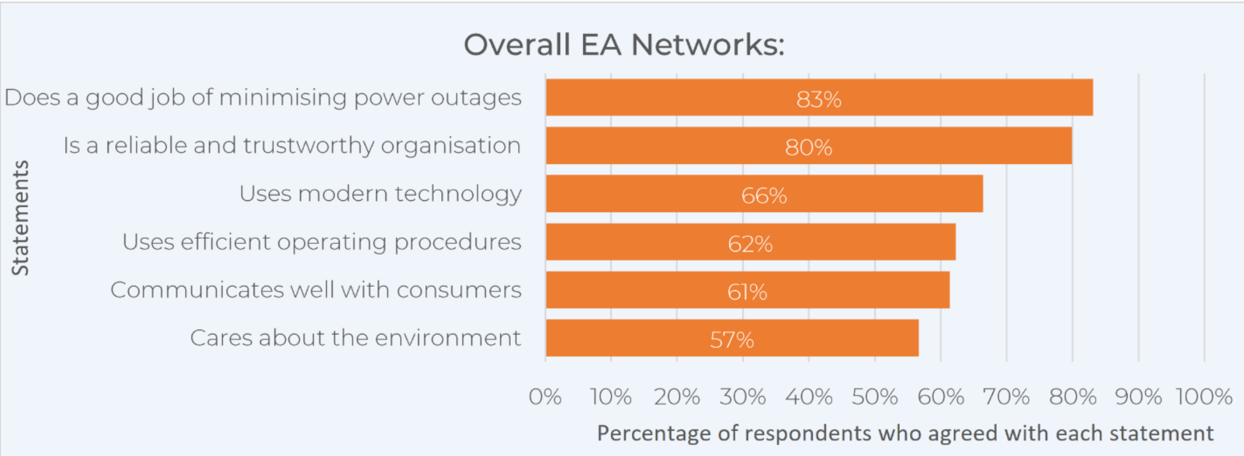
A consumer engagement telephone survey had been undertaken annually from 2006-2013. A one-year gap then occurred with no survey until 2015. The most recent survey was in December 2019. Since 2017, the survey has been significantly different than prior surveys. It was undertaken by a different company using a different set of questions and different analysis technique. The historical survey results are shown below for reference.

The results of the final historical 2015 survey had a margin of error of ± 4.9% at the 95% confidence level. The 400 randomly selected consumers were split 70% urban, 30% rural.

Other opinions were also sought relating to EA Networks' role in the community, on-property asset ownership and satisfaction in dealings with EA Networks. It is relevant that between the first two surveys a major snowstorm had caused lengthy and widespread power outages that had affected virtually every EA Networks consumer. Somewhat surprisingly, the survey results showed little change in the opinion of the participants towards outages and restoration times.

Question	2006	2007	2008	2009	2010	2011	2012	2013	2015	
Acceptance of three planned outages per year.	88	90	95	89	93	90	83	88	93	
Acceptance regarding planned outages lasting on average five hours each.	65	73	76	66	72	71	72	75	77	
Advice received during the previous six months about a planned electricity outage.	5	14	11	11	10	7	9	7	14	
Satisfaction with amount of information and period of notice.	100	100	95	98	90	100	94	100	94	
Customers experiencing an unexpected interruption to their electricity supply during the previous six months.	21	36	44	43	25	18	35	63	23	
Time taken to restore electricity supply. < 2hrs	56	56	56	55	69	65	50	44	41	
<4 hrs	84	84	77	87	82	83	68	54	54	
Electricity supply restored within an acceptable timeframe.	83	85	88	89	91	86	75	89	71	
Accept slightly increased charge in order to ensure timely restoration of electricity supply following an unexpected outage	1	6	9	4	8	6	5	6	3	
Acceptance of 0-3 hours overall timeframe for supply restoration following an unexpected interruption	60	60	42	44	53	40	38	33	36	

The most recent (2019) survey provided a worthwhile response to the different questions posed, with overall satisfaction being very high.



The following extract of the executive summary provides some relevant information:

- *Eighty six percent of customers were satisfied with the overall service provided by EA Networks (provision and reliability of services, quality of communication and reputation).*
- *The overall assessments of performance were high, and respondents' comments didn't clearly identify any areas that need significant attention.*
- *Reliability and trustworthiness: EA Networks' brand is perceived highly by consumers. Every effort should be taken to maintain this strong performance through good practices, communication and follow through of actions.*
- *Environment protection: given that environmentalism is a growing concern, consider including EA Networks environmental protection measures. Survey responses indicated that providing more*

information to consumers about EA Networks' environmental protection efforts could be beneficial.

- *Local ownership is important to EA Networks' customers, with 92% of respondents sharing this sentiment.*
- *When asked how many outages are reasonable to expect per year, 64% of respondents felt that 1-2 outages would be reasonable.*
- *A pre- registered text message was the preferred method (69%) for receiving information about power outages.*
- *Respondents tended to view 30% lines charges as being more fair than their overall electricity bill.*
- *Overall, a strong majority (73%) of respondents supported keeping lines charge prices the same, with the same likelihood of power outages. This result is further support for pricing being fair; along with a balance being struck between price and service provision.*
- *Overall, less than 10% of respondents across all groups thought that power was not restored within a reasonable timeframe. Rural respondents were most likely to think that power was not restored within a reasonable timeframe (9%), and urban respondents least likely (2%).*

One of the comparable questions was whether people were prepared to pay more for increased reliability and only 4% indicated they were willing, which compares with 10% in 2017 (it should be noted that this response has varied considerably through the years, but never exceeded 10%).

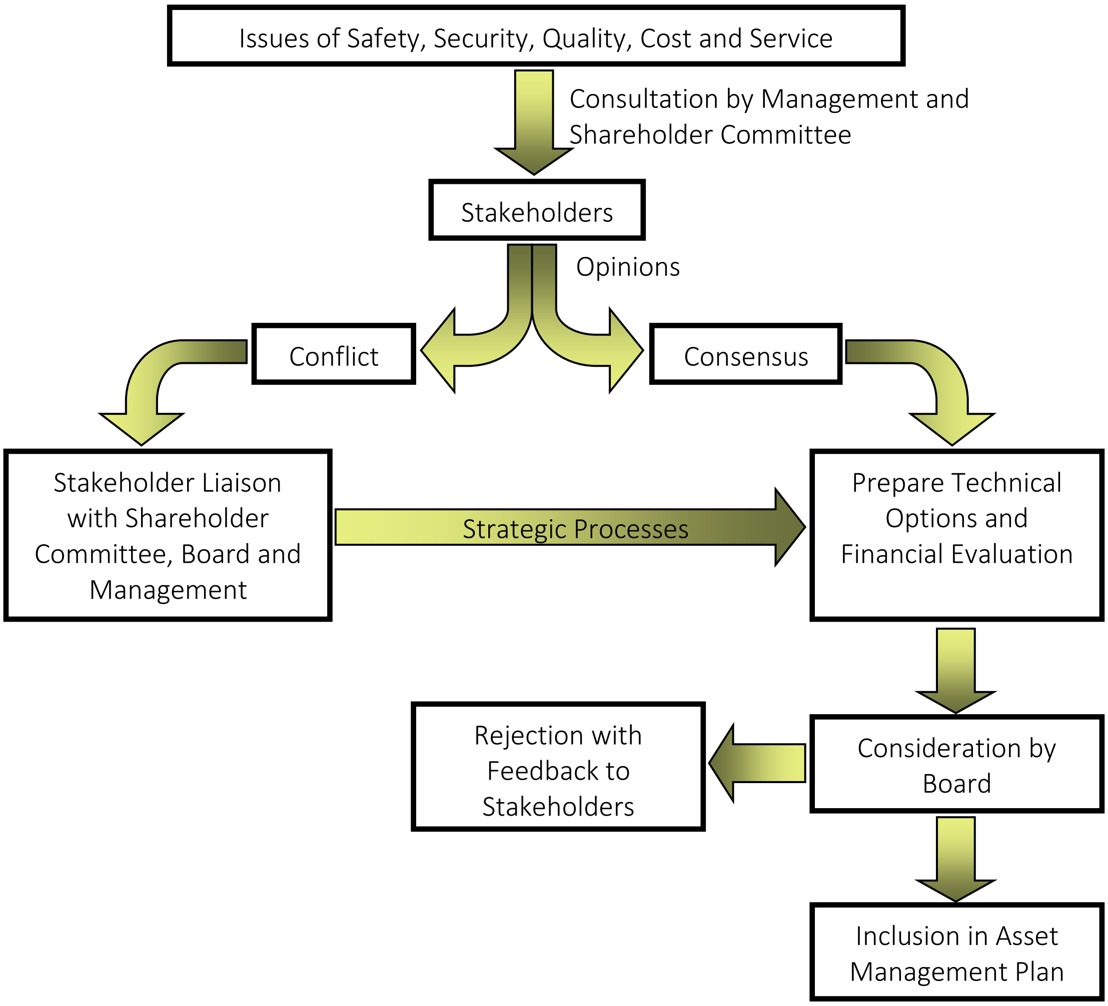
Managing Conflicting Stakeholder Interests

As a co-operative company, the vast majority of consumers are in fact shareholders (more than 99%) and they directly elect a Shareholders' Committee who in turn appoint the directors. When shareholder viewpoints are required, the Shareholders' Committee provides the effective voice for consumers/shareholders. Regular consultation occurs between the Board and the Shareholders' Committee where any issues that concern either party are discussed. Examples of the type of discussion that occur are:

- the cost implications of various network performance improvements (price/quality trade-off)
- the conflict of the differing scale of urban versus rural reliability/cost/capacity/aesthetic impact
- the balancing of asset management practices with potentially conflicting shareholder interests
- the path of proposed network development and the consumer price implications
- major projects that are proposed and the impact they will have on EA Networks and consumers
- the Statement of Corporate Intent and the associated Trend Statement which documents targeted financial and reliability performance indices into the future (the Shareholders' Committee receive/scrutinise the Statement of Corporate Intent)

The Shareholders' Committee provide a commentary on the performance of EA Networks for inclusion in the EA Networks Annual Report each year. In short, it continues to endorse the general direction of the company's performance. The company have taken this endorsement as concluding an appropriate method of reconciling stakeholder/shareholder interests and asset management practices.

Perhaps the most potential for tension tends to exist between company owners and customers. The co-operative by its nature self-manages this to an extent, given that EA Networks' owners are also EA Networks'



customers (generally). As such, if one group is favoured over the other, ultimately the same person benefits. The balance is between consumer service levels and shareholder financial return. Between the Shareholders Committee and the Board of Directors, the interests of these two groups are considered and managed appropriately.

When an obvious conflict between significant stakeholders' interests arises, the technical and strategic elements are separated. The technical options are conceptualised, and approximate costs prepared along with the pros and cons for each option. These are presented to the Board for consideration alongside the strategic ramifications of the technical options that exist to address the conflict. Once in the realm of socio-strategic evaluation, the process of reconciling the technical and social aspects is left to the Board and Shareholder Committee to reach a consensus. The decision is then passed back to management for implementation.

In conjunction with the abovementioned forms of consultation, EA Networks management liaises with the Energy Retailers to determine the expectations of their customers and quantify these in terms of desirable reliability indices as well as other relevant system or process improvements.

The EA Networks control centre accepts calls from consumers (but does not actively encourage them) and this inadvertently forms another useful avenue for consumer research. Although the consumer is generally contacting EA Networks to report a power outage, the consumer's attitude is almost always courteous and understanding. There are relatively few instances of angry callers and where appropriate the caller's concerns are documented and passed on to the relevant staff member. Field staff also pass on any constructive comments from consumers to the relevant staff members.

When requested, large users of electricity are contacted to ascertain their satisfaction with current service levels. The Commercial Division of EA Networks undertake this consultation. When service issues are raised, a range of alternative solutions are prepared to encourage the consumer to consider the service/cost trade-off. Typically, this has resulted in relatively minor changes to the status quo.

3.3 Strategic and Corporate Goals

EA Networks is committed to an open and neutral policy of operation. Its prime responsibilities are to manage the distribution system reliably, efficiently, economically, and to meet its users' needs in providing quality electricity supply services. EA Networks operates to meet those needs effectively and efficiently, recognising its position as Mid-Canterbury's dominant provider of electricity distribution services. Minimisation of operational costs is sought through the introduction of distribution automation as appropriate and the strict management of all projects to set standards of safety, performance, budget and timing.

The present condition (and by implication reliability) of any distribution line is largely a factor of its age and the environmental aggression of the locations it traverses. Historically, maintenance has been reactive rather than proactive.

One aim of the Asset Management Plan is to normalise the age profile of the system as much as possible by maintaining the average age of the network at approximately half of the weighted service life of the assets. At the same time, the condition of all lines will be carefully monitored to make sure that the integrity and reliability of the network is not unduly compromised.

Network performance indices, such as measured by SAIFI and SAIDI (among other performance indices), are key parameters in determining whether sufficient maintenance expenditure is being provided to sustain a satisfactory level of network reliability.

The underground conversion programme is primarily driven by the condition of urban overhead lines and the need to either convert them to underground cable or rebuild them overhead. It must be noted however that additional considerations were involved in the Board decision to allocate these funds. One of the significant influences was (and still is) the desire to provide fairness in the degree of investment provided in rural versus urban areas. The many millions of dollars spent in developing the rural network to accommodate irrigation demand are being counterbalanced by the allocation of additional discretionary funds for urban development for additional reliability, capacity, security and environmental appeal. The outcome of this strategy continues to be satisfied consumers/stakeholders in both the rural and urban areas.

3.4 Network Service Levels

The overall level of system reliability can be measured in many ways that are combinations of the number of interruptions, the length of interruptions, the frequency of interruptions, the number of consumers affected by the interruptions, the total number of consumers, and the total length of lines. These parameters are used to disclose a range of performance measures which are used for comparison with other, similar, companies.

The following published parameters are used to measure EA Networks' performance in comparison to other Power Companies (see Appendix A for explicit definitions):

Consumer Service Levels:

System Average Interruption Duration Index

$$\text{SAIDI} = \frac{\text{Sum of (number of interrupted consumers x interruption duration)}}{\text{Total number of connected consumers}}$$

System Average Interruption Frequency Index

$$\text{SAIFI} = \frac{\text{Sum of (number of interrupted consumers)}}{\text{Total number of connected consumers}}$$

Customer Average Interruption Duration Index

CAIDI	=	Sum of (number of interrupted consumers x interruption duration) / Sum of (number of interrupted consumers)
Total Interruptions	=	Sum of (number of interruptions)

The above indices reflect a measure of continuity of supply and supply restoration time to individual consumers. While SAIDI largely depends on restoration time, SAIFI is a measure of outages - which depend on the planning, design and condition of assets. While it is possible to control these indices to an extent, it is not always feasible or practical to do so. As examples, extreme weather conditions and vehicle vs. pole collisions can significantly influence these parameters.

Asset/Financial Performance Levels:

Faults per 100km	=	100 x Sum of faults at a particular voltage and line type / Sum of (length of particular voltage and line type) in km
Fault Restoration	=	Maximum time taken to restore power to the EA Networks network after an unplanned interruption.

Electricity (Information Disclosure) Regulations are designed to ensure that Network Line Companies provide an appropriate level of reliability and security of supply to their consumers.

3.4.1 Target Level of Service

While ultimately it is consumers' requirements and financial commitments that drive work, possibly altering system reliability, the Asset Management Plan is based upon meeting or exceeding a set of predetermined targets.

It should be noted that the statistics used to measure performance against these targets could vary significantly from year to year due to the random occurrence of a single major outage, seriously weighting the overall statistic. Further analysis by EA Networks will seek to identify trends in underlying system reliability so that appropriate management responses can be taken.

2020-21 Reliability Forecast : Target

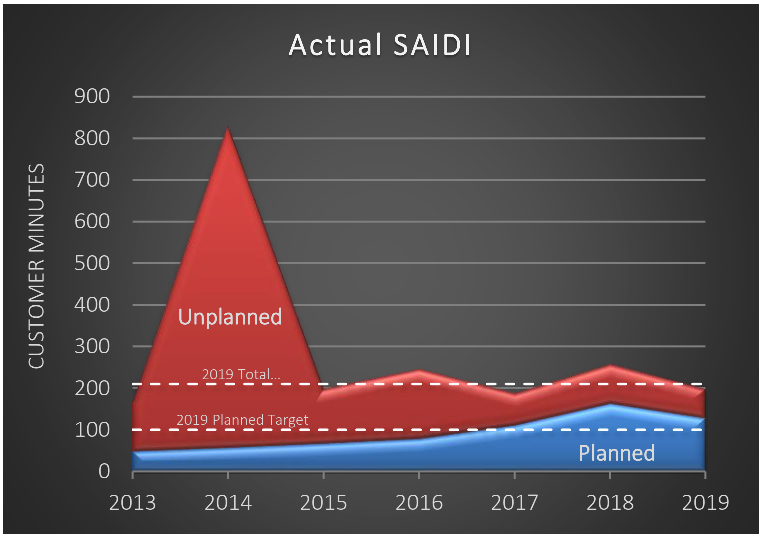
Index	Unplanned	Planned	Total
SAIDI (min)	120	110	230
SAIFI (p.a.)	1.25	0.40	1.65
CAIDI (min)	96.0	275	139
Faults/100km			5

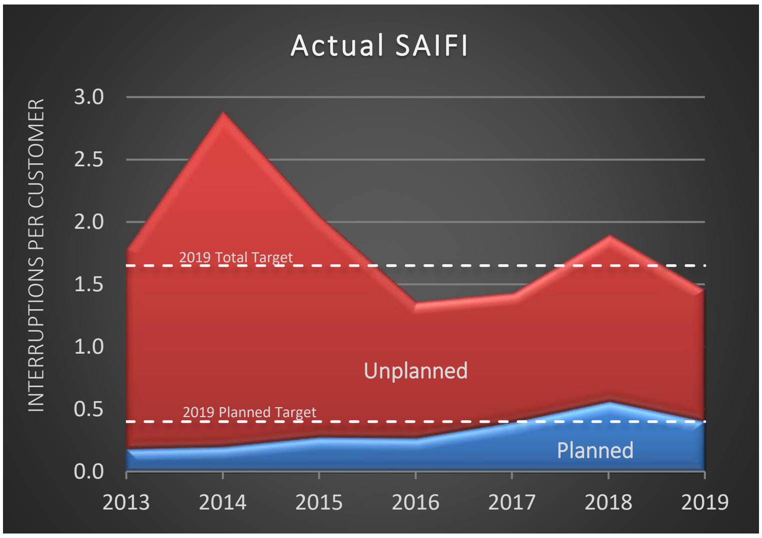
Note: These non-normalised targets were set in January 2020.

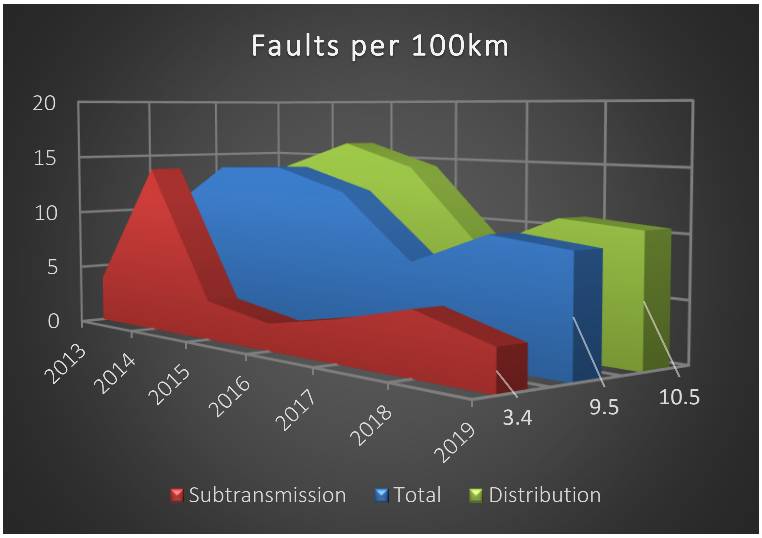
The targets are set by:

- examining the historical performance of EA Networks,
- aligning planned outage performance with the level of work planned on the overhead network,
- evaluating historical performance when compared with all lines companies and separately with similar lines companies then defining a position close to the desired performance relative to the other companies,
- taking account of consumer feedback from surveys and shareholder/consumer representatives,

- ensuring the target dictated by industry comparisons is both desirable and ultimately achievable.
- recognising the improvements made to the network infrastructure and the positive impact that will have on system performance







EA Networks justify setting targets in this manner because it not only ensures that consumer/shareholder preferences are accommodated but any movement in performance by the whole industry will cause a shift in emphasis for EA Networks. Performing above or below the normal bounds of the group of peer companies highlights areas where, as a minimum, an explanation is required and, in the worst case, significant alteration to asset management or operational methodology is necessary.

History has shown that the performance targets quantified are ambitious, but they are shown as a downward trend during the planning period to reflect the network improvements being made. Once the targets are being consistently achieved, they will be reviewed to ensure they continue to match stakeholder expectations. This review may result in changed targets which will be published in applicable documents. This review is likely to establish a more rigorous methodology to quantitatively set and review future targets.

While significant amounts of capital are being spent on development, it does not necessarily follow that dramatically higher levels of reliability will occur. In fact, at times through the 11kV to 22kV conversion process, security is temporarily lowered as previous tie points must remain as an open point because of the voltage difference. In the long term, security will increase for most consumers and EA Networks are confident this will have a positive effect on reliability (all new assets are designed to meet security standards while a range of existing ones do not meet them). There has however been no effort made to mathematically quantify the likely increase in reliability in this plan. Future plans may attempt to provide analysis of this data thereby influencing targets.

The unplanned SAIDI & SAIFI targets have been based on the average of the years ending 2010 to 2019 excluding 2014 which had a windstorm. The planned SAIDI and SAIFI have been calculated using long-term averages with a variable component based upon the amount of overhead line work planned in that year. These values form the two components of the overall SAIDI and SAIFI targets. This approach ensures that achievable targets are set while still challenging the asset manager to make the best planned and unplanned historical performances coincide as often as possible. A return to live line work that was suspended during 2016 and 2017 has permitted a lowering of the planned outage frequency and system duration (SAIDI) closer to levels seen in 2011-15.

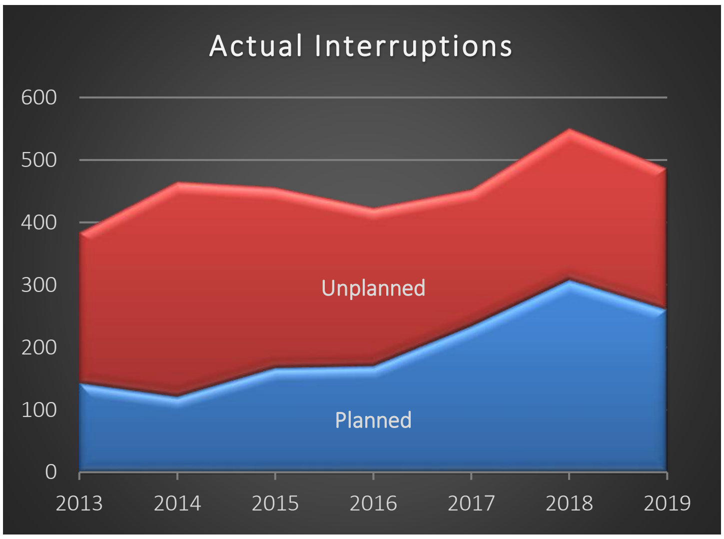
The targets are reviewed annually by management, the Board, and the Shareholders' Committee to ensure that they are relevant and reflect consumer feedback accurately. These targets assume "severe weather events" (admittedly undefined) are excluded from the averages.

The Hexagon Geographic Information System (G/Technology) that EA Networks use, can "trace" the network to determine which connections are without power for any open/close combination of switches and fuses. The OSI advanced distribution management system can also do this. The results of these analyses are fed into the Faults system that records each outage against individual connections. This system can then be interrogated to establish performance over any time scale at each connection.

EA Networks have additional detailed targets. The following tables provide some of these.

Faults per 100km: Target					
Year	66kV Lines	33kV Lines	22kV Lines	11kV Lines	All Lines
2020-21	2	3	6	6	5
2022 – 2025	2	3	6	6	5
2026 – 2030	< 2	< 3	< 6	< 6	< 5

Number of Interruptions: Target			
Year	Unplanned	Planned	Total
2020-21	150	300	450
2022 – 2025	150	300	450
2026 – 2030	< 150	< 300	< 450



The number of interruptions is an absolute value that varies with both unplanned (fault) activity as well as planned (construction or maintenance) activity. The marked increase in planned outage numbers in 2017 and 2018 was caused by a suspension in live line working which caused also impacted the 2018-19 year. EA Networks has now returned to live-line working for specific high-impact work which would otherwise have significant impacts on the targets. The criteria for live line use is now more stringent and this will mean higher ongoing level of planned outages than seen historically.

The number of interruptions is probably the simplest measure of reliability available, as zero interruptions means SAIDI and SAIFI would also be zero.

Network Performance Target Comparisons

The performance achieved by the EA Networks network is acceptable within its peer network line companies. Although EA Networks can improve its performance, the medium-term target for the critical indices is to be better than the median performance of all New Zealand power companies and in the top third amongst its predominantly rural peers (measured by percentage of urban network and percentage of underground cable).

The following table compares EA Networks' 2019 performance targets with the industry performance as a whole and then peer companies. The "Industry Average" is the average value for all disclosing distribution lines companies. The "rural average" is the average value for those companies that have:

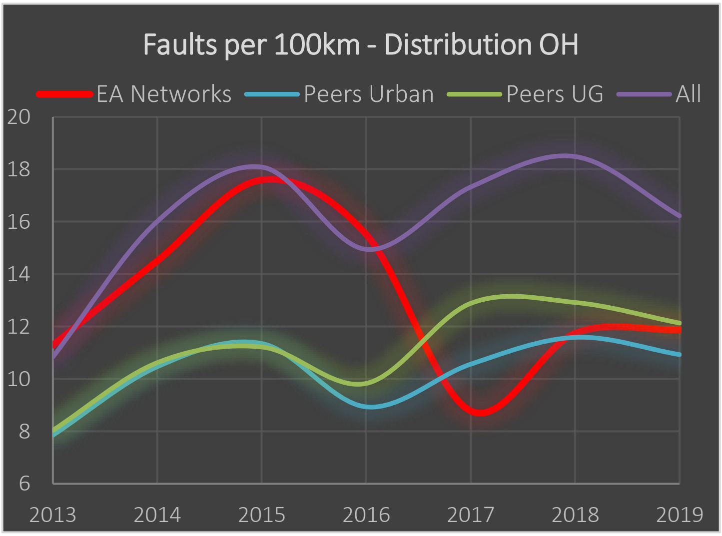
a) between 17% and 30% of "Total Circuit Length for Supply" is underground. EA Networks have 22.6% underground supply network.

b) between 1% and 12% of their overhead network in urban areas. EA Networks have 3.8% of their overhead network in urban areas.

Comparison of Target Performance Indices: 2018 & 2019

		EA Networks 2021 Target	2013-19 Industry Average	% of Average	2013-19 Rural Peers Average	% of Average
SAIDI	Total (mins)	230 120 Planned 110 Unplanned	296	**78%**	338	**68%**
SAIFI	Total (interruptions)	1.65 0.4 Planned 1.25 Unplanned	2.49	**66%**	2.87	**57%**
Faults/100km	Total	5.0	16.05*	**31%**	-	-

* This value is calculated by summating all faults from 2013-2019 (152,961) multiplying by 100 and dividing by 7 years then dividing by the average sum of all "Total Circuit Length (non-LV)" from 2013-19 (136,133 km).

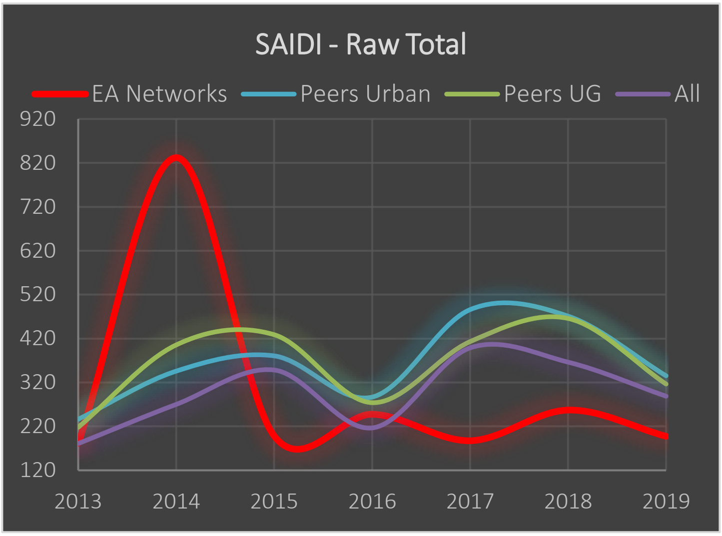


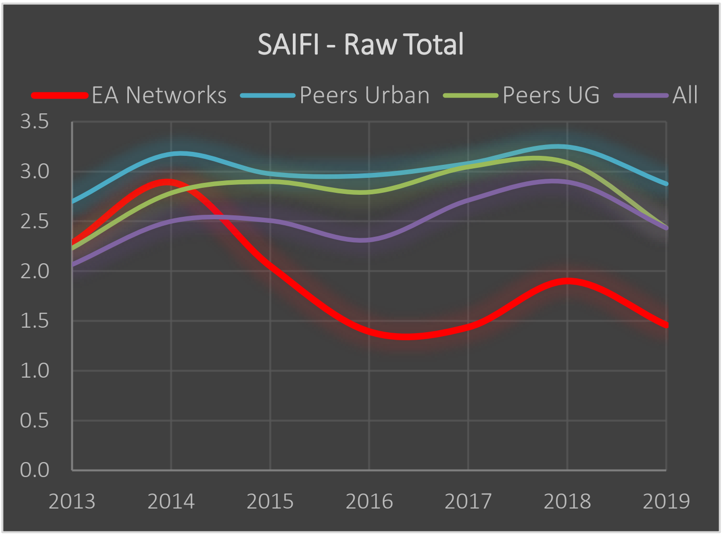
The predominantly rural group of 18 peer companies supply 37% of the total consumers in New Zealand using 57% of the total lines in New Zealand that have 41% of the total distribution network value. The percentage of average is an indication of EA Networks target level (lower is better ~ better than average is less than 100%).

Comparing EA Networks 2019 targets with the actual industry performance (disclosed in March 2019) it is apparent EA Networks' reliability targets are appreciably better than the average performance of both peers and all other companies. If the targets can be achieved regularly it will reflect in a newly revised target the following year. This will probably reflect in a lowering of the average score percentage when compared to the industry average. This will provide useful feedback to the stakeholders allowing them to consider how much reliability is sufficient or even what the added cost of reliability well above the industry norm may be and whether they wish to pay that cost in the future.

There continues to be reasonable amounts of planned development and maintenance work. Planned SAIDI and SAIFI is one of the few outage reasons that EA Networks has direct control over. If stakeholders indicate that the duration or frequency of planned outages are above tolerable levels, then EA Networks could use less efficient but lower outage duration approaches to doing planned work. These approaches could include:

- employing additional contractors or staff to get much more done during any given outage or shortening the outage,
- using live line working techniques to do some work that is currently done de-energised,





- more widespread use of generators to supply load that would otherwise be interrupted,
- building new lines on routes not occupied by the existing lines (for example the other side of the road),
- converting more of its rural network to underground.

Although all these approaches are possible, there must be demonstrable advantages to employing them. Several of the approaches have been used - not always for lower outage duration during construction, but that has become a side benefit.

It must be remembered that the industry-wide "All" average values above, include all of the urban network data which are not considered to be typical of EA Networks' peer companies. Another aspect of the EA Networks network is that one Transpower substation serves the entire EA Networks area. This is uncommon for the size of network load EA Networks carry. One of the consequences is that EA Networks takes the 'risk of fault' on the additional length of subtransmission lines and the energy losses that are borne by Transpower in most other line company networks.

Historically, EA Networks has undertaken a lot of planned development work and this is reflected in traditionally high planned CAIDI and SAIDI values. This will change as 66kV line development work decreases, although 11kV to 22kV conversion work still has an impact.

EA Networks averaged 11.1 planned interruptions per 100km of lines in 2018-19 compared to an average of 12.1 for the industry (0.92 x the industry average). This is an increase for both EA Networks and the industry generally. Much of this increase will be caused by the suspension of live line working in 2016. The return to live line working should see this reduce significantly in 2019-20. It is anticipated that this planned outage rate will vary in proportion to the level of overhead line development work and line maintenance. Line development is largely dictated by on-going load growth.

Internal reporting and targeting of performance indices are more detailed than those discussed here. EA Networks management report performance against these to the Board each month and they take an active interest in not only the nature of the targets but also how they are influenced by a variety of factors.

There are other financial and technical indices published as part of the disclosure process, but these can be very misleading without a great deal of technical analysis using background information about each company's load types, locations, profiles and seasonality. In future plans, more detailed cross-company comparisons may be attempted if significant asset management benefit is seen by using these indices.

EA Networks is constantly endeavouring to improve its service performance. As part of this effort, EA Networks has started to implement an analytical approach to identify various network trends. Several initiatives have been planned for the upcoming years. For example, a review of the outage management database is underway to align historical and current performances. Feeder performance comparisons will be included as part of a regular reliability analysis.

As part of its on-going commitment to improve system performance, the Company is implementing a distribution management system. This system has the potential to reduce response times significantly. Future plans will detail when and how these new features facilitate these improvements.

Use of System Agreement

EA Networks have a "Use of System Agreement" with energy retailers that outlines a number of connection service standards that EA Networks must meet.

Service guarantees to consumers include:

- Not to accidentally disconnect supply to a consumer.
- To provide written notice 7 business days in advance of planned maintenance interruptions and no more than two in any 12-month period (unless by agreement).
- To advise requirements for new connections within 5 business days and connect on agreed day provided all requirements are met.
- To disconnect or reconnect at an agreed time, or within 8 business hours for urban addresses and 12 business hours for rural addresses from request - subject to safety approvals.
- To provide a written response or estimate for new or additional supplies within 5 working days.

3.4.2 Forecast Level of Service

The targets set in the previous section indicate the level of service that EA Networks would expect to deliver in a year when the impact of external influences is at a minimum and planned work is at a normal level. Meeting our target level of service would be considered a good, although not extraordinary, year.

A normal year will have external influences impact on the level of service EA Networks delivers and it is 50% probable that the target will be exceeded.

Future Performance Target/Forecast : 2021-30

Indicator	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	Default Quality Path Limit
SAIDI Planned (mins)	120	115	115	90	85	80	80	80	80	80	-
SAIFI Planned (#/yr)	0.40	0.35	0.35	0.35	0.30	0.30	0.30	0.30	0.26	0.26	-
SAIDI Unplanned (mins)	110	100	95	90	88	88	88	88	88	88	-
SAIFI Unplanned (#/yr)	1.25	1.25	1.25	1.25	1.25	1.25	1.25	1.25	1.25	1.25	-
SAIDI Total (mins)	230	215	210	180	173	168	168	168	168	168	**151**[1]
SAIFI Total (#/yr)	1.65	1.60	1.60	1.60	1.55	1.55	1.55	1.55	1.51	1.51	**1.61**[1]
Faults/100km	5	5	5	5	5	5	5	5	5	5	-

[1] These are the Commerce Commission DQP (default quality path limits). These limits are "normalised" and remove aberrant fault events and a proportion of the planned outages. The targets are non-normalised and include all planned events.

In order to provide a realistic expectation of future performance, a set of forecast performance indices have been calculated based upon historical fault performance and future network expenditure (see table above).

The unplanned SAIDI and SAIFI reflect the average actual performance over the last four years. The planned SAIDI and SAIFI are simple estimates based upon the most recent actual performance (2015-20), known planned work, and with the return to live-line working factored in.

Over recent years, EA Networks has had a program of installing additional remote controllable switching points within the Network. Considerable effort has been expended to enable the remote-control of these devices. While some devices are installed specifically to improve network segmentation, most are installed as part of other works - most commonly an overhead line requiring rebuilding (either overhead or by underground cable). As a result of this approach, devices tend to be scattered around the network rather than concentrated in specific areas. While each device helps to improve reliability, large improvements are not seen until the population reaches a critical mass or a specific area is completed. EA Networks are anticipating a general improvement in reliability due to the increase in switching points. The population is on the cusp of being extensive enough to see wholesale improvements, particularly with remote-control and indication available.

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It has already been noted that a lot of the 'Quality of Supply' expenditure in this plan will increase security of supply for relatively rare but very consequential events. If none of these events have occurred in recent years or occur in the disclosure year, then the future impact on the level of service of this expenditure may not be particularly measurable/visible. Having said that, it is expected that the increases in security will have considerable advantages to the consumer in service level improvements, but those improvements are difficult to directly quantify.

For many years, EA Networks experienced load growth well above the national average load growth. This has resulted in rapid expansion of the network's load serving capability. In meeting this huge load growth, it has often not been possible to fully complete the finer details of the job. For example, fuses are uprated to gas switches or reclosers and this new equipment has remote-control capabilities. Unfortunately, time and the pressure of other load growth requirements meant that effort could not be devoted to completing the remote-control aspect. As load growth tails off, time and resources are becoming available to complete these projects with high returns in reliability and safety.

Similarly, load growth has bought about the requirement to convert parts of the network from 11kV to 22kV operation. Again, time and resource constraints mean that only the practical minimum is converted to meet the increased load at that time. This has resulted in what was once a fully meshed network having open points introduced as a consequence of the different voltages. With the reduced new connection growth currently being experienced, EA Networks are now in a position where resources can be allocated to go back and rectify the reduced security introduced by the former load growth requirements. As this work is not directly caused by load growth, it is classified as a reliability improvement. In reality, it is only returning security to previous levels.

In a similar vein, EA Networks has a policy of converting urban overhead lines to underground when they fall due for condition-based replacement (the Urban Underground Conversion Programme). This work is classified as Asset Replacement, however, at times it is appropriate to go further than the absolute minimum, e.g. convert a further section of line so the underground area become contiguous or extend it further to remove the risk from a significant tree plantation. These extensions are classified as reliability improvement when often they are Asset Replacements done in advance of the actual need.

There are many types of faults that are almost impossible to prevent without disproportionate cost – particularly in rural areas. Trees falling through overhead lines is one; as the tree regulations do not permit obligatory tree control beyond a set radius of the line. A tall tree can fall from across the road (well outside the trim radius) and cause considerable damage to any overhead line. The only way to avoid this risk is to build outside the road corridor (easements and associated cost and access difficulties) or underground conversion of the line (cost). EA Networks are currently talking to tree owners where an overhead line is within the fall distance of their tree. EA Networks are encouraging these tree owners to consider the ramifications if their tree damages EA Networks' line and encouraging them to take appropriate action.

3.4.3 Significant Recent Events

It is considered worthwhile to document any recent events that have had a significant impact on network performance and asset management strategies. The following events are ones that have caused sufficient impact as to cause (or potential to cause) network performance to exceed targeted values.

December 2019 Lightning Event

In December 2019 a significant lightning event took place that caused many small-scale outages. This had a significant SAIDI impact for the month (22 minutes compared to about 6-10 minutes for an average month). The event was the longest and most intense lighting in living memory and lasted about 12 hours continuously. Large lightning events are rare in Mid-Canterbury and there is a low benefit/cost ratio in attempting to make the network more lightning resistant.

December 2019 Rangitata River Flood

Around the same time as the lightning storm, torrential rain in the headwaters of the Rangitata River caused an extremely flood event. The two 11kV crossings of the river were washed away (having stood for around 40 years) and Transpower also had at least one tower washed away and significant damage to eight others.

Generators were introduced to supply the network beyond the failed 11kV crossings. The total SAIDI "cost" is in the order of 10 minutes. Repair of one of the crossings was achieved within weeks while the second crossing is much more challenging and is, at the time of writing, still being reinstated.

Once the network is fully restored, options for increasing the resilience of the affected network will be examined.

3.5 Network Security Standards

3.5.1 Introduction

Electrical supply security can be generally defined as the ability of a portion of the electrical network to resist loss of supply to consumers. EA Networks have adopted a security standard that is comparable to the "Security of Supply in NZ Electricity Networks - 2013" prepared by Electrical Engineers Association of New Zealand Inc. It is EA Networks' assessment that the comprehensive standards that have been adopted meet, and in some circumstances exceed, the above-mentioned standards.

As previously discussed, security is normally defined in terms of "n-a" where "n" is the number of possible supplies for a particular consumer or group of consumers, and "a" is the number of these supplies whose loss can be tolerated while still keeping full capacity available. If "n" is one, then the loss of one supply (a=1) means no supply. If n is two, the loss of one supply (a=1) will mean at least 50% of the total capacity is still available, and if the load is less than 50% of the total supply capacity it can be said to have n-1 security. If the load is more than 50% of the total supply capacity, then only a portion of the load has n-1 security. For example, Ashburton zone substation has a nominal total supply capacity of 40MVA (two x 10/20 MVA transformers), allowing for loss of one transformer means this substation has a "firm capacity" of 20MVA. For all practical purposes this substation is considered a 20MVA substation, so following the loss of any one item (transformer, incoming line etc) to be at n-1, then a "full" 20MVA of load can be supplied. Where additional switched capacity is available, the firm capacity can be considered as the overload capacity of the smallest transformer or line (if there is more than one) for the duration of switching excess load to other substations. This overload capacity can easily be 20% for typical switching times (24MVA for a 20MVA transformer).

Very secure loads can be configured to have n-2 security, which means two supplies can fail and the supply capacity can still be greater than the load. EA Networks have no consumers with any assurance of n-2 security. The more secure a system is, the more reliable it tends to be.

Another term that requires definition is the "firm" capacity available to a consumer. The firm capacity is the total supply capacity with the largest of any possible supplies out of service. Firm capacity can be either "no-break" or "break/switched". No-break would infer that two supplies are operating in parallel and no loss of supply is experienced when one supply fails. Break/switched firm capacity is when the supply fails, and the alternative unit/supply must be switched into service to restore the supply. For the purposes of this plan, no-break firm capacity is generally only used when referring to parallel zone substation transformers and firm capacity without a qualifier will be the alternative supply capacity available after switching.

Environmental security has two aspects - (1) the effect of the environment on the electricity network and (2) the effect of the electricity network on the environment. Both are considered under the environmental security standards.

The resilience of the network is typically increased with additional security. Some projects are driven solely by the need to improve resilience and do not result in any additional security of supply but do ensure the system components can more adequately resist failure.

3.5.2 General

When the EA Networks network is maintained or upgraded, the electrical configuration of the network can change. This rearrangement could lead to individual connections or groups of connections having a different level of security of supply. An example of this is with the continuing conversion of the distribution network from 11kV to 22kV. This work was initially triggered by increasing loads. As parts of the network have been converted, the lack of 11 to 22 kV conversion on the boundaries of the converted area lead to a temporary reduction in security until further parts of the network are converted.

The security level of any one connection will not permanently decrease over time. The only exception to this is at dedicated, high voltage, single user connection points, where security can be varied by agreement. For the purposes of this guideline, the term "permanent" means any period greater than 24 months.

The term critical load describes load that would be severely disadvantaged by an outage of more than about 90 minutes. Examples of critical load would include diabetics, hospitals, milking machines on dairy farms, retirement homes, lighting at night, refrigerated food storage etc. Non-critical load would include all air-conditioning, pumped irrigation, some types of industrial load (where they have discretion), commercial heating, and all water heating etc. For the purposes of this standard, critical load will be taken as 50% of the peak through/busbar load unless more authoritative information is available.

A significant proportion of the EA Networks network meets the adopted security standards. Proposals to improve the remaining portions are included in Section 5 – Planning Our Network. The dynamic nature of the subtransmission and distribution network in recent years (caused by significant development) has made thorough analysis of the areas that do not meet the security standards difficult. Engineering staff have been diverted to load-driven development rather than assessment tasks. All development will ultimately improve security levels. Additional effort will be required to identify non-compliant portions of the network and these results will appear in future plans as they are completed.

3.5.3 Transpower Grid Exit Points

The main on-going requirement for GXPs (Grid Exit Points) will be that the firm transformer, or alternative feed capacity, will match or exceed the any-time GXP maximum demand. This criterion will mean that the failure of any single item of Transpower plant will not lead to on-going loss of supply under any conditions. Depending upon the Transpower failure, restoration of all load by switching within the EA Networks will occur within 90 minutes.

3.5.4 Main Subtransmission Ring Systems

Sufficient redundancy shall be designed into the subtransmission system to ensure no on-going loss of supply should certain credible contingency events arise. The following criteria define these contingencies:

- All load must be restored within 90 minutes of any one section of a circuit becoming unavailable.
- For a single point failure affecting 2 circuits, critical load must be restored within 90 minutes and all load within the designated Connection Service Standard target time limit.
- No single point failure will affect more than two circuits.

Subtransmission system design shall allow for maintenance, including major component replacement e.g. transformers, circuit-breakers, poles and conductors to be carried out at appropriate times, without the above criteria being violated to any significant degree or for any significant length of time.

The precise level of redundancy built into specific parts of the subtransmission system depends on the likelihood of contingency events occurring, the costs of reinforcement, and the desired level of resilience. Each situation shall be treated on its merits and subject to rigorous financial/engineering analysis.

3.5.5 Radial Subtransmission

The radial subtransmission system comprises those parts of the network that act as spur supply systems for specific sites or connections. Currently these spurs include:

- Methven 33kV Zone Substation (unloaded), Montalto Power Station, and Montalto (Temp) Zone Substation
- Mt Somers Zone Substation (n-1 subtransmission security in the plan)
- Highbank Power Station (by agreement)
- Dorie Zone Substation
- Mt Hutt Zone Substation
- Northtown Zone Substation (has two 66kV circuits but, currently, one of the circuits does not provide meaningful in-feed capacity during summer).

These sites have a single circuit supply (some in common with adjacent substations) and any failure will result in the need for a back-up supply via the 11kV and/or 22kV distribution system. The restoration of all load, after any one failure, must occur within the designated Connection Service Standard target time limit (unless agreed otherwise with the connected consumer).

3.5.6 Zone Substations

The zone substation's function is to provide transformation from the subtransmission voltage to the distribution voltage. In performing this function, it is a critical element in the path from point of supply to connection. If it fails, the consequences are seen over a wide area and there are relatively few parallel paths to provide back-up supply. To minimise the risk at these substations, the following criteria have been developed:

- The capacity of any subtransmission or distribution busbar within a zone substation will not limit the operation of the network for credible network configurations.
- Except for bus-coupling devices, all zone substation switchgear can be worked on with only one other circuit element (i.e. electrically adjacent transformer, line etc) out of service.
- All zone substations normally supplying less than 2,000 connections shall permit restoration of critical load within 90 minutes and the balance within 48 hours under all credible n-1 contingencies.
- All zone substations normally supplying greater than 2,000 connections shall have a no-break supply for all load under all credible n-1 contingencies.
- Zone substations dedicated to an individual connection will have a security level negotiated with the electricity user supplied using that connection.
- All zone substations must be able to deliver nominal secondary voltage for n-1 scenarios whilst delivering supply.
- The distribution voltage substation bus must be able to be used as a "through/linking" bus when the transformation is out of service.

The zone substation security standard has been revised. The electrical load served by a transformer has been removed from the standard and a 2,000 consumer threshold introduced for a full no-break n-1 supply. In lieu of a second transformer at many of the high seasonal load, low consumer count, rural substations, a second spare 66/22kV transformer has been purchased (CRW) that can be relocated at any time to replace a failed unit. This unit also provides cover for a second failure while a faulty unit is either replaced or repaired. These types of repairs can take up to 12 months and a new transformer will typically require 9-12 months for delivery from order placement.

The resilience of zone substations is of critical importance and significant effort has been undertaken to ensure as many known risks as possible have been considered and factored in during design.

3.5.7 22kV and 11kV Distribution System

The overhead line distribution system is typically less reliable than the subtransmission system. There is significantly more length of distribution line, it is lower to the ground, and there are significant numbers of privately owned distribution lines connected to the same system (which are outside EA Networks' direct control for maintenance and tree control purposes). Rural underground cables offer a higher level of reliability, but they are still subject to reliability issues arising from being supplied via overhead lines or overhead lines being supplied from the cables. The urban underground reticulation has a much higher reliability than the rural overhead lines. The urban network is also heavily interconnected which typically allows faster restoration times.

EA Networks' policy of requiring all new connections to the network to be by way of underground cable is helping to improve the reliability of the rural distribution system. Many consumers who now see the reliability and safety gains of having their on-property lines underground are voluntarily converting existing overhead lines to underground cable.

The only performance requirement for the distribution system is that the restoration of all load, after any one failure, must occur within the designated Connection Service Standard target time limit.

3.5.8 Low Voltage System

The only performance requirement for the low voltage system is that the restoration of all load, after any one failure, must occur within the designated Connection Service Standard target time limit.

3.5.9 Protection

The systems that detect and isolate either faulty equipment or external interference with electrical equipment have a large influence on the outcome of any incident. The systems that detect and isolate electrical plant when undesirable electrical situations arise is generically known as "Protection". Protection systems generally measures AC currents and voltages to determine when an undesirable situation has arisen.

As a policy, new or rebuilt nodes on the subtransmission network will have protection systems that are in line with modern standard practice.

Protection systems for the EA Networks network will be designed to:

- detect faults between phases or between phases and earth,
- allow plant to carry rated maximum load without disconnection,
- disconnect faulty plant from the system with minimum damage,
- disconnect faults quickly enough to avoid system instability,
- minimise the likelihood of personal injury or property damage,
- minimise supply interruptions,
- detect abnormal operating conditions which could result in plant damage,
- disconnect only the plant item affected,
- prevent damage due to through faults,
- operate with a level of reliability that can be economically justified,
- operate with a level of sensitivity that will not result in tripping of circuit-breakers at normal load levels.

Abnormal Conditions

For zone substation transformers the protection will be set to detect conditions that may lead to significant overheating and possible failure of equipment. Overload protection will be provided for subtransmission circuits only where potential system configuration could lead to sustained overload conditions.

Selectivity

The protection will be set so that when all protective relays and circuit-breakers are functioning as designed, the protection system will clear only the faulted equipment from the system.

If a circuit-breaker fails to operate correctly, it is desirable that the remaining equipment operates selectively.

Fault Clearance Time

Clearance times will be:

- limited so that damage at the point of fault is reduced to that economically justified by the increasing protection expenditure
- such that the short time rating of equipment is not exceeded
- short enough to ensure that system stability is maintained for all foreseeable fault conditions, where the fault is cleared by the main protection. It is desirable that this time is also short enough even when the fault is cleared by backup protection

Risk to People

The protection system will always comply with the Electrical Supply Regulations. Particular attention will be paid to providing fast and reliable protection in urban areas.

Protection Reliability

Protection systems will be designed to have a high degree of reliability because of the extreme consequences of failure to operate.

Protection Security

Protection systems will be designed with a form of backup protection should the primary protection fail for some reason. This backup protection will be in line with industry standards.

3.5.10 Reliability by Design

To ensure some emphasis is placed on minimising the extent of any one outage, the target maximum number of connections on any one continuous section of network (no isolation within the section) has been defined. This provides guidelines limiting the number of consumers who have an extended outage while a fault is repaired (reducing SAIDI). In addition, the maximum number of consumers on a distribution feeder limits the impact of a feeder circuit breaker tripping on a fault (reducing SAIFI).

These design parameters ensure that the network can be restored as quickly as possible after a fault with as few consumers left without supply as possible. It also provides a degree of determinism about how many consumers should be affected by any on-going outage for the duration of a repair. This determinism does assume that the network can provide adequate back-feed capacity at every location on every feeder at all times of the year. This is not currently possible. Provided the repair does not exceed the Connection Service Standard target time limit, the performance standards have still been met.

The table above identifies the current guidelines for design.

These parameters also drive useful increases in resilience as the number of connections on a failed section of network will directly influence the impact of a significant event if it causes that section of network to fail. The resilience of neighbouring sections is therefore increased with the ability to isolate the failure and restore supply.

Target Number of Consumers per Electrical Asset

	Design		Maximum	
	Urban	Rural	Urban	Rural
Radial Subtransmission	1,500	1,500	2,000	2,000
Zone Substation	1,000	1,000	2,000*	2,000*
Distribution Feeder	200	200	250	250
Distribution Segment	45	45	50	50
Distribution Substation	45	5	60	5
LV Feeder	20	4	25	4
LV Segment	10	3	15	3

Design - Maximum number of consumers connected to asset when asset is designed.

Maximum - Maximum number of consumers connected to asset during steady state operation. Once exceeded, redesign/reconfiguration required to reduce to design level.

* For single transformer zone substations. Once zone substation consumer count exceeds the maximum limit a second transformer is required.

3.6 Network Power Quality Standards

The principal aspects of quality are voltage variation and control, and the voltage waveform. Ideally, it is EA Networks' intention to supply a pure sinusoidal voltage to all consumers and for consumers to take a pure sinusoidal current from the network.

EA Networks is judged by the quality of electricity delivered to consumers. There are some aspects of power quality that are outside the control of EA Networks. It is not the responsibility of EA Networks to "condition" the supply voltage waveform it receives from generators either directly or via Transpower. Transpower are contracted to supply an appropriate level of power quality performance at the GXPs.

The network is designed to remain within the normal tolerance voltage ranges for the forecast loading conditions considered. For the various credible contingency situations identified and studied for security purposes, the voltage should not go beyond the voltage range prescribed by the regulations.

3.6.1 Steady State Voltage

Programmes and projects are typically justified on the basis of the following benefits from improved voltage level or controls:

- the ability to meet any legal or contractual requirements with respect to voltage standards
- specific consumer requirements which the consumer is willing to pay for
- improvements in subtransmission circuit capacity and the consequential deferment of capital expenditure

Most consumers are connected to the system at LV (230 or 400 volts) and EA Networks undertakes to control this within a range of ± 6% as per legal requirements.

For 11kV and higher voltage consumers, the design voltage range is from 96% to 103% of rated voltage.

In recent years the number of voltage complaints have consistently reduced. This can be attributed to much better harmonic distortion controls and the extent of 11-22kV conversion improving voltage regulation. When a complaint does occur, it is investigated rapidly and typically resolved either by confirming:

- there is no problem,
- the problem is within the consumers wiring,
- the problem is with EA Networks and the necessary adjustment or other work is completed.

There are no unresolved voltage issues on the network.

3.6.2 Transient Voltage Disturbances

EA Networks design to limit transient voltage disturbances in accordance with the AS/NZS 61000.3.5 (LV) and 61000.3.7 (MV) standards. Motor starting is controlled according to The Electric Supply Engineers' Institute of New Zealand Inc. "Committee Report on Motor Starting Currents for AC Motors - February 1982".

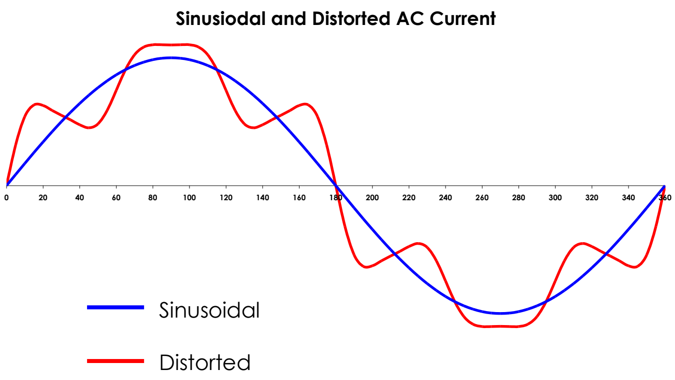
3.6.3 Harmonic Voltage and Current Distortion

Harmonics are non-sinusoidal currents or voltages produced by nonlinear loads. Nonlinear loads such as Variable Speed Drives (VSD), switch mode power supplies (SMPS), electronic ballasts for fluorescent lamps, and welders inject harmonic currents into the power distribution network. These harmonic currents couple with the system impedances creating voltage distortion at various points on the network. As a result, equipment such as computers, digital clocks, transformers, motors, cables, capacitors, and electronic controls connected to the same point, can suddenly malfunction or even fail completely - beyond economic repair.

As harmonics are produced by the end users, it is important that these harmonics are controlled at the end user connection. This is considered good practice, as by controlling the emission levels of individual sources of harmonics, the flow of harmonics into the network is restricted at the point of common coupling (PCC) with other consumers. This will, in turn, limit widespread effects of harmonics in the entire network.

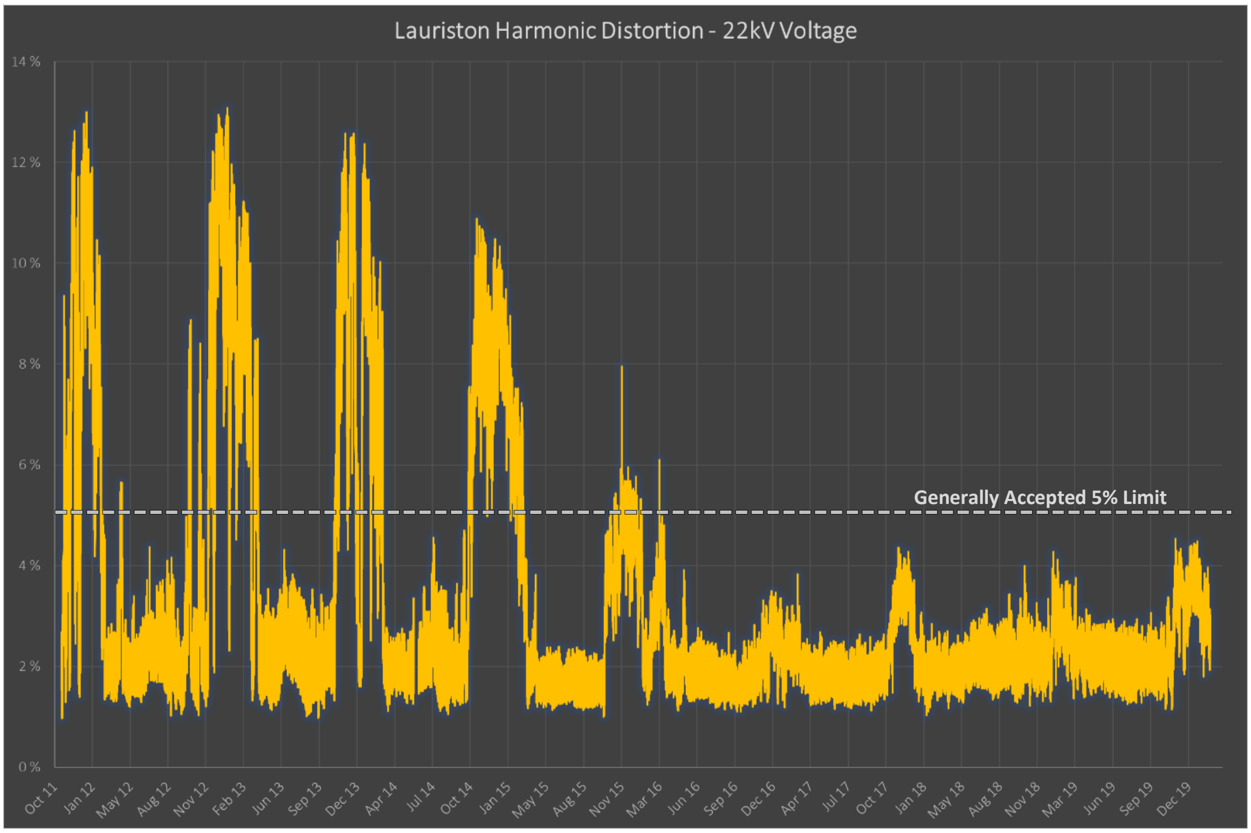
EA Networks endeavours to ensure that the quality of voltage in the network is always maintained at an acceptable level. In recent times, EA Networks has observed network voltage problems that are associated with harmonics. EA Networks acted and took all the necessary measures to minimize the widespread effects of harmonic pollution. The end result has enabled EA Networks to provide better voltage quality to all consumers.

EA Networks have implemented measures to control harmonic currents (and therefore voltages) in the network. The network standard that has been implemented requires all new rural loads to meet current distortion limits (typically 8% maximum). It is expected that the design practices and equipment purchases for the network will continue to meet the requirements of EA Networks' harmonic standard for limiting harmonic voltages at consumer connection points.



There are about 1,600 irrigation connections to the network, and they constitute most of the summer peak load. About one quarter of these loads are active harmonic producing loads. This assessment is based upon a full survey completed during 2013-14. EA Networks realised that it is not easy to track the exact number of variable speed drives because the consumer's equipment can change over time and any new equipment's characteristics are not necessarily provided or available to EA Networks. The number of variable speed drives increased steadily between 2000 and 2015 and some more may be connected in future. The per substation irrigation load shown in Section 4.2.3 provides an illustration of the potential scale of distorting irrigation loads on each substation.

A scheme to subsidise the mitigation of harmonic distorting equipment was introduced (April 2014). Under this scheme the cost of a filter or other form of mitigation was heavily subsidised for the first year of the scheme's operation and this rolled back to no subsidy over the subsequent two years. Owing to the economic downturn in the rural area a differential tariff that was to operate from April 2016 was delayed. Some discretion may be exercised with the loads that have not been corrected by October 2018. Without compelling reasons, these distorting loads will be disconnected for non-compliance. The zone substation power quality monitoring devices have shown a worthwhile reduction in peak harmonic distortion since 2014-15 summer (see chart above) during which, an all-time peak demand was experienced. This programme will continue until all rural pump loads comply (only a handful remain unfiltered). Overall, the harmonic reduction scheme has been very successful.



3.7 Safety

Electricity is potentially dangerous. All participants in the electricity industry have an obligation to ensure staff, contractors and the public are well informed of potential hazards and how to avoid them. Industry participants also have an obligation to minimise the exposure of all people to hazards by designing to an appropriate level for the environment in which the electrical equipment is installed.

In general terms, the safety standards are determined by relevant legislation and industry best practice on any particular issue.

The commitment to education and training of all staff is a core obligation of EA Networks' approach to safety. EA Networks are committed to having appropriately competent persons working on and operating the network. All work is carried out in accordance with nationally accepted regulations, guides, codes and rules. Records of worker competency levels are held on file with regular refresher training undertaken to maintain current competence. EA Networks work closely with the industry training organisation (ESITO) to promote worker competency standards.

The general public are kept informed of safety issues by regular radio and newspaper advertising of the hazards of all electrical equipment - particularly overhead lines. Safety presentations are regularly made to emergency services personnel to ensure safe behaviour of all people in emergency situations. Extensive warning labelling of EA Networks equipment is undertaken where public access to kiosks, poles or other safety perimeters is possible. All accidental line contacts are recorded, and informative letters sent out to those involved with the event.

EA Networks are aware of increasing safety issues with privately owned lines. Aging overhead lines are creating potential hazards by contacting trees, sagging lower than legal heights and component failure. A free condition assessment is offered to owners of HV service lines and this highlights any problems to them in writing. If our recommendations are ignored, a more assertive stance is taken that entails providing a written warning and, if this is disregarded, a copy of the letter is forwarded to the Energy Safety Service.

EA Networks have a Public Safety Management System (PSMS) in place that covers all aspects of asset management including:

- management of risk, hazards and change,
- equipment specification,
- procurement,
- network design,
- network construction,
- network operation,
- public awareness.

3.8 Environmental

EA Networks is committed to being environmentally responsible and strives to minimise the effects of its activities and actions on the environment.

A range of environmental phenomena have an influence on the security of the electricity network. The following environmental factors are considered significant in electricity network performance and impact:

Seismic

EA Networks has taken expert advice on seismic design and a design standard has been prepared for structural design of foundations, supports, structures and buildings. The level of seismic resistance incorporated into the standard is at least 50% higher than the general building requirement.

The standard has been reviewed because of the Canterbury earthquakes. A revised standard based upon NZS1170 Part 5 methodologies and updated risk factors has resulted. Typical seismic horizontal load coefficients in use are 1.0 - 1.1g.

Pollution

Where harsh environmental conditions exist, such as saline pollution in coastal locations, appropriate provision is made in specifications for anti-corrosion protection of surfaces, and for insulation performance.

Acoustic

EA Networks currently requires certain equipment to meet international standards on noise levels, and in locations adjacent to urban areas will require plant to be installed to meet defined criteria at the site boundaries.

Climate

The summer peak of EA Networks' network demand requires careful consideration of the specifications of major transformers and the sag and clearance design of network overhead lines.

Oil Containment

It is policy to provide oil containment facilities at substations with oil filled equipment or storage facilities containing 1,500 litres or more of insulating oil. The standard design incorporates a bund wall around transformers with manually controlled storm-water drainage to a field drain or to the surface (where there is no risk of the discharge entering waterways). At some sites a polymer cartridge has now been installed that allows clean water to flow through but forms an impermeable barrier once hydrocarbon contaminated water encounters it.

Oil spill kits are maintained at certain strategically placed zone substations and any discharge from the bund is controlled by strict guidelines stipulating no contamination.

If oil is spilled, all the contaminated earth is collected and disposed of at authorised disposal facilities.

Statutory Obligations

The electricity network has an influence on the environment. To control this influence, certain statutes apply to EA Networks in its operation and maintenance of the distribution network.

These include the Resource Management Act. Section 9 of RMA relates to Restrictions on use of land -

"(1) No person may use any land in a manner that contravenes a rule in a district plan or proposed district plan unless the activity is

a) Expressly allowed by a resource consent granted by the territorial authority responsible for the plan; or
b) An existing use allowed by section 10 (certain existing uses protected)."

EA Networks' Network currently crosses land governed by two different Territorial Authorities, each with their own District Plan and each slightly different in the rules governing the construction of new distribution lines.

EA Networks' protection of existing works is covered by Section 22 of the Electricity Act 1992 and the rights of entry in respect of these works are covered in Section 23 of the Act. Prior to commencement of any construction or maintenance of works, EA Networks must give notice to other utility owners and the appropriate Territorial Authority of its intention to commence construction or maintenance on its works.

EA Networks' Distribution Network generally runs along the roadside throughout the Mid-Canterbury plains area. Mid-Canterbury is predominantly a farming area and the only cost-effective means of supplying these farms with electricity is via overhead power lines. In the future, for specific applications, EA Networks may be required to use alternative methods of construction to minimise the effects on the environment. An example of this was the supply to Mt Hutt ski-field. The impact on the environment would have been too great had an overhead line been constructed. An underground cable was installed in that case. District Plan rules require consultation with the Council when installing lines in areas of high scenic value and EA Networks consults and works with the District Councils when working in these areas. This consultation may be required for tree trimming, agreement on line routes or just general distribution line upgrades.

Other sections of the Resource Management Act also help shape EA Networks' approach to network design and construction. As an example, the urban underground conversion programme is a way EA Networks chooses to improve the urban environment with no assistance from external funding sources.

SF_6 Gas

As a major user of SF_6 gas, EA Networks is a participant in a monitoring regime to ensure annual loss of gas is kept below 2%. To date there has been no loss detected that is outside the measuring tolerances. EA Networks have also registered with the New Zealand Emission Trading Scheme as a major user of SF_6 (greater than 1,000kg of SF_6 in use and storage).

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4.1 Service Area Characteristics

The Mid-Canterbury area (see AMP cover) has a number of activities that in some way contribute to the demand on the EA Networks electrical network or influence the design and operation of the network.

The activity that Mid-Canterbury is most known for is farming. The 'patchwork quilt' effect when flying over the district illustrates the various crop types that are growing, each crop having a distinctive shade of colour. The variety of colours are reducing as more farms are converted to grow grass which feeds dairy cows. The productivity of Mid-Canterbury dairy herds is amongst the highest in New Zealand. To grow enough grass, thereby ensuring an economic level of milk production, it is essential to irrigate the grass. This irrigation demand influences the design, capacity and maximum demand of the EA Networks electricity network. Irrigation occurs throughout the Plains area of Mid-Canterbury. Currently, EA Networks have about 1,600 irrigation connections. The dairy sheds associated with these farms also place a significant demand on the network. Farmers are very keen to have high electrical reliability to these diary sheds as a couple of missed milking cycles can cause the cows to 'dry off' and this can have a catastrophic impact on the farmer's income.

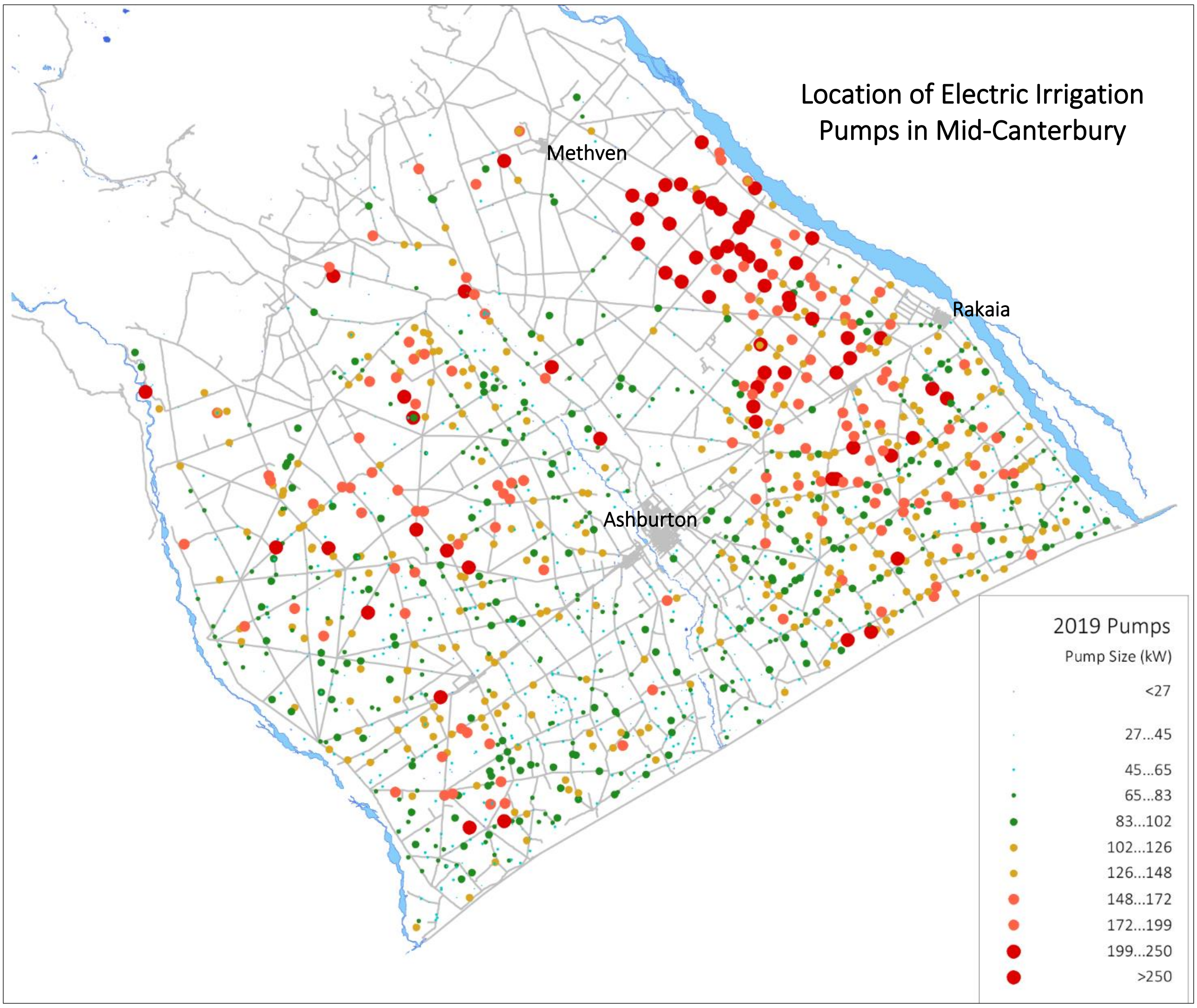
Another feature of the district is the meat and vegetable processing facilities. There is one meat-works supplied by EA Networks (Silver Fern Farms at Fairton ceased operation as a meat works in 2017) as well as a vegetable processing factory. These facilities either have dedicated electricity substations or a dedicated supply from a substation. The key issues these consumers have are capacity and reliability.

Mt Hutt ski-field is also located in the district and it has electric tows and snow-making facilities. The location of the field means that the electricity supply is both electrically and environmentally challenging. The supply to the ski-field requires dedicated power lines from Methven to a substation above the Rakaia Gorge. From the substation, a pair of underground cables wend their way up a steep slope across the main ridgeline and descend into the My Hutt basin. This route was the only one that was acceptable to the Department of Conservation and overhead lines were not acceptable from an environmental perspective or from a viewpoint of serviceability. In winter, the route can be covered by several metres of snow and winds on the ridges regularly exceed 160 km/h. This is no place for an overhead line.

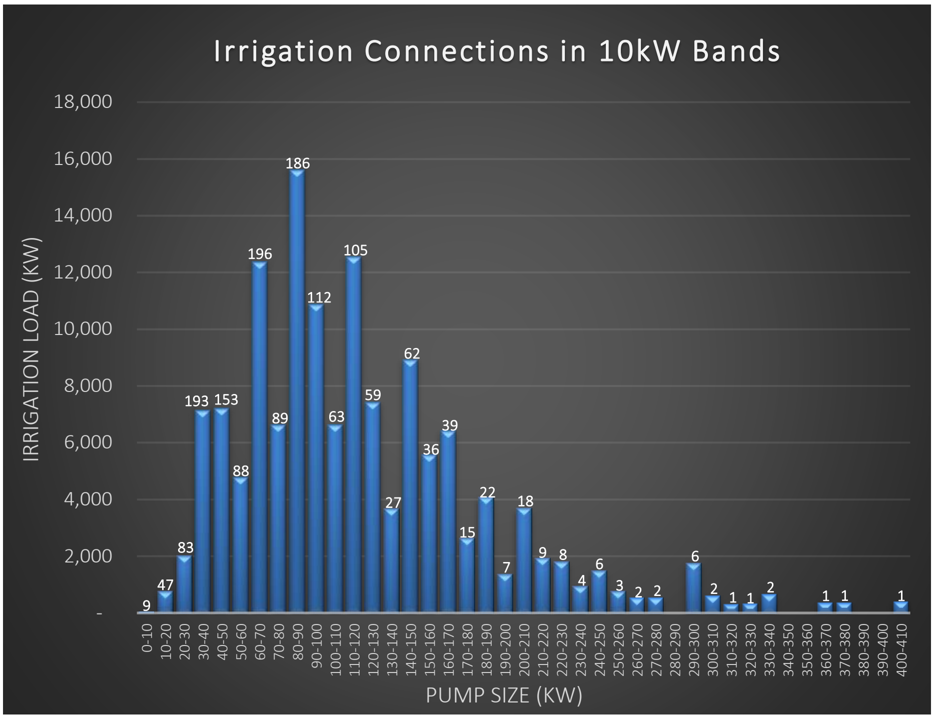
The main settlement in the District is Ashburton township and it holds about 17,000 people. Smaller towns of Methven (1,400 people) and Rakaia (1,100 people) are also significant in terms of electricity consumer count.

The district has a total population of about 30,000 people.

In the early 20th century, the Government decided to build an irrigation canal that takes water from the Rangitata River and transports it across the Canterbury Plains as far as the Rakaia River. This canal is called the Rangitata Diversion Race (RDR). During summer the RDR is used as an irrigation water canal and several downstream irrigation schemes are supplied from it. These schemes distribute water onto farms using various sizes of irrigation races. In recent times, some of these races have been converted to piped schemes which eliminates evaporative and ground losses as well as providing gravity pressurised water to the farm gate. To reduce the risk during dry periods, many farmers on open race schemes have constructed large storage ponds on their farms. The farmer may then take their full allocation of water at any time it is available, and any water not required at that moment is stored for later use. The farmer can pump the water from the pond at any rate they choose.



One of the uses for the RDR is power generation. There are two hydro generators on the RDR, one at Montalto and another at Highbank. The Montalto generator provides output all year round while Highbank can only generate if most irrigation schemes are not taking water (during autumn, winter and early spring).



There are several other small hydro generators in the district at Cleardale (Rakaia Gorge), Barrhill, and on an irrigation canal at Ealing.

The electrical demand needed to irrigate a hectare of land at a rate of 0.6 litres/second/hectare (the generally accepted rate) varies depending on the source of water and irrigator type. A modern centre pivot irrigator supplied with water from a surface pond will require about 0.55 kW/hectare. So, a 900m radius centre pivot will require a pump of approximately 140 kW to drive it. If the water comes from a deep well, the pump must also overcome the additional gravity head of the well. If the same 900m centre pivot is supplied with water from a 120m deep well, another 0.71 kW/hectare must be added. This would mean the installation would need a 320 kW electric pump to drive it. This type of load places considerable demand on a rural electricity network. The average size of EA Networks' irrigation connections is 86 kW.

The Highbank Hydro Power Station has been equipped with an array of six 1.5 MW pumps that allow it to take water from the Rakaia River and pump it up the power station penstock (a height of about 100m) into the RDR. The water is then available for irrigators to use. This scheme is generally referred to as the BCI scheme (www.bciwater.co.nz). This load is typically coincident with the summer peak demand (dry years cause low diversity of irrigation demand). There is an agreement in place that should a 66kV subtransmission circuit be unavailable because of a fault, the supply to these pumps will not be available (i.e. the Highbank pump load is interruptible). This is a condition negotiated before the load was initially supplied.

The following table depicts the major loads supplied by EA Networks.

Significant Load	Typical Energy (MWh)	Peak Load (kW)
Meatworks #1	16,500	6,000
Ex -Meatworks (Refrigeration only)	2,100	900
Vegetable Processor	12,600	4,100
Plastic Goods Mfr	2,800	1,700
Ski-field	1,200	2,400
BCI Irrigation Scheme	5,800	8,100
Irrigation (District-wide)	220,000+ (Typical Year)	143,000
Other Load	250,000+ (Typical Year)	65,000
TOTAL	600,000+ (Typical Year)	181,000

More than 50% of the energy transported by EA Networks is delivered to 8% of the connected consumers. The peak demand (which occurs in summer) is almost entirely determined by the amount of rainfall, which in turn influences the amount of irrigation that takes place. The winter peak demand is approximately 40% of the summer peak and is largely determined by the harshness of the winter and low temperatures driving residential heating. The winter load is concentrated in the townships, particularly Ashburton, and the urban underground network is designed with this in mind. Mt Hutt ski-field is also peaking its electricity usage in winter and the early part of winter can see the snow-making systems working at full capacity, particularly overnight when it is colder.

The diagrams in section 4.2.3 show the seasonal variation in load between rural/urban zone substations as well as the seasonal load/generation balance.

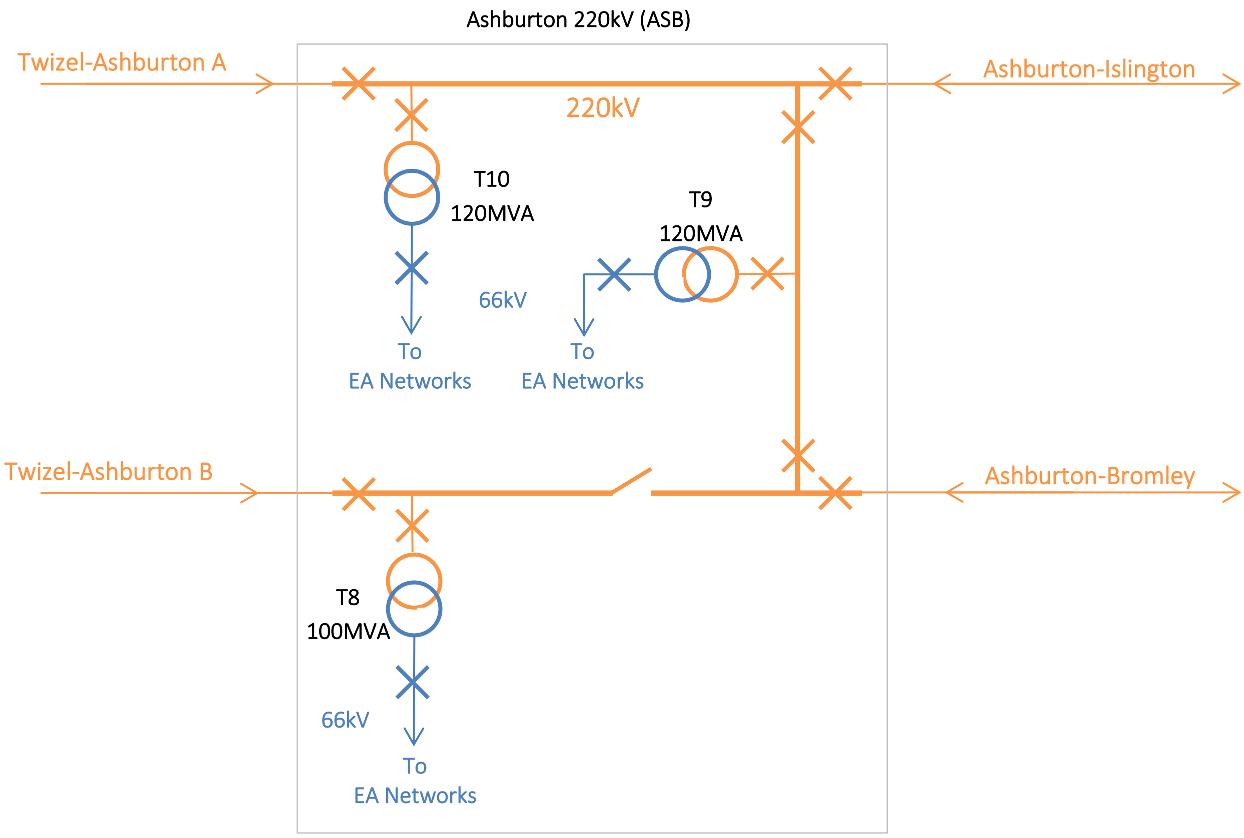
4.2 Network Configuration

This section describes the general arrangement of each major section of the EA Networks electricity network.

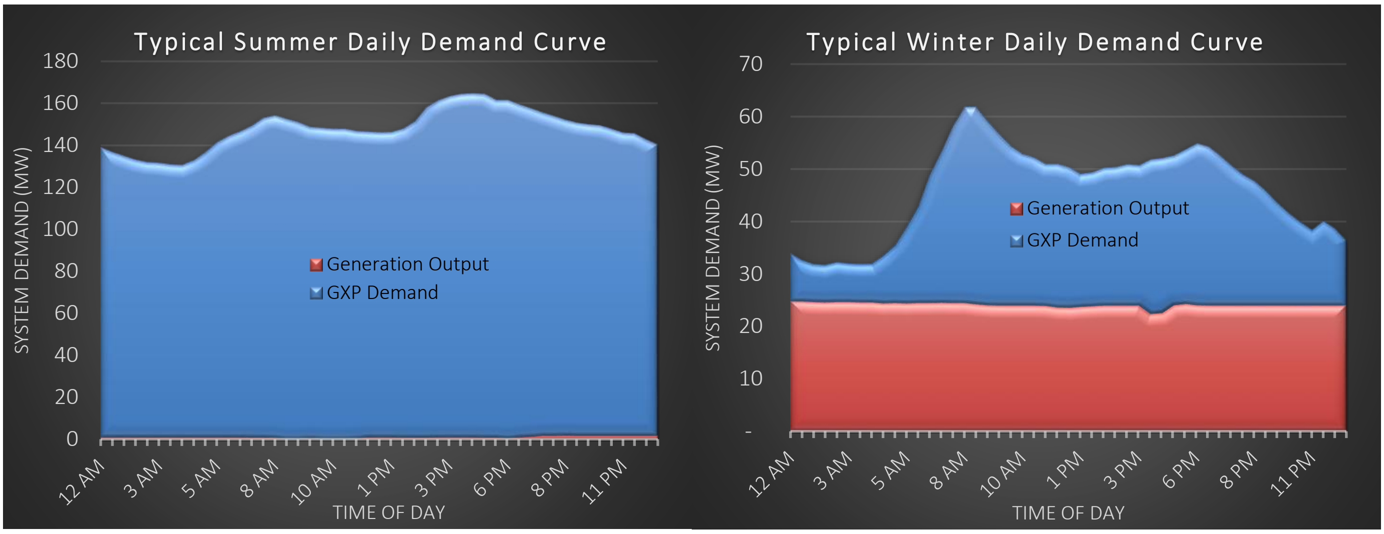
4.2.1 GXP and Generation

EA Networks take supply from the national grid company (Transpower) at a site approximately 7km south-east of Ashburton township. The Transpower Ashburton Substation (known as Ashburton220 or ASB - since EA Networks also have an Ashburton substation) supplies EA Networks with 66kV subtransmission voltage. These supply points are also known as a GXPs (Grid Exit Points). The following diagram illustrates the configuration of the Transpower ASB substation.

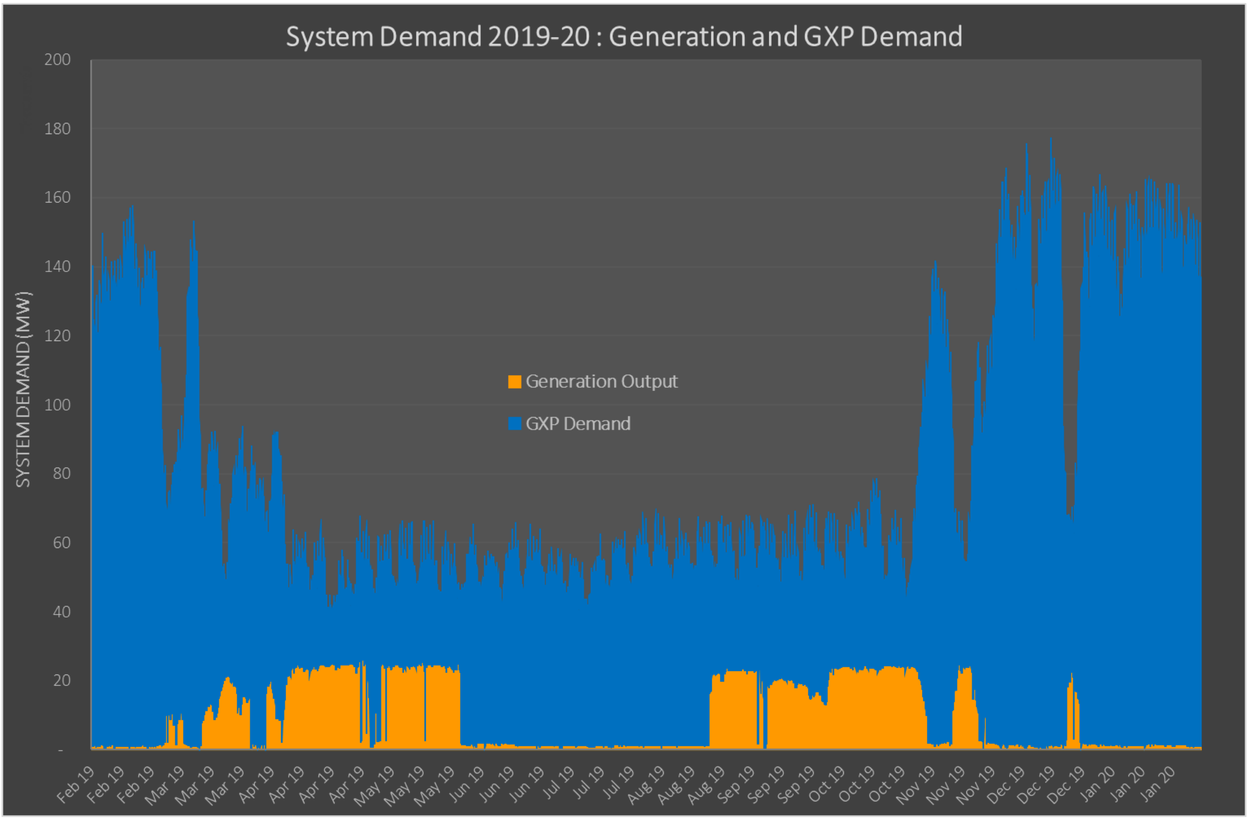
EA Networks Grid Exit Point Configuration



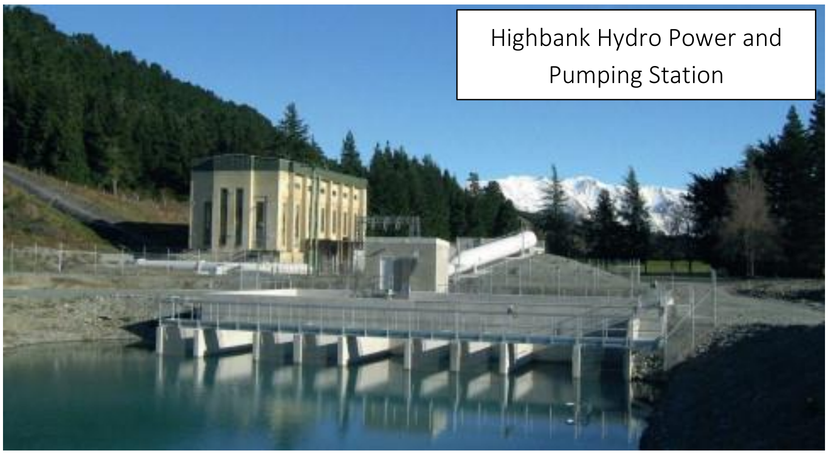
The orange lines represent 220kV (the national grid transmission voltage). The blue lines are 66kV. The capacity of each transformer is shown above. The 66kV GXP has a peak load below the combined rating of T8 (the smallest of the three 220/66kV transformers) and one other of T9 or T10. T9 was commissioned during 2013. This configuration ensures 66kV loads up to 220 MVA have n-1 security.



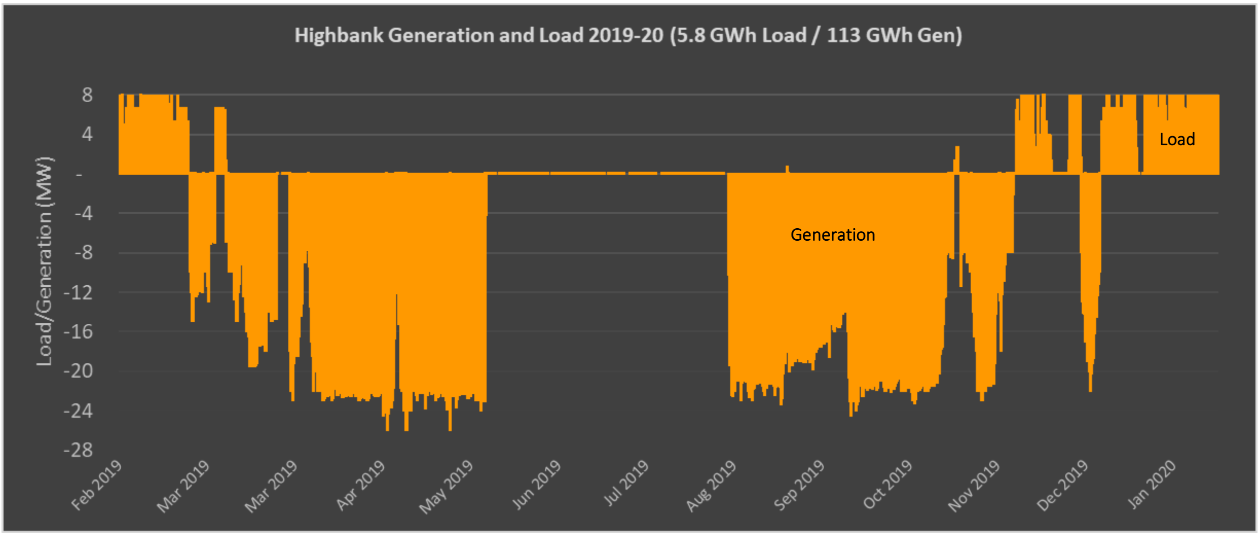
The 66kV GXP supplies all of EA Networks' consumers. The load charts above illustrate the irrigation vs residential/commercial nature of the load on the GXP. In summer, the large irrigation base swamps the daily residential variation, while in winter the variation is clear to see (and significant generation is present) . The daily load variation is very marked during morning and evening meal times with both heating and cooking loads being heavily used. The chart below illustrates the weekly load variation which can be clearly seen with significant dips at the weekends. It is at these times that water heating load control is used to ensure both the Transpower grid and EA Networks assets are not unnecessarily high capacity for a load that can be shifted a few hours without consumer impact. Note that during June-August the Highbank hydro power station was out for maintenance.



Irrigators do not tend to have a daily or weekly load variation. Once the water is required, the irrigator is left to run for possibly weeks on end. The irrigation is predominantly used in the summer although a farmer's growing season can extend into April in some years. Equally, a dry winter can cause early irrigation demand to occur in August or September as happened in 2014. A wet spell during December has reduced that demand for several weeks and even allowed some hydro generation. The load on the 66kV GXP varies from a maximum of 180MW in summer to a minimum of 25MW in winter.


Highbank Hydro Power and Pumping Station

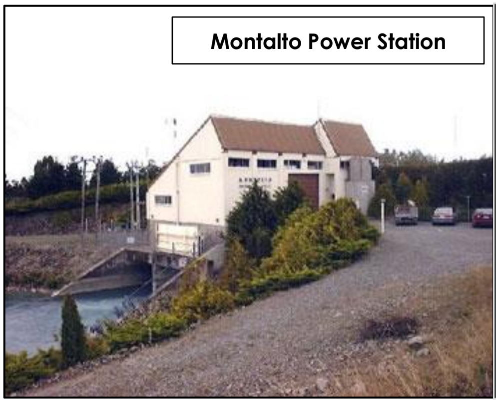
The Highbank Hydro Power Station is rated at about 28MW output. It has a single turbine with a head of 104m. The RDR race has a flow of 31 m³/s at peak times when no water is being used for other purposes. There is no ability to store water in the RDR and Highbank is considered a 'run of the river' station. The output diagram for 2019-20 can be seen below and when irrigation demand begins in September and October the water supply becomes less consistent and daily peak generation output can vary significantly. Being a single turbine station with no water storage facilities, EA Networks cannot rely on Highbank operating at any particular point in time. As such, EA Networks do not factor in Highbank output during supply security studies.

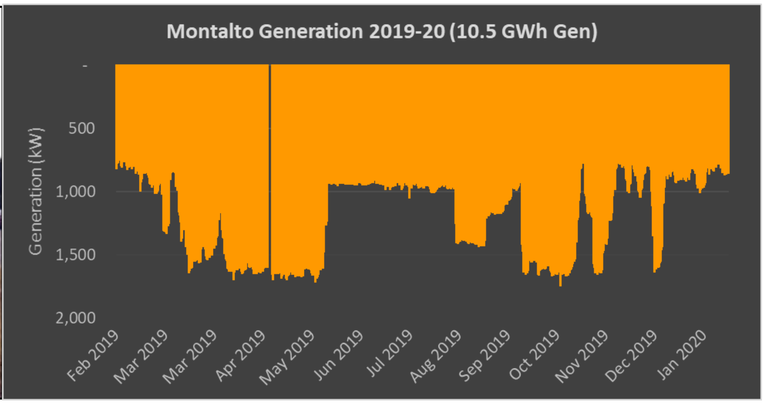


Highbank also has pumps located at it to allow Rakaia River water to be pumped up into the RDR. These pumps have been used significantly during 2019-20 and appear on the Highbank load graph as load of about 8MW. So, the Highbank 66kV connection demand varies from -27MW during winter (generation) to +8MW during summer (pump load).

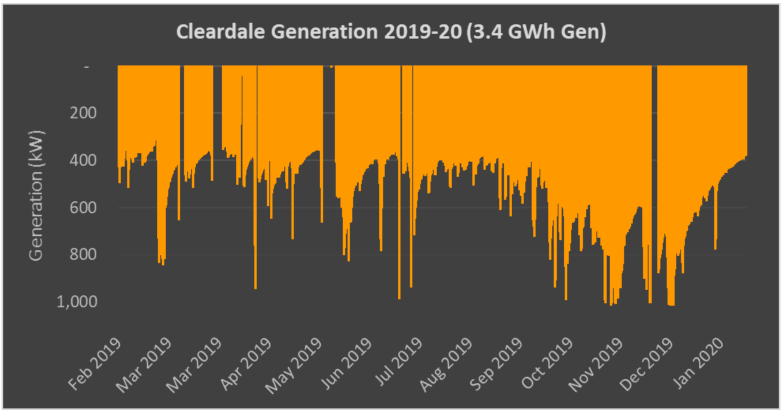
There are three other embedded generators of note connected to the EA Networks network.

Montalto is also located on the RDR but its location offers year-round output. Connected at 33kV, the generator is an induction machine which means it cannot provide any system support or provide emergency output during network faults. Winter output is around 1.6MW while summer output is about 1.1MW.

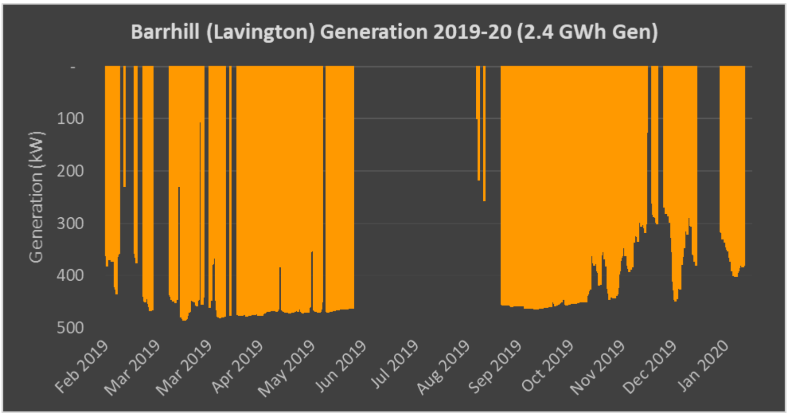

Montalto Power Station



Cleardale is a 1MW generator in a valley adjacent to the Rakaia River gorge. A high head low flow machine, it generally has year-round output. The 11kV connection is relatively remote and its output is largely absorbed in the Methven area after being transformed up to 33kV. The machine cannot provide emergency output (no islanding ability). The additional expense to provide islanding ability was examined at the time of installation but could not be justified for the small variable output and local fault frequency/consequences.



In 2016, an additional hydro generator was connected to the EA Networks 22kV system near Barrhill. The unit is owned by BCI Irrigation and rated at 520kW output. This output is absorbed into a 22kV feeder from Lauriston zone substation. The output of the generator is determined by BCI's irrigation customer demand for water. The intake for the generator is some 6.7km upstream of the generator site and a large diameter plastic pipe delivers the water to the generator with a 32m static head. Just above the generator site is a bifurcation of the delivery pipe and gravity pressurised irrigation water is diverted as required for delivery onto the Canterbury Plains. Flow into the irrigation system is controlled by the main valve on the generator. The generator offers close to rated output for a significant portion of the year, but during peak irrigation demand in summer (when it would be of most use on the 22kV network), its output drops to zero.



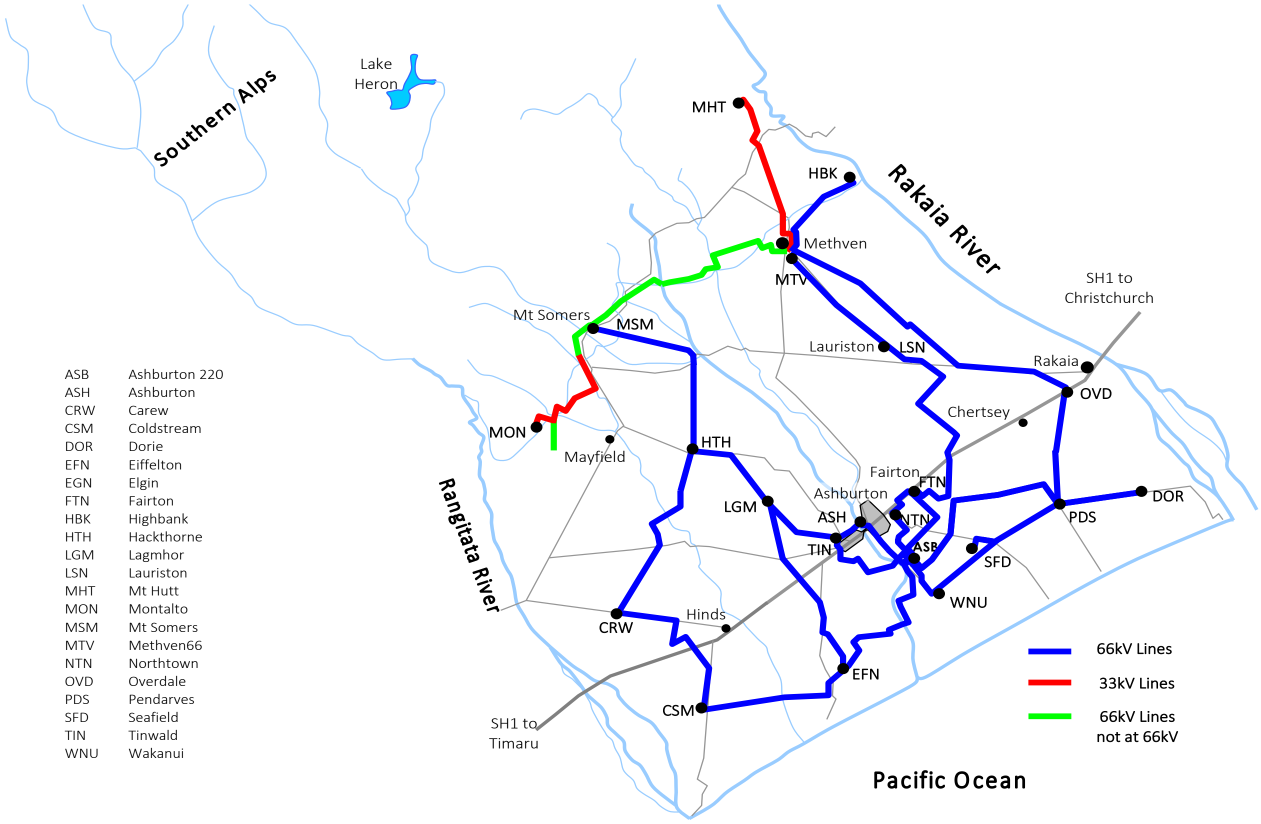
The very small hydro turbine at Ealing Pastures is located on an irrigation race and is normally used as a mechanical drive to a pump. When there is excess mechanical power a 200kW induction generator provides electrical power for on-farm needs and any excess is then exported onto the EA Networks system at 22kV. The generator has virtually no impact on the network other than to periodically reduce the farm's demand during the irrigation season (although not reduce the capacity required to supply the peak demand).

The geographic location of the main generators as well as Transpower's ASB substation are shown in the diagram in section 4.2.2.

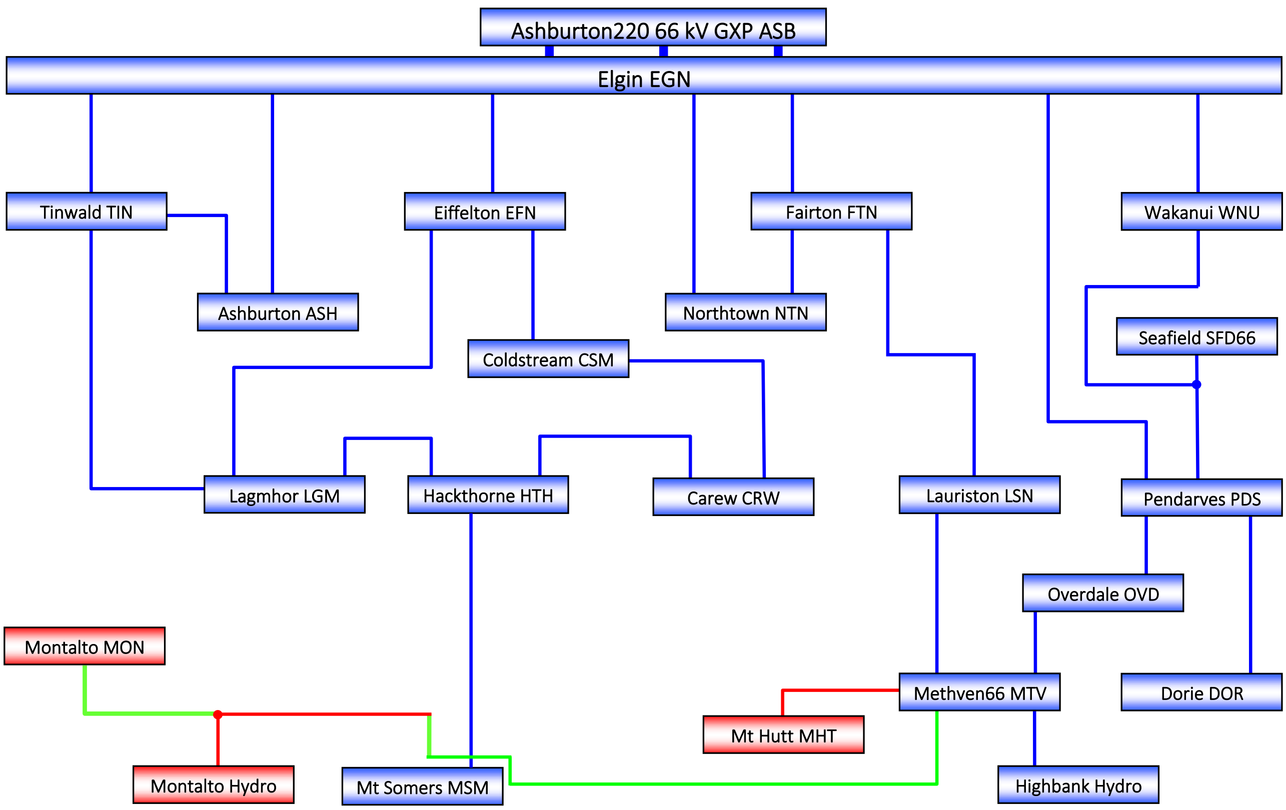
Distributed Generator	Typical Energy (MWh)	Capacity (kW)
Highbank	102,545	28,000
Montalto	9,978	1,650
Cleardale	4,300	1,000
Barrhill (Lavington)	2,800	520
Ealing Pastures	35	200

4.2.2 Subtransmission

EA Networks use two voltages for subtransmission: 33kV and 66kV. The 33kV network is limited to one distinct



2020 EA Networks Subtransmission Network



zone (two until recently).

The most heavily loaded 33kV network was directly connected to the 33kV GXP and supplied Ashburton, Fairton, and optionally, the ANZCO meat works (SFD). This network was retired from service during 2019 after conversion/construction of zone substations to/at 66kV.

The remaining section of 33kV network is two radial 33kV lines supplied from the Methven 66/33kV substation. One is dedicated to the Mt Hutt 33/11 kV substation, which supplies the Mt Hutt ski field as well as the Cleardale generator. The other 33kV line supplies Methven 33/11kV substation (soon to be decommissioned), Mt Somers substation (as a back-up to the 66/22kV transformation), Montalto substation and Montalto Hydro Power station. These two 33kV lines are radial, so a fault anywhere along their length will typically mean loss of supply will occur.

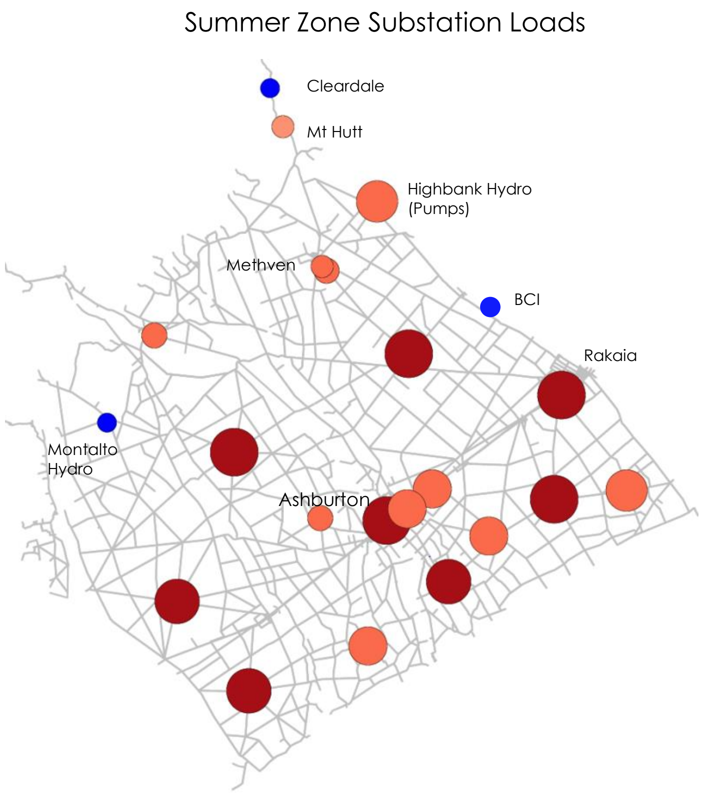
The 66kV subtransmission network is the core of the rural supply system for EA Networks. The configuration of the 66kV network consists of two closed rings.

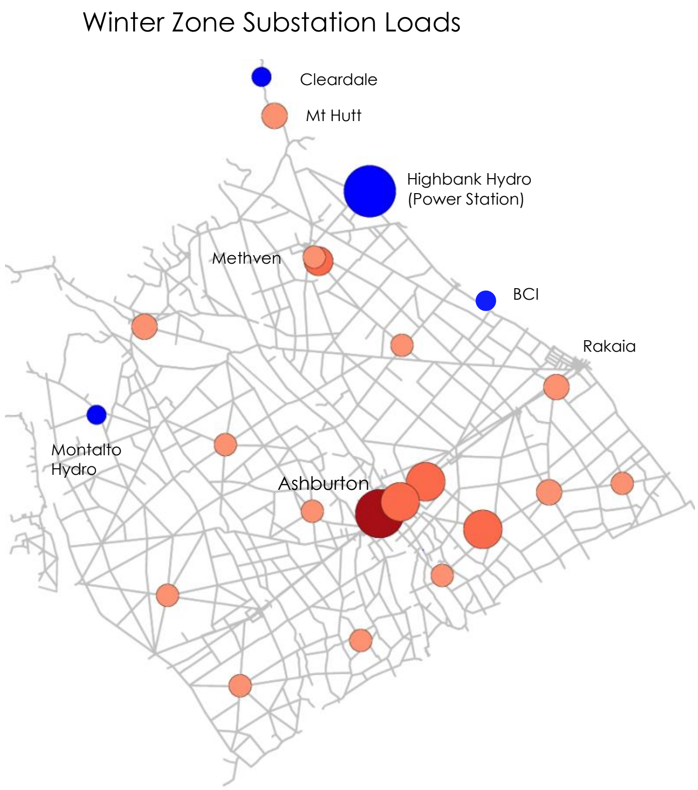
The northern network supplies a number of 66/22 kV substations as well as Methven 66/33kV & 66/11 kV substation. There is a three terminal 66kV line in this section of the network that supplies the Seafield66 (SFD) zone substation. In the middle of summer, this portion of the network supplies more than 80 MVA of load.

The southern 66kV ring is also operated closed and has an internal 66kV line joining two substations. This line offers additional security for faults in the first section of the ring leading away from the 66kV GXP. A fault in any 66kV line in the southern ring should not result in any outage for consumers. A 66kV line between Elgin (EGN) and Ashburton 66/11kV substation (ASH) has recently been completed and includes about 2km of 66kV underground cable. This new circuit has increased the security of Ashburton township considerably.

4.2.3 Zone Substations

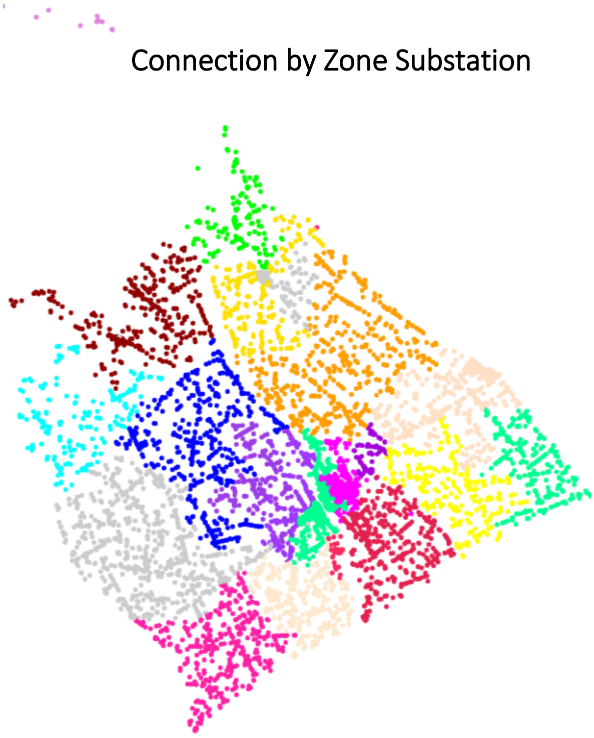
Zone substation loads and security are detailed numerically in section 6.7 as well as Appendix C. The load/generation centres shift between the summer/winter seasons. This shift requires the network to support high urban loads and high rural generation during winter, while during summer the rural load increases dramatically, and generation disappears. These two distinct load/generation configurations are not particularly conducive to efficient network utilisation since energy is not being generated close to the available load. Another factor with electric irrigation is the need to keep fault levels relatively high so that motor starting (an





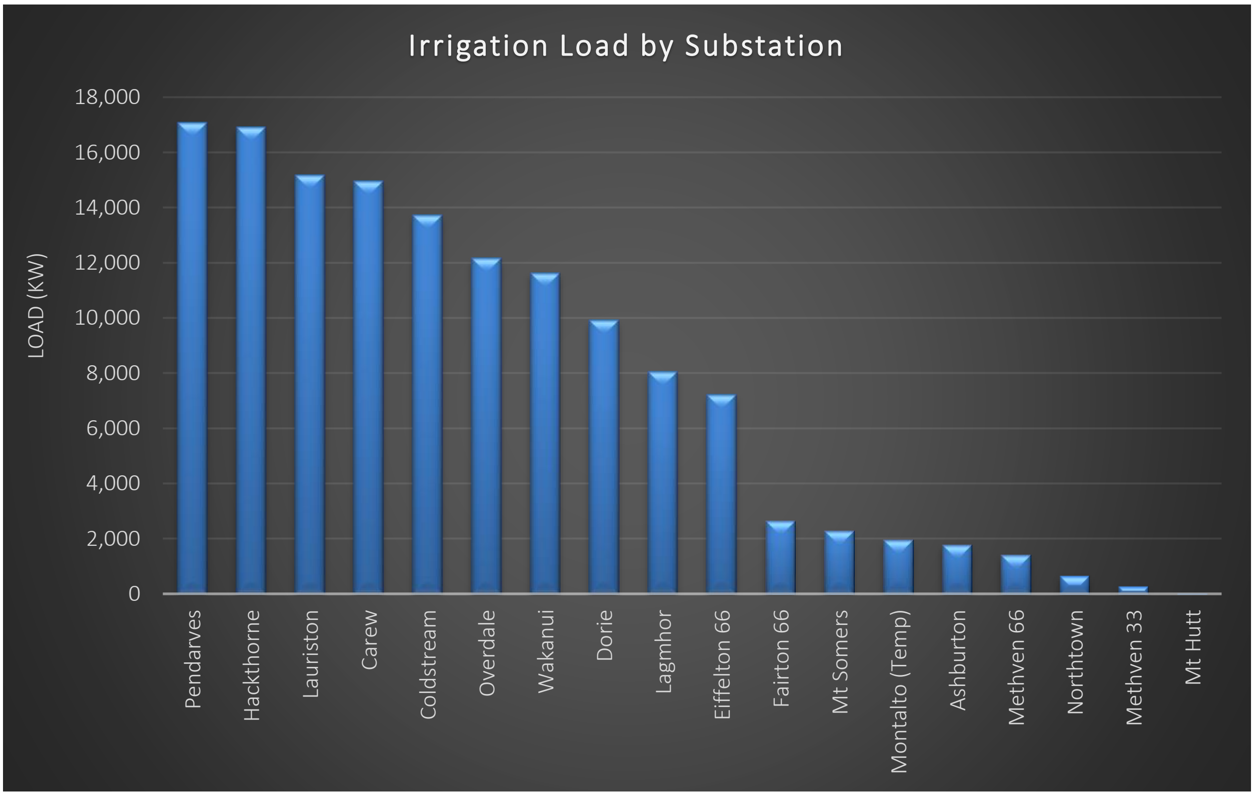
intrinsically poor power factor situation through predominantly reactive overhead lines) is less disturbing to other consumers. Modern "soft" starters and variable speed drives have helped this aspect, but drives can introduce other potentially disturbing characteristics.

A typical 66/22kV zone substation will have two 66kV lines supplying it. Line differential and distance protection is installed on each line terminal circuit-breaker. The tubular aluminium 66kV bus is supported by steel stand and has high impedance bus zone protection installed. An ONAN/ODAF 10/20 MVA 66/22kV transformer with a +5/-15% tap-changer is installed with an accompanying 22kV 40Ω NER. A numeric transformer differential relay protects the transformer. An indoor 22kV 5-way switchboard (one incomer and four feeders) is installed with numeric protection relays. The 22kV feeders leave the substation in 250 amp rated underground cables that are terminated outside the substation on suitable poles. Large urban substations will have multiple 66kV bus-sections, bus-section circuit-breakers, multiple 66/11kV transformers, multiple 11kV switchboards with at least one bus section circuit-breaker in each board.



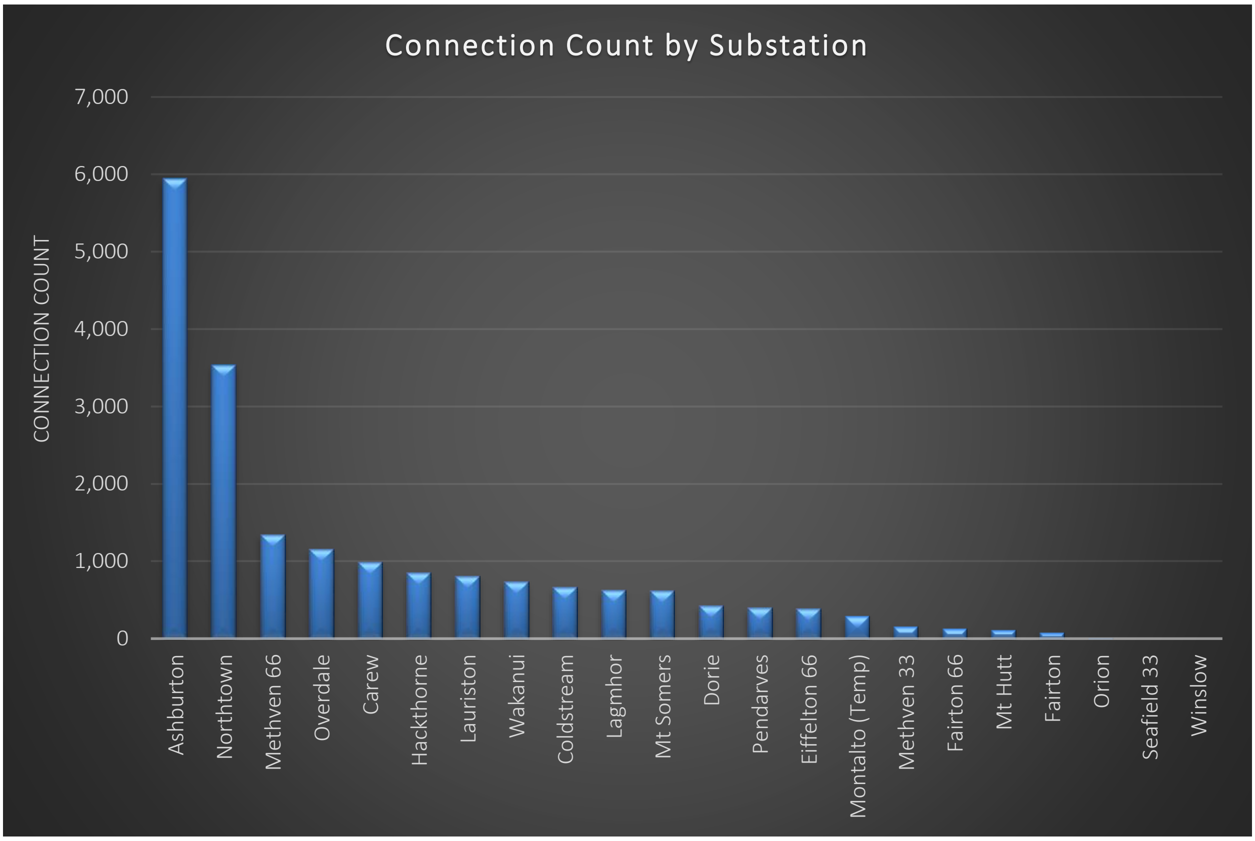
The preceding load maps represent existing zone substation maximum demands themed by colour and circle diameter. The larger and redder the circle, the larger the load is. The blue circles represent embedded generators. Highbank at 28 MW is by far the largest of the four and currently only runs during winter due to irrigation demands on its water supply (Rangitata Diversion Race) during summer.

The three charts above and below show the irrigation load by zone substation as well as the connection count per substation. Examination clearly shows the large disparity between the two measures. 50% of the



connections that EA Networks supply are on two substations (Ashburton and Northtown). The irrigation load that these two substations serve is about 3.3% of the total (and dropping, as 11 to 22kV conversion proceeds).

A more detailed description of the assets at each zone substation is included in section 6.7.



4.2.4 Distribution System

The distribution system is the most obvious and visible part of the electricity network. It is on the side of many roads and when it is overhead the poles and wires are immediately evident. It is also the most numerous, asset intensive and fault prone portion of the electricity network.

Medium Voltage

EA Networks operates two medium voltage distribution voltages.

The 11kV network is the system which has been used since around 1960 in Mid-Canterbury. It has served EA Networks well and it will remain as the dominant voltage for distribution in Ashburton and Methven townships. The extensive 11kV underground cable network in both townships means that it is not economically viable (or currently technically necessary) to convert it to 22kV.

The 22kV network voltage has been in use since about 1997. Each year since then, some portion of the heavily loaded 11kV network has been converted to 22kV. 22kV has become EA Networks' rural distribution voltage of choice. The dramatic increases in irrigation load during the early part of this century could not have been accommodated on the pre-existing 11kV network or even a heavily upgraded 11kV network.

It is fortunate that the small rural townships had not been heavily converted from overhead lines to underground cables. This has allowed townships such as Hinds, Rakaia and Chertsey to be supplied directly from the surrounding 22kV distribution network. Other townships such as Mayfield and Mt Somers have been converted to underground distribution and all these cables are operating at 22kV.

A typical rural 22kV feeder will have about 175 connections on it. The feeder will leave a zone substation indoor circuit-breaker in a short length of underground cable and connect to the overhead line on a nearby pole. The main feeder line will then radiate away from the substation for an average of about 10-15km before it encounters the end of an adjacent feeder (typically fed from another zone substation). At intermediate points along the feeder there may be spur lines protected by reclosers or sectionalisers. These devices prevent the main feeder circuit-breaker from tripping for faults on these spur lines thereby keeping supply on to most consumers during such faults. There will typically be several points along the feeder where it can interconnect with adjacent feeders. These normally open switches are either disconnectors, SF6 gas switches, or ring main units. Remote control of these switches can speed restoration significantly. Fault indicators will be located at some junctions where multiple lines branch off the main feeder line. These indicators will show if a fault current has passed it recently. If an indicator is triggered, the fault is beyond that point. Ring main units are being used at points in the rural network where there are many lines that require switching (at least three, normally four). 22kV feeders can have peak loads up to 7MVA although typically they are around 4MVA. The length of a rural feeder is constrained by voltage drop along its length. It is very rare that a thermal limit is reached as conductors must be sized for voltage drop and this typically results in larger conductors than would otherwise be thermally required to supply the load.

A typical urban 11kV feeder is completely underground and currently has about 450 connections on it. At every distribution substation on the feeder a ring main unit will be installed that allows isolation of the cables connected to it, as well as the transformer supplied from it. This allows ready isolation of a faulted item, speeding restoration as well as permitting planned outages of assets without supply interruption. Fault indicators are used at regular intervals along a feeder to permit prompt identification of a faulty cable or transformer (which will normally cause a feeder circuit-breaker tripping). The opportunity for interconnection with other feeders is far greater in an urban area simply because of proximity/density. It would not be uncommon to have four or five points that permit at least partial back-feeding of an urban 11kV feeder. The ‘reach’ of an urban 11kV feeder is normally constrained by cable thermal considerations. The rating of a buried cable is thermally limited and prudent sizing is required to ensure adequate capacity for future demand without over-specification. An underground feeder may radiate up to 4km long (cable route) and typically has a peak load of around 3MVA. This limit ensures a 4.5MVA capacity feeder can provide back-feed support to adjacent feeders in case of a fault.

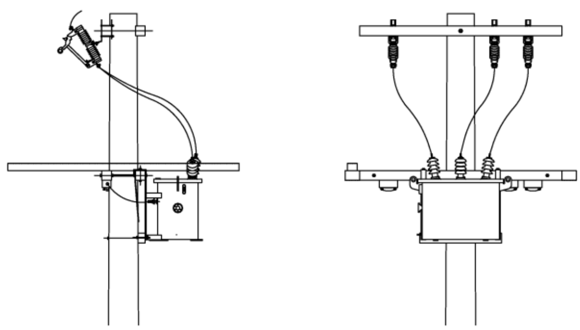
The degree of underground cable usage is very dependent on the voltage. The urban 11kV areas adopt intensive use of underground cable. Methven township is completely underground at both 11kV and LV levels. The only poles in Methven are street lighting poles (supplied from underground cables). Ashburton township is approximately 89% underground cable at 11kV and at LV is 83% underground. Overall, the 11kV network is 31.3% underground and the LV network is 85.5% underground.

At 22kV, the penetration of underground cable is much less. 9.2% of the 22kV network is underground.

The distribution network (22kV, 11kV and LV) is 25.9% underground by circuit length.

Distribution Substation

A distribution substation is a facility in the network that accommodates equipment that switches and transforms MV (medium voltage - 22kV and 11kV) to LV (low voltage - 230-400 volts). There are a range of styles of distribution substations.



A pole-mounted substation is a relatively simple assembly of assets. The key component is the transformer which is hung from a short crossarm using galvanised steel brackets that are supplied with the transformer. These brackets are secured to the crossarm for both seismic security and restraint should a vehicle contact the pole. The transformer has a set of MV drop-out fuses mounted above it (generally on a separate crossarm) that provide the transformer with fault protection as well as the ability to isolate the transformer should it be required for maintenance or replacement. A set of LV fuses are installed on the transformer hanger arm which ensure any fault in the connected LV network does not cause the MV fuses to operate and also provides some overload protection to the transformer.

Several types of ground-mounted distribution substations are in use. The simplest ones consist of an off-the-shelf ‘microsub’ or ‘minisub’. These are a ground-mounted transformer with two cabinets directly attached to the body of the transformer. One cabinet has the MV bushing wells in it and can have one or two cables per phase connected (two cables allows a connection to another transformer). The second cabinet houses the LV bushings and can accommodate several LV cables and a number of LV fuse-disconnectors. This style of substation is used when small (<150 kVA) supplies are needed and there is no need for multiple high capacity LV circuits. They are commonly used on rural properties for houses, sheds, small dairy sheds, etc particularly when they are fed from a nearby overhead line. Some of the larger microsubs have two MV bushing wells per phase (bridged internally) that allow two cables to be connected. This permits simple disconnection of one set of screened elbow terminations to occur when the need arises. The microsub and minisub both use precast concrete foundations.

The next level of sophistication comes with a pad-mounted transformer and either one or two separate small steel kiosks. This arrangement provides the ability to house a MV ring main unit in one kiosk and a multi-way LV switchboard in the other kiosk. These substations can be large (up to 1,000kVA) and are used in commercial/industrial applications where an exposed transformer is less conspicuous. The concrete foundations for these units are also precast to one of two standard designs (depending on transformer rating). These substations can be integrated into an interconnected urban/industrial/commercial LV network.

The final variant of the distribution substation is a large single kiosk design (below; 11kV left and 22kV right). The kiosk is either steel (22kV) or fibreglass (11kV) and houses a transformer (up to 500kVA), a MV ring main unit (up to 5 x 11kV or 3 x 22kV circuits), a LV switchboard (up to 7 x 630 amp rated circuits plus 3 x 60 amp streetlighting circuits), and any ancillary equipment such as ripple relays and maximum demand indicators. These substations are the standard style used for residential areas and integrate fully into the MV and LV networks.

An urban distribution substation can supply up to 100 residential connections on multiple LV feeders.

Low Voltage

The low voltage distribution network is largely located in the urban areas. Rural LV is typically short overhead lines or underground cables from a pole mounted distribution substation to the property boundary (EA Networks ownership typically ends at the boundary).

The urban LV network is either older overhead lines located in the smaller townships or predominantly underground located in the larger townships. Overhead LV is smaller in capacity and has virtually no interconnection (via switches) with adjacent overhead LV network fed from other distribution substations. The reason for the low level of interconnection is twofold: the small capacity means it is typically incapable of providing adequate back-feeds and the pole-mounted distribution substations are typically much smaller and cannot provide the capacity for back-feeding. The urban underground LV network is much higher capacity and has a great deal of interconnectivity. This allows the shifting of segments of the LV network from feeder to feeder and substation to substation during either planned or fault

work. The switching of these segments (between substations) takes place at distribution boxes housing compact LV switchgear (see image at right). The style of switchgear in use allows live (dis)connection of cables, installation of new ways, and even interconnection of two adjacent cables without using the bus. This very flexible system provides opportunities to accommodate unusual operating conditions. The distribution boxes are standardised designs that use a common backplane/bus that permits addition/removal of plug-in switching devices as required.

4.2.5 Secondary Assets

There are a range of EA Networks assets that are ancillary to the structural or high current/voltage functionality of electricity distribution. These include the following:

Protection Relays

The protection relay assets at EA Networks vary from relatively few old electromechanical devices through to many modern microprocessor-based units. The standard approach is to use a limited range of standardised devices so that existing designs can be reused, and staff are do not have to retain familiarity with too many different devices. Although this may not be the cheapest initial cost it provides the most economical lifetime cost. At subtransmission voltages every protection scheme incorporates a local device that will provide back-up in the event of failure or non-detection of a fault. This ensures that the minimum amount of equipment is removed from service during fault conditions. At distribution voltages the zone substation transformer protection provides back-up to the feeder protection. Beyond the feeder circuit-breakers exist a range of reclosers and sectionalisers that do not have local back-up but rely on the feeder protection relay to detect the fault if they do not. This leads to larger loss of supply, but the fault is still cleared safely.

Section 4.12 provides some additional information about the protection relays at EA Networks.

Ripple Injection Systems

EA Networks operate a 283 Hz decabit ripple injection system. The injection plant is all solid state. There are three injection plants, two of which are actively used. The 11kV plant at Ashburton 66kV substation (ASH) provides signal injection for about 60% of Ashburton, Fairton and Seafield substations. This represents about 33% of the connections on the network and a significant proportion of the controlled water heating load. The 33kV plant at Transpower's Ashburton220 substation (ASB) provides signal for the entire 66kV network using a 33/66kV step-up transformer in the adjacent Elgin substation. The signal level has been boosted by utilising synchronous injection from both plants. In the event of a problem with the ASB plant the ASH plant can provide some signal but it is unlikely to provide complete system coverage. The small third injection plant at Methven 33kV substation (MVN) can provide some cover in the event of a problem with the ASB plant but it does not provide complete coverage. There are two projects in the plan to enhance load control.

SCADA Systems

The SCADA system is available at all of EA Networks' zone substation sites. The newer sites with numeric protection relays have all been integrated onto the SCADA system. One of the smaller sites does not have full monitoring but does have remote control. Section 6.14 provides additional information about the SCADA system.

Telecommunication Systems

EA Networks own a fibre-optic data network (as a separate commercial function) and extensive use is made of it for electricity network telecommunications. A digital mobile radio (DMR) network has been implemented as the primary voice communication system for EA Networks. DMR offers digital audio clarity and the ability to transparently transport small data packets such as GPS location, device control signals or SMS messages. Another advantage of DMR is the ability to integrate multiple base stations to provide better coverage. The 5 (soon to be 6) base stations are interconnected using TCP/IP over the fibre network.

Other uses of the large reliable bandwidth that fibre offers include the SCADA system and video monitoring of zone substation buildings and yards. This allows not only intruder detection but also an additional layer of safety as the control centre can monitor staff while they are on site and response to any incidents can be immediate.

A more comprehensive description of the telecommunications network is available in section 6.14.

4.3 *Asset Justification*

In order to justify the existence of the present EA Networks owned electricity network assets one could look at it from first principles and prove by calculation that the class and size of each asset category is the minimum needed to support the loads that exist on the network. Alternatively, one could assume that only variations from the Australasian norm would need to be justified – the evolution of the Australasian electricity networks have occurred progressively over the last 50 years and most networks have ended up with a similar style and scale of investment. The following table documents what EA Networks anticipate the electricity industry considers to be the "average" network:

Network Feature	Characteristics
Connection(s) to National Grid:	One or more supply points operating at one or more voltages at or between 11kV, 33kV, 66kV and 110kV. Typical respective capacities: 10-60 MW (11kV urban supply), 20-100 MW (33kV general supply), 50-250 MW (66kV general supply), and 150-500 MW (110kV general supply). Capacity is comparable with the peak load of the supplied network.
Subtransmission Network:	33kV, 66kV or 110kV network with typical respective capacities of 25 MW, 55 MW and 95 MW per overhead circuit. Maximum voltage drop not exceeding 10% during n-1 security events. Typically, overhead lines in rural and light urban settings. Normally underground cables in high density urban settings.
HV Distribution Network:	6.6kV, 11kV, 22kV and rarely 33kV network. Capacity determined by thermal rating for short feeders and voltage drop in long feeders. Rural network and older urban network are usually overhead lines. Newer urban network is usually underground cables. Typically rated at between 200 and 400 amps. Voltage drop should not exceed about 5% under normal peak loading.
LV Distribution Network:	230/400 volt network. Rural network and older urban network typically overhead lines. Newer urban network typically underground cables.
Embedded Generation:	If it exists, it is typically up to several MW at discrete locations around a network. Can be connected to either HV distribution or subtransmission networks. In recent times, solar photovoltaic systems have begun to appear on domestic and some commercial rooftops. These generally do not exceed 10kW output and 100% self-consumption is the most economic strategy.

EA Networks' network can be briefly described as follows:

EA Networks Network Feature	Characteristics
Connection to National Grid:	One supply point operating at 66kV. 66kV capacity 2 x 120 MVA + 1 x 100 MVA. 66kV peak load approx. 180 MW. EA Networks have fewer supply points (1) than most similar companies.
Subtransmission Network:	Extensive 66kV network with capacity 55 MW per overhead circuit (500 amps). Some radial 33kV network (approx. 20MW per circuit) with no alternative 33kV supply. All significant subtransmission is overhead except for one run of 66kV cable in the Ashburton urban area. Prior to conversion to 66kV, parts of

	the 33kV network were operating at 30kV (-10%) during peak loads with all circuits in service.
HV Distribution Network:	11kV and 22kV network. Urban network is mixed overhead and underground 11kV. Per circuit capacity of 200 to 400 amps. Rural network is both 11kV and 22kV overhead lines. Portions of 11kV network can approach 5% voltage drop during peak loading. Prior to conversion to 22kV much of the 11kV network exceeded 5% voltage drop at peak loading.
LV Distribution Network:	230/400 volt network. Rural network and older urban network overhead lines of modest capacity. Newer urban network is underground cables of significant capacity.
Embedded Generation:	Four significant embedded generators: 0.5 MW, 1.0 MW, 1.6 MW and 26 MW. The 0.5 MW and 1.0 MW units are connected to the distribution network. Both larger units are connected to the subtransmission network. The 26 MW unit required dual 66kV circuits from Methven to Elgin to provide security and limit voltage rise.

The reader is directed to section 1.1 for the evolution of the present network and it is hoped that along with this section it provides adequate justification for the network in use today.

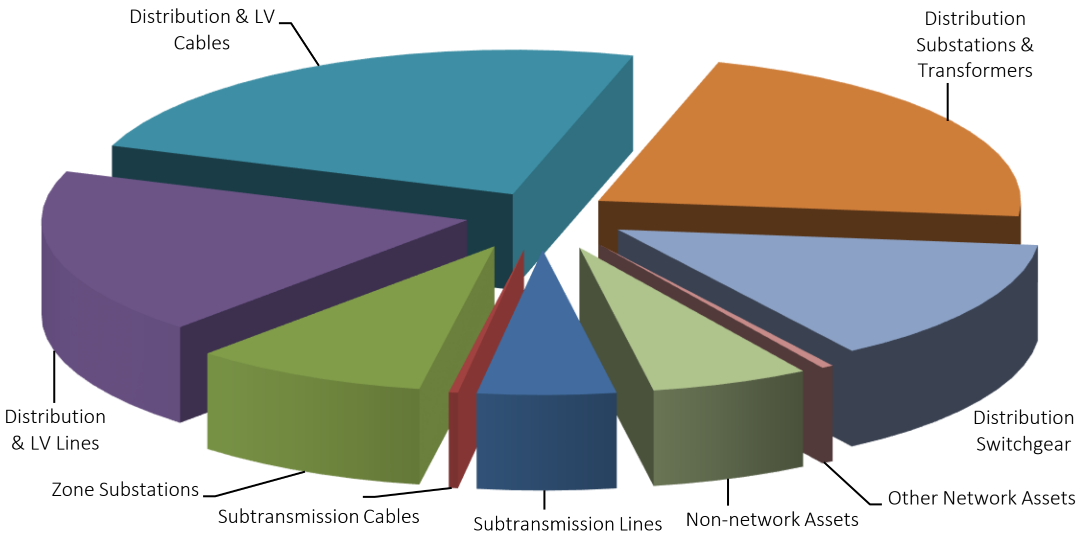
4.4 Asset Value

EA Networks are required by regulation to periodically disclose the value of its assets. This value derived from this process is called the Regulatory Asset Base (RAB).

In order to provide indicative values for the assets covered by this asset management plan the most recent RAB components are detailed below. The table (below) and chart (above) describe the proportion and value of assets in each category.

The values stated in the table and displayed in the chart are extracted from the 2019 RAB disclosure of asset value as at 31 March 2019. The RAB categories are not completely aligned to the categories used in this plan but do provide an indicative distribution of the value in each category.

Summary of EA Networks Regulatory Asset Base (2019)		
Asset Category	RAB Value ($M)	Percent of Total
Subtransmission Lines	12.6	4.7%
Subtransmission Cables	0.8	0.3%
Zone Substations	23.6	8.8%
Distribution & LV Lines	48.7	18.1%
Distribution & LV Cables	72.0	26.8%
Distribution Substations & Transformers	59.8	22.3%
Distribution Switchgear	35.3	13.1%
Other Network Assets	1.5	0.6%
Non-network Assets	14.1	5.2%
TOTAL	**$ 268M**	**100%**



The 2019 closing Regulatory Asset Base (RAB) was $268.45 Million.

Additional information concerning the make-up of EA Networks RAB can be downloaded from:

http://www.eanetworks.co.nz/Disclosures/Regulatory.asp.

PLANNING OUR NETWORK

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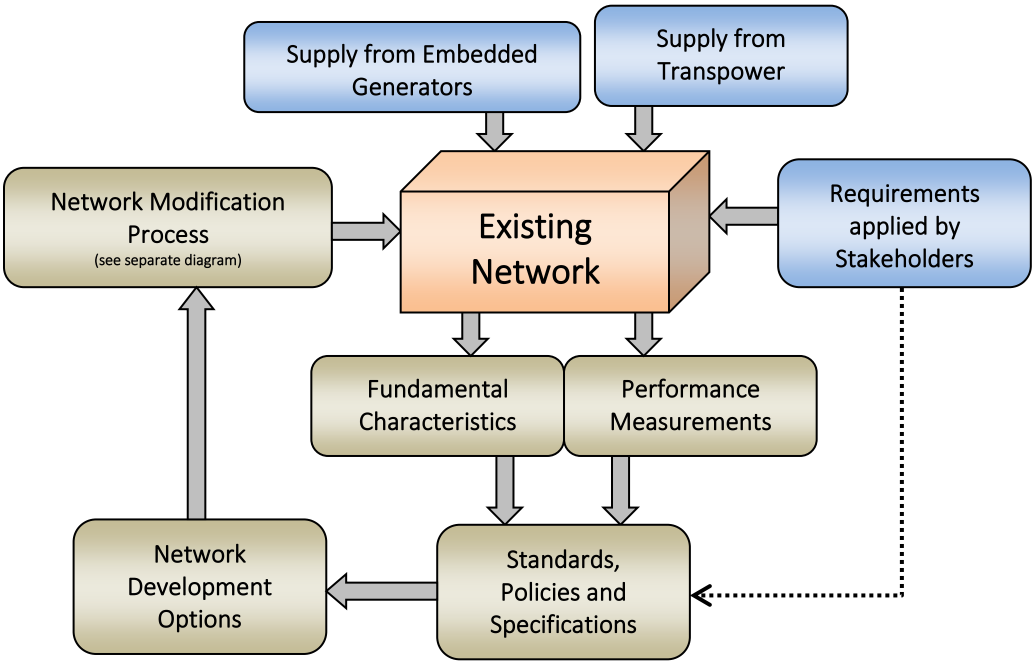
5 PLANNING OUR NETWORK

5.1 Network Development Processes

This section of the Plan attempts to outline the processes and criteria used for network development. It cannot be completely authoritative because the network development environment is not purely technical in nature and normal business negotiations can provide solutions that would otherwise not have been considered.



The EA Networks electricity network that exists today exhibits characteristics and levels of performance that may or may not be adequate to satisfy stakeholders requirements now or in the future. These stakeholder requirements are encapsulated by standards, policies, statutes, regulations, specifications, and contracts/agreements between EA Networks and other parties. If the performance of the network is considered to be inadequate because it does not meet one or more of the stakeholder requirements or a new requirement occurs, some form of network development must be initiated. Once initiated, there are a vast range of methods available to modify the characteristics or performance of the network.

5.1.1 Network Characteristics

An electrical distribution network is fundamentally simple to characterise in electrical terms. Its prime purpose is to transport electricity from one location to another with maximum reliability and minimum loss. The inputs are from either Transpower or a directly connected generator. The outputs are to consumers who are connected to the EA Networks network.

At each point in the EA Networks network the fundamental characteristics are voltage and fault level. The voltage is what consumers observe. The fault level defines how the network responds to demands placed upon it either by loads or faults.

EA Networks use standard voltages that are industry norms and have international standards that support their use. The range over which these standard voltages can vary is partly controlled by standards and regulations. This is particularly so for standard low voltage supplies (230/400 volts). Higher voltages have standard prescribed upper limits that equipment is built to tolerate both in steady state and in temporary overvoltage situations. EA Networks have determined operational limits for all voltages in use. The standards and operational limits are detailed in the following table.

Voltage	Normal Operational Range (Design)	Contingency Operational Range	Maximum Rated Voltage[1]	Short-Time Withstand	Impulse Withstand
66kV	105% to 92.5%	106.5% to 89%	72.5kV	140kV	325kV
33kV	105% to 92.5%	106.5% to 89%	36kV	70kV	250kV
22kV	103% to 96%	103% to 94%	24kV	50kV	125kV
11kV	103% to 96%	103% to 94%	12kV	28kV	75kV
230/400V	106% to 96%	106% to 94%	n/a [2]	n/a [2]	n/a [2]

[1] Maximum rated voltage is approximately 9% above nominal voltage, but other limitations preclude operating at this level.

[2] Because consumers are directly connected at this voltage the voltage limits are determined by appliance tolerance to overvoltages and appliance standards vary. No overvoltage tolerance is assumed.

Fault levels vary depending upon the electrical path taken from the respective supply points. The maximum fault levels observed on the network determine minimum equipment specifications and minimum consumer connection standards. It is possible to control some additions to fault level by specifying new equipment so that it restricts the contribution it can make to the total fault level. High fault levels cause equipment heating, mechanical stresses on equipment, and require the capability for equipment to interrupt high currents.

EA Networks have established limits to the maximum prospective fault current at each voltage level. These are based upon a combination of historical fault levels that Transpower provide, likely future GXP expansion, typical transformer impedances, and future embedded generation. The maximum fault levels are detailed in the following table.

Voltage	Maximum Prospective 3Ø Fault Current [1]	Power Equivalent	Typical 3Ø Fault Current [2]	Minimum 3Ø Fault Current [3]	Typical 1Ø Phase-Earth Fault Current [4]
66kV	16 kA	1,800 MVA	7.5 kA	1.3 kA	1 kA
33kV	4 kA	250 MVA	3 kA	0.7 kA	1 kA
22kV	16 kA	600 MVA	7 kA	0.5 kA	0.3 kA
11kV	20 kA	380 MVA	9 kA	0.5 kA	0.3 kA
230/400V	20 kA	14 MVA	9 kA	0.5 kA	9 kA

[1] This value represents the assessed highest future fault current anywhere on the EA Networks network rounded up to the next standard IEC value.

[2] This value is the typical fault current close to the source of that supply voltage.

[3] This value is at the extremes of the EA Networks network with at least one network element out of service.

[4] All voltages other than 230/400V have Neutral Earthing Resistors restricting the total maximum earth fault current to that shown. Actual currents flowing to earth in a fault would normally be less than this value.

5.1.2 Network Performance

Given a network with the characteristics detailed above, applying the electrical loads, reliability expectations, and the stakeholders' power quality requirements tests the capability of that network to deliver satisfactory performance. The reliability of the network is continuously measured and reported in documents such as this Plan. The two things that determine reliability are fault frequency and the ability of the network to tolerate that fault with minimum or no interruption to consumer's supply. Fault frequency can only be influenced when probable causes can be prevented. Network resistance to faults can be influenced by asset availability, design and operation. Power quality is influenced by many factors, only some of which can be directly controlled by the network owner.

Reliability Requirements

The stakeholders determine the acceptable level of reliability by providing feedback to EA Networks using the methods detailed in section 3.2. This information is used to set desirable network performance criteria which are then measured against the required stakeholder-influenced targets. If these targets are not able to be met using the existing asset configuration or operational methods, then a network development process is initiated. Once triggered, this process is likely to influence the security requirements in some way.

Security Requirements

In simple terms, the security level is determined by the level of redundancy built in to the electricity network either by quantity and/or configuration. Section 3.5 details the criteria EA Networks apply when evaluating the suitability of the network to deliver the required level of reliability.

Power Quality Requirements

The simplest power quality measure is the presence or absence of voltage. Very short blackouts (less than 2 seconds) are typically considered as a power quality issue rather than a reliability issue. The effects can be very similar to a much longer outage, but the cause is generally very different. Another fundamental power quality issue is low or high voltage. Consumer-observed low voltage is typically an indication that the LV feeder load has increased to a point that the network cannot keep within the voltage design range. This unexpected issue would initiate the network development process.

A range of other power quality measures are considered as network development initiators including harmonic distortion and flicker. If reliable measurements show that the network is delivering unacceptable levels of any power quality measure, a response will be initiated.

Section 3.6 details the power quality criteria that EA Networks apply when assessing the performance of the network.

Safety Requirements

If it is apparent that the network is providing elevated levels of risk to people or property the risk will be quantitatively assessed and, if it is unacceptably high, a network development response will be initiated. Sections 1.7.1 and 3.7 outline the primary criteria integrating safety into asset management.

5.1.3 Equipment Characteristics

Any item of electrical equipment should perform satisfactorily when it is used within the parameters considered when it was designed. It is important to respect the limits of any items capabilities while still considering any limited scope to use temporary overload capacity to increase security. An important set of network development criteria relate to the specification of equipment used within the network as the 'network' is simply an assemblage of many individual items of equipment. Once the equipment is in the network, how it is operated is as important as how it was specified.

Specifications

EA Networks specify all equipment to exceed the relevant electrical parameters detailed in the Network characteristics section above. This ensures the item will operate reliably regardless of its location within the network. Each type of equipment (transformer, circuit-breaker, cable etc) has additional characteristics that are specified on a case by case basis, but every effort is made to specify standard models of equipment with standard ratings tested to internationally accepted specifications such as IEC.

The capacity and performance requirements of each asset type is detailed in Section 5.4.

Operating Range

Every item of electrical equipment has a rated current and a rated voltage. Utilising these ratings to their maximum (or above) during contingencies can provide a more secure network. To do this reliably, good knowledge is required of the overload capabilities of the equipment and the effects any overload will have on continued equipment operation.

To allow adequate margin for contingent operation, the normal level of operation must be below the rated maximum capacity. Different categories of asset may permit unique (over)loading characteristics.

EA Networks have a largely radial distribution network with multiple interconnections to adjacent feeders and zone substations. The same principle applies for urban 230/400 volt distribution between distribution substations. This network architecture assumes that if an item of equipment fails, the distribution network will be able to back-feed from adjacent feeders. In most cases this will mean a faulted feeder will have at least two adjacent feeders that can provide back-up and a faulted transformer would have two adjacent substations to provide back-up. These principles allow the following general design/operation thermal limits to be stated in the following table.

Asset Type	Assumed Conditions	Normal Operation	Contingent Operation	30 minute Operation
Power Transformer	Still Air @ 25°C	100%	120%	135%
Overhead Conductor	1ms^{-1} Air @ 25°C	75%	100%	110%
Underground Cable	Ducted in 15°C Soil	75%	100%	110%
Feeder Circuit-Breaker	Air @ 25°C	75%	100%	100%
Disconnector /Switch	Air @ 25°C	50%	100%	100%

For specific network development designs these general guidelines for normal operation are indicative only. Certain situations may require lower or permit higher loadings than those shown. The contingent operation limits are fixed and determine the required nominal rating of each item of equipment based on any contingent scenarios considered at the design stage.

The operational voltage limits of equipment have been incorporated into the network characteristics contingency limits detailed above (see Section 5.1.1).

5.1.4 Design Standardisation

An approach to design that encourages standardisation has many advantages that can provide tangible cost efficiency gains. Provided the standard designs are not over-specified for the average application (a design that considers the anywhere anytime worst possible case is generally over-specified) then EA Networks will normally consider adopting the design for use elsewhere.

The standardisation approach is particularly prudent when external design expertise has been used to certify or validate a design such as seismic or structural elements. Repeated use of external consulting to 'optimise' a design is frequently a loss-making exercise (the cost saving in optimised equipment is less than the consulting cost of the expert). In these circumstances, the designer is advised of the need to consider the design to be a 'standard' design and document the environmental and operation limits of the design so that it can be reused with confidence within those limits.

The tangible benefits of standard design include:

- Lower equipment population lifetime engineering costs, although the initial standard design process may be much more time consuming than a one-off design.
- Standard designs can be applied by personnel with less design expertise provided they appreciate and keep within the limits of the design.
- Staff and contractors are familiar with the techniques used to construct and operate the design, which should promote a safer operating environment and more cost-effective construction.

- Design staff have confidence that the design will perform as expected (based upon experience already gained with the design).
- Minimising the stock of spare equipment that must be kept for repairs and new on-demand projects.
- Incremental design improvements can normally be incorporated without affecting backwards compatibility.
- The components for the standard design can be purchased in bulk which encourages cost-effective procurement.
- Standard designs based upon standard components can be more cost-effective assuming the components are in turn based upon some common standard that allows multiple competitive sources for the component.
- Any issues that may arise with a standard design can be attended to with a universal solution rather than individually engineered solutions.

EA Networks' standard designs are identified by the frequency of use and the incremental cost of both the equipment and the design resource required to adequately engineer a solution. If a design is expensive to do and the equipment relatively inexpensive then is makes sense to standardise the design. Alternatively, if the incremental cost of equipment is expensive and the design is relatively inexpensive it could make sense to individually examine each application of the equipment to ensure it is necessary and not excessive in that specific circumstance.

An example of expensive design and relatively inexpensive equipment is protection schemes. The design effort required to specify and document the details of a 66kV bus zone scheme are typically more than the cost of the protection relay hardware, so it makes sense to standardise the design. Conversely, long runs of 66kV cable are incrementally expensive to increase in size and it pays to spend sufficient design time to ensure the optimal choice is made (within a preferred selection of sizes).

The following table identifies the range of standard designs (either in full or in part) that contribute to the cost efficiency of EA Networks' asset management:

GXP	
Transformer Size	Compatible with transformer n-1 situations i.e. firm capacity is n-1 x transformer capacity rather than sum minus largest single unit.

Zone Substation	
Transformer Design & Size	Standard size, foundation interface, HV outdoor interface, MV cable interface, control cable interface, impedance, tap range etc allow any 66kV transformer to be relocated to any other site without redesign. All units can be parallel connected if needed.
66kV Bus and Line/Transformer Bays	Seismically certified stand designs and buswork designs are reused at each new/expanded site.
Foundation Design	Seismically certified foundation designs are reused at new/expanded sites.
Building Design	A standard seismically certified building design is reused where appropriate.
Protection Design	Standard protection designs are reused at new/expanded sites for 66kV lines, 66kV bus, 66kV transformer, and 22kV feeders.
22kV Switchgear Type	A restricted range of 22kV switchgear types maintains

	compatibility with standard buildings/foundations, mounting frames, arc flash controls, and seismic restraints.
66kV Switchgear Type	Standard styles of 66kV circuit-breakers (dead tank) and disconnectors (centre rotating) ensure foundation, stand, and mechanical interfaces are all compatible with the standard designs.

66kV Overhead Line	
Structure Designs	All 66kV structures are standardised other than for very rare specific applications.
Conductor Type & Size	A limited range of conductors is used at 66kV (currently only 2). This assists in minimising structural design and inventory of spares and production stock.

66kV Underground Cable	
Cable Size & Type	Wherever possible, one of a limited selection of standard cable sizes are used. Only two types of cable construction have been used.
Trench Profile	A standard trench profile/backfill has known thermal and mechanical performance characteristics which do not require further design for reuse.

22kV Overhead Line	
Structure Designs	All 22kV structures are standardised other than for very rare specific applications.
Conductor Type & Size	A limited range of conductors is used at 22kV (currently 4) when building new lines. This ensures spares and production inventory is kept to a minimum.

22kV or 11kV Underground Cable	
Cable Size & Type	A limited selection of cable sizes and types is used to keep the stock of spares and accessories to a minimum.
Trench Profile	A standard trench profile/backfill has known thermal and mechanical performance characteristics which do not require further design for reuse.

Distribution Substation	
Foundation Designs	Several standard seismically designed foundations are in use. A number are precast designs which are recoverable for reuse should the site be decommissioned.
Kiosk Cover Designs	A range of standard kiosk covers with matching foundations allows a versatile mix of standard modular substation

	components to be combined. An example would be a high capacity substation consisting of: MV kiosk for MV switchgear, a precast pad for the transformer, and a LV kiosk for the LV switchgear.
Switchgear Support Frame Design	Support frames for MV and LV switchgear is standardised and allows different standard switchboard design combinations to be accommodated.

Distribution Transformer	
Size	Standard sizes based upon industry standards.
Bushing Interface Design	Interchangeable outdoor (porcelain) and indoor (bushing wells for screened elbows) bushings, which mean the transformer manufacturer's standard configuration can be accommodated under kiosk covers (no special bushing layout for EA Networks).
Foundation Interface Design	All ground-mounted transformers have standard hold down positions which ensures standard foundation use, full interchangeability and certified seismic strength.

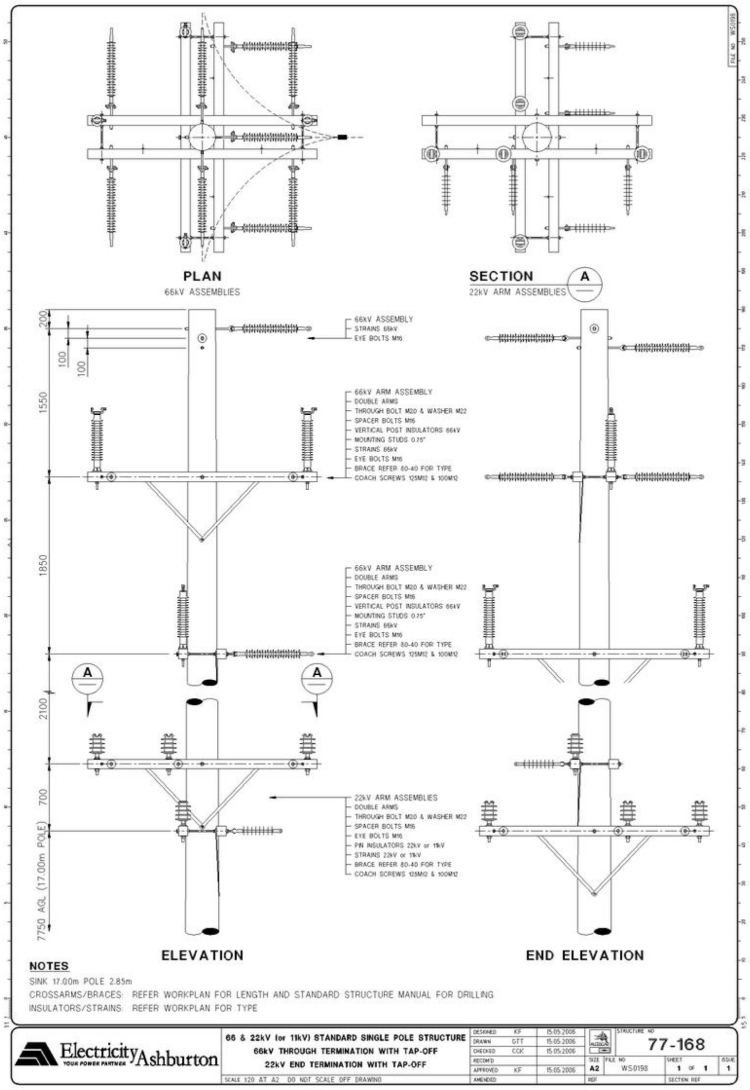
HV Switchgear	
Mounting Design	Gas switches, RMUs, 22kV or 66kV zone substation CBs all fit on standard mounting frames or foundations.

LV Switchgear	
Model Range Limitation	Three styles of LV switchgear are used, and each has standard housings and mountings. The link/distribution box switchgear has a standard touch safe busbar that accommodates modular switch types. Only the necessary modules are initially installed but any combination is possible after installation.
DIN Standard Design	The use of DIN standard design LV Fuse Disconnectors allows standard busbar mounting and interchangeability with multiple manufacturers' equipment.

LV Underground Cable	
Cable Size & Type	A limited range of cable sizes and types is used to keep the stock of spares and accessories to a minimum.
Joint Types	Standard joint types for standard cable sizes allows stocks of spares to be kept to a minimum.
Box Designs	Standard box designs and layouts allow spare box stock to be kept to a minimum and known capacity of LV switchgear can be accommodated. Also allows production of preassembled boxes for stock.

SCADA & Communications	
SCADA Protocol	Use of the industry standard DNP3.0 protocol ensures that engineering work is limited to settings 'per device'. Combined with standard protection designs this encourages engineering efficiency.
Ethernet Switches	The layer 2 Ethernet switches in use within the SCADA data communications infrastructure are all industry standard devices which are interchangeable with various makes and models.

Standard Design Drawing for 66-22kV Overhead Line Structure



5.1.5 Statutes, Regulations, Standards and Policies

Almost all network development will be in response to one or more non-compliant network performance measures which are in turn based upon statutes, regulations, standards, policies, codes, specifications, contracts or agreements. The range of documents this covers is significant and only those that have broad application will be detailed here.

- Safety. Overarching all the other criteria is the requirement to design, build and operate the network in a safe manner.

- **Statutes and Regulations**. Statutory/regulatory obligations are a given and the network is operated and developed to comply with all statutory requirements.
- **Service Levels.** Service levels are set by agreement with stakeholders and these can change from time to time. Service level standards flow through into many technical standards which are intended to result in a network that meets the service level standards.
- **Technical Standards.** These cover the bulk of asset intensive network activities. Areas covered by technical standards include: Equipment Specifications, Procurement Standards, Design Standards, Construction Standards, and Maintenance Standards.
- **Financial Requirements.** EA Networks need to make an adequate return on new network development. Any network addition must meet minimum criteria for financial viability. The viability threshold is normally a rate of return set by the board from time to time. A determination of viability can however be a trade-off with other (possibly future) benefits that are less tangible in the short term.
- **Use of System Agreement.** All consumers who connect to the EA Networks network are bound by the obligations of the use of system agreement via their Retailer. This document encapsulates references to other policies and standards that ensure consumers do not cause unexpected effects on the network or other users of the network. Equally it obliges EA Networks to provide the levels of performance prescribed by the multitude of standards and policies currently in force. The Connection Standard referenced by the Use of System Agreement includes obligations on consumers regarding underground connection, power factor, harmonics limitation, motor starting limitation and consumer owned equipment safety.

The policies and standards of EA Networks are based on certain underlying principles. The following list provides a broad summary of these:

- The network will not present an elevated safety risk to staff, contractors, the public or their property.
- The network will be designed and operated to meet or exceed all statutory requirements.
- Procurement and installation of network equipment will be compliant with network standards and manufacturer's instructions to ensure optimal life and performance.
- Network developments will provide an acceptable commercial return for EA Networks.
- Different consumer connection groups will have different reliability and security standards applied to them which represents the price/quality trade-off.
- The reasonable electricity capacity requirements of a consumer will be met.
- A prudent level of additional capacity is designed into the network to allow for predicted load growth.
- All network assets will be operated within the design thermal and voltage ratings to ensure they are not damaged by overloading or overstressing.

5.1.6 Network Development Initiation

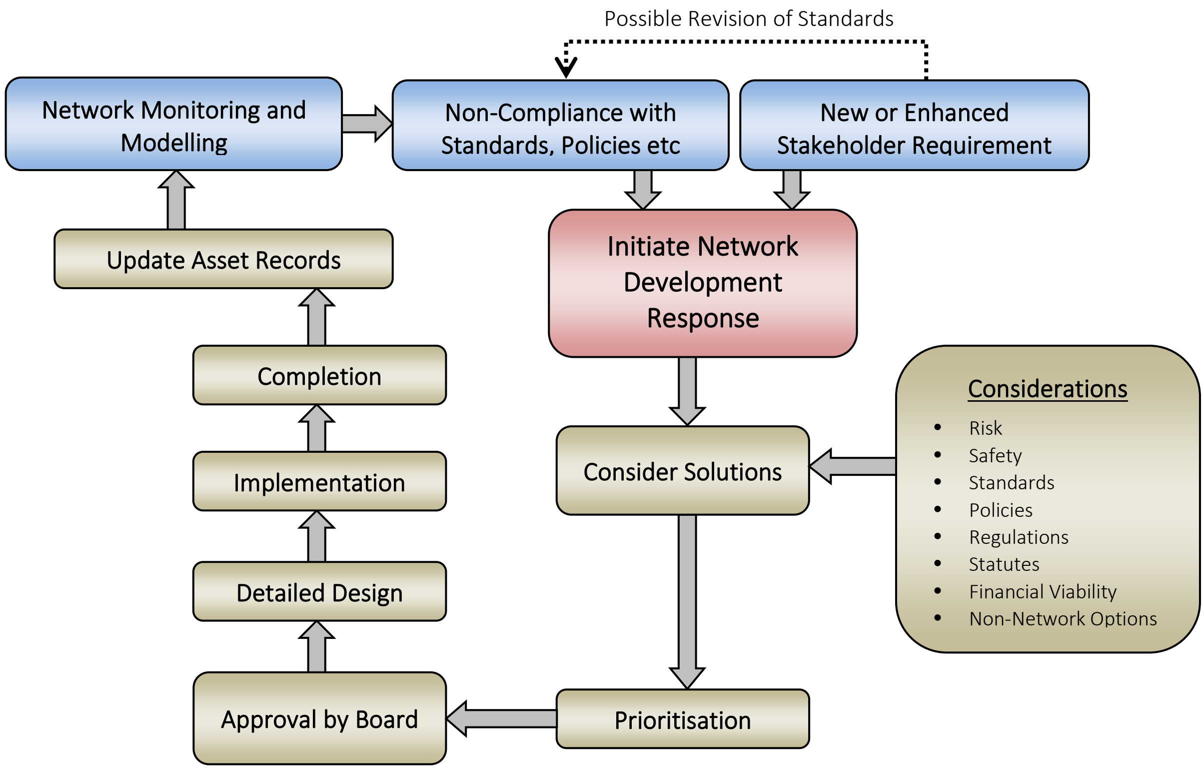
The network development planning process is tightly integrated with this plan. The diagram of section 1.7.1 gives some idea of the continuously looped sequence of events that deliver the network development strategies presented in this plan. Given that there is an existing network that exhibits certain characteristic levels of performance, the best place to enter the loop is by measuring the performance of the network 'Network Monitoring and Modelling'.

There are essentially two key reasons the network development process will be initiated.

1) If an existing or new stakeholder approaches EA Networks with either new or increased electrical remand or a desire for enhanced requirements/characteristics at the interface(s) with EA Networks.
2) One or more of the statutes, regulations, standards, policies, codes, specifications, contracts or agreements is not being complied with.

Once the process is initiated it goes through the same series of tests and justifications as any business proposal.

Network Development Initiation, Modification Process and Responses



5.1.7 Network Development Implementation

Once an option or strategy has been adopted and approved, it is incorporated into the internal policy documents as well as the Asset Management Plan. This will cause any new project or programme to comply with these approved strategies. An example of this would be the continuing use of 22kV conversion as a solution to increasing distribution system capacity and quality issues as the norm. 11kV reconductoring projects would require a different style of approval mechanism as they do not fit an approved strategy.

Once a project is approved by the Board it enters the normal process for scheduling, detailed design and construction. This is typically completed using internal resources. Once complete, the new/altered asset is incorporated into the asset records and the fiscal/accounting aspects completed.

5.1.8 Network Development Options/Considerations/Methods

There are multiple possible reasons the network development process has been initiated. Not all of these will involve changes in load or security, although the majority do. At times, stakeholders will request changes in perceived safety or even aesthetics and the Shareholder Committee, Board and management will consider these requests with the same rigour as any other.

The options available to respond to changes in load or security are very similar in many cases. They will typically involve a change of operating technique for existing assets, an upgrade of existing assets, or the addition of new assets. Non-network solutions are considered but must be suitable to the stakeholder both commercially and practically.

Each of the following options is carefully evaluated based on economic efficiency and technical performance. Wherever possible, capital-intensive development is delayed until absolutely necessary and non-asset intensive solutions used where these are not incompatible with future development plans. The first three solutions listed are essentially non-asset intensive (non-network in some cases).

The options include:

- Tariff structure (Non-network)

Demand based tariffs give the end user strong incentives to reduce peak demand and maximise plant load factors. This results in less peak demand and better regulation on the EA Networks network.

- Demand side management (Non-network)

Use of Demand Side Management is linked to the tariff structure and allows the consumer or EA Networks to control the internal demand by shedding non-essential load at peak periods. The success of demand side management is related to the value the consumer places on electricity at peak times versus the cost of supplying electrical demand at that peak time.

- Line drop compensation (Non-network)

Line Drop Compensation (or LDC) can be used in specific circumstances to boost the sending end voltage on a feeder to improve down line regulation. This effectively increases the available capacity on some feeders.

- Localised energy generation and/or storage

The rise in availability and reduction in cost of both solar photovoltaic generation and battery storage (household level and grid level) allows various combinations of these to be a consideration for resolution of a network constraint or security issue. Solar PV alone will rarely be able to provide the necessary predictability or availability. Batteries can be used with or without local forms of generation to provide on-demand power/energy. The main constraint with battery solutions is the initial cost and the capacity they offer. The normal life expectancy of both the batteries and the power electronics (10-15 years likely maximum) must be factored into any comparison with a longer life (40+ years) conventional asset-intensive solution.

- Voltage regulation

Voltage regulators can be a useful measure if load growth can be reliably predicted. If the load exceeds the rating or boost capacity of the regulator, a new larger unit must be purchased requiring the smaller unit to be relocated, stored or sold. Regulators can increase losses and are an increased security risk as they can fail (a spare is therefore required).

- System reconfiguration

System reconfiguration is the first choice of any asset manager in accommodating additional load. Caution must be exercised to ensure that the combination of reconfiguration and new load does not compromise the security levels offered to existing and new consumers. Typically, the capacity liberated by reconfiguration is limited.

- Reactive compensation (capacitors or power electronic devices)

Installing capacitors at strategic points in the network where voltage constraints are present or imminent can postpone the need for more asset intensive solutions. In some cases, load growth for a particular installation may require increased reactive support, and the consumer is required to contribute to the capital expenditure involved. Irrigation sourced harmonic levels on the EA Networks network make a capacitor option more expensive than on many other networks.

Recent development of lower cost power electronic devices that can provide power compensation are another option. These may be able to simultaneously provide other functions such as harmonic filtering.

- Conversion to a higher voltage

Conversion to higher voltage is particularly effective solution. Doubling the voltage (from 11kV to 22kV as an example) provides a four-fold increase in capability when the line is voltage constrained. The cost of voltage conversion is higher than some of the other solutions, but it provides a capacity increase that none of the other options can.

- Reconductoring

Reconductoring is asset intensive and can require involve significant cost if the poles supporting the existing conductor are insufficiently strong for the larger conductor. The additional capacity introduced by reconductoring depends on the pre-existing conductor size. The most one could typically expect to achieve on the same poles would be a 100% increase in capacity (for example, going from a Mink sized conductor to Jaguar – an increase from 220 amps to 500 amps).

- Overlaying with a higher voltage

Overlaying with a higher voltage (LV with 11-22kV or 11-22kV with 66kV) is very asset intensive, and often cannot be justified in terms of the cost involved. In many cases this cost must be borne by the consumer requesting the new or increased supply and becomes their decision in the final analysis.

- Additional SCADA remote control

Automation allows timely pre-emptive or reactive responses to impending or actual events. This can effectively increase reliability and can possibly liberate additional capacity.

- Load Diversity

Ensure that the diversity within and between different types of consumer groupings are accurately modelled. If the peak demands of each group do not coincide then capacity is either liberated or not required.

- Loading Knowledge

Accurate information about the existing network loading is essential to permit accurate calculations of spare capacity and the need for upgrades or additions.

- Long-Term Planning

Every solution should be compatible with the long-term plan for network development. This will ensure minimum long-term cost and disruption.

- Coordinated Development

All the proposed projects on the EA Networks network (development, maintenance, replacement etc) must be fully coordinated to ensure any possible synergistic benefits are realised.

The load growth estimates are used as a basis for determining the likely timing of projects which are justified by load growth and/or security.

The performance targets are used to develop strategies to accommodate both increased demand and other (presumably) improved performance targets. These strategies cover all voltage levels and asset classes and include non-asset solutions. The different strategies are evaluated against each other and the feasible options are then presented to the Board for consideration (see section 1.7).

Network/asset performance is multidimensional. There are capacity, regulatory, cost, reliability, safety, environmental and power quality dimensions that trade off against each other. For example, to have the lowest possible risk to personnel there is likely to be a compromise with either cost or reliability. It is generally more expensive to do live line techniques than to have an outage and work with the network earthed, but the trade-off is that live line work makes the reported system reliability higher while incurring some additional risk (or at least a different risk spectrum). EA Networks presently take the approach that live line work is only used where the benefits comprehensively outweigh the risk and cost.

The measurement of all network performance must be objective and complete.

The capacity of the network is the biggest issue that is debated between the regulator, funder, network designer, network owner, network operator, and consumer (all stakeholders). Too much capacity and it is seen as wasteful. If there is too little (or it is delivered too late) then it is seen as poor service. While there are no simple ways to measure performance in this area, the Board have the desire that any small-medium consumer (typically <500 kW) that applies for a new or enhanced connection before the end of one irrigation season can expect to be connected before the next season starts. It must be explained that the term ‘irrigation season’ implies that an application received before April would be connected by September. Most other urban and industrial connections are easily achieved within this timescale. In order to provide a prudent level of capacity, the estimated 10-year future load (as per Appendix C) is used as a minimum to size distribution assets when they are installed.

Regulatory performance is a given. All personnel are fully conversant with the regulations that cover their area(s) of responsibility and they are always expected to comply with them (see section 1.7.6). Measuring performance in this arena is as much about peer awareness and external observations (such as other organisation’s performance and practices) as it is about internal processes and systems. There have been rare occasions when non-critical regulatory requirements were unable to be achieved. These are generally resolved in the shortest possible timeframe and the necessary resources engaged to prevent a recurrence. Unless the non-compliance is consequential it is not explicitly reported.

EA Networks believe that they are painstaking in their efforts to ensure the network reliability indices reported reflect all incidents that require inclusion in those indices. All outages are ‘traced’ using the electrically connected model included in the Hexagon GIS system to obtain a list of affected connection points. All faults are then entered in to the 'Faults' database and this allocates all connection points interrupted by that fault to it. This allows every connection point interruption to be identified and, if necessary, individual CAIDI and CAIFI values reported. The 'Faults' database provides the storage and analysis of EA Networks' reliability data.

The financial performance indicators are as accurate as the data they are based upon. This presumes that the categorisation of all projects is precise and that allocation guidelines are followed in every instance. These financial values are subject to audit and consequently there is no reason to doubt their precision.

Safety, power quality and environmental performance is measured and recorded in systems that are best suited to each area.

The safety performance data is integrated with competence, training and other personnel specific information in a system that runs in parallel with the asset management environment. Any safety issues that are linked to asset performance are reported via the Safety Committee to the Network Manager. The Network Manager then obtains engineering advice on available solutions to mitigate or eliminate the source of risk. Where necessary, that solution will be inserted into the asset management approval process for acceptance into the appropriate methodology by the management and/or Board.

The power quality performance (other than outages) is monitored in a less sophisticated fashion than some other parameters. Consumer level voltage performance tends to be monitored on demand using small data loggers that provide files that can be analysed for compliance with standards of steady state voltage as well and momentary excursions. These are registered as a simple 'justified' or 'not justified' tag for the purposes of a 'Voltage Complaint' index. Harmonic distortion is a power quality parameter that EA Networks have become too familiar with in the two decades. In 2007, an awareness of the distortion levels on the EA Networks network was obtained. A collection of both portable and fixed harmonic monitoring equipment was purchased/installed. These devices have accumulated large volumes of data that can be analysed for both compliance with standards as well as examining trends in background/average values. As mitigation measures were enforced, their effectiveness was measured over time. It is satisfying to report that they now show compliance with industry guidelines.

Environmental monitoring has been limited to compliance with the relevant legislation and Regional/District Plan rules. This particularly concerns noise, gas and liquid discharges, and District Plan aesthetic rules. EA Networks monitor and, where necessary, record the loss levels of gases (such as Sulphur Hexafluoride) as well as fluids such as transformer and hydraulic oil or stormwater from transformer bunds. The aesthetic rules relate to all new plant being underground in urban and fringe urban zones. These zones are well known and there have been no issues of non-compliance.

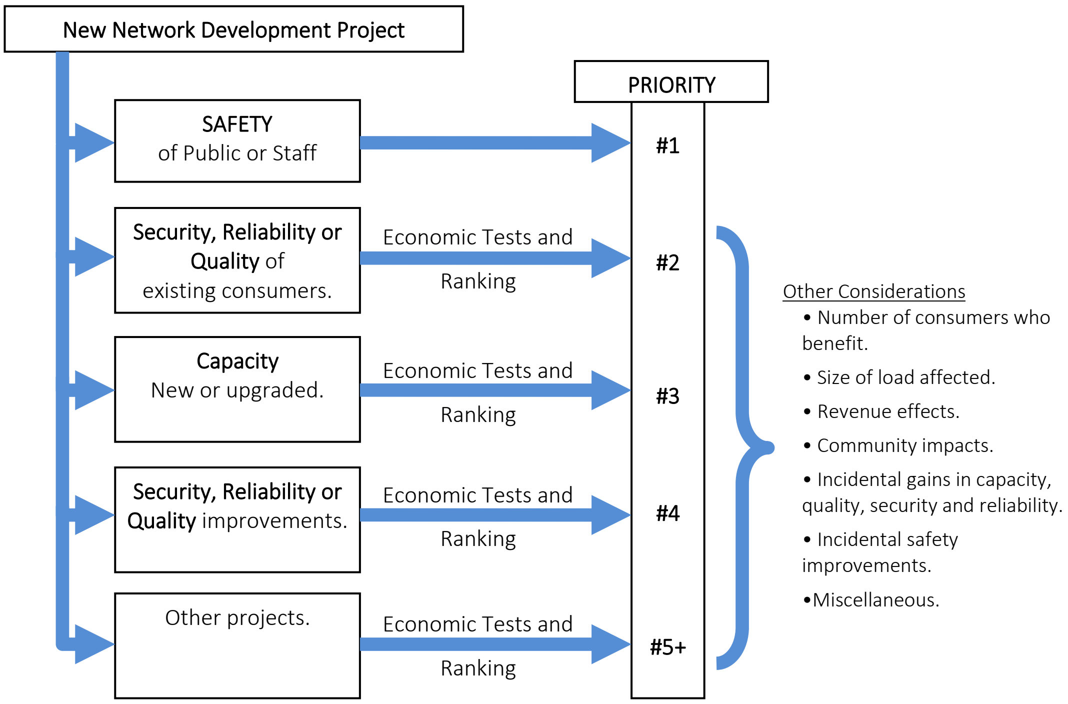
5.1.9 Network Development Prioritisation

Particularly during periods of rapid demand growth, there is a tension between various projects that need EA Networks' available financial, physical and intellectual resources. The resolution of which issue requires priority is not necessarily straight forward. The general methodology and criteria for the technical and financial evaluation of network development projects can be summarised in the diagram shown below.

The required economic rate of return is set in the Statement of Corporate Intent. This rate of return can occasionally be discounted when other less tangible benefits can be identified.

Any capital expenditure must be fully justified and in normal circumstances such a project is expected to add value to the company by providing a competitive Return on Investment (ROI) over a 40-year life. Competing projects are compared using Internal Rate of Return studies (IRR), and this is used to prioritise the order of projects in terms of Net Present Value (NPV). This determines which projects can be justified for funding out of a limited capital budget.

Ultimately, it is the Board that dictates the immediate focus for the company, and they consider not only the advice offered by management but also external factors including matters such as public perception, politics and overarching business strategies.



5.2 Load Forecasting

5.2.1 Introduction

Future load projection is a difficult task and is based on a complex multivariate environment. A careful and rigorous approach must be taken to developing future load projections based on historical trends, available information and estimates on future changes.

5.2.2 Derivation of Forecasts

Forecasts of maximum demand on the subtransmission system have been derived from internal modelling work. Sources of information include:

- Historical demand and energy usage data,
- A report commissioned by EA Networks from farm management consultants Englebrecht, Evans & Co Ltd,
- Discussions with real estate agents, well drilling contractors, irrigation system consultants and other service/equipment providers for rural industries,
- Major consumers connected to the network,
- The "Canterbury Groundwater Study: Sustainable Yield of Aquifers in Ashburton District" – April 2005,
- The "Ashburton District Development Plan" – June 2005,
- The “Canterbury Irrigation Peak Electrical Load” report prepared for Transpower NZ Ltd by Aqualink Research Ltd – November 2010,
- “The economic value of potential irrigation in Canterbury” prepared for Canterbury Development Corporation by AERU Lincoln University - September 2012,
- “Canterbury Strategic Water Study (CSWS) Stage 3” Lincoln Environmental – 2008,
- “Canterbury Water Management Strategy” Canterbury Mayoral Forum – November 2009,
- “The economic impact of increased irrigation” NZIER - November 2010,
- Environment Canterbury reports and resource consent applications.

- Electric vehicle uptake statistics from NZTA and trends in solar PV applications to EA Networks.

These information sources have been used to generate a forecast (Estimation) that analyses individual zone substation maximum demands based on present demand with likely additional load allocated by each zone substation for the next ten years. This model has the advantage of locating the estimated load within the subtransmission and distribution networks allowing analysis of the capacity utilisation of many network components. The disadvantage of this forecasting technique is that unknown future loads are not accounted for.

An alternative statistical projection based upon historical demand data cannot account for the now observed downturn in irrigation load growth caused by water extraction restrictions. On the other hand, the individual load estimation reflects that downturn but does not account for unknown future load. The historical projected load growth is considered unrealistic. The estimated load growth has been revised to reflect water extraction and now nutrient run-off restrictions recently imposed by ECAN. The summer system maximum demand will probably be about 188 MW by 2030.

5.2.3 Significant Drivers

Some factors that could significantly affect electricity consumption have been taken into account in the forecasting process, and these have been projected forward. They are:

Population Impact

Population projections, broken down into local supply areas are provided by Ashburton District Council's District Plan. The impact of population growth on load is largely that of additional domestic consumption, although population-based industries such as entertainment and retailing also tend to grow. Domestic loads are typically peaking at mealtimes and early morning and are obviously concentrated in urban areas. Cold weather will also cause domestic consumption to rise and the coldest weather typically causes the regional/national peak in electricity demand. Hot weather is also beginning to increase demand as domestic heat pump/air-conditioning units become much more ubiquitous. The impact of purely population driven demand is much lower in the EA Networks network than in many others because the irrigation demand is so dominant. There has been no measurable impact on demand post-earthquakes caused by Christchurch residents shifting to Mid-Canterbury.

Price Impact

In an efficient environment, energy prices (at least for marginal sales) should be close to marginal cost. Marginal prices have spiked very high in some years due to a shortage of fuel for generation. Electricity growth could begin slowing down as prices increase. This may not impact on the growth in system maximum demand however, since maximum demand is measured over any half-hour period - a short time for energy consumption. The use of energy may become more selective - only when the return on expenditure is high (a very dry year in the case of irrigation).

To date, the increasing price of electrical energy does not appear to have changed usage patterns or volumes to any measurable degree. Most people see electricity as an essential service that they cannot do without and are not currently making decisions based on doing without. Industries may be looking for more efficient technologies to use electricity, but few are abandoning its use for alternatives.

Price may encourage consumers to seek alternative energy sources. The ability to generate and store electricity at home using solar PV and batteries is here. What this is likely to mean is that over time energy through the meter will drop but maximum demand in winter will remain. Daytime demand will be lower for residential consumers, but night-time and winter demand will likely remain high.

Closure of the Bluff aluminium smelter could have a significant impact on electricity prices. When, or if, that happens, consideration will be given to the degree of price decrease and the consequential increase in demand.

Major Industries Impact

Most forecast increases in load are an indirect response to economic and demographic pressures and cannot be related to any particular electricity consuming development. Some major industrial loads can be anticipated however, particularly in the food processing industry. Unfortunately, these are also the most difficult to predict or quantify as they depend on investment decisions from major industries. Historically, final commitments on these projects have been deferred to a very late stage, often involving significant last-minute load revisions, leaving EA Networks in a difficult situation from a planning perspective.

Meat processing industries and the food processing industry generally are of sufficient size (and in specific locations) to need to be studied separately. These industries are generally year-round with relatively consistent loads and are not weather dependent. The existing industrial loads greater than 1 MW are limited to RX Plastics (plastic product manufacturing), ANZCO Seafield (meat processing), Talleys Fairton (vegetable processing), ex-Silver Fern Farms Fairton (refrigerated storage), Mt Hutt ski-field (snow making & tows) and Trustpower BCI Highbank (irrigation water pumping). ANZCO is served directly via a dedicated zone substation and security is negotiated directly with them. The ex-Silver Fern Farms Fairton plant is likewise served directly via a zone substation which also serves Talleys via a relatively short 22kV feeder. Mt Hutt ski-field has a dedicated zone substation. The large (2 x 950 kW) air compressors for snowmaking have been replaced with a smaller set of compressors and this has decreased the ski-field load. The water pumps associated with the snow-making system cause large voltage depressions on the zone substation 11kV bus during starting. No other consumers see this voltage depression. Mt Hutt is a winter only load. Trustpower BCI Highbank has six 1.5 MW pumps (1.4MW loaded) that run during summer. The supply to these pumps is from a Trustpower owned 66/11kV transformer. EA Networks provide a single circuit 66kV supply to this transformer. All these loads have to some degree individually negotiated their capacity and security.

Dairy farming and irrigation are the dominant industrial loads in the EA Networks network, and these have been growing at a significant rate. Irrigation load has been the dominant contributor to system peak demand for many years and will continue to be so for the foreseeable future. Total chargeable irrigation load now exceeds 148 MW (including almost 9MW of pumping at Highbank Power Station). It has been suggested by most informed industry commentators that conversion to spray irrigation development of farms (both dairy and cropping) is largely complete and further irrigation development is limited by both water availability and nutrient run-off issues. The other factor with potential to affect electrical irrigation load is the piping of historically open race irrigation schemes. This conversion can provide gravity pressurised water at the farm gate displacing the previous electric pumping. The new BCI scheme is also predominantly a gravity pressurised piped scheme. Some pumping is required when insufficient gravity head is available. It is unknown whether the reliability of the piped schemes is sufficient for farmers to forego the back-up of a deep well electric irrigator. Only a handful of farmers have so far chosen to permanently disconnect pumps.

The irrigation load is very dependent on weather conditions. During a "wet" summer the diversity in use of irrigation plants increases considerably, which in turn lowers the simultaneous demand placed on the EA Networks network. A "dry" summer tends to remove the diversity from irrigation load and can cause very significant jumps in maximum demand from year to year. As an example, 2005-06, had a summer peak demand of 104 MW while a year later (with the addition of 8 MW of new irrigation plants) the summer peak demand dropped to 100 MW because of a less arid summer. The current irrigation season started relatively late (end of October) and sporadic rainfall has constrained the peak demand to 177MW. In 2010-11, the summer demand peaked at 148 MW. A year later, the demand peaked at 143 MW despite the addition of 17MW of irrigation load. In summer 2017-18, an all-time high maximum demand of 181 MW occurred. 177 MW was the previous record maximum demand and that occurred in a relatively ‘normal’ year (2015-16) and in 2018-19 the peak was only 158MW.

Large irrigation plants can range up to 300 kW in size for an individual pump (this is equivalent to about 100 residential homes). The irrigation "season" can start as early as August and last until as late as April. Once operating, an irrigation plant can typically be left to run for days or even weeks - particularly the centre pivot types. Electrically irrigated farms were historically restricted to more coastal parts of Ashburton district. Over the last two decades, deeper and deeper water wells have been funded by the improved economics of intensive farming. This has caused the load density to intensify closer to the Southern Alps which is further from EA Networks’ GXP. This increases losses in the subtransmission network.

Historically, irrigators have indicated (after being consulted specifically on the issue) that they would prefer to pay higher charges than be subject to load control at times of maximum demand. The network has evolved to suit that requirement. This attitude does not appear to have changed and the returns from irrigation are sufficiently high that it has been assumed that there would have to be a major change in global food demand to influence prices sufficiently to make load control an acceptable option.

Two significant irrigation developments have been implemented in recent times. The schemes are generally described as the ‘Barrhill Chertsey Irrigation (BCI)’ scheme and the ‘Acton’ scheme.

The BCI scheme consists of a water intake from the Rakaia River supplying a pumping station lifting up to 8 m^3/s ($4m^3/s$ initially) of the water from river level to the normally empty end of the Rangitata Diversion Race (RDR) and a piped pressurised water distribution network on the plains. In electrical terms, the item of interest is the pumping load. The initial pumping station is a load of 9.0MW composed of 6 x 1.5 MW motors. More motors are being mooted, potentially taking the total load to 12MW. The impact of this load on the subtransmission network is considerable and it has been arranged so that it is interruptible during subtransmission outages. Additional pumping load on the distribution network has been allowed for as the scheme will liberate water for on-farm pumping from other parts of the RDR. The water distribution network will be a gravity pressurised pipe network which will only require small amounts of electrical pumping to boost pressure at the initial points of offtake from the RDR. This may reduce the overall electrical pumping load on the EA Networks network over time.

The Acton scheme is a canal-based distribution network fed from a river level intake near Rakaia township. The canal required no electrical pumping, but the on-farm electrical pumping needs have been estimated at approximately 3 MW. This load increase has been shared across Overdale, Pendarves and Dorie zone substations and was in addition to existing irrigation pump load.

Regulatory Uncertainty

ECAN (Environment Canterbury – Canterbury Regional Council) has returned to a fully elected council after being run by a Government appointed commissioners. One of the reasons the Government took the move to appoint commissioners was to provide a clear path forward for water management in the Canterbury region. A 'Canterbury Water Management Strategy' has now been prepared, facilitated by the Canterbury Mayoral Forum. The strategy has been embraced by ECAN as a suitable way forward. The Canterbury Natural Resources Regional Plan is a parallel process that ECAN must progress that set environmental flows in several Canterbury rivers. As the strategy matures and the recommendations of stakeholders in various district committees are presented to be enacted the impact of their decisions on EA Networks will be considered.

If the underlying assumptions about water availability and portability were changed by ECAN, it could result in another surge of irrigation demand in areas currently assumed to be fully electrically serviced for available irrigation demand. It would appear that any changes to the regulatory environment will be more restrictive to irrigation and there will be no material changes to the availability of ground water (as presently constrained by ECAN) caused by the regulatory environment (Canterbury Land & Water Regional Plan).

The ECAN Water Regional Plan, Plan Change 7 was advertised in July 2019. This plan change places further restrictions on intensification of irrigation to address the over-allocation of water resources and nutrients generally and specifically in the Hinds/Hekeao Plains Area. This will be achieved through limits on nitrate levels in groundwater and nitrogen leaching from land areas. The outcome of this variation is that additional irrigation development south of the Ashburton River will be very limited.

Economic Uncertainty

Economic activity is difficult to predict accurately over a period of 10 years, and this will have consequential effect on electricity demand. Likewise, factors such as population, price of electricity and the effect of other fuels are uncertain over this period.

The global and national economies are currently at a low ebb. How this affects the primary industries that EA Networks' peak load is driven by is uncertain. It is possible that existing load will continue to operate but the connection of new load may be delayed or cancelled. To some degree the estimated load forecast takes this downturn into account, the projected load forecast does not. It has been observed that inquiries for new irrigation and dairy sheds has dropped to very low levels and is unlikely to increase. There is still commercial interest in dairy conversion in the rural community. The perceived constraints are currently the availability of finance, milk fat price, and water availability.

Over time, the electricity used per unit of production will change, and automation may result in electricity replacing labour. The extent to which this will happen over the next decade is hard to predict.

Similarly, there may be improvements in energy efficiency, so that over time energy requirements (per unit of production) may diminish. This will not necessarily reduce electricity consumption, as in many instances efficient use of electricity may be a better use than the direct use of fossil fuel resources. Energy efficiency measures can also see a rise in peak demand while lowering average demand.

Demand Structure

The characteristics of the various classes of load; domestic, commercial, irrigation and industrial are quite different. Domestic consumption has a particularly low daily load factor and is a major contributor to system peaks (despite the use of water heating load control). Irrigation has a high daily load factor during summer but a low annual load factor. The base load varies from commercial/domestic heating in the winter to industrial/irrigation load in the summer. Tariff structures reflect these load characteristics and allocate cost where it falls but this does not necessarily materially affect the behaviour of consumers.

Recent irrigation scheme changes have provided farmers with the option to purchase the right to use water from piped schemes that deliver pressurised water onto the farm. These schemes are providing both new water resources as well as converting existing open race schemes to piped schemes. The impact of these changes on actual and future electrical demand has been complex. Where the farmer has not had access to water previously or used flood irrigation, these schemes have had little impact on connected irrigation demand. If new irrigation water is available, there is likely to be some additional demand from farms that convert to dairy production. A significant number of farms that have signed up for pressurised water delivery already have either deep well irrigation plants or surface water pumping systems. These farmers are retaining their deep well electrical pumping facilities to provide high reliability irrigation during periods of restrictions on the piped scheme water sources. A consequence is that the electrical load is no longer contributing to irrigation peaks in normal years. This latent demand is a big risk for the EA Networks network as it can be simultaneously activated after being dormant for many years - potentially overloading assets that were historically adequately sized. Irrigation pumps can no longer be switched to non-irrigation rates to prevent this situation from getting any worse.

A major impact looming on the horizon is that of electric vehicles. The energy and demand impacts of widespread use of home charged electric vehicles are enormous. The small vehicles currently being introduced to the market are useful city cars with enough range for a daily commute. The smallest battery pack on these electric cars has a capacity of 16 kWh. The specified recharging time is 7 hours from a standard 10 amp socket. At almost 100% efficiency that represents 2.3 kW of demand per vehicle. As car and battery technology advances it can only be assumed that much larger vehicles with improved range and performance will be developed. A vehicle/battery with 100 kWh or more is likely, and the consumer will expect to be able to recharge a significant fraction of this overnight at home or substantially more quickly at dedicated recharging facilities (vehicle manufacturers are touting 350kW fast-charging rates as a reality in the next few years). A household is likely to have more than one vehicle. Considerable thought needs to go into the way electric vehicles will be integrated into both the national and local infrastructure that presently adequately serves the existing load. At this stage, no specific allowance has been made for the additional demand electric vehicles would place on the EA Networks network, other than providing a path for urban network reinforcement should that be necessary.

The Canterbury Regional Council (ECAN) has clean air requirements for solid fuel space heaters. This strategy is aimed at reducing the quantity of airborne pollution, particularly that caused by domestic solid fuel heaters. The requirements have seen additional electrical heating demand come on to the residential portions of the EA Networks network and the majority of the appliances are inverter style heat pumps. The impact on the peak demand has not been considerable and may be offset to some degree by the new heat pumps displacing resistive heating in homes that would have used fan heating for initial comfort in the early evening or morning. No specific allowance has been made for the impact of the clean air strategy, but significant numbers of heat pumps have been installed in recent years (prior to the clean heat strategy) and the rate of winter load growth reflects this. The possibility of these heat pumps being used for cooling during times of peak demand in summer is of more consequence to overall system demand and this will be monitored.

Diversity

Peak demands for different supply points do not necessarily occur simultaneously. The natural diversity among loads can be used to advantage. Since a zone substation MD (Maximum Demand) will be less than the sum of individual distribution substation MD's served from it, the major distribution elements can be designed to a smaller capacity than the sum of individual consumer connections. Similarly, the expected system demand for EA Networks and each GXP (Transpower Grid Exit Point) will be less than the corresponding sum of the zone substation totals.

Diversity can also work against the Asset Manager. The diversity in the connected irrigation load EA Networks has varies considerably with the weather. During a season with average rainfall, the diversity is average. When the season is particularly dry (every five years or so), there is minimal diversity and all pumps that can be operated are. This can cause a false sense of security for the Asset Manager during the preceding four years and may have implications for emergency capacity.

Distributed Generation

Distributed generation has the potential to reduce the peak demand EA Networks impose on the Transpower grid. It must however be of such a scale and be sufficiently reliable (both mechanically/electrically and with its source of fuel) to guarantee that EA Networks can avoid investment in major system components while retaining the appropriate level of security to service load. If the distributed generation was for example wind powered, a calm summer day during a dry year would cause peak demand on the EA Networks network, but none of the wind turbines would be generating because of lack of wind. The Highbank hydro power station is another example that generates only during winter (off-peak for EA Networks, but presently during the period of peak regional demand that Transpower charges for). Only distributed generation with very high availability, some form of fuel storage (for generation on-demand) or a diverse range of independent fuel sources will offset the need for network investment.

The estimated future network demands have not assumed the existing distributed generation plants (Barrhill – 0.5MW, Cleardale – 1.0MW, Montalto - 1.6MW and Highbank - 26MW) to be operating. The nature of the plants (single penstock, run of the river, single turbine) means that they can be (and sometimes are) unavailable at peak times. In terms of energy, the existing embedded generators are predicted to supply about 18% of the 604 GWh to be delivered to consumers during the 2019-20 year.

A range of generation proposals have been discussed in recent years. Most of the projects are still commercially sensitive. Section 5.4.12 has details of the type and scale of these potential developments. None of these projects are sufficiently mature and/or large to be included in the load estimates although some of them could have a meaningful effect on substation and system demand should they proceed. Once firm details are available, the impact on peak load will be assessed and included in the demand estimates.

Photovoltaic solar panels have been installed on some residential and small business premises (237 installations totalling 1,034kW as of February 2020). The distributed nature of these installations and the modest output has not yet caused any measurable impact on the distribution network. One installation has highlighted the small size of overhead LV lines connecting it to the distribution transformer (since resolved with underground conversion), but the remainder are operating without any negative impact.

Demand Management

The only form of direct demand management currently in place is that of ripple control of hot water and night storage heating facilities. Indirect demand management by signalling of price is accomplished by a tariff structure that makes night energy cheaper than day energy. EA Networks do not have in place any dynamic signalling of demand peaks to consumers. There are currently no plans to implement dynamic demand signalling to individual consumers.

Future demand management would certainly be imposed on widespread electric vehicle fast recharging.

During 2014, there were a range of network security options placed before the Board for consideration. One of the options discussed was contingency load management. This would require that certain types of load be automatically interrupted during faults. Restoration of this load would then be done by remote control (either feeder by feeder or over larger areas - depending on the type of fault). This action would, under many circumstances, allow the remaining connected loads to be supplied via un-faulted network paths while the fault is repaired. Contingency load management could be an appropriate response to a low likelihood high impact event such as a zone substation transformer failure. Well managed, contingency load control could provide capacity for all essential load and share the remaining capacity in an equitable manner. This would not be possible if the larger, non-critical, interrupted loads remained connected. No immediate commitment was made, and future plans will disclose the results of any Board decisions.

In the set of forecasts that follow, no specific allowance has been made for intangible factors, other than in line with historical trends. Increasingly, it may be possible to control load so that appropriate action can be planned ahead of time. Thus, for example, as a specific subtransmission circuit approaches capacity, it may be preferable to improve the efficiency of utilisation in the area rather than immediately increase capacity.

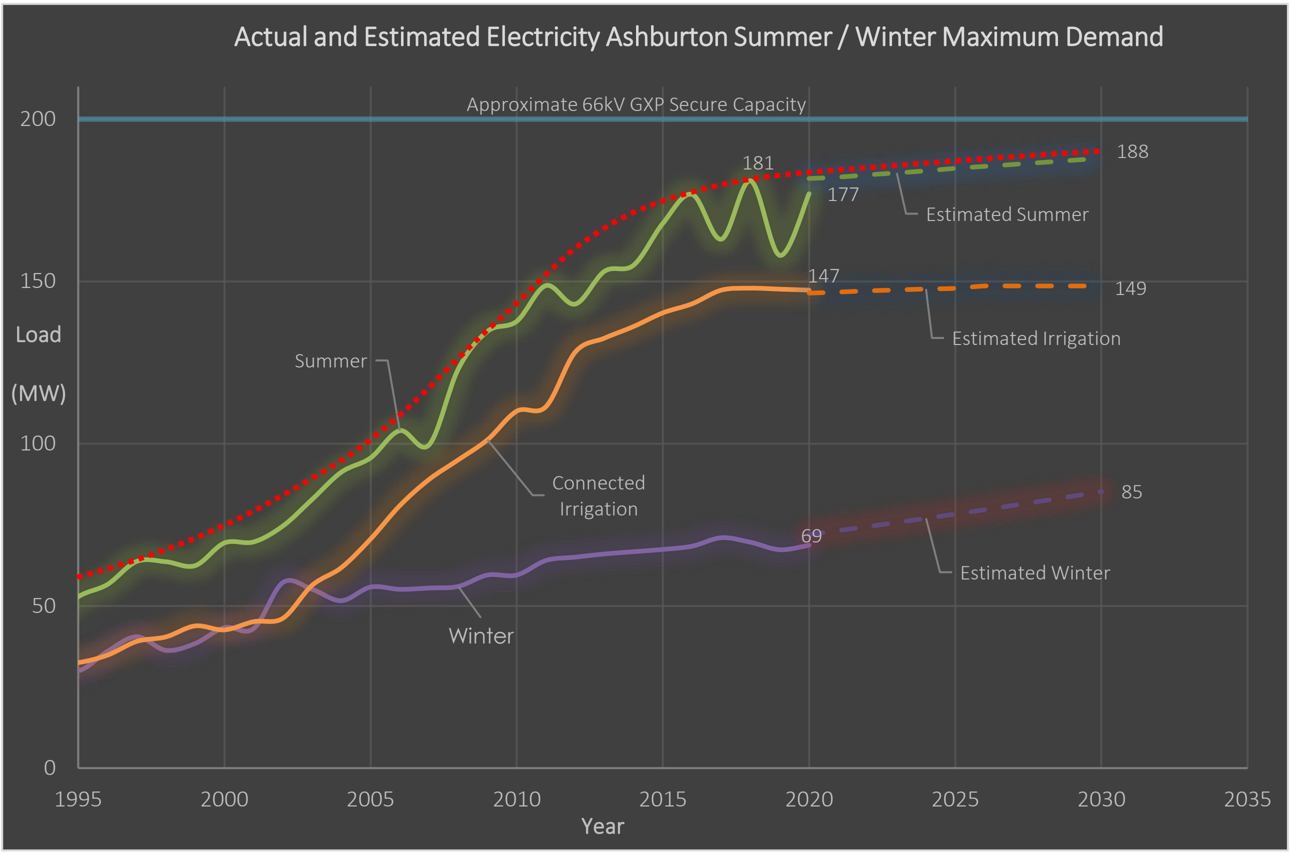
5.2.4 Future Load Projections

Statistical forecasts have been developed and were prepared on a "high", "medium" and "low" basis. All things being equal, the "medium" figures would have been the expected projected forecast. This technique is now proving ineffective as irrigation is constrained. Estimated load is now used. Both techniques are subjective and uncertainties in population, price of electricity, economic activity and the intensity of use of electricity in industry all influence future demand.

Forecasts of estimated maximum demand indicate a medium 10-year growth averaging less than 1% p.a. in summer ADMD (After Diversity Maximum Demand). This is a lot lower than the average of the last ten years. Winter ADMD is predicted to grow at about 1.6% p.a.

Appendix C contains additional data used to derive this forecast plus the estimated individual zone substation maximum demands for the next ten years.

The estimated growth in individual zone substation loads is a subjective process in that it relies on the opinions of a range of people who are knowledgeable within the various industries that contribute to most of the electrical demand in the Ashburton district. For irrigation, localised trends are prepared for each zone substation and incorporated in the future load figures. A recent report prepared for Transpower has provided some additional estimates of future irrigation load and these have been considered when preparing our own estimates. Other industries contribute likely step load increases, and these are allocated individually to zone substations at the expected load commissioning date. Residential and general supplies are trended in percentage growth terms and this is seen as acceptable, bearing in mind the difficulty in alternative models and the relatively low impact of this growth on the total peak loads (particularly at subtransmission levels).



Some additional estimates of maximum regional irrigation demand were provided in the "Canterbury Irrigation Peak Electrical Load" report. The estimates for the total irrigation demand on the EA Networks network varied between 114.4 MW to 167.4 MW depending upon the assumptions made. The highest value assumed intensive irrigation of all available area including large portions of the high-country basins. This would appear to be highly unlikely at the energy densities assumed in the report. EA Networks have used a similar technique for estimating system wide demand in the past but the sensitivity to assumed energy intensity is so great that it is only broad quantitative indicator rather than a precise forecasting tool. EA Networks' estimate of complete consentable district irrigation using existing demand density is around 146 MW although the uncertainty surrounding this is likely to be at least ±10%. The estimated irrigation load of 158 MW in 2025 contained in the report is within this band of uncertainty. The lower regional load estimate of 114.4 MW is actually a considerable reduction in load caused by increased use of gravity pressurised pipe schemes. Several of these schemes have been installed in recent years and appear to be successful. Where they are converting an existing open-race scheme to pipes, the electrical demand of surface spray irrigators is eliminated. When a new scheme is introduced using newly consented water (or water is conserved by piping) some deep well pumps are only used as dry year backup when the surface water supply may be restricted. The potential demand still exists but is not expressed during 'normal' years. If a new piped scheme proves to be reliable, the deep well consents may be sold to other interests within the same aquifer zone - shifting the electrical demand on the EA Networks network.

Growth at these estimated rates will still require development work on the EA Networks network to accommodate the load while continuing to meet the security standards.

Forecasts of summer projected maximum demand statistically extrapolated at -¾ %, 0 %, and +¾ % of historical growth trends indicate a 10-year summer growth averaging 4.1 % p.a. in ADMD (After Diversity Maximum Demand). Winter ADMD is predicted to grow at a lower rate of about 1.6 % p.a.

These summer load projections are looking hopelessly unrealistic now that gravity pressurised irrigation schemes are proving successful and levels of water availability are becoming more definitive. Water storage is the pervading sentiment as the way to advance irrigation water availability in the Canterbury region. The statistical summer load projection is no longer a valid predictor of future demand. Winter load growth is at a rate comparable with other urban networks.

Winter peak demand growth is constrained by regional load control strategies and the growth of uncontrolled load such as heat pumps. It is possible that widespread uptake of electric vehicles could potentially change the estimated/projected peak winter demand (increased demand) as could additional battery storage and/or distributed generation (decreased demand). The scope for decreasing demand across significant parts of the network (thereby decreasing demand on upstream assets) depends on the location and scale of any distributed generation or batteries. Energy efficiency may slow the growth rate over time.

5.3 Network Level Development

All the following network level developments provide energy efficiency benefits. By utilising the correct voltage and larger or more numerous conductors/cables the energy efficiency of the network is measurably higher. Although the primary reason for doing the developments was not energy efficiency it was certainly one of the influencing factors.

5.3.1 66kV Subtransmission

During the mid to late 1990s the EA Networks 33kV subtransmission network was showing its age. The incessant growth in irrigation had caused parts of the network to sag to 30kV with all circuits in service. This surge in demand caused large energy losses and meant there was zero security should a 33kV line fault occur. Some zone substation transformers were also operating on maximum boost tap. It was obviously time to reconsider the subtransmission development at EA Networks. The peak load then was a little over 60MW.

A range of options were investigated including the following:

- More than one new 33kV GXP from Transpower

Although the option of additional GXPs from Transpower was viable, the risk was that the load would grow to the extent that even three GXPs may not provide sufficient subtransmission capability without having to build many more large 33kV lines. The security of each GXP was also an issue. Each GXP would require at least two transformers to prevent loss of supply if one faulted. If one GXP was used only two transformers of appropriate size would be required (or three once the load grew even further). The poor flexibility and cost-effectiveness of this approach and its limited capacity at a distance (33kV volt drop) caused it to be discarded.

- Many additional 33kV lines

The single 33kV GXP with many new 33kV lines radiating from it was soon ascertained to be impractical. Analysis of the distances from the GXP and size of loads that needed serving soon showed that the number of 33kV lines required would occupy almost every roadside for many kilometres from the GXP. The absolute capability of this approach was also very poor. This option was discarded as impractical and poor value for money.

- Migration to 66kV

The option of using 66kV as a subtransmission voltage was immediately appealing. The ability to supply the scale of loads EA Networks were anticipating would occur and the distance from the GXP they would occur at was a good match. The techniques used to construct 66kV lines were similar to those used at 33kV so EA Networks personnel could build and maintain them without major reskilling or retooling. The cost of major components for 66kV were only 15-20% more costly than 33kV items. In some cases, the cost was virtually the same. The increase in capacity was almost 400% for the voltage constrained parts of the network. 66kV appeared to be a very viable option as a solution to the subtransmission capacity constraints at EA Networks.

- Migration to 110kV

110kV substations and lines are considered to be a true transmission voltage (as opposed to 33kV and 66kV which are considered as subtransmission voltages). It soon became apparent that it would be much more costly to use 110kV subtransmission as the equipment costs were beginning to rise considerably above 66kV equipment. The scale of line construction was also right at the limits of the capability of EA Networks plant and machinery which meant that construction and maintenance may in some cases need to be outsourced (not necessarily a problem, but an emergency response is several hours delayed as a result). The capacity that 110kV offered was also well in excess of the forecast need on the EA Networks subtransmission network (at the time, one 110kV circuit would have supplied the entire EA Networks load). The solution was viable technically and was very appealing from a capacity perspective but could not really be justified as the excess capacity would potentially be unused for several decades.

So, the options (including approximate costs) were presented to the Board for discussion and it concluded with a request to provide an estimate of cost for a conversion of a significant portion of the 33kV subtransmission network to 66kV. A project to solve the immediate 33kV problem with 66kV operation was approved. Once that commitment had been made, the Asset Management Plan became the vehicle to communicate future subtransmission plans to the Board. In subsequent years, as the pace of irrigation load growth accelerated even further, the Board further endorsed the principle that the future of the subtransmission network was with 66kV. In future, if the 66kV subtransmission system begins to reach its limits, a second 66kV GXP would provide immediate and on-going relief.

5.3.2 22kV Rural Distribution

The late 1980s had already seen significant irrigation load growth occurring on the EA Networks distribution network. This was putting the 11kV distribution voltage under stress in a number of places on the network. Energy losses were high and power factor was dropping (high kVAr losses in the reactive overhead lines). In some cases, the measured distribution voltage was as low as 10.3 kV (minus 6.5%) which made motor starting and running very difficult and the voltage range consumers were experiencing was exceeding the standard range that EA Networks had prescribed as acceptable. In some cases, attempting to start one motor would stop an adjacent one. The 11kV fault levels were becoming inadequate for the increasing size of individual loads being supplied.

A solution to this issue was required. Forecast load growth was increasing and these voltage regulation issues were going to be very widespread if nothing was done. A range of potential solutions were considered including the following options that were analysed in detail:

- 11kV reconductoring

The most obvious option was to increase the size of the conductor on the existing pole lines. This results in a relatively small incremental change in capacity as the existing poles can typically only double the area of conductor at best. So, a line carrying Mink conductor (75mm²) may be able to be restrung with Dog (120mm²) but this results in a 40% increase in capacity at best (if the entire line is restrung) with no further options for size increase without reconstructing the entire line with stronger poles (expensive). The extent of the potential voltage problems were sufficiently widespread that a lot of restringing would have been required with a capacity increase ceiling at the conclusion. The restrung network would still have very limited back-feeding capacity at times of peak demand (distribution security levels would not increase appreciably). The distribution system fault levels would perceptibly increase with this solution but motor starting would still be limited in many cases. Although this option was certainly viable it was not the long-term solution that would solve the issues facing EA Networks. This solution was not preferred or recommended to the Board.

- 11kV regulators

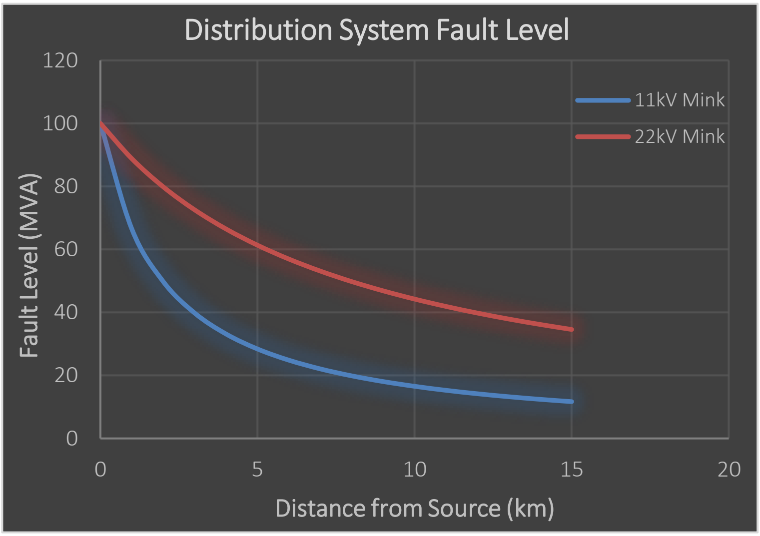
Another method of boosting voltage was the in-line voltage regulator. This is essentially a localised solution for maintaining voltage on a distribution feeder. It does not increase fault levels (in fact they slightly reduce) so motor staring is still difficult for larger loads. It is a relatively low risk option in that the regulator can be relocated if necessary or additional ones can be installed to further boost voltage. On the downside, system losses begin to increase and back-feeding through a regulator is not always straight-forward. The extent of distribution system reinforcement required would have involved the purchase of dozens of voltage regulators and this would essentially be solving one of the symptoms of an overloaded distribution network without solving the underlying problem. This solution was not preferred or recommended to the Board.

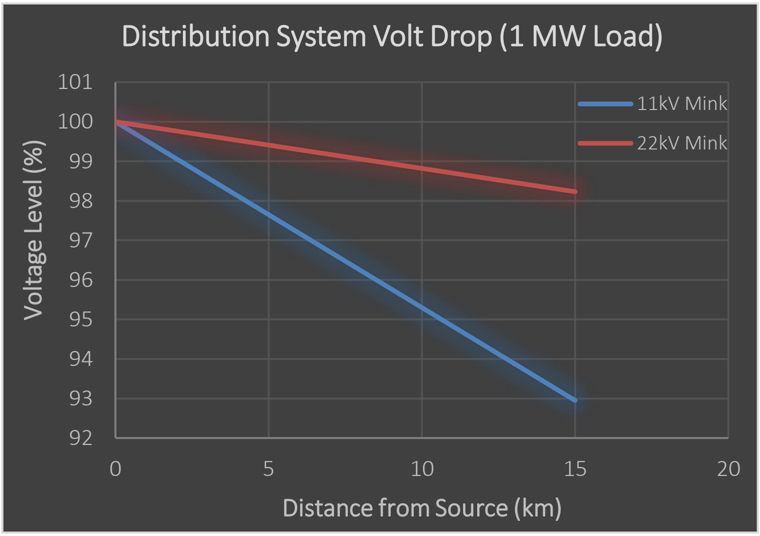
- Additional zone substations

An expensive but technically viable option would be to build additional zone substations between the existing ones thereby shortening the 11kV feeder length by approximately 50%. This has a number of technical advantages but is very costly. It doubles the number of 11kV feeders, each with half the number of consumers per feeder, which means any distribution fault only affects half the number of connections. The load per feeder is halved which solves the voltage drop issues and the fault level increases as a consequence of shorter line lengths from the 11kV source. It seems to be a good solution but the downside is certainly the cost and complexity of many more zone substations of half the size that would otherwise be required. A loss of load diversity means that each smaller zone substation would actually be more heavily loaded than 50% of the one that originally supplied the entire load. The fact that the 33kV network was showing signs of duress and that 66kV was already being contemplated as an option meant that the cost of building twice the number of new 66kV substations was not very appealing economically. This solution was not preferred or recommended to the Board.

- 22kV conversion

Although the option of converting to 22kV seemed costly, in reality there was little waste in the exercise. The main costs are in reinsulating existing overhead lines (a relatively low cost (three insulators for most poles) and replacing the existing distribution transformers with 22kV units. The transformers can be reused on 11kV portions of the network or sold to other networks. In the worst case, the very old ones are scrapped. The overwhelming technical advantages of 22kV were plain to see. The percentage voltage drop on the same conductor falls by 75% allowing 4 times the load for the same voltage drop as 11kV. The fault level also increases considerably and stays much higher over the entire feeder length. This allows much larger motors to be started without causing interference with neighbouring consumers. Existing poles and conductor could be retained and the only things needing replacement were the insulators, the fuses and switchgear, and any surge arrestors. The incremental cost of 22kV equipment over 11kV equipment varies from zero to at most 20% (overall 8%). In many cases the equipment is the same as it is not cost effective to manufacture both voltage classes of equipment. The source of 22kV could be provided by 11/22kV star connected autotransformers which maintained zero phase shift and allowed them to be moved along a feeder as conversion proceeded. This solution was recommended to the Board as a solution that could be applied where 11kV was likely to no longer be adequate for the loads being served.





The Board were presented with the various options that had been considered and were content that 22kV conversion offered the best long-term value for money. It was pointed out that within a decade or so the subtransmission network and a portion of the rural distribution network could be renewed and the opportunity to migrate to what is generally accepted as the modern distribution voltage class of 24kV was one that should not be missed. The fact that the subtransmission voltage at the time was 33kV (only 50% higher than 22kV) tended to reinforce the notion that it too was under pressure. Ultimately, the Board agreed that 22kV was the best choice overall for stakeholders where significant distribution system voltage regulation was an issue.

In hindsight, had the move to 22kV not occurred, the dramatic load growth that occurred from 2000 to 2010 would have overwhelmed the 11kV network and loads would have been turned away. This would not have been a good situation for the local or national economy. The combination of 66kV subtransmission and 22kV distribution seems to be close to the perfect match for the scale and distribution of loads presently on the EA Networks network.

5.3.3 Urban Underground Conversion

As a cooperative company, the ownership structure of EA Networks encourages the Board to make decisions that are in the long-term best interests of the shareholders/consumers and other stakeholders that use or interact with EA Networks network. One of the areas that EA Networks Board have chosen to reinvest in the community that they serve (and where the majority of shareholders reside) is by continuing to convert end-of-life urban overhead lines to underground reticulation. The Board are well aware of the alternative, which is to rebuild the network as overhead lines. Overhead lines are certainly less costly, but they provide very few of the other benefits of underground cables:

- Underground cables are immune to the frequent snow and wind storms that Mid-Canterbury experiences. One such storm in the 1970s caused virtually every pole in Methven to fail and consequently power was not restored for several weeks.
- The safety of an underground system is several powers of magnitude greater than overhead lines due to its largely buried situation. The exposed nature of overhead lines (particularly in an urban area) is a significant risk and adverse weather, trees, vehicles, kites, fireworks, vandalism etc. can all place the urban dweller at greater risk of accessible or damaged overhead conductors.
- The capacity of a low voltage underground cable is typically much greater than the equivalent overhead line as it serves only half the number of consumers and is usually of greater cross section (lower voltage drop).
- The flexibility of interconnected underground cable systems normally means planned outages are very infrequent as the various parts of the network can be isolated without interrupting supply.
- The aesthetic benefits cannot be ignored. Residents are much more satisfied with underground reticulation.
- The reliability of underground networks is significantly higher than overhead networks, so the consumer has a better power quality and lower outage duration. When a fault does occur, restoration is typically much faster also.
- Energy losses are typically much lower in underground networks, largely because of the larger conductors and greater number / lighter loading of individual LV circuits.
- Fewer (but larger) distribution transformers are required (all of which are ground-mounted). This minimises the potential oil spill risk.

Feedback from consumers has shown that they are very satisfied with the continuing underground conversion programme. The Shareholders’ Committee (the elected/appointed shareholder representatives) have also supported the urban underground conversion philosophy. In addition to the technical and service benefits, there are on-going strategic drivers. As a cooperative company the return to shareholders needs to be distributed in a fair manner and with considerable investment in the rural area to support irrigation and farming generally, there needs to be a counterbalance for the urban consumer/shareholders. All conversion programs are driven by the need to replace existing overhead lines owing to diminished capabilities and condition.

An underground conversion programme has now been included in the plan which provides for the removal of all distribution voltage power poles from the townships within the Ashburton District. The programme identifies projects by specific streets. These projects are based upon assessed overhead line condition and the timing of the replacement with underground cable is scheduled to ensure the risk of pole failure before conversion is acceptably low.

5.3.4 Core Urban 11kV Network

The EA Networks “Reliability by Design” guidelines put greater emphasis on the number of consumers supplied from (or affected by) any particular electrical asset. Of critical importance is the number of consumers supplied from a zone substation feeder circuit breaker. Currently, there are a number of individual urban 11kV feeders supplying more than 1,000 consumers each. As of 2020, a 1,000 consumer feeder represents about 5% of the total EA Networks consumer count. A fault causing this circuit breaker to operate will rapidly impact on the reliability measures such as SAIDI and SAIFI as well as inconvenience 1,000 households or businesses. A 20 minute outage for 1,000 consumers represents 1 minute of SAIDI.

The Ashburton urban area has about 9,000 consumers supplied from two zone substations. The two substations have about 26 existing or potential 11kV feeders. This is an average of more than 340 consumers per feeder. To bring this down to the design guideline of 200 consumers would require another 19 feeders (a total of 45 feeders).

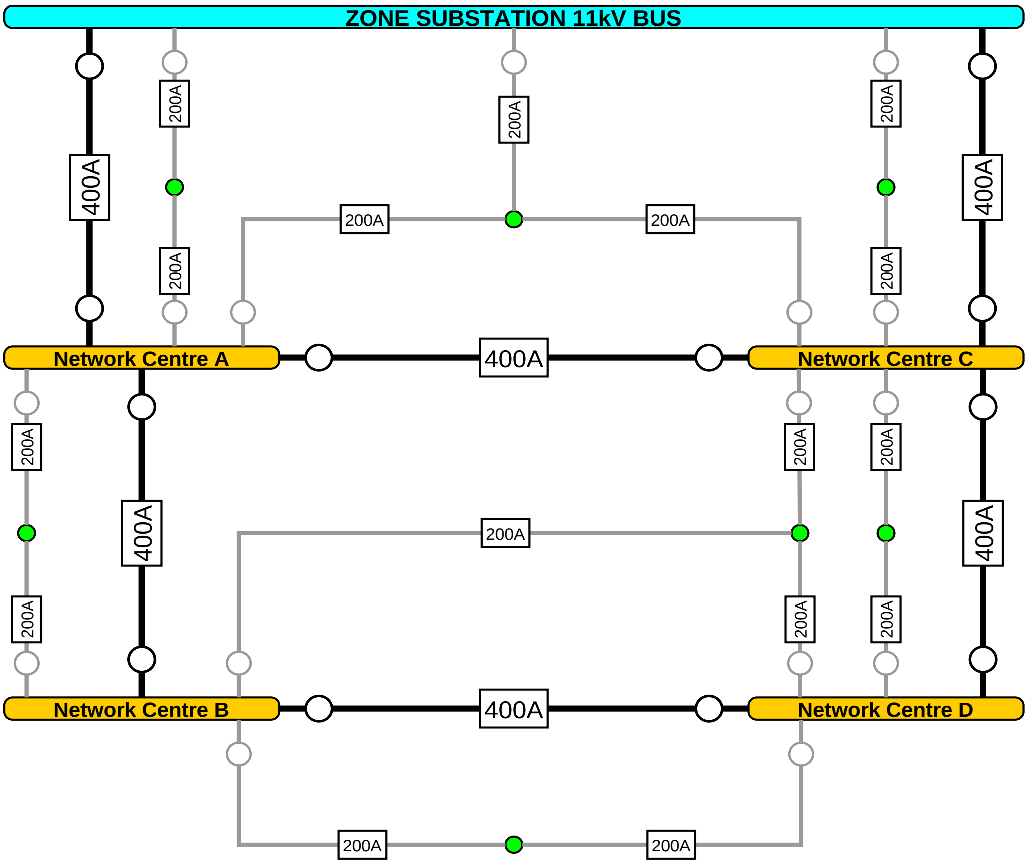
To comply with the new guidelines on maximum number of consumers per feeder, there are several possible approaches.

1) Nineteen additional 11kV feeders from existing zone substations. Although this is possible, it is particularly asset intensive. New switchboards are required, and cabling will have to be installed and extended to a location in the existing network where it can create new smaller feeders. The new switchboards will require enlarged or additional buildings on the zone substation sites and this may involve obtaining additional land which could be a difficult prospect in an urban setting. This option is not the preferred option.

2) Two new zone substations in urban locations distant from Ashburton and Northtown zone substations. This is also possible, but even more asset intensive than option (1). This would require two new sites, at least four new transformers, new buildings, switchboards, protection and supporting infrastructure. New 11kV cables would also need to be run from the new sites to integrate with existing 11kV cabling forming the 19 new feeders. Initial estimates place the cost of this option at several times that of the other options with no quantifiable benefits other than a doubling of the already adequate total 11kV infeed capacity. This option is not the preferred option.

3) An additional layer of high capacity 11kV distribution. This option involves a new network of core 11kV circuits that do not directly connect to distribution transformers. The core 11kV would be a transport level only. An 11kV circuit breaker switchboard at a network centre or zone substation would provide the termination point for each end of a core 11kV circuit. Core 11kV circuits will form closed rings (the core circuits operating in parallel) between network centres and zone substations. Several spare (or repurposed existing) circuit breakers would be required at each existing zone substation. The initial

Ashburton Township 11kV Reinforcement



assessment of Ashburton and Northtown substations suggests there are sufficient circuit breakers to fulfil the requirements. New network centres would need to be constructed at various locations in the urban area and obtaining land for these may be an issue. Each network centre would have at least two core circuits terminating at it and between three and five lower capacity 11kV feeders radiating from it. After careful consideration, this solution was chosen as the preferred option.

The diagram above gives some idea of the core 11kV network concept. The bold black lines are the high capacity circuits. The grey lines are the low capacity feeders. The orange objects are network centres. The larger circles are circuit breakers. The smaller green circles are open RMU switches at distribution substations.

The scale of this core network development is significant. It will take most of the planning period to fully implement, and a commitment is needed to continue the work to completion. Partial implementation would not achieve the desired improvements and could make the impact of some faults more extensive.

Previous Asset Management Plans had allowed a programme to cover this work starting in 2017 and continuing until at least 2023. This programme now runs from 2020 until 2028. The first two network centres are now under construction. Once complete, new core and feeder cables can be terminated via the switchboards and used - albeit initially not in a fully secure core network configuration.

5.4 Strategic Plans by Asset

Once the security standards have been set, the rate of growth has been predicted, and assumptions have been made about the location of the additional load, decisions must be made on how to accommodate it on the network. This section identifies each major voltage level and functional grouping and then goes on to describe what impact the additional load will have and what changes will be necessary to cater for it.

Please note that the [10045] type reference in each project title is the project code for reference to financial detail in Appendix B. Project costs can be seen in Appendix B - referenced by the year and project code. A year in [red] indicates that the project has unexpectedly carried over from the previous year without budget allowance.

5.4.1 Transpower Grid Exit Points

EA Networks has one grid exit point (GXP) that is at the Transpower Ashburton Substation - a site approximately 7km south-east of Ashburton township. Transpower call this substation Ashburton Substation but for clarity (EA Networks also have an Ashburton Substation in Ashburton township), it is known as Ashburton220 (220kV is the highest voltage on Transpower’s Ashburton site).

Ashburton220 provides EA Networks with a 66kV GXP. Until 2019, there was also a 33kV GXP on the same site. Immediately adjacent to Ashburton220 is an EA Networks substation called Elgin. This provides two major functions. Firstly, it takes the three 66kV supplies from Transpower and splits them into the seven individual circuits that form the 66kV subtransmission network. Secondly, it historically provided a (normally open) link between the 33kV GXP and the 66kV GXP in the form of a 60 MVA autotransformer. This autotransformer currently allows a 33kV ripple injection plant to serve the 66kV network and is about to be reconfigured to also provide a 22kV supply to the distribution network.

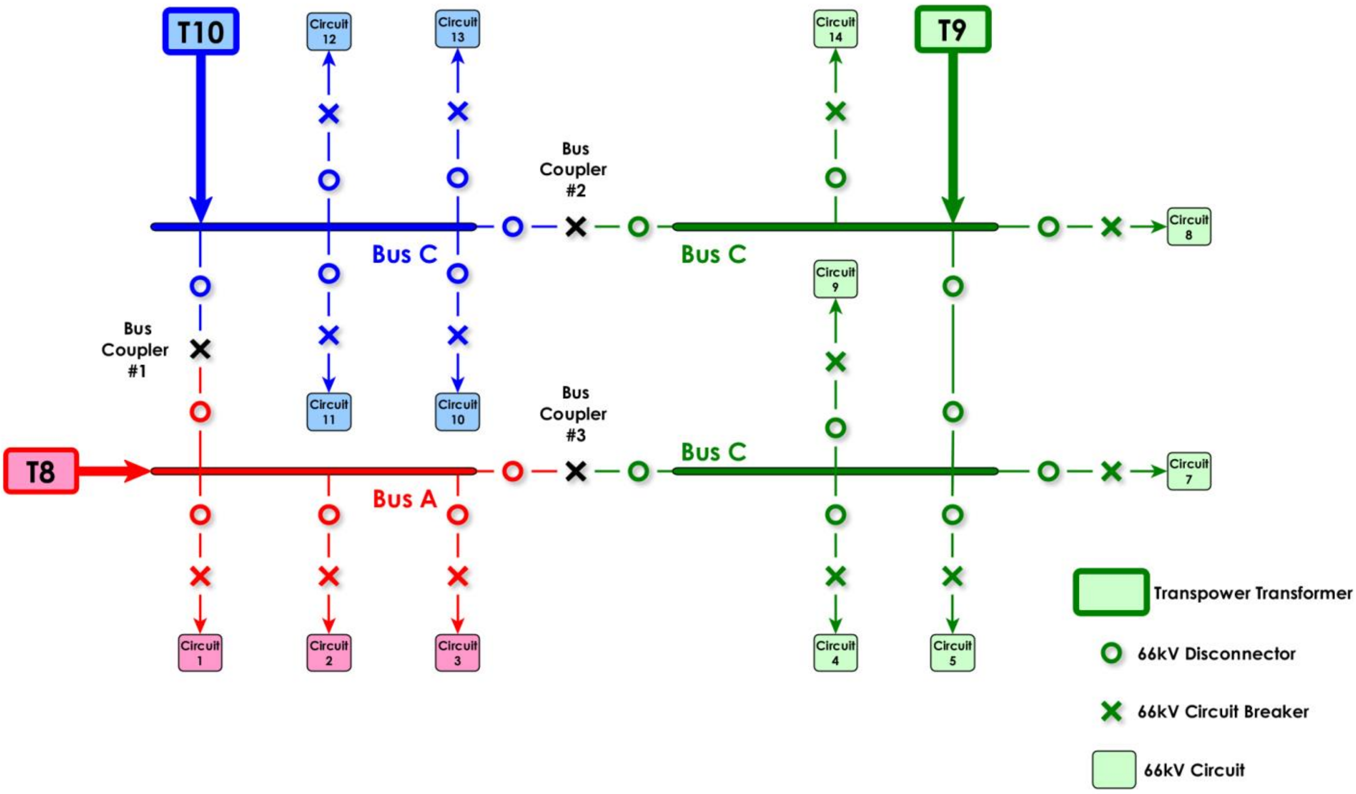
The capacity and configuration of the Ashburton220 substation largely determines the security and reliability of the GXPs at that site. It is the responsibility of EA Networks to plan the configuration of those GXPs and the way the connections to GXPs are made to promote high performance and good value. The cost of Transpower assets that are dedicated to supplying EA Networks are passed on to EA Networks in the form of an annual charge that reflects a rate of return and some assessment of maintenance requirements. This charge is in turn passed on to the consumers that use the EA Networks network.

The existing arrangement meets the security standards at peak load times and for the foreseeable future. The addition of a third 220/66kV transformer during 2013-14 enabled full security policy compliance. The all-time maximum of 181 MW is within the new firm site 66kV GXP capacity of 220 MVA.

Capacity of New Equipment

The security standards effectively set the requirements for immediate capacity and security (section 3.5.3). The margin allowed for growth is the only parameter that is not predetermined by the security standard. The addition of a second 66kV GXP will require consideration as it will alter the security of both the GXPs and the subtransmission circuits fed from them. The number and size of transformers at each GXP will be an important factor in determining overall GXP security. If the technology for contingency load management is viable and

<u>Elgin 66kV Bus Configuration</u>



approved by the Board, the need for a second GXP may be delayed for some time (until the combination of risk and consequence become unacceptable).

Projects & Programmes

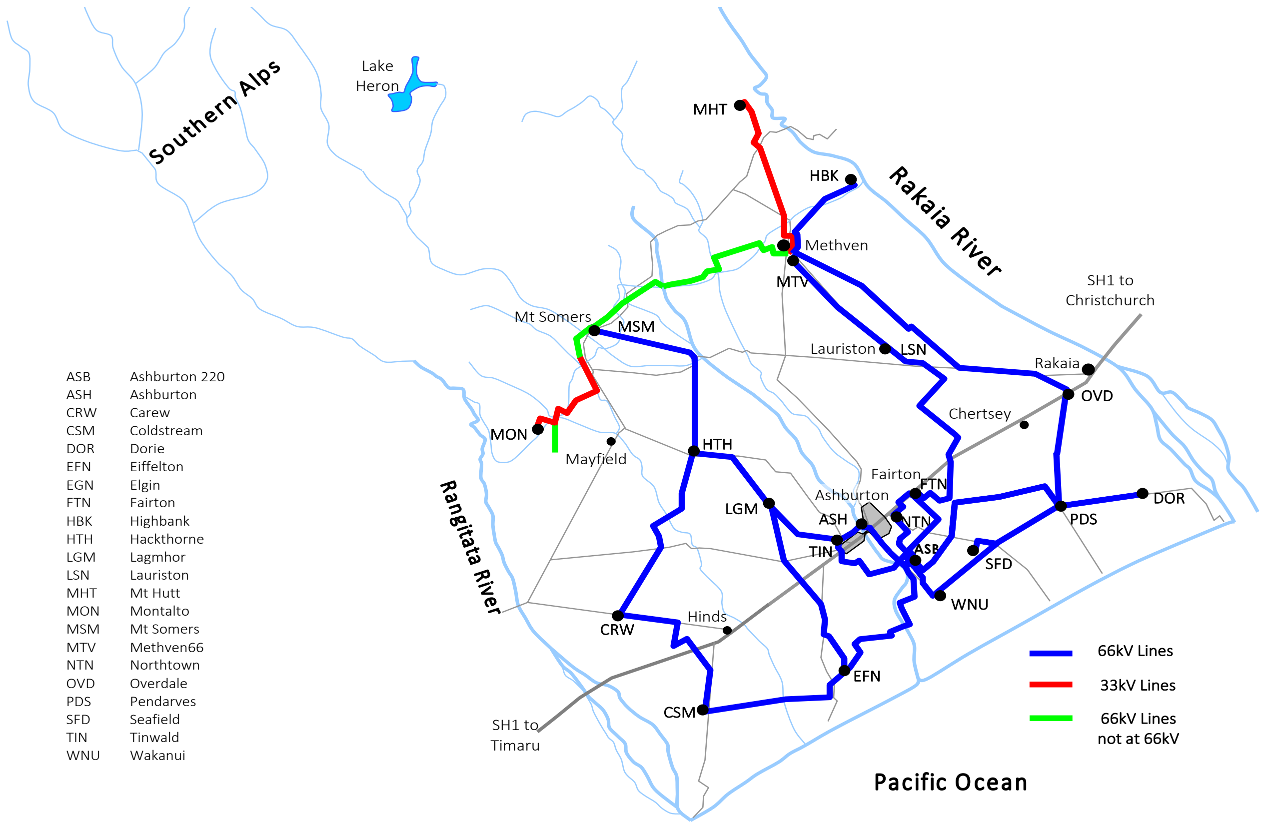
Project	Year	Name	Category
-1156	2028	ASB GXP Capacity Increase (GXP2 - Stage 3)	System Growth

The 220kV bussing project that Transpower completed several years ago forced a rapid decision on the 220kV bus configuration for all of the transformers supplying EA Networks. The conclusion that was reached is that each transformer required a separate 220kV bus section to prevent capacity limitations (caused by multiple transformer outages) during planned or unplanned bus (or other equipment) outages. The site redesign has accommodated this requirement and each transformer is now connected to a separate section of 220kV bus which is electrically distinct from the other transformers.

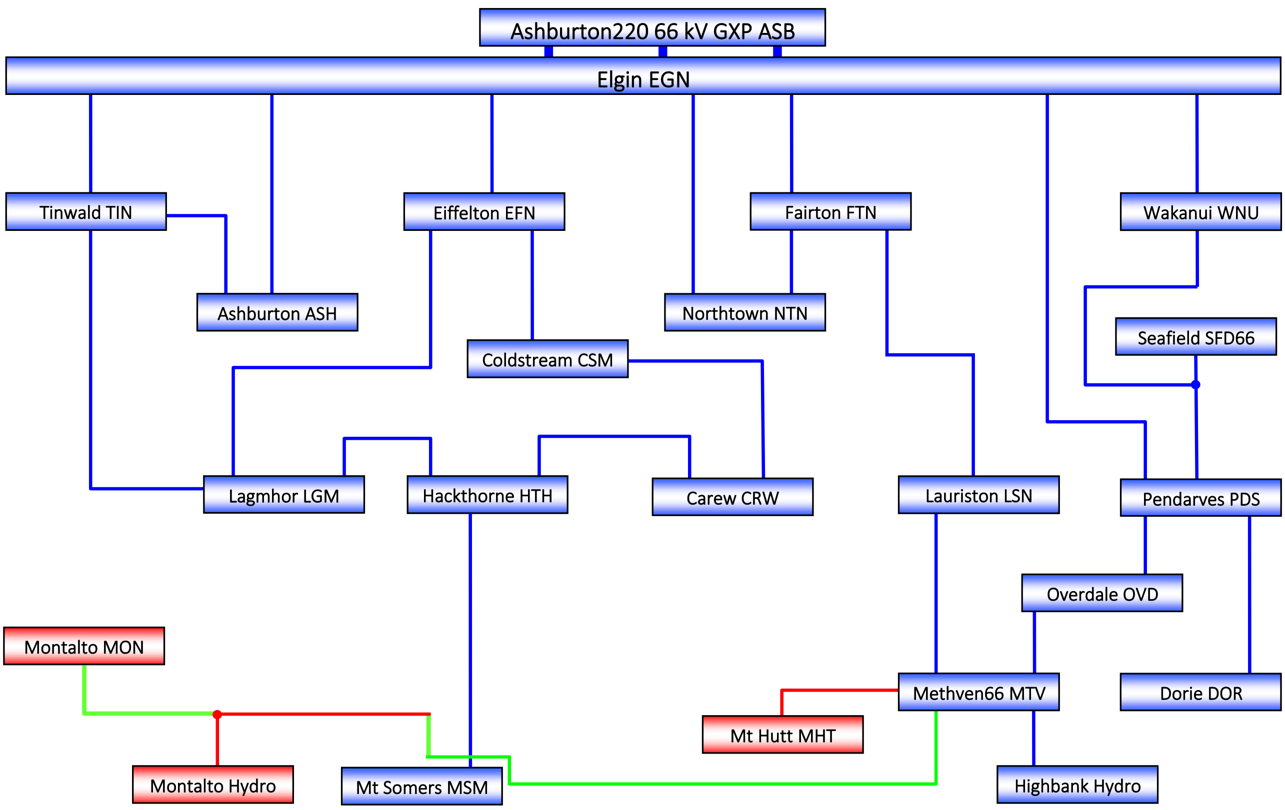
Having connected a third 220/66kV GXP transformer (T9) and implemented a 3 section 66kV ring bus, the 66kV GXP and Elgin site now meet current security requirements. It is unlikely that further development will occur at this GXP as the routes leaving the site are fully occupied with 66kV lines and these lines are loaded at near capacity during n-1 events.

The trigger point for a second geographically distinct 66kV GXP is still being considered and a realistic case of 2028 has been included. There are many factors that need consideration including: GXP loading, GXP/network security, new GXP lead time, 220kV capacity, 66kV subtransmission constraints, practical GXP sites, and new GXP cost compared to alternatives. The biggest factor for triggering the need for a second GXP is load growth and the associated load security. At this point in time, it is unlikely that significant irrigation load growth will continue. Many factors are influencing this, and EA Networks will continue to improve the background information and modelling on irrigation density, economics, options, and any possible new generation that could tie in with water distribution schemes.

Once a consensus is reached on the new GXP trigger point, it will be documented in a future plan. The ‘likely’ date has been placed in the current plan from a timing perspective.



2020 EA Networks Subtransmission Network



5.4.2 Subtransmission Network

The 66kV subtransmission network is the backbone of the EA Networks network. The capabilities of a 66kV network are in keeping with the scale of loads that EA Networks serve. All EA Networks load is presently supplied from a single Transpower substation. Thermally, the same conductor offers twice the capacity at 66kV than at 33kV. If voltage drop is the limiting factor, the same conductor running at 66kV offers approximately a four-fold increase in carrying capacity over a 33kV operating voltage. At 66kV, the subtransmission network capacity is thermally limited in some sections close to the GXP and generally voltage limited in other sections more remote from the GXP.

Capacity of New Equipment

The capacity of any new subtransmission line is determined by a combination of required mechanical strength, thermal rating constraints and voltage drop considerations. The specification of these parameters is as follows:

For all foreseeable n-1 contingencies the thermal rating of any subtransmission line must not be continuously exceeded and the voltage at any point on the subtransmission network must not drop below 90% of its nominal value. A load considered to be probable 10 years into the future will be applied to a model of the entire subtransmission network (as it is planned to be in 10 years into the future) to measure compliance with these parameters. The mechanical strength of all subtransmission lines will be such that it adequately resists all reasonable environmental influences for the duration of its life.

The Ashburton District Plan contains a rule that makes any new line over 110kV a non-compliant activity. This does not mean that it cannot be built, it flags that a resource consent is required. Resource consent applications can be a difficult, time consuming, and costly process. It is likely that additional subtransmission reinforcement will be justified, thereby meeting the security standards, if load grows significantly beyond that used to test compliance with security standards.

Other considerations will also come into play when determining new subtransmission equipment capacity including: energy losses, expected equipment life, pollution resistance, aesthetic impact etc.

Projects & Programmes

Most of the projects in this subtransmission section are in some way linked. As an example, if 66kV supply is introduced at the source of a subtransmission circuit, the need to convert existing lines connected to the same source line or build new alternative ones becomes unavoidable.

Around 1997, before the first 66kV line was built or the first 66kV substation was even designed, a broad concept was provided to the EA Networks Board for their consideration. It showed the evolution of the then overloaded 33kV and 11kV networks to a predominantly 66kV and 22kV system. Budgetary estimates of the cost to develop the 66kV aspect of the concept were provided and the benefits in capacity and security were outlined. After evaluating the alternatives (massive increase in size and quantity of 33kV lines, 110kV & 33kV, or not supplying the new load) the Board provided an endorsement to proceed with system development keeping this ultimate 66kV concept in mind. This initial endorsement has been subsequently reinforced by approval of many projects that fit into the concept. This must be borne in mind when considering many of the subtransmission projects identified below. The substantive alternatives have already been considered as part of a much larger 'all of network' concept and EA Networks are not aware of any new technologies or opportunities to use non-network options that would provide an adequate substitute for the solution included in the initial concept. Should an alternative solution become apparent it will be evaluated and the decision documented in future plans.

To provide a sense of where all the individual projects are taking the network, a series of diagrams have been included. Each one represents a stage in the evolution of the subtransmission network from where it is now in 2020, to where it will be during 2024, to the end of the planning period - where it is entirely 66kV with a second 66kV GXP.

The first diagram (2020 above) shows the network with a single Transpower GXP at 66kV. The 66kV network consists of:

- a northern interconnected closed ring supplied by four circuits with several radial lines supplying individual sites,
- a southern closed ring supplied from three circuits.

The associated geographic map provides the location of each of the sites described in the schematic diagram.

The remaining steps to change from 33kV to 66kV are limited to two lines, one of which is not scheduled for conversion within the planning period and three zone substations, two of which will be decommissioned or converted to 22kV within the planning period.

Project	Year	Name	Category
-1156	2020	**EGN to FTN New 66kV Line Stage 2 (9km)**	System Growth

At the time of writing this 9km line has been fully constructed and is in the final stages of commissioning.

-1037	2021	**LSN to LSNT New 66kV Line Stage 1 (3 km)**	System Growth

During certain 66kV line outages, the supply to Lauriston and Overdale zone substations can experience lower than desirable 66kV voltages which can in turn off lower than acceptable 22kV and 400V supply voltages to consumers. This is caused by the long 66kV route required to supply them. During an outage of the PDS-OVD 66kV circuit the supply must travel from Elgin all the way to Methven and then back to Overdale. During an outage of the FTN-LSN 66kV circuit the supply must travel from Elgin to Overdale to Methven and then to Lauriston.

By the addition of 3km of 66kV line between Lauriston and the OVD-MTV 66kV circuit, the supply path during a circuit outage can be shortened by 25km. This provides a reduction in 66kV voltage drop that allows an acceptable supply voltage to be maintained to consumers.

This project partly delays the HTH-LSN 66kV line project but does not remove the need for it should a second GXP be required.

The completion of this line has been delayed by the Ashburton District Council proposing to reposition a roadway. The Council is currently in consultation with the community and, once concluded, the location of the final 0.5km will be finalised and built.

-1155	2028	**HTH to LSN New 66kV Line (24 km)**	System Growth

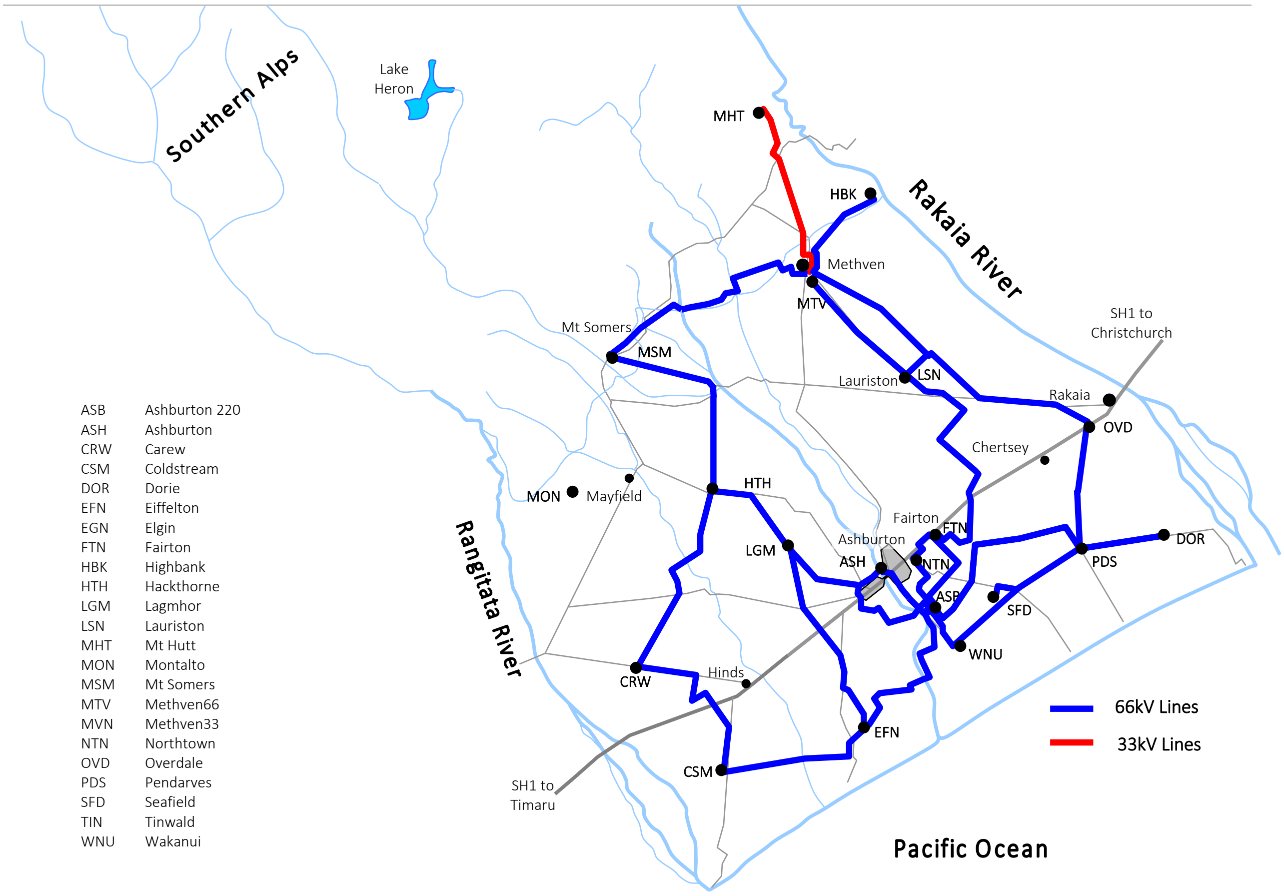
This project has been further delayed by the lack of new irrigation load occurring in the north and north western parts of the 66kV network. The requirement for this circuit depends upon multi-MW load growth from either Mt Somers, Hackthorne, Montalto, Methven or Lauriston substations. In recent years there has been very little new load and due to gravity-fed pipe networks there has been a slight load reduction in some places.

Triggers to build this line would include load growth (particularly more pumping at Highbank) or, should a second GXP proceed, the proposed location of the second 66kV GXP would require this line to supply into the southern 66kV ring.

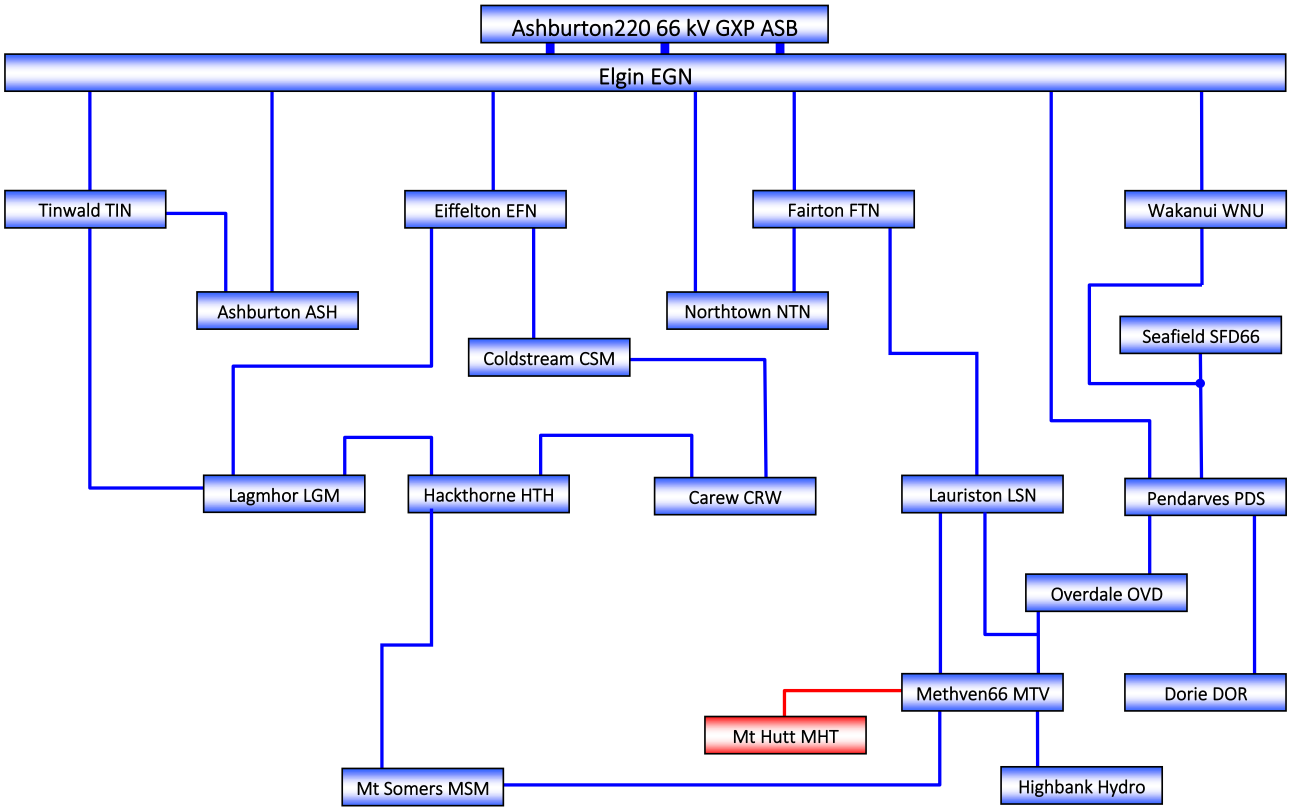
Alternatives to this solution may still be available and continue to be investigated. The initial stages of the BCI scheme have been completed, but the scheme has not been fully developed. Once additional irrigation water is required from the Rakaia River this project will almost certainly be necessary to service the 12 MW load during n-1 outages as well as to keep 66kV voltage at an acceptable level when all 66kV circuits are in service. Alternative options (both network and non-network) will continue to be investigated and the most prudent selected. The line is shown as dashed on the diagrams to indicate its uncertain status.

Project	Year	Name	Category
Programme	2021-23	**Overhead Line Replacement 66kV**	Asset Replacement

These projects are a complete rebuild of lines which were originally constructed as a 33kV circuit and later converted to 66kV by the addition of steel pole extensions and 66kV insulators. The lines will be 36-40 years old by the time they are rebuilt and the high security requirements of the 66kV network as well as the retrofitted nature of the lines suggest that it is prudent to rebuild the circuits before they become prone to failure.



2024 EA Networks Subtransmission Network



Close inspection of the lines may delay or advance the projects by a year or so. These lines represent the "bump" in the 66kV pole age profile of Section 6.3.1.

-1038	2021	**SFD-PDS 66kV Line Rebuild (7.5km)**	Asset Replacement
-1102	2022	**WNU-SFD 66kV Line Rebuild (8km)**	Asset Replacement
-1118	2023	**PDS-DOR 66kV Line Rebuild (8.3km)**	Asset Replacement

Programme	2029	New Lines 66kV	Varies
-1164	2029	**New MON to MSM 33-66kV Line Stage 3 (7.6km)**	System Growth

Further delayed due to lack of load growth. In preparation for the commissioning of the new Montalto zone substation [00513], this line will provide a 66kV supply from the existing Mt Somers substation into Montalto and Montalto Hydro. The line will initially be operating at 33kV, leaving Montalto Hydro and Montalto zone substation supplied from Mt Somers via a 22/33kV step-up arrangement. If required by security or load growth considerations, the 33 & 11kV load/generation will be transferred and supplied at 22kV from a new Montalto 66/22kV zone substation. Regardless of the load and security concerns, this line will be required to be built before 2024 due to the condition of the existing 33kV line (built 1982) supplying Montalto Hydro and Montalto zone substation.

This MON-MSM 66kV line is being built in three stages. The first two stages have been completed.

Bearing in mind the existing 33kV subtransmission arrangement does not meet the EA Networks security standards, this project is the only one of relatively few alternatives that can provide a degree of compliance and ultimately contribute to a fully compliant solution of two 66kV lines [00507/00508] supplying a new 66/22kV Montalto zone substation.

Given that the Montalto substation requires at least one subtransmission supply, there are no alternatives to this project.

This is the third stage of the 66kV line to connect the new MON zone substation [00513] to a 66kV supply.

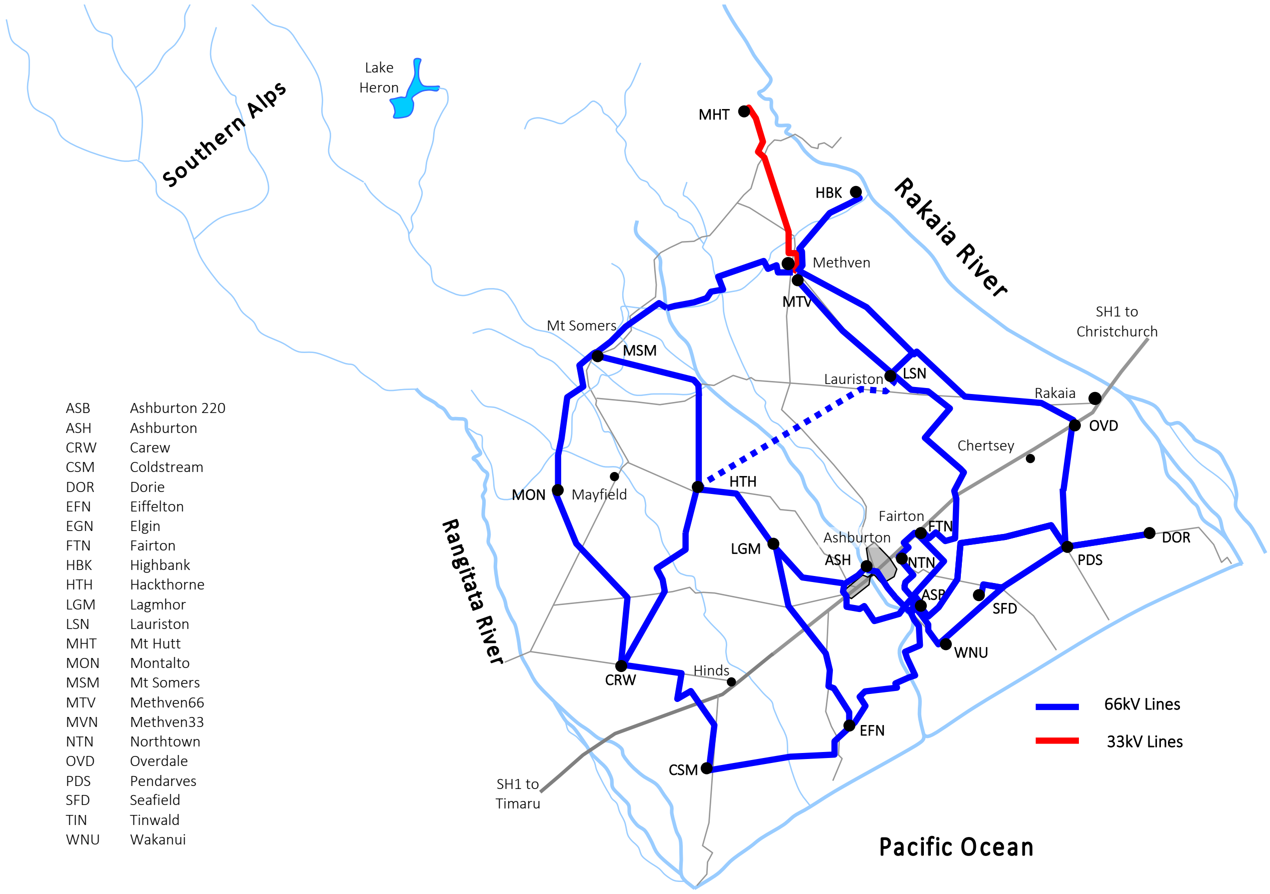
-1168	2029	**CRW to MON 66kV Line Stage 1 (10km)**	Quality of Supply

Further delayed due to lack of load growth. Should the load or generation on Montalto substation dictate that a higher security level is justified, a 66kV circuit can be provided between Carew substation and Montalto substation. This will allow loss of the Montalto to Mt Somers circuit or the Montalto to Carew circuit without an outage at Montalto substation.

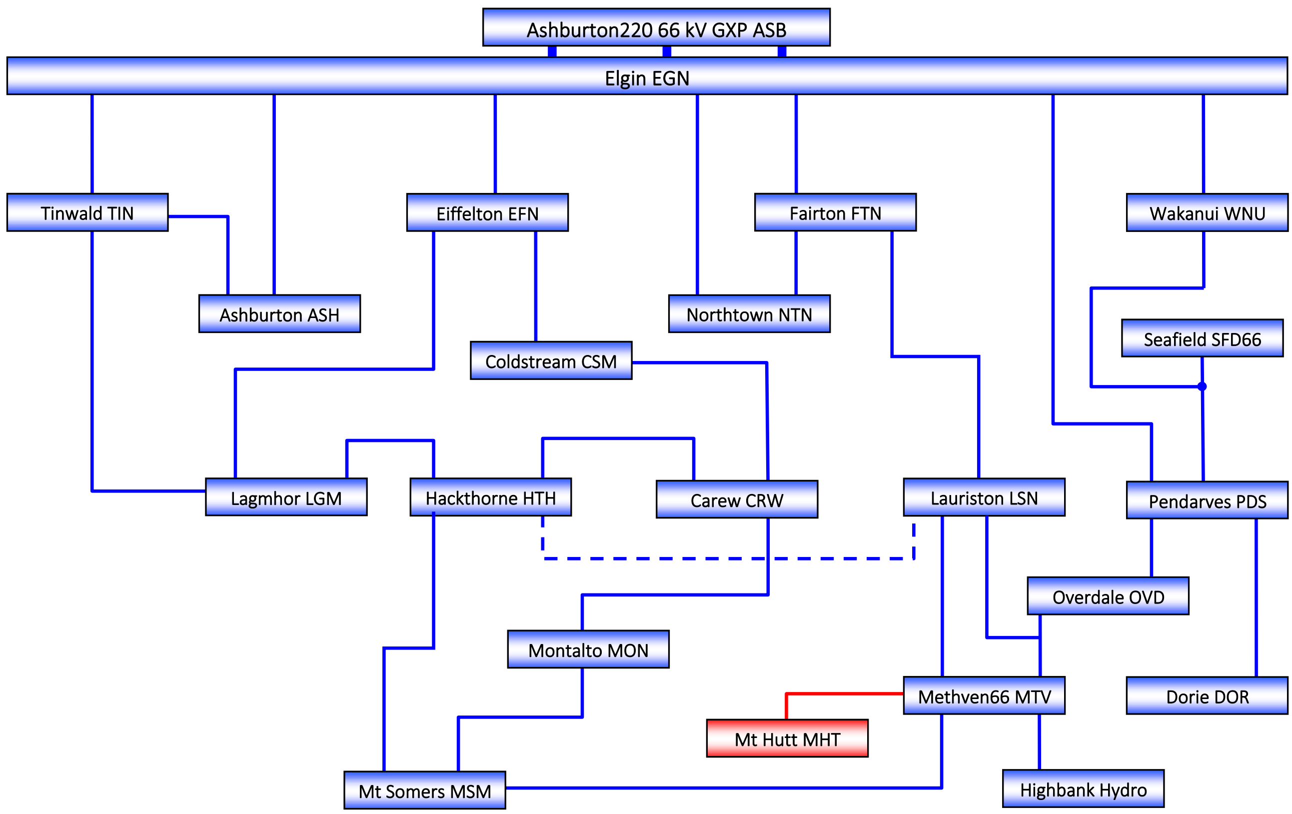
There are no alternative solutions that can offer the no-break capacity of a second 66kV circuit. An assessment of the need for this level of security will be made and if the requirement is deemed to be a no-break supply, this project will be the only possible solution.

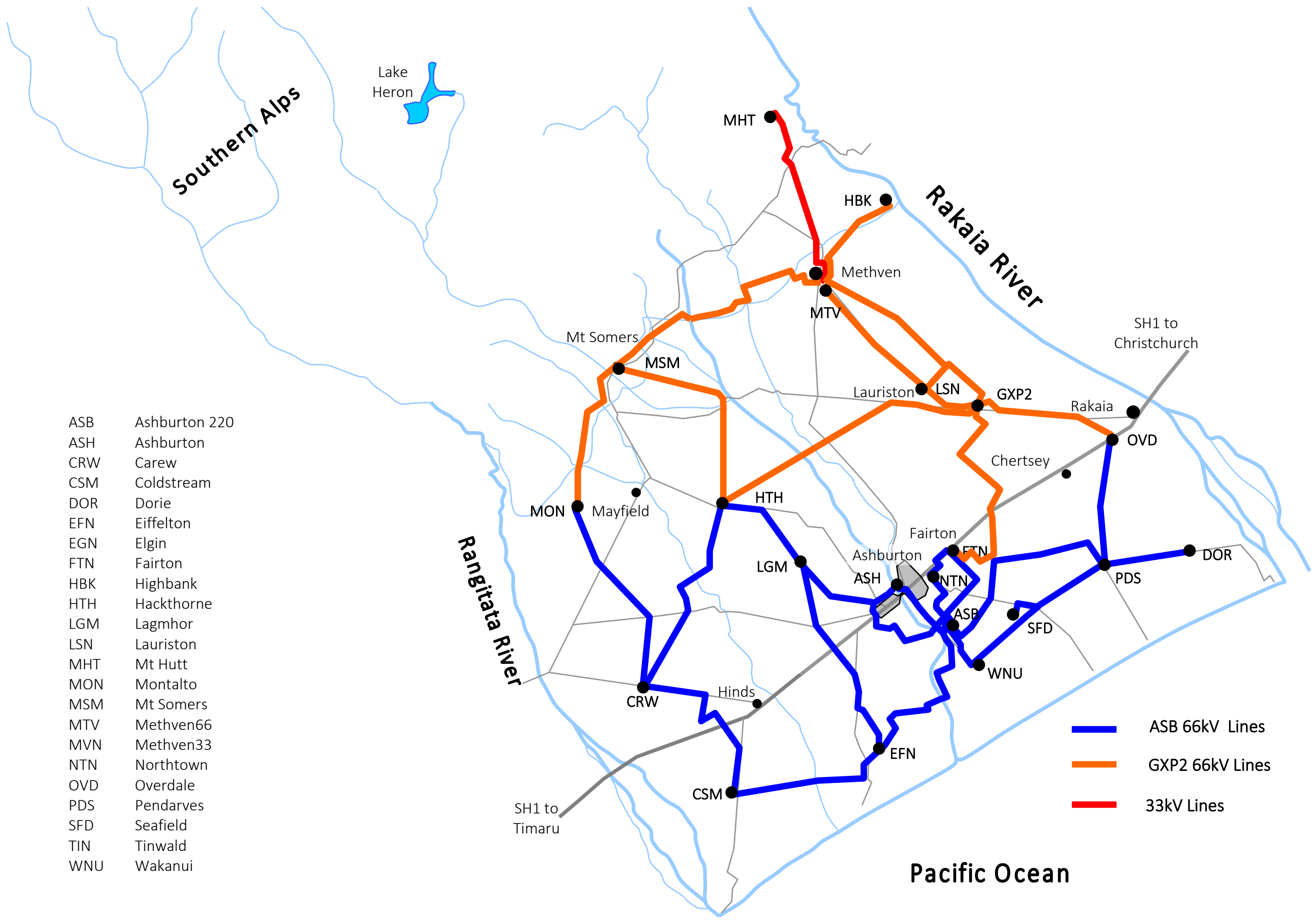
-1168	2029	**CRW to MON 66kV Line Stage 2 (10km)**	Quality of Supply

This project is the second and final stage of the project.

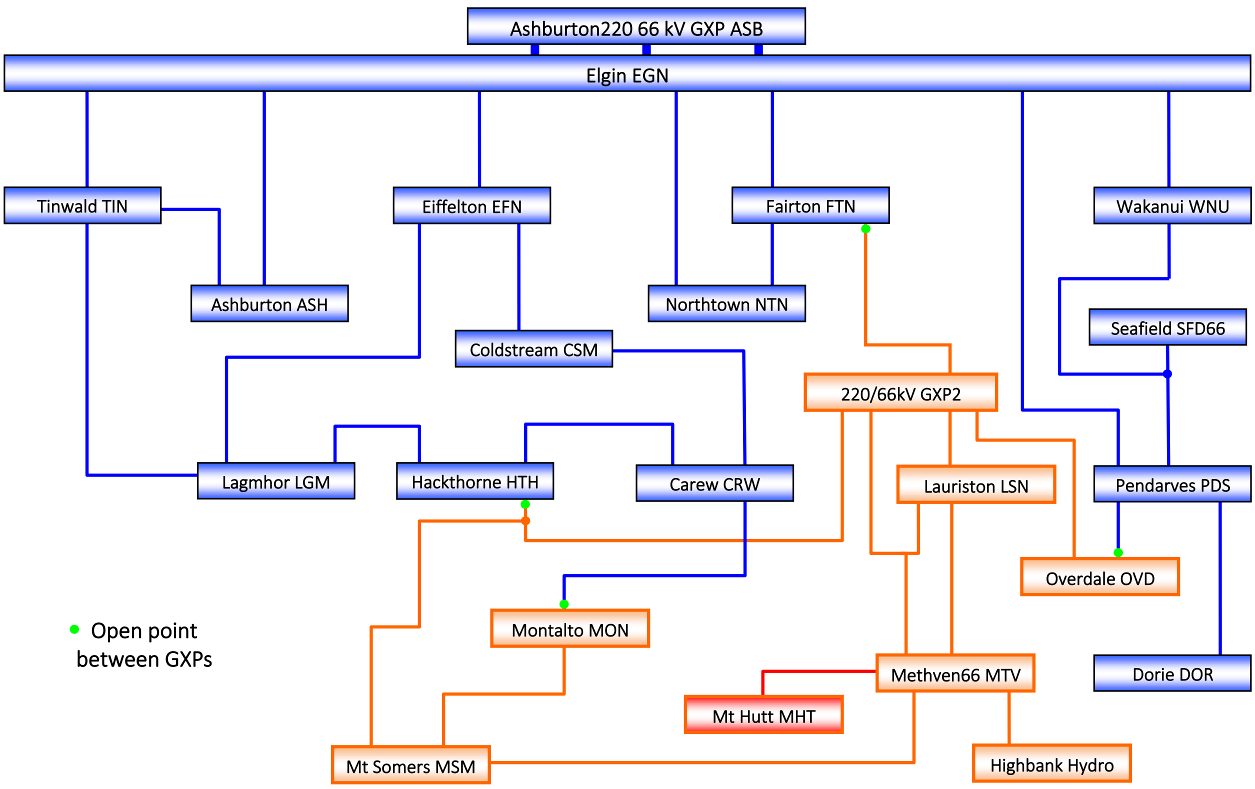


2029 EA Networks Subtransmission Network





2029+ EA Networks Subtransmission Network (including GXP2)



5.4.3 Zone Substations

The development at zone substations is typically a very costly and important part of network development. The drivers for doing this work are generally load growth and security. It may be that as the number of substations running at 66kV increases, another driver will emerge, and that is an economic one. Transpower costs are based on peak demand and Transpower assets employed. As 33kV load reduces, EA Networks can supply load at 66kV more economically than persisting with a 33kV supply from Transpower. By discontinuing the 33kV GXP and spending money on the EA Networks 66kV network, the decrease in GXP costs should result in overall savings in the long term.

EA Networks currently has 17 sites operating at 66kV and once fully developed, an additional 7 sites will be either decommissioned, converted from 33kV, or constructed from scratch. The zone substations operating at 33kV are typically less secure with less capacity than the ones operating at 66kV.

Capacity of New Equipment

A range of equipment is introduced when a new zone substation is constructed. The most critical and high cost items are the power transformers and the circuit-breakers.

The capacity of a new power transformer is influenced by a range of parameters, some of which relate directly to the load being served and some of which are externally derived. The only power transformers that EA Networks now purchase are units with 66kV primary voltage. The secondary voltage is either 11kV or 22kV. All units purchased so far have been capable of both secondary voltages using a series/parallel connection of the windings. This configuration allows operation at 66/22kV, 66/11kV and 33/11kV. The transformer power rating is based on the minimum economical size of 66kV transformer while keeping a degree of standardisation amongst the installed population of units. To date, two sizes of unit have been purchased, 10/15 MVA and 10/20 MVA. These share the same impedance as well as a common external electrical and mechanical connection arrangement which allows any unit to be exchanged with any other unit. The security standard (section 3.5.6) dictates the combination of single or dual transformers that are required to be installed to serve particular sizes and types of load. 10-20 MVA units are a close match to these security requirements.

Circuit-breakers and disconnectors are a simpler specification. At both 66kV and 22kV the continuous thermal and short circuit ratings of almost all available equipment exceeds the requirements at both voltage levels. Minimum ratings of 630 amps and 16 kA are easily met by virtually all equipment. Except for urban Ashburton sites, all new distribution equipment is 22kV rated. All new subtransmission equipment is 66kV rated.

Projects & Programmes

Project	Year	Name	Category
-1079	2019-21	**EGN Reconfigure Site (T1) as 66/22kV Substation**	System Growth

The 66/33/12.7 kV YNa0(d1) autotransformer located at Elgin is presently used for ripple injection onto the 66kV bus. Once the 66kV ripple injection system has been replaced [-1148] the autotransformer will only serve as an injection path for the existing 33kV ripple plant acting as a back-up. When it was purchased this eventuality was considered and the delta tertiary winding was specified as 12.7kV and all the winding ends were externally terminated. This offers the possibility to reconfigure the autotransformer as a 66/33/22kV YNyn0 transformer with a 15/20 MVA rating. By doing this and installing a 22kV switchboard and feeder cabling from Elgin, the load on several 66/22kV substations can be reduced thereby unloading the 66kV subtransmission circuits. The 33kV tapping on the 66kV winding will continue to have occasional use with the 33kV back-up ripple plant (should that remain in service).

Zone substations that would benefit from this project by off-loading and back-feeding ability include: Wakanui, Fairton, Eiffelton, and Pendarves. Other zone substations such as Ashburton, Northtown, and Seafield would consequently have additional back-feed capacity available during contingency events.

Project	Year	Name	Category
-1080	2021	LSN New LSN-LSNT 66kV Line Bay	System Growth

The construction of the 66kV line from Lauriston to Lauriston Tee [-1037] necessitates a new line bay and line protection.

The project will involve civil works, a section of 66kV bus, a 66kV circuit breaker, two disconnectors, a line termination structure, and 66kV line protection.

Given that the line will be built and requires connection, there are no alternatives to this project.

-1082	2021	MTV New 66kV Line Bay	System Growth

The conversion of Mt Somers substation to 66kV will also involve the conversion of the MTV-MSM line to 66kV. This requires the provision of a line bay at Methven substation to terminate the line.

The project will involve civil works, a 66kV circuit breaker, disconnector, and 66kV line protection.

-1082	2021	MTV Convert T1 to 66/22kV. Add T4 and T5 to 22/11/33kV Step-Up	System Growth

The load on the Mt Hutt ski-field is winter-only, and in recent years has decreased through more efficient snow-making facilities. Once Mt Somers and Montalto substations have been converted to 66kV operation, the 18/25 MVA transformer at Methven substation will only be supplying the Mt Hutt Substation. It is likely that an evaluation of the economics of retaining the transformer as 66/33kV versus supplying Mt Hutt using alternative means will come out strongly in favour of converting the 18/25 MVA transformer to 66/22kV operation and supplying Mt Hutt from the 22kV supply. A 22/11 kV autotransformer and 11/33kV OLTC transformer would be significantly cheaper than a small 66/11kV transformer and 66kV line conversion that would otherwise be required.

When the transformer was purchased in 1999 the possibility of 33kV abandonment was considered and the 33kV star winding was specified with a fully rated 22kV tapping. Some simple reconfiguration of the internal leads via a hatch will allow operation as 66/22kV.

Converting MTV T1 transformer to 66/22kV provides a much more secure situation for MTV load. The 11kV and 22kV loads will be served by T1 (66/22kV), T2 (66/11kV) and T3 (22/11kV). This provides full n-1 security for a transformer failure (fast restore - not firm capacity). The 22kV supply will be used to supply the surrounding rural area and provide local switched firm capacity to Methven township at 11kV via a 10 MVA, 22/11 kV, YNyn0(d1) transformer. The 22kV supply will also be able to provide significant back-feed capacity to Lauriston substation.

To minimise the total cost of supplying Mt Hutt, the intention is to reuse some of the assets that have been made surplus by 11-22kV conversion and 33-66kV conversion. A 5MVA, YNa0d1, 22/11kV autotransformer will be placed in series with a 5MVA, YNyn0(d1), 11/33kV, OLTC transformer (both already owned) to provide a regulated 33kV 5MVA supply to the existing Mt Hutt 33kV circuit and substation. EA Networks hold spares of both types of transformer and should a failure occur could replace the failed unit quickly. Recently, a surplus to requirements, unused, 2007, 33/22kV 5MVA transformer has been offered to EA Networks that would serve this application well. It is intended to negotiate to procure this unit.

Alternatives are the status quo, converting the entire Mt Hutt circuit and substation to 66kV, or supplying at a different voltage. The only limiting factor is the large pumps on the ski-field that require a reasonable fault level to limit voltage drop during starting (although this may be catered for with modern starting technology). Unless a better value for money solution arises, the proposed solution will be used.

It should be noted that beyond the planning horizon, the MTV-MHT 33kV line will require replacement due to condition. At that time, a decision will be required as to whether to persist with 33kV or to change to 66kV.

Project	Year	Name	Category
-1164	2029	**New 66kV Line Bay MSM Zone Substation**	System Growth

Further delayed due to lack of load growth. The construction of Montalto 66kV substation will involve the conversion of the MSM-MON line to 66kV. This requires the provision of a line bay at Mt Somers substation to terminate the line.

The project will involve civil works, a 66kV circuit breaker, disconnector, and 66kV line protection.

-1163	2029	**New MON Zone Substation**	System Growth

Further delayed due to lack of load growth. The BCI irrigation project has become a reality. The injection of water at the bottom of the Rangitata Diversion race has liberated water at the top end (near Montalto). This water is available for pumping onto farms. In time, the additional load could exceed the capacity of not only the 2.5 MVA transformer at the temporary Montalto substation but also cause additional voltage drop in the 33kV network. The first response to this will be to construct a permanent Montalto 66/22kV substation on a new site

A raft of alternatives exist for this project and some may yet be utilised. The chosen solution will depend upon the scale and rate of BCI/irrigation inspired load growth and local hydro generation.

A recent ECAN decision has seemingly placed almost complete restriction on new irrigation south of the Ashburton River in Mid-Canterbury (Montalto is in this area). This restriction is via nutrient discharge limits. Currently, the only reason this project may proceed is a desire to increase security and reliability to the Montalto district and surrounds. The situation will be monitored for developments.

-1126	2023	**Montalto Hydro Injection at 22kV**	Consumer Connection

There are two potential reasons the existing Montalto Hydro generation station (33/3.3kV) will require conversion to 22/3.3kV. The first is the planned conversion of the Montalto area to 22kV which will permit the decommissioning of Montalto 33/11kV substation, the decommissioning of the Mt Somers 22/33kV step-up transformers and the reuse of the existing Montalto to Mt Somers 33kV line at 22kV. It will not be viable to commit to maintaining the infrastructure to allow Montalto Hydro to continue injection at 33kV.

In addition, once Montalto 66/22kV substation is certain, Montalto Hydro would need to be injected at a different network location and a non-33kV voltage. The new Montalto substation is near Montalto Hydro and the opportunity to inject at 22kV would exist as soon as the substation is commissioned.

Both of these triggers involve changing the existing (Trustpower owned) 33/3.3kV transformer to a 22/3.3kV unit and plumbing it into a 22kV feeder.

-1166	2030	**New 66kV Line Bays CRW and MON**	Quality of Supply

Further delayed due to lack of load growth. The construction of the 66kV line between Carew and Montalto substations [-1168] will require a 66kV line bay at each substation. The line bays will involve the procurement and installation of some civil works, 66kV disconnectors, 66kV circuit-breakers, and line protection relays.

Given that the line is being built, there are no alternatives to this solution.

-1149	2026	**Tinwald Substation 66/11kV Transformer**	Quality of Supply

Presuming the load in Ashburton continues to grow, there will be a need to provide additional firm capacity within urban Ashburton. It is sensible to have geographically diverse 11kV supply points and the Tinwald 66kV switching station will be available to house a 66/11kV 10/20 MVA transformer supplying the existing 11kV switchboard. A transformer, 66kV circuit-breaker & disconnector, protection, and concrete pads will be required.

700	2024-30	**New/Smart Technology Programme**	System Growth

The range of technology applicable to the electricity distribution sector and related areas is expanding at a rapid rate. Broad areas with potential for rapid evolution include:

- Generation (Solar PV, Wind, etc),
- Storage technologies (batteries, hydrogen, thermal etc),
- Sensing technology (internet of things sensors, IP connected equipment, etc),
- Data storage and manipulation (energy use/availability, environmental, demographic, etc),
- Software applications (peer-to-peer trading, consumer portals, etc),
- Network intelligence (self-healing networks, continuous asset health monitoring, active capacity optimisation, etc).

It is almost inevitable that some of these technologies will be introduced into the EA Networks system at some stage within the planning horizon. One or two of them are already under active consideration.

Many of these technologies are changing rapidly and ten years is a long time within which major changes in capability and affordability are likely. Bearing in mind much of the change is likely to be based upon technology EA Networks are now only seeing glimpses of, it is not yet possible to determine which options EA Networks will be commercially compelled to implement.

The New/Smart technology programme is intended to provide for the ability to implement these types of technology projects at relatively short notice without specifically identifying them at this early stage.

Ultimately, any of the options that are chosen will be driven by consumer demand for a product or service that EA Networks can foresee will provide an appropriate return on investment be it in retaining/expanding energy delivery market share or finding ways to utilise existing or new assets in new and novel ways.

5.4.4 Rural 11kV and 22kV Distribution Network

The loading, security and load growth on each of EA Networks' rural distribution feeders is assessed annually and this assists in preparing enhancement and development projects for this plan. The need for reinforcement is typically driven by the security standards and how the HV distribution network would cope with loss of an overhead line segment. Once a candidate feeder has been identified, the potential solutions are developed and then rigorously analysed to select the option offering best value.

Rural feeders are almost always limited by voltage drop. There are a range of solutions that can be applied to reinforce these feeders to meet the security standards. These include (but are not limited to):

- increase the conductor size
- reconfigure the network
- install capacitors
- install voltage regulator(s)
- convert to higher operating voltage
- install additional inter-feeder tie lines
- install additional feeders from the zone substation
- install additional line reclosers to increase segmentation

Almost all rural load is summer peaking irrigation or dairy shed load. Although peak demand load determines the feeder capacity it may not determine the feeder configuration or its compliance with security standards. A lightly loaded rural feeder with little irrigation load may have many consumers supplied from it and consumer numbers rather than load may dictate the appropriate level of security.

Capacity of New Equipment

The capacity of new rural distribution lines is nearly always determined by voltage drop and mechanical considerations. The primary requirement in sizing rural overhead lines is to ensure that no part of the feeder in question experiences a voltage below 95 % of nominal during a foreseeable n-1 security event using the load probable 10 years into the future. Thermal constraints can exist in the portion of line immediately beyond the feeder circuit-breaker. These are considered on a case by case basis but generally will not require a rating exceeding 300 amps (11 MVA at 22kV).

Rural distribution transformers are sized based upon the scale and type of load being served. Small domestic and non-irrigation loads will be provided with transformers closely matched to the load. Irrigation pumps were historically provided with transformers that were larger than normal due to the harmonic derating effect of variable speed drives (compulsory harmonic limits now preclude the need for derating).

Projects & Programmes

Project	Year	Name	Category
11136	2021-30	**Consumer Connections – Rural LV/Rural Transformer**	Consumer Connections

When a new connection is supplied there is typically some modification or extension to the distribution network. This can range from a replacement pole through to a significant 22kV extension of several kilometres with several new substations.

Being unscheduled, this work is essentially completed on demand (assuming the new or altered connection load is advantageous to EA Networks). The solution chosen to supply a new/altered load is typically agreed during consultation with the consumer to determine a price/quality/security trade-off they are happy with.

-1002	2021-30	**22kV OH Unscheduled Reconductoring**	Asset Replacement

Unplanned replacement of inferior conductors or conductors at the end of useful life.

Some conductor condition is not obvious until either a fault or planned work identifies deterioration that is not obvious from ground level inspection. If this is found and needs timely attention the work is completed from this fund.

When required, significant reconductoring works are identified as individual projects separate from this programme.

-1167	2029	**MON 22kV Feeder Integration**	System Growth

Further delayed due to lack of load growth. The new Montalto substation requires integration into the existing distribution network. This project will involve the construction of several kilometres of Dog conductor 22kV overhead line. Dog conductor allows Montalto to supply some or all the near-by loads presently connected to Hackthorne, Mt Somers and Montalto (temp) substations and offer back-feed opportunities during adjacent substation or feeder outages.

This project has no alternatives.

Programme	2021-30	**Overhead Line Replacement 22kV**	Asset Replacement

The programme of rebuilding rural overhead lines when they reach the end of their useful structural life is an accepted routine activity. With a legal requirement to maintain the supply to existing consumers in place there is no option but to replace the old line with a modern equivalent overhead line using 22kV components and a standard conductor size/type. The following schedule is those lines that have been identified as needing replacement within the next few years.

-1000	2021-30	**22-11kV OH Scheduled Pole Replacements**

A programme of planned minor replacement works that typically involve replacing one or two poles at a time. Prior year's inspection programme is likely to have identified the target poles.

-1001	2021-30	**22-11kV-LV OH Unscheduled Pole Replacement**

A programme of unplanned minor replacement works that typically involve replacing one pole at a time. Current year's routine inspection will typically drive this programme.

-1019	2021	**A.R.G. Rd (A.F. Cemetery Rd - McFarlanes Rd) (2.3km)**
-1020	2021	**Ashburton Staveley Rd (Allan Smith to Goughs Crossing Rds) (2km)**
-1021	2021	**Bells & Longbeach Rds (5.2km)**

-1022	2021	Corbetts Rd North (Mainwarings Rd South to end of line.) (0.3km)
-1023	2021	Dip Rd (Reynolds - Flemings Rd) (2.65km)
-1024	2021	Flemings Rd (Dip Rd South to BW70) (0.45km)
-1176	2021	Gibsons Rd (Fitzgerald Rd - North to end) (1.6km)
-1013	2021	Grahams Rd (Grove St - Gartarton Rd) (1.2km)
-1025	2021	Hackthorne Rd (TWM to Frasers Rds) (2.35km)
-1179	2021	Jacksons Rd (1.6km)
-1026	2021	Maronan Rd (Maronan Valetta Rd East) (1.1km)
-1027	2021	McCrorys Rd (Dorie School to Acton Rds.) (2.4km)
-1028	2021	McCrorys Rd (Mainwarings - Dorie School Rds) (2.7km)
-1035	2021	OH Underbuild - Bells & Longbeach Rds (4.2km)
-1029	2021	Pudding Hill Rd (Hobbs Rd - Spaxton St) (1.6km)
-1030	2021	Rakaia Barrhill Methven Rd (West Town Belt West) (0.9km)
-1014	2021	Rakaia Gorge Planning (1ea)
-1015	2021	Rangitata Gorge (Coal Hill - Waikari Hills) (6km)
-1015	2021	Rangitata Gorge (Rangitata River - Waikari Hills) (6km)
-1031	2021	Rangitata Terrace Rd (Maronan Cracroft Rd East to BV08) (0.9km)
-1016	2021	Taits Rd (1.2km)
-1032	2021	T.W.M. Rd (Jacksons to Rushford Rd) (2.9km)
-1033	2021	Upper Rakaia River Crossing (2.7km)
-1034	2021	Winters Rd (Christys Rd - East) (2.4km)
-1090	2022	Allan Smith Rd (1.8km)
-1091	2022	Allan Smith Rd (Ash Staveley Rd to on property) (1.2km)
-1083	2022	Cliffords Rd (1.2km)
-1092	2022	Copley Rd (Chertsey Kyle Rd East to end.) (1.4km)
-1093	2022	Crows Rd (Emersons to Dowdings Rds) (1.5km)
-1084	2022	Fords Rd (Griffiths - Wheatstone Rds.) (1.9km)
-1094	2022	Hackthorne Rd (Valetta Westerfield - Frasers Rds) (3.6km)
-1094	2022	Hackthorne Rd Section 1 (TWM - Barford Rds) (4.2km)
-1095	2022	Harrisons Rd (Dorie School to Acton Rds) (1.9km)
-1096	2022	Hollands- TWM Rd (1.3km)
-1097	2022	Lismore Mayfield Rd (Hackthorne - Lismore School Rds) (4.7km)
-1085	2022	Lower Downs Rd (Blairs Rd north to end.) (0.5km)
-1086	2022	Rakaia Gorge Section 1+2 (6.2km)
-1098	2022	Seafield Rd (Christys - Buckleys Rds) (6.5km)
-1099	2022	Stevens Rd (Dowdings Rd South to ET05) (0.95km)
-1100	2022	Valetta Westerfield Rd (Westerfield School to Sheates Rd) (1.8km)
-1101	2022	Windermere Rd (Surveyors Rd West) (3km)
-1116	2023	Anama School Rd (6.5km)
-1114	2023	Ashburton Gorge - Section 1. (6km)
-1117	2023	Crows Rd (Dowdings Rd - East to end) (2.3km)
-1086	2023	Rakaia Gorge Section 1+2 (5km)
-1086	2024	Rakaia Gorge Section 3 & 4 (5.1km)
11704	2021-30	Unscheduled Asset Replacement and Renewal

The overhead rebuild programme is still being researched to give an accurate year 4-10 assessment. By using the stored age of overhead lines, a provisional assessment has been made of the quantity of lines needed to be rebuilt within the planning period. This assessment has been costed and included in the plan as an average annual cost. The next plan will have a more fully populated 5-year programme identifying the likely rebuild candidates.

Programme	2021-24	Rural Underground Conversion	Asset Replacement

The state highway network through mid-Canterbury covers about 100km of rural road. EA Networks have electricity lines along the side of a significant length of this highway network. NZTA have road safety as a primary goal. To achieve this, they have indicated the desire to remove roadside obstacles including power poles. EA Networks have come to an arrangement with NZTA to part-fund the removal of poles from any state highway when the opportunity arises. This is typically considered when the line in question reaches the end of its useful structural life.

Such an arrangement obviously has some pros and cons for the line owner. The principal requirement is to replace the existing end-of-life overhead line with a line of the same or similar functionality.

A new overhead line would achieve this but would not improve the fault resistance of the line (weather, wildlife, vehicles, vandalism etc would still pose a threat). NZTA would not contribute to the replacement as it has no road safety benefits and in fact extends the roadside pole hazard for another 40 or more years. This option is the cheapest option but the least safe for the public.

Placed underground, the line is almost entirely immune to traditional (and common) sources of rural faults. It is exposed to the hazard of someone digging into it in ignorance (the law is not on the side of the person excavating) and the infrequent above ground portions can be exposed to vehicles, heavy flooding and vandalism. The line will typically be of larger cross section and lower voltage drop than the overhead line it replaces. The removal of poles will attract some funding from NZTA in the interests of road safety. It is highly likely that during the following 40 years, one or more lives will be saved by avoiding a high-speed car versus pole collision. This option is more expensive than the overhead alternative.

There are various other smaller rural underground conversion projects (not on State Highways) that attract no funding from NZTA.

Project	Year	Name	Category
Sub-Programme	2021-24	Rural State Highway Underground Conversion	Varies

A series of projects that, with the assistance of NZTA, rebuild the existing end-of-life overhead line as underground cable. The projects will replace the existing overhead line with underground cable and connect existing overhead spur lines using either ring main units or three way disconnectable joints ("elbow" connectors).

-1056	2021	Hinds Hwy. Cracroft St to Coldstream Rd (1.8km)	RSE Safety
-1061	2021	Methven Hwy (Pole Rd - Methven) (2.5km)	Asset Replacement
-1062	2021-22	Methven Hwy (Rooneys - Shearers) (3.1km)	Asset Replacement
-1109	2022	Methven Hwy (Thompsons Track - Pole Rd) (8.0km)	Asset Replacement
-1121	2023	Methven Hwy (Blands Rd - Thompsons Track) (2.7km)	Asset Replacement
-1130	2024	Methven Hwy (Shearers - Blands Rd) (2.6km)	Asset Replacement

Sub-Programme	2021-24	Rural School Underground Conversion	RSE Safety

Two projects to underground the 22kV network in the vicinity of rural schools. To eliminate the risk of pole or conductor failure, the short sections of line near the schools will be placed underground.

-1048	2021-22	Ashburton Christian School (0.1km)	RSE Safety
-1105	2022	Dorie School (0.3km)	RSE Safety

Sub-Programme	2021	**Other Rural Underground Conversion Projects**	Varies
-1051	2021	**Convert State Highway OH crossings to UG (3 ea)**	RSE Safety

Many of the existing 22kV consumer service connections are overhead lines that cross the road from the main 22kV line. These spans of conductor are typically not at normal working tension in order to relieve the sideways pull of the span on the network pole, this means they sag more in the middle of the span. They also "tap-off" the main line below the main circuit. This combination of factors means that the span crossing the road is lower than many of the other conductors on the roadside.

These spans are a significant hindrance when a "high load" is required to pass underneath such as a house being moved, or a tilt-slab concrete panel being shifted. EA Networks will provide a pilot vehicle when this type of load is shifted and on occasion certain spans crossing the road may require isolation before they can pass.

This project aims to replace some of the lowest 22kV spans crossing state highways (particularly SH1) with a short section of underground cable. This will remove the safety hazard and preclude the need to isolate the line during high load transit. This project has carried over from 2016 and 2017.

-1059	2021	**Longbeach Rd, Hinds Hwy to east (0.7km)**	Asset Replacement

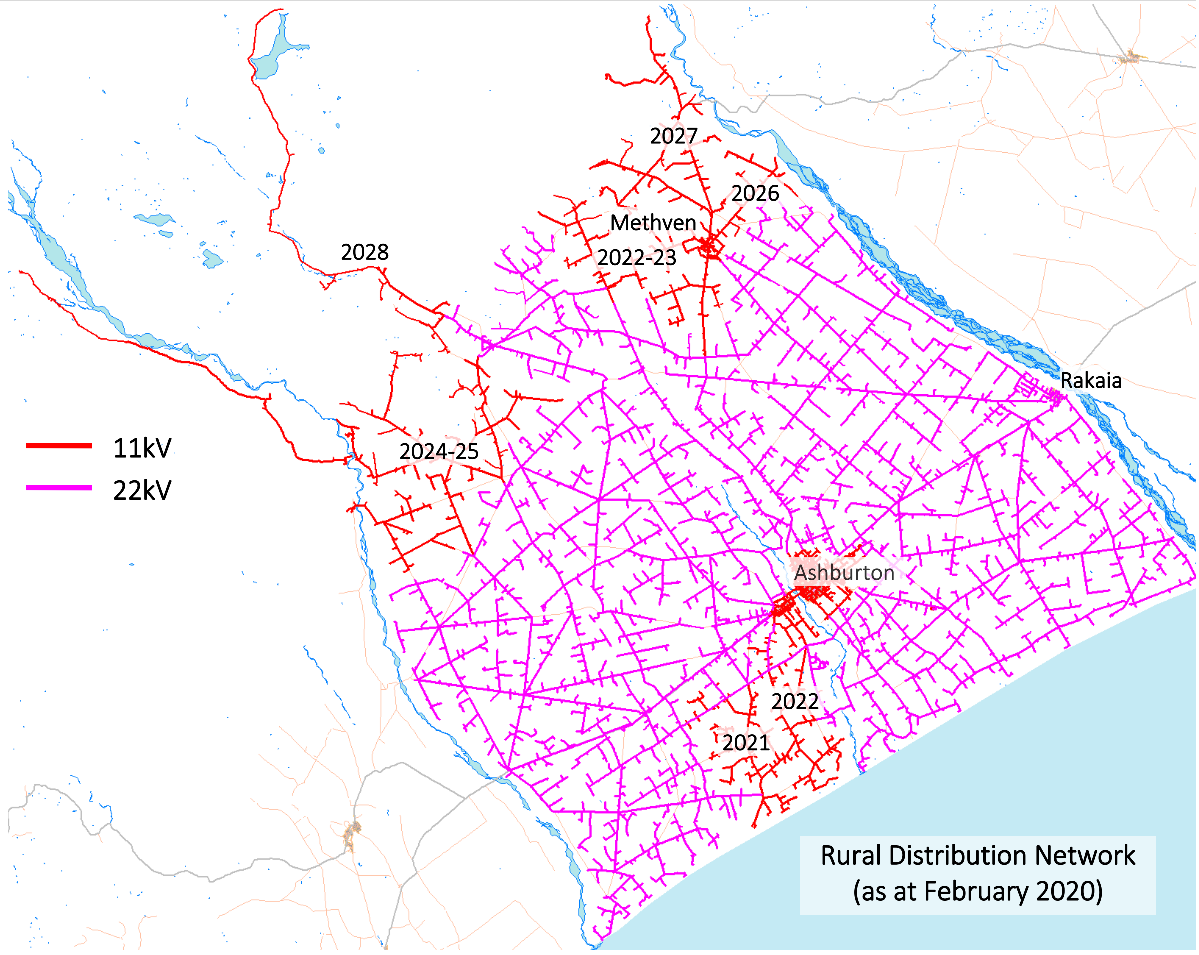
A section of EA Networks 22kV line crosses private property and is in very poor condition. A decision has been made to reroute it and supply it from the now 22kV underground Hinds Highway. Approximately 180m of new 22kV network cable will be laid and 540m of on-property 22kV and LV cable will be installed to remove all EA Networks OH line from private property. Requires easements which has delayed progress.

Project	Year	Name	Category
Programme	2021-28	**Upgrade Rural Network 11kV to 22kV**	Varies

The 22kV conversion programme is a carefully considered decision between upgrading existing 11kV lines in an area to provide a moderate incremental increase in capacity or converting to 22kV providing a significant step increase in capacity. Each proposal is treated on merit and what it can offer in the way of long-term benefits. Capacity (at a distance), earning potential, quality of supply, security, motor starting demands, future load growth, risk and outright cost are but a selection of the considerations made when the options are weighed. This programme is essentially "on-demand" as an alternative to other technical solutions available to all lines companies.

A programme has been established that provides a progressive conversion of areas that require either reinforcement or additional back-feeding capability. The programme extends out for most of the planning period. The projects identified are firm proposals to solve existing loading or security concerns. The full range of alternative solutions described in section 5.3.2 are always considered alongside the conversion option. There are occasions when alternatives such as conductor size increase has been chosen over 22kV conversion, but each situation is individually examined and only the optimal capacity and security enhancing solution chosen.

-1017	2021	**Eiffelton / Windermere**	System Growth
-1017	2022	**Flemington / Huntingdon**	System Growth
-1089	2022-23	**Methven Highway**	Quality of Supply
-1172	2024	**Montalto / Rangitata**	System Growth
-1088	2024	**Ruapuna**	System Growth
-1133	2025	**Anama**	System Growth
-1139	2026	**Highbank / McLennans Bush**	System Growth
-1150	2027	**Mt Hutt / Rakaia Gorge**	System Growth
-1154	2028	**Ashburton Gorge**	System Growth



Several of the projects are large areas of 11kV that will be supplied by a single 11kV line bordered by 22kV network. The circuit will have more than 250 consumers on it and no back-feeding options for a fault at the root of the feeder. The only viable solution is 22kV conversion as 22/11kV interconnecting autotransformers are technically not an acceptable long-term solution.

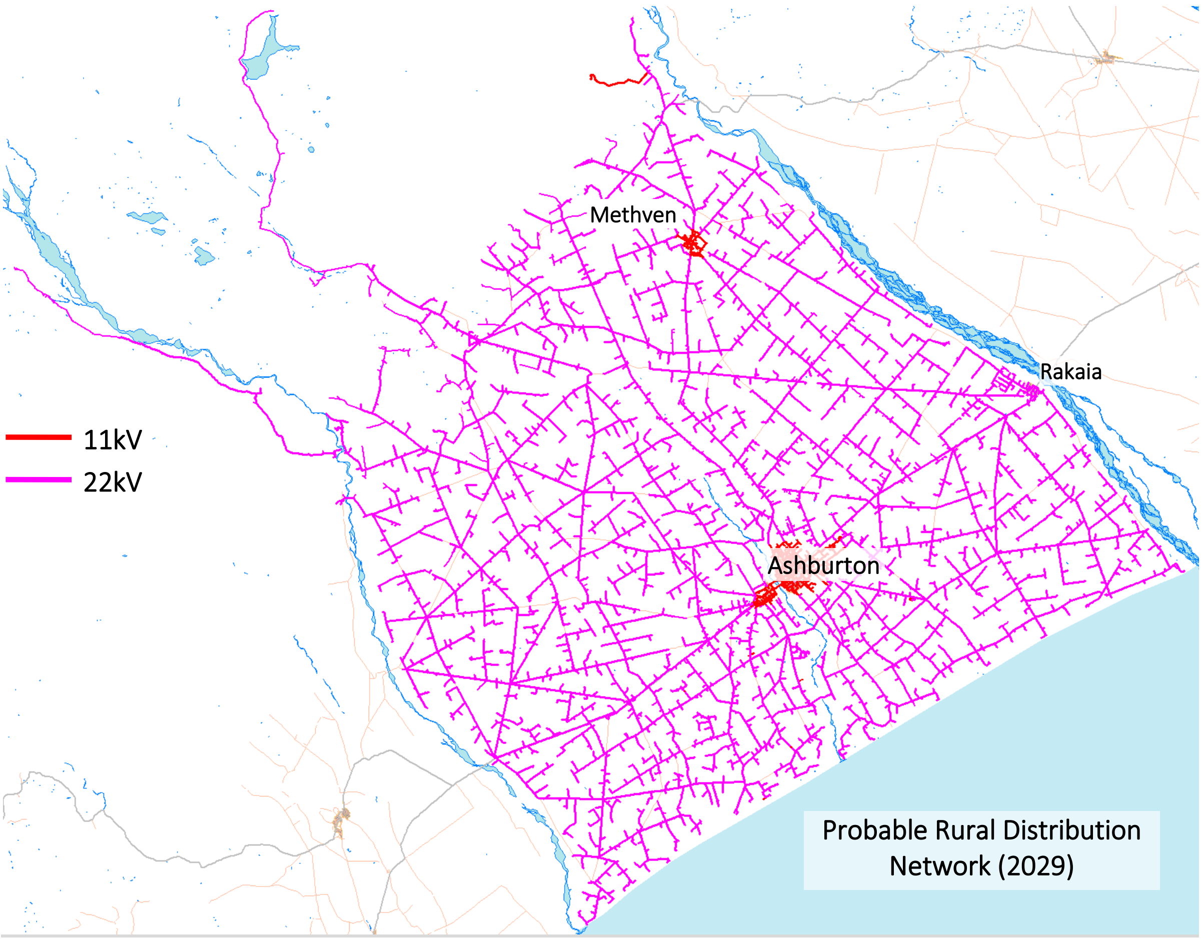
The projects will provide a significant boost to the security and reliability of the connected consumers as well as boosting the capacity significantly. Compliance with the Reliability by Design guidelines will be greatly assisted by the work.

It should be noted that load growth which occurred over the previous decade or more has prompted the security issues that these projects resolve.

The limitation of 11kV transporting large amounts of load is quite severe in that attempting back-feed from other feeders or substations is very difficult because of voltage regulation. Transporting 5MW over a distance of 5km using Dog at 11kV will cause approximately 8% voltage drop. This would exceed the legal limits and cause significant issues for consumers. The exact same circuit and load operating at 22kV would only have 2% voltage drop and can therefore offer vastly more capacity to adjacent feeders and zone substations.

The rural loads EA Networks experience are very significant and the only viable option to eliminate operational constraints that have arrived with the increase in load that has occurred over time is to complete the conversion to 22kV in the remaining rural 11kV areas .

At this stage the presumption is that the 22kV conversion programme will continue until no rural 11kV remains. The supply from Orion in the upper Rakaia is likely to always be 11kV as will the Mt Hutt skifield supply (2 x 11kV cable circuits of about 7km length).



5.4.5 Urban 11kV Distribution Network

"Urban" distribution feeders are restricted to Ashburton, Methven, Mt Somers, and Rakaia townships. Other townships are typically connected to a rural overhead feeder with additional network segregation using line reclosers to offer the township a more secure supply.

In recent times, a third 11kV feeder cable has been laid to secure the supply from the Methven66 zone substation to the Methven urban area. A new 11kV inter-feeder cable was also installed to provide balance between the feeders and increasing back-fed capacity during a cable fault.

Urban reinforcement solutions are typically implemented by adding additional cable routes from a zone substation, although a point is reached when congestion makes this impractical. Around 2005 Ashburton substation reached that situation and the chosen solution was to introduce Northtown substation.

To meet both the capacity and security standards in place, the need has arisen to provide reinforced 11kV ties and distributors from both Northtown and Ashburton substations. Some circuits are close to reaching thermal capacity and consequently security suffers. To resolve this, and thereby increase security and capacity, a decision has been made to introduce an additional layer of 11kV cabling within the Ashburton urban area. These large capacity cables (400+ amps) will be used to transport energy away from the zone substations to other nodes and between those nodes. Normal capacity distribution feeders (200 amps) would then radiate from these nodes, interconnecting with existing feeders.

Capacity of New Equipment

The capacity of a new urban 11kV underground distribution circuit is typically sized between 200 amps and 300 amps. The exact sizing is determined by likely feeder loading and its function during n-1 security events. Typically, this will mean the load will be no more than 50% of the thermal capacity to allow for growth and adjacent feeder back-feeding during n-1 events.

Urban distribution transformers are sized using either an average diversified load for domestic consumers (4kVA) or assessed load information from industrial/commercial consumers. Maximum demand meters in the distribution substation ensures calculated values can be readily confirmed.

Projects & Programmes

Project	Year	Name	Category
Programme	2021-30	**Unscheduled Urban Works**	Varies

A small amount of budget is set aside for unscheduled work that occasionally occurs. This could involve one or many classes of asset. It has been included in the urban distribution section as a significant proportion of EA Networks' consumers reside there. It is therefore likely that some of the demand for unscheduled work would come from these areas.

It should be noted that the Ashburton District Plan does not permit the installation of additional poles in the urban and fringe urban zones and replacement poles must be of the same or similar height and scale and in the same or similar location. This precludes significant changes to any overhead line if it was going to be rebuilt.

11059	2021-30	**Unscheduled System Growth**	System Growth
11078	2021-30	**Unscheduled Quality of Supply**	Quality of Supply
11079	2021-30	**Unscheduled Other Reliability Safety Environment**	RSE
11704	2021-30	**Unscheduled Replacement and Renewal**	Replacement & Renewal

Programme	2021-30	**Urban Consumer Connections**	Consumer Connections

When a new connection is supplied there is typically some modification or extension to the distribution network. This can range from a replacement pole through to a significant 11kV or 22kV extension of several hundred metres with a new substation. Typically, the new consumer will be required to contribute to the cost of the work.

Being unscheduled, this work is essentially completed on demand (assuming the new or altered connection load is advantageous to EA Networks). The solution chosen to supply a new/altered load is typically agreed during consultation with the consumer to determine a price/quality/security trade-off they are happy with.

Although subdivision work is categorised as Consumer Connection – Other, as it is triggered by the desire to take additional electrical connections to the network, it does not immediately create any new ICPSs. In fact, the bulk of new connections generally occur a year or so later as the marketing takes effect. A consequence of this is that there are generally no new ICPs reported next to subdivision work in the disclosure documentation. Other types of new connections are charged directly against the project creating them and can be resolved back to the relevant connection category.

11058	2021-30	**Urban Connections - Transformer**	Consumer Connections
11058	2021-30	**Urban Connections – LV**	Consumer Connections
11058	2021-30	**Urban Connections - Alteration**	Consumer Connections
11058	2021-30	**Urban Connections – Other**	Consumer Connections

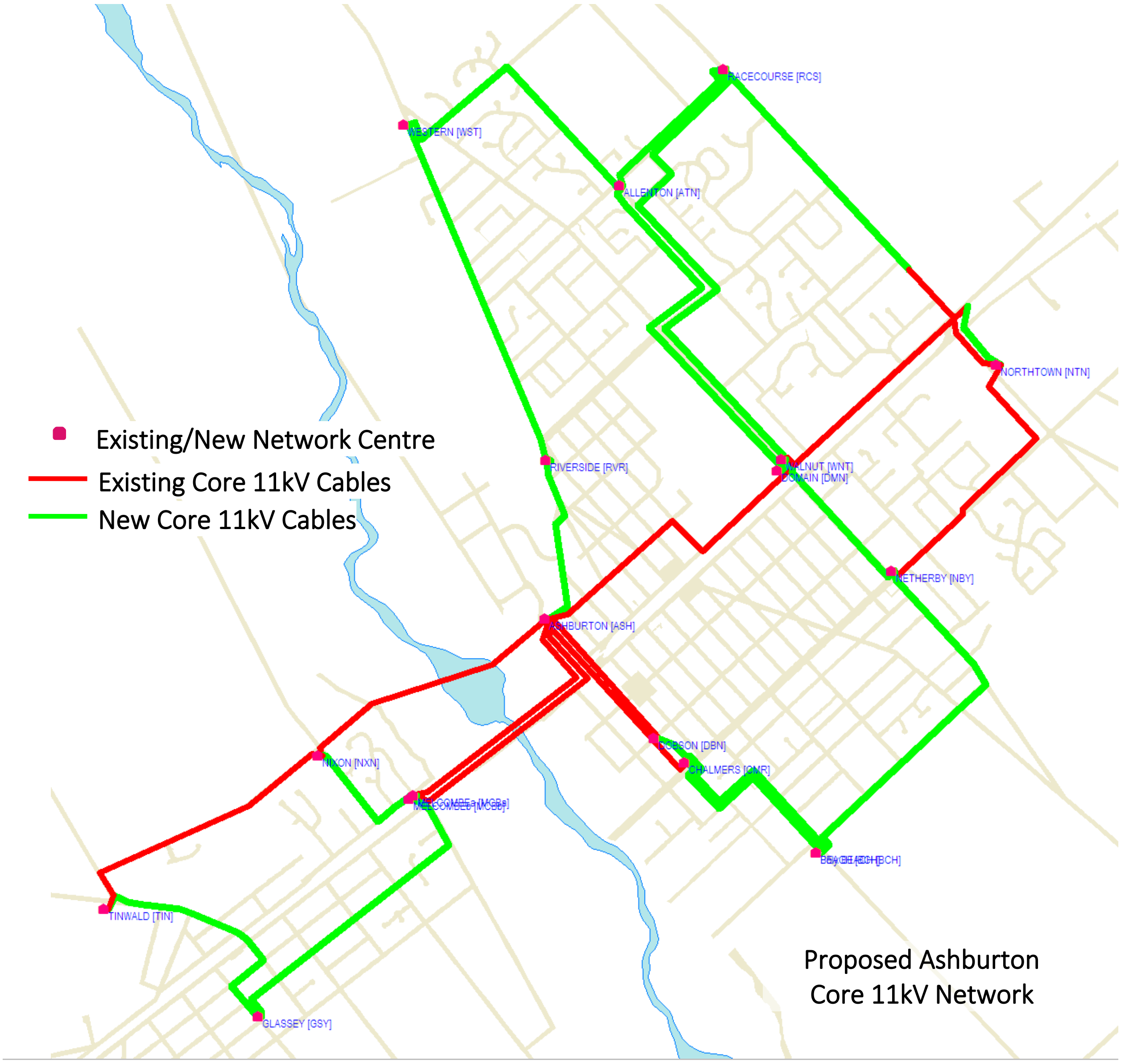
Programme	2021-28	**Ashburton Core Urban 11kV Network**	System Growth

The adoption of the Reliability by Design guidelines by the Board has added impetus to the need to reduce the scale of urban 11kV feeders. The new guidelines have a maximum of 250 consumers per feeder before action is deemed necessary to reduce that number to below 200. There are many urban feeders that exceed that number by a significant margin and a range of initiatives are underway to close the gap to complying with the guidelines. This "Core Urban 11kV Network" programme (Section 5.3.4) is one of the most significant ones, and it will provide additional feeders from new Network Centres (switching centres) embedded within the urban areas.

The planned reinforcement would take the form of relatively few, new, high capacity (7 MW) 11kV Core Network circuits radiating from both Ashburton and Northtown substations. These circuits would terminate in new switching centres that would supply (via circuit-breakers) the smaller (4 MW) existing zone substation feeders and additional feeders (created by utilising existing and new 11kV cables). Distribution substations would not be directly connected to the new Core Network circuits. These high capacity Core Network circuits would then interconnect between Network Centres to provide an 11kV backbone which could be used to shift load during cable faults and zone substation transformer outages. An added benefit is that the existing smaller feeders would be more than halved in length and load, so any cable fault should affect less than half as many consumers and restoration to the un-faulted sections would be significantly faster.

With the continuing use of heat pumps to displace solid/liquid/gas fuel heating, the introduction of home electric car charging, and as the general growth in electricity demand continues, it is very likely that additional distribution system capacity will be needed in the Ashburton urban area. This programme will increase the capacity to supply load under both normal and contingency conditions.

This programme of works will only be undertaken as necessary. The addition of unforeseen load may accelerate the programme and, equally, a prolonged period of low growth may postpone parts of the programme. Once started, there will be key points where a pause can take place, but these points must be reached as incomplete closure of a ring of the core 11kV circuits would heavily compromise security. The



progress of the programme will be optimised by coordinating with the urban underground conversion programme.

Alternative distribution architectures may yet surface that provide a viable solution. These new technologies will be considered as part of any solution as will future load shifting or embedded generation or energy storage technologies.

This part of the programme identifies the roughly 22km of new 11kV cabling required. Much of the new cable will be run in existing/new ducts installed during the UG conversion programme (particularly in Tinwald). The network centres are identified in Section 5.4.8.

-1010	2021-28	**11kV Core Network Cables**	System Growth

- Northtown [NTN] to Racecourse [RCS] Network Centre (1.5km).
- Netherby [NBY] to Walnut [WNT] Network Centre (0.9km).
- Northtown zone substation [NTN] to Walnut [WNT] Network Centre (0.5km).
- Melcombe [MCB] to Glassey [GSY] Network Centre (1.7km).
- Tinwald [TIN] to [GSY] Network Centre (1.3km).
- Domain/Walnut [DMN/WNT] to Racecourse [RCS] Network Centre (2.9km).
- Domain/Walnut [DMN/WNT] to Allenton [ATN] Network Centre (2.1km).
- Racecourse [RCS] to Allenton [ATN] Network Centre (1.0km).
- Ashburton zone substation [ASH] to Western [WST] Network Centre (2.9km).
- Dobson [DBN] to Beach [BCH] Network Centre (1.3km).
- Western [WST] to Allenton [ATN] Network Centre (1.6km).
- Chalmers [CMR] to Beach [BCH] Network Centre (1.1km).
- Nixon [NXN] to Melcombe [MCB] Network Centre (0.7km).
- Netherby [NBY] to Beach [BCH] Network Centre (2.1km).

Programme	2021-29	**Urban Underground Conversion**	Asset Replacement

During the 1960s and 1970s a significant amount of the urban electricity network was (re)built to service the new influx of electric ranges, electric heaters, electric washing machines, fridges and freezers. The network has lasted very well but is now overdue for replacement. The last urban overhead line that was rebuilt in 1993 is now 25 years old, many other lines are considerably older. Although the Ashburton District Plan allows the replacement of overhead lines with the same or similar type of construction there are no additional new poles allowed and all extensions and subdivisions are required to be completely underground. EA Networks has a policy that all new network connections are required to connect via underground cable.

As discussed elsewhere in this plan, the stakeholders and Board have shown considerable support for the progressive removal of overhead lines from the urban areas. The widespread support of the consumers/shareholders lends additional weight to the other less obvious advantages that accrue from this work. The additional quality of supply, security, capacity, flexibility and low maintenance characteristics all contribute to greater consumer/shareholder satisfaction. Other stakeholders are also encouraging of this work.

The individual projects funded by this programme are prioritised by the following factors:

- The condition of the existing overhead lines and therefore the safety of them
- The benefits to reliability and security obtained by underground conversion
- The need to increase line or transformer capacity in an urban area

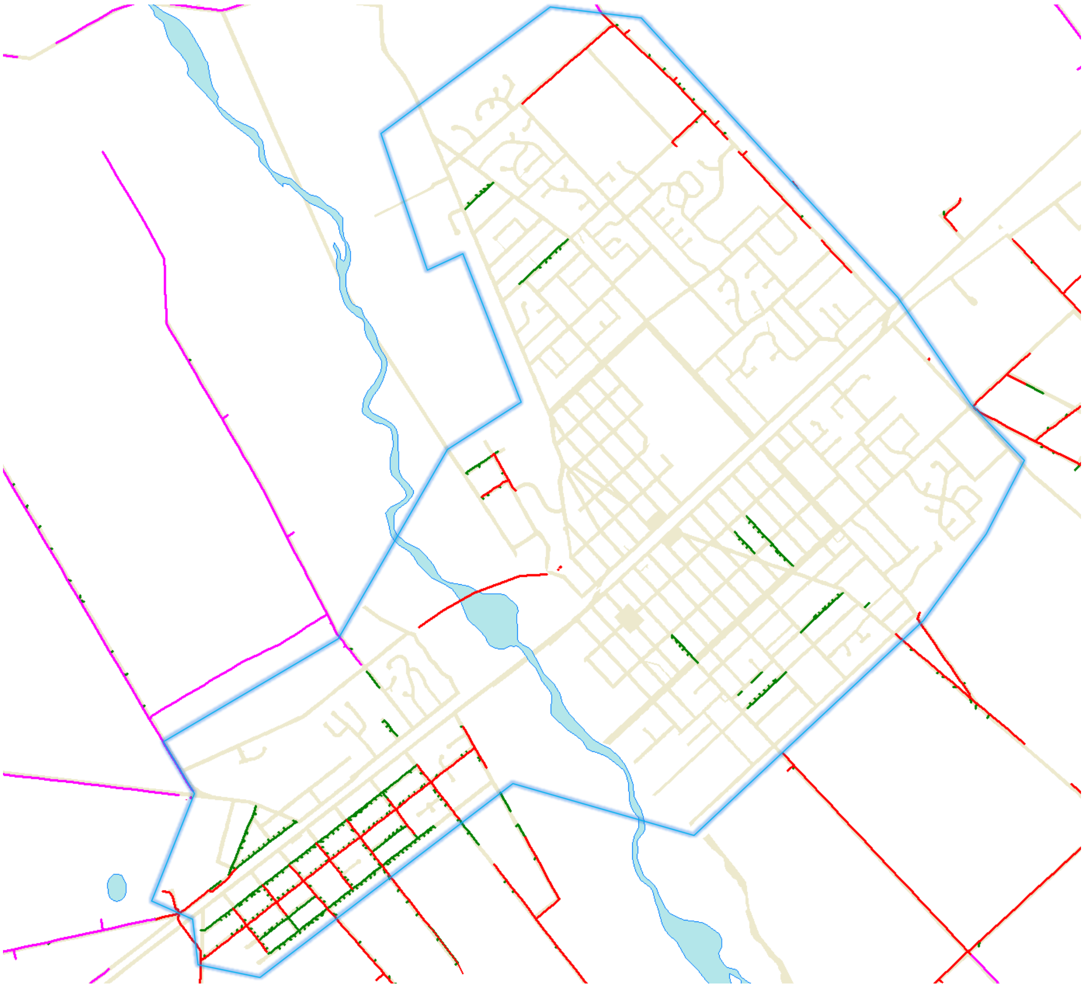
This programme targets the lines in poorest condition as a priority. Once they have been replaced with underground network the remaining overhead lines will be continuously aging and at the end of the programme the major components of the final line to be removed will be 30 years old.

The map shows remaining overhead lines (11kV and LV) stored in the GIS database at the time of writing.

There are some shown that are not in service and are awaiting removal following underground conversion. Additionally, there is presently a delay in processing as-built information and some of the lines shown may have already been physically removed.

The blue line represents the effective boundary of the urban area (as defined by EA Networks).

February 2020 - Remaining 11kV and LV Overhead Lines in Ashburton

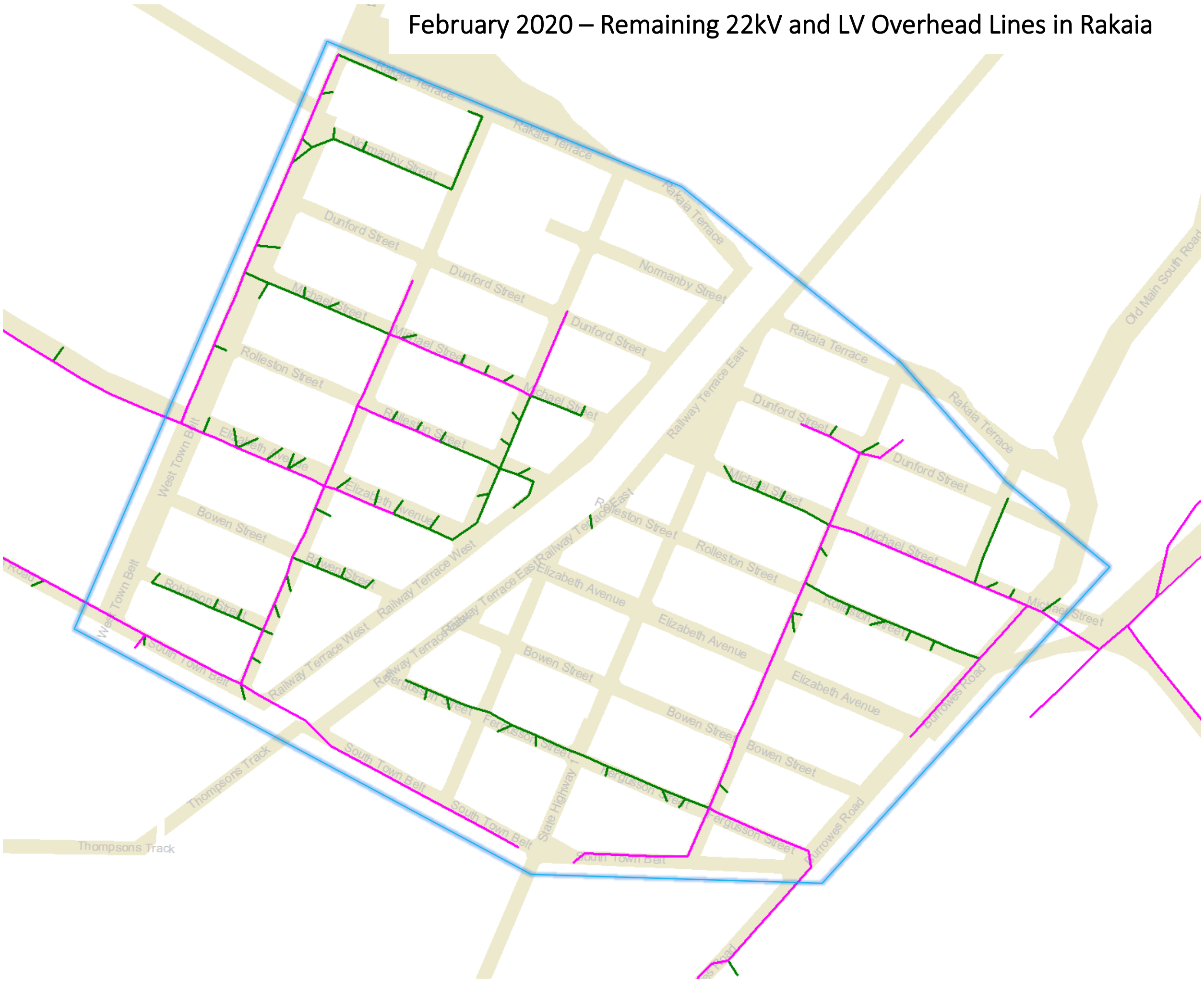


Project	Year	Name	Category
-1047	2021	Anne St	Asset Replacement
-1049	2021	Bowen St West (Cridland St - Railway Terrace West)	Asset Replacement
-1050	2021	Cambridge St (Nelson St - Wakanui Rd)	Asset Replacement
-1052	2021	Cridland St Rak (Rakaia Tce to Elizabeth Ave)	Asset Replacement
-1053	2021	Cridland Street (South Town Belt - Elizabeth Ave)	Asset Replacement
-1054	2021	Elizabeth Ave West (South Side, West Town Belt - Railway Tce West	Asset Replacement
-1055	2021	Elizabeth Ave West Rak (West Town Belt to Cridland St north side)	Asset Replacement
-1057	2021	Johnstone St, Hinds (Peters St - Nugent St)	Asset Replacement
-1058	2021	Lauriston Township	Asset Replacement
-1060	2021	McMurdo St (Hassel St - Wilkins St)	Asset Replacement
-1063	2021	Michael Street (West Side, West Town Belt - Railway	Asset Replacement

		Terrace West)	
-1064	2021	Moore St (William St - Chalmers Ave)	Asset Replacement
-1065	2021	Normanby Street & Cridland St (West Town Belt - Rakaia Tce)	Asset Replacement
-1066	2021	Peters St, Hinds (Cracroft St - Isleworth Rd)	Asset Replacement
-1067	2021	Rakaia Terrace	Asset Replacement
-1068	2021	Robinson St, Rakaia (West Town Belt - Cridland St)	Asset Replacement
-1070	2021	Upper Hakatere Huts No's 29 to 59	Asset Replacement
-1071	2021	West Town Belt (Elizabeth Ave - Rakaia Tce)	Asset Replacement
-1104	2022	Cracroft St, Hinds (Peters St - Nugent St)	Asset Replacement
-1106	2022	Gray St, Hinds (Cracroft St - Isleworth Rd)	Asset Replacement
-1107	2022	Isleworth Rd, Hinds (Peters St - Nugent St)	Asset Replacement
-1057	2022	Johnstone St, Hinds (Peters St - Nugent St)	Asset Replacement
-1064	2022	Moore St (William St - Chalmers Ave)	Asset Replacement
-1066	2022	Peters St, Hinds (Cracroft St - Isleworth Rd)	Asset Replacement
-1112	2022	Rolleston Street West HV Only (Cridland St - Mackie St)	Asset Replacement
-1070	2022	Upper Hakatere Huts No's 29 to 59	Asset Replacement
-1119	2023	Fergusson Street (Rakaia Terrace East - Burrowes Rd)	Asset Replacement
-1120	2023	McNally St (Range St - McGregor Ln)	Asset Replacement
-1122	2023	Peter Street (William St - Cass St)	Asset Replacement
-1123	2023	Robinson St (McNally St - Smallbone Dr) & Watson St (Range St - Robinson St)	Asset Replacement
-1124	2023	Sth Town Belt East (Bridge St - Burrowes Rd)	Asset Replacement
-1125	2023	Tancred Street, Rakaia (South Town Belt - Dunford St)	Asset Replacement
-1171	2024	Carters Tce	Asset Replacement
-1170	2024	Harland St (Catherine St - Graham St)	Asset Replacement
-1127	2024	Johnstone St (McMurdo St - Grove St)	Asset Replacement
-1128	2024	Manchester St (McMurdo St - Harland St)	Asset Replacement
-1129	2024	Melcombe St (Anne St - Lagmhor Rd)	Asset Replacement
-1129	2024	Melcombe St (Anne St - Maronan Rd)	Asset Replacement
-1131	2024	Michael St (East Side, Bridge St - Burrowes Rd)	Asset Replacement
-1132	2024	Oxford St (Beach Rd - Wellington St)	Asset Replacement
-1134	2025	Allens Road (Harrison St-Alford Forest Rd)	Asset Replacement
-1135	2025	Allens Road (Racecourse Rd-Carters Rd)	Asset Replacement
-1136	2025	Farm Rd (Middle Rd - Racecourse Rd)	Asset Replacement
-1137	2025	Mt Hutt Stn Rd (Methven - Holmes Rd)	Asset Replacement
-1138	2025	Racecourse Rd (Farm Rd - Russell Ave)	Asset Replacement
-1140	2026	Burrowes Road (Elizabeth Ave - Michael St)	Asset Replacement
-1141	2026	Burrowes Road (STB to Elizabeth Ave)	Asset Replacement
-1142	2026	Jane St (McMurdo St - Grove St)	Asset Replacement
-1143	2026	Mackie Street (Elizabeth Ave - Dunford St)	Asset Replacement

The map below shows remaining overhead lines (22kV and LV) stored in the GIS database at the time of writing. There are some shown that are not in service and are awaiting removal following underground conversion. The blue line represents the effective boundary of the urban area (as defined by EA Networks).

February 2020 – Remaining 22kV and LV Overhead Lines in Rakaia



-1144	2026	Mackie Street HV Only (Rolleston St - Michael St)	Asset Replacement
-1145	2026	Rakaia Huts	Asset Replacement
-1146	2026	Rolleston Street West (Mackie St - Cridland St)	Asset Replacement
-1147	2026	Wilkin St (McMurdo St - Millibrook Pl)	Asset Replacement
-1151	2027	Lower Hakatere Huts Stage 3	Asset Replacement
-1152	2027	Rolleston Street (Tancred St - Burrowes Rd)	Asset Replacement
-1153	2027	South Town Belt - West (West Town Belt - SH1)	Asset Replacement
-1151	2027	Upper Hakatere Huts Stage 2	Asset Replacement
-1157	2028	Grahams Street (McMurdo St - Grove St)	Asset Replacement
-1158	2028	Thomson St (Carter Tce - Wilkin St)	Asset Replacement
-1158	2028	Thomson St (Grahams St - Hassel St)	Asset Replacement
-1158	2028	Thomson St (Wilkin St - Grove St)	Asset Replacement
-1160	2029	Agnes St (McMurdo St - Grove St)	Asset Replacement
-1161	2029	Catherine St (McMurdo St - Grove St)	Asset Replacement
-1162	2029	Shearman St	Asset Replacement

5.4.6 Industrial 11kV Distribution Network

The major industrial zoned areas of Ashburton, Methven and Rakaia are generally close to existing or proposed zone substations. This has made planning for the security and capacity requirements of these areas relatively straightforward. As necessary, additional feeders will be taken into these areas to ensure compliance with the security and power quality standards. A new industrial park has been developed to the northeast of Ashburton township and it is in close proximity to both Fairton and Northtown substations.

A number of industrial plants are directly connected to EA Networks' HV distribution network and these consumers have individual arrangements with regards the security, reliability and quality of supply they wish to receive. Most of these consumers are adjacent to a zone substation and they take ownership of the HV distribution network (generally excluding transformers) as it enters the plant boundary. Any alteration of the supply up to the boundary is done either at the request of the consumer or by negotiation with the consumer. Any alteration to the HV network within the plant boundary is the responsibility of the consumer and although EA Networks can offer advice on solutions it is up to the consumer to ensure adequate capacity and performance.

Capacity of New Equipment

The majority of equipment is sized to suit individual industrial consumers. Consumers are asked to reveal any expansion plans so this can be factored into the sizing calculation. Most industrial consumers of note are served by a dedicated distribution substation and the cost to the consumer indirectly reflects the investment in these assets i.e. the consumer gets the capacity and security they pay for.

Projects & Programmes

Project	Year	Name	Category
Programme	2021-30	**Unscheduled Industrial Works**	Varies

Projects as per reference to Unscheduled Works in section 5.4.5.

Any work identified here is to secure industrial load as part of the underground conversion programme. Most of this load is on a radial feed, and work would typically increase security while relieving feeders that are heavily loaded.

Programme	2021-30	**Industrial Consumer Connections**	Consumer Connections

Projects as per reference to Consumer Connections in section 5.4.5.

When a new connection is supplied there is typically some modification or extension to the distribution network. This can range from a replacement pole through to a significant 11kV or 22kV underground extension of several hundred metres with a new substation.

Being unscheduled, this work is essentially completed on demand (assuming the new or altered connection load is advantageous to EA Networks). The solution chosen to supply a new/altered load is typically agreed during consultation with the consumer to determine a price/quality/security trade-off they are happy with.

5.4.7 Low Voltage Network

The LV distribution network is heavily interconnected in the urban area. This generally permits reconfiguration to solve simple capacity problems. If a new consumer load exceeds the additional capacity reconfiguration can liberate, a new cable is normally run from the either a suitable distribution substation or higher capacity LV node.

Should the load exceed the ability of the LV network to meet the security standard, a new distribution substation is the most common alternative. Essentially the LV network is extended or installed on demand.

The low consumer count on each LV segment typically precludes a high level of security at the individual connection. Some larger consumers will be supplied from a switching point from which two supplies can be selected. This allows restoration of supply relatively quickly after an LV segment faults, while others directly connected to the segment will have to wait for either physical disconnection of the faulted cable or the full repair time.

The LV network in Ashburton is approximately 80% underground by area. This underground area is largely fault-free. Occasional terminal or connector problems arise and there have been some instances of older single core PVC insulated aluminium cables corroding causing an open circuit fault.

The capacity of the LV underground network is adequate for the planning period except for a few very early underground subdivisions where the cables were undersized by modern standards. These are not currently causing a problem but could become an issue (with new loads such as electric vehicle charging) before the end of the planning period as both the thermal rating and guideline voltage drop limits are exceeded.

Widespread adoption of long-range electric vehicles requiring 10kW+ home charging facilities would cause issues for the existing network. The present design of the urban LV network is conservative and allows for 5kW of diverse loading per household. The addition of 10kW or more (even off-peak) would obviously compromise the original design limits by quite a significant margin. It is assumed that vehicles with large battery storage will not be prepared to pay for the network capacity to charge from flat at home overnight and they will instead visit a fast charging station to obtain at least 80% of their charge (this could be at the local distribution substation 100-200m up the road). The remaining top-up could be serviced by a slow charger in their garage overnight (20kWh for 6 hours is 3.5kW).

Should peer-to-peer trading of electricity become widespread, then solar PV may be another challenge for the urban LV network. Currently, the buy-back rate for solar PV is low enough to discourage high capacity export to the network. Should a peer wish to purchase that electricity for their electric vehicle they could pay enough for the solar PV owner to export much of their peak generation to the peer. This may cause large network import spikes during the sunniest days that will cause voltage rise on the LV network. Modern solar PV inverters can provide some control over this voltage rise, but it is limited, and has other impacts that may ultimately restrict its use. Until solar PV penetration exceeds 5-10% (currently <1%), it is unlikely the issue will have a major asset management impact.

Urban Methven has been completely underground for several years and has a low-maintenance LV network. Load growth is typically hotels, accommodation houses, restaurants or smaller industrial loads. The accommodation houses and restaurants are usually supplied from the LV network and have consumed much of the extra capacity built into the LV network at the design stage. Fortunately, the density of these developments has peaked, and it appears that as a new one opens, another tends to close. The larger hotel and industrial loads are supplied from a dedicated distribution substation in most cases. When they are supplied from the LV network, care has been taken that the additional source impedance does not permit inrush loads such as motors to interfere with other consumers on the same LV segment.

Rural LV distribution is traditionally overhead and serves one or two consumers on each segment. Other than conversion to underground cable (normally at the consumer's cost) there is little that can be done to collectively and economically improve the security of these lines.

Capacity of New Equipment

The value of the cable is typically a relatively minor component of the total cost of LV underground network installations. The standard cable in use at EA Networks is either 185 mm² aluminium or 240 mm² aluminium 3 core neutral screened XLPE insulated cable. This allows optimal spacing of distribution substations while ensuring adequate capacity to allow for adjacent distribution substation outages caused by maintenance or fault. The key parameter is that the voltage at any connection point must not drop below 95% of the nominal value during a foreseeable n-1 security event. The thermal rating of the cable must not be continuously exceeded at any time.

Projects & Programmes

See the projects listed under section 5.4.5 as they contain the majority of new LV network – installed in conjunction with MV work.

Project	Year	Name	Category
Programme	2021-30	**LV Consumer Connections**	Consumer Connections

Projects as per reference to Consumer Connections in section 5.4.5.

Programme	2021-30	**Urban Underground Conversion**	Asset Replacement

Projects as per reference to Urban Underground Conversion in section 5.4.5.

As the urban underground conversion programme progressively covers the urban areas, the security and capacity of the LV distribution network improves significantly. This programme is the only identifiable initiative to reinforce this section of the network to accommodate future demand and security objectives. The modern cable designs and installation techniques will guarantee a long trouble-free life for this plant. The consumer/shareholder enthusiasm for this programme is very high. All stakeholders in this plan are satisfied that the urban underground conversion programme is the best solution for an aging urban overhead network.

5.4.8 High Voltage Switchgear

The range of high voltage switchgear in use at EA Networks covers 66kV, 33kV, 22kV and 11kV voltages; circuit breakers, disconnectors, load-break switches, fuse switches, fuses, links; and is located on poles, on the ground, inside kiosks, inside buildings, and inside zone substations. Although the voltage, type and location of the devices vary greatly they are all electromechanical in nature and share common asset attributes and maintenance requirements.

Generally new switchgear is installed as an adjunct to subtransmission, distribution or zone substation projects. There are a few projects and programmes that are explicitly switchgear focussed and they are described here.

Capacity of New Equipment

Switchgear capacity is typically sized to comfortably exceed the load rating forecast for ten years into the future. Most high voltage switchgear has minimum ratings that significantly exceed EA Networks' requirements. The required fault ratings are determined by the parameters detailed in Section 5.1.1.

Operational safety requirements are considered when new types of switchgear are evaluated for introduction into the EA Networks network.

Projects & Programmes

Programme	2021-23	**Ashburton Core Urban 11kV Network**	Quality of Supply

See section 5.3.4 and section 5.4.5 for details on the Ashburton Core 11kV Network.

A total of seven network centres will be required in the Ashburton township and three in Tinwald.

-1011	2021-23	**11kV Core Network Centres**	Quality of Supply

- Allenton [ATN] Network Centre.
- Melcombe [MCB] Network Centre.
- Hollands [HLD] Network Centre.
- Glassey [GSY] Network Centre.
- Domain [DMN] Network Centre.
- Netherby [NBY] Network Centre.

- Racecourse [RCS] Network Centre.
- Dobson [DBN] Network Centre.
- Beach [BCH] Network Centre.
- Western [WST] Network Centre.

Programme	2021	**Rural Ring Main Unit (RMU) Installation**	Quality of Supply

One of the programmes that has been pursued by EA Networks is the strategic use of ground mounted ring main units (RMUs) in the rural area where a three-way or four-way intersection of circuits occurs. The use of a RMU provides a number of benefits over a conventional disconnector. RMUs can be readily remote-controlled and most have built in fault indication and voltage indication. The environmentally isolated switching and insulation systems ensure a much higher insulation integrity as well as traditionally higher reliability of operation. In-built fault-making earth switches (which can be remotely closed after on-site selection on the EA Networks RMUs) provide much safer isolation and earthing points than traditional pole-mounted switchgear. Some modern RMUs have vacuum circuit-breakers in the place of fuses and this allows not only repeated operation but also the potential for single operation auto-reclose.

Field staff have reported a great deal of comfort and confidence in using the RMUs for switching, isolation and earthing. The accessibility and relatively small amount of effort required to operate the switchgear (when remote control is not available) is certainly useful for a mixed gender workforce and a workforce with an age range spanning five decades. Some older pole-mounted switchgear is very challenging for individuals to not only access but also operate due to wind, rain, snow, vegetation, terrain, and mechanical effort required. All rural RMUs have a hot-mix apron in front of the doors to provide a firm and even footing for the operator and ensure a very high resistance to earth when touching the metal parts of the RMU.

This programme covers the installation of a significant number of RMUs at various locations. All of the RMU ways are circuit breakers and will have protection and auto-reclose functions available which will be applied where it is deemed appropriate. These projects are the conclusion of planned rural RMU installation.

Project	Year	Name	Category
-1045	2021	RMU (3 x CB) - cnr of Dromore Methven Rd & Winchmore School Rd	Quality of Supply
12440	2021	RMU (4 x CB) - cnr of Scales Rd & Swamp Rd	Quality of Supply
12464	2021	RMU (4 x CB) - cnr Rakaia Barrhill Methven Rd & Wolseley Rd	Quality of Supply

5.4.9 Protection Systems

The demands of the security standards and increased load require that the protection systems not only detect faults but also, whenever possible, prevent overloading of network components. As technology advances this is becoming more achievable. Devices now exist that can monitor and model many different power system components while offering fault protection functionality as their primary purpose. With an accurate model, many power system components can be run at higher than rated capacity for short periods without any detrimental effects. This can liberate previously unavailable capacity to supply either additional short-term peaking load or offer higher security to consumers reliant on that component as an alternative supply.

When any network is made more secure there is normally a protection relay that is providing the logic to keep the supply on to consumers. At subtransmission voltages this involves isolating the faulted path, leaving the unfaulted path(s) to carry the full load. This philosophy may also exist in heavily loaded HV distribution networks. In HV distribution the goal is usually to:

1) ensure the fault is not transient (a branch touching a line then burning away) - in which case the line will be automatically relivened (this is not used for underground cable circuits),
2) if the fault is permanent, interrupt only the faulted segment of network in the fastest possible time,
3) if it is possible to reconfigure the network to resupply consumers that are not connected to the faulted segment, do so in the shortest possible time.

All these goals are to some degree achievable and, if implemented, can help increase compliance with security standards as load grows.

Projects & Programmes

The zone substation replacement, development and enhancement projects all contain aspects of protection technology. Although it is possible that protection will be upgraded independently of these projects, the majority of new protection will be introduced as a result of zone substation work.

The introduction of closed 66kV rings requires some form of directional, distance or differential protection scheme to take full advantage of the additional security two 66kV lines per substation offers. EA Networks standard approach is to use line differential protection with a distance backup on all 66kV line terminals and also use bus differential protection on each 66kV busbar. The line differential protection uses the EA Networks inter-substation fibre optic network. The 3 zone distance protection will also be the master control device for the line bay (marshalling or controlling items such as: status, analogue values, reclosing and remote control etc). Once complete, all equipment from the 66kV GXP to the zone substation 22kV (or 11kV) busbar will be covered by differential protection zones. This arrangement will provide selective operation of all circuit-breakers in the fastest possible way – minimising voltage depressions and outages experienced by consumers.

There are a range of alternative protection schemes that could possibly be engineered to perform a similar function (at significant engineering cost both initially and for maintenance) but none would offer the same level of performance on offer by the differential/distance combination. Also, none of the alternative protection schemes would scale up as easily or be as stable with the level of interconnectivity that the 66kV system will eventually exhibit.

Project	Year	Name	Category
10988	2021	**Synchrophasors (66kV System Sync-Check)**	Quality of Supply

The embedded hydro generator at Highbank is a synchronous machine that can create an island situation if the 66kV subtransmission network clears a fault that trips both of the 66kV lines that interconnect MTV substation with the EGN/ASB GXP. This situation can be catastrophic if the network is reconnected to the Highbank supplied island when it is out of phase with the EGN supplied network. The generator can suffer irreparable damage. Currently there is no automatic reclosing on the 66kV network and even during controller-initiated closures of 66kV circuit breakers Trustpower shuts down the Highbank generator to guard against out of synchronism events. The disadvantages of this mode of operation are clear. All 66kV circuit breakers fault operations must be patrolled before any thoughts of closing the circuit breaker and before that can occur, Highbank must be shut down. This all adds to delays and inefficiency.

This project is to provide a mechanism that guarantees that synchronism exists between EGN and MTV and communicates this to all of the nodes on the 66kV network. The approach that EA Networks intend to take is to install a device at EGN and another at MTV that sense the 66kV voltage and communicate samples of this with a very accurate time stamp (Synchrophasors) to a calculation device. The calculation device checks the absolute and relative phase angle of the two signals to see if it is stable and within acceptable bounds. If it is, a signal is propagated across the network to indicate that it is permissible to close a 66kV circuit breaker. The absence of this signal will be used to inhibit closing of all 66kV line circuit breakers.

Discussion with Trustpower has begun to ensure they are satisfied with the degree of security that this check offers and, if agreement is reached, the project will proceed.

The alternative of the status quo, while safe and low risk, is very inefficient and cumbersome. The only additional option would be to fit 66kV line VTs and synchronising relays to all line terminals in the EA Networks 66kV network. This would cost a considerable sum and is unlikely to be any more secure than the proposed solution.

The budget for this project was rescoped during 2018 and at the time of writing it is looking probable that all this work will carry over in to 2021 (100% still to complete).

Project	Year	Name	Category
-1011	2021-23	**Ashburton Core Urban 11kV Network**	Quality of Supply

This programme will include a significant quantity of 11kV protection relays. They will be line differential relays operating across core 11kV circuits which will utilise interconnecting fibre optic links. There will also be a number of simple overcurrent feeder relays.

All the projects, costs and associated work are included in the 11kV network centre developments (Section 5.4.8).

-1075	2021-26	**Replace 20-year old Numeric Protection Relays**	Asset Replacement

The relays that were installed when the first 66kV lines were constructed in 1999 are about to reach 20 years of age. Any electronic device that is 20 years old is more prone to failure than one that is 2 years old. Having consulted with various manufacturers of numeric relays, they all say that a 20-year old relay is end-of-life in critical applications. 15-20 years is the typical lifespan of a numeric relay. Most manufacturers now have 10-year warranties of their relays which gives confidence to that age. Assuming they have built in a safety margin to the expected point of failure it is not unreasonable to add 50-100% to the 10-year warranty. A paper published in 2010 backed up these estimates (albeit for relays made in the 1990s). Running a protection relay to the point of failure because of age is not an option.

This programme will replace 3 x 66kV line distance relays per annum over the duration of the programme. The recovered relays will be either scrapped or retained for spares.

There has already been a programme to upgrade older numeric relays involved in transformer and 11-22kV feeder protection which replaced all the electronic components in the relays and provided a 10-year warranty from that point onwards.

As the relay population ages, there will be additional programmes introduced to upgrade or replace numeric relays.

5.4.10 SCADA, Communications and Control

SCADA is an acronym for Supervisory Control And Data Acquisition, which essentially means remote control of power system equipment and getting information back from remote power system equipment. In this case "remote" is anywhere other than "here". SCADA systems are not new and have existed for many decades in various forms. The most rapidly changing aspect of SCADA systems is the devices they connect to in the substation and at other points on the network. Microprocessor-based protection relays and modern electronically controlled reclosers have a wealth of information on offer to SCADA systems about power system conditions and faults. It is now possible to look at real-time values of current, voltage, power, thermal demand, harmonic currents and voltages and virtually any other measurable power system quantity as well as historical logs of any of these values. If a fault has occurred, the relay can provide a surprisingly accurate estimate of distance to the fault and data to display the waveform of the currents and voltages before and after the event. All this information can assist in planning a more responsive power system that can provide higher levels of fault immunity and assist in identifying under-utilised capacity such as when power factor is too low at peak times.

A SCADA system can also be used to schedule events such as switching on or off capacitors or generation that prevents overloading of a piece of equipment during a period of normal peak loading or during fault events when being used to supply load above normal levels.

Any reasoned decision that a human can make can now be programmed into a server application and it can then reproduce that logic for similar situations. In the future, with sufficient processing power, communications, data gathering and remote control, it will be possible to provide a much faster response to loading and fault situations than is presently the case. It may even prove possible to reliably predict loading minutes or hours in advance (given sufficient data to derive an accurate model). These capabilities can be used to dynamically configure the network so that overloading is avoided and faults affect fewer consumers. This concept is the next step in a system called distribution automation. Distribution automation is currently a predominantly reactive process which attempts to restore supply once it has been lost.

The current SCADA system is likely to be supplanted by a distribution management system that will include all existing and new zone substations as well as many smaller switching and data gathering locations. Data communication to all zone substations has dramatically improved by using the fibre optic network and allows reliable data, video and voice communication. The fibre optic provision is occurring as a separate commercial development by EA Networks which is not suitable for inclusion in this electricity network asset management plan.

Projects & Programmes

No SCADA-specific projects have been identified. As new sites are developed, they will incorporate SCADA functionality and will contribute to a more complete automation system. There are a small number of projects related to communications and control.

Project	Year	Name	Category
11074	2021	Distribution Management System	Non-Network Assets

An ADMS (**A**dvanced **D**istribution **M**anagement **S**ystem) is in the process of being commissioned at EA Networks.

An ADMS incorporates all the features of a SCADA system but also adds the idea of electricity network modelling into the mix. This means that there is a degree of “intelligence” that the DMS can have about what the context is for the information it is receiving and the actions it is being asked to undertake.

The ADMS incorporates the following features/subsystems:

- A SCADA subsystem that interfaces to devices of all types in the physical world (protection relays, remote controlled switchgear, power meters, load control devices, weather collection devices, asset condition monitors, GPS location devices, etc)
- A mapping subsystem that can show both:
- traditional location maps of assets, SCADA information about those assets, the physical environment, personnel location (assuming GPS equipped radio),
- interactive schematic views of the connected electricity network including most of the static and real-time information about assets.
- An outage management subsystem that reports in real time the consumers and portions of the electricity network that are without supply and predicts the fuse or circuit-breaker (if not on the SCADA system) that is likely to have operated. This subsystem also provides SAIDI and SAIFI statistics over timescales varying from the last 5 minutes to the last 5 years.
- A network analysis engine that can calculate/estimate the existing power flows, voltages and fault levels in the electricity network as well as predict the electrical consequences of operating a device in advance of doing do. Given sufficient information, the engine can also estimate the location(s) of a fault.
- A distribution automation engine that can suggest a restoration sequence for a human controller to

implement. Optionally, the restoration sequence can be automatically executed using SCADA control in full automation mode.

- A load management subsystem that provides demand side management of load/generation to ensure regional, GXP, zone substation and even feeder loading limits are respected.
- A customer interface subsystem that can receive and send messages from/to email, SMS, web site submission, dedicated smartphone app's, interactive phone call (with caller id), last gasp messages from meters, etc. This allows the DMS to estimate the extent of an outage based upon the known location of the customer on the electrical network.
- A crew management to assign a piece of work to a crew/truck and monitor their status and workload.

The ADMS has obvious benefits to the asset owner. Power can be restored within tens of seconds (unless you are supplied from the faulted segment) and the asset owner does not have to spend time manually finding and isolating the fault. This type of system relies on sensing the fault location by passage of fault current through devices and communicating the information to a central point and the ADMS then making the logic decisions.

The ADMS acts to firstly gather fault detection data and then to control the distribution system to isolate the fault. There is no need for additional hardware in the field. The ADMS is essentially software running on a series of secure servers that are configured to respond in a particular manner should a fault be detected. If necessary, the ADMS can be overridden by the controller.

This project provides for the continuing implementation of the ADMS to achieve many of the features detailed above. Some of the advanced automation features may not be initially activated but the software will be configured to allow that to happen.

Project	Year	Name	Category
11636	2021-25	Distribution Automation Programme	Quality of Supply

This is a programme of works to progressively add both SCADA and fault detection/isolation features to existing rural ring main units and pole-top switchgear that are ready for automation.

A typical implementation will be the additional of a modern protection relay that permits direct integration with a SCADA protocol, giving a raft of information and control capabilities. The communication will be either by fibre optic (if it is within easy reach) or DMR (utilising a small radio data transceiver). Once implemented, the relay can be used to provide full protection and reclosing on ring main unit circuit-breaker(s) or sectionalising capabilities on a pole-top, CT-equipped, load-break switch.

The DMR radio system that EA Networks use can transport data packets transparently. This feature can be used to implement a piece of hardware that acts as a combined radio and RTU. The DMR radio supplier that provisioned the voice system has developed such a product. A DMR repeater will be added to provide coverage up into the Ashburton and Rangitata Gorges so that workers can be confident of radio reception at all parts of the power system they may be working on. These repeaters will also provide the ability to remote-control circuit-breakers and switchgear in these distant areas. Even without controlled switchgear, the DMR RTU will notify EA Networks of outages that would otherwise require a consumer to phone in about the issue.

The remote-control hardware used can be utilised by any master control system that uses a modern SCADA protocol. As such it does not matter if the current SCADA system is supplanted by a DMS – the field devices will continue to provide the same (or greater) level of functionality.

The programme will continue until all suitable candidates for automation have been provided with the necessary capabilities.

5.4.11 Ripple Injection Plants

The ripple control system is a very useful way to control the maximum load at any given time. This system can be used in a variety of ways but is predominantly employed to shift water-heating and space-heating load to off-peak times. This limits the maximum load that the EA Networks electrical network must supply at peak times. Another term for the ripple control system is "demand side management".

During summer, the rural irrigation load causes the annual system peak to occur (currently about 181 MW). Somewhat uniquely, EA Networks has a summer peak demand and until recently it has been only during winter that the regional peak occurs. This is changing and the growth in irrigation throughout Canterbury along with increased air-conditioning loads has caused some of the 100 highest regional peaks to occur during summer. During regional peaks, EA Networks use the ripple control system to minimise the demand placed on the Transpower GXP. This has the coincident benefits of reducing total losses and lowering the required average capacity of EA Networks equipment. The urban network is comparatively lightly loaded during summer and ripple control during summer does not assist in optimising urban network capacity.

During winter, the energy retailing companies direct EA Networks to control the same heating loads when the cost of wholesale electricity is high. This winter control has the by-product of keeping urban distribution peak demand lower than it otherwise would be, which frees up additional capacity for uncontrolled loads such as lighting, cooking and other household appliances. This peak control can also reduce the need for reinforcement of the urban network, although EA Networks do not currently control load for that reason.

Should a fault occur that limits the supply capacity into a specific portion of the network, ripple control could be used reduce the load to a level where all consumers have supply but only if they accept that controlled load is off until a repair is completed. This could be a useful method to help achieve the security standards without dramatically inconveniencing consumers. EA Networks have not yet implemented this strategy, largely because of limited ripple channel granularity and system capacity being adequate under most n-1 scenarios.

Capacity of New Equipment

Because the investment in plant is relatively expensive and typically non-recoverable, the sizing calculation is very important for ripple injection facilities. The probable future network configuration is ascertained and a plant capable of injecting signal successfully across that proposed network will be specified.

Projects & Programmes

Until 2005 there had been no firm projects planned to enhance the capability of the ripple control system. Failure of a critical component on one of the ripple injection plants in late 2005 caused a rethink as the age of the technology was such that it could not be fixed. The failed piece of equipment has now been replaced with a modern equivalent, sized to suit potential future use at 66kV.

The single 66kV GXP now in use has prompted the reconfiguration of the two in-service ripple plants. The ex-33kV unit at Ashburton 66/11kV substation has been reconfigured to operate as an 11kV plant. The pre-existing 33kV plant (stepped up to 66kV by an autotransformer) at Ashburton 220/66kV GXP has been retuned and the two plants (11kV and 33kV) now inject synchronously which provides signal reinforcement.

Project	Year	Name	Category
700	2021-23	**New Technology – ICP Load Monitoring and Control**	System Growth

The current ripple injection system for the 66kV network is provided by a 33kV ripple plant coupled to the 66kV bus via a 60 MVA autotransformer at EGN. The original injector for the 33/66kV ripple plant failed during 2011 and a decision was made to purchase the spare unit that the manufacturer had available. The purchased unit is smaller than will ultimately be required for injection at 66kV, but it is larger than the failed unit. The failed unit is no longer supported by the manufacturer and is not readily repairable.

The capacity of this plant was sufficient when the 66kV bus was supplied from two 220/66kV transformers. A third 220/66kV transformer is now in place, and that, along with increasing 66kV load, has caused the signal strength to decrease to the point that some receiver maloperation occurred. Since then, retuning the ripple coupling cell has improved the situation to restore reliable operation. Additionally, there is no viable alternative ripple signal source should the 33kV injection plant fail.

The signal level offered by the existing 33kV plant is sufficient at most times of the year and under most loading conditions. If necessary, the 33kV plant's signal level can be improved by temporarily taking one of the three 220/66kV transformers off load.

There is a complication with EA Networks' ripple system in that the proliferation of 6 pulse variable speed drives on irrigation pumps has caused a significant rise in harmonic distortion on the EA Networks network. The predominant harmonics generated by these drives are 5th (250 Hz) and 7th (350 Hz) multiples of the fundamental frequency (50 Hz). The ripple injection frequency used by EA Networks is 283 Hz. To suppress the distortion of these drives, both new and existing installations require compliance with IEEE519 and in practical terms this means that a harmonic filter will be required at each drive - limiting harmonic current distortion to no more than 8%. Unfortunately, these filters can also attenuate the ripple signal and, regardless of the injection plant capacity, signal is absorbed and distorted by the drives and filters.

One answer to the age and sufficiency of the existing ripple plant is to replace it with a brand new 66kV ripple injection plant. There are commercial risks in installing new ripple injection plant(s) when other communication/control technology may quickly supersede it and strand the asset. Devices are becoming available that can independently control the same load that ripple presently controls. This could mean a conflict between the retailer/meter owner/controller and the network operator who wish to shift/control load at different times for different reasons.

Alternative signalling technologies are available or nearly available and EA Networks have been actively investigating their suitability for load control.

This project has been included on the presumption that an alternative signalling/control technology will be successfully trialled by EA Networks and will supplant the existing ripple control system. The scope of the project would include some form of high reliability radio transceiver system with multiple base stations and a transceiver device at each ICP that would control existing ripple-controlled loads as well as additional loads that the consumer has agreed to allow control of (such as EV charging, solar PV output, irrigation pump, etc).

Should the trial not be successful, the funds set aside for this project will be used to purchase and install a new 66kV ripple plant.

11074	2026	**EGN Replacement 33kV Ripple Plant**	Asset Renewal

Presuming the new technology ICP load control system is adopted, the existing 33kV ripple plant will not be in service beyond 2024 and this project will not be required.

Should the new technology system [700] not be adopted and a new 66kV ripple plant be installed, then the age of the existing 33kV ripple plant components (purchased 1988) will be such that replacement is well overdue. Replacing these components will ensure back-up plant availability via the EGN 33/66kV autotransformer.

It is possible that other technology may have superseded the ripple injection signalling by 2026 and this replacement may not occur.

5.4.12 Distributed Generation & Storage

Distributed generation can be broadly described as any type of electrical generator that is completely embedded within the network of a lines company. A distributed generator can range in size from a photovoltaic panel on a domestic rooftop that has an output of several hundred watts, to hydroelectric or wind generators of several tens of megawatts. Every generator has a different impact on the security and capacity of the network depending upon the size and location of its connection and its generation pattern.

A distributed generator can provide additional security/capacity to the EA Networks network but it also has security and capacity requirements of its own. A generator which can always operate during peak demand periods can reduce the required capacity of a portion of the immediate network. If an individual generator is not available, it cannot offset the need to provide network capacity for consumers without breaching security standards. Alternatively, a generator which is unable to dispatch its available generating capacity because a network fault either disconnects it from sufficient consumers, or limits its ability to inject into the network, is unlikely to satisfy the generator's security requirements.

EA Networks encourage connection of new distributed generation. The general philosophy is that generators do not pay any on-going asset charge to connect to existing network (provided it has the capacity to absorb the generation without alteration). Only the additional or upgraded assets required to connect the generation are considered for cost recovery. Any fiscal benefits from coincident demand reduction are shared with the generator. If the network is not loaded sufficiently, export into Transpower can occur which results in HVDC (export) charges, which are passed back to the generator. By arrangement, during low load periods, the export risk can be signalled to the generator before export occurs.

If distributed generation becomes a widespread phenomenon, the diversity amongst a group of generators can make it a useful alternative to network reinforcement. This assumes that the generators do not have similar generation or fuel availability patterns that cause minimum generation at times of peak demand.

EA Networks already has significant distributed generation in the form of four hydroelectric generation plants one at Cleardale in the Upper Rakaia (1.0 MW), one at Montalto (1.6 MW), one at Barrhill (0.5 MW) and one at Highbank (26 MW). New distributed generation of any scale is encouraged and will be connected subject to suitable commercial and technical arrangements made according to industry rules and guidelines governing these activities. The Electricity Governance (Connection of Distributed Generation) Regulations 2007 have required all lines companies to publish guidelines for the connection of distributed generation to their respective networks. EA Networks have done this (www.eanetworks.co.nz) and since publishing two formal applications have been made and connected (Cleardale). Several potential developments are detailed in the projects section below. The clarity these regulations provide is useful for all participants.

EA Networks are always reviewing the feasibility of locally connected distributed generation that would enhance the security and profitability of both the company and the community. Several preliminary studies have been undertaken and this has identified some promising options that will be detailed in the Asset Management Plan if they become a commercial proposal.

The photo above shows a distributed generation system which injects into the EA Networks distribution network. This project made use of previously wasted energy from drops in a medium sized irrigation race that ran parallel to the property boundary. At 200kW maximum output it is sufficiently large to provide for all of the on-farm energy requirements plus a small surplus. It does not supply all the farm's power requirements and in mid-summer it will often have zero output while the farmer is irrigating at 100%. Like most of these types of small schemes it has no storage and can only generate when the energy source arrives (water in this case, but equally the sun in the case of solar panels and a wind in the case of wind turbines). Without storage of the energy they produce or the fuel that feeds them, peak system load on the EA Networks network may not be reduced significantly by distributed generation (consider a cold, calm, frosty, dark winter morning).

Capacity of New Equipment

All equipment installed for generation plant is sized in agreement with the generation owner although this is usually only required where the generation exceeds 100 kW.

Projects & Programmes

The opportunity for discussion with third parties who are interested in developing a wide range of small and large generation projects in the Mid-Canterbury region has continued in recent times.

The following table details the style of project by energy source, likely timescale, estimated capacity and a percentage rating of likelihood to proceed (based on information at hand).

Project	Energy Source	Timescale [1]	Estimated Capacity [2]	Likelihood [3]
B	Hydro	3 – 10 year	17 MW	15%
C	Hydro	5 year	2.2 MW	15%

E	Hydro	5 year	20 MW	10%
G	Wind	Unknown	5 – 50 MW ?	10%
H	Wind	Unknown	30 – 80 MW ?	10%
J	Hydro	10 year	20+ MW	5%
K	Hydro	4 year	1.0 MW	30%

1 Timescale is an estimate by EA Networks based on generalised discussion with third parties.
2 Capacity is either based on third party disclosure or, for larger proposals, an estimate by EA Networks.
3 Likelihood is an entirely subjective assessment by EA Networks which does not imply any evaluation of feasibility or commercial viability. 0% likelihood means EA Networks believe the option is no longer feasible or even physically possible.

Two projects have been removed from the list as they were successfully commissioned in recent years. Several other projects have been removed as they were withdrawn by the potential developer. None of the proposals listed are being actively discussed or progressed with EA Networks.

Cleardale Hydro resulted from a farmer in the Rakaia Gorge deciding to irrigate his farm and, in the process, provided the opportunity for Mainpower Generation to install a 1 MW pelton wheel turbine. The electrical output of the installation varies considerably during the year and there are times when it is unable to run at all through lack of water. The installation is connected to the 11kV network and feeds in to Mt Hutt substation. There have been no problems with its operation on the 11kV network.

BCI was commissioned in early 2016. It is a cross-flow turbine and operates in conjunction with an irrigation scheme and provides a modest output throughout the year. It is injected into the EA Networks 22kV network via a feeder from Lauriston substation. As irrigation demand builds, the summer output drops as the summer water is diverted to irrigation. It is advantageous that this generation is generally operating at the same time as the electric irrigation pumps as it reduces the peak demand on the 22kV feeders, zone substation, subtransmission network and GXP, although 2017 has shown its output is zero at times of peak irrigation.

The wind opportunity that has been listed is still very early in the investigation process and EA Networks had to make discrete inquiries to even determine who the potential developer was. It is possible that the EA Networks network may not be able to absorb the level of generation proposed, in which case it is not an issue that needs consideration other than for grid interconnection at a GXP.

An interesting discussion has been held with a proponent of wave power. The area off the Canterbury coast is apparently well suited to the type of device that the organisation was considering. The commercial and technical viability of wave power may be in its infancy, but if a commercially competitive product evolves it could hold a great degree of promise for an island nation such as New Zealand.

There have been no firm proposals for connection of non-hydro forms of distributed generation to the EA Networks network that would prudently affect the predicted maximum demand.

There are some other very small scale distributed run-of-the-river hydro generation opportunities that are being discussed and have in one case been developed, but their collective output accounts for only two or three typical irrigation pumps and in drought years they are unlikely to be generating because of water restrictions on river off-takes. It is also possible that the hydro turbine mechanical output will be used directly for mechanical water pumping with no electrical generation or pumping.

It should be noted that the economics for new generation investment are particularly poor at the present time. A flat wholesale price path for electrical energy and speculation that the Tiwai Point aluminium smelter may not be operating in several years, means that the incentives for new generation have reduced to the point that a number of significant renewable projects have been shelved. Should demand begin to increase because of EV charging or process heat, then some of the projects may be reconsidered by their proponents.

No specific projects or programmes have been allowed for regarding the impact of large scale (50kW+) distributed generation.

Solar Photovoltaic

Solar PV is continuing to be adopted by a small percentage of consumers. At the time of writing 237 ICPs are known to have solar PV (1.2% of consumers) and the approved peak output totals 1,034 kW. It is probable that more consumers will adopt solar and the complimentary technology of batteries as the price decreases. Initial investigations into the impact of solar PV show that it will take significantly more widespread adoption before network issues arise. The newer (2016+) inverters also provide much better mitigation of those network impacts by providing facilities for volt/watt/var responses that reduce output or change the power factor of the output to control network loading and voltage.

No specific projects or programmes have yet been allowed for regarding the impact of solar PV although there is scope for solar PV to become quite disruptive.

Batteries

Although not generation in the traditional sense, battery storage is a significant factor that may address a range of issues for both networks and consumers. The ability to charge batteries at times when excess generation and/or network capacity is available and then discharge them to directly supply load or provide embedded network generation capacity is attractive. The current hurdle is cost. It is not economically viable for consumers to provide battery storage solely to reduce network demand. The possibilities of electric vehicles (EVs) filling that role is beginning to evolve. There may be very specific network issues that could be resolved by using battery storage that are close to economically viability, but none have been identified by EA Networks at this stage.

EA Networks believe the role of batteries is going to be as daily or inter-daily load levelling rather than as seasonal 'power stations'. A battery can only store energy that is provided to it – it does not create or convert energy. If people expect to be able to store their summer solar PV output for use in winter they will be very disappointed. The storage requirements for seasonal energy storage are so vast that it will never be possible using the current scale and technology of battery storage. The chances of mass disconnection from the urban distribution network are low, as the diverse interconnection of generation, storage and load that it facilitates are what is required to maximise the value of each consumer's investment in solar PV, storage, and EVs. Without the distribution network, every disconnected consumer would need to invest in enough generation and storage to be fully self-sufficient at all times of the day and year. The distribution network will facilitate peer-to-peer trading of energy to and from all sources and loads.

EA Networks have yet to formulate a strategy for utilising either domestic or grid scale batteries to resolve existing or future issues on the network. There is an awareness that change will occur and that before it begins to impact the network it will be critical to adapt to the needs of consumers quickly and effectively or risk becoming less relevant.

No specific projects or programmes have been allowed for regarding the impact of storage batteries, although the New/Smart Technology programme is likely to involve battery technology in some form.

MANAGING OUR ASSETS

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6 MANAGING OUR ASSETS

6.1 Introduction

This section is where the detailed asset-specific management issues are discussed. It describes each asset by category and details quantities, condition, performance, maintenance and the operational standards of each in turn.

The management plans for each asset category detail how EA Networks intends to operate and manage the assets so that they meet the required performance standards. The focus on optimising lifecycle costs shapes all the processes involved.

EA Networks owns electricity reticulation assets that are used to provide distribution and connection services to electricity retailers and generators. These assets generally comprise equipment that is common to all New Zealand electricity lines businesses and, wherever possible, industry standard assets have been employed. The Asset Management Plan covers the electrical reticulation assets and associated systems owned by EA Networks.

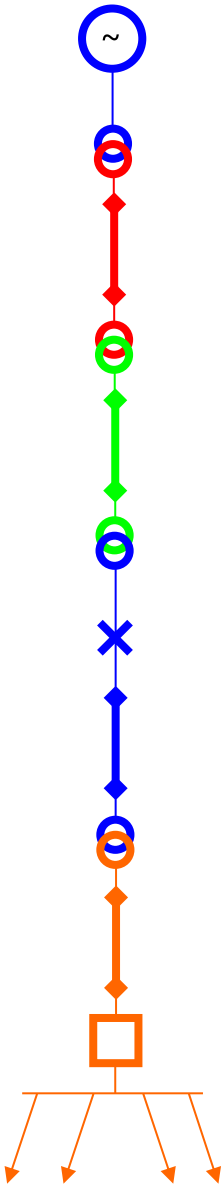
For the purposes of managing the assets that EA Networks own, logical groupings of assets are required. These groups may have members that are geographically distant or installed in a different application but they are most effectively managed as a single population. These groupings comprise the following:

- *Subtransmission Line Assets* - Electric lines and cables, including associated easements and access ways operating at voltages of 33kV and 66kV.
- *Overhead HV Distribution Line Assets* - Electric overhead lines, including associated easements and access ways operating at a voltage of 11kV or 22kV.
- *Underground Cable HV Distribution Assets* - Electric underground cables, including associated easements and access ways operating at a voltage of 11kV or 22kV.
- *Overhead Low Voltage Line Assets* – 400V electric overhead lines, including associated easements and access ways.
- *Underground Cable Low Voltage Assets* – 400V electric underground cables, including associated easements and access ways.
- *Service Lines* – Connection assets at any voltage owned by EA Networks for the purpose of supplying a single consumer (not including the line on the consumer’s premises but including any portion of the service line in, on, or above the legal roadway).
- *Zone Substations* – High voltage substations connected to the subtransmission network. This includes plant and equipment within the substations such as power transformers, foundations, oil interception equipment and incidental equipment such as DC batteries and chargers together with station land and buildings. Other items such as switchgear, structures and buswork, earthing, SCADA and protection, are covered by other definitions.
- *Distribution Substations* – Substations connected to the distribution network. This includes plant and equipment within the substations such as foundations, platforms and Maximum Demand Indicators, together with land and kiosk covers, but excludes transformers, MV and LV switchgear and earthing.
- *Distribution Transformers* – Standard transformers used in distribution substations ranging from 5kVA to 1000kVA and generally having a primary voltage of 11kV or 22kV. Also includes MV regulators or autotransformers up to 5,000kVA.
- *High Voltage Switchgear* – Circuit-breakers, reclosers, sectionalisers, disconnectors, ring-main units, expulsion drop-out fuses, structures and buswork used in the distribution and subtransmission systems.
- *LV Switchgear* – Load-break switches, fuse switches, fuses, support frames, busbars and capacitors used in the LV line and cable systems.
- *Protection Systems* – *Fault protection* includes all protection relays, associated panels, metering devices, current transformers, voltage transformers and control cabling.
  – *Over-voltage protection* includes surge arrestors and spark-gap devices.
- *Earthing Systems* – All earthing systems that are owned by EA Networks and connected to EA Networks equipment.

- *SCADA, Communications and Control Equipment* – SCADA, Communications Equipment and associated facilities installed at any location. This includes Control Room equipment, Remote Terminal Units, radio repeaters and dedicated fibre optic systems installed, owned and maintained by EA Networks.
- *Ripple Control* – Ripple Injection Equipment.

The size and complexity of EA Networks' fixed asset base is considerable when compared to other businesses such as retail chains and serves as a major differentiator for this company and other utility organisations. Below is a diagram illustrating some of the different asset categories and typical ownership involved in the electricity supply industry.

Asset Owner	Voltage(s)	Equipment
Generator/ Retailer	11kV or similar	Generator (Wind, Hydro, Gas, etc)
Generator/ Transpower	11kV and 220kV	Generator Transformer
Transpower	220kV (Transmission)	Transmission Overhead Line(s)
Transpower	220kV and 66kV	GXP Substation Transformer(s)
EA Networks	66-33kV (Subtransmission)	Subtransmission Overhead Line(s)
EA Networks	66/22-11kV or 33/11kV	Zone Substation Transformer(s)
EA Networks	22-11kV	Zone Substation Feeder Circuit-Breaker and Protection Relay
EA Networks	22-11kV (Distribution)	Distribution Overhead Line or Underground Cable
EA Networks	22-11kV and 400 V (LV)	Distribution Substation Transformer
EA Networks	LV (Low Voltage)	LV Distribution Overhead Line or Underground Cable
EA Networks	LV	Consumer Connection Point (Pillar Box or Pole Fuse)
Private	LV	Consumer Service Line



Variations on this ownership structure exist, particularly in industrial or rural situations where the consumer is likely to own 22-11kV lines on private property which are dedicated to servicing their property.

6.2 Overview

This section outlines the lifecycle management plan required to maintain, enhance and develop the operating capability of the system. The programmes are outlined by asset type and, within this, according to area and then by maintenance activity.

- Maintenance
    - servicing, inspections and testing
    - fault repairs
    - planned repairs and refurbishment (including replacement at the component level)
    - planned replacement programmes (at the asset level)
- Enhancement
- Development

Section 8.1 - Appendix A has a more complete series of activity definitions.

For the purposes of lifecycle management, the Enhancement and Development categories can be seen as the asset creation/acquisition phase of the cycle. The Replacement category will introduce new equipment of similar function at a similar location and have a similar purpose as the existing asset.

Each category of asset has a "Standards" subsection that details the documentation available for each activity undertaken on that category. This is one area that still requires some work to complete. Many categories do not have documentation to cover post-commissioning activities such as inspection and maintenance. The actual work is done to an acceptable standard, but the methodology is not yet formally recorded.

Asset disposal is typically done only at the end of an asset's useful life. Most of these assets are equipment that is only suitable for scrap and it is normally disposed of in an appropriate manner as part of the activity replacing it. Any asset that becomes surplus and is not at the end of its service life will have a specific disposal plan. As at the time of writing there are relatively few assets that have been identified that will require disposal in this manner and only those asset categories will contain a Disposal activity.

6.2.1 Maintenance

Maintenance work is largely based on the condition of the assets.

The scope of work planned under each maintenance activity is quantified wherever possible to assist in reviewing EA Networks' achievement in future years. The estimated maintenance expenditure is projected in this section and where relevant, the consequences of the proposed maintenance programmes are noted. It should be noted that analysis of maintenance strategies and programmes is an on-going process and the most cost-effective means of maintaining the network is constantly under review. In some instances (e.g. pole replacement) further investigation and analysis is required to determine a suitable strategy.

The maintenance requirements are influenced by development projects, many of which, if they proceed, will lead to dismantling and decommissioning of assets that would otherwise require significant repairs and/or replacement. The maintenance programmes described in this section cover the anticipated situation where all the planned development projects proceed.

The base-line planned maintenance expenditure projections assume, for consistency within this plan, that development projects take place as projected in Section 5 – Planning our Network. It will be necessary to monitor closely the likelihood of each project proceeding and additional remedial work will need to be programmed if certain projects do not proceed or are significantly delayed.

6.2.2 Replacement

When an asset reaches the end of its useful life and economic maintenance options have been exhausted, the only remaining options are scrapping the asset without replacing it or, replacing it with a modern equivalent asset. Under most circumstances, assets will be replaced with an asset that exhibits the best price/performance ratio. Each individual case will be examined for the economic efficiency of the options.

Replacement work does not intentionally increase the asset's design capacity but restores, replaces or renews an existing asset's function to its original capacity and lifespan.

6.2.3 Enhancement

This activity outlines work that is planned to enhance the system. By this, it means that this increases the capacity of the asset to:

- supply increased load
- enhance voltage regulation
- improve security and reliability

or

- increases the expected lifespan of the asset significantly beyond its original end of life date

It includes projects (at specific sites) and programmes of related work covering several sites. Project numbers (e.g. [10023]) are used to identify individual projects or programmes. Appendix B has a complete list of these, including costs and categorisation.

Specific enhancement projects are detailed in Section 5 – Planning our Network.

6.2.4 Development

Specific development projects and programmes are described in Section 5 – Planning our Network, which outlines the projects currently anticipated over the planning period. The nature of each project is briefly described along with the reason why it appears to be required. The justifications for including each of the projects in the plan are categorised as follows:

- safety-related issues
- specific consumer requests (and commitment to incur project-related charges)
- anticipated demand growth
- to meet security planning guidelines
- economics (i.e. where the project produces overall cost savings)

The projects described in this document represent an indicative plan based on the best information currently available. There is currently no commitment by EA Networks to undertake all or any of the specific projects listed, nor should consumer commitment be inferred from the inclusion of any project in this plan, except where they are described as already committed. Further, it should be noted that more detailed investigations will undoubtedly lead to changes in the scope of projects that do proceed. There may be considerable scope for integrated subtransmission/distribution system planning to achieve the required results by somewhat different means.

Because of the need for consumer consultation and, in many cases, agreement, as well as uncertainty in the fickle prediction of future load growth, it is likely that some projects in the first half of the planning period will not proceed or will proceed later than indicated in this plan. Secondly, because investigations tend to be more focused on the short-to-medium term, it is likely that additional required projects will arise, particularly towards the end of the planning period.

6.2.5 Asset Renewal Processes

The general renewal strategy is to rehabilitate or replace assets when justified by:

- *Safety*

  The asset represents an unacceptably elevated risk to the safety of people or property.

- *Asset performance*

  Renewal of an asset is where it fails to meet the required level of service. The monitoring of asset reliability, capacity and efficiency during planned maintenance inspections and operational activity identifies non-performing assets. Indicators of non-performing assets include:

- Structural life
- Repeated failure
- Ineffective and/or uneconomic operation

- *Economics*

  Renewals are programmed with the objective of achieving:

  - The lowest life cycle cost for the asset (uneconomic to continue repairing), or
  - An affordable medium-term cash flow, or
  - Savings by co-ordinating renewal works with other planned works

- *Risk*

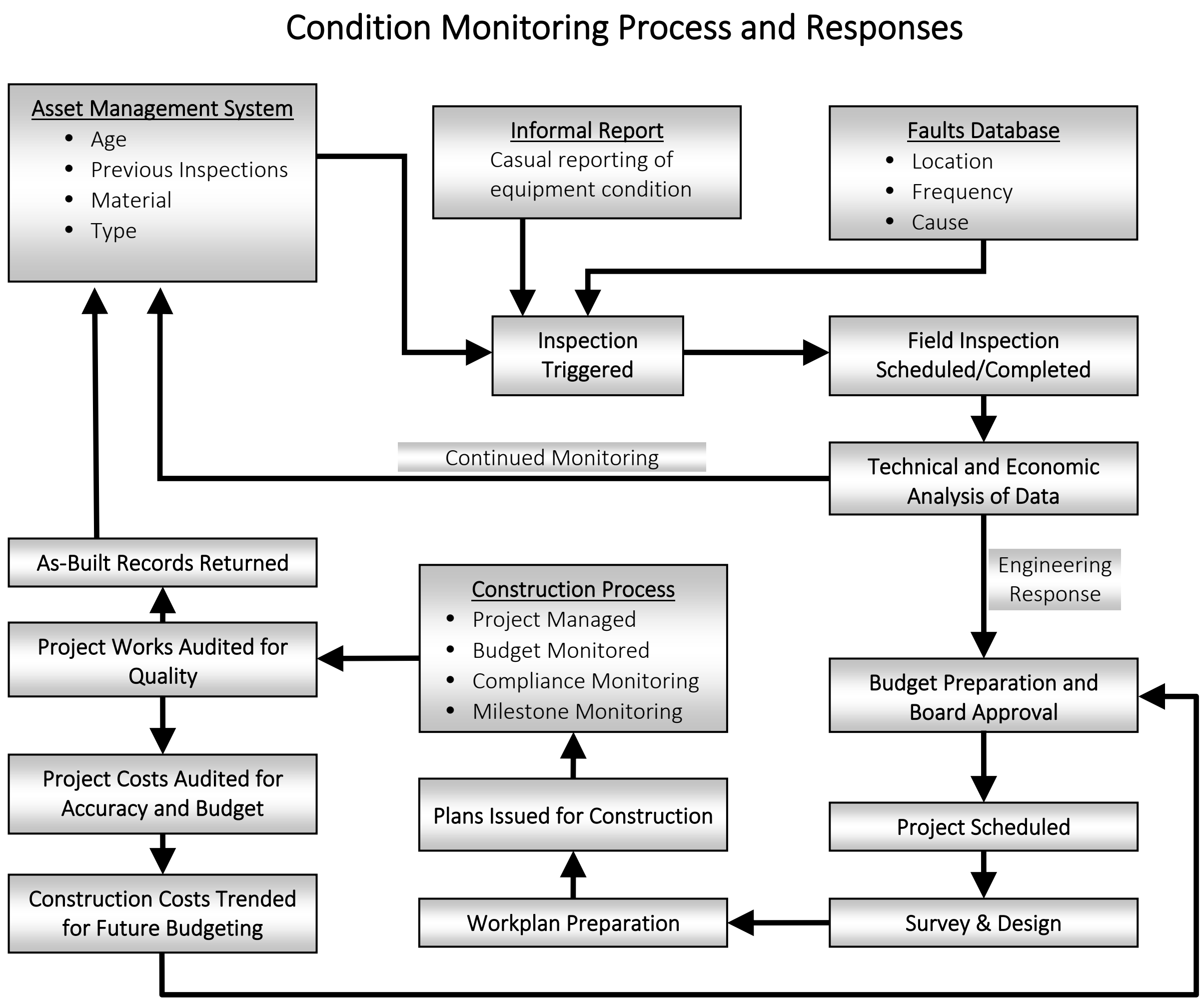
  The risk of failure and associated environmental, public health, financial or social impact justifies proactive action (e.g. impact and extent of supply discontinuation, probable extent of property damage, health risk etc)

Selection Criteria for Asset Renewal	
Priority	**Renewal Criteria**
1 (High)	• Safety concerns • Asset failure has occurred. • Asset failure of critical system component is imminent. • Regular maintenance required. • Complaints
2	• Failure of non-critical asset is imminent, and renewal is the most efficient life cycle cost alternative. • Maintenance requiring more than six visits per year.
3	• Reticulation maintenance involving two to three visits annually. • Difficult to repair, due to fragile nature of material, obsolescence.
4	• Existing assets have low level of flexibility and efficiency compared with replacement alternative.
5 (Low)	• Existing asset materials or types are such that known problems will develop in time

Planned and reactive replacement works can be prioritised in accordance with the priority ranking shown in the above table.

The process of asset renewal is generally triggered and managed according to the flow-chart shown below. The asset management system is used to examine candidates for inspection based on a combination of age, material of construction, make or type of equipment, and any previous inspections. Other triggers for inspection include information from the Faults database and ad-hoc reports from either field staff or the public describing a potential condition-related problem.

The inspection is scheduled and completed using the appropriate personnel (internal for routine inspections, external specialists for some unique or critical equipment). The results of the inspection are passed to engineering staff for evaluation. Consideration is given to all stakeholders' interests when evaluating possible replacement equipment. If the inspection reveals an acceptable level of remaining life in the equipment the inspection details are recorded against the equipment in the asset management system database and scheduled for reinspection at a future date. If the economic test is passed other considerations are introduced to ensure opportunities for security or capacity improvements at little or no extra cost are not lost. The best value option



is ultimately selected where the "value" is not only financial but, on occasion, also relates to less tangible stakeholder interests. The project budget is prepared and submitted to the Board for approval. If approved, the project is scheduled for construction and detailed design occurs, ultimately leading to the issue of workplans to the chosen contractor (by default internal). A project manager from the Asset Management function of EA Networks is appointed to monitor all aspects of the project and ensure a successful outcome. Project timing, budget monitoring, spot auditing, compliance with the specification, and adherence to normal contractor standards (safety and contractual) are the common areas attended to by the project manager.

Once notified as complete, the works are audited by the appropriate inspection staff to ensure quality and completeness are acceptable. The as-built records are incorporated into the GIS and asset management systems so that the dismantled plant is removed, and the new plant is added. The completed project is then financially analysed to ensure accuracy and the cost compared to budget and any discrepancies investigated. The actual costs are used to refine the budgeting process for future project costing.

6.2.6 Line Maintenance - General Observations

<u>Line Repairs and Refurbishment</u>

All line repairs are carried out to the requirements laid down in EA Networks' line maintenance standards. These are based on international practice combined with local knowledge and New Zealand legislative requirements.

Major Refurbishment

Multiple HV overhead lines will require refurbishment or replacement during the planning interval. Known candidates are explicitly identified in the first 3 years. Beyond that time the projects are pooled and allocated a value based on the known distribution pole age profiles and historical trends. The subtransmission lines that are approaching the end of their mechanical life are identified by line section and a Project number.

Wood Poles and Crossarms

Approximately 1,600 hardwood poles are over 40 years old (another 1,500 are 35-40 years old). It is currently projected that approximately 400 poles per year would need either changing or replacing with underground cable over the next 5 years to cope with defects. However, this number will gradually decrease as lengths of very old wood pole lines are dismantled. Towards the very end of the planning period an upswing in hardwood pole replacements is expected as the age profiles illustrate a greater annual construction rate occurred 30 years ago (late 1980s irrigation development).

Conductors and Accessories

As a policy, all replacement Aluminium Conductor Steel Reinforced (ACSR) is being purchased with a greased core wire. Some aluminium wrap splices have failed, and investigations are being undertaken to discover the mechanism of failure. Once the cause is found remedial action will take place to minimise the risk or recurrence. Some single strand conductor types are considered deficient and have been targeted for replacement.

Insulators and Insulator Fittings

Neoprene wrap-lock ties were used for a period but have proven troublesome by loosening the grip from wire to insulator when exposed to normal wind vibration. Replacement of these ties is occurring as a moderate priority. EA Networks' current standard practice is to bind the conductor to the insulator with wire of the same metal as the conductor.

Diagnostic Techniques

The purchase of an infrared thermographic video camera allows EA Networks personnel to regularly inspect overhead lines for failing or overloaded connections or equipment. This is a very good preventative measure that has already saved several fault outages (albeit that a planned outage took its place). A second high-resolution camera has now been purchased to allow a faster 'drive-by' scan of equipment.

6.2.7 Present Planning Priorities

Load growth caused by increased consumer demand and consumer expectations of reliability, security and power quality, as well as the regulatory and statutory environment set by central, regional and district government all guide the planning priorities of EA Networks.

In recent years, the principal focus has been on providing capacity for the dramatic pumped irrigation load growth in rural areas. In conjunction with this stimulus there were other security and capacity issues that required resolution. As a result of these combined pressures, 66kV was implemented as a subtransmission voltage. Eighteen zone substations have now been built and operate at 66kV. Three more zone substations remain to be either converted to 66kV, built from scratch, converted to 22kV, or decommissioned. The vast majority of the subtransmission network by length is now insulated at 66kV. All zone substations that are planned to be built at 66kV or converted from 33kV are included in the ten-year plan.

The development focus is also on the Ashburton urban area and the capacity and security requirements of the township. At Ashburton substation, the transformers are now 66/11kV and all switchgear is less than 20 years old. An additional zone substation has been constructed to provide additional capacity and supply security to Ashburton township consumers. Northtown, as the substation is known, has been commissioned for approximately seven years and has proven to be very beneficial. Northtown was recently converted to 66 kV operation. An allowance has been made for a 66/11kV transformer at Tinwald zone substation to accommodate urban load growth and security.

In Ashburton township, the 11kV feeders have a high connection count per feeder and many are approaching the limit of secure thermal loading. To restore security and capacity into the urban 11kV network, a programme to add an upper "core" 11kV network is in place. This programme will ensure the security standards are met and provide additional capacity for urban growth.

At the rural HV distribution level, conversion from 11kV operation to 22kV operation has been the chosen option for many of the areas facing the need for reinforcement associated with additional pumped irrigation load. This form of reinforcement has proven to be very successful and is likely to continue as the preferred option where significant rural HV distribution reinforcement is required.

EA Networks continue to monitor and assess the condition of all network equipment and, where necessary, this equipment is replaced or maintained depending upon the risk it presents and the whole life economics of repair versus replacement. The risk each piece of equipment represents is assessed according to the methodology outlined in Section 2 – Managing Risk & Resilience.

June 2006 Snow Storm Review

In the aftermath of the damaging snow storm of June 2006 a number of reviews were done to assess the adequacy of the existing network and of the suitability of the current line design standards. The review of the existing network identified a number of component types that appeared to be inadequate to meet current security standards. A full report was prepared and submitted to the Board for assessment. The major items that have been identified as needing attention are:

- Long spans (>100m) of small conductors such as squirrel (lower priority)
- One, two or three strand conductors such as #8 galvanised steel (number 8 fencing wire), 3/10 copper (relatively high priority)
- Older, low strand count, copper conductors (of any span length) that appear to have become more brittle over time (relatively high priority)
- 1940s vintage steel poles (so called Bates' poles) which do not have adequate strength reserves (higher priority)
- Understrength mechanical fittings (particularly near the historically lightly snow loaded coast) which cannot withstand the weight of conductor when loaded with snow. (lower priority)

The Canterbury-wide review of the existing line design standards showed that they were very close to the suggested level. The line design standards remain largely unchanged, but the specification of equipment used to build lines has been raised to ensure all components are rated and applied to meet these design standards. The main change has been the use of Flounder conductor in place of Squirrel conductor for new and rebuilt lines.

September 2010 and February 2011 Earthquakes

The earthquakes of 2010-11 were a tragedy for Christchurch and provided a severe test for all utilities serving the affected population. The severity of the shaking felt in Ashburton was significantly less than that felt in Christchurch during both major events. During the September earthquake, the peak recorded ground acceleration anywhere in the Ashburton District was less than 0.2g. This compares with acceleration of more than 0.3g in most of Christchurch and more than 0.7g in rural areas closer to the Greendale fault. The February earthquake was further from Ashburton than the September one and Ashburton District ground acceleration was less than 0.1g. The Christchurch urban area experienced ground acceleration between 0.5g to 0.9g with one recorder peaking at more than 2.0g.

The experience of the earthquake has refocused EA Networks. Preparedness is essential to prevent catastrophic equipment failure. EA Networks have observed and learned from the information Christchurch-based lines company Orion who have shared information about risk preparedness and recovery. EA Networks are well aware of the many natural and man-made risks that are faced by an electricity utility and have begun to progress risk and recovery planning into formal documentation that could be called upon in an emergency.

The seismic design standards that EA Networks use are considered and robust. This should ensure that modern equipment is largely serviceable after a significant seismic event. The main area of concern is likely to be the significant quantity of older equipment that was installed prior to the adoption of current standards.

Future plans will address in greater detail the additional planning required for high impact low probability events and the impact they have on an electricity utility.

6.3 *Subtransmission Assets*

6.3.1 66kV Subtransmission Lines

Description

EA Networks now own significantly more 66kV insulated overhead line than 33kV overhead line (368km vs 54km). The 66kV network (see Section 4.2.2 for a map of the layout) is in two distinct rings. The northern section is an interconnected ring directly supplying Northtown (NTN), Fairton (FTN), Wakanui (WNU), Pendarves (PDS), Dorie (DOR), Overdale (OVD), Lauriston (LSN) and Methven66 (MTV) zone substations. Highbank (HBK) power station is connected on a 66kV spur line beyond Methven66. To the south of Ashburton, a southern 66kV ring supplies Ashburton66 (ASH), Eiffelton (EFN), Coldstream (CSM), Carew (CRW), Hackthorne (HTH), Tinwald (TIN) and Lagmhor (LGM) zone substations.

Two types of construction have been used to build 66kV overhead lines. The first type is brand new Jaguar, Lemon or Dog ACSR line constructed with treated hardwood poles and polymer insulators. The second type is reinsulation of older, pre-existing, 33kV lines on hardwood poles. Steel extensions were used to provide adequate clearance to the under-built 22kV circuit on these reinsulated lines.

The capacity of the conductors in use is:

- Jaguar (low snow loading areas) or Lemon (heavy snow loading areas) which both have a conservative 'still air' thermal rating of approximately 400 amps (summer) and 500 amps (winter),
- Dog has a conservative 'still air' thermal rating of about 250 amps (summer) and 300 amps (winter).

All 66kV insulators are manufactured using polymer materials (synthetic rubber) with a clamp top rather than the traditional porcelain and binder. This allows construction of new lines without crossarms (see adjacent photo).

One 2km length of 66kV cable has been installed between Ashburton Zone Substation and the edge of urban Ashburton. This replaces an overhead 33kV line at the end of its life that was largely on private property and very difficult to access. There are some short sections of 66kV underground cable that have been used to provide egress from sites at Pendarves and Elgin (adjacent to ASB). The 66kV subtransmission cables located at the Pendarves substation are copper conductor / XLPE insulation / HDPE sheathed cables and they were installed in 1999 and 2001. Other short sections of 66kV cable have been installed from Elgin substation to the overhead lines which supply Coldstream and Northtown substations. At the request (and partial funding) of a land owner, a 300m section of 66kV cable has been installed across private property allowing the removal of a section of 33kV overhead line. These cables have a thermal rating to match the connected 66kV overhead line and are expected to have a lifetime in excess of 50 years.

Condition

Poles

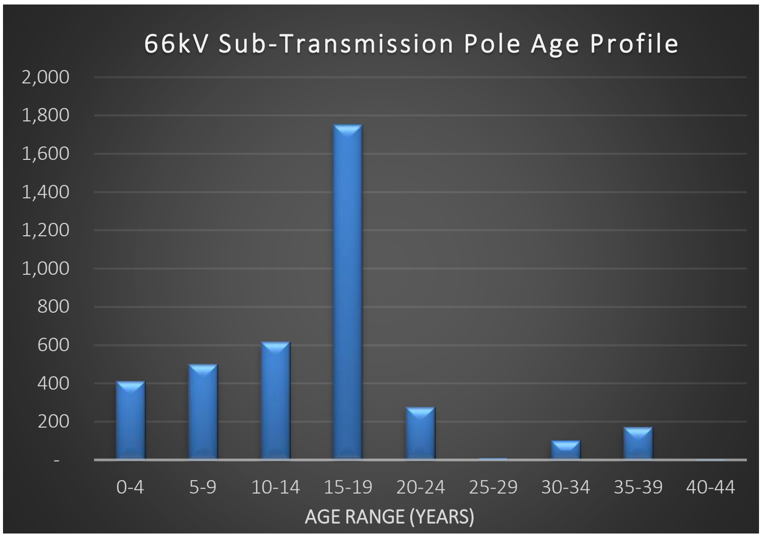
The condition of the 66kV subtransmission assets largely reflects their age and the quality of materials used in construction. The vast majority of the poles are less than 20 years old and the cluster of older poles represent the lines that were converted from 33kV. All of the poles have a life expectancy of at least 40 years from new.

Insulators

The 66kV insulation has no known issues.

Fittings

Fitting of vibration dampers as standard to all 66kV circuits and to the underbuilt HV distribution circuit (where larger conductor sizes are used) has reduced aeolian vibration effects to an acceptable level. Wedge connectors are universally used for conductor junctions and have proven to be very reliable.



There are no known issues with the condition of any of the 66kV lines currently in service although the older ex-33kV poles are scheduled for replacement within the first half of the planning period (poles shown at right in 30-34 and 35-39 age groups).

Standards

Documentation of standards presently used for testing, inspection and maintenance of the 66kV subtransmission network is still being developed. Construction standards are fully documented, and all new work is audited for compliance.

Maintenance

Inspections, Servicing and Testing

The condition of the 66kV subtransmission network is monitored using the following techniques:

- corona camera survey (insulators and cable terminations)
- complete visual inspection every 5 years (roadside location assists in reporting of any uncharacteristic behaviour)
- periodic infra-red scanning (typically every two years)
- analysis of fault information
- tree control inspections annually.

Fault Repairs

There have been very few faults on the 66kV subtransmission network. The only issues that have arisen are one occurrence of a loose bolt holding a 66kV insulator causing a pole fire (necessitating pole replacement) and several instances of insulator failure on the under-built circuit causing pole fires. The majority of 66kV faults have been caused by vehicles, wildlife or trees.

Planned Repairs and Refurbishment

Other than routine tree cutting there is only one remedial project planned. No other repairs or refurbishment is scheduled.

Retrofitting of 66kV Vibration Dampers

During the early periods of 66kV line construction it was not obvious that 100m+ length spans would cause aoelian vibration of conductors. A significant programme revisited early 66kV circuits and fitted vibration dampers to the conductors. The dampers prevent the vibrations from damaging the insulators and other pole fittings, extending the life of the line considerably. This programme is nearing completion and there is no additional damper installation retrofitting planned beyond 2021.

Replacement

There are plans to replace the ex-33kV poles during the planning period [12701], [-1102] & [-1118].

Enhancement

See section 5.4.2 – Planning Our Network for details.

Development

See section 5.4.2 - Planning Our Network for details.

6.3.2 33kV Subtransmission Lines

Description

EA Networks have a rapidly shrinking 33kV subtransmission network, having recently relinquished the Transpower 33kV GXP - Ashburton (ASB) (see Section 4.2.2 for a map of the layout). There are now only two radial 33kV lines suppling four zone substations (MVN, MSM, MON, MHT) from Methven 66kV zone substation where a 66/33kV transformer is located. This arrangement has evolved as 66kV subtransmission has been introduced and 33kV line length will continue to shrink as more conversion to 66kV occurs. The total route length of the 33kV network is 58km.

The 33kV lines take a variety of standard construction forms. The early lines are on hardwood poles with porcelain insulators and many of these still standing today. During the 1970s and 1980s concrete poles came into vogue for 33kV construction and a number of lines use either prestressed or mass reinforced (spun) concrete poles. Pin insulators are exclusively porcelain, but the strain insulators are a mixture of porcelain and polymer materials. Conductor types are exclusively ACSR and AAC. The most common sizes are Jaguar, Mata, Waxwing and Dog.

The capacity of the conductors in use is:

- Jaguar (snow loading areas) or Mata (low snow loading areas) which both have a 'still air' thermal rating of approximately 400 amps (summer) and 500 amps (winter),
- Waxwing has a 'still air' thermal rating of about 300 amps (summer) and 350 amps (winter),
- Dog has a 'still air' thermal rating of about 250 amps (summer) and 300 amps (winter).

EA Networks have approximately 4.5km of 33kV underground cable in various locations around the district. All 33kV cables are XLPE insulated with heat-shrink terminations and joints.

The most significant 33kV cable length (3km) is installed between Ashburton township zone substation in Dobson Street (ASH) and the northern end of Ashburton urban area. This cable is single core 185 mm² aluminium conductor with XLPE insulation, aluminium wire screen and PVC oversheath (conservatively rated at 295 amps). This cable is now redundant for use at 33kV and will be reused at 11kV as part of the Ashburton 11kV Core Network. Subsequent plans will manage this cable as 11kV.

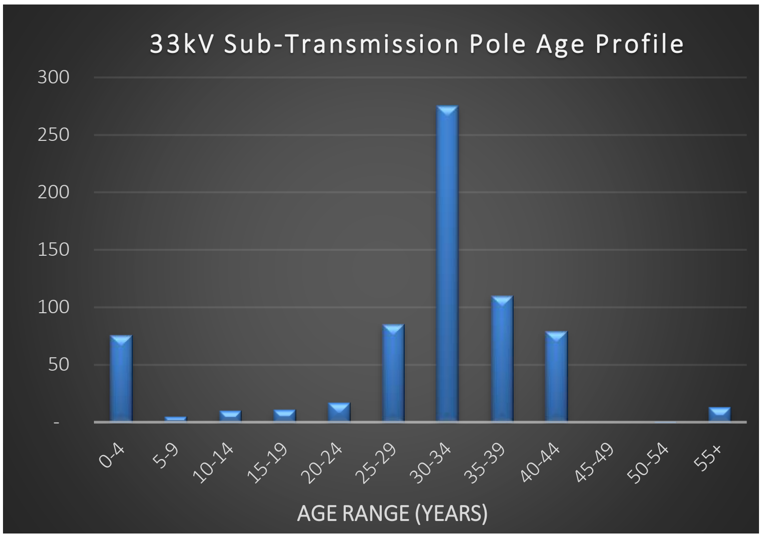
Other 33kV cables installed at ASB and ASH were used to connect from substation busbars to overhead lines. The cable used is single core 400 mm² aluminium conductor XLPE insulated, copper wire screened with an HDPE/LDPE oversheath (rated at 500 amps). These cables are up to 200 metres long. These cables have been retired from 33kV use and may be reused at 22kV in some cases.

There are a variety of other short 33kV cable lengths installed (typically 185 mm² aluminium) that overcome height restrictions under Transpower lines and glideslopes at airstrips.

Condition

Poles

The age profile of the 33kV subtransmission poles shows that the only new poles that have been installed since 66kV subtransmission became the preferred voltage, are to either replace defective ones or those damaged in car crashes. One exception is a section of line that has been built to retain supply to Montalto Hydro and Montalto substation. The condition of the line was such that replacement was required and the portion with underbuilt 11kV line could not be relinquished. Within the planning period this line will be repurposed as a 22kV distribution circuit.



With the decommissioning of Lismore zone substation, a portion of the 33kV line from Lismore – Montalto to Mt Somers Substation has been made redundant. It was constructed in 1972, is assessed to be in a fair condition, and has been partly reused at 22kV. The piled poles which form part of this line in the Hinds River, failed during a rainstorm event during 2002. The failed hardwood piles have been replaced with a much more substantial form of steel foundation. The first portion of this circuit has been rebuilt at 66kV to supply the proposed Montalto substation (project [-1163]). The remaining line will be rebuilt as 22kV-only once the Montalto area has been converted from 11kV to 22kV. This will remove the need for 33kV in the area and some 200 old 33kV poles will be removed. This will remove a significant number of older 33kV poles from the network.

As of February 2020, the 33kV system involved approximately 70 Concrete poles and 612 hardwood poles. Of these, it is estimated 70 hardwood poles (11% of total) will need replacing within 5 years. Approximately another 100 are estimated to need replacement closer to the end of the planning period (subject to further evaluation). Some of these poles are now operating at lower voltages such as 22kV.

If the EA Networks network evolves as described in this plan, the 33kV network will be almost entirely superseded with a new 66kV network by the end of the planning period leaving only one 33kV line (MTV to MHT) in service. This obviously solves all the 33kV line conditions issues identified above. Many 33kV poles have underbuilt distribution lines on them and they will continue in service beyond the end of the planning period. These poles will be managed as distribution poles once they operate at 22kV or 11kV only.

Fittings

There is a mixture of old technology (porcelain) and new technology (polymeric) insulation used on the 33kV subtransmission system. Due to the low pollution environment in Mid-Canterbury and the replacement of failed first generation polymeric (cycloaliphatic) insulation some years ago, it is not envisaged there will be a need for a widespread insulation replacement programme before retirement or conversion to a lower voltage.

During 1999, radio interference problems occurred on a section of 33kV over 11kV line built in the early 1990s. The problem was identified as deterioration of the neoprene cushion within pre-formed insulator wrap lock ties used to attach aluminium conductors to insulators. Apart from the possibility of interference as the cushion deteriorates further, there is a possibility of the conductor parting company with the insulator as it loosens. EA Networks have installed approximately 7,000 of this type of tie on the system to date but discontinued their use approximately ten years ago. It can be expected that during the planning period there is a high likelihood of the ties deteriorating further requiring their progressive replacement. This work will be covered by progressive 66kV conversion. Should the 66kV conversion not progress as planned any 33kV lines requiring attention will be resolved separately.

Termination or connector practices have varied over the years ranging from PG (parallel groove) connectors, line taps and over recent times a policy of using only wedge connector clamping has been implemented. The existing PG clamps are prone to overheating and/or corrosion and subsequent failure. The line tap arrangement was subject to failure during through-fault conditions. While the PG connectors and line taps still exist in the EA Networks system, it is not intended to undertake a mass replacement programme. However, the PG clamps will be monitored on a regular basis by thermographic methods and individual clamps replaced as and when necessary.

Underground Cables

The 33kV single core cables laid from the Ashburton zone substation out to Racecourse Road are some 3km in route length and have an Aluminium/ XLPE insulated PVC sheath with an aluminium screen. This cable was installed in 1986 and has been the subject of several failures due to water between the aluminium screen and the sheath entering joints. It is suspected that the water problem occurred both during the manufacturing process and prior to installation (poorly fitting end caps). Further analysis revealed a problem that required attention. The issue that was identified was that of excessive circulating currents in the cable screens. The cable has now been mid-point earthed and cable screen voltage limiting devices installed at each end of the cable. This work permits the full cable rating to be sustained without excessive heating.

Partial discharge tests, wire screen continuity/impedance tests and insulation tests would suggest that the cable itself is unlikely to fail catastrophically within its useful lifetime of operation at 33kV. This cable has been de-rated to 11kV operation as Northtown and Ashburton substations are both operating at 66kV. This cable will be incorporated into the core 11kV network as two or more circuits between 11kV network centres and zone substations.

Standards

Documentation of standards presently used for testing, inspection and maintenance of the 33kV subtransmission network are unlikely to be developed. It is unlikely this work will proceed to conclusion with the conversion to 66kV or retirement of 33kV lines well within the planning period. Construction standards are fully documented, and all new work is audited for compliance.

Maintenance

Inspections, Servicing and Testing

The condition of the 33kV subtransmission network is monitored using the following techniques:

- corona camera survey (insulators and cable terminations)
- complete visual inspection every 5 years (roadside location assists in reporting of any uncharacteristic behaviour)
- periodic infra-red scanning (typically every two years)
- analysis of fault information

As with the entire 33kV network, inspection and patrols are important to reduce fault incidents. The 33kV network has a higher impact on reported statistics than lower voltage lines and this encourages more preventative action and research. The majority of the 33kV network is on public road reserve (as are most EA Networks lines) and this fact tends to encourage both staff and the public to report components that are causing concern. The Lines Inspector will examine the 33kV network at least once during the planning period.

Fault Repairs

The history of faults on the 33kV network would suggest that one or two a year would occur on average. This rate could increase slightly up until the date the oldest lines have been either replaced or refurbished.

It is very difficult to predict the number of faults from year to year due to climatic conditions. An estimate for fault work is provided based on historical fault data for the entire 33kV network.

The 33kV lines have had a variety of faults affecting them over recent years. The most concerning was a spate of 33kV porcelain insulator failures where the binder groove would crack off the top of the insulator allowing the conductor to drop and cause either an earth fault or a pole fire. Analysis of the failed insulators did not suggest any specific cause and the corona surveys have not revealed any additional problems. The usual problems of trees, wildlife and car crashes account for the remainder of the problems. These insulators have been removed by 66kV construction.

Planned Repairs and Refurbishment

Other than regular tree cutting, there are no scheduled plans for repairs or refurbishment of portions of the 33kV network.

Replacement

Should the need arise, any replacement of 33kV lines will be with 66kV lines in a location compatible with future requirements. This will make the work enhancement rather than replacement.

Enhancement

See section 5.4.2 – Planning Our Network for details.

Development

See section 5.4.2 - Planning Our Network for details.

6.4 Distribution Assets

Electric lines and cables, including associated easements and access ways operating at a voltage of 11kV and 22kV make up the bulk of EA Networks' infrastructure assets, in terms of both value and number. The extent of the distribution network is such that it covers virtually all of the plains in Mid-Canterbury and three long spur lines reach 35km into the foothills of the Southern Alps via the Rangitata, Ashburton and Rakaia Gorges.

6.4.1 11kV and 22kV Overhead Distribution Lines

Description

EA Networks have extensive 11kV and 22kV distribution networks. Until the early 1990s, EA Networks only used 11kV as a distribution voltage. The rapid increase in irrigation load caused steady state 11kV voltage to drop to intolerably low levels. The security of the distribution network also fell, since back-feeding was not an option, as it would have resulted in an unacceptably low voltage. A rigorous investigation of the various solutions led to the adoption of 22kV as the preferred solution to the raft of capacity and security problems.

The 22kV network is proving to be an excellent distribution voltage. As an example, most people in the industry are familiar with conductor sizes by code names. Swan or Squirrel ACSR conductor run at 22kV has a lower percentage volt drop for a given kW load than Dog ACSR run at 11kV. Ferret conductor at 22kV has 21% less voltage drop than Jaguar ACSR at 11kV. These capabilities ideally suit a rural voltage-constrained network. The two-fold increase in thermal capacity (absolute power rating) of all conductors is merely a useful by-product of the conversion work.

Capacity Class	11kV Circuit Length (km)	22kV Circuit Length (km)
Light	185	648
Medium	80	960
Heavy	0	37
TOTAL	265	1,645

11-22kV construction types are many and varied with lines that cover various materials, ages and designs. Pole types include hardwood, treated hardwood, treated softwood, prestressed concrete, mass reinforced concrete and steel (expanded I-beam). All these different poles have their strengths and weaknesses. Crossarms are either hardwood or steel.

Major insulation hardware has always been, and continues to be, porcelain pin insulators because of competitive pricing and a respectable track record. Strain insulators of choice have changed from being porcelain to universal adoption of polymer strain insulators at 11kV and 22kV.

Current standard construction employs hardwood poles and crossarms in a conventional style with porcelain pin insulators and polymer strain insulators.

The table above details the route length of the overhead distribution assets owned by EA Networks by 'ODV' capacity class. It should be noted that a significant quantity of the lines categorised as 22kV will be insulated at 22kV but operating at 11kV.

The HV overhead distribution lines that radiate from rural zone substations are what most people see running along the rural roadsides. EA Networks own a total of 1,910km of 11kV and 22kV overhead lines that are predominantly located on the roadside. Some of the poles that carry these lines also carry subtransmission or LV lines. The highest voltage the pole was constructed to carry provides the asset category that is responsible for the structure's asset management.

Other line owners supplied by EA Networks own about 483km (488km in previous plan) of HV overhead line which is all on private property.

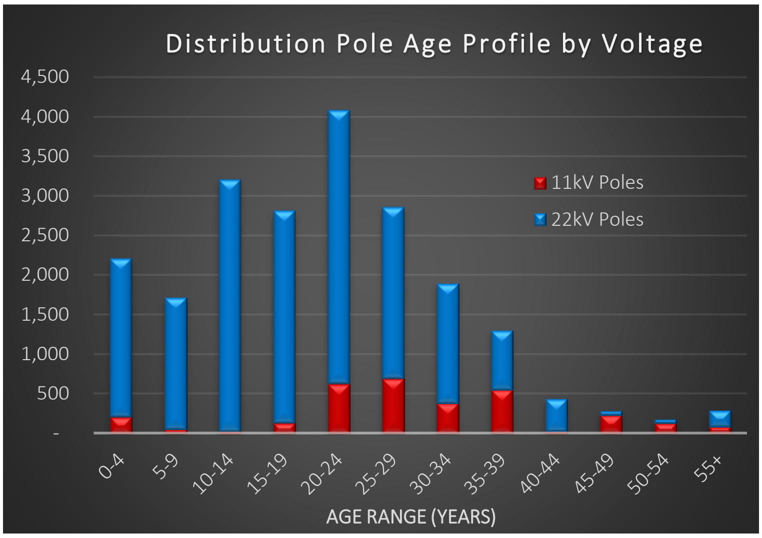
As of the date of this plan, the data available for management of pole hardware is incomplete. The total number and age of poles is known from work-plan information however the hardware fitted to these poles has not been captured. The relatively low incidence of ancillary component failure on poles and the ability to repair failures quickly means that there is a low return on gathering and maintaining this data. At this point in time, data on components other than poles will be gathered if and when personnel visit the host pole. It should be noted that replacement of any existing pole will result in brand new pole hardware being fitted.

Distribution Components		Type	Quantity
Distribution Structures (not overbuilt)			
	Wood	- Hardwood	16,866
		- Softwood	2,208
	Concrete		2,098
	Steel Poles		29
	TOTAL		21,201
Distribution Pole Supports			
	Guy Wires	- Aerial	356
		- Single Down	2,830
		- Double Down	2,463
	In-Ground Pole Blocks		6,505
	Prop Poles		9
Conductor			
	Conductor Length (km)	- 11kV	729
	(Span length x No of wires)	- 22kV (inc. 22kV at 11kV)	4,879
	TOTAL (km)		5,608

The next stage in data capture will be capturing the structure type and this will permit the use of standard bill of material schedules to determine total quantities of cross arms, insulators braces and even nuts, bolts and screws. This will also tie into costing, budgeting, asset valuation, stores management, asset management and financial reporting.

Condition

The present condition of any distribution line is largely a factor of its age, the quality and type of materials used and the climatic conditions the lines are exposed to in various areas. EA Networks' location is largely free from corrosive airborne contaminants such as salt. The major life accelerating factors are sun (attacks insulation and protective coverings), wind (vibration and cyclic stress) and pole resilience to fungal or insect attack. At this stage, relatively few young poles have been individually inspected. The older poles have been inspected and



those in need of attention replaced. The age profile would suggest that the bulk of the backlog maintenance has been attended to.

Hardwood Poles

There are approximately 16,866 hardwood poles (80% of total distribution poles) in the overhead distribution network. The distribution lines are 22kV or 11kV single circuit and double circuit construction with an age ranging from new to around 50 years old. Many of the older lines have been replaced over recent years, but this has still left a small but significant percentage of poles exceeding 45 years old. Several of these lines are scheduled for replacement over the next two years. Over the years, three styles of hardwood poles have been used in the EA Networks system. These styles are - natural round (first generation pole), desapped hardwoods and more recently CCA treated hardwood poles. The average age of the hardwood distribution poles is 20.0 years.

Concrete Pole Lines

Concrete poles make up approximately 10% of the total distribution poles used in EA Networks' system.

There are 2 two types of concrete poles used

Pre-Stressed concrete poles - these various pre-stressed types of concrete poles were first installed around the late '60s and therefore not expected to need to replacement during the planning period. An early type of pre-stressed pole (called Burnett) was deemed defective and dangerous and these have all been replaced with other manufacturer's pre-stressed concrete poles, softwoods and hardwood poles.

Mass-reinforced concrete poles - these are in excellent condition and are likely to last well beyond 40 years.

The average age of the concrete distribution poles is 28.1 years.

Treated Softwood Pole Lines

Construction of treated softwood pole lines began in the early 1990s for economic reasons, and continued through until 1997, when the cost differential between hardwood and treated softwood poles became less and the quality of the softwood poles received deteriorated. These poles make up approximately 10% of the total system poles.

The green (damp) nature of the poles when first installed has seen the pole tops in many cases setting with a twist as the timber dried out causing the conductor to become unevenly sagged. This in turn leads to the possibility of conductor clash during turbulent wind flows. Large cracks have also appeared during the drying process in some poles that may pose a problem if the poles continue to split especially around any bolt holes. The splits also allow moisture into the untreated pole interior.

Due to the varying diameters of the poles they can be susceptible to birds resting between the centre insulator and pole causing a current to earth and the resulting burning-out of the top portion of the pole.

It is not envisaged a wide-spread remedial maintenance programme be set in place during the planning period. Repair work will be expected in some cases, but this will occur as and when problems develop. Each specific case will be examined at that time to determine if it is symptomatic of a wider problem. The expected life of these poles is greater than 30 years.

The use of these poles may be reconsidered, as a refined treatment process now produces a higher quality pole. The technical/economic balance will determine future softwood pole usage.

These lines are typically wired in ACSR conductor.

The average age of the softwood distribution poles is 24.9 years.

"*Bates" Steel Pole Lines*

These poles were installed in the mid-1940s and account for approximately 0.1% of the system total (0.3% in previous plan). These poles are rapidly approaching the end of their life with all poles requiring replacement within 5 years.

The rapid deterioration through rusting has seen a programme introduced to replace almost all these poles within the planning period. The June 2006 snowstorm reinforced this opinion as some steel poles failed during this severe weather event.

As of February 2020, 29 “Bates” Steel poles remain standing having operated at (or still operating at) 11kV or 22kV. Approximately half of these poles are in the process of removal having been replaced by rural underground conversion.

The average age of the steel distribution poles is 45.9 years.

Conductors and Conductor Accessories

A variety of conductor types have been used over the years ranging from galvanised steel, Aluminium Conductor Steel Reinforced (ACSR), All Aluminium Conductor (AAC), copper weld (copper coated steel), #8 copper (solid high strength copper) and stranded copper.

Most of the ACSR and all AAC installed are in a good condition and there is no intended replacement programme for any of these conductors. After the recent snowstorms it was decided that the small relatively low strength ‘Squirrel’ conductor would not be used for new or rebuilt lines. In its place a much stronger smooth body conductor ‘Flounder’ will be used.

Galvanised steel, #8 copper and copper weld conductors make up approximately 0.6% of the total distribution conductor length. Some galvanised steel conductors are beginning to rust (in some cases quite significantly), while the copper weld conductor is becoming brittle and is prone to breaking. It is anticipated that most of these conductors will require replacement during the planning period and there has already been significant progress along this path – a reduction of about 5km since the last plan was published. This leaves approximately 33km of these conductors in service at 11kV or 22kV. Some of this conductor length is the first span of an on-property extension owned by others (which is partly in the road corridor - estimated to be about 26km of conductor length). The 7km of roadside conductor has projects in the plan to remove it within 2021.

Line splices have started to cause an increase in faults. It appears the application of these splices has not been according to the manufacturer’s instructions. Remedial action will be taken once a survey of suspect splices has been completed using thermography.

Wire termination and connector practices have been amended as per the current practice for subtransmission lines (see section 6.3.2 - Fittings).

Insulators and Insulator Fittings

A majority of the insulation used on the distribution system is porcelain and generally considered in reasonable condition. Given the relatively low pollution environment it is not envisaged that any major replacement programme will need to be implemented in the near future.

Wrap-lock ties were also used at 11kV and the situation described in section 6.3.2 - Fittings also applies to a proportion of 11kV lines.

The June 2006 snow storm identified that in some cases mechanical fittings were inadequate and they failed prematurely, dropping conductors onto the ground. The application and use of these types of fittings has been reconsidered and provided they are applied correctly they are adequate.

Standards

Documentation of the standards presently used for testing, inspection and maintenance of the HV overhead distribution network is still being developed. Construction standards are fully documented, and all new work is audited for compliance.

Maintenance

HV distribution assets comprise most of EA Networks’ asset base by distance, value and most other measures. Consequently, the asset type also accounts for the greatest share of maintenance and enhancement expenditure.

The value of distribution lines included in projects that are triggered by subtransmission development is beginning to reduce. These lines are incidentally reconstructed on the route of new 66kV subtransmission lines (or existing 33kV lines being converted to 66kV). The cost of these rebuilt distribution lines has been estimated and allocated so that a true indication of increasing asset value can be obtained.

Any line in the 22kV network is at worst a refurbished line and at best a brand new one. This situation has arisen from the 11kV to 22kV conversion programme. Lines are generally reinsulated without full replacement work being necessary, however, if any faulty components are discovered they are replaced. This process effectively extends the planned maintenance-free period on 22kV lines for at least ten years from the date of conversion.

Inspections, Servicing and Testing

The rural 22-11kV network is the area that consumes most of the Lines Inspector's time. Much of the inspection budget is spent assessing poles and hardware on these lines. A gradual accumulation of information on lines is being achieved with inspections targeting the oldest lines first. Future plans may allocate the inspection time more systematically.

The refurbished nature of the 22kV network has relegated it down the priority list for patrols and inspections. It is anticipated that the data gathered during the conversion work so far will be used to assess the refurbished lines, looking for inspection candidates towards the end of the planning period.

Fault Repairs

This section of the network absorbs the biggest portion of the fault budget every year. The usual culprits are wind, wildlife, cars, trees, snow, irrigators (large rotating steel booms), occasionally aircraft (top dressing), vandalism, equipment failure, consumer earth faults intruding into the distribution network causing protection to trip a feeder, and completely unknown causes. The projected costs are based on historical values adjusted for major replacement, refurbishment and development projects.

A surprising statistic has come from the fault data gathered since 22kV conversion was started. There appears to be an irreducible lower level of faults that exist for all open wire distribution lines. Asset management staff were hoping to see the number of faults fall to low levels in the 22kV areas, but this was not the case. The fault level certainly dropped, with aged equipment failure virtually eliminated (faulty or damaged new components accounted for most equipment failures). Seemingly, provided there are people, birds, exotic marsupials, and trees (including blue gum trees with bark streamers), faults will occur. Dramatic reductions in this base level of faults will require alternative construction techniques.

The fault repairs on the HV distribution network have been estimated from the pool of fault maintenance done in previous years.

Planned Repairs and Refurbishment

The various repairs and refurbishments have not been identified individually. The present rate of maintenance is likely to reduce over the planning period as the average pole age decreases.

Single Strand Galvanised Steel Conductor (on-going)

The single strand galvanised steel conductor (predominantly #8 galvanised steel fencing wire) historically used in the 11kV network is considered deficient. It has corroded and during wind and snow events is prone to failure which will drop a conductor onto the ground in many cases. A conscious decision has been made to eliminate this conductor from the distribution network. It will be replaced with the minimum modern equivalent conductor for the structure/line to survive until the pole is at the end of its useful life. A maintenance programme is almost complete to give effect to this strategy. The remaining conductors are the first span leaving the roadside network onto private lines and, as they are rebuilt by the owner, it will be replaced.

Replacement

The rural HV distribution network is decreasing in average age. A considerable effort has been made in recent years to catch up on backlog maintenance that was postponed during times of major enhancement and development. This has reduced the level of annual maintenance required to a more routine amount. Routine amounts would be 2.0 to 2.5% (40 to 50-year average lives) of the total pole population per year needing replacement. With a distribution pole population of approximately 21,000 this represents approximately 500 poles per annum. This of course assumes a flat age curve, and this is not the case. The present rate of replacement would be about half this number (250 per annum). Towards the end of the planning period, the pole replacement rate may begin to increase as the age profile indicates more aging poles reaching about 40 years old.

Bates Steel Poles (on-going)

The Bates steel poles, which have given long service, are reaching the end of their mechanical life. As part of the pool of overhead HV distribution line replacement funds allowed in the planning period, these poles will be progressively replaced. Approximately 79 of these poles have been replaced/removed since the last plan was published - leaving 42 in service (at all voltages). The rural underground conversion programme has decommissioned many of these poles and they await removal. The remaining poles are being closely monitored.

Enhancement

See section 5.4.4 - Planning Our Network for details.

Development

See section 5.4.4 - Planning Our Network for details.

6.4.2 11kV and 22kV Underground Distribution Cables

Description

Underground cable is becoming a significant asset for EA Networks. It is being used to service any new urban development as well as replacing urban overhead plant when it requires rebuilding. The Methven urban area is completely underground. The decision to proceed with undergrounding Methven was taken after a disastrous snowstorm in the 1970s that left many poles and wires lying in the streets. It took many weeks to repair the damage sufficiently to return supply to all consumers.

Voltage (kV)	Description	Current Rating (amps)	Capacity (MVA)
11	3 core 95 mm² XLPE aluminium (urban distribution)	200	3.8
11	3 core 150mm² XLPE aluminium (distribution feeder root)	255	4.9
11	3 core 300mm² XLPE aluminium (“Core”distribution)	400	7.6
22	3 core 35mm² XLPE aluminium (rural consumer connection)	120	4.6
22	3 core 95mm² XLPE aluminium (general distribution)	200	7.6
22	3 core 120mm² XLPE aluminium (distribution feeder root)	240	9.1

Urban Ashburton is being progressively converted to underground cable as the condition of the existing overhead lines deteriorate, demanding replacement. When prioritisation is required because of limited resources, the HV distribution voltage lines are chosen before the LV reticulation as they have a higher public safety risk and a more dramatic impact on reliability.

It is not only urban areas that benefit from underground cable installation. Where necessary, short sections of rural distribution lines have been placed underground to avoid conflict with Transpower transmission lines, airstrips and to get around problematic obstacles. Distribution feeder entry and exit from zone substations is also normally achieved with short lengths of underground cable. More extensive rural underground distribution is being undertaken with approximately 28km of end-of-life overhead line being replaced with underground cable during the planning period. With the assistance of NZTA, currently only state highways are being targeted for rural underground conversion. An assessment of the actual costs and operational experience will determine if rural underground becomes more commonplace.

It should be noted that EA Networks has a policy that all new connections to the EA Networks network must be made using underground cable (up to and including 22kV).

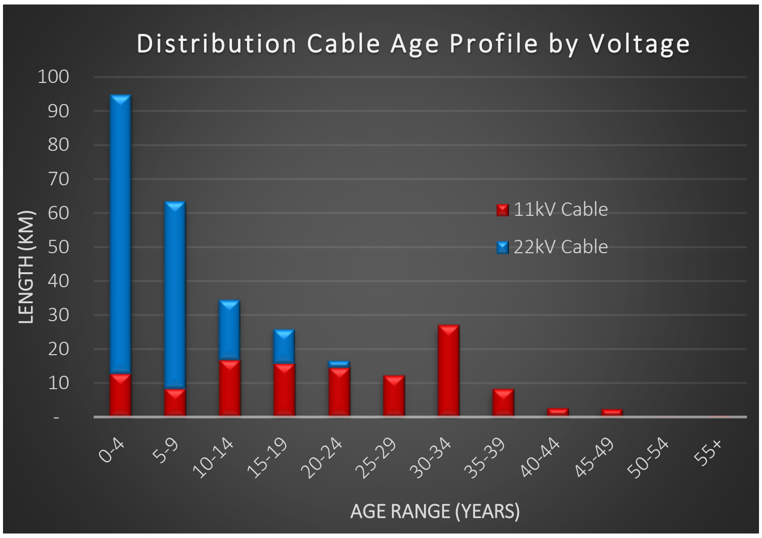
The distribution voltage cables used by EA Networks are almost entirely XLPE insulated. The cables in common use at EA Networks are shown in the table above.

Since about 1995, the cable specification changed from a copper tape screen with PVC over-sheath to a copper wire screen with HDPE over-sheath.

EA Networks presently have about 120km of 11kV cable installed (an increase of 5km from the last plan) and 167km of 22kV cable (an increase of 21km from the last plan).

Condition

EA Networks have a mixture of old and new technology cables throughout the system and these are generally in reasonable condition and trouble free. As with most power companies, failures are typically associated with joint and termination problems or mechanical damage. The spike in cable 30-34 years old is a consequence of 14km of 11kV cable being installed onto Mt Hutt ski-field in the late 1980s.



Cable Accessories

Any remaining older style cable terminations are of concern from a reliability point of view. EA Networks is targeting these for prompt replacement during the planning period.

Historically, a series of joint failures occurred in an 11kV cable in William Street, Ashburton. A thorough investigation was less conclusive than was hoped. It is suspected that a crimp connector failed and caused a heavy current fault. This fault may have weakened similar crimped connectors in other joints in the same cable. Additional care is now being taken during application of crimp connectors and where possible existing and new joints are being engineered out of the cable system. Where possible, new distribution cable installations use shear-bolt connectors, which appear to be more tolerant of cyclical heating.

Standards

Documentation of the standards presently used for testing, inspection and maintenance of the HV underground distribution network is still being developed. Construction standards are fully documented, and all new work is audited for compliance.

Maintenance

The maintenance requirement of underground cable is virtually nil and the urban Ashburton 11kV network is being placed underground based on condition, solving the problem for the foreseeable future. The other township areas that have some 22-11kV overhead distribution, namely Rakaia and Hinds face the same destiny of being placed underground - when condition demands it. There will be no urban overhead lines remaining at the end of the planning period provided the underground conversion programme proceeds as programmed. This approach provides for medium to long-term cost minimisation.

Inspections, Servicing and Testing

There is limited inspection and testing work that can be done on any buried equipment. Periodically, electrical tests are done on cable segments that are out of service for other reasons, but condition is predominantly ascertained by tracking fault information. Some tests using partial discharge mapping have been trialled after a series of faults occurred in quick succession. The results of the testing were not particularly compelling, and it was decided widespread adoption of the technique would not offer good value.

Fault Repairs

There is a very low frequency of faults on the HV distribution cable network. A small allowance is made for fault repairs annually.

Planned Repairs and Refurbishment

There are no planned repairs or refurbishment scheduled.

Replacement

There are no plans to proceed with any replacement work.

Enhancement

See section 5.4.5 and 5.4.6 - Planning Our Network for details.

Development

See section 5.4.5 and 5.4.6 - Planning Our Network for details.

6.5 Low Voltage Line Assets

These assets include 400V overhead lines and cables used to reticulate electricity to the boundary of consumer's premises where it connects to the service line.

6.5.1 400 V Overhead Distribution Lines

Description

EA Networks uses a conventional overhead low voltage configuration with insulated conductors and wooden crossarms. Aerial Bundled Cable (ABC) construction techniques are not employed. The total length of line in this category is approximately 68km (a decrease of 27km from the previous plan). This quantity has reduced from the last plan through a combination of removal and refinement of ownership for spans that leave an EA Networks pole and connect to a privately-owned pole. These lines are in both urban areas and on the rural roadside. The urban lines will typically be heavier construction with larger conductor and almost always three phases. The rural lines are likely to be lighter and commonly will be only single phase. A significant proportion of the circuit length identified here is likely to be road crossings and the first span leaving the road to service a consumer's property. Despite being dedicated to each consumer, these short spans are all owned by EA Networks as they are fully or partially over the public roadway.

Copper conductor was used extensively until the mid-1970s but was gradually replaced with PVC covered aluminium because of economic and constructability considerations. The last large-scale urban overhead reconstruction was completed in the early 1990s and used PVC covered Weke AAC conductor. Since then, there has been no significant urban LV reconstruction undertaken. The present policy of the EA Networks' Board is to convert to underground cable whenever an urban overhead distribution reconstruction becomes necessary because of the line's condition.

The smaller rural villages and townships of Lauriston, Rakaia, Hakatere Huts, Rakaia Huts and Hinds all have some LV overhead reticulation, much of which is approaching the end of its useful life. Hinds is approximately 75% underground. Mayfield and Mt Somers townships have both been converted to underground in recent years and Chertsey is now complete. The urban underground conversion programme is scheduled to place the remaining township reticulation underground before the end of the planning period based upon condition.

The supply to some of these settlements is via long overhead distribution lines, which is the most significant risk in the overall security to the consumer. Underground conversion has been selectively applied in these areas where it is truly advantageous to all stakeholders. An example of this is at the Rangitata Huts where (with the assistance of EA Networks) the Hutholders' Association organised the conversion of both HV and LV overhead to underground cable (photo below). This solved safety, capacity and reliability issues within the settlement and provided a much more aesthetically pleasing environment.

There is very little truly rural LV network. The majority of this is single spans leaving or crossing the road reserve.

Service Poles

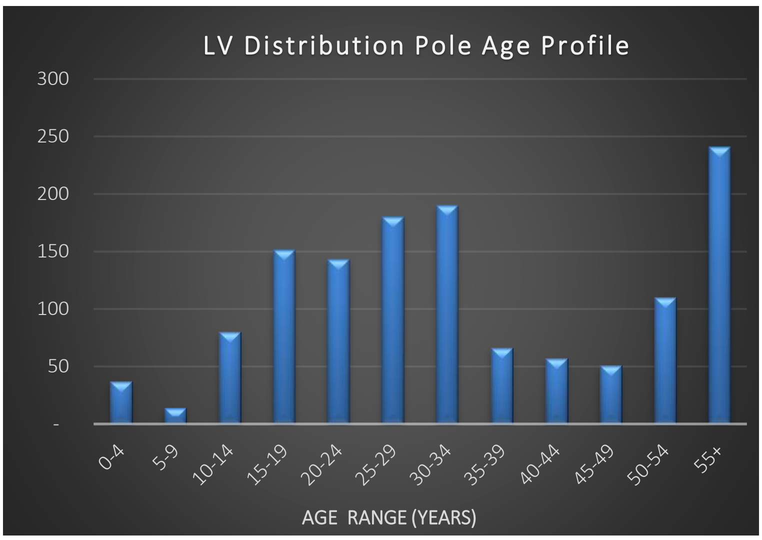
Service lines on consumer's premises are generally owned and maintained by the individual consumers - irrespective of voltage. The only ownership interest EA Networks maintains is in the span leaving EA Networks' network pole (while it is above the road reserve) and poles in the road reserve that only support one or more services. Service poles can be likened to aerial pillar boxes.

Street Lighting

A network of street lighting pilot wires has been run to supply street lighting. These pilots are switched at distribution substations by a ripple control relay that is signalled at dusk (on) and dawn (off). This conductor is typically 16 mm² copper in overhead reticulated areas. EA Networks own 23km of overhead street lighting pilot line. The overhead pilot network is generally as reliable as the other LV overhead distribution and malfunctions/faults are generally caused by clashing wires or a faulty ripple control relay.

There are some cases where EA Networks have converted to underground reticulation and have made available an underground cable street lighting pilot, but the street light owner has chosen not to use it or install new street lighting columns. In these circumstances, the overhead street lighting pilot and supporting poles continue to deteriorate and although EA Networks could remove the pole – it chooses not to. Recent discussion with the street light owner has accelerated the adoption of new street light columns, and lights using the underground street lighting pilot.

Condition



The age-based condition of LV overhead lines is a relatively evenly distributed profile. The distribution represents all LV poles, and these are distributed in both rural and urban areas. The poles less than 15 years old are mostly located in the rural area. Then urban lines are split between much older lines that will be converted to underground within the next ten years and relatively new lines that were rebuilt in the 1980s and early 1990s. These newer lines will generally be in very good condition. The older lines (>40 years) are one of the principal targets of underground conversion. They will typically be smaller conductors with either no covering, or failed covering, that offers little protection against conductor clash or accidental contact. The conversion to underground will eliminate any condition related issues.

The EA Networks policy change to enforce all new network connections be underground has caused a dramatic drop in the number of LV poles under four years old. This will become even more apparent in future years.

The overhead lines constructed over the last twenty years consist mainly of PVC covered All Aluminium Conductor (AAC) or PVC covered hard drawn copper and are in generally good condition.

A few older lines still exist using original braid covered conductor. The general condition of this conductor is very poor and is subject to conductor clashing. In some places insulated spreaders have been used to reduce this problem. It is not intended to prioritise replacing these conductors, as the undergrounding programme will take care of this very soon.

The recently adopted policy that all new connections to the network will be via underground cable will see a gradual reduction in the quantity of overhead LV network although its average age is likely to increase.

Standards

Documentation of the standards presently used for testing, inspection and maintenance of the LV overhead distribution network is still being developed. Construction standards are fully documented, and all new work is audited for compliance.

Maintenance

Inspections, Servicing and Testing

Major inspections were performed during 2007 and 2013. This ascertained the condition of all urban poles including LV and service poles. This data is being used to further prioritise and schedule reinspections and the urban underground conversion effort. In rural townships this data may promote some replacement activity of overhead lines. Rural LV lines are only reinspected if the associated HV distribution line has triggered a visit.

Fault Repairs

The frequency of LV faults on the EA Networks network is very low. This is reflected in the relatively low cost of LV faults overall.

Of the sum allowed for LV faults system-wide, Rakaia takes a slightly higher than average proportion. This is purely age related and reflects the "minor maintenance until converted to underground" approach considered as prudent by EA Networks.

Planned Repairs and Refurbishment

No substantial repairs or refurbishment are proposed during the planning period. Most maintenance work is on an as-required basis.

Replacement

There are no plans to replace any LV overhead network in urban areas during the planning period. Rural areas are likely to have some replacement work completed as part of HV distribution replacement or enhancement work.

Where individual poles are close to failure, in an otherwise sound line, a pole replacement will occur, generally with a pole that matches the remaining life of the rest of the line.

Enhancement

See section 5.4.7 - Planning Our Network for details.

Development

See section 5.4.7 - Planning Our Network for details. The Ashburton District Council's District Plan has rules that make additional pole locations in urban areas a non-compliant activity.

6.5.2 400 V Underground Distribution Cables

Description

As has been already mentioned EA Networks has a significant amount of underground cable and this is increasing as LV overhead lines require reconstruction. The Methven, Chertsey, Fairton, Mt Somers, Mayfield, and Rangitata Huts urban areas are completely underground and approximately 90% of Ashburton is underground by area.

Various cable types were used during early underground installations. This included PVC insulated single solid aluminium core cable. The present standard types are:

Description	Current Rating (amps)	Capacity (kVA)*
3 core 16mm² XLPE copper (standard urban connection)	85	60
3 core 25mm² XLPE copper (larger urban connection)	120	85
3 core 35mm² XLPE copper (pillar box to main cable)	150	107
3 core N/S 95mm² XLPE aluminium (light duty LV distribution)	200	142
3 core N/S 185mm² XLPE aluminium (standard LV distribution)	300	213
4 core 185mm² XLPE aluminium (old standard LV distribution)	300	213
4 core 240mm² XLPE aluminium (heavy duty LV distribution)	360	256

* It should be noted that distribution LV cable circuits are typically limited by voltage drop not thermal rating.

In many cases the ability to supply load with a LV cable is determined by voltage drop rather than thermal capacity. The total distance of LV cable presently installed and owned by EA Networks is approximately 404km. This includes all cable sizes from 16 mm² to 500 mm².

Currently, all new urban subdivisions are reticulated underground as a requirement of the appropriate District Plan. District Plan provisions ensure that no new poles (where one does not already exist) can be located in urban areas. This means that any new urban reticulation is typically underground.

Various roadside boxes are required to complete the LV cable system. These vary in size and are categorised as follows:

- Pillar box — Residential pillar box that can accommodate up to six single phase or two three phase connections,
- Link box — This is typically at a junction in the LV network and provides network reconfiguration capabilities or supplies a larger three phase load,
- Distribution box — This is the largest LV box and can provide up to four 400 amp three phase connections and its typically used in commercial and industrial areas.

The typical configuration of urban LV underground distribution is that a cable will be run on each side of the street in individually fused feeders from a distribution substation. The cables either loop between pillar boxes or are tapped off to pillar boxes that are used to connect the consumer's service cable via fuses. At the end of a cable run, a link box or distribution box will allow interconnection to adjacent LV cables that may be from a neighbouring substation. This arrangement allows reconfiguration to accommodate changes in load or back-feeding during cable failure or distribution transformer replacement.

Box Type	Quantity
Pillar Box	5,264
Link Box	584
Distribution Box	390
TOTAL	6,238

Service Cables

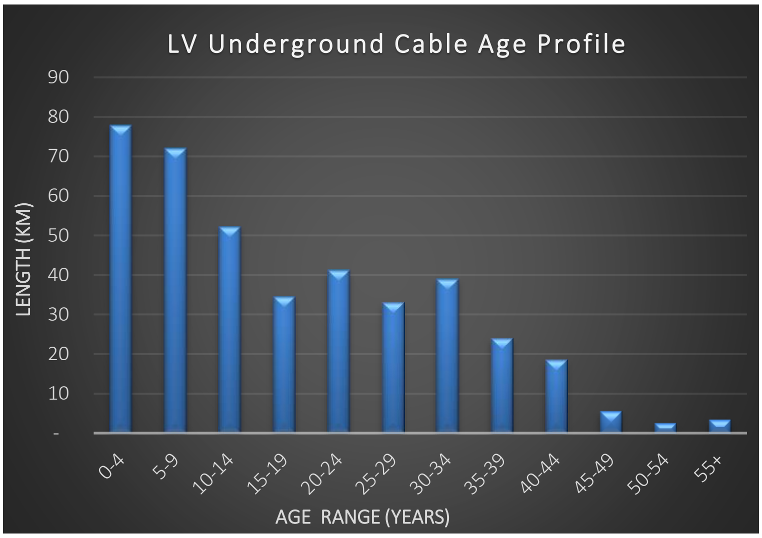
The cable from pillar box to house or business does not always exit directly from the pillar box across the road boundary. Often during underground conversion, the most cost-effective and least disruptive route is along the footpath and then across the boundary. EA Networks retain ownership of the portion within the road reserve. The underground service cable is generally very reliable in the roadside unless excavated by other utilities or contractors. There are no known problems with this portion of the LV network.

Street Lighting

As mentioned above, a parallel network of street lighting pilot cables has been run to supply street lighting. This cable is typically 16 mm² copper neutral screened cable in underground areas. EA Networks own 290km of underground street lighting pilot cable. The pilot cable network is very reliable, and malfunctions/faults are generally at the ripple control relay or caused by third party damage.

Condition

EA Networks has a mixture of early generation PVC and modern XLPE insulated, PVC covered, low voltage cables in the low voltage network. Generally, these are all very reliable excepting some early single core aluminium cables that have a very thin plastic sheath and are therefore prone to mechanical damage from stones etc. These cables only form a small percentage of the total low voltage cable population – less than 2%. It is intended to replace these cables as they begin to fail at an unacceptably high rate.



The age distribution shows the effect of more than 30 years of underground conversion and new urban subdivision. This chart has all EA Networks owned underground cable including small in-road service cables. The underground LV cable system is generally in excellent condition. The exposed parts of the network, such as boxes, can be subject to vandalism and vehicle damage but the frequency of damage is very low and there are no known outstanding condition-related issues.

Standards

Documentation of the standards presently used for testing, inspection and maintenance of the LV underground distribution network is still being developed. Construction standards are fully documented, and all new work is audited for compliance.

Maintenance

Inspections, Servicing and Testing

Inspections of LV boxes, cables up poles and cable terminations are typically only instigated when damage is noticed, or reports of unusual appearance are received.

During 2017-18 a survey of all pillar boxes in Ashburton township was undertaken and a programme of remedial maintenance will be undertaken to resolve a range of condition-related issues. This programme is now complete, and a very low amount of remedial work was necessary.

Fault Repairs

Fault repairs are typically very low in frequency and in many cases are chargeable to the party causing the fault.

Planned Repairs and Refurbishment

There is one historical problem with the LV network in urban Ashburton. The phasing of different parts of the network is not necessarily the same. That is, the "red" phase wire cannot be guaranteed to have the same absolute phase angle as another "red" phase wire in an adjacent substation area. Correct phasing is necessary when using LV ties between substations. Multiple LV links are now labelled "Do Not Operate" because of the phase difference across them. This situation has arisen from the historical lack of LV interconnectivity. The overhead LV network was built in a substation-by-substation manner with no reference to adjacent or absolute phase angle. A survey of phase angle is complete and each Magnefix ring-main unit has been labelled with the known and true, red, yellow and blue phase conductors. This gives all personnel the information needed to correctly connect a standard Dyn11 distribution transformer as HV RYB ABC and LV ryb abc. Work is proceeding to physically correct the phasing both as a stand-alone programme (during periods of reduced workload for high priority tasks) as well as in association with other routine projects or tasks. Good progress continues to be made, and only 5 distribution substation areas remain to be corrected. These remaining areas should be addressed during 2020-21.

No other repairs are planned.

Replacement

There are no plans to replace any significant portion of underground LV network during the planning period.

Enhancement

See section 5.4.7 - Planning Our Network for details.

Development

See section 5.4.7 - Planning Our Network for details.

6.6 Service Line Connection Assets

Description

This asset consists of the equipment used to interface approximately 19,900 connections to the EA Networks distribution network.

The major component of this asset is the service protective device, which may be one of the following:

- 400V re-wireable pole fuse
- 400V HRC pole fuse
- 400V HRC pillar box or distribution box fuse
- 11-22kV drop-out fuse
- 11-22kV disconnector
- 11-22kV circuit-breaker

The service line on the premises of the consumer is owned and maintained by the consumer. There are circumstances where EA Networks will contribute towards consumer owned service lines. One example would be during underground conversion. EA Networks fund the first 20 metres of underground service line conversion onto private property. This ends up in consumer ownership but is a cost against the project and therefore against the LV network assets. Any portions of service line assets on the road reserve are considered EA Networks' asset as a private land owner has no explicit right to own equipment in the road reserve.

Condition

The connection assets are largely in sound order with the most common condition related issue being gradual deterioration of the fuse link as fault current (interrupted by on-property equipment) passes through the fuse. Occasionally, the fuse link carrier may deteriorate through corrosion or thermal (overloading) damage and this is replaced as and when required.

Standards

Documentation of the standards presently used for testing, inspection and maintenance of service line connection assets is still being developed. Construction standards are fully documented and all new work is audited for compliance.

Maintenance

In general, EA Networks does not carry out maintenance on consumer owned service lines unless contracted to do so. These are the responsibility of the consumer to maintain and they can use any competent contractor to do so.

The situations where EA Networks do maintain service line related equipment include:

- replacement of blown service fuses due to faults
- replacement of service poles on the street where these are sub-standard
- repairs to network connection equipment
- repairs to service spans across road reserve (any asset located in the road corridor is assumed to be EA Networks' responsibility unless informed otherwise).

Financial control procedures mean that only approved work is carried out and that the consumer will be required to pay for most work on consumer-owned service lines.

Inspections, Servicing and Testing

There are no scheduled inspections of the LV service asset category.

The Board have indicated that they believe EA Networks are in the best position to offer advice to consumers about their 11-22kV service lines. Consequently, the lines inspector visits private on-property lines to assess them and advise the owner of any remedial work that is required. Currently there is no charge for this inspection. The relatively few HV service lines connected via a circuit-breaker are subject to regular inspection and servicing as per section 6.10. HV EDO fuses connecting HV service lines are examined whenever they are operated.

Fault Repairs

Service lines are generally owned by the end consumer and as such are not maintained by EA Networks. The only maintenance item of note is the occasional replacement of a defective service fuse carrier, cartridge or base.

Planned Repairs and Refurbishment

No repairs or refurbishments are planned.

Replacement

The gradual replacement of re-wireable fuses with HRC types as part of LV replacement projects is expected to reduce the number of premature service fuse failures, which should be reflected in a reduced cost of fault work.

Enhancement

There are no enhancement proposals.

Development

There are no development proposals. It should be noted that all new connections to the EA Networks network are required to be made using underground cable (at all reticulated voltages below 33kV). This will lower the mechanical burden on the service line connections and should decrease further the impact of failed service lines on the EA Networks network.

6.7 *Zone Substation Assets*

Description

Zone Substations are used to transform power from subtransmission voltages of 66kV or 33kV down to EA Networks' standard distribution voltages of 11kV or 22kV.

These substations comprise buildings, switchyard structures and associated hardware, high voltage circuit-breakers, power transformers, instrument transformers, and a multitude of other associated power supply cabling and support equipment. Furthermore, the substations range in size from 5 MVA to 40 MVA and are used to feed all areas of EA Networks' network, thus playing a critical role in the overall reliability of EA Networks' network. Section 5.4.2 shows the location of EA Networks' 21 Zone Substations. Highbank is not shown as it is owned by Trustpower although it both injects winter generation and takes summer pump load. EGN is adjacent to the Transpower 66kV GXP and does not supply any distribution load (although this is planned during 2020-21).

Abbreviations have been used to keep substation descriptions concise. The substations are listed below along with some vital statistics. Note that firm capacity in this context relates to the loss of a power transformer.

Each site has its own unique characteristics that tend to relate to the design and technology at the time of construction. The full details of each site are too much to describe here, but a brief overview follows. The distribution load details in each title line are pre-diversity and non-seasonal. The General category will include a lot of commercial users such as retail, accommodation, dairy sheds and warehousing while the majority is residential. The actual peak load is in the summary description that follows.

Code	Name	Transformer Count	Peak Load (MW)	Sub-transmission Line Security	Firm Capacity (MW)	Firm (Break) Capacity (MW)	ICP Count
ASH	Ashburton 66/11	1 x 10/20 MVA	19	n-1	0	30	5,100
CRW	Carew 66/22	1 x 10/15 MVA	15	n-1	0	9	890
CSM	Coldstream 66/22	1 x 10/15 MVA	13	n-1	0	9	780
DOR	Dorie 66/22	1 x 10/15 MVA	11	n	0	9	430
EFN	Eiffelton 66/11	1 x 10/20 MVA	9	n-2	0	4	450
EGN**	Elgin 66/33	1 x 45/60 MVA	-	n-1	-	-	0
FTN	Fairton 66/22/11	2 x 10/20 MVA	6	n-1	20	26	250
HTH	Hackthorne 66/22	1 x 10/20 MVA	15	n-1	0	9	810
LGM	Lagmhor 66/11	1 x 10/15 MVA	7	n-2	0	6	380
LSN	Lauriston 66/22	1 x 10/20 MVA	15	n-1	0	7	780
MVN	Methven 33/11	1 x 5 MVA	-	n	0	4	0/1,370
MHT	Mt Hutt 33/11	1 x 5 MVA	2	n*	0	2	210
MON	Montalto 33/11	1 x 2.5 MVA	2	n	0	1	300

MSM	Mt Somers 66/22	1 x 10/15 MVA	3	n	0	5	510
	Mt Somers 33/22	1 x 5 MVA	-	n	0	5	0/510
MTV**	Methven 66/11	1 x 10/15 MVA	5	n-1	0	5	1,370
	Methven 66/33	1 x 18/25 MVA	5	n-1	0	5	1,100
NTN	Northtown 66/11	2 x 10/20 MVA	14	n-1	20	30	3,800
OVD	Overdale 66/22	1 x 10/20 MVA	14	n-1	0	10	1,260
PDS	Pendarves 66/22	2 x 10/20 MVA	16	n-1	20	30	420
SFD22	Seafield 22/11	1 x 5 MVA	-	n*	0	5	0/1
SFD66	Seafield 66/11	1 x 10/15 MVA	8	n*	0	10	1/0
TIN**	Tinwald 66 (22/11)	1 x 6/8 MVA	-	n-2	0	10	0
WNU	Wakanui 66/11	1 x 10/15 MVA	13	n-1	0	10	550

n* - these substations are dedicated to one industrial consumer each and security levels have been negotiated with that consumer. SFD22 is essentially hot standby for SFD66.

** EGN and MTV 66/33 do not have any distribution voltages present.
MTV 66/33 supplies MVN, MHT, MSM and MON.
TIN has a 22/11kV transformer present, but it is not loaded under normal conditions.

Ashburton (ASH)	General: 19 MW	Industrial: 4.0 MW	Irrigation: 2.3 MW

This site used to be Transpower's supply point into Ashburton. The site is expansive and well fenced. The 66kV switchyard is well laid out, easily maintained and has new equipment (2016-2019). The 66/11kV transformers are new (2019). The main building dates from the late 1940s but was extended in 2003 to accommodate two 11kV switchrooms. The 11kV load is served from two 11kV switchboards. 11kV feeder protection uses numeric relays. Full SCADA functionality exists. An old 25 tonne gantry crane has recently been removed to eliminate seismic risk. The site currently supplies 60% of urban Ashburton and some outlying areas. The load has a winter peak consisting almost entirely of residential dwellings. Northtown zone substation offers additional switched firm capacity. Total switched firm capacity matches load.

Carew (CRW)	General: 2.3 MW	Industrial: 0 MW	Irrigation: 14.3 MW

A recent 66/22kV site. Two 66kV circuits forming a closed ring serve this site. The 66kV numeric line protection is line differential with backup distance. The site has modern numeric transformer and 22kV feeder relays fitted and SCADA. The site is proving to be low maintenance. The load is summer peaking and irrigation based. The high general demand is a consequence of the large number and size of dairy sheds. Firm capacity exceeds load. The site has a 10/20 MVA and a 10/15 MVA transformer fitted to provide a spare system transformer, more firm capacity to load, and adequate back-feed capacity to adjacent sites (CSM, HTH & LGM).

Coldstream (CSM)	General: 1.7 MW	Industrial: 0 MW	Irrigation: 14.4 MW

A relatively new site that operates at 66/22kV and serves an area that has seen significant growth in irrigation requirements. Two 66kV circuits from a closed ring serve this site. Line distance and differential protection is fitted. Modern electronic relays are fitted, and SCADA is fully operational. Load exceeds firm capacity. The high general demand is a consequence of the large number and size of dairy sheds. The dominant load is irrigation pumps which are summer peaking. A 10/20 MVA transformer is utilised.

Dorie (DOR)	General: 1.8 MW	Industrial: 0 MW	Irrigation: 9.9 MW

This site is compact and originally housed a 33/11kV substation. Rebuilt as a 66/22kV site around 2000, it has a concrete block building and all electrical equipment is new. A single 66kV circuit serves this site. Indoor 22kV circuit-breakers are used. 22kV feeder protection and the 66kV transformer inter-trip signalling has been updated in 2013-14. The site summer peaks with irrigation load. The high general demand is a consequence of the large number and size of dairy sheds. SCADA system installation covers 66/22kV transformer and 22kV feeder protection. Firm capacity via 22kV interconnections exceeds load.

Eiffelton (EFN)	General: 1.7 MW	Industrial: 0 MW	Irrigation: 7.5 MW

Eiffelton site (EFN66) is a newer site with a 66/11 kV, 10/20 MVA transformer, 22kV capable indoor switchboard, numeric 11kV feeder, transformer, 66kV bus, and 66kV line protection. SCADA control is available. The three 66kV circuits that are connected provide excellent security. Firm capacity is slightly below load due to 11kV back-feed limitations.

Elgin (EGN)

A site that is located adjacent to the Transpower Ashburton GXP. This site houses EA Networks' main 66kV supply bus and a large (60 MVA) 66/33kV autotransformer to allow ripple plant signalling on the 66kV network (also previously used to provide security to the 66kV bus). Significant changes occurred during 2012-13 to make the 66kV bus more secure. The 66kV bus has three sections with bus zone protection over each section. There are no distribution feeders currently supplied from this site. Firm capacity and load is dependent on Transpower GXP configuration. Now that all 33kV load has been migrated to the 66kV GXP, the 60 MVA 66/33/12.7kV YNa0d1 autotransformer will be reconfigured as a YNayn0 66(33)/22kV transformer [12073]. This will allow load to be served directly off the EGN 66kV bus which provides some steady state demand relief and significant back-feed capacity to Wakanui, Eiffelton, Ashburton, Northtown, Fairton, and Seafield substations.

Fairton 66 (FTN)	General: 2.6 MW	Industrial: 5.5 MW	Irrigation: 0.1 MW

Fully commissioned in 2017, this is a site that provides capacity for rural residential, industrial, and irrigation load. It supersedes the Fairton 33/11 kV site which was about 100m away. The site has: three 66kV circuits, a 66/22kV 10/20MVA transformer, a 66/11kV 10/20MVA transformer, a 6/8MVA 22/11kV transformer, a 10-way 11kV switchboard in two sections, and a 10-way 22kV switchboard in two sections. The Silver Fern Farm meat-works have ceased production and only the site's cool store facilities are being utilised by a third party with limited electrical demand (~1.5 MVA). The industrial load is non-seasonal but total load peaks in summer with irrigation load. The meatworks and a vegetable processing plant form a base load.

Hackthorne (HTH)	General: 2.5 MW	Industrial: 0 MW	Irrigation: 14.9 MW

A modern site configured for 66/22kV operation. Two 66kV subtransmission circuits are connected in a closed ring. The site has modern numeric relays fitted and SCADA. Full 66kV line protection is fitted (differential & distance). The site is proving to have low maintenance requirements. The load is summer peaking and irrigation based. The high general demand is a consequence of the large number and size of dairy sheds. Maximum load currently exceeds firm capacity. 22kV incomer cables have been replaced to obtain full 20MVA rating from transformer. The recent addition of a three-way switchboard extension has increased the feeder count to six (up from four). Additional 22kV conversion has increased firm capacity, as Mount Somers substation is now operating at 66/22kV.

Lagmhor (LGM)	General: 0.5 MW	Industrial: 0 MW	Irrigation: 7.1 MW

This site was developed in 2006. 2012 saw conversion from 33/11 kV operation to 66/11kV operation. During late 2012, the site was converted to 66/22kV operation. Three 66kV subtransmission circuits are connected which gives excellent security. A 10/15 MVA transformer is relatively lightly loaded although feeder reconfiguration has increased this and relieved Hackthorne substation somewhat. Numeric 22kV feeder and transformer protection is installed. 66kV bus differential and full 66kV line protection is installed. Indoor 22kV vacuum circuit-breaker switchboard. Fibre-optic communication gives full SCADA facilities. Firm capacity exceeds maximum load.

Lauriston (LSN)	General: 4.0 MW	Industrial: 0 MW	Irrigation: 15.6 MW

Rebuilt in 2000 and now operating at 66/22kV. The site was established in the 1980s anticipating a surge in irrigation demand that didn't arrive until ten years later. Two full capacity 66kV circuits offer n-1 security. Load has seemingly reached a plateau with limits on new water extraction. Irrigation pumps are large in this area due to depth of wells (200m+). SCADA system is operational on most relays. Maximum load exceeds firm capacity. Summer peaking due to irrigation demand. The high general demand is a consequence of the large number and size of dairy sheds. Recent 22kV conversion has largely secured most load. The conversion of the 66/33kV transformer at Methven to 66/22kV (project [00495]) will secure all distribution load. A 10 MVA 22/11kV transformer has been installed at Methven to increase switched firm capacity to both sites.

Methven33 (MVN)	General: 0 MW	Industrial: 0 MW	Irrigation: 0 MW

A site that was developed on the edge of Methven to offer reliable service to this tourist village. Chalet style A-frame building houses problematic 11kV switchgear and a 33kV ripple plant. Outdoor 33kV switchgear in a compact pole-mounted arrangement. SCADA system fitted but not fully functional. Currently available as a hot-standby to Methven 66/11kV substation. Scheduled for decommissioning during 2020-21. The site may be retained as a remote storage and backup network control centre facility.

Methven66 (MTV)	General: 5.0 MW	Industrial: 0.2 MW	Irrigation: 1.4 MW

A site that was established as part of the initial 66kV ring development and Highbank generation embedding. Three 66kV lines terminate at this site, two of which are high capacity alternatives. The third (radial) circuit serves Highbank power station. This site serves as a 66/33kV transformation to supply Methven33, Mt Hutt, Montalto Hydro, Montalto and Mt Somers substations. There is also a 66/11kV transformer, which offers Methven township n-1 levels of security on an entirely underground 11kV network. Load is winter peaking as a consequence of tourist/skiing influx and residential/commercial predominance. SCADA system is fully functional. Firm capacity of 11kV exceeds maximum load. 33kV firm capacity is zero. All 33kV switched firm capacity is via the distribution network. The 18/25MVA 66/33kV transformer will be converted to 66/22kV operation in 2021 [-1082] and a 5MVA 22/33kV unit will provide the supply to Mt Hutt 33/11kV substation.

Montalto (MON)	General: 0.5 MW	Industrial: 0 MW	Irrigation: 1.3 MW

This site has been in service for a few years. It is currently a temporary substation located near the Montalto hydro power station. If more irrigation water becomes available, a future project will possibly construct a brand new Montalto 66kV substation at a permanent site about 3 km away (Project [513]). The new substation is dependent on new irrigation load occurring. If significant new load does not occur the new substation construction will be delayed.

Conversion of the surrounding distribution network to 22kV will make this substation redundant in 2025.

Mt Hutt (MHT)	General: 0.4 MW	Industrial: 2.6 MW	Generation: 0.1MW

A 1980s site with indoor SF6 11kV switchgear and a compact outdoor 33kV bus arrangement for the single incoming 33kV underground feeder. Small concrete block building. Fully functional SCADA system using digital microwave link. Load peaks in winter associated with ski-field activities. Maximum load exceeds firm capacity. Zero irrigation. Cleardale hydro generation is connected at 11kV. Modern numeric protection is fitted. Switched firm capacity is sufficient for essential services of the major consumer. Any increase in security is by negotiation.

22kV conversion will increase switched firm capacity in 2026.

Mount Somers (MSM)	General: 1.7 MW	Industrial: 0.7 MW	Irrigation: 1.6 MW

A 1970s site with one 66kV circuit and one 33kV circuit (insulated at 66kV). The 33kV circuit supplies Montalto substation and Montalto Hydro. New 66kV switchyard. Fully functional SCADA system. Maximum load matches firm capacity. A new building has been constructed and a new 22kV switchboard has been commissioned along with modern transformer and feeder protection. Fibre-optic is connected. A 66/22kV 10/15 MVA transformer is installed, and a 33/11kV 5/10 MVA transformer in conjunction with an 11/22kV 5MVA autotransformer provides 5MVA of n-1 hot standby. The load is balanced between extensive rural farms (many non-electric irrigated), Mt Somers township, and a couple of lime quarries. The load is slightly summer peaking due to the irrigation but remains close to the summer peak during winter due to the residential demand. There is scope for additional irrigation load to occur on this site if more water is made available from the RDR. The second 66kV circuit will be commissioned in 2024.

Northtown (NTN)	General: 14MW	Industrial: 2.6MW	Irrigation: 0.8 MW

A site completed in 2006 that is operating at 66/11kV. Two 66kV subtransmission circuits supply an outdoor 66kV switchyard. Two 10/20 MVA 66/11kV transformers. The 11kV switchgear is configured as two switchboards, each with a bus-coupler and two incomers, in two separate rooms giving four bus sections with one incomer and four outgoing feeders on each section. Modern numeric protection relays and SCADA. This site is intended to complement Ashburton (ASH) substation providing additional capacity and security to Ashburton township and immediate surrounds. Firm capacity exceeds maximum load. Load is winter peaking in line with residential demand.

Overdale (OVD)	General: 5.0 MW	Industrial: 0.3 MW	Irrigation: 14.8 MW

A site constructed in 2004. Two full capacity 66kV circuits offer n-1 security. The site has a 10/20 MVA transformer (upgraded in 2014), indoor 22kV vacuum circuit-breaker switchboard, modern numeric relays fitted and SCADA. The site is exhibiting low maintenance requirements. The load is summer peaking and irrigation based, although Rakaia township with its residential/commercial demand causes higher base loads than some other irrigation-serving substations. Firm capacity exceeded by maximum load. New FTN 66/22kV substation has increased switched firm capacity.

Pendarves (PDS)	General: 1.6 MW	Industrial: 0.2 MW	Irrigation: 17.5 MW

Two full capacity 66kV circuits offer n-1 security, a third offers limited back-feed ability. A fourth 66kV radial circuit feeds Dorie substation. All modern equipment with a newly replaced/enlarged building. Outdoor 66kV bus and circuit-breakers. New 22kV circuit-breakers. Irrigation load causes this site to summer peak at 10 times its winter peak. Full SCADA system functionality. Firm capacity is available to all load as the site has two 10/20 MVA transformers (one of these is considered as the system spare). Project underway to provide fire barrier between the two 66/22kV transformers.

Seafield (SFD22 & SFD66)	General: 0 MW	Industrial: 8.0 MW	Irrigation: 0 MW

These sites are dedicated to Canterbury Meat Packers meat-works. SFD66 is a new site separate to SFD22 and is supplied from a single “T” connected 66kV line. A single 66/11kV 10/15 MVA transformer normally supplies the industrial load via one of two 11kV incomers at SFD22. A concrete building with the facility for indoor 11kV switchgear. One outdoor 11kV circuit-breaker feeds a 500amp capacity overhead line to SFD22. Maximum load exceeds firm capacity (contracted terms imply limited backup capacity). At SFD22, a single 22kV line feeds onto an outdoor bus via an outdoor circuit-breaker. From there it passes into a 5MVA 22/11kV autotransformer and then into the second 11kV incomer. The indoor 11kV switchgear feeds into a consumer-owned cable network. Concrete block building. Non-seasonal peak load. Limited SCADA system to permit switching load between SFD22 and SFD66.

Tinwald (TIN)	General: 0MW	Industrial: 0 MW	Irrigation: 0 MW

A site commissioned in 2017 to provide 66kV switching and 22/11kV transformation between the 22kV rural area and the 11kV urban area using a 6/8MVA transformer. 6-way 22kV indoor vacuum switchboard, 9-way 11kV indoor vacuum switchboard, numeric 66kV line, 66kV bus, transformer, and feeder protection relays. Facility to accommodate a 66/22kV and a 66/11kV transformer in future. 22/11kV transformer operated in hot standby mode (capable of supply in either direction).

Wakanui (WNU)	General: 2.5 MW	Industrial: 0.2 MW	Irrigation: 10.1 MW

66/22kV site with a summer peak load. Is unique in the EA Networks network as a split-level site. Two full capacity 66kV lines serve a single 10/15 MVA 66/22kV transformer and 22kV indoor vacuum switchgear. The site has modern numeric relays fitted and SCADA. Firm capacity is insufficient to secure all load. Additional 22kV conversion will progressively increase firm capacity. Elgin 66/22kV reconfiguration (project [12073]) will increase switched firm capacity.

Power Transformers

EA Networks has 26 power transformers (23 x 66kV and 3 x 33kV primary voltage) installed at its Zone Substations, (as opposed to distribution transformers, which are used in distribution substations). There are 11 other units in storage awaiting reuse or disposal.

All the power transformers are three phase units fitted with on-load tap-changers. A mixture of tap-changers have been used, including:

- Easun MR (Reinhausen)
- MR (Reinhausen)

- Ferranti
- ATL
- Fuller
- ABB

Oil Containment

Oil containment facilities have been installed at all major substations constructed since 1991. The only site not to have a bunded containment is Mt Hutt Substation. EA Networks' policy is to install these facilities at all new sites where single vessels contain 1,500 litres or more of mineral oil and at existing sites where there is a risk to the environment.

Other Equipment

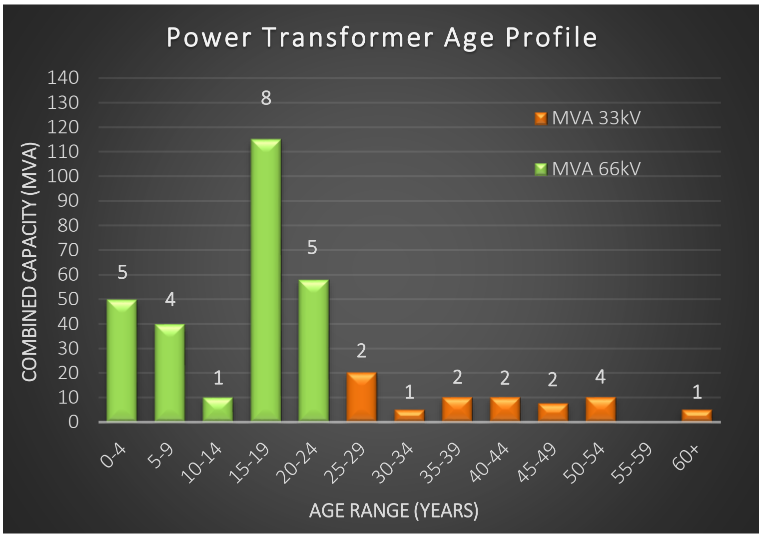
Three revenue energy meters owned by EA Networks are installed at Transpower's Ashburton220 substation (one on each supply transformer) and these are used as "check" meters for comparison with Transpower's meters. The only other energy meters installed on the network are principally used for power quality monitoring at zone substation bus distribution voltages. EA Networks do not own or operate any power factor correction equipment at any voltage.

Condition

The 21 zone substations that EA Networks operate range in age from brand new to almost 35 years old. The new sites are obviously in excellent order while older, smaller, sites such as Mt Hutt (MHT) are beginning to reach the point where maintenance is increasing.

Transformers

The population of zone substation power transformers are generally in very good order. A proportion of the units could be said to have entered middle age, and, like anything in middle-age, it pays to monitor certain critical parameters more closely. Dissolved Gas Analysis (DGA) has allowed EA Networks to monitor the internal condition of its power transformer population and demonstrate that, in general, there is little evidence of accelerated insulation ageing or deterioration. The age chart clearly shows the younger and larger 66kV transformers versus the older and smaller 33kV transformers.



Four smaller (2.5 MVA) 33/11kV units, manufactured by ECC in the mid-1960s, have all been de-tanked after a design flaw was exposed as a result of an 11kV fault. No major damage was done (an exposed tertiary inter-phase conductor had touched the tank) and some minor corrective engineering achieved an acceptable solution. While de-tanked, the core and winding clamps were tightened and a general internal wash (with clean oil) refurbished the units. None of these units is currently in service, and they are awaiting disposal. With the conversion to 66kV at some sites, several 33/11kV units have been taken out of service and been relocated to other sites facing increased loading or the existing transformer reaching end of life. Some transformers are currently in storage awaiting commissioning, redeployment or disposal.

Oil Containment

All oil containment bunds installed at Zone Substations are in excellent condition. Some of the bund field drains have become clogged with detritus from bird's nests and leaves. These will be renovated and are likely to be converted to the more modern surface drain type permitting much simpler maintenance. EA Networks have trialled polymer filter devices to allow direct drainage of stormwater from the bund without a normally closed valve. Unfortunately, they appear to be prone to clogging with dust and detritus which makes them impermeable. These units have been returned to manually operated gate valves.

Other Station Equipment

Batteries at all stations are now monitored with portable specialist equipment and analysis of the data obtained has kept the batteries in good order. HV switchgear is considered in section 6.10 and protection in section 6.12.

Standards

Documentation of the standards presently used for testing, inspection and maintenance of zone substations is still being developed. Construction standards are fully documented, and all new work is audited for compliance.

Maintenance

All Zone substations are routinely inspected, tested and maintained regularly in accordance with EA Networks' standard requirements. Maintenance is categorised as either minor (non-invasive) or major (invasive). Visual Inspections are categorised as minor.

Inspections, Servicing and Testing

Visual Inspections

All Zone substations are visually inspected monthly as a minimum, increasing to fortnightly during high load periods. Visual inspections incorporate the checking of oil levels, voltage regulation, switchgear condition, battery test and security. A detailed report is made of load and equipment operation. This information is used to assist with forward planning and maintenance.

Battery Banks

While the modern battery is considered virtually maintenance free, high importance is placed on the reliability of substation batteries, as many of the new protection devices are reliant on stable DC supply for correct operation. Batteries and chargers are visually examined at each monthly inspection and every three months a non-intrusive battery impedance test is carried out and recorded for comparison with previous values. Regular analysis of the trend can used to determine battery replacement criteria.

Many sites have dual battery banks to guard against individual cell failure causing loss of protection functions. Dual battery banks are standard at new sites.

Infrared Camera Thermal Inspection

Inspections using a sensitive thermal infrared digital camera are carried out on most equipment on at least an annual basis.

Ultrasonic

Ultrasonic outdoor inspections are performed bi-annually to detect high levels of discharge.

Partial Discharge

Partial discharge testing is performed on indoor equipment on a bi-annual basis. This technique is used selectively where certain switchgear/bus components are known to present a risk or represent a security hazard.

Other Station Equipment

Other switchyard equipment such as local service transformers, surge arrestors, cables, etc is maintained as necessary when the associated circuit is taken out of service.

Power Transformer Testing

As part of EA Networks' maintenance programmes all major power transformers have an annual minor maintenance service which encompasses a visual inspection, routine diagnostic tests and minor repair work in accordance with EA Networks standards which incorporate manufacturers' recommendations and EA Networks' experience.

In general, maintenance on the transformers consists of maintaining oil within acceptable dielectric and acidity standards, patching up corrosion, fixing oil leaks, annual diagnostic tests on the insulating oil, and a suite of standardised diagnostic tests using a recently purchased high voltage/current test set. In addition, the units fitted with oil-switched on-load tap-changers require periodic (4 yearly) inspection of the tap-changers and the contacts are dressed or replaced as necessary during the annual maintenance. Additional remedial work required outside the scope of the maintenance standard is referred to the asset management team for further action, which is budgeted as repairs and refurbishment.

Oil Testing - Dissolved Gas Analysis

For two decades, all Zone Substations have had annual dissolved gas analysis tests carried out and this has helped identify potential problems that need monitoring. A baseline Dissolved Gas Analysis (DGA) test was carried out on most power transformers in 1996 (the remainder in 1997). Trends revealed by this analysis give some indication of internal condition. After a period, the frequency of testing may be reduced on units showing no discouraging trends.

Costing for minor maintenance is very dependent on location and based on historical maintenance expenditure.

Costing for major maintenance, i.e. on-load tap-changers, is not only dependent on the location of the site but also the usage and types of unit and is such that some units are scheduled to be serviced every four years and others (vacuum switched units) only when operation count exceeds manufacturer's recommendation.

Fault Repairs

Equipment failures tend to occur randomly and generally without warning and range from a simple battery failure or a faulty resistor, to a costly transformer winding failure. The cost budgeted is the cost to restore supply or the service following the failure, not the cost of any repair work after supply or service has been restored.

The projected expenditure is based on actual expenditure incurred in recent years. It is not practicable to allocate projected expenditure against each substation asset category given the range of faults which can occur.

Planned Repairs and Refurbishment

This area of expenditure includes corrective work identified during inspections and tests while undertaking routine maintenance or following equipment failures. The magnitude of costs can vary significantly.

Planned expenditure also includes the cost of materials and spares.

Power Transformers

Major causes of power transformer failures to date have been winding, internal connection faults and on-load tap-changer mechanism failure. No faults to power transformers have been caused by lightning to date, however, surge arrestors are installed at all zone substations as a precaution.

The other major internal maintenance on a power transformer is oil refurbishment, which is carried out as required based on oil acidity and moisture test results. It is not expected that this will be required on any EA Networks units within the planning period. Some older transformers do require regular maintenance for oil leaking around radiator connection fittings. This work is usually combined with other maintenance such as painting.

Repainting

Painting is carried out on a regular basis at a period of generally between 10 to 15 years depending on site conditions. It is planned to paint approximately 0.5 site/transformer per year over the period 2021 - 2030.

General

The general condition of most zone substation sites is good to excellent. Having been recently rebuilt as 66kV sites nearly all sites are to a modern standard and older sites have been decommissioned.

Replacement

There are no plans to replace any of the existing power transformers during the planning period based on the age and condition of the units. The recent 66kV subtransmission expansion has introduced a significant number of newer transformers (less than 20 years old) that help decrease the average age of power transformers. Within the plan horizon, planned 66kV development will ensure all older transformers are retired from 33kV service and any that remain in alternative applications will have suitable replacements available.

The 33kV transformers that are significantly older than 40 years are likely to be scrapped. Newer 33kV transformers will be either kept as spares or sold. The 33/11kV units available for reuse will provide an opportunity to decrease the average age of 33kV transformers. A few of these 33/11kV transformers will be investigated for reuse as 11/33kV step-up transformers (MTV and MSM) and spares.

Regardless of whether a pre-emptive replacement programme is undertaken, it seems likely that the oldest units will fail at an increasing rate in future, and this will force replacement. Provided sufficient diagnostic tests are undertaken to identify imminent failure and provided some suitable spare units are available, this should not lead to a noticeable decrease in consumer supply reliability and could be a cost-effective replacement strategy option.

Enhancement

See section 5.4.3 - Planning Our Network for details.

Development

See section 5.4.3 - Planning Our Network for details.

Disposal

When zone substation equipment becomes surplus to requirements it is either scrapped in a commercially and environmentally appropriate way or, if it is saleable, it will be offered to other electricity network companies. Should a serviceable unit not sell it is likely to be stored for use as spares or until it is certain no third parties are interested at which point, depending upon the value of the item, consideration will be given to selling the item as scrap.

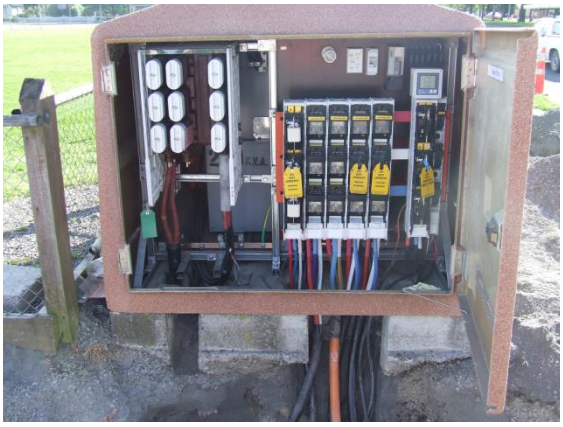
Zone substations represent some of the larger single location land holdings of a network operator and there have been occasions where some site rationalisation has occurred. It is typically impractical to offer the result of small boundary adjustments to anyone other than the adjacent land owner. Each situation is treated on its merits. Should an entire site require disposal, a real estate company would value it then market it.

6.8 Distribution Substation Assets

Description

Pole-mounted substations generally consist of a distribution transformer (defined elsewhere) and associated equipment including:

- 11 or 22kV Drop Out Fuses
- Surge Arrestors
- Low Voltage Fuses
- Support Crossarms



In addition to these items, larger substations rated at 100kVA or 150kVA will often have the following additional components:

- Galvanised Steel Cantilever Platform
- Maximum Demand Indicator

Distribution Substation Type	Quantity
Ground-Mounted	1,900
Pole-Mounted	4,605
Autotransformer/Regulator	7

In some applications, transformers as large as 300kVA have been placed on a pole-mounted platform consisting of two poles with broad beams between them, upon which the transformer sits (this is no longer done for reasons of seismic security and the borderline economic advantage of pole mounting). Any new pole mounted transformers (maximum 100kVA) reside on one pole only.

All new substations greater than 100kVA use pad-mounted construction, where the transformer is placed on the ground. One such site is shown above. The EA Networks Board have adopted a 'New Connections and Extensions Policy' that requires all new connections to the EA Networks network to be via underground cable at less than subtransmission voltages. In addition, the policy requires that all new on-property transformers are ground-mounted. This means that the only new pole-mounted substations are those that are established on EA Networks owned poles on the rural roadside and are less than 150kVA capacity.

Generally, EA Networks provides the recoverable substation assets without a capital contribution from the consumer. This policy has caused a significant increase in the number of ground-mounted substations.

Extra assets required for ground mounted substations usually include:

- Concrete pad
- Fibreglass or steel cover
- HV and LV Feeder Cables
- HV ring main unit (when part of a cable network)
- DIN LV Fusegear
- Anti-ferroresonance capacitors (when single phase switched at a distance) or three-phase remote switching
- Land purchase or easement.

Condition

The condition of these assets covers the whole range from needing replacement to brand new. The assets in need of prompt replacement are generally either smaller, very old, rural sites or urban sites built on platforms between two poles. Very few remain in urban settings and they will be replaced with a pad-mounted site. The small rural sites will be prioritised for refurbishment.

The volume of transformer replacement and upgrading caused by load growth has ensured that most substation sites have been at least proven mechanically sound during the last 15-20 years.

Standards

Documentation of the standards presently used for testing, inspection and maintenance of distribution substations is still being developed. Construction standards are fully documented, and all new work is audited for compliance.

Maintenance

Inspections, Servicing and Testing

All distribution substations are required to be tested every five years for safety reasons in accordance with the Electricity Regulations. At the same time, the general condition of the transformer is checked, and an oil sample may be taken to monitor the internal state of the unit.

Fault Repairs

Lightning damage, pole failure or ingress of water causes most transformer faults.

Regular inspection of transformers and covers reduces the number of failures due to water ingress caused by deterioration such as rusty tanks as these are clearly obvious to the naked eye.

Pad-mounted substations have relatively few faults and usually the substation itself is not damaged (other components such as transformers or HV and LV switchgear tend to be at fault).

Planned Repairs and Refurbishment

There are very few substations that are known to be needing repairs or refurbishment. Those that are will be attended to under a general repair budget set aside for this and other minor repairs.

Replacement

The urban underground conversion programme will often revisit substations that were first installed in the 1960s or earlier. These tend to be either pole-mounted on a platform (not suitable for underground conversion) or "tin box" style units that cannot accommodate the modern style of HV and LV switchboards used by EA Networks. The result is a rebuilt substation that has the same capacity but is dramatically more flexible/functional and achieves much higher levels of operator and public safety.

Enhancement

See sections 5.4.4, 5.4.5 and 5.4.6 for details.

Development

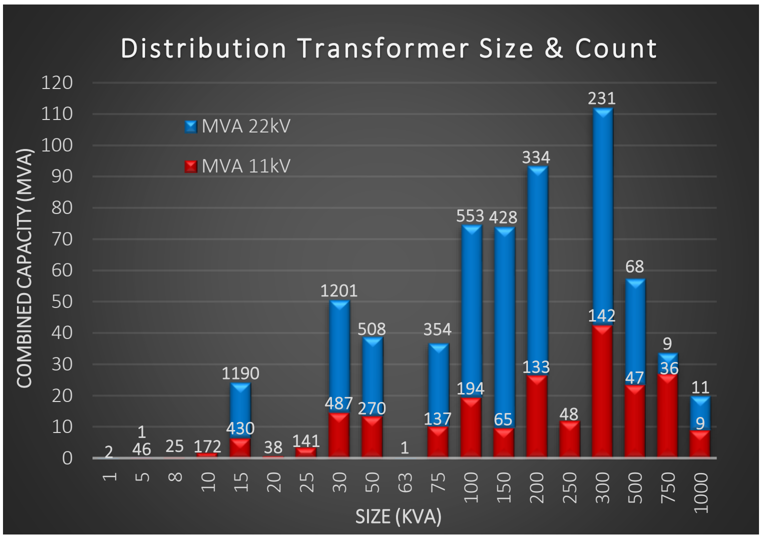
See sections 5.4.4, 5.4.5 and 5.4.6 for details.

6.9 Distribution Transformer Assets

Description

Distribution transformers come in a variety of forms suited to particular applications. Many small transformers (<75kVA) are mounted on a single pole by a hanger bracket and suited to rural situations such as a farmhouse, dairy-shed or workshop. A significant proportion of these small transformers will in future be mounted on the ground in accordance with EA Networks' 'New Connections and Extensions Policy'. Modern low-maintenance specifications require galvanised steel tanks supplied as standard for all pole-mounted distribution transformers.

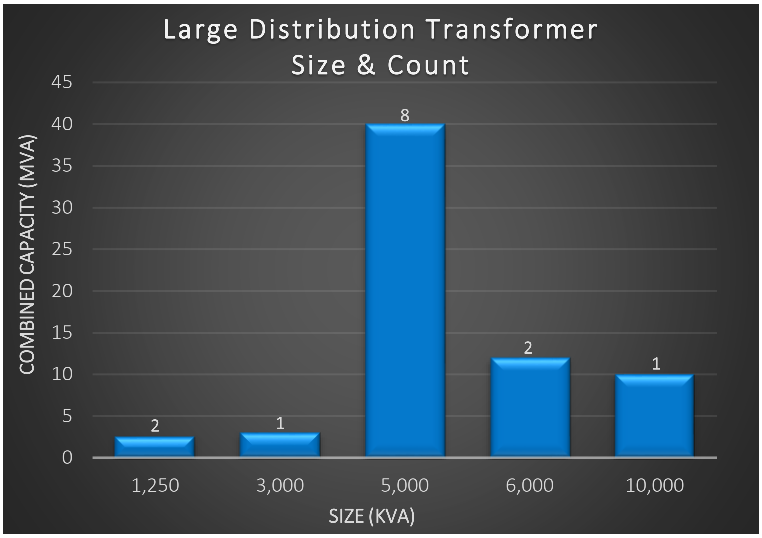
Larger distribution transformers take a similar form when they are designed for pole mounting (up to 100kVA), but tend not to have hangers, as the mass is too great for a single crossarm. All new transformers larger than 100kVA are now ground mounted to ensure adequate seismic security and immunity to pole condition. When the transformer is designed for ground mounting there are several options, of which EA Networks has at least one example of each. EA Networks' standard specification for transformers has facilities to fit HV and LV cable boxes and wall mounted HV bushing wells (which allow screened cable termination elbows to be connected). The lid is fitted with outdoor porcelain bushings as standard and these are removed and blanked-off when ground mounting is required. Other types of transformers in use include pre-packaged "mini-subs" which have integral equipment cubicles at each end and specialist kiosk mounting units which have the HV and LV bushings adjacent to each other on one wall of the tank.



All new ground-mounted transformers are fitted with in-tank HV fuses. These allow multiple transformers to be installed on an underground cable without the need to consider individual fault rating or fuse operation (no shared fuses) causing ferroresonance issues.

The chart above shows the total MVA of each different standard transformer size and the number of each. The chart excludes regulators and autotransformers.

Extra-large distribution transformers are those that operate at distribution voltages on both primary and secondary. Examples of these in use at EA Networks are a 3MVA 11kV regulator, eight 5MVA 11/22kV autotransformers (several containerised), and two older 1.25MVA 11/22kV transformers. There are also three 6-10MVA dual-wound 22/11kV transformers permanently located at zone substations. These transformers are designed, constructed and operated in a similar fashion to "large" ground-mounted distribution transformers and hence they are covered by this description. A regulator was used on only one portion of the 11kV network. After conversion to 22kV, the regulator has now been recovered and is awaiting redeployment, sale, or scrapping. 11/22kV autotransformers are used at locations where the 11kV network and 22kV network meet mid-feeder or at zone substations to provide a source of 22kV or 11kV depending on the substation bus voltage. Low impedance, bi-directional power flow (maintains neutral earth reference), portability (housed in 6 metre shipping containers with cable connections), and low losses are some of the appealing features of the autotransformers. There are 67.5MVA of 11/22kV transformers and 11kV regulators on the network, all of which are in good order.



The tanks of most distribution transformers have in recent times been supplied with bolted lids. This is important, with widespread use of in-tank fuses. All units have an off-load tap-changer with a boost capability of 7.5% and a buck capability of 2.5% to account for heavy voltage regulation.

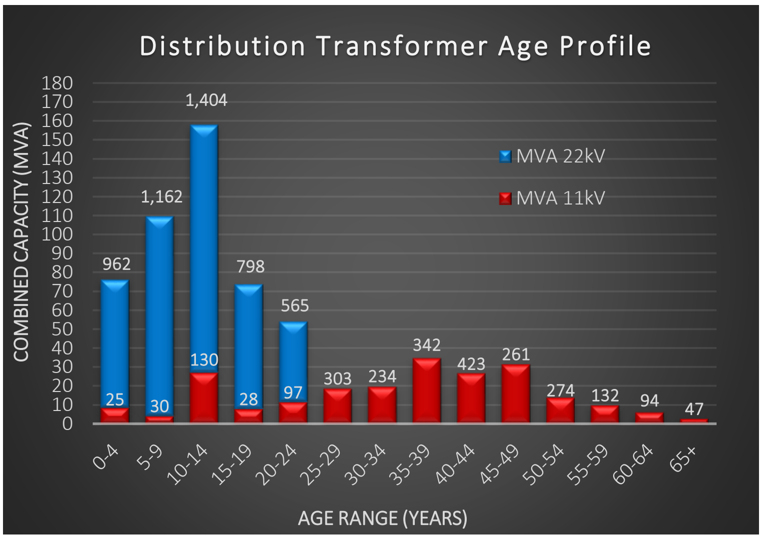
All substation data including servicing records are stored in the asset management system. This system will include links to the GIS, which can locate substations and electrically trace upstream to feeder circuit-breakers or downstream to consumers (ICP's) for the purposes of outage notices and fault statistics.

Condition

In the past three decades, and particularly in recent years, EA Networks has purchased significant quantities of distribution transformers at both 22kV and 11kV. The main driver for this either directly, or indirectly (via 22kV conversion), is the growth in load. A population of transformers with low average unit age of 20 years (average kVA-weighted age is 19 years) is a relatively low fault and maintenance asset. The average transformer size is about 87 kVA.

There are a number of transformers that are very old, and these are normally retired when they either fault or are removed from service for other reasons. It must be said that many of the older transformers were built to last and consequently they have a longer life expectancy than the newer units.

The total population of in-service distribution transformers numbers 7,310 (6,734 previous plan) and the combined capacity is 634 MVA (579 MVA previous plan). There are a large number of transformers in storage either ready for service or ready for assessment/servicing.



Many of these are related to 11kV to 22kV conversion work. These stored transformers are now included in the age profiles.

Standards

Documentation of the standards presently used for testing, inspection and maintenance of distribution transformers is still being developed. Purchasing specifications are fully documented, and all transformers are inspected for compliance.

Maintenance

The population of distribution transformers covers a diverse range of sizes, types and ages. As such, it is important that a comprehensive management plan is put in place, as the condition of the asset is not always easily discernible on a population-wide basis.

EA Networks' policy is to extend the life of distribution transformers where this is economically feasible. In support of this policy, many distribution transformers run well below their rated values for much of the time, resulting in long lives for the cores and windings. Provided that the tanks and oil are well maintained, the overall unit may be kept in service for up to 55 years or more. In this way, the maximum return can be leveraged from these high value assets.

Inspections, Servicing and Testing

Smaller pole-mounted distribution transformers are regularly inspected on a rolling five-year basis in conjunction with EA Networks' substation earth testing programme.

The inspection includes checks for

- tank corrosion
- paint chips
- breakdown
- oil leaks
- insulator damage
- breather condition (where fitted)
- termination faults

Where possible, the oil level is checked and recorded and if an oil sample valve is available (standard issue on all new transformers), a sample of the oil is taken and checked for dielectric breakdown.

Larger pole-mount and all pad-mount units have Maximum Demand Indicators (MDI's) which are read every 12 months. This indicates loading trends to be monitored and that allows for early intervention should a unit become overloaded.

Very large transformers in areas such as the CBD of Ashburton or industrial sites such as ANZCO have annual thermograph surveys carried out to check the tank and termination temperatures as well as to identify any other potential hotspots.

Any indications suggesting that the transformer requires attention results in prompt on-site repairs, or if this is not possible, the transformer is swapped with a spare unit from the store and sent back to the transformer workshop for refurbishment.

Fault Repairs

A lot of the faults in distribution transformers are caused by lightning damage. Because of the regular inspection and servicing carried out, it is very rare for a unit to fail because of old age or deterioration.

Most faults are handled by swapping the transformer with a spare and sending the damaged unit back to the transformer workshop for inspection and repair – or scrapping if the damage is too severe.

An exception to this is bushing faults on large units - where the bushing can be easily repaired or replaced on site.

A result of 11kV to 22kV conversion is that many 11kV transformers are returned into stock. Some of these units have reached the end of their useful life and they are scrapped. The remainder are either sold or refurbished for use elsewhere on the distribution network.

EA Networks have a limited stock of “emergency spares” which are used only under the circumstances of unexpected failure. A single dual voltage (22-11kV), 1,000kVA unit covers all pad-mounted situations and is equipped with 15m flexible HV and LV cables to permit installation adjacent to the failed unit.

Planned Repairs and Refurbishment

Repairs can range from a minor paint touch-up on earlier painted units through to insulator repairs and bolt replacements. Refurbishment may include oil changes, rewinds and even tank replacements.

Rewinds are only attempted on relatively modern units where modular replacement windings are readily available.

Tanks are often subject to corrosion, especially in the case of older painted units. At the same time however, the internal core and windings may be in excellent condition. For this reason, tanks are often repaired or replaced if the unit is otherwise in good condition.

Each unit is assessed on its age, loss characteristics, condition, and service history in determining whether to repair or replace the unit.

Oil refurbishment is planned for up to 100 distribution transformers per year.

Generally, it is necessary to refurbish a transformer’s oil initially after a 25-year period then approximately every 10 years which, with EA Networks’ in-service distribution transformer population, means oil refurbishment will be required on a number of units throughout the planning period. With an estimated life of 55 years, this means each transformer will have its oil refurbished at least 3 times in its life.

It is expected that in the future, because of the high-quality requirements for the insulating oil in transformers now being purchased, the initial and following periods to oil refurbishment will be less than the afore mentioned 25 and 10 years.

Replacement

Very old transformers that require extensive refurbishment or transformers that have been extensively damaged due to say a lightning strike are often replaced rather than repaired. This is a purely economic decision.

All replacement units are purchased to EA Networks’ specifications, which prescribe galvanised tanks, stainless steel fixings and oil sampling valves to minimise the cost of future maintenance.

The 22kV conversion programme ensures that a steady flow of used 11kV transformers return to stock. This is in addition to those units that have failed because of old age or lightning damage. The transformer technician individually assesses each transformer when returned to the store and estimates the likely cost of repair and subsequent life. A spreadsheet is then used to make an appropriate economic decision to scrap or repair the unit.

This economic decision-making process is a means of prudently managing the asset and ensuring that an appropriate age profile is maintained. The asset management system records all available information about transformer condition and history. This data will be used in future plans as a maintenance cost projection technique.

Enhancement

Occasionally, the need arises for a pad-mounted cable box style of transformer. The EA Networks distribution transformer specification allows for conversion of a pole-mounted unit 150kVA or larger to a pad-mountable arrangement. The cost of doing so is typically $500-$600. This capability is used regularly but this work is done on demand rather than as a planned activity. While this is being done, in-tank HV fuses will be retrofitted.

A standard seismically designed precast concrete foundation pad is now in use for all uncovered ground mounted distribution transformers. These pads allow very accurate location of holding-down bolts cast into the pad. All transformers larger than 100kVA that are cycled through the store for reuse are modified to accommodate the standard mounting template. This process ensures that all transformers will over time adopt a rigorously designed and standardised hold-down arrangement.

In some cases, the rehousing of the core and windings of smaller (<100 kVA) pole-mounted transformers in good condition into new ground-mounted tanks is viable. This is only commercially feasible because of the recent increase in price of the materials that are used in the core and windings. The value of the New Zealand dollar also impacts the economy of this approach.

Other than this capability, little enhancement work is carried out on distribution transformers, as these are essentially a standard module, with no capacity for upgrading.

Development

EA Networks provide most distribution transformer assets as part of the network line charging mechanism. Any new development of note will require a suitable transformer. The 22kV conversion projects have liberated a reasonable quantity of 11kV transformers which are used whenever possible. Failing this, a new unit will be purchased or a second-hand unit may be sourced from other network companies.

Disposal

When EA Networks regularly undertakes 11kV to 22kV conversion, a significant quantity of older 11kV transformers become surplus to requirements. Any transformer returned to stock has an evaluation completed to determine its remaining life and value. Any units that are considered saleable are offered to other electricity network companies at a cost that reflects the remaining life and maintenance costs required to return it to service. Any transformers that are unsaleable are disposed of as scrap after removal of insulating oil.

6.10 High Voltage Switchgear Assets

Description

This class of equipment includes all of the following items regardless of location:

- Disconnectors (66, 33, 22 and 11kV)
- Gas (SF_6) Switches (22kV and 11kV)
- Circuit-breakers (66, 33, 22 and 11kV, indoor and outdoor)
- Voltage Transformers (66, 33, 22 and 11kV, indoor and outdoor)
- Reclosers (33, 22 and 11kV)
- Sectionalisers (22 and 11kV)
- Ring Main Units (22kV and 11kV)
- Expulsion Drop-out fuses (22 and 11kV)
- Structures and Buswork (66, 33, 22 and 11kV)

Disconnectors

Units at all voltages other than 66kV are a rocking post design. Some units operating at 33kV and below are fitted with load-break heads where load current exceeds the interrupting capacity of the bare disconnector. The 66kV disconnectors are a double-break centre rotating design. Recent purchases of 66kV disconnectors have been sourced from off shore. Several disconnectors were unsuccessfully fitted with remote operating mechanisms, which have now been removed. The rating of these disconnectors well exceeds the rating of the circuits they are installed on. Typical ratings are 630 and 800 amps. A few older 33kV and 11kV disconnectors are still in use and they are more prone to failure than the modern designs. The decision has been made not to purchase any new 11kV or 22kV disconnectors for in-line use – buying gas switches instead. Disconnectors are still used to connect consumer's 11kV and 22kV cables to the network.

Gas (SF_6) Switches

A worthwhile addition to the EA Networks network is SF_6 load break switches designed for pole mounting. They offer very reliable operation when compared to a load-break disconnector. The decision to purchase these devices was a balance between the additional cost and the significant benefits in distribution automation, operator safety, and lower future maintenance. The units that were purchased are 24kV 400 amp rated and have: stainless steel tanks, manual and motorised operation, internal current transformers (for measuring load or fault current) and can be converted to sectionaliser operation where required. The design of these units allows them to be used as isolation for working on lines, so no additional devices are required in series. To protect the unit and guarantee the insulation characteristics of an open switch, six surge arrestors are fitted to every gas switch (one per bushing). A photo of an installed gas switch is shown above.

Circuit-Breakers and Reclosers

EA Networks have used a large range of circuit-breaker/recloser, indoor/outdoor equipment over the last fifty years, and this has caused difficulty in training personnel and maintenance. EA Networks have now attempted to limit the different makes/models of circuit-breaker in operation at the various system voltages. The philosophy taken is that two different makes of each category of equipment will be selected and, on each occasion, either make will be awarded a contract for equipment supply. This limits the variety of equipment to two, while ensuring a competitive contract price.

Still in use today at 33kV and 11kV are two bulk oil circuit-breakers manufactured by AEI and Yorkshire. These units are in the process of either removal or are disabled to prevent the need to operate or disturb them.

A recent addition to the ranks of circuit-breakers are what have traditionally been considered ring-main units. Some manufacturers have produced competitively priced ring main units that contain vacuum circuit-breakers instead of fuses. This has created possibilities for additional fault-breaking isolation in both urban and rural settings. Many of the installed ring main unit circuit-breakers do not currently have protection enabled and are categorised as ring main unit switches. SCADA and auto-reclosing has now been standardised, and the protection will be enabled on many and they will be operated as true circuit-breakers.

Voltage Transformers

Voltage transformers are not actually capable of switching anything. They are however closely associated to switchgear. 11kV and 22kV voltage transformers are fitted to most indoor circuit-breaker switchboards and are used to control and monitor voltage and calculate feeder power in modern protection relays. The gas switches purchased for 11kV and 22kV are also fitted with a 500VA 3% accuracy voltage transformer when remote control is required (the voltage transformer provides power to charge the batteries for the switch as well as providing an indication of the phase to phase voltage). 33kV and 66kV voltage transformers are mounted outdoor on stands and these are used to monitor voltage and provide a reference for directional and/or distance protection relays protecting subtransmission lines.

HV Switchgear Summary by Type					
Type	66kV	33kV	22kV	11kV	Total Units
Disconnectors	89	64	576	65	794
Load Break Disconnectors	0	0	109	5	114
Circuit-Breakers or Reclosers	71	22	153	47	293
Voltage Transformers	19	3	26	15	63

Gas Switches	0	0	111	0	111
Sectionaliser	0	0	0	2	2
Drop-out Fuses	0	0	5,565	1,546	7,112
Pacific Glass Fuses	0	0	0	24	24
Ring Main Unit Circuit-Breakers	0	0	308	2	310
Ring Main Unit Switches	0	0	186	782	968
Total Units:	179	89	7,034	2,488	9,791
Resin/Air Ring Main Units			170	323	493

This table summarises the presently documented population of high voltage switchgear.
There are quantities of switchgear that are in storage awaiting reuse, disposal or refurbishment.
The stored switchgear is not necessarily counted in these totals.

Sectionalisers

EA Networks own two oil-filled sectionalisers that are located on lines that cannot justify a recloser but require the ability to detect earth-faults (fuses cannot). The two units are in use to supply relatively short lengths of feeder across the Rangitata River and beyond Montalto into the foothills.

Ring-Main Units

Three different models of ring-main unit (RMU) are owned and used by EA Networks. All bar one are resin/air insulated 12kV Eaton Holec Magnefix units or 24kV Eaton Holec Xiria units. The majority of ground-mounted 11kV kiosk substations have a Magnefix unit installed. The other brand of unit is a single Felten & Guillaume 24kV SF6 unit. All brands of RMU have the option of either fuses, or more recently, circuit-breakers installed in certain models. It is now possible to purchase a reasonably priced vacuum circuit-breaker in a Magnefix unit and this option has been used on two locations.

Expulsion Drop-out Fuses

The most common HV protective device in the distribution network is the expulsion drop-out (EDO) fuse. Manufactured by many companies, most fuse-link carriers tend to be compatible with one another, and the simplicity of operation, low price (for bases and replacement fuse-links) and relative reliability and safety make them very attractive. EA Networks have significant quantities of these type of fuses (33kV, 22kV and 11kV) as well as a rapidly diminishing number of "Pacific" glass tube fuses (11kV only) which are being replaced by EDO fuses as required.

EDO fuses are located at (or on the supply to) every pole-mounted transformer providing fault and heavy overload protection and at strategic locations on the distribution network (line fuses) to sectionalise faults.

Note that the drop-out fuse quantities are an estimate of transformer fuses plus an accurate inventory of system-numbered devices. Fuses supplying transformers directly (on the same pole) are presumed to be one per transformer in this total. The quantities are the number of installations not the number of individual phase items.

Structures and Buswork

At many locations where HV switchgear is located an outdoor busbar system is also present. These busbars and associated switchgear require support and interconnection. EA Networks have a range of structural supports and busbar types. These range from simple wooden poles on the roadside with flexible jumpers as the bus, to galvanised steel flange-mounting posts in zone substations, supporting post insulators and 75 mm diameter hollow aluminium buswork. Other supports are made of reinforced concrete or short wooden poles. The bus systems can also be made from tubular copper, stranded copper, stranded AAC or ACSR conductor. All these methods are in use at EA Networks.

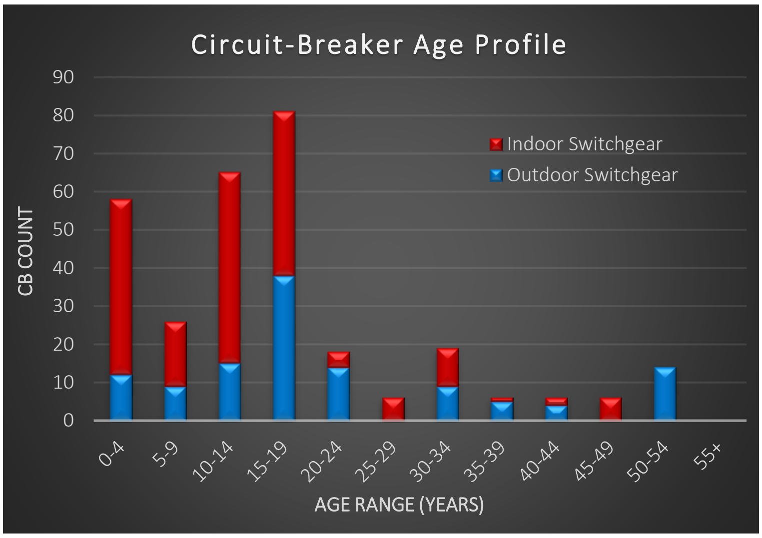
Condition

Circuit-Breakers

Ground-mounted outdoor and indoor circuit-breakers in use at EA Networks are all in reasonable condition.

Metal-clad switchgear deteriorates with age resulting in degraded insulation materials, such as formation of voids and penetration of moisture. Corona and/or partial discharge often accompany this.

Replacement is justified primarily on reliability/risk of failure grounds and consumer service operating limitations. There is potential for explosive failure, which has occurred very infrequently. Historically, approximately one such failure every ten years (two in total – both non-catastrophic) – caused by one specific model of older, indoor, oil insulated, withdrawable switchgear (now retired).



As personnel work near the equipment there is an increased risk of personnel injury. Best practice appears to suggest that adopting designs such that oil-filled equipment is avoided, and substantial walls are installed between old equipment and places where personnel are required to work for extended periods. At the time of writing, the last indoor oil-filled switchgear has been disabled but not yet decommissioned.

Modern SF6/vacuum replacement installations, with SF6, air, or resin insulated bus chambers (rather than the old oil or compound insulated types) are virtually maintenance free. There has been a high cost associated with maintenance of old oil filled and compound insulated equipment, which usually requires major service after faults.

The typical economic life of EA Networks' indoor 11kV metal-clad switchgear installations has been assessed to be 50 years based on experience. At present, more than 84% of indoor circuit-breakers are less than 19 years old. As 66kV and 22kV conversion proceeded, the older indoor circuit-breakers have been progressively replaced with modern equivalent assets, decreasing the average age. The few remaining older units are either SF6 and in good order, or in the process of being retired.

The bulk-oil indoor 11kV SoHi units have had failures at other power companies. EA Networks has experienced two non-catastrophic failures in the past. The two remaining SoHi units have been from disabled and are in series with a modern circuit-breaker. At the time of writing, the ex-Silver Fern Farms site they service is for sale and any future use will not use these as the supply.

The population of outdoor circuit-breakers has been largely trouble-free, with wildlife (birds and possums) usually the principal cause of damage.

Pole-Mounted Reclosers

The range of pole-mounted reclosers that EA Networks own covers three voltage levels (33kV, 22kV and 11kV) and several technologies (oil, SF6 and vacuum). The only units to cause some problems are the zone substation housed 33kV models, which are soon to be decommissioned. These have flashed over on the bushings on several occasions (despite having surge arrestors mounted adjacent to the terminals). The conversion of several zone substations from 33kV to 66kV has liberated some less troublesome 33kV SF_6 circuit-breakers for redeployment in place of oil-filled units. Ultimately, as 33kV equipment is decommissioned it may be redeployed at 22kV.

The more recent 22kV and 11kV reclosers have been largely trouble-free with no problems on the high-voltage side of the devices. A minor technical problem with the control circuitry was attended to by one manufacturer at no cost to EA Networks.

An older generation of oil-filled 11kV reclosers have had some problems in the wound primary CT chamber. These problems are now well known and largely eliminated. As necessary, these units will be upgraded with new units and either scrapped or shifted to uses which represent a lower risk to security, reliability and on-going maintenance. A significant population of these old oil-filled 11kV reclosers have been progressively retired as 22kV conversion has made then redundant, only one or two remain in service.

Voltage Transformers

The population of voltage transformers at EA Networks had historically proven to be trouble-free until about

2006. A make of 66kV voltage transformer failed on three occasions and based on the post-fault analysis it appeared that the manufacture of the units was at fault. An inspection of all the suspect units occurred and all of them have been replaced. One set of the recovered units has been kept as emergency spares but will not be placed in service under normal circumstances. After assessment, some of the additional recovered units may be reused at a lower voltage (monitoring 22kV NER voltages - where they are not exposed to voltage unless an earth fault occurs).

Sectionalisers

The two sectionalisers in service with EA Networks are aging (1992), but are expected to remain trouble-free for the duration of the planning period. Being 11kV rated, they will not remain in use beyond the end of the planning period.

Disconnectors

The disconnectors in use at all voltages have been reasonably reliable in the low-pollution environment of Mid-Canterbury. Some of the older disconnectors have had problems with failing insulators, but the occurrence of this type of failure has been infrequent enough not to require a special replacement programme. Remedial action will be taken on these affected units as they come to notice. There are some very old two insulator disconnectors that are in a state of decline and at this stage they have not proven to be particularly unreliable, but they are subject to operational restrictions on breaking load. As 22kV conversion proceeds any 11kV disconnectors (which includes all old units) are recovered.

The population of 22kV and 66kV units is very new and as such are in very good condition.

Expulsion Drop Out (EDO) Fuses

The population of EDO's in the EA Networks network includes 22kV and 11kV variants. The different makes of 11kV fuse bases and carriers have at times contributed to different reliability issues. A type manufactured locally for many years experienced some problems at EA Networks and other power companies. EA Networks have moved to alternative suppliers who manufacture to an international design standard.

The 22kV EDO (24kV class) is the only voltage rating of EDO now purchased. The unit is in some cases the same as is offered for 11kV use. These have been trouble-free and are expected to remain so for the duration of the planning period.

The glass "Pacific" fuse is prone to failure when interrupting heavy faults or when it is exposed to salt spray. The spray covers the glass tube and when the element melts, tracking occurs down the outside of the glass tube gradually causing heating until either is fails catastrophically or disintegrates when an attempt is made to remove it. Rated at 11kV, these will be eliminated once the rural area is fully converted to 22kV.

Gas (SF_6) Switches

This type of switch was installed from 2003 to 2010. They are in very good condition. The ruggedness of the switch and mounting arrangement was shown during the 2006 snowstorm when one switch's bushings had to support the three wires of an entire span of snow laden conductor after the crossarm failed. The only damage to the switch was the bushing terminals were bent. No gas leaked, and the unit has returned to service. The switches have become attractive for nesting birds and a remedial programme of fitting bird resistance features has started.

Ring Main Units

Three different types of ring-main unit are in service. All types are in satisfactory condition and should remain so (with suitable servicing) for the duration of the planning period. A decision was made to replace the solitary remaining oil-insulated ring main unit with a modern resin insulated item in 2015. This has now been done and reduced the number of types of ring main units to three and increased operator familiarity and safety.

Structures and Buswork

The structures and bus-work that form switchyards and switching locations come in many forms and represent different risks. The majority of 66kV and 33kV bus structures are very sound and in satisfactory condition.

The support structures put in place in recent times are all steel with a hot-dip galvanised coating. This will ensure that they remain in service for many decades with no major maintenance work required.

An unanticipated issue arose with the 66kV buswork used at all of the 66kV sites. Aeolian vibration occurred on the longer unsupported spans of 75mm diameter tubular aluminium buswork. A vibration logger was installed, and it determined that the installation of some suitably large ACSR conductor inside the tube effectively damped the motion. This ACSR solution has been applied to all affected spans as outage opportunities arose.

Standards

Documentation of the standards presently used for testing, inspection and maintenance of HV switchgear is still being developed. Purchasing specifications are fully documented and all new HV switchgear is audited for compliance.

Maintenance

Inspections, Servicing and Testing

Circuit-Breakers

Circuit-breakers are subjected to minor and/or major maintenance routines in accordance with the requirements of the manufacturer's maintenance standards. Fault maintenance is also carried out on oil or SF6 circuit-breakers when a unit has completed a specified number of fault trippings.

Modern vacuum circuit-breakers are subjected to minor services and condition monitoring tests only at 4-5 yearly intervals. Invasive major servicing/adjustment is not scheduled and would be carried out only if required and indicated by condition monitoring tests.

As with power transformers, there are two levels of servicing:

- minor servicing, involving external servicing (non-invasive)
- major servicing, which involves invasive servicing

The frequency and scope of servicing is defined uniquely for each type, make and model of circuit-breaker, and costs per breaker vary significantly. Typically, minor servicing is carried out as recommended by the manufacturer at a relatively low cost per service. While major servicing is typically undertaken when condition monitoring tests determine it to be necessary (at a more significant cost per service). There are breaker types that lie outside of these ranges both for frequency of service and service cost.

The tests performed as part of zone substation inspection and testing cover indoor switchgear.

Other

Disconnectors, ring-main units, sectionalisers and drop-out fuses are operated sufficiently regularly to identify any servicing requirements. Generally, this is limited to lubrication and cleaning.

The gas (SF_6) switches have caused several faults when birds nest in the support frame. Over time the nesting material spills out and either catches fire or causes a flashover. When the opportunity arises, such as during a planned shutdown, a barrier is added to the frame to prevent the birds accessing the problem areas.

Fault Repairs

Circuit-Breakers

Fault repairs to switchgear take place as required, but as the population of older bulk-oil reclosers diminishes in line with the 66kV and 22kV conversion sequence, the occurrence of these faults has greatly diminished. Within three years there will be no oil-filled circuit-breakers in use at EA Networks.

Failures in indoor switchgear are also relatively rare, and with the 22kV conversion programme replacing units prone to failure, it is expected that the fault rate will continue to decrease over the next five years. There have been no failures during the intervening period since the last plan.

Disconnectors

Disconnectors normally fail due to deterioration of the operating arms with corrosion or from an arc developing across two or more phases. By identifying under-rated disconnectors and replacing these with gas switches, the incidence of arcing faults should be reduced. Where the disconnector is required to interrupt load a gas switch will replace it.

Expulsion Drop-out Fuses and "Pacific" Glass Fuses

"Pacific" glass fuses are subject to pollution contamination in coastal areas and fragility when operating. Any fault in these fuses will result in replacement with modern EDO fuses. They are also replaced when any planned work takes place in the vicinity.

Resin Ring-Main Units (RMU)

Only one problem has occurred with some RMU's that resulted in a component failing in a safe manner. The manufacturer has provided replacement units at no cost to EA Networks.

Planned Repairs and Refurbishment

Planned repair work in respect to circuit-breakers relates to additional corrective work and refurbishment identified during routine services, inspections and tests, or following failures. Refurbishment work planned includes overhaul of decommissioned circuit-breakers prior to placing in stores.

Replacement

EA Networks has determined its replacement programme for high voltage switchgear based on the following criteria:

Safety

Where equipment presents a higher than normal risk to personnel during operating or maintaining the equipment e.g.

- generic types of aged bulk oil circuit-breakers with history of failures
- circuit-breakers requiring local hand closing

Technical Suitability

This applies to equipment that is no longer suitable for its service application e.g.

- disconnectors and circuit-breakers unreliable or inconsistent in performing their functions due to excessively worn mechanisms
- equipment which fails to meet EA Networks' seismic requirements
- electrically under-rated equipment
- where the existing circuit-breaker is not able to be remotely controlled
- where there is a need to obtain more metering information.

Economics

This is where replacement is justified purely for economic reasons, e.g.

- equipment is excessively expensive to maintain or repair
- high cost of spares or where spares can no longer be purchased
- maintenance intensive equipment installed at a sensitive supply location

Circuit-Breakers

In line with the practice of overseas utilities as reported by CIGRE, EA Networks has a policy, subject to project-specific economic analysis, of replacement rather than life extension of aged deficient bulk oil and minimum oil circuit-breakers by major refurbishment.

Circuit-breakers are also replaced for the following reasons:

- where they have high maintenance costs
- where they are unreliable due to an increased defect rate
- where a system node requires a maintenance-free circuit-breaker i.e. maintenance outages cannot be tolerated.

It is internationally recognised that forty years is generally the "time expired" life of oil circuit-breakers. Some types have an economic life greater or less than this figure. Bulk oil breakers generally have a longer life, while minimum oil breakers typically last only 30-35 years.

While age is not itself a criterion for replacement, analysis based on likely total economic lives for each type, make and model of circuit-breaker provides a means of assessing likely future replacement requirements. The replacements themselves would be determined by safety, economics and reliability assessments at the time.

Following several incidents involving a specific make and model of indoor bulk-oil circuit-breaker, a decision was made to replace all such units within the EA Networks network. This work has been completed with one exception which is locked to prevent operation (it is in series with a modern circuit-breaker).

Voltage Transformers

Following two catastrophic failures, a thorough inspection of 66kV voltage transformers confirmed that one make/model was substandard and needed replacement because of poor quality control during manufacture. All the potentially faulty units have now been replaced. EA Networks are not currently aware of any other issues with voltage transformers.

Ring Main Units

The last oil-filled ring-main unit in service on the urban 11kV network was replaced during 2015-16. This reduced the types of ring main unit in use to three and eliminates some equipment that is aged and represented an operating limitation based on field experience.

Other

None of the other high voltage switchgear identified in this plan meets the criteria for replacement within the planning period.

Disconnectors are scheduled for replacement when they develop a history of unreliability or failures, when their maintenance costs become unacceptably high, or when they are identified as being electrically under-rated. Should a disconnector require replacement, current policy would see it replaced with a gas switch.

Aged instrument transformers are only replaced when they fail, or when they are about to fail as diagnosed by testing. They are then replaced with a similar unit, usually a spare. Other replacements occur during site development works and depending on whether the condition and ratings etc. of the transformer are suitable for use at another site, they may be scrapped.

Enhancement

See sections 5.4.3, 5.4.4, 5.4.5 and 5.4.6 for details.

Development

A significant amount of high voltage switchgear has been purchased in the last two decades and a reasonable quantity will be purchased during the planning period. This is predominantly ring main units, fuses and disconnectors associated with the 22kV conversion programme. See section 5.4 - Planning Our Network for details.

6.11 Low Voltage Switchgear Assets

Description

Housed in various enclosures are a range of LV switchgear, which perform various protective and operational functions. The simplest item in this category is a fuse connecting a consumer to the LV network from a pole or pillar box. Most pole-mounted substations will have a single set of fuses on the LV side to protect the connected cable or conductor from fault. These have traditionally been porcelain bases with HRC fuses. Extensive use has now been made of underhung DIN style fuse-disconnectors where loads have approached the rating of the porcelain equivalent.

The most extensive use of LV switchgear is in kiosk distribution substations and roadside link/distribution boxes. DIN fuse disconnectors of various sizes ranging from 100 amp to 1,200 amp ratings form the LV switchboard in these applications. Two standard types are used, a full-size DIN unit for substations and a proprietary compact unit for roadside boxes.

A full inventory of all LV switchgear types, locations and quantities is gradually being gathered. Once complete, additional quantitative details will be given in the plan. An estimate of these quantities is as shown in the table above. Additional locations and types will be detailed once the data is available.

Condition

Low voltage switchgear is dispersed widely across the area EA Networks service. Almost all of these devices are in good order. Some link boxes and distribution substation switchboards use a specific type of fuse base and porcelain carrier (JW3) that is prone to overheating when approaching its rated current. Under normal loading conditions they are very reliable. The condition of heavily loaded JW3 installations will be monitored closely for deterioration. The JW3 also has exposed live terminals on it and is not touch-safe in the open or closed position.

LV Switchgear by Type & Location

Switchgear Location & Type	Number 3ph
Link Box (JW3 Porcelain Fuse)	566
Link Box (Switch/Fuse Switch)	1,936
Distribution Substation (JW3)	531
Distribution Substation (DIN)	1,744
Total 3ph (Estimated)	**4,777**

The modern DIN switchgear used in most distribution substation switchboards since 1988 is very reliable and no electrical failures have been recorded. Several failures of link box LV DIN fuse units have been recorded. After researching the issue, it was noted that the loads had exceeded the unit rating and the derating of multiple adjacent units in a small enclosure had not been considered. More monitoring is taking place. These devices can be described as in very good condition.

Standards

Documentation of the standards presently used for testing, inspection and maintenance of LV switchgear is still being developed. Purchasing specifications are fully documented and all new LV switchgear is audited for compliance.

Maintenance

Inspections, Servicing and Testing

This asset requires only low-level inspection and servicing. The sites where these items are located tend to be visited for operational reasons and this is when the very infrequent problems are found. An infra-red non-contact thermometer is routinely used to check for thermal issues.

Fault Repairs

There is a minimal amount of fault repair work required on this asset class. Fault repair generally falls into the replacement category.

Planned Repairs and Refurbishment

These assets tend not to be repairable as such. The value and construction of the items generally involves complete replacement of the asset.

Replacement

Some of the larger distribution substations (500kVA and larger) have a type of low voltage fuse (JW3) that is known to cause problems as it approaches its maximum rating. These are being progressively replaced with DIN type switchboards at the rate of two per year. The safety of the JW3 switchboards is also suspect and this provides additional justification for replacement. The cost of this is part of the general scheduled underground work.

Enhancement

There is no practical means to enhance this class of asset.

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Development

The majority of LV switchboard development is in conjunction with the underground conversion programme and any new urban subdivision that occurs.

6.12 Protection System Assets

Description

Electrical Fault Protection

Electrical Fault protection is one area that has made rapid technological advances in recent years. Historically, electromechanical devices were required to respond to various electrical inputs and then trip a circuit-breaker. This is how the name "relay" evolved. Modern protection is closer to a personal computer than a click/clack relay. The steps between these two extremes were solid state electronic relays, then "intelligent" relays that used the analogue solid state information, and EA Networks are now at the point where almost all protection is undertaken by "numeric" relays which calculate all the necessary parameters from raw current and voltage inputs.

EA Networks have some of each of these technologies. In some applications, the earliest technology still does a reasonable job. The major benefits of numeric protection devices are the flexibility to alter the logic of the device as well as being able to "talk" to it using a SCADA system or a local computer. Once you are connected to it you can extract any information that it has. This information is almost limitless. The numeric relay replaces chart recorders, stand-alone panel meters, SCADA transducers, SCADA RTUs and switches. All of these are built into the one box. Zone substations tend to have a proliferation of protection devices and this is where the majority are located. Reclosers have the protection built into the supplied equipment and these are also becoming increasingly sophisticated. The modern pole-mounted recloser controller can measure current, voltage, power, direction of power flow and many other useful parameters. EA Networks have approximately 179 numeric relays in service in zone substations at the time of writing.

Numeric Protection Relays by Model

Relay Model	Quantity
Schweitzer 2100 MB Hub	2
Schweitzer 2440 Numeric RTAC	5
Schweitzer 311C Numeric – Mk0	14
Schweitzer 311C Numeric – Mk1	28
Schweitzer 311L Numeric	2
Schweitzer 351-6 Numeric	4
Schweitzer 351S Numeric	2
Schweitzer 387L Numeric	42
Schweitzer 551C Numeric	1
Schweitzer 587Z Numeric	20
ABB RACID	2
GE Multilin SR745 Numeric	1
GE Multilin SR345 Numeric	2
GE Multilin URF35 Numeric - H/W rev 5	11
GE Multilin URF35 Numeric - H/W rev 7	19
GE Multilin URT60 Numeric - H/W rev 3	2
GE Multilin URT60 Numeric - H/W rev 5	9
GE Multilin URT60 Numeric - H/W rev 7	13
Total	**179**

This number will climb further over the next few years as the 22kV network replaces the 11kV network and more network intelligence is introduced. A full inventory of protection equipment age and condition is still being prepared and will be available in a future plan.

Overvoltage Protection

The area in which EA Networks operate is not particularly prone to lightning which is a blessing for the asset manager. Lightning causes very large voltages on the lines and cables of the electrical network and these tend to "flash-over" to earth at the weakest point. In many cases this point is the earthed tank of a transformer or circuit-breaker. Once a flash-over has occurred, significant damage can be done to the bushings, insulation and contacts in the device.

Nothing can truly protect a device from a direct strike by lightning, the energy involved is too great to contain. There is equipment that can protect a device from indirect strikes or switching surges. These are called surge arrestors.

EA Networks apply distribution class surge arrestors to any equipment deemed sufficiently at risk or critical to network security. This has generally involved line-mounted circuit-breakers and sectionalisers, zone substation transformers and any cable termination.

Accurate quantities of surge arrestors will be obtained for inclusion in future Asset Management Plans.

Surge Arrestor by Operating Voltage	
Arrestor Operating Voltage	Number 3ph
66kV	70
33kV	16
22kV	1,448
11kV	169
Total 3ph Sets	**1,703**

EA Networks have an additional consideration when applying surge arrestors. The 66kV network, 22kV network and the 11kV network are all earthed using neutral earthing resistors. During a single-phase to earth fault the "healthy" phases can rise to a voltage 70 % higher than the normal phase to earth voltage. Surge arrestors must be selected taking this into account.

Condition

Electrical Fault Protection

The electrical fault protection system (protection system) is designed and manufactured to be inherently reliable and low maintenance. This is certainly true of the modern numeric relays that, through self-monitoring, are very low maintenance. The in-built monitoring of these units can detect when a problem has occurred and alert the relevant control system to create an alarm.

The very few electromechanical relays in the network are beginning to show their age. These devices are much like a mechanical clock and require reasonable attention for optimum performance. Even some solid-state relays are now failing as electronic components age. Solid state relays are not usually repaired when they fail, they are replaced with complete spare units or a modern numeric device.

The age of some of the early numeric relays is approaching 20 years old. Component availability as well as economic viability may mean that the repair or refurbishment of aged (>15 years) numeric relays is doubtful. The features and price of numeric relays continue to improve, and it is unlikely a numeric relay will be repaired if it is more than 10 years old. A replacement would be purchased, and the faulty unit kept for spares or scrapped.

The tests that have been performed on a regular basis reveal any relays in poor condition and they are promptly repaired or replaced. As such, the condition of the modern solid-state relays can generally be reported as good and the electromechanical units are ageing but still serviceable.

The register of devices is incomplete and represents only the protection relays located at zone substations. There are a range of other protection relays associated with reclosers and ring main units that will have additional data captured about them over time.

Over-voltage Protection

The surge arrestor population on the EA Networks network is limited to critical items of plant and cable terminations. The rate of surge arrestor failure is rising on the 22kV network. Adequately testing these items in or out of service is difficult. The anecdotal evidence would suggest that the population is still in reasonable condition but that either the specification or electrical conditions are causing failures. The previous specification 22kV arrester was as per the manufacturer’s suggestion for a 22kV resistance earthed network. Work will continue to ascertain the reason for 22kV arrester failures and whether a replacement programme should be undertaken. The failures are having a notable impact on SAID and SAIFI. An alternative arrester manufacturer is now the current supplier. The arrester specification has been increased beyond that normally specified for a 22kv resistance earthed network.

Standards

Documentation of the standards presently used for testing, inspection and maintenance of protection equipment is still being developed. Purchasing specifications are fully documented and all new protection equipment is audited for compliance.

Maintenance

Although referring to two distinct classes of asset, fault protection and over-voltage protection, this section makes no further reference to overvoltage protection, as the devices in question are low maintenance, low cost and generally very reliable. Additionally, there is little data to provide meaningful analysis of asset condition.

Inspections, Servicing and Testing

The policy in this area is to maintain protection schemes with alternate major and minor services every 4-8 years, on each protection device depending on the type of protection (numeric/electronic/mechanical). Electromechanical types are tested more frequently while numeric types are tested less frequently.

It should be noted that "maintenance" on protection equipment is essentially "recalibration and testing" rather than the conventional view of maintenance, which would imply replacement of consumable parts. Protection maintenance is mainly required to re-affirm that the protection is calibrated within tolerance and will operate when called upon to do so. Some of this maintenance is as simple as checking relay logs to ensure it has operated correctly on a fault condition in recent times.

There are international trends towards reduced maintenance. Typically, intervals are being increased to between 5 and 10 years in other utilities comparable to EA Networks. This is particularly so where microprocessor (numerical) protection systems are used, as these protections have in-built self-testing and monitoring routines which reduce the necessity for manually driven maintenance testing. Once the input linearity/accuracy of the device has been proven (this can be done with load current and line voltage), a simple timing test should establish that the internal processes are working correctly. Other sources of information to prove the status of the equipment include event records which show both operation and pick-up on faults, along with the associated currents, voltages and times.

EA Networks have an advanced relay test set to facilitate maintenance testing. This will be used for commissioning of new protection (developments and enhancements) as well as maintenance.

Fault Repairs

Fault repairs on protection are not generally carried out. Thorough examination of the entire scheme is generally done, and a complete service of the scheme advanced from the next planned service.

Surge arrester fault repair is limited to discovery after a fault incident and the replacement within 6-8 weeks. Most arresters have base isolators that disconnect a faulty arrester from earth automatically. Once it is isolated the arrester is live at the base and relies upon a very limited level of insulation to prevent a permanent earth fault. If the arrester is left failed and isolated too long the insulation fails, and a permanent earth fault occurs, causing auto-reclosing to lockout and an outage. EA Networks make every effort to avoid this situation arising.

Planned Repairs and Refurbishment

The expenditure planned over the review period is mainly in the following areas

- replacement of aged lead acid batteries
- seismic strengthening of protection panels
- seismic restraints for batteries

Replacement

Many protection relays will be replaced during the planning period. This is likely to be in conjunction with larger zone substation and subtransmission developments and could be considered in the enhancement category due to the extra functionality that they provide - making some other assets redundant.

Some new 22kV switchboards may be installed in place of existing 11kV outdoor units. In some cases, this will also see replacement feeder protection installed.

Enhancement

Additional load could require enhanced protection assets in some locations. It is not anticipated that this is likely.

In conjunction with the SCADA expansion programme it is possible that some protection equipment may be replaced as the most cost-effective way to integrate remote control and data collection into the sites. Other reasons for replacing older equipment would be lack of protective features or reliability of operation.

Development

It is obvious that there are significant development projects for the protection system during the planning period. The majority of these projects involve the installation of replacement or additional relays in zone substations protecting 66kV lines, 66kV transformers or distribution feeders (Section 5.4.3 and Appendix B – Projects and Programmes identifies the location and extent of expenditure).

6.13 Earthing System Assets

Description

Earthing systems form an important part of the electricity network. Under normal circumstances no electricity should flow from a circuit into earth. This allows protective devices to sense when a fault has occurred, such as a tree touching a line or a person touching a toaster that has become live. To provide this protection, the connection to earth of the electrical supply system must be adequate to allow a certain minimum amount of current to flow. For a high voltage network this value is generally 20 amps or more. This corresponds to a value of earth resistance of no greater than 100 ohms (for 11kV) once all the equipment in the fault loop has been accounted for and a safety margin added.

Distribution Earth Count* by Location	
Location	**Quantity**
Distribution Substation	6,499
Disconnector/RMU	763
Recloser/Sectionaliser	27
Surge Arrestor	427
Total	7,716
*** The counts shown here are an estimate**	

All equipment that has conductive components that can be touched must be earthed in a safe manner. Any neutral connection must be earthed at the source. This means that all distribution substations need a substantial earth, as do surge arrestors (necessary for correct operation), disconnector handles, recloser operating boxes, cable terminations and any other item designed to be "screened" or "bonded" to earth.

Much larger earth mats are installed at zone substations and these must account for voltages that develop on the ground and on equipment within the substation. Additional buried conductors can control these voltages to a safe level and all zone substations have been reviewed to ensure safe conditions exist.

At zone substations with 22kV supply busbars, a device called a neutral earthing resistor (NER) has been installed in the neutral connection of the supply transformer(s). An NER restricts the amount of current that can flow into any type of earth fault. This makes for a safer system, but it can make it more difficult to detect very high resistance faults such as trees brushing the line.

In the future, it is likely that earthing installations will be identified individually within the GIS and asset management system and the items of plant using that earth will then be associated with it. This will enable an accurate inventory of earths to be kept (all earths are known and measured but several devices may share the same earthing system and not all of these can be associated with it in the GIS or asset management database).

The total number of earths in the EA Networks network is currently obtained by adding together the quantity of equipment known to have earthing systems (excluding zone substations).

Condition

The 2010 Electricity (Safety) Regulations state that all works must have earthing systems that are:

designed, installed, operated, and

maintained to ensure, as far as practicable,-

(a) the effective operation of protection fittings in the event of earth fault currents; and

(b) that the voltage of each conductor is restricted to a value consistent with the level of insulation applied; and

(c) that step voltages, touch voltages, and transferred voltages are controlled to prevent danger to any person.

If an earthing system complies with Electrical Code of Practice (ECP) 35 it is deemed as compliant with this clause of the regulations. In EA Networks' situation, because of the very high soil resistivity that is often encountered, a risk-based process must be employed to establish a practical means to comply with the Regulation. The EEA Guide to Power Systems Earthing (August 2009) provides guidance and advice on safe earthing practices for high voltage AC power systems adequate to meet the requirements of electricity safety legislation. EA Networks are using this document as a benchmark for compliance.

The Regulations do require that earthing systems be tested *regularly*, and EA Networks has been addressing this issue in earnest. To meet the requirements, a programme of continuous earth testing is underway and will continue to progressively test the total substation population at no more than ten-yearly intervals. Any distribution substation, disconnector or surge arrestor that is altered, has its earthing retested and improved if it is substandard.

Based on experience, it is expected that during the testing phase, some substandard earthing installations will be identified that are capable of being practically upgraded. A programme of upgrading these earth systems using driven rods and extra copper conductor will follow on directly from the earth testing exercise. The single most important criterion for earth improvement will be - that the resistance of the earth system at any site must provide an earth path of low enough resistance to ensure the HV feeder circuit-breaker operates under all circumstances if a single phase to earth fault occurs at that site. The exercise of earth improvement is not trivial, and it is probable that over time significant resources will be required to attend to this problem.

Large earthing systems such as that found in zone substations are regularly measured to ensure on-going integrity of the conductors and rods. None of the zone substation sites have shown a level of deterioration that requires attention.

Urban distribution substations have the multiple-earthed neutral as a continuous metallic connection from the zone substation out to the earthing point. The result is that urban earthing is never a problem in terms of the value of resistance achieved. Because the earth resistance is low the currents that flow are much higher and connectors must be checked for integrity whenever the earth is inspected/measured. The use of 20/40Ω 11/22kV neutral earthing resistors restricts this current to 320 amps which is around load current levels.

EA Networks has an electrical earthing installation at every substation, disconnector, recloser, sectionaliser, and surge arrestor connected to its network. All these earths are required to serve a specific purpose related to personnel and/or equipment safety. The ability of an earth to achieve an acceptably low resistance (to a truly remote earth) is dependent on two major parameters. The first and most important is the earth resistivity[1] of the soil, stones and rocks into which the earth installation must be placed. The second parameter is the physical extent of the installation itself. EA Networks operate in an area where earth resistivity varies considerably. The best locations achieve an average of 300 ohm-metres, which is considered poor in many other regions. The worst locations are almost ten times this at an average of 2,800 ohm-metres. Achieving a desirable low earth resistance value (such as 10 ohms) in these conditions is next to impossible. EA Networks have adopted a pragmatic approach to the problem and concluded that the primary criterion for each installation's earth resistance is that should the phase wire of any high voltage line contact metalwork connected to that installation, the operation of a high voltage circuit-breaker must occur. Another Canterbury lines company with a similar range of earthing conditions established this principle. The impedance of the earth fault loop has a safety factor of two. The guidelines that have been established and compliance with the Regulations will be used as the criteria to improve the performance of the EA Networks earthing system.

EA Networks are watching the implementation and user experience of resonant earthing systems in other networks. A resonant earthing system reduces earth fault currents to very low values making step and touch hazards much lower. It could be that resonant earthing systems are an option for the future.

Standards

Documentation of the standards presently used for testing, inspection and maintenance of earthing systems is

[1] The resistivity of a material is a measure of how easily current flows through the material when a voltage is applied to it.

in place. Construction standards are fully documented. All new earthing systems are audited for compliance.

Maintenance

Inspections, Servicing and Testing

Regular earth testing is performed on all earth installations in the EA Networks network. The typical return period for any one site is 10 years. In conjunction with normal line inspections, the above-ground portion of the earthing system is inspected every 5 years. All the data gathered is saved in the asset management system.

Fault Repairs

A faulty earth typically requires either complete replacement or significant enhancement.

Planned Repairs and Refurbishment

Whenever a substation is altered in any way (this includes a transformer change) the earth installation is retested. If these tests do not meet the established guidelines the site is given priority for earth improvement. A description of the earth improvement programme is shown in the enhancement category.

Earth Testing and Restoration

If, during regular testing or via other means, existing earths on substations and switchgear are discovered to have deteriorated to the point of non-compliance, these are restored to EA Networks' current standard.

Replacement

There are no proposals to completely replace any earth installation during the planning period.

Enhancement

Based on data held in the asset management system a statistical assessment has been made of the number of earth installations requiring improvement. This is approximately 350 earths, which represents 4.5% of the total earth population. It has been determined (both theoretically and practically) that the only reliable technique to establish a lower earth resistance is to deep drive rods in to the ground. Extending the earth horizontally simply extends the hazardous area without necessarily lowering the resistance appreciably. Surge arrestor earth installations will be installed to the same guidelines as distribution transformer earths. Disconnectors may be solved in a different manner. The only reason a disconnector must be earthed is the continuous metallic path between the disconnector assembly proper and the operating handle. If the operating handle is electrically isolated from the disconnector the need to provide a substantial earth is removed. It is proposed to use a 1 metre fibreglass section in the pipework to isolate the handle from the switch and then bond the handle to an earthed conductive operating pad (which is EA Networks' standard practice). This ensures that regardless of the condition of the disconnector, the operators do not have any voltage difference between hands and feet.

To achieve the goal of improving the earthing system to an acceptable level of performance will take a long-term effort. The time scale will determine the annual cost to EA Networks. The earthing improvement programme is currently targeting the highest 10% of non-complying earths per annum. This equates to about 50 earths each year.

Development

Whenever a new substation is constructed, an earth is also installed. These earths must meet the established guidelines of tripping a high voltage circuit-breaker for a single-phase fault. An annual allowance has been made for the duration of the planning period to provide for the number of new earths that have been installed in recent years. Several zone substation projects incorporate significant earthing systems, but this development is incorporated in the overall zone substation project cost.

6.14 SCADA, Communications and Control Assets

This includes all communications equipment and radio repeater sites as well as vehicle-mounted equipment and the entire Supervisory Control and Data Acquisition (SCADA).

Description

EA Networks have a SCADA system in operation that covers all its modern zone substations and a growing number of remote "pole top" and RMU sites.

A detailed description of the SCADA system will not be given, as such information could be beneficial to someone with a malicious intent. Suffice to say that the necessary information and control will be available to those personnel that require it.

SCADA systems enable fast responses to situations as they arise. The information and control that SCADA provides can shorten restoration times considerably. The historical data that accumulates is also of value to the asset manager as substation asset utilisation is readily apparent. Dynamic rating capabilities can be evaluated at some sites as temperatures are transduced on some zone substation power transformers.

EA Networks has been using a SCADA system developed by QTech Systems since 1993. While still functional, this system cannot provide the full range of services required for a modern, intelligent electricity network.

EA Networks has a project underway to enhance its communication with its customers during network outages. This requires our internal systems to be able to gather more accurate and timely information that can be used to inform our customers.

With these factors in mind, in 2019 EA Networks committed to purchasing a new SCADA system from Open Systems International (OSI). The OSI system introduces a new SCADA system with state-of-the-art features and greatly enhanced cyber security features. Building on this base are advanced applications such as an Outage Management System which includes predicted fault location and the ability to communicate with customers via email, text message, dedicated app and web site. Other advanced features include real time fault and voltage analysis and switch order management amongst others.

When fully implemented, it will be possible to create a self-healing network for automated fault response.

The new system is being implemented as a joint project between EA Networks and Westpower.

Remote Stations

The concept of an RTU at EA Networks' modern zone substations is largely redundant in that modern protection relays have sufficient inputs and outputs to control and monitor substation functions and can transduce, calculate and record virtually any electrical parameter.

The functionality of the protection devices connected to the transformers and feeders is such that they handle virtually all I/O and transducing. An industry standard protocol is used to communicate with the protection devices.

At sites requiring SCADA that do not have advanced numeric protection relays, a small conventional RTU is installed to provide the necessary control and data gathering.

Communications System

The EA Networks communications network consists of a mix of several technologies of various ages and age profiles. This equipment provides bearers for operational speech, operational SCADA and load management information. It also permits engineering access to a range of devices allowing remote detailed interrogation.

Primarily driven by the need for fast acting differential protection on its subtransmission systems, EA Networks has developed an extensive fibre optic network that now links all but two of its zone substations. Of the remaining two one is a temporary substation (MON), and the second is economically challenging for fibre optic access (MHT). All but one communication link is duplicated with very few common paths. Even the primary radio repeater site is serviced by fibre with a microwave backup.

Built on top of the fibre network is a fully routed layer three IP network, providing logical redundancy to all connected zone substations. Currently, speeds of 1Gbps are provided. This can easily be raised to 10Gbps using the existing switching infrastructure should the need arise. The availability of reliable communication paths with low latency and high bandwidth has enabled new features such as VoIP phones and video surveillance to be delivered to connected zone substations. Because EA Networks also provides a public fibre based broadband network, it is possible to use this where it passes remote controllable devices, providing secure, reliable communication to those devices.

As the control centre has moved off-site from the Ashburton substation, for real time control applications the new corporate office is connected to the communications hub by diverse, redundant 10Gbps links. Our offsite disaster recovery site for network control will be located in Westpower's Greymouth office once the new OSI system is fully functional.

The fibre optic network is a separate business function and as such the asset management of that network is not part of this plan. Only fibre optic cables fully contained within a zone substation site and dedicated to power system functions will be considered in this plan.

The Digital Mobile Radio (DMR) system used for voice communication is 100% digital. Consequently, the system can transport non-voice data transparently. This has been used to supplement the SCADA system by utilising a small DMR data unit as a remote control 'mini RTU'. These devices will be used where it is difficult to obtain access to the fibre network.

Mobile Speech Network

The DMR mobile speech network is provided via a number of digital radio repeaters used exclusively by the Network and Field Services divisions of EA Networks. All but one of the repeaters is housed on EA Networks sites and is connected by a redundant IP backbone. One repeater is co-located on a Transpower site.

A further repeater is about to be installed on a remote mountain site in the Ashburton Gorge (Mt Tripp). Once this site is commissioned, EA Networks will have virtually 100% coverage of its network by voice radio and low-speed data communications.

Building on the digital infrastructure, EA Networks have implemented additional safety features for its employees, particularly lone workers. These include man down and emergency call features and the ability to use portable radio devices across most of the network.

To further enhance our safety operations, we are trialling remote access to the radio via intelligent device (phone or tablet). This enables whole crews to have access to the two-way radio system from a job site e.g. upon noticing a safety issue a person in the bucket of an Elevated Work Platform could, via their cell phone, establish a call via the two-way radio network back to the Network Operations Centre (NOC) or initiate a system wide emergency call.

The longer-term proposal is to turn the vehicle into a communications hub where DMR is just one of the communications links to the vehicle, others being WiFi and cell data. This will reduce the need for the operator to decide which communications mechanism to use when communicating with the NOC. Typical examples of usage would be:

- if a photo of failed network equipment is to be sent, it will be routed via WiFi or cell data,
- if written switching instructions are being sent then they will use the DMR data channel to ensure delivery in virtually all places and conditions.

Further enhancements may include two-way radio traffic being transmitted via WiFi or cell data when vehicles are operating out of DMR network coverage. This will enhance control and communications when we assist other networks in times of disaster.

The DMR radio system is supplemented by a VoIP phone installed in every connected substation and communications facility.

At most zone substations, a 19m concrete communications tower has been installed and this serves as the platform for all radio communications needs to and from the site.

Condition

SCADA

As part of the implementation of the OSI system, our SCADA base stations and underlying computing layer are being replaced with up to date equipment. Both the old and new SCADA systems are comprehensive at the sites they cover. Backup systems are already in place for data and power supply and are being enhanced with the move to the new system. Maintenance of the SCADA system should be limited to occasional computer infrastructure refreshes, setting changes of the protection relays, software upgrades of the SCADA application, or other operating system revisions.

Communications

EA Networks has now successfully rolled out a digital DMR system. This system provides GPS location of all vehicles and handheld radios and, in the future, will potentially have a degree of in-field data coverage.

As mentioned previously, the trunked DMR system can also provide remote control and indication of pole top and other remote devices.

The building housing the communications facilities at Gawler Downs has been replaced in 2009 and in 2012 communication facilities were constructed to house both the SCADA IP based systems and the public broadband system.

The analogue UHF network had equipment dating back to the mid-1980s and has been withdrawn from service. A backup digital microwave link to the Gawler Downs hill-top repeater site remains.

The microwave link to the repeater co-located at a Transpower site is new, having been installed in 2018.

The condition of other communications assets is adequate for the required level of performance.

Standards

Documentation of the standards presently used for testing, inspection and maintenance of SCADA, communication and control systems are still being developed. Construction standards are fully documented, and all new SCADA, communication and control equipment are audited for compliance.

Maintenance

Inspections, Servicing and Testing

SCADA

The integrity of the main hardware and software system at the NOC is of the highest importance to the on-going management and safety of the electricity network. EA Networks' Network Division staff, with assistance from the IT staff, manage the computer system and maintain the operational state of the software and hardware systems. Full 24hr monitoring of SCADA equipment is provided by automated systems. This is a 24-hour per day task, with staff on call to ensure high availability of equipment. The main SCADA computer hardware is non-proprietary and suitable spares are readily available, as are entire workstations should the need arise. The base station operates in a virtual arrangement spread across several hosts, with independent back up processors and a remote system capability housed in Greymouth.

The Network Division maintains most equipment external to the master station and sufficient spares are held to guarantee prompt response and repair times.

Communications

The intra-substation fibre optic cables that EA Networks own are "new" in infrastructure timeframes, and in excellent order. Automated monitoring equipment monitors all communication links and supporting hardware such as UPS's 24 hours a day.

Similarly, the inter-substation fibre optic cables that EA Networks own (in a separate business unit) are "new" and in excellent order. Automated monitoring equipment monitors all communication links and supporting hardware such as UPS's 24 hours a day.

Fault Repairs

In recent times, maintenance technicians have had to respond to relatively few SCADA or communications faults in any particular year.

Planned Repairs and Refurbishment

SCADA

As mentioned earlier, we are in the process of installing a new OSI Advanced Distribution Management System, which incorporates, amongst other systems, a new SCADA system.

Communications

A replacement and augmentation project for our fixed communications bearers is nearing completion. The only remaining issue is communication into the valleys in the foothills of the Southern Alps.

Replacement

SCADA

The process of installing new systems is currently underway. The new SCADA is currently operating for three zone substations and several pole-top devices, it is anticipated the entire system will be commissioned in the 2020-21 financial year. Once all sites have been converted to the new system, the old SCADA system will be completely decommissioned.

Communications

It is only planned to replace electronic communications equipment during the planning period. This primarily involves replacing the IP switches in zone substations which are at the end of, or nearing the end of, their design life. This replacement program has started.

Enhancement

SCADA

With the advent of industry-wide performance monitoring, EA Networks is benchmarked against other Electricity Companies in terms of system reliability and continuity of supply. Furthermore, consumers are becoming more aware of fault outages, this being partly due to the increase in the number of electronic home appliances and the resulting reliance on a continual supply of electricity. For these reasons, it is becoming increasingly important to cut down on fault restoration times.

One way to do this is by automating remote switches. This greatly reduces the travelling time required for a faultman during sectionalising of faulted line sections. It also means that fewer staff are required to isolate the fault, reducing the overall cost of fault restoration.

It is proposed that critical main line switches continue to be automated at the rate of five to ten per annum. This process will be in conjunction with the use of gas switches and rural ring main units which are purchased ready for remote control. Good progress is being made with this programme.

Communications

The recent addition of a digital microwave link from Methven substation to Round Top hill-top repeater site has provided a DMR repeater that can be used up into the Rakaia Gorge. A digital microwave link has also been commissioned between Round Top and Mt Hutt zone substation to provide a high bandwidth digital link into Mt Hutt permitting SCADA, remote engineering access to the substation equipment, and VOIP telephony.

Development

See section 5.4.10 – Planning Our Network.

6.15 Ripple Injection Plant Assets

Description

EA Networks own three ripple injection plants, with one each at Ashburton 66/11kV Substation (ASH), Transpower Ashburton Substation (ASB), and Methven33 (MVN) Substation. All plants are solid state and manufactured by Landis & Gyr Ltd (formerly Zellweger Ltd), and use the Decabit code system. The plant at the

Ashburton 66/11kV substation is an 11kV injection plant. The 33kV plant at ASB is used to inject ripple onto the 66kV network via a 33/66kV autotransformer. The ASB plant and the ASH plant are centrally controlled from the QTech power management system and inject synchronously so they reinforce the signal strength across the network. The Methven plant is a standby unit for use if the ASB plant fails and it can cover a portion of the northern 66kV network.

Condition

EA Networks sold all of its ripple relays to the incumbent retailer (Trustpower) on 31 March 1999 along with exclusive use of channels in use at that time. The ripple injection plants were retained for the purpose of load control as well as providing a load switching service to retailers under contract.

All ripple injection plant components appear to be in acceptable order, but at up to 26 years old they have the potential for age-related issues. There have been two injector failures (ASH plant and ASB plant). The ASH failure was resolved with the supplier and a modern replacement injector unit was installed at ASH. The ASB failure was solved by purchasing the 'spare' injector held by Landis & Gyr. Both the ASH and ASB plants are now a hybrid of a new high capacity injection component and older lower capacity high voltage coupling components.

Summary of 33kV Ripple Injection Plant Components			
Site	Capacity	Install Date	Manufacture Date
Ashburton 66 (ASH)	440/60kVA	2007/1985	2007/1985
Ashburton 220 (ASB)	200/60kVA	2010/1992	2010/1988
Methven 33 (MVN) - Spare	25kVA	1985	1985

Because of the solid-state construction of the injection plants, faults are unlikely to be a frequent occurrence. If they do occur, the consequences can be considerable extra cost of an unconstrained system peak at the Transpower GXP and high loadings on network equipment. Some consideration will be given to early replacement of critical components in an attempt to prevent faults occurring. The age of some of the solid-state components (> 25 years) is such that spare parts are becoming difficult or even impossible to source.

Standards

Documentation of the standards presently used for testing, inspection and maintenance of Ripple control systems is still being developed. Construction standards are fully documented, and all new Ripple control systems are audited for compliance.

Maintenance

EA Networks' two in-service ripple injection plants (a smaller spare unit exists at Methven33) are both the same make (Landis & Gyr), making lifecycle management easier to implement. Although not identical, the plants have some interchangeable components and operate in an identical manner. Recently some components were used from Methven33's plant to temporarily repair the Ashburton 66 plant. The Methven33 plant has since been restored to operational capability, although it only has manual control facilities (keypad entry of commands to send control signals for channel on or channel off). The Methven plant also has limited reach into the 66kV network and it will not provide network-wide control. The injection plant supplier has stated that they terminate support for any specific generation of equipment 10 years after it has ceased production. Two of the plants are now in that position.

Inspections, Servicing and Testing

Monthly checks are carried out as part of regular zone substation visits which include the visual inspections of the

- converters
- coupling transformers
- coupling cells

Advice received from the manufacturer indicates a higher risk of intermittent faults can be expected as the plant age nears 20 years. With this in mind, a service contract is in place with the manufacturer, which includes an annual test on performance plus a full inspection. Tests include injection levels, current balance, optimum tuning and load sharing with other units.

Fault Repairs

The solid-state construction of the injection plants means that faults are very infrequent.

On rare occasions, the high-power output transistors may require replacement, or the logic board may require repair (although this is becoming more difficult on the older units).

Vermin may get into the high voltage coupling cells causing flashover although this has not occurred on any of EA Networks' plants.

The redundancy built into the injection network is becoming less robust. Failure of the ASB plant could severely impact on overall ripple signal propagation causing loss of load and tariff control. The MVN plant can inject over most of the northern 66kV network keeping many ripple relays operating correctly but the southern 66kV ring is likely to be uncontrolled.

Planned Repairs and Refurbishment

Minor repairs are required on the coupling equipment and converters from time to time caused by fault events.

There is no repair and refurbishment program planned for this equipment, which is in acceptable condition. It is expected that the plants should give continued service for some years.

Replacement

A consequence of component failure, two of the older (1985/88) inverter units were replaced in 2007 and 2010. One of these has been sized to suit future use at 66kV. The other was the only available option at the time. EA Networks continues to consider alternative signalling technology as a range of technical and commercial challenges appear. Presuming ripple is still the preferred signalling technology in 2026, the 33kV ripple plant (by then acting as a back-up) is scheduled for replacement [-1148]. The Methven plant will be permanently retired once Methven 33 zone substation is decommissioned (2022).

Enhancement

The capacity of the existing ripple equipment is limited and provides no room for 66kV network expansion. As the network configuration changes, there will be a need to look at alternative signalling technology, ripple plant control technology, location, and size.

Development

With the conversion of all load to 66kV, the ripple control system has been assessed to ensure it provides adequate security and signal level. The addition of a third 220/66kV transformer supplying EGN from ASB has lowered the available signal level.

An option for a new type of load control technology has arisen that is being actively pursued and trialled. Provided the trial proves successful, it is probable the ripple plants will be made redundant.

Should the new technology trial prove unsuccessful, the funds set aside for implementing the new technology roll-out will be used to install a new 66kV ripple plant at EGN which could signal the entire network. The existing 33kV plant at ASB will be left as a back-up plant capable of signalling most of the network under most loading conditions if the new 66kV plant is installed.

See section 5.4.11 – Planning Our Network for details.

SUPPORTING OUR BUSINESS

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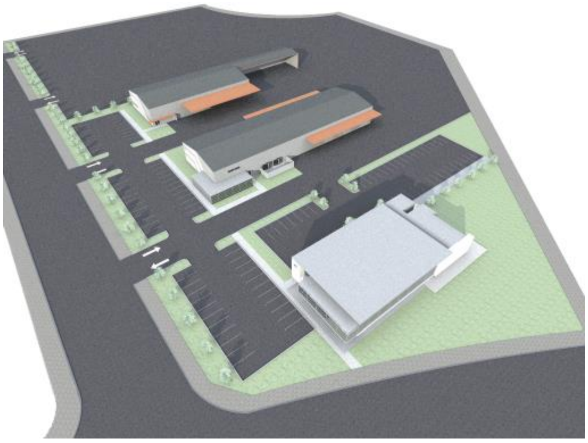
7 SUPPORTING OUR BUSINESS

The definition of these assets is "assets related to the provision of electricity lines services but that are not a network asset". Examples given are land, buildings, furniture, vehicles, tools, plant, machinery, IT systems, asset management systems, software etc. Every effort will be made to identify these assets. The non-network asset quantities are unlikely to be as definitive as the network assets as they are not generally included in the same datasets or maintained in the same way.

7.1 Non-Network Asset Description

<u>Land and Buildings</u>



EA Networks have a long history in the Mid Canterbury district. Since inception, the main office was in the middle of Ashburton adjacent to what was the NZED Ashburton substation which supplied the town and surrounds with electricity at 11kV. This site had evolved over the years and the town had evolved around it. The age of many of the buildings, the surrounding retail environment, the recent Canterbury earthquakes, the dispersed nature of stock storage, among a host of other pressures led to a decision by the Board to search for a new base. Fortuitously, the Ashburton District Council were developing a new business park at his time. In late 2012,

EA Networks shifted from Kermode Street (in the CBD of Ashburton township), to a new purpose-built facility in the Ashburton Business Estate north of Ashburton. The site covers about 3.6 hectares and is fully self-contained with main office, Field Services office/workshops, and main store/pole yard. The site has diesel fuel facilities, is generator backed-up, has multiple access roads to/from the site, and is designed for heavy traffic egress. The buildings have been designed as 'IL4' facilities which provides assurance that during and after a significant seismic event they will remain fully functional and permit EA Networks to respond to any earthquake damage without having to remediate or shift from its base facilities first.

Other interests in land and buildings include a small number of decommissioned substation sites that have yet to be disposed of or retasked.

<u>Furnishings</u>

The buildings have been furnished with new equipment (circa 2012-13) in most cases. Desks, storage cabinets, chairs and tables are almost all in good condition.

<u>IT Hardware Infrastructure</u>

Desktop PCs and monitors are all in serviceable condition. PCs are replaced on a regular basis and the server infrastructure is replaced every 5+ years. The LAN wiring and WiFi infrastructure is in fully serviceable condition.

The back-office systems such as telephony and server infrastructure are adequate, although on-going development and replacement will ensure additional performance and functionality will be provided. Extensive use is made of server virtualisation which ensures high levels of flexibility and relative ease of recovery from server hardware failures.

Vehicles

There are a range of vehicles associated with the provision of the electricity line service function. These range from executive vehicles (some with private use as part of salary packages) through to two forklifts, two small flat-deck trucks, and a pole handling vehicle for use in the stores yard. The Field Services vehicles are part of that business function and as such are assets of the Field Services division of EA Networks.

The quantities are as follows:

Car/Wagon/SUV	13
Utility	8
Forklift (Stores)	2
Pole Handler (Stores)	1
Small Truck (Stores)	2

Tools/Plant/Machinery

The inventory of tools, plant and machinery is reasonably extensive but is not categorised in a fashion that permits meaningful reporting. Additional categorisation will be added to the dataset to enable a meaningful schedule of these items in future plans. Included in this area are items such as electrical test equipment, portable power quality recorders, thermographic equipment, etc.

Software and IT Systems

EA Networks have a range of software licences ranging from desktop operating systems and general document editing software through to advanced technical analysis software. Corporate server-based systems include financials, stores, asset management, payroll, and other typical back-office systems.

The major corporate systems/applications are:

- Financial/Stores/Payroll - Technology One
- GIS - Hexagon/Intergraph G/Technology
- Asset Management System - Technology One
- Technical Analysis - DigSilent and ETAP load flow and fault analysis
- Customer Management System - Customised Salesforce Platform (Cloud hosted)
- Data Warehouse - MS SQL Server with management layer
- Electricity Network Billing Engine - Custom application
- Distribution Management System - OSI Monarch (SCADA, OMS, DMS, & Others)

Desktop licences include:

- Microsoft Office
- Custom Software – QuickMap GIS
- Technology One - Asset Management System & ERP system clients
- Hexagon – G/Technology GIS clients
- Tableau - Business Information clients
- Salesforce – Customer Management

7.2 Non-Network Policies

There are a limited range of formal policies relating to non-network assets.

Buildings are currently all brand new and as such there is no policy relating to development. The maintenance and renewal of the buildings will have a formal policy prepared to ensure the standard of maintenance is sufficient to guarantee full functionality and value is retained. It will be some time before any age-related building renewal will be required.

Vehicle replacement is covered by a corporate policy and this states that a vehicle will be replaced whenever it is 3 years old (unmarked – private use) or 5 years old (marked – no private use).

Office furniture procurement has no formal policy, but any reasonable ergonomic requirement can be accommodated. Furniture is expected to last a minimum of 5 years with 10 years being a practical end of life for many chairs.

Desktop PCs have an average replacement cycle of 3 years. This ensures computing platforms are kept current and PCs are replaced before components begin to fail causing data loss and unnecessary downtime for the employee.

The IT infrastructure (servers and switches) is generally upgraded as and when required rather than on any set timescale. When an update occurs, it generally provides a significant increase in performance and until that performance advantage is eroded to an unacceptable level, the status quo will prevail.

7.3 Non-Network Programmes and Projects

There is a background level of expenditure on non-network assets such as vehicles, plant and IT that is routine and largely constant. Periodically, larger sums will be required for specific development, replacement or upgrade projects/programmes.

There are a number of projects in the coming year (2020-21) that have been identified.

Project	Year	Name	Category
11074	2021	**Advanced Distribution Management System**	Non-Network Assets

Largely covered by the description in Section 5.4.10, EA Networks are in the process of implementing a system that can administer many aspects of operating an electrical network. The range of benefits that the system provides covers many areas of the business and it deserves mention under this section as well.

This project is implementing a solution that will provide most of the desired functionality such as SCADA, real-time schematic and dynamic tracing of all connected network. Other features such as call management and workforce management will also be developed over time.

The project has carried over from 2020 due to some delays caused by the vendor.

11550	2021	**Control Centre Layout Changes**	Non-Network Assets

The Network Control Centre at EA Networks JB Cullen Drive headquarters requires some improvements to accommodate the new ADMS system. More, larger screens need to be accommodated as do additional work areas for staff. The changes will occur within the existing control room footprint.

10990	2021-30	**GIS Development Programme**	Non-Network Assets

The Hexagon GIS (Geographic Information System) is the storage and maintenance system for the corporate geospatial data and the electrical and fibre optic network models.

To gain the most value and benefit from the GIS it is important to not only develop the product and its workflows but to also extend the functionality so that it integrates widely into the corporate systems architecture.

This programme of development work will permit increases in: productivity, asset data timeliness and accuracy, asset financial data accuracy and integrity, information timeliness and accuracy to customer interfaces, and a wealth of other benefits. As specific goals are identified, they will be documented in the plan and progress towards those goals will then be reported.

-1009	2021-30	**Routine Replacement Vehicles**	Non-Network Assets

The replacement of network vehicles occurs at a rate of about 4-6 per annum.

The 2021 year has introduced an amended vehicle policy and it requires a higher than normal level of replacement to synchronise the backlog of existing vehicles to the new requirements.

These projects provide for the replacement vehicles and any accessories necessary to make it suitable for use (flashing beacons, canopies, storage boxes, aerials and DMR radio, etc).

-1007	2021-30	**Non-Network Routine Information Technology Projects**	Non-Network Assets

Although they are not individually identified, there will inevitably be I.T. projects that are required to keep the business operating at a reasonable level of efficiency and application sophistication.

This programme provides for one or two medium sized I.T. developments each year to ensure the business does not fall behind with the IT tools that keep it within the peer business norms of I.T. usage.

Some of the developments are likely to be ongoing for several years.

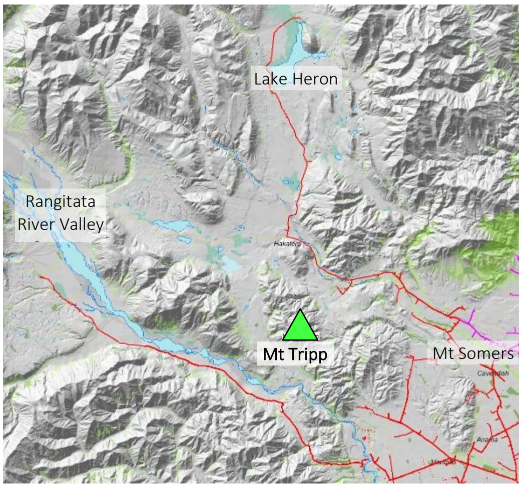
11550	2021-30	**Office Building Alterations and Improvements**	Non-Network Assets

This programme provides for some minor alterations and improvements to the main office buildings to either improve the working environment for existing staff, or, rearrange the internal configuration to accommodate additional staff.

-1041	2021-30	**Aerial Photography**	Non-Network Assets

EA Networks have joined a consortium of Canterbury organisations that procure aerial photography for a variety of uses. There are two key variants: rural with 0.2m GSD (ground sample distance ~ physical pixel size), and urban with 0.075m GSD. These allow data capture of pole and other asset location as well as preclude the need for many site visits when (re)designing assets. The photography is re-flown every 4 or 5 years and this has been allowed for in the plan.

11651	2021	**DMR Repeater Stations for Ashburton / Rangitata Gorges**	Non-Network Assets



The DMR (Digital Mobile Radio) system is the primary operational voice communication system for EA Networks. It has good coverage over the plains area of the network but the area in the foothills of the Southern Alps is devoid of both DMR and cellular phone reception. This project will install a new repeater station atop Mt Tripp.

The new repeater will give DMR coverage to the remote river valleys. This provides the ability to monitor personnel when they are working in these locations. The DMR system has GPS location as well as a "man-down" alarm. "Man-down" detection works using sensors in the hand-held radios to identify when a person has transitioned from the vertical to the horizontal orientation and it alarms the worker. If no response is received from the worker (button push), the radio will then alert the controller that the worker is down and give them their location. The worker can also trigger an alarm by holding down the alarm button on the radio for several seconds. Both alarm triggers cause the worker's microphone to transmit for 30 seconds without touching the radio (overriding other users). The controller then has a similar (and exclusive) length of time to talk to the worker.

The safety enhancement this provides along with the operational benefits fully justifies the investment.

-1042	2021	**DMR Unify Vehicle Mobility and Hot Spot**	Non-Network Assets

1042 [2021] DMR Unify Vehicle Mobility and Hot Spot

This project installs an additional feature to existing mobile DMR installations to facilitate the use of vehicle based WiFi mobile data using a hierarchy of paths. The primary path is WiFi if available. Cellular data is used if WiFi is unavailable. If cellular is unavailable, the low bandwidth DMR data channel is used. There is also the facility to use satellite data, but that has not been utilised at this stage.

The ability to use wireless data virtually anywhere on the network ensures that electronic messaging is pervasive. Operational instructions and other small data packets can be sent and received minimising the risk of mistakes in transcription from verbal radio messages. When in cellular or WiFi coverage, photos and larger data files can be sent and received by workers ensuring good, timely information is available to those that need it.

FINANCIAL SUMMARY

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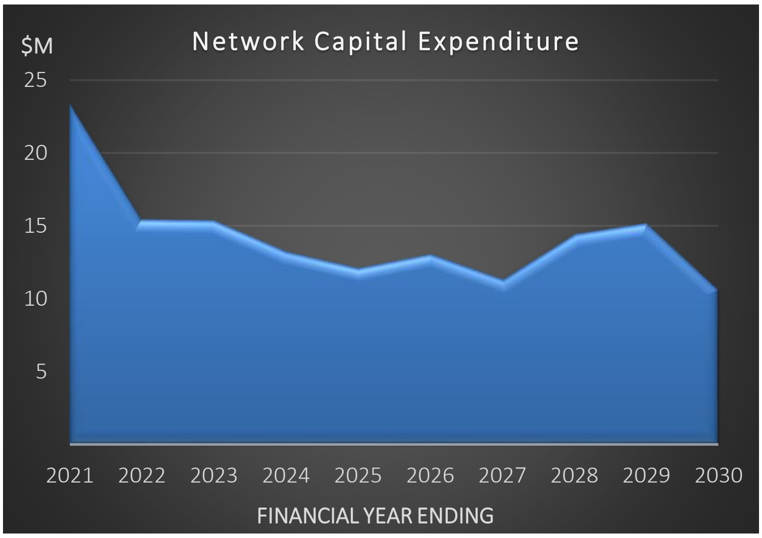
8 FINANCIAL SUMMARY

8.1 *Capital Expenditure*

Costing has been prepared for all projects and programmes identified in this plan. Detailed project costs are shown in Appendix B. Also see the Executive Summary for a capital expenditure by programme breakdown.

Overall Network Capital	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
Subtransmssion	1,247	1,045	1,028					1,675	2,625	1,443
Zone Substations	2,078	477	466	458	462	1,972	365	527	2,537	837
OH Distribution	4,240	3,393	3,238	2,116	1,722	1,707	1,813	2,283	3,188	2,251
UG Distribution	7,225	3,556	2,946	4,345	3,586	3,515	3,112	3,967	1,997	1,359
Dist'n Substations & Transformers	4,855	3,394	3,991	4,124	4,016	4,019	4,093	4,039	2,860	2,931
Distribution Switchgear	1,036	415	425	718	713	664	670	757	625	612
Other	592	2,291	2,298	512	505	211	203	207	239	209
Non-Network	2,171	904	1,004	1,004	1,136	1,004	1,107	1,003	1,132	1,008
TOTAL ($k)	23,444	15,475	15,396	13,277	12,140	13,092	11,363	14,458	15,203	10,650



It should be noted that the estimates for the first half of the planning period are based on known drivers and hence are more accurate than those for the second half which are more in the nature of trend analysis due to a large number of unpredictable factors.

The general trend is for a decreasing expenditure after an initial peak with a bulge later in the planning period. A significant amount of development causes a large, but decreasing, amount of expenditure through most of the planning period (2021-28). It must be remembered that there is more uncertainty towards the end of the plan. The first year has been impacted by delayed projects that have skewed expenditure by several million dollars over that predicted previously.

The development programmes that prompt expenditure are: underground conversion (urban and rural), 11-22kV conversion, 66kV overhead rebuilds (2021-23), Ashburton 11kV core network, and distribution automation as reclosers, gas switches and rural ring main units are progressively automated. By doing this, EA Networks is planning to reduce outage quantities, durations and switching times, ultimately resulting in improved reliability statistics.

As would be expected, the bulk of the expenditure involves developing EA Networks' major assets – lines and substations. Non-network expenditure has become a significant cost as office-based systems to support the business increase in scale and complexity. By 2023, almost all subtransmission line and zone substation development work has been completed and capital expenditure then drops significantly. By 2029, the underground conversion programme is finishing, the 11kV core network cabling finishes about the same time, as does the 11-22kV conversion. The possible (but very uncertain) developments around the need for Montalto 66/22kV zone substation and a second GXP are timed for 2028-2030 and form the bulge in that interval. The 'baseline' level of capital expenditure (which includes consumer connection expenditure) is about $10M. The next rise in expenditure could occur when the decision is made to contract Transpower for another 66kV GXP (although this is likely to be largely operational expenditure).

The 'Other' category is the residual items in projects that are difficult to otherwise categorise. It represents a small proportion of the total.

Consumer Connections	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
Subtransmssion	0	0	0	0	0	0	0	0	0	0
Zone Substations	0	0	0	0	0	0	0	0	0	0
OH Distribution	491	486	479	474	463	459	452	440	438	454
UG Distribution	1,121	708	684	706	681	661	629	611	609	632
Dist'n Substations & Transformers	1,731	1,466	1,712	1,475	1,466	1,446	1,446	1,406	1,401	1,453
Distribution Switchgear	209	68	70	73	74	71	70	68	68	71
Other	0	0	0	0	0	0	0	0	0	0
Non-Network	0	0	0	0	0	0	0	0	0	0
TOTAL ($k)	**3,552**	**2,728**	**2,945**	**2,728**	**2,684**	**2,637**	**2,597**	**2,525**	**2,516**	**2,610**

Consumer connections are completely demand driven i.e. they occur when the consumer requires a new or enhanced connection rather than in any reliably predictable manner. Statistically, there have been a certain number of new connections and this, along with known development, has been used to project the future requirements.

System Growth	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
Subtransmssion	83	0	0	0	0	0	0	1,675	1,234	0
Zone Substations	946	0	0	358	362	1,511	365	527	2,537	368
OH Distribution	384	122	554	253	162	161	163	578	1,033	15
UG Distribution	735	579	504	1,247	1,261	1,285	1,270	1,237	578	544
Dist'n Substations & Transformers	1,824	1,025	1,139	1,906	1,842	1,825	1,855	1,808	651	676
Distribution Switchgear	48	15	5	327	321	318	324	315	300	311
Other	248	1,965	1,966	199	201	211	203	207	239	204
Non-Network	0	0	0	100	101	100	101	99	98	102
TOTAL ($k)	**4,268**	**3,706**	**4,168**	**4,390**	**4,250**	**5,411**	**4,281**	**6,446**	**6,670**	**2220**

System growth assumes the peak demand growth estimated in section 5.2 occurs. If the load growth does not occur or is significantly delayed, then some of this expenditure will drift later in the planning period or not occur at all. The baseline increase in underground distribution is caused by the 11kV underground cable component of the core network programme to reinforce the urban Ashburton network from 2020 onwards finishing in 2027. The zone substation developments cause large peaks in this expenditure which typically correspond to significant increases in distribution capacity available from that site (Methven & Lauriston 2020/21; Tinwald and

Montalto in 2026 and 2029 respectively).

Asset Replacement & Renewal	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
Subtransmssion	904	990	1,028	0	0	0	0	0	0	0
Zone Substations	154	67	67	68	69	68	0	0	0	0
OH Distribution	3,328	2,650	2,071	1,355	1,063	1,053	1,163	1,232	1,335	1,385
UG Distribution	4,898	2,042	1,637	2,324	1,575	1,500	1,143	2,051	742	112
Dist'n Substations & Transformers	786	716	730	646	609	649	692	728	711	701
Distribution Switchgear	502	316	334	312	312	268	271	368	251	224
Other	18	16	16	13	0	0	0	0	0	0
Non-Network	0	0	0	0	0	0	0	0	0	0
TOTAL ($k)	**10,590**	**6,797**	**5,883**	**4,718**	**3,628**	**3,538**	**3,269**	**4,379**	**3,039**	**2,422**

Asset replacements are at a significant level for the first six years. This can be explained by the amount of development that has occurred and is still planned. All condition-based underground conversion (urban and rural) is included here. The remainder is rural overhead distribution line rebuilding and three 66kV line rebuilds (converted 33kV lines from the 1980s). Once the underground conversion programmes begin to wind back (2029 onwards) the level of replacement activity drops sharply to largely rural overhead distribution line rebuilding activities.

Asset Relocations

Asset relcoations are relatively rare events in the predminantly rural Mid Canterbury district. When they do occur they are on-demand at relatively short notice so cannot be reliably predicted. EA Networks have not allowed for any asset relocations.

Reliability, Safety & Environment	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
Subtransmssion	260	55	0	0	0	0	0	0	1,391	1,443
Zone Substations	875	410	398	31	31	392	0	0	0	470
OH Distribution	37	134	134	34	34	34	35	34	381	396
UG Distribution	472	227	121	68	69	68	70	68	67	70
Dist'n Substations & Transformers	513	187	409	98	99	98	100	97	97	101
Distribution Switchgear	278	16	16	6	6	6	6	6	6	6
Other	325	310	317	300	303	0	0	0	0	5
Non-Network	0	0	0	0	0	0	0	0	0	0
TOTAL ($k)	**3,230**	**3,403**	**1,872**	**1,175**	**518**	**532**	**2,269**	**2,797**	**205**	**205**

The reliability, safety and environment category contains a number of the development programmes that EA Networks runs. These include the Ashburton 11kV core network switching centres, rural ring main unit programme (finishing in 2020-21), one 11-22kV conversion project (2022-23), the distribution automation programme, and a number of subtransmission and distribution projects that have generally been triggered by a desire to improve reliability and/or safety.

8.2 Maintenance Expenditure

In future plans, the maintenance programmes will be assessed individually and trended and the impact of both more modern and increased quantities of equipment will be factored into the cash-flows. Currently the maintenance planning costing is relatively short-term and this has been extrapolated forward as the best information currently available.

As information systems and condition data improve it will be used to refine the future maintenance expenditure forecasts.

Overall Maintenance	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
Subtransmssion	129	132	133	134	134	134	134	135	135	135
Zone Substations	417	429	429	432	432	432	432	432	432	432
OH Distribution	1,897	1,921	1,889	1,893	1,843	1,847	1,865	1,869	1,873	1,877
UG Distribution	138	126	130	150	152	156	137	138	138	138
Dist'n Substations & Transformers	629	627	627	647	647	647	627	627	627	627
Distribution Switchgear	511	517	521	521	522	522	524	525	525	526
Other	186	184	184	214	214	231	231	214	214	214
TOTAL ($k)	**3,907**	**3,936**	**3,913**	**3,991**	**3,944**	**3,969**	**3,950**	**3,940**	**3,944**	**3,949**

The EA Networks network is relatively young overall. The significant levels of recent development have replaced much of the subtransmission network and coincidentally the distribution network on the same route. The 11-22kV conversion programme has 'refreshed' much of the distribution network although it has not necessarily extended the life of individual overhead structures. All the 22kV transformers are in very good condition. Underground conversion continues to remove the oldest urban overhead lines from the asset pool and consequently there is no 'maintenance mountain' within the planning period.

Service Interruptions & Emergencies	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
Subtransmssion	45	46	46	46	46	47	47	47	47	47
Zone Substations	38	38	38	38	38	38	38	38	38	38
OH Distribution	771	775	779	783	787	791	794	798	802	806
UG Distribution	53	53	53	53	53	53	53	53	53	53
Dist'n Substations & Transformers	23	23	23	23	23	23	23	23	23	23
Distribution Switchgear	170	172	172	173	173	174	174	175	175	175
Other	0	0	0	0	0	0	0	0	0	0
TOTAL ($k)	**1,100**	**1,107**	**1,111**	**1,116**	**1,120**	**1,126**	**1,129**	**1,134**	**1,138**	**1,142**

The levels of expenditure for faults are forward extrapolations of a typical year. Future plans will continue to refine the impact that intensive development and maintenance have on the fault rate/cost.

Vegetation Management	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
Subtransmssion	27	27	22	22	22	22	22	22	22	22
Zone Substations	0	0	0	0	0	0	0	0	0	0
OH Distribution	306	306	254	254	254	254	254	254	254	254
UG Distribution	0	0	0	0	0	0	0	0	0	0
Dist'n Substations & Transformers	0	0	0	0	0	0	0	0	0	0
Distribution Switchgear	0	0	0	0	0	0	0	0	0	0
Other	0	0	0	0	0	0	0	0	0	0
TOTAL ($k)	**333**	**333**	**276**	**276**	**276**	**276**	**276**	**276**	**276**	**276**

Trees are the bane of network operators. The control and management of trees appears to be an on-going and unavoidable cost. It is possible these costs may be changed in the future if vegetation control policies are revised in an attempt to reduce tree-related faults. The impact of such a policy is shown as a step change down in 2021.

Routine and Corrective Maintenance and Inspection	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
Subtransmssion	36	40	40	40	40	40	40	40	40	40
Zone Substations	347	359	359	362	362	362	362	362	362	362
OH Distribution	269	287	291	291	291	291	291	291	291	291
UG Distribution	59	45	48	67	67	70	51	51	51	51
Dist'n Substations & Transformers	191	187	187	207	207	207	187	187	187	187
Distribution Switchgear	176	183	183	183	183	183	183	183	183	183
Other	34	38	38	44	44	44	44	44	44	44
TOTAL ($k)	**1,112**	**1,139**	**1,146**	**1,194**	**1,194**	**1,197**	**1,158**	**1,158**	**1,158**	**1,158**

The inspection, servicing, testing and fault-reactive expenditure has been kept to the same level through the plan to continue monitoring the condition of older components such as hardwood poles so that future maintenance may be targeted toward life extension of ageing assets. Newer assets are also monitored and tested to ensure they are maintained to an adequate level to preserve capability and guarantee a full expected lifetime of operation.

Asset Replacement and Renewal	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
Subtransmssion	0	0	0	0	0	0	0	0	0	0
Zone Substations	32	32	32	32	32	32	32	32	32	32
OH Distribution	314	315	276	276	223	223	237	237	237	237
UG Distribution	27	28	29	31	32	33	34	35	35	35

Dist’n Substations & Transformers	416	417	417	417	417	417	417	417	417	417
Distribution Switchgear	165	162	165	165	165	165	167	167	167	167
Other	145	146	146	170	170	186	186	170	170	170
TOTAL ($k)	1,099	1,100	1,065	1,091	1,039	1,056	1,073	1,058	1,058	1,058

There are relatively low levels of like-for-like component replacements in the EA Networks asset pool. The majority of asset replacement/renewal involves an intentional increase in capacity or functionality to offer additional system capacity, system security or reliability. The two areas of note where some like-for-like replacements occur are overhead distribution lines (e.g. 11kV or 22kV refurbishment) and distribution transformers and substations where physical deterioration can cause a component of an asset to be replaced.

Non-Asset Specific	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
Business Support	5,574	5,602	5,630	5,658	5,686	5,715	5,743	5,772	5,801	5,830
Operations & Network Support	3,791	3,833	3,852	3,871	3,891	3,910	3,930	3,950	3,969	3,989
TOTAL ($k)	9,365	9,435	9,482	9,529	9,577	9,625	9,673	9,722	9,770	9,819

The non-asset specific expenditure covers the running costs of the business – both technical and back-office. These costs are reasonably well known and do not vary year-to-year by a significant amount. In recent years, staffing levels have increased to rebalance the technical side of the business which has been diluted by the demands of the more rigorous regulated business environment EA Networks operate in.

Staff numbers are anticipated to continue slowly growing. When development rolls back, technical staff will be redeployed to develop the systems and processes that can justify investment. The Operations and Network Support cost begins to increase towards the end of the planning period as staff are reassigned to non-capital work.

DELIVERING ON OUR PLAN

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9 DELIVERING ON OUR PLAN

9.1 *Progress Against Plan*

It has become evident to EA Networks that during times of rapid load growth, significant demands are placed on the company and its resources – both financial and human. This extra pressure means that work is prioritised and even though every best endeavour is made to complete work in the timescale originally proposed, occasionally it is not. This can be for any number of reasons but primarily it is that there were more important things that had to be done and any work that could be deferred was. In recent times, external factors such as resource consents have caused some delays. If the task involves supplying new load or a safety requirement, it will inevitably be done. Where the task involves improvements to security or reliability it will be done with the next highest priority. Where the task is largely documentary and pre-emptive (e.g. contingency plans), it has been known to slip down the list of priorities. As growth declines, EA Networks will be able to progress the Asset Management Plan to become an increasingly accurate and mature document, with more robust linkages to other systems.

9.1.1 Physical

Physical progress is essentially measured against the items in the financial plan for any given financial year. This can give a slightly distorted view in that a delay of weeks or a few months causes some projects to slip from one financial year to another which, for equipment with life expectancies of 40 to 50 years, is negligible. If replacement works or new project planning is timed that critically (other than for specific new loads) that it cannot wait for a few months, then it has been left too late.

Targets

The basic target for physical progress is to ensure that network performance is not sacrificed because of planned work not proceeding on the proposed timescale.

Outcome

Capital projects critical for supplying new load and dealing with immediate security concerns were generally attended to. Some less immediate and more strategic projects have been deferred, a few by only months.

The 2016-26 Asset Management Plan identified many projects that were planned for completion during the 2016-17 financial year. The following table identifies each incomplete major project (>100k) listed in the 2016-26 Asset Management Plan, its status as at 1 February 2018, and a commentary on the project.

There was no 2017-27 Asset Management Plan (an update was issued in its place). There was however a schedule of projects that were planned for completion during the 2017-18 financial year. The following table identifies each incomplete major project (>$100k), its status as at 1 February 2018 and a commentary on the project.

2019-20 Asset Management Plan Project Progress/Forecast as at February 2020

Planned F.Year	Project ID	Description	Status Feb 2020	Commentary
2020	-1010	11kV Core Network Cables	5%	Design resources and Network Centre location uncertainty has delayed the programme. Design progressing.
2020	-1011	11kV Core Network Centres	5%	More time than anticipated has been spent resolving urban site availability. Design now progressing.
2020	12045	11kV Metering Point - Rakaia Gorge	0%	Delayed while Upper Rakia River Crossing project is delayed. Equipment purchased.
2020	12418	11kV OH Rebuild - Rangitata Gorge (Coal Hill - Waikari Hills)	0%	Various resource constraints prevented progress on this project.
2020	12050	11kV OH Rebuild - Rangitata Gorge Bluffs	0%	Various resource constraints prevented progress on this project.

Planned F.Year	Project ID	Description	Status Feb 2020	Commentary
2019	12427	22kV OH Rebuild - Gibsons Rd (Fitzgerald Rd - North to end)	0%	Planned outage suspension in Jan-Mar 2020 has prevented construction.
2020	12614	22kV OH Rebuild - McCrorys Rd (Mainwarings - Dorie School Rds)	50%	Planned outage suspension in Jan-Mar 2020 has prevented completion.
2019	11893	22kV OH Rebuild - Upper Rakaia River Crossing	5%	Resource consent issues and seasonal river flow constraints caused April/May 2019 slot to be missed. All design done.
2020	-1037	66kV OH New - LSN-LSNT	85%	Resource consent and Council road relocation proposal & consultation has delayed Lauriston end of line.
2020	12084	DSS Rebuild - Moore St 93 Substation	5%	Location of site requires new seismic design for pad and this has taken longer than anticipated.
2018	11651	Non-Network - DMR Repeater Stations for Ashburton/Rangitata Gorges	10%	All equipment procured but access to preferred Mt Tripp site declined by DoC. Alternative site being negotiated.
2020	11074	Non-Network - Software - Distribution Management Software - Control Centre	60%	Delays caused by vendor resourcing issues and scope alterations. Significant progress achieved.
2020	-1045	RMU (3 x CB) - cnr Dromore Methven Rd and Winchmore School Rd	10%	Some progress but other design workload has delayed progress.
2020	12440	RMU (3 x CB) - cnr Scales Rd & Swamp Rd	90%	Largely complete but cable connections delayed because of suspension of planned outages.
2020	12464	RMU (4 x CB) - cnr Rakaia Barrhill Methven Rd & Wolseley Rd	5%	Design resources delayed progress but design now complete. Work may start before end of 2019-20 year.
2016	-1007	Electricity Billing Engine & CRM System	10%	Will continue in 2020-21. Historical difficulties with development has pivoted focus to a collaborative effort with other ENA members. RFP will be issued. CRM is making progress with ADMS interface.
2016	-1007	Enterprise Resource Planning System	15%	Reliant on other system developments that are still incomplete.
2016	12443	UG Conversion - Convert State Hwy OH crossings to UG	5%	Designs progressed but corridor managers have yet to approve access. Should be complete in first part of 2020.
2017	10954	Non-Network - Survey Accurate GNSS Unit	20%	Some trial units purchased, and probable will be complete in 2019-20.
2019	12077	ZSS ASH - Building Improvements	0%	Concepts have been completed, but design and construction not progressed because of internal resource constraint.
2018	11586	11kV OH Rebuild - Rangitata Gorge (Bluffs - Forest Creek)	0%	Design and build resources are over capacity. Design now complete and planned outage suspension prevents start.
2018	11586	11kV OH Rebuild - Rangitata Gorge Bluffs	0%	Design complete, but progress delayed because of planned outage suspension and Rangitata River flood.
2020	12073	ZSS EGN - Reconfigure Site (T1) as 66/22kV.	85%	Most major work complete but some unexpected issues with reused equipment have delayed completion.
2018	11473	66kV UG New - EGN-ASH Cable	100%	Commissioned in late 2019.
2020	12079	ZSS MHT - New Local Service RMU	5%	Several changes in the configuration of the design have delayed the final design. Equipment procured & design fixed.
2020	-1081	ZSS MHT - Replace 33kV CB with ex-EFN dogbox.	10%	Substation design resources are under pressure and design now complete, but on-site work yet to start.
2018	11636	SCADA - Distribution Automation Programme	50%	This is an ongoing programme but ADMS has taken priority.

Planned F.Year	Project ID	Description	Status Feb 2020	Commentary
2018	11070	SCADA - Tap Changer Comms	75%	Good progress made but ADMS priorities took priority. New resource has made further progress
2020	-1058	UG Conversion - Lauriston Township	25%	Some work has been completed but priorities shifted. In conjunction with LSN-LSNT 66kV OH line, work will be completed.
2018	11471	UG Conversion - Longbeach Rd. ON HOLD	0%	Challenges with easements for on-property cable have caused delays. Firm commercial development proposal has now given this some momentum.
2020	-1082	ZSS MTV - MTV-MSM 66kV Line Bay & Protection	5%	What was conceived as a simple project has evolved into a multi-dimensional challenge to develop the site while preventing planned outages. Design is now firm, but path for construction is complex and interdependent.
2018	11618	ZSS - Substation Security (Access Control Only) Programme	75%	An ongoing programme that has been delayed by ADMS pressure. Good progress made and final sites likely to be complete in 2020.
2018	10988	ZSS - Synchrophasors - Stage 1 and Stage 2	2%	Discussions have started with Trustpower and progress is expected in 2020.

Reasons for Variance

In general, new connections (and work further into the network) that is required to support new connections is given priority over other capital or maintenance except for work required to mitigate safety issues.

Delays in projected work have many underlying reasons ranging from the need to level human resource demands, to legal proceedings or on occasion access difficulties. The window of opportunity for much of the work on the EA Networks' network is narrow as irrigation demand removes the summer months from the rural work schedule. This leaves the less settled autumnal, winter and early spring months as the rural work window. With the advent of dairy herds across the entire EA Networks region, it has further narrowed this window as milking also occurs outside the irrigation season. To further compound this, dairy supplies often limit planned outages to between 9am and as early as 3pm. When a significant winter storm occurs, it can take resources away from planned work and create a backlog of project work that must be either completed or deferred until next autumn at the earliest. Thankfully, during 2018-2020 the weather caused few widespread issues.

The notable slowing in peak load growth has altered the priorities of the forecast work. A 5-10 year individual project schedule for underground conversion work and 11-22kV conversion is incorporated in the plan. Both these programmes are forecast to conclude during the planning period.

Delays in critical projects can have a cascading effect as others are either directly dependent or will impact negatively on security if they proceed prior to the critical project. In these cases, every effort is made to address the delay as quickly as possible but there are occasions when this is outside the control of EA Networks.

<u>Engineering Resources</u>

During the last few years, EA Networks has employed multiple engineering staff to assist in the workload that a considerable number of projects have placed upon the existing resources. It takes time for new engineers to become familiar with the business and adapt to a workplace after leaving university. To become productive, the new engineers are mentored by existing staff and this does take time away from 'production' tasks such as design and planning. Graduates show much promise to fill the gaps that have caused many delays in the past. EA Networks currently have no engineering vacancies.

<u>Volume of Externally Driven Work</u>

The volume of work that has been driven by external agencies and organisations can be significant. The state highway projects that have changed from overhead rebuilds to underground conversion has increased workload as do large subdivisions. All this work increases demands on engineering and construction staff. Staff do their best to meet these challenges, but there are times when they cannot meet all expectations and this period has been one of those times.

Managing expectations of external organisations is an important aspect of dealing professionally with them. Realistic timeframes need to be given when it is known that the staff involved are already very busy. This has not always been handled well.

Contractor Availability

The availability of contractors and the progress they make compared to that anticipated can both have a significant impact on project progress. There are a limited number of contractors active in the mid-Canterbury area. There are times when EA Networks is using most of them in some capacity. If other important clients call upon the contractor's services EA Networks' projects can slip.

Planned Outage Availability

The nature of the Default Price-Quality Path for 2015-2020 is such that should some unexpected faults occur that threaten to cause a breach of the SAIDI and/or SAIFI cap then the only way to prevent this is to reduce planned outages. This is the case for the 2019-20 year. Two significant events have pushed unplanned SAIDI uncomfortably close to the regulatory limit. In December 2019, a long and widespread lightning storm caused significant numbers of transformer failures and shortly afterwards the Rangitata River flooded to historic levels and washed away two river crossings serving more than 50 consumers.

A decision was made to suspend planned outages to prevent a breach. This has obvious consequences for a range of work and has impacted on progress for the 2019-20 year.

Plans to Address Variance

To date, the variation in planned work completion dates has not had a material effect on network performance. Essential work is always completed and any work that is targeted for deferral is evaluated for its criticality. If it is seen that a particular project must proceed, external assistance is sought to ensure its completion in the required timeframe.

Load growth has slowed considerably, and this has freed up some resources. The internal contractor still has vacancies for staff and the likelihood of further pressure nationwide for skills will continue with some other lines companies having ambitious programmes to upgrade their networks.

Our overhead network continues to age. The requirement of all new connections to the network at 22kV or below to be by underground cable has placed additional workloads on cable laying resources. As a result of this, EA Networks has increased its field resources in this area.

On a more general note, EA Networks had invested in additional resources, both human and non-human, to address some of the project management issues that have hindered completion of some jobs. Now that the optimal number of engineering staff are employed, over the next few years it is hoped that they can make a marked difference in the performance of the network and timely progress on planned work.

9.1.2 Financial

For a decade, the EA Networks Asset Management Plan has formed the core of future financial planning for the Board and management of EA Networks. Corporate 10-year cash-flows are based on the data contained in the schedules prepared for the annual Asset Management Plan.

The reader is also referred to https://www.eanetworks.co.nz/Disclosures/Regulatory.asp for additional detailed information about the financial performance of the company and its assets.

Budget

Each year the AMP is prepared in tandem with the annual budget and the major projects are extracted from the AMP to form the core of the budget. Smaller, previously unscheduled, works are identified in the budget and used to 'flesh out' the AMP to include the details of work that comes to light at relatively short notice or is based upon newly gathered information.

This approach to budgeting/AMP preparation tends to cause an influx of small projects into the AMP project schedules that were previously unidentified. These numerous small projects, although not identified, are allowed for in the AMP forecast as 'unscheduled' items that are grouped together in an estimate of the total likely cost of such activities (based upon historical statistics).

As budgeting techniques and tools are refined, and more staff resources can be made available for data analysis showing trends and previously hidden statistics, it is possible that some of the unscheduled work will be placed in to scheduled projects and programmes to target specific aspects of network performance.

The following analysis focuses on network expenditure rather than non-network expenditure. The AMP's focus is on managing the assets in the network, so this approach is considered valid. A summary of non-network

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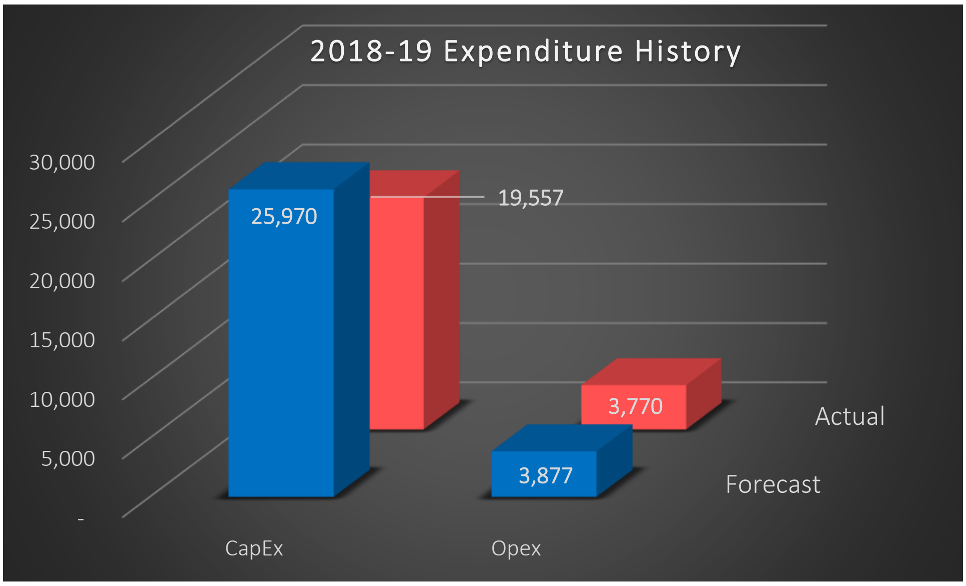
expenditure is provided but no detailed explanation is provided.

The 2018-28 Asset Management Plan Update contained the following financial plan for the 2019 financial year (actual results are shown alongside):



	Category	Capital Expenses		Operational Expenses		Delta
		Forecast	Actual	Forecast	Actual	
2018-28 AMP Forecast - 2019	Customer Connection	3,268	3,075	-	-	-193
	System Growth	4,933	3,294	-	-	-1,639
	Reliability, Safety and Environment	3,231	3,464	-	-	233
	Asset Replacement & Renewal	11,941	8,769	-	-	-3,172
	Asset Relocations	-	-	-	-	0
	Non-Network Assets	2,597	955	-	-	-1,642
	Routine & Preventative	-	-	1,082	1,214	132
	Refurbishment & Renewal	-	-	1,361	1,313	-48
	Fault & Emergency	-	-	1,101	773	-328
	Vegetation Management	-	-	333	470	137
	TOTAL ($,000)	**25,970**	**19,557**	**3,877**	**3,770**	**-6,520**
	Non-Network System Operations & Network Support	-	-	3,690	3,809	119
	Non-Network Business Support	-	-	4,715	4,527	-188

Outcome

The chart above shows the disclosed 2018-19 actual performance compared to the forecast amount in the 2018-28 plan.

The actual values have been extracted from 2018-19 disclosure data.

As can be seen from the chart, the operational (maintenance) expenditure was 97% of that forecast (-$107k). The capital expenditure was 75% of the forecast (-$6,403k).

Overall Operational expenditure was very close to the values predicted.

Capital expenditure was not as forecast. Customer connections were at a slightly reduced level compared to forecast. Several underground conversion projects remained incomplete caused by resource limitations in design and build. Non-network assets were below forecast as significant I.T. projects faced delays largely caused by internal resourcing issues.

Reasons for Variance

Explanation of variance more than 10% and others for interest:

Capital Expenditure. Customer Connection (-$193k ~ -6%)

The actual investment in consumer connection has historically and continues to be affected by numerous external macro events. EA Networks has no control over those macro events, such as dairy pricing or ECAN regulatory rules, which in turn drives irrigation connection demand. While EA Networks incorporate all known factors into its connection AMP forecast a large amount of data remains hidden from EA. ECAN nutrient run-off restrictions which limit irrigation water use, and an ample supply of developed urban subdivisions suppressing demand for further development are contributing factors. There will always be some variance from forecast to actual as the ebb and flow of the economy governs consumer decisions.

Capital Expenditure. System Growth (-$530k ~ -11%)

Several large projects had timing slips which impacted on end of year progress.

- Zone Substations: Projects at Elgin and Ashburton were delayed by seasonal constraints and logistics with outages. Some progress was made but not all budget spent.
- 66kV Overhead Line New: EGN-FTN line was started but seasonal outage constraints limited construction time. Some progress was made but not all budget spent.
- Distribution Transformers: 11-22kV conversion transformers were over-forecast.

Capital Expenditure. Reliability, Safety and Environment (+$233k ~ -7%)

Overall, the category was close to budget but within the category some variations existed. Carry-over projects and delays partially cancelled each other.

- 11kV metering Point: Delayed due to resource consent issues on Upper Rakaia River crossing.
- Rural Ring Main Units: Carry-over from prior years.
- SCADA Distribution Automation: Carry-over from prior years.
- ZSS Upgrading 110V DC Supplies: Equipment cost less than budget.
- 11kV Core Network (Urban): Delayed by negotiation with local council and site availability.
- 66kV OH Damper Installation: Delayed by field services resource limitations and limited outage windows.
- 66kV Synchrophasors: Limited engineering resources committed elsewhere.
- Distribution Earth Upgrades: Delayed due to resourcing issue.
- UG Conversion - Rakaia Highway: Increased costs caused by undetected damage to existing ducts requiring re-excavation.
- State Highway Road Crossings: Other condition driven work took priority.

Capital Expenditure. Asset Renewal and Replacement (-$-3,172k ~ -27%)

The budget for Asset replacement and renewal has been managed as a combined budget rather than an item by item base. The main reason for the variance is:

- Upper Rakaia River crossing has been delayed by resource consent issues ($851k).

- The EGN-ASH 66kV underground cable project was delayed by cable delivery issues ($2,845k).

Capital Expenditure. Non-network Assets (-$1,642k ~ -63%)

There were a combination of cost under runs and delays that contributed to a significantly lower than forecast expenditure.

- ZSS ASH Building Improvements: Delayed by focus being on 66kV EGN-ASH cable project (same staff project managing).
- Website development: Chose a lower cost option than was budgeted for.
- Routine vehicles: Fewer vehicles purchased, due to a change in operational requirements.
- Distribution Management System: Change in key milestone payments and vendor delays has caused lower than budgeted expenditure.
- Software - Payroll & ERP System: Focus has been on embedding asset management software rather than shifting effort to development.
- Other Projects: Delayed by a year due to resources being limited.

Operating Expenditure

This operational expenditure was in-line with forecasts and a lack of inclement weather assisted greatly in achieving this.

Please refer to EA Networks annual regulatory disclosure for further details.

Plans to Address Variance

While distributed load continues to grow in somewhat unpredictable locations and scale, the rescheduling of capital projects and expenditure during the forecast year cannot be precluded. Any capital expenditure is spent completing projects for legitimate reasons, there are no plans to address the variance with any specific actions (other than completing delayed projects as soon as it is pragmatic).

The recent increase in engineering resource and the appointment of dedicated project managers for substations and overhead and underground works will help provide better coordination of works as well as focusing personnel on the critical path for all projects.

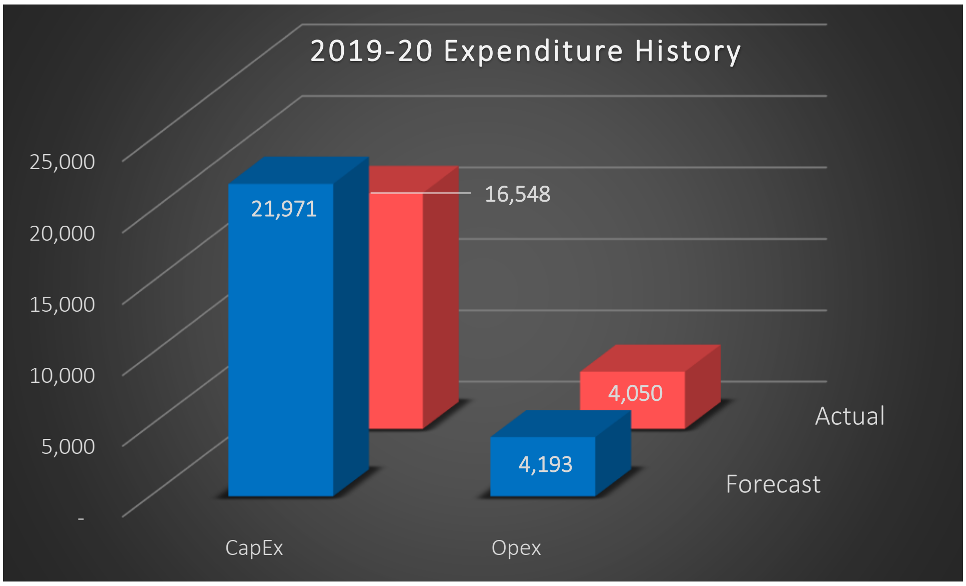
A forecast is simply that, a forecast and not a fact. There are times when the prevailing conditions make it difficult to provide a long- range forecast and aberrant localised conditions can mean forecasts are dramatically wrong.

Efforts are being made to provide a progressive planning mechanism that will review the planned projects every three months and develop a moving 18-36 month active projects database. The projects at the 18-month horizon are candidates for inclusion in the coming year's works programme. The 36-month horizon projects are more conceptual and will only become realistic proposals once thorough investigation has taken place. The projects in the database will be refined as time goes by to ensure their viability and scope. By the time they come to be designed in detail there should be a large amount of knowledge built up about how the project will be designed, built, commissioned and operated. All the project knowledge will be held in the database, so any interested personnel can contribute ideas and critique the technical, timing and cost aspects of the proposal.

Forecast for 2020 Financial Year

As at 1 February 2020, the forecast end of year expenditure versus the 2019-29 AMP Update forecast for the 2020 financial year was as follows:

	Category	Capital		Maintenance		Delta
		AMP Forecast	EOY Forecast	AMP Forecast	EOY Forecast	
2019-29 AMP Update Forecast - 2020	Customer Connection	3,592	1,669	-	-	1,923
	System Growth	4,921	4,805	-	-	116
	Reliability, Safety and Environment	4,009	1,848	-	-	2,161
	Asset Replacement & Renewal	8,024	7,547	-	-	477
	Asset Relocations	-	-	-	-	0
	Non-Network Assets	1,425	679	-	-	746
	Routine & Preventative	-	-	1,430	1,221	209
	Refurbishment & Renewal	-	-	1,157	1,209	-52
	Fault & Emergency	-	-	1,113	1,070	43
	Vegetation Management	-	-	493	550	-57
	TOTAL ($,000)	**21,971**	**16,548**	**4,193**	**4,050**	**5,566**
	Non-Network System Operations & Network Support	-	-	5,008	3,580	1,428
	Non-Network Business Support	-	-	5,511	5,240	271



Commentary on Forecast Variance

While the forecast outcome for the 2019-20 financial year is still open to variance, there are several significant projects that are known to have impacted on the expenditure.

Capital Expenditure

The capital expenditure is expected to be well below the forecast expenditure - by about $5.4M (-25%). There are a range of medium sized projects that have been delayed. The key ones are identified below.

- The Rangitata Gorge 22kV overhead rebuild project has had a series of delays caused by challenging terrain, December 2019 flooding, and planned outage suspension ($468k).
- Ashburton 11kV core network cables have been delayed the previous delays in situating the network centres containing 11kV switchgear – the destination for these cables ($460k).
- The Advanced Distribution Management System has had delays outside EA Networks control imposed on it. This has caused under-expenditure during 2019-20 as milestones were not met (~250k).
- Two rural ring main unit projects were delayed by a reprioritisation of design resources ($304k).
- The Upper Rakaia Crossing has been further delayed by resource consent finalisation causing the contractor to miss the window to work in the river bed ($543k).
- Lauriston township underground conversion has been started but will not be completed in 2019-20 (~350k).
- Methven zone substation reconfiguration has been delayed by the need for intensive project planning to avoid planned outages ($222k).
- There are a range of other projects that have been postponed because of resourcing issues or design changes that were not foreseen at the beginning of the 2019-20 year (collectively $1,300k).

The downturn in customer connection activity has also been significant and represents 35% ($1,900k) of the difference.

Counterbalancing the above projects are undoubtedly some 2018-19 projects that unexpectedly had some expense in the 2019-20 year. Further details will be available once the year has concluded.

Operational Expenditure

Overall, the operational expenditure is broadly in-line with expectations although the components within it seem to have some variability. Until the details have been examined closely the individual work order categorisations may be subject to correction thereby making the categories more in line with forecasts.

9.2 Service Level

9.2.1 Actual Levels of Service

Network Performance

EA Networks have historically set high expectations for its network performance. This is driven by the rising dairy industry profile - where even momentary interruptions caused by a circuit breaker reclosing causes significant disruption to a dairy shed's operation. There is also a rising expectation from all customers that the power will "always be on".

While setting high expectations is a worthy exercise, it can be a difficult target to reach. The method used to set the individual performance targets is to take the average of the last four years planned performance (excluding aberrant years) and add this to the average unplanned performance. This technique attempts to provide a target that is achievable at least some of the time. Previous methods of calculating targets gave unrealistically low values that were very rarely achieved.

The targets are now located in amongst the peer companies that have similar styles of networks. For example, the average SAIDI forecast for peer companies for 2020-24 is 201 minutes while their 5-year average performance is about 360 minutes. The current target for EA Networks SAIDI is 210 minutes. Previous EA Networks targets have been as low as 149 minutes – 25% below the peer average. EA Networks' SAIFI performance is better than average in comparison with both peer companies and slightly better than average for lines companies generally. The 18 peer group lines companies have a SAIFI forecast of 2.31 and a median/average 5-year SAIFI performance of about 2.90.

SAIDI	Total	Unplanned	Planned
2019-20 Targets	210	110	100
Actual / EOY Forecast	200	100	100

The internationally recognised CAIDI, SAIDI and SAIFI indices are useful barometers of how a network has performed over a given interval. These indices can be plotted over time to establish any trends. The tables above and below represent EA Networks' performance during 2019-20 (to 31 January 2020 – Feb/Mar estimated).

The SAIDI target looks likely to be at target.

The planned SAIDI is on target, but this is only because planned outages have been suspended since January 2020 to prevent a breach of the Default Quality Path cap. Fault SAIDI is approaching the target and this is because of lightning and flooding in December 2019.

SAIFI	Total	Unplanned	Planned
2019-20 Targets	1.65	1.25	0.40
Actual / EOY Forecast	1.89	1.54	0.35

The overall SAIFI performance looks to be exceeding target by about 14%. Unplanned interruptions have been impacted by the December 2019 lightning and flooding. Planned interruptions were positively impacted by the resumption of live-line working on all lines and the suspension of planned outages post December 2019.

It should be noted that, in the interests of safety, EA Networks has strict criteria for relivening rural circuits after a fault event. It is possible that irrigators can become entangled in HV lines. There are significant line lengths in and around farm yards. Car vs pole events are not uncommon. For these reasons, in almost all cases EA Networks' standard requires a full line patrol (including on-property lines) after the occurrence of an earth fault. This significantly increases fault restoration times, however, public safety, in EA Networks' opinion, requires this.

Interruptions	Total	Unplanned	Planned
2019-20 Targets	450	150	300
Actual / EOY Forecast	489	288	201

The total interruptions index is only useful to compare to previous network performance as intercompany performance is skewed by the length of network each company operate. From 2015 to 2019, the total interruptions have averaged 474 per annum. 2019-20 appears to be similar, although the number of planned outages is likely to have been inflated by the suspension of planned outages post December 2019.

The faults per 100km (by voltage) parameter is the most useful index to the asset manager.

The performance of the network at subtransmission voltages is encouraging despite exceeding the target values. The voltages which require improvement are the 11kV and 22kV networks. For 2018-19 the overall rate of faults per 100km seems to be about 175% of the target value although appreciably better than the industry and peer average.

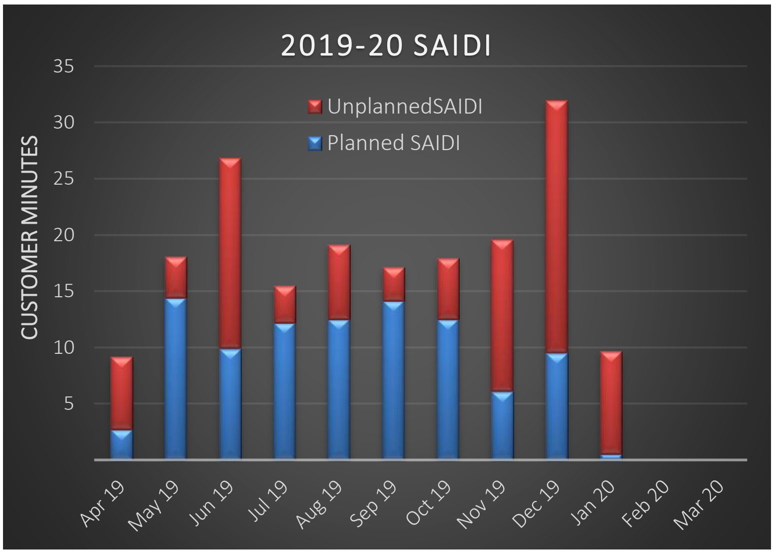
The table shows the voltage at which the network faults are occurring and the chart in section 3.4.1 illustrates the trend of these faults.

Faults/ 100km	Total	11kV-22kV	33kV-66kV
2019-20 Targets	5	6	2.5
2018-19 Performance	9.47	10.52	3.38
2015-19 All Industry Average	16.71	18.32	5.05
2015-19 Peer Average	13.22	14.31	5.72

- These values are calculated using combined *Circuit Lengths* and combined *Number of Faults* from disclosure data 10(v) for 2015-19.
- Overall average is 17.35 faults per 100km (23,631 faults and 136,133km of circuit length) (calculated using combined averages for 2015-19).

EA Networks have revised its vegetation management and line inspection procedures to better predict and prevent future network failures.

Discussion



A considerable quantity of 22kV conversion is undertaken each year. Every effort is made to minimise interruptions by employing additional contractors to complete as much work as possible in every planned interruption. As mentioned previously, the influx of dairy farming severely impacts on the available number of shutdowns and the duration of each shutdown has an effect. The option of live-line techniques for 22kV conversion projects is prohibitively expensive and slow.

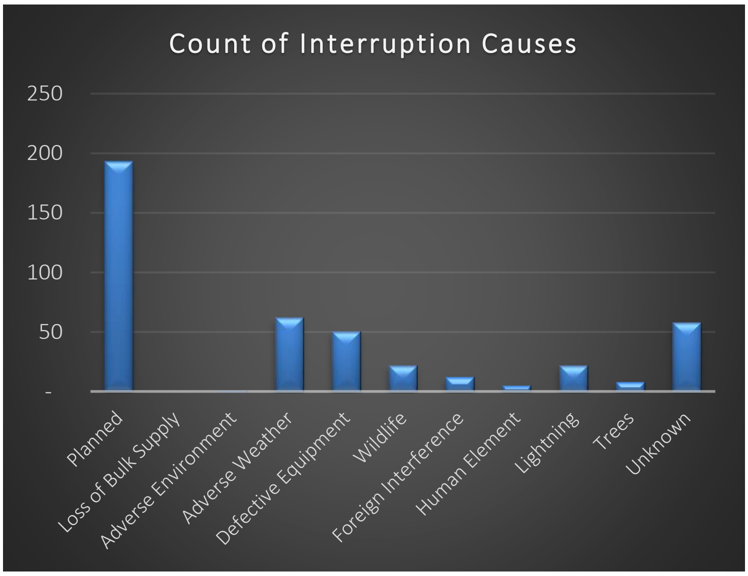
The contribution of planned work to lost customer minutes is significant and this can only be reduced by doing less construction work or more live-line work. The suspension of live-line work in mid-2016 caused the planned SAIDI and SAIFI to rise considerably. There is now a new live-line work protocol in place to assess each job to ensure it is appropriate to use live-line as a benefit/risk trade-off. Planned outages have reduced from the highs of 2017-18 but will not return to pre-2016 levels as the tasks approved for live line work are now more restrictive.

Over recent years, EA Networks has invested heavily in remote controllable devices in the field. This involves installation of modern reclosers, gas switches and, in situations where 3 or 4 lines meet, ground mounted ring main units. At the same time, almost all zone substations have been linked with fibre optic cable. The advent of the fibre optic cable is allowing differential line protection to be fitted to virtually all sub-transmission circuits. Along the fibre route RMUs, reclosers and gas switches are now being connected to the communications infrastructure. This will facilitate quicker fault location identification and restoration on sections not directly affected by the fault. Outside the fibre route, remote-controlled devices will be connected via a radio network. Mid-Canterbury's flat terrain makes reliable radio communication difficult (hence the deployment of a fibre network for protection purposes) however EA Networks have a device available that creates a data network using EA Networks radio voice network core infrastructure.

Installation of remote controllable devices has generally occurred when other works are happening. As a result, it takes some time to get sufficient concentration of these devices in any one area to make a noticeable difference to overall performance. There is now a concerted effort to roll out remote control to as many devices as is practical to achieve noticeable improvements in SAIDI.

Several years ago, EA Networks introduced a policy requiring all new connections to the network at 22kV or below had to be via underground cable. The policy was to reduce the large number of faults that occurred on private property but resulted in a network outage. Since implementing this policy, EA Networks have had very few incidents on property involving underground cable, much less than would have been expected from an overhead service. In addition, safety has been improved through less chance of strikes by irrigators, grain augers etc.

22kV conversion work (and to a much lesser extent 66kV conversion work) will continue to influence the indices for several more years. If unexpected increases in load occur, networks at both voltages may need to be extended and the best cost/reliability trade-off occurs by having relatively few, reasonably long, but very productive planned interruptions.



EA Networks initial 22kV conversions were driven directly by the inability of the existing 11kV network to maintain acceptable voltages under increasing loads. On a voltage-constrained network, doubling the voltage allows four times the load to be delivered with regulatory voltage tolerances. This is achieved for a modest increase in cost and with little change to operating and construction procedures. As the 22kV network has expanded, it has introduced several areas where network security has been compromised owing to the need to supply additional load. EA Networks are now in a catch-up situation where there is a need to convert additional sections of network to restore the previous security levels. This expenditure is a legacy of responding to rapidly increasing loadings and will prevent future deterioration in reliability performance rather than necessarily improving future performance.

The rates of faults per 100 km of distribution lines is now at a level that is competitive in the industry. While all measures are above the target values, the targets do not appear unobtainable. The subtransmission fault rate was impacted by several car vs pole incidents in 2018-19. Car versus pole incidents continue to occur.

A variation in 11kV vs 22kV performance (not shown in tables or diagrams) can be partly explained by the location of 22kV and 11kV across the district. Looking at the diagram showing the location of the 11kV and 22kV distribution lines in Section 5.4.4, it is apparent that events can affect one voltage more than the other as a consequence of their geographic location. When strong wind, lightning or other environmental events occur the network impact is not always uniform. For example, strong winds are channelled or dispersed by geographic features and if the voltage of the network in near proximity is 22kV, then the faults are attributed to the 22kV network even though an 11kV network would also have failed had it been similarly exposed.

The contributions of the various categories of fault cause have shown that although planned faults are the highest individual category in terms of total quantity and duration, it is the next two highest categories of unplanned fault that are worthy of examination. Adverse weather and defective equipment suggest that there are components in the network that are deficient. Of note are the high levels of 22kV surge arrester failures which have not yet been explained. A change of supplier and specification has occurred. Examination of the individual faults in 2018-19 shows that some of the categorisation choices are struggling to separate cause and effect. For example, a transformer that fails during a lightning storm is not defective equipment – that is the result of it being struck by lightning.

During June 2015, Mid-Canterbury was subjected to a reasonable snow storm. Generally, the network held up well; better than it has in the past, and power was restored more quickly than would previously have been expected. There were however many faults that originated on property that affected the network. Typically, these are earth faults where the network protection is faster or more sensitive than the fuse supplying the customer. Investigation revealed a large quantity of old, poor condition conductor on property, much of it #8 galvanised steel (fencing wire). A programme to encourage line owners with poor condition lines, especially #8 galvanised steel has begun with a view to getting these lines bought up to standard.

EA Networks has performed relatively poorly in CAIDI (restoration time - heavily influenced by planned outages) and SAIDI (directly related to CAIDI). Another factor that undoubtedly influences the relativity of EA Networks' restoration times is the strict adherence to the EEA publication "Manual Re-Closing of High Voltage Circuits following a Fault (Guide) (2014)". EA Networks will examine this document closely and decide if, in balance, the new guide provides a more suitable approach to post-lockout circuit breaker closing. EA Networks are not able to comment on other companies' practices, but anecdotal observations would suggest that not all companies are quite as rigorous in their application of what EA Networks considers to be industry best practice (patrolling of lines following a recloser lockout). The other factor influencing SAIDI heavily was live-line working (or lack thereof). This has now been resumed and it is anticipated planned SAIDI will decrease in 2019-20 and beyond, but not to pre-2016 levels.

Faults per 100km is better than average for all lines. Faults per 100km is trending lower for 11-22kV lines. It is below the median for all companies and is trending down. The targets are approximately 55-75% of the values being achieved and it will take considerable ongoing effort to bring the actual performance down to the desired values.

Service Levels

This is the area of performance measurement that directly affects the quality of service that consumers experience. Section 3 of this plan "Our Customers" addresses most aspects of performance and performance improvement as it relates to service levels.

Targets

The service level targets have been detailed in section 3.4.

Outcome

See section 3.4.1.

Reasons for Variance

There are a range of reasons whereby performance may not be as per target. The significant ones are:

- The reclassification of live-line working has impacted planned outage SAIDI and SAIFI. This reconsideration of when and where to use live line techniques is in reaction to industry concern over liability. Adherence to "Patrol after auto-reclose lockout" philosophy. This can delay restoration considerably but ensures a much lower risk of livening onto vehicle or other situation where it could place the public at risk.
- The reduced, but still high, levels of planned outages.
- A number of lightning, weather and perennial 'unknown' faults have contributed to the observed network performance.

There are the other perennial reasons such as trees and wildlife that always cause issues, but they tend to be lower frequency and sporadic.

Plans to Address Variance

Addressing service level performance issues is an on-going process. There is no magic answer to solve all the issues at once. EA Networks are concentrating on solving the obvious issues as they become apparent.

The resumption of live-line working has measurably reduced the planned SAIDI and SAIFI. This was possible as the distribution industry now seems to have converged on an agreed protocol for justifying the use of live-line techniques for approved jobs.

The replacement of faulty equipment prior to failure is a simple action to increase performance if the imminently faulty equipment can be reliably detected. More effort with diagnostic equipment such as infrared cameras is being made and this will continue for the foreseeable future. Consideration of the high failure rate of a particular type of 22kV surge arrester is being considered. If it can be determined why the failures are occurring, there may be a proactive replacement programme targeting the most prone locations.

More research is being done on the causes of faults. Distribution areas each have their own character whether it be trees, wildlife, mechanical interference, vehicle crashes etc.

The recent policy to encourage on-property underground distribution will, over time, lower the frequency and impact of on-property faults which are commonly cleared by a network circuit-breaker. The operation of a circuit-breaker affects large feeder segments or entire feeders instead of just the consumer causing the fault. A fault in an underground cable is rare and when it does happen will commonly be caused by mechanical interference which is generally reported by the person excavating allowing faster isolation and restoration of supply.

All customers with poor condition lines, especially #8 galvanised steel, are being contacted with a view to getting these lines bought up to standard.

There are no plans to change the line patrol after auto-reclose lockout policy until the new EEA guide on manual reclosing has been thoroughly assessed.

The level of planned work is a fact of life. While new load appears, it will require servicing. Live line techniques are not suitable for the scale of work required for large line rebuilds.

Advances in SCADA operation and distribution automation will reduce the time taken to restore consumers after a fault. This will greatly assist in reducing SAIDI and CAIDI. EA Networks is currently in the implementation phase of an advanced distribution management system. Completion of the initial functions should be complete during 2020.

It is apparent that relatively few faults can have a dramatic effect on EA Networks performance. For a smaller company (<20,000 ICPs) the relatively rare event of a typical urban feeder tripping once can have a dramatic effect on system SAIDI as the affected ICP count is a significant proportion of the total. Compare this with a large urban company (100,000+ ICPs) where a single urban feeder tripping is unlikely to impact on system SAIDI by a detectable amount. The only way to address this is by reducing the proportion of ICPs per protective zone so that a single fault affects fewer than say 2-3% of the total ICP count (in EA Networks case this would be 400-500 ICPs). For a large utility this could be 2,000 to 3,000 ICPs. EA Networks are planning to proceed down this path with more urban circuit breakers and reduce feeders to fewer than 250 ICPs on each. In rural situations, the customer count is rarely high enough to affect SAIFI on a single fault but SAIDI can be adversely affected when faults take a long time to diagnose. The installation of many rural RMUs with SCADA, fault detection and interrupting capability will begin to address some of these issues as well.

9.2.2 Overall Reliability

The overall reliability for the 2019-20 year has shown a consistent fault-related performance. At time of writing, the forecast default price path SAIDI and SAIFI are perilously close to being exceeded. Most of this can be attributed to the December 2019 lightning and flood events and a slightly higher than historical level of planned outages (new live line working protocols). The forecast suggests end-of-year SAIDI being 200 (210 target) and SAIFI 1.89 (1.65 target), assisted by suspending planned outages post December 2019.

The EA Networks tree control policy will be administered with rigour. The tree control policy is based upon the Electricity (Hazards from Trees) Regulations 2003 but has additional opportunities for the tree owner to allow EA Networks tree control standards to apply. If the tree owner chooses to allow EA Networks to apply their own tree proximity and trim standards (more rigorous than those in the 'Tree Regulations') then there is the possibility of significantly reduced cost of tree control to the tree owner. Together, it is hoped that these measures will reduce the impact of any future weather events and thereby prevent any future breach of the price-quality path thresholds. The relatively low number of tree faults that occurred can be attributed to both this new policy and the lack of wind and snow during 2018-20.

EA Networks' HV distribution network (particularly 22kV) has not performed to the target. The performance of this voltage (22kV) does appear to be occasionally approaching the target. The target appears to be ambitious when compared to the industry average. It is possible that the EA Networks target is unachievable in all but the most environmentally benign of years. The planned interruption rate was reducing as development work tailed off. 22kV conversion work continues to have some planned outage impact and potentially several of the coming years will feel the impact of 66kV or 22kV line construction/rebuild projects.

When planned outage frequency begins to drop, the system interruption duration will drop with it. As the 66kV subtransmission network is largely developed, many of the high impact faults seen historically have been reduced as circuit redundancy eliminates outages. As always, tree control is an ongoing problem that specific regulations and EA Networks own tree control policy now cover. It appears that assertive tree control will continue to reduce fault frequency to some degree. Of more concern than fault frequency are duration measures such as restoration time. Full line patrolling after an auto-reclose lockout is something that EA Networks always undertakes. It is unknown whether this is the norm for all other similar companies. This has a significant impact on restoration time if no cause is found and the line is successfully restored, but it is industry best practice to do this.

A major boost to performance is expected with additional SCADA control over remote switchgear. This will provide significant information and faster responses to interruptions, reducing the duration aspects of faults but probably not the frequency (although intensive monitoring of protection relay reclosures and pickups may allow proactive preventative maintenance actions).

The planned interruption rate is completely under EA Networks' control and it forms a large portion of the frequency and duration indices. Other than the impact of new live line working protocols, it is unlikely that these will fall dramatically until the major line construction and voltage conversion projects are complete.

In summary, the overall performance of the network shows it is relatively fault resistant when compared with similar companies, but fault response needs to continually improve.

9.3 Service Improvement Initiatives

Having identified the level of performance that EA Networks are achieving and the level of performance and standards that stakeholders, consumers and EA Networks wish to achieve, this section details proposals that, where necessary, will drive improvements to the services EA Networks delivers to consumers. The solutions relate to different voltage levels and components within the EA Networks network. See section 6.1 for a chart showing the different voltage levels and the interconnections between them.

As EA Networks move from a period of extremely high growth to one of modest growth, the maintenance regime at EA Networks will become much more focused on preventing failures rather than reacting to them or maintaining equipment at set time-based intervals. EA Networks look at any new diagnostic tests that become available and assess their usefulness for preventative maintenance. When it can be shown that the tests can reliably predict the condition of equipment and any incipient fault, it is used in a targeted fashion on the equipment that is most critical for security or other performance criteria such as safety.

All the initiatives that have been identified for implementation are subject to economic analysis to ensure EA Networks are offering value for the increase in performance. The value can sometimes be difficult to quantify and if a business case cannot be made, the costs, pros and cons will all be presented to the Board to consider. The Board provide the sometimes intangible strategic influence of consumers/shareholders wishes on the proposal.

9.3.1 Transpower Network

Transpower has identified that it has a need to increase the capacity of the national transmission network to maintain the level of security required of a national grid. Proposals have included a new 400kV line that takes electricity from the hydro schemes in the south of the South Island to the greater Christchurch area. Other, interim, less expensive steps have now been suggested and they appear to be the preferred option. All these approaches will offer increased security to Transpower's Ashburton substation (Ashburton220) thereby improving both the security and quality of supply to EA Networks' consumers. Transpower have previously altered Ashburton220 to interconnect both circuits of the Twizel-Bromley-Islington double circuit 220kV line (previously only one of the circuits was deviated into Ashburton220). As well as assisting in relieving Transpower's grid constraints, this project has increased the security of Ashburton220's 220kV bus from n-1 to at least n-2 in relation to 220kV circuits.

The addition of a third 220/66kV transformer (T9) permitted a reconfiguration of the Elgin 66kV bus which connects to Ashburton220. Protection system alterations have also been implemented that improve the performance of the EA Networks subtransmission network protection and allows more reliable and selective detection of faults. This assists in reducing the extent of future outages when particular types of fault occur.

The third 220/66kV transformer has provided a level of firm capacity that exceeds the present 66kV peak load. There are no projects planned to further increase the 66kV capacity at Ashburton220. In future, should load begin to exceed the level deemed suitable for supply from Ashburton220, a new geographically separate GXP will be developed to both increase GXP security and reduce the loading on the EA Networks 66kV network. A project has been included in 2027 to accommodate such a development [-1156].

9.3.2 Subtransmission System

At least one part of the subtransmission network carries electricity to every consumer supplied by EA Networks. A consequence of this is that loss of any part of the subtransmission network is felt far more widely than the loss of an equivalent portion of the distribution voltage networks.

There are a range of initiatives that have been undertaken to improve the service levels obtained from the subtransmission network:

- 66kV line design has been externally reviewed to ensure reliable conductor displacements under both normal and extreme conditions
- vibrations dampers have been (retro)fitted to subtransmission circuits - this lowers vibration related faults on the subtransmission network and ensures the line endures for its full design life.
- older lines have been inspected with a corona camera and have had subsequent inspections using ultrasonic equipment that detects cracked or faulty insulators as well as defective insulation on most equipment
- infra-red cameras that detect thermal discrepancies are used on an annual basis to examine important lines for overloaded or potentially faulty joints and connections
- high performance protection equipment has been installed on the all 66kV subtransmission circuits resulting in lower fault clearance times, increasing safety and decreasing the duration of voltage depressions

9.3.3 Zone Substations

A failure in a zone substation can be particularly difficult to deal with. A combination of sensible overall design and modern asset specification can reduce the risk of failure considerably and therefore increase the level of service it provides. Specific initiatives undertaken in zone substations include:

- Very careful monitoring of critical equipment using partial discharge tests, infra-red cameras, ultrasonic equipment and sophisticated oil analysis to provide details of internal transformer condition.
- Selection of equipment for new substations that is more immune to factors that have been the cause of historical failures.
- Configuration of new substations that makes them more tolerant of equipment failure - supply is not completely lost during or after a critical equipment failure.
- 66kV bus zone protection that reduces fault clearance times to a few cycles, dramatically reducing fault damage (although not preventing the fault) and localising the outage to the faulted equipment only.

There are a raft of other changes that have been implemented as a consequence of the major zone substation construction programme of the last 10 years. Suffice to say that they all assist in providing a higher level of service from the zone substation to the consumer.

It is noticeable that there are increasing numbers of devices being connected to the network that are creating harmonic distortion of the supply. EA Networks have engaged in a more proactive stance on this and have installed real-time monitoring equipment at most zone substations.

9.3.4 22kV and 11kV Distribution System

The high voltage (HV) distribution network (22kV and 11kV) has the most geographically widespread lines in the entire EA Networks network. HV distribution also forms the highest percentage of total lines and switchgear. Consequently, it features in most faults affecting consumers.

Underground

The underground HV distribution network is generally meeting expected performance. Some condition monitoring is done on cables although it has not proven to be particularly good value because the low fault frequency requires monitoring a large proportion of the network to provide a proactive response. Generally, the few faults that do occur in the underground HV network are caused by either external influences such as mechanical excavators (this is only preventable by extensive education), or faulty joints and terminations which are always being re-evaluated based upon performance.

Future developments are planned to include a new core 11kV cable network programme for Ashburton township [-1010] & [-1011]. This will decrease the average number of ICPs per feeder to lower levels and increase overall capacity. This will mean a lower impact for any given cable fault since fewer consumers will be affected. The same network will also allow much more substantial and faster load transfer between Ashburton and Northtown substations during both planned and unplanned outages. This should make planned outages of urban Ashburton ICPs very rare and unplanned outages very short.

Overhead

The overhead HV distribution network is much more prone to external influences and the majority of overhead line faults affecting consumers occur on the overhead HV distribution network. There are a number of improvement initiatives that have already been undertaken:

- urban underground conversion programme - progressive conversion of the urban overhead HV distribution lines to underground cable causes dramatic reductions in fault frequency
- rural underground conversion where it is deemed to be prudent and sufficiently advantageous
- thermal imaging analysis of major distribution feeders to detect faulty connections or overloaded components
- an on-going tree control programme that is now backed up by additional measures for tree owners who wish to take advantage of them
- replacement of parallel groove connectors and line taps with higher reliability wedge connectors
- repositioning displaced line reclosers to increase network segregation
- the routine use of more reliable and remote controllable gas switches instead of air-break switches
- the installation of rural ring-main units to increase switching reliability and safety while providing the opportunity for ring-main unit circuit-breaker fault clearance, single-shot auto-reclose, as well as remote control.
- vibration dampers are being fitted to underbuilt HV distribution on long spans to decrease vibration damage
- additional surge arrestors have been fitted at locations where existing equipment provides the relatively high cost of an earthing system (e.g. SF6 load-break switches)
- universal application of possum guards to poles with high voltage attached to them
- 11kV glass tube fuses are progressively being replaced with expulsion drop-out types
- additional interconnections between feeders to provide alternative supplies
- 11kV to 22kV conversion increases capacity significantly and permits back-feeding which lowers both planned outages and unplanned outage length
- neutral earthing resistors reduce the thermal stress on wires and connectors during earth faults as well as dramatically reducing the fault voltage depression seen by consumers
- more rigorous actions in relation to non-compliant privately owned HV lines
- elimination of unfused overhead extensions onto private property
- thermal infrared camera inspection of lines and accessories to detect abnormal heating
- the requirement that all new network connections (both LV and HV) shall be via underground cable and encouragement to have all on-property reticulation underground

There is still the need to further improve the performance of the overhead HV distribution network and there are three main possibilities for achieving this.

(1) Reduce Fault Frequency (SAIFI reduction)

This is possibly the most difficult of the three methods to increase performance. There will always be people driving cars that crash into poles, irrigators that either push wires together or directly hit the wires, birds that perch on insulators, etc. Fault immunity can be increased by these initiatives that EA Networks are initiating or contemplating:

- use of covered conductor in specific areas prone to conductor contact by trees or machinery (not being actively pursued),
- use of insulator shrouds and conductor insulation in areas prone to wildlife interference (being used for specific equipment),
- use of pole-mounted fully-enclosed load-break switchgear in place of air-insulated disconnectors - reducing the frequency of equipment malfunction,
- possible provision of an on-property service line maintenance service contract that would ensure lines that are presently privately owned and are on private property do not cause preventable outages on the EA Networks network,
- review of recent severe weather events has identified certain types of conductor, poles and fittings that feature in a high proportion of faults (these assets are targeted for replacement as the opportunity arises),
- even stricter enforcement of tree control to prevent (a) earth faults caused by trees touching the line, (b) bark and branches blowing onto the line, and (c) trees falling and mechanically damaging the line. This has been implemented,
- careful consideration of asset location to avoid vehicle contact,
- underground conversion of overhead assets where there is a compelling safety case when assisted by roading authorities.

(2) Reduce Extent of Fault Impact (CAIDI/SAIDI reduction)

Another possible performance improvement is to reduce the number of consumers affected by a fault. This can be either fewer consumers with the power off, or fewer consumers seeing the consequences of the fault. Several initiatives are under consideration or have been implemented:

- application of neutral earthing resistors in an urban cable network to reduce the thermal stress on wires and connectors during earth faults as well as dramatically reducing the fault voltage depression seen by consumers (widespread implementation),
- increase the total number of HV distribution feeders thereby reducing the number of consumers served by each feeder (planned for urban Ashburton),
- continue to install additional line reclosers increasing the network segmentation (rural RMUs are displacing/supplementing reclosers),
- implement a degree of distribution automation that would rearrange the network, automatically restoring supply to some consumers within 60 seconds (possible via the advanced distribution management system).

<u>(3) Reduce Duration of Fault Impact (CAIDI reduction)</u>

If the fault is inevitable (some are) and the number of consumers affected cannot be economically reduced, the last option is to restore supply to as many consumers as possible, as quickly as possible. This is one area where modern technology can have a considerable impact. The initiatives under action or consideration are:

- more remote control of line reclosers, disconnectors, gas switches and ring-main units (actively being implemented),

- increase the sophistication of protection systems to limit the duration of fault voltage depressions (actively implemented at 66kV, less so at distribution level),
- permanently install distributed power quality monitoring equipment at consumers' properties to report not only fault information but also other power quality statistics (some aspects of this have arisen through the fibre optic network which also supplies on/off information via the consumer connected modem and there is potential for every connection to have a remote signalling voltage/load transducer if an alternative load control system is adopted),
- equip field staff with devices that assist in locating faults and provide real-time operational information to allow fully informed decisions (project completed),
- possible use of a large (200-300kVA) generator and step-up transformer to provide an alternative supply during all types of interruption (still being considered).

Switchgear

The majority of switchgear has proven to be trouble-free provided the manufacturer's recommended maintenance is performed. There are however some particular items of plant that are sub-standard and the only remedy short of major modification is to replace the item. Things that have been done to improve performance or are proposed to be done include:

- replace switchgear where there is a known risk to safety and/or equipment integrity,
- use of equipment with better cable termination integrity, lowering the burden on jointers to use materials that are prone to environmental influences,
- regular inspection of ground-mounted switchgear using partial discharge detection equipment,
- use of equipment that is designed to be fundamentally safer, more durable and more reliable,
- increased use of remote control to minimise exposure of personnel to switching equipment,
- fault indicators are being applied in more locations to reduce restoration times by locating the fault,
- adopting the routine and extensive use of fully-enclosed SF_6 gas load-break switches which are both more reliable, more capable (400 amp load breaking) and safer than open contact style switches for both new and many existing sites.

Transformers

Distribution transformers have proven to be a very reliable asset category. Failures are typically caused by wildlife, lightning or overloading, with equipment failure coming much further down the list. Since distribution transformers are very reliable, little additional effort can be justified in further increasing performance. The main initiative that has been implemented is a universal system spare 1,000kVA distribution transformer. This unit is self-contained with HV and LV cables and can operate at either 22kV or 11kV. It has been put to good use on a number of occasions already during transformer faults that would have been difficult to deal with otherwise.

Although not particularly increasing the reliability of the transformer, EA Networks has adopted the use of in-tank high voltage fuses for all new transformers intended for ground mounting (this typically encompasses all transformers larger than 100 kVA and 'microsub' style units used when the choice is made to mount smaller units on the ground. These fuses are intended solely as fault protection for the transformer internals and equipment directly connected to the low voltage bushings. By putting these fuses in the transformer now it prepares them for inclusion in any future underground reticulation network that may not allow for costly ring main units at each transformer site. It also overcomes the problem of adequately protecting a large and small transformer (such as occurs on many farms) on the same piece of underground cable. Previously, the fusing for a large and a small transformer was done collectively at the start of the underground cable and this was not entirely satisfactory.

One of the intentions of the policy of ground-mounting any new transformer above 100 kVA is to promote a more reliable mounting arrangement for each transformer. During extreme events such as snow storms, wind storms and major earthquakes, a ground-mounted transformer is much more secure than the equivalent pole-mounted unit.

9.3.5 LV Distribution System

The low voltage (LV) distribution network (400 volts) is typically quite reliable and any faults that occur affect relatively few consumers (security standards dictate no more than 25 initially and no more than 15 during the repair). There have been several improvement initiatives that have provided worthwhile increases in performance:

- conversion of overhead LV lines to underground cable has provided significantly increased reliability, capacity and quality (better voltage regulation and fewer fault voltage depressions),
- replacement of old open contact LV fuses and links with modern high capacity switchgear has improved the reliability, configurability and safety of kiosk substations, roadside switching boxes and consumer service fuses,
- when overhead lines are installed or replaced in rural areas, PVC covered LV wires are now universally used and prevent problems with wires clashing and reduce safety concerns.

9.3.6 SCADA, Communications and Control

The SCADA functionality at EA Networks has been evolving for some time. It is now able to provide a significant improvement in network performance with the widespread ability to control switchgear and other power system devices as well as retrieve information that assists in diagnosing both faults and power quality issues.

The system is fully functional and expanding. The opportunity exists to have the SCADA system extend into automation of some network activities. This will permit faster restoration and allow staff to concentrate on repair of the fault rather than switching of the network.

Having stated in older plans that the ripple control system had proven to have high availability, the electronic portion of one of these plants failed during 2005 and then another failed during 2011. Certain electronic components are no longer available and in some cases the service contractor cannot repair failed equipment. Unfortunately, this was the case with both plants that failed. A decision was made to repair one of the failed plants using parts of the standby plant. The 2005 failed equipment has been replaced with an item sized to suit future application at 66kV. This returned the injection plant count to three and will ensure no on-going loss of load control for a fault in one plant under most loading conditions.

The issue of high harmonic distortion and the potential for the required mitigation measures to degrade the signal of the ripple system appears not be a significant issue.

There are two projects in the plan to replace the present ripple system with either new technology or a new 66kV ripple injection plant. If the 66kV ripple plant option proceeds, the existing 33kV ripple plant will be replaced in 2026 to provide backup control.

9.3.7 Protection Systems

Any electrical protection component is by design a high reliability item. The configuration of individual components of protective plant can have a considerable influence on the performance of the protection system in total. Protection maloperation is rare, but it does happen. Depending on the back-up component available, it can lead to a more widespread outage.

Protection relays ("relay" is a term for the control box that senses faults and switches the circuit-breaker off) are becoming much more sophisticated than they have been. Most modern protection relays are based on microprocessor technology which permits not only advanced decision making, but also direct digital communication with other devices such as PC's and of course SCADA systems.

EA Networks have utilised many of these modern protection relays, and they have proven valuable in providing all manner of loading information as well as post-fault analysis. There is a lot of scope in the application of advanced protection relays for improved network performance. This is not only in the way the relay controls the circuit-breakers but also the information they provide to staff for future engineering decisions.

Live line work is now a routine part of network construction and maintenance techniques. Modern protection relays have the capability of being programmed to disable automatic reclosing either locally or remotely (via SCADA) and, if so desired, change the protection settings for live-line working so that a trip operation is extremely fast compared to normal operation. This does not lower the risk of an incident occurring, but it can make the consequences much more tolerable.

The main initiative will be to keep abreast of developments in the protection field so that maximum benefit can be obtained from worthwhile technology.

Some of the early electronic relays are now beginning to show sign of age-related degradation. The oldest relays are being progressively replaced either as issues become apparent during testing or simply based on the age of the unit, its criticality, the spares held, and its repairability. Fortunately, the conversion of the subtransmission network to 66kV has made the vast majority of aged protection relays redundant. Some of the early 66kV line relays have been scheduled for replacement as they approach 20 years of age.

9.4 Asset Management Maturity Evaluation

There has been insufficient resource available to attend to a rigorous and formal evaluation of asset management processes and systems at EA Networks.

Appendix G contains EA Networks disclosed AMMAT response.

9.5 Gap Analysis

The service level performance gap analysis has been partly addressed in section 9.3 with a range of initiatives targeting systemic baseline performance characteristics.

EA Networks have not been able to complete a comprehensive AMMAT gap analysis. Rather than present an insubstantial commentary on the range of issues requiring attention, it has been decided to leave this section without comprehensive analytical content. Suffice to say that there are a range of AMMAT topics that will require attention and as internal resources permit, they will be developed, documented and addressed. Some of the latent issues that have existed for some time are documented in section 9.6 below.

Future plans will contain a more rigorous AMMAT discussion and analysis of gaps that exist and the areas that EA Networks consider worthy of on-going attention – offering value for money.

9.6 Asset Management Improvement Initiatives

There are a raft of processes and systems that need significant improvement to become equivalent to the level of excellence that are considered industry's best practice. To attempt to improve all these elements in the short-term would be folly. There are some key processes and systems that need immediate attention, while others represent a high benefit/cost ratio and should be advanced on simple economic grounds.

The following items represent elements of EA Networks' Asset Management that were targeted in the previous plan (2018-28) as essential for improvement during the short term (3 years).

SCADA – Control and Data Gathering

The SCADA system is now fully functional at all zone substation sites. Distribution system sites continue to be connected as communications paths become available. The DMR system is boosting the numbers of distribution SCADA sites dramatically, with the addition of a small radio/RTU device that can be used wherever voice coverage is available.

A big part of the successful SCADA implementation was obtaining reliable data communication to all zone substations. A separate fibre-optic communications infrastructure was developed as a commercial enterprise and all 66kV zone substations are connected plus other field equipment in close proximity are being progressively connected. This platform provides a very secure and reliable network.

Once fully operational at all controllable sites, the SCADA system will provide: full remote control (a means to reduce restoration times), remote fault diagnosis, gathering of equipment loading in real time, gathering of condition-related data in real time, gathering of power quality data in real time, and temporal trending of a range of power system parameters. All this data supports effective asset management.

Risk Management

The appointment of additional resource has permitted good progress in the risk assessment process. There are now a number of contingency plans to assist staff in the event of a risk affecting particular items of equipment or classes of equipment. After consideration, some risks may be treated by engineering responses to reduce exposure to the risk instead of attempting to reduce its consequences after the event through contingency planning.

The target of EA Networks' risk management is to follow through on high risk items already identified and create documentation to manage the outcome of that risk. This work is progressing well, and additional analysis will continue. More contingency plans will be created as the need is identified.

Spatial Information and Network Modelling

The spatial data storage application EA Networks are now using is called Hexagon G/Technology (formerly Intergraph G/Technology). The same application maintains the electrical model of the network which facilitates intelligent tracing of faults and analysis of the network. G/Technology also captures and models the EA Networks fibre-optic network. The as-built data provided by field staff is now captured quickly and available to all users the next day.

The Hexagon G/Technology system offers a stable and robust platform from which integration with other asset-related systems has already increased and much more creative use will be made of the electrical model and other valuable stored data.

Levels of Service

Having set in place a number of security standards that are supposed to target improvements in the levels of service, additional effort is required to determine the degree of compliance with these standards. All new projects are designed to offer the prospect of improved compliance with the standards but may require some redesign to achieve 100% conformity.

The ability to efficiently analyse compliance with the security standards has been hindered by the lack of integrated data. The Advanced Distribution Management System and other inter-system integrations currently underway will enable this work to be undertaken and monitored.

The target for this aspect of asset management is to identify the non-compliant sections of the EA Networks network and rank them according to priority. Previous targets were not met. Now that engineering resources are at close to optimal levels, good progress should be made by 2022.

9.7 Capability to Deliver

This plan has been published annually for more than 20 years and has been instrumental in guiding the development and lifecycle management of the EA Networks electricity assets. There have been a number of years when the annual goals have not been met, but overall, the strategies outlined around the year 2000 (66kV subtransmission and 22kV rural distribution) have succeeded or are steadily progressing the network towards the desired level of performance. The plan performance targets have been in many cases based upon the best aspects of historical performance. This ensures they are achievable, but ambitious.

The ability of EA Networks to achieve the plan objectives is tested annually, not only by the Board, but also the Shareholders' Committee who provide a commentary on the performance of the company in the Annual Report.

At the management level, the expectation is that any planned project is identified as early as possible and included in the Asset Management Plan project database to give an estimate of the project duration and timing, financial resources, design resources and construction resources required to achieve the goal. This database can be interrogated to ensure that the cost and design/construction resourcing are within the means of EA Networks and its contractors for any given period. Additionally, analysis of the long-term benefits of the individual projects and programmes must be sufficient (either individually or collectively) to justify their inclusion in any future plan.

In recent years, EA Networks has grown. Additional staff have been employed to bolster the technical and business capabilities. This growth has increased the rigour of a number of the internal processes including those on investment and project commercial viability.

Although some projects are still ultimately considered at Board level using the ethos of a cooperative company structure, the knowledge of underlying commercial considerations will always be relevant.

The EA Networks business structure has shown itself to be remarkably stable over time. This stability existed during a period in its history which will be remembered as when asset development was at the highest ever level. The fact that significant network level decisions made more than 20 years ago have been successfully implemented demonstrate that the business structure and processes are sufficient to support the continued implementation of the plan. During this period, all new consumers (irrespective of size) were connected without unreasonable delay.

As the development workload decreases, it will permit more time to be spent refining the lifecycle management structures and systems as well as developing the formal documentation of many processes and systems that are currently understood and adhered to while not being contained within a 'controlled document'.

One area where EA Networks have struggled, is to retain younger engineering staff. Because Ashburton is a smaller rural township, it has few local people trained as electrical engineers. Consequently, EA Networks must attract engineers to a small rural town and that is challenging to start with. Once they are here, it is then a further challenge to retain those staff as the appeal of larger centres draws them away (either for lifestyle reasons, partner's work, etc). EA Networks encourage local students into electrical engineering whenever possible, but there is no certainty that they will choose to return once qualified.

The next decade will require careful consideration of succession planning for a range of positions. The average age of EA Networks' workforce is above 45 and a significant proportion are in their 50s and early 60s. The knowledge and experience of these personnel must not be lost to the next generation of staff that will succeed them. Effective mentoring of those that will follow is an essential aspect of managing the workforce.

APPENDICES

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10 APPENDICES

10.1 Appendix A - Definitions

The Electricity Distribution Information Disclosure Determination 2012 contains an extensive range of definitions covering a range of activities, assets, and associated terms. In future plans it is intended to make every effort to synchronise the terms in use in the plan (and here in the definitions) with those used by the Disclosure Determination. Unfortunately, there has been insufficient time available to change the structure of this plan to reflect the Disclosure Determination preferred terms.

EA Networks do have philosophical issues with some of the Disclosure Determination asset definitions, seemingly having more to do with financial asset definition than physical populations of like assets which are managed in common using the same methodology.

Maintenance Activity Definitions

Inspection, Service and Testing

Routine

This is expenditure on patrols, inspections, servicing and testing of assets on a routine basis. Typically, these activities are conducted at periodic intervals defined for each asset or type of asset. This work does not involve any repairs other than some minor component replacements during servicing.

Special Inspection, Service and Testing

Expenditure on patrols, inspections, servicing and testing which are based on a specific need, as opposed to being time based as with periodic inspections and servicing.

Faults

Repairs undertaken during fault conditions to restore supply. This does not include the eventual repair of a faulted asset, where it is taken out of service while repairing the fault; only the expenditure required restoring supply is included.

Planned repairs and refurbishment

Repairs to, and refurbishment of, an asset which may involve component replacement but not the complete replacement of the asset. This includes corrective repairs of defects identified within a year, "special" repairs (e.g. based on an identified type failure or type weakness) and planned refurbishment's that may involve a significant proportion of component replacement. However, to identify refurbishment's as distinct from general repairs would require identification of all specific refurbishment projects over the planning period and this has not proved feasible for this plan.

Planned replacement

Replacement of an existing asset with a modern equivalent asset providing similar capacity or other aspect of service provided. Note that the asset need not be identical in capacity etc, but should be materially similar.

Maintenance contingency

An explicit planning contingency, where it is not feasible to identify all minor work, or where it is expected that work will arise, but its classification cannot be easily predicted. All contingencies are specifically identified, and no implicit contingencies are included in the detailed expenditure projections for other activity classifications.

This contingency is converted into one of the above activity classifications once committed. Therefore "Maintenance Contingency" is not a real activity for reporting purposes.

Enhancement and Development Activity Definitions

Enhancement

This is the replacement of an existing asset with a modern equivalent asset, which is materially improved on the original asset, or modifications to an existing asset, which have this effect. Specifically, this will include improvements to the existing asset configuration, which are undertaken with the purpose of:

- Further improving the inherent safety of the system (e.g. installing smoke/heat detectors and entry alarms in substations)
- Improving the level of consumer service (e.g. increasing capacity by replacing a transformer with a larger unit, or adding an extra circuit to it to increase security)
- Improving economic efficiency or investing to improve the asset by reducing operating or maintenance costs (e.g. fitting vibration dampers to specific lines to reduce the rate of component deterioration)
- Improving environmental risk management (e.g. fitting oil containment facilities at substations)
- Improvement to corporate profile (e.g. landscaping station grounds, although this is also fully justifiable based on reduced grounds maintenance)

Note that each aspect of improvement is related to a specific asset management performance driver.

Development

This is work which involves installation of new assets in sites or configurations where none previously existed. This may also include substantial upgrade work (e.g. re-building a substation at a higher voltage) in which the original configuration is significantly altered or extended.

Development contingency

An explicit planning contingency, where it is not feasible to identify all minor work, or where it is expected that work will arise, but its classification cannot be easily predicted. No implicit contingencies are included in the detailed enhancement and development expenditure projections. For the same reasons as those discussed under "Maintenance Contingency", this activity is not included in financial reports.

Other Activity Definitions

Operating

Any disconnection of consumer's services for any reason except non-payment of electricity accounts. This includes activities such as house painting, transportation of high loads and low voltage switching. It also includes operation of the high voltage network where this is not directly associated with maintenance or enhancement work.

Trees

This activity covers all tree cutting and trimming to maintain safe working clearances from power lines and any costs incurred during negotiations with consumers regarding tree trimming.

Planning Period Definitions

Plan(ning) Period

In this plan the term is used to describe the interval that the plan is attempting to predict with a tolerable degree of certainty. Beyond the end of this interval there are too many unknown factors that will influence contemporary engineering decisions to allow reasoned assessment. The solutions that are proposed in this plan will have lifetimes considerably exceeding the planning period but may not provide the specified level of service beyond the planning horizon without enhancement.

During periods of high load growth, such as historically experienced by EA Networks, the accuracy (and therefore risk) of looking too far ahead can be unacceptably poor. EA Networks have chosen to keep the load forecasting horizon coincident with the end of the planning period for the moment. Projects that are initiated during the planning period are designed with future expansion capability in mind to provide options for accommodating unknown future load/security requirements.

Plan(ning) Horizon

The end of the planning period.

Asset Type Definitions

High Voltage Lines and Cables (Subtransmission and Distribution)

Includes all power distribution and subtransmission lines with a rated voltage of 11kV or higher. Within the plan, lines may be further disaggregated into major components, being:

- Poles
- Conductors and accessories
- Insulators and hardware
- Down and aerial guys
- Underground cables
- Terminations
- Joints
- Ducting
- Land or easements

Low Voltage Lines and Cables

Includes all low voltage lines with a rated voltage of 400V or lower up to the consumer's service fuse. As for high voltage lines, lines may be further disaggregated into major components, being:

- Poles
- Conductors and accessories
- Insulators and hardware
- Underground cables
- Distribution, link or pillar boxes
- Terminations
- Joints
- Ducting
- Land or easements

Service Lines (High Voltage and Low Voltage)

Includes all service lines on road reserve from the consumer's service fuse to the point at which it crosses the consumer's boundary. This includes:

- Lines and cables
- Fuse arms
- Service fuses
- Service lines on road reserve

Zone Substations

This includes substation facilities such as land and buildings and the power transformers within them that are connected to the subtransmission network. Individual items of equipment such as disconnectors, circuit-breakers and bus-work are covered in other asset type definitions, which are generic for the whole network. For example, no distinction is made between a disconnector in a substation and one on a distribution line.

- Power transformers
- Foundations
- Oil interception equipment
- Land or easements
- Buildings and fencing
- Other ancillary station equipment such as batteries, chargers, NER's etc

Distribution Substations

All distribution and regulator substation equipment including:

- Kiosk covers
- Foundations
- Connection cables LV and HV
- Land or easements
- Accessories - heaters, instruments, CT's etc

High voltage and low voltage switchgear located in distribution substations are covered in separate asset definitions.

Distribution Transformers

All distribution transformers from 5kVA to 1,000kVA 11kV and 22kV primary voltage, including regulators or autotransformers up to 10,000kVA:

- Ground-mounted transformers
- Pole-mounted transformers
- 11kV or 22kV Regulators, 22/11kV Transformers and 22/11kV Autotransformers

High Voltage Switchgear

All high voltage switchgear, busbars and other items of equipment, both on lines and within substations, including:

- Circuit-breakers
- Reclosers
- Sectionalisers
- Disconnectors
- Ring-main units
- Expulsion drop-out fuses
- Structures and bus-work
- Instrument transformers
- HV Capacitors

Low Voltage Switchgear

All low voltage switchgear and busbars installed in distribution substations, distribution boxes, link boxes or pillar boxes, including:

- Load-break switches
- Fuse Switches
- Fuses
- Support frames
- Busbars
- LV Capacitors

Protection Systems

There are two main protective systems applied to the electrical network. These are:

a) the systems that detect when a piece of electrical equipment has become faulty or has been damaged making it unsafe or at risk of further damage.

The electrical fault protection system is comprised of many components that include:

- Electronic relays (solid state and numeric).
- Metering/Datalogging devices.
- Interconnecting cables.
- Panels for mounting.
- Control switches and control devices.

b) the systems that prevent excessive voltages from damaging network equipment.

The over-voltage protection that is applied to protect the EA Networks network is limited to the following components:

- Metal Oxide Varistor (MOV) surge arrestors
- Spark-gap devices mounted on some transformers

Earthing Systems

All earthing systems connected to EA Networks equipment. The componentry required to construct earthing systems is relatively simple and includes:

- Driven earth rods from 10 mm diameter to 40 mm diameter, copper and steel.
- Buried copper conductor
- Insulated copper conductor
- Crimped, welded and clamped joints

SCADA, Communications and Control

Includes SCADA Master Station(s) and Remote Terminal Units at individual sites. Communication equipment comprises specific communications sites, associated equipment and facilities and radio communications equipment installed in vehicles, at substations and other bases. Radio aerial support structures are included in this category.

Ripple Control

Ripple Injection Plants installed at Zone Substations or Grid Exit Points. This definition also includes the load control software included in the SCADA Master Station. The physical injection plant consists of solid-state components. These complex plants comprise capacitors, inductors, transformers, generators and controllers.

Performance Indicator Definitions

There are a range of parameters that can be derived from raw reliability statistics to indicate the level of performance of a particular network or portion of network. In order to reliably compare these "performance indicators" between networks, the specific method of calculation needs to be defined. The majority of these parameters are as defined in the "Electricity Information Disclosure Requirements 2004" but they are reproduced here for completeness.

Consumer Service Indicators

Interruption:	in relation to the supply of electricity to an electricity consumer by means of a prescribed voltage electric line, means the cessation of supply of electricity to that electricity consumer for a period of 1 minute or longer, other than by reason of disconnection of that electricity consumer for breach of the contract under which the electricity is supplied. For the purposes of this plan "interruption" does not include events originating in the Transpower network.
Planned Interruption:	means any interruption in respect of which not less than 24 hours' notice was given, either to the public or to all electricity consumers affected by the interruption.
Unplanned Interruption:	means any interruption in respect of which less than 24 hours' notice, or no notice, was given, either to the public or to all electricity consumers affected by the interruption.
Interruption Duration:	means the time from the cessation of supply of electricity until the supply of electricity is restored.
Interruption Duration Factor:	in relation to an interruption, means the sum obtained by calculating, for each electricity consumer that is affected by that interruption, the duration (in minutes) of that interruption and adding together the results of each calculation.
SAIDI:	means the system average interruption duration index. The sum obtained by adding together the Interruption Duration Factor for the interruption(s) of interest, divided by the total number of consumers served by EA Networks. For the purposes of this plan, faults originating on the Transpower network are not included in this index.
SAIFI:	means the system average interruption frequency index. The sum obtained by adding together the number of electricity consumers affected by the interruption(s) of interest, divided by the total number of consumers served by EA Networks. For the purposes of this plan, faults originating on the Transpower network are not included in this index.

CAIDI:	means the electricity consumer average interruption duration index. Is the sum obtained by adding together the interruption duration factors for the interruptions of interest, divided by the sum obtained by adding together the number of electricity consumers affected by each of those interruptions. For the purposes of this plan, faults originating on the Transpower network are not included in this index.
Consumer:	an individual or organisation beyond a network connection point, to which electricity is conveyed by means of works owned, provided, maintained and/or operated by EA Networks.
Network Connection Point:	means a point where a supply of electricity may flow between EA Networks' electric lines and the electrical installation of a consumer or consumers.
Urban:	means a zone or geographic area that is predominantly used for relatively high-density housing and business use.
Rural:	means a zone or geographic area that is predominantly used for farming, forestry, or recreation and cannot be construed as a city or township, but is accessible by more than one major arterial road.
Remote:	means a zone or geographic area that is distant from the general location of the rural population. Typically served by only one minor road and subject to disruption of vehicular access during adverse weather.
Prescribed Voltage Electric Line:	means an electric line that is capable of conveying electricity at a voltage equal to or greater than 3.3 kilovolts.

Asset Performance Indicators

Fault:	means a physical condition that causes a device, component or network element to fail to perform in the required manner.
Faults per 100km:	means the number of faults per 100 circuit kilometres of prescribed voltage electric line (can be broken down into per nominal line voltages).
System Length:	means the total circuit length (in kilometres) of the electric lines that form part of the EA Networks system.
System:	means all works owned, provided, maintained, or operated by EA Networks that are used or intended to be used for the conveyance or supply of electricity.

10.2 Appendix B - Asset Management Plan Cash-flow Schedule

This appendix contains the network capital cash-flow schedule which includes all capital items from the electricity network portion of the current EA Networks 2020-21 budget, the capital projects and programmes and baseline unscheduled capital expenditure currently identified as being necessary in the financial years 2021-30.

For legibility it is recommended that the following four pages are printed at A3.

CAPITAL CASHFLOW

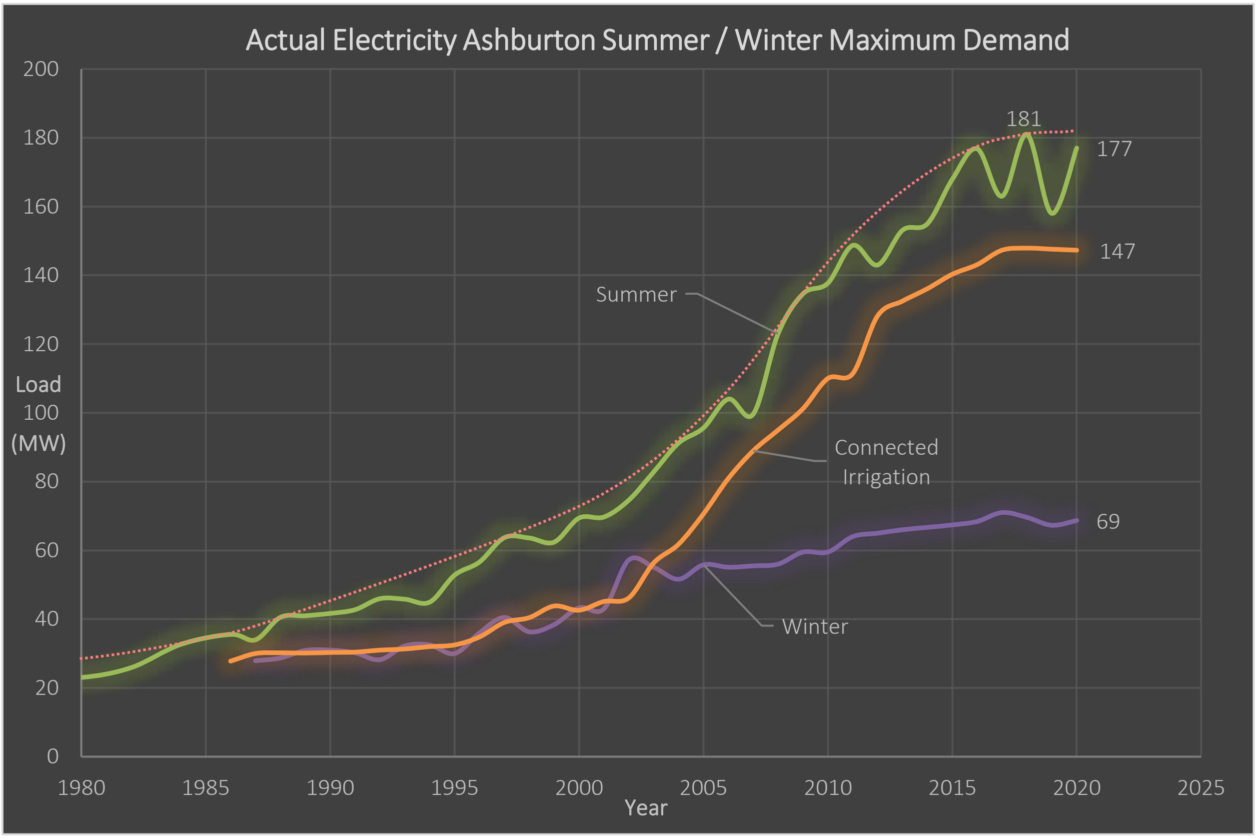
Parent	Child	Name	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
11172		~Consumer Connection - Other (inc Large Subdivisions)	43	44	66	89	90	67	45	44	44	45
11136		~Consumer Connection - Rural Alteration Capacity	116	113	113	115	110	109	111	105	104	108
11136		~Consumer Connection - Rural Alteration Safety	486	499	449	455	409	405	360	351	350	363
11136		~Consumer Connection - Rural LV	197	202	186	188	190	188	192	187	186	193
11136		~Consumer Connection - Rural Transformer	1,036	1,001	1,002	1,015	1,025	1,016	1,033	1,006	1,003	1,040
11058		~Consumer Connection - Urban Alteration Capacity	2	2	2	2	2	2	2	2	2	2
11058		~Consumer Connection - Urban LV	169	173	173	175	177	176	179	174	173	180
11058		~Consumer Connection - Urban Transformer	95	97	97	99	100	99	101	98	98	101
-1006		~DTX - System Growth (inc 22kV Conversion)	1,489	921	1,132	1,147	1,159	1,149	1,168	1,138	113	118
-1005		~DTX - Renewal & Replacement	26	27	27	27	28	27	28	27	27	28
-1004		~DTX - Reliability, Safety & Environment	11	11	11	11	11	11	11	11	11	11
-1174		~DTX - Consumer Connection (Rural Capacity)	79	78	78	79	75	74	76	72	71	74
-1174		~DTX - Consumer Connection (Rural LV)	61	63	58	59	60	59	60	59	58	60
-1174		~DTX - Consumer Connection (Rural Safety)	98	101	92	93	83	82	73	72	71	74
-1174		~DTX - Consumer Connection (Rural TX)	315	323	324	328	331	328	334	325	324	336
-1175		~DTX - Consumer Connection (Urban TX)	32	32	32	33	33	33	33	33	32	34
-1009		~Non-Network - Routine Vehicles	570	320	320	320	320	320	320	320	320	320
-1008		~Non-Network - Routine Plant	10	10	10	10	10	10	10	10	10	10
-1007		~Non-Network - Routine Info Tech	772	520	520	520	520	520	520	520	520	520
11550		~Non-Network - Routine Building Work	100		100		100		100		100	
11059		~Unscheduled System Growth	57	59	59	59	60	59	60	59	59	61
11078		~Unscheduled Quality of Supply	54	56	56	56	57	56	57	56	56	58
11079		~Unscheduled Other Reliability, Safety and Environment	55	57	57	57	58	57	58	57	57	59
11704		~Unscheduled Asset Replacement and Renewal	158	162	1,623	1,644	1,661	1,646	1,841	1,973	2,163	2,244
-1002		~22kV OH - Unscheduled Reconductoring	32	32	32	33	33	33	33	33	32	34
-1001		~22/11kV/LV OH - Unscheduled Pole Replacements	68	70	43	44	44	44	44	43	43	45
-1000		~22/11kV OH - Scheduled Pole Replacements	68	70	70	71	72	71	72	70	70	73
-1003		~DSS - Earthing Upgrades	387	80	80	81	82	81	83	81	80	83
		SUBTOTAL ANNUAL PROGRAMMES	6,586	5,123	6,811	6,809	6,899	6,723	7,005	6,924	6,178	6,273
-1010		11kV Core Network Cables	459	471	471	716	724	717	729	711		
-1011		11kV Core Network Centres	540	455	671							
-1012	12045	11kV Metering Point - Rakaia Gorge	4									
-1013		11kV OH Rebuild - Grahams Rd (Grove St - Gartarton Rd)	80									
-1014		11kV OH Rebuild - Rakaia Gorge Planning	21									
-1015		11kV OH Rebuild - Rangitata Gorge (Rangitata River - Waikari Hills)	289									
-1015	12418	11kV OH Rebuild - Rangitata Gorge (Coal Hill - Waikari Hills)	315									
-1015	12050	11kV OH Rebuild - Rangitata Gorge Bluffs	153									
-1016		11kV OH Rebuild - Taits Rd	72									
-1017		22kV Conversion - Eiffelton/Windermere Section 2	132									
-1017		22kV Conversion - Eiffelton/Windermere Section 3	204									
-1017		22kV Conversion - Eiffelton/Windermere Section 4	208									
-1017	12702	22kV Conversion - Eiffelton/Windermere Section 1	95									
-1018	12691	22kV OH New - EGN Feeder Underbuild (Wakanui Rd & Nicolls Rd)	56									
-1019		22kV OH Rebuild - A.R.G. Rd (Alford Forest Cemetery Rd - McFarlanes Rd)	127									
-1020		22kV OH Rebuild - Ashburton Staveley Rd (Allan Smith to Goughs Crossing Rds)	133									
-1021	12692	22kV OH Rebuild - Bells & Longbeach Rds	346									
-1022		22kV OH Rebuild - Corbetts Rd North (Mainwarings Rd South to end of line.)	18									
-1023		22kV OH Rebuild - Dip Rd (Reynolds - Flemings Rd)	139									
-1024		22kV OH Rebuild - Flemings Rd (Dip Rd South to BW70)	24									
-1176	12427	22kV OH Rebuild - Gibsons Rd (Fitzgerald Rd - North to end)	58									
-1025		22kV OH Rebuild - Hackthorne Rd (TWM to Frasers Rds)	156									
-1179	12613	22kV OH Rebuild - Jacksons Rd	42									
-1026		22kV OH Rebuild - Maronan Rd (Maronan Valetta Rd East)	73									
-1028	12614	22kV OH Rebuild - McCrorys Rd (Mainwarings - Dorie School Rds)	83									
-1027		22kV OH Rebuild - McCrorys Rd (Dorie School to Acton Rds.)	171									
-1029		22kV OH Rebuild - Pudding Hill Rd (Hobbs Rd - Spaxton St)	106									
-1030		22kV OH Rebuild - Rakaia Barrhill Methven Rd (West Town Belt West)	64									
-1031		22kV OH Rebuild - Rangitata Terrace Rd (Maronan Cracroft Rd East to BV08)	54									
-1032		22kV OH Rebuild - Tinwald Westerfield Mayfield Rd (Jacksons to Rushford Rd)	94									
-1033	11893	22kV OH Rebuild - Upper Rakaia River Crossing	543									
-1034		22kV OH Rebuild - Winters Rd (Christys Rd - East)	126									
-1035		22kV OH Underbuild - Bells & Longbeach Rds	106									
-1036		66kV OH Dampers Installation.	54	55								
-1037		66kV OH New - LSN-LSNT	83									
-1038	12701	66kV OH Rebuild - SFD-PDS	1,131									
12087		DSS Monitoring - Trial of Monitors	53									
12084		DSS Rebuild - Moore St 93 Substation	55									
-1040		DSS Replacement - Reclosers End of Life	60	62	62	62	63	63	64	62		
-1039		DSS Relocation - ADC Civic Centre & Library	126									
700		New Technology - ICP Load Monitoring & Control	210	1,965	1,966							
-1041		Non-Network - Aerial Photography	20				30				30	
-1178	11651	Non-Network - DMR Repeater Stations for Ashburton/Rangitata Gorges	24									
-1042		Non-Network - DMR Unify Vehicle Mobility and Hot Spot	55									
11550		Non-Network - NOC Layout changes	37									
-1043	11074	Non-Network - Software - Distribution Management Software - Control Centre	531									
-1044	10990	Non-Network - Software - GIS Development Programme	53	54	54	55	55	55	56	54	54	56
-1045		RMU (3 x CB) - cnr Dromore Methven Rd and Winchmore School Rd	135									
		ANNUAL TOTAL	23,444	15,474	15,395	13,277	12,140	13,091	11,363	14,458	15,203	10,649

Parent	Child	Name	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
-1045	12440	RMU (3 x CB) - cnr Scales Rd & Swamp Rd	64									
-1045	12464	RMU (4 x CB) - cnr Rakaia Barrhill Methven Rd & Wolseley Rd	169									
12087	11636	SCADA - Distribution Automation Programme	289	296	296	300	303					
12087	12088	SCADA - Replacement of Realtime Network IP Switches	18	16	16	13						
12087		SCADA - Tap Changer Comms	12									
-1047		UG Conversion - Anne St	376									
-1048		UG Conversion - Ashburton Christian School	37	38								
-1049		UG Conversion - Bowen St West (Cridland St - Railway Terrace West)	73									
-1050		UG Conversion - Cambridge St (Nelson St - Wakanui Rd)	293									
-1051	12443	UG Conversion - Convert State Hwy OH crossings to UG	45									
-1052		UG Conversion - Cridland St Rak (Rakaia Tce to Elizabeth Ave)	98									
-1053		UG Conversion - Cridland Street (South Town Belt - Elizabeth Ave)	235									
-1054		UG Conversion - Elizabeth Ave West (South Side, West Town Belt - Railway Tce West	326									
-1055		UG Conversion - Elizabeth Ave West Rak (West Town Belt to Cridland St north side)	44									
-1056		UG Conversion - Hinds Hwy. Cracroft St to Coldstream Rd	223									
-1057		UG Conversion - Johnstone St, Hinds (Peters St - Nugent St)	40	42								
-1058		UG Conversion - Lauriston Township	480									
-1059	11471	UG Conversion - Longbeach Rd.	97									
-1060		UG Conversion - McMurdo St (Hassel St - Wilkins St)	1,443									
-1061		UG Conversion - Methven Hwy (Pole Rd - Methven)	286									
-1062		UG Conversion - Methven Hwy (Rooneys - Shearers)	178	183								
-1063		UG Conversion - Michael Street (West Side, West Town Belt - Railway Terrace West)	478									
-1064		UG Conversion - Moore St (William St - Chalmers Ave)	106	172								
-1065		UG Conversion - Normanby Street & Cridland St (West Town Belt - Rakaia Tce)	76									
-1066		UG Conversion - Peters St, Hinds (Cracroft St - Isleworth Rd)	183	188								
-1067		UG Conversion - Rakaia Terrace	22									
-1068		UG Conversion - Robinson St, Rakaia (West Town Belt - Cridland St)	172									
-1069		UG Conversion - Stranges Rd	103									
-1070		UG Conversion - Upper Hakatere Huts No's 29 to 59	82	84								
-1071		UG Conversion - West Town Belt (Elizabeth Ave - Rakaia Tce)	233									
-1072		UG New - Ashburton CBD Duct Network	79	75								
-1073		UG New - EGN 22kV Feeder Cables	70									
-1074		UG New - Subdivision - ADC Business Estate Area A	389									
-1074		UG New - Subdivision - ADC Business Estate Area B	308									
-1075		ZSS - Protection - Replace 20 year Old Numeric Relays	66	67	67	68	69	68				
12087	11618	ZSS - Substation Security (Access Control Only) Programme	12									
12087	11617	ZSS - Substation Surveillance Programme	22	23	23	31	31					
-1076	10988	ZSS - Synchrophasors - Stage 1 and Stage 2	38									
-1077	12077	ZSS ASH - Building Improvements	103									
-1078		ZSS EFN - 66/22kV Conversion	53									
-1079	12073	ZSS EGN - Reconfigure Site (T1) as 66/22kV.	63									
-1080		ZSS LSN - New LSN-LSNT(HTH) 66kV Line Bay	496									
-1081		ZSS MHT - Fence Replacement	65									
-1081	12079	ZSS MHT - New Local Service RMU	105									
-1081		ZSS MHT - Replace 33kV CB with ex-EFN dogbox.	23									
-1082		ZSS MTV - 66kV Line Bay Changes	375									
-1082		ZSS MTV - MTV-MSM 66kV Line Bay & Protection	223									
-1082		ZSS MTV - Reconfigure T1 as 66/22kV.	83									
-1082		ZSS MTV - Relocate T2	76									
-1082		ZSS MTV - 22/33kV Step-up	210									
-1083		11kV OH Rebuild - Cliffords Rd		65								
-1084		11kV OH Rebuild - Fords Rd (Griffiths - Wheatstone Rds.)		126								
-1085		11kV OH Rebuild - Lower Downs Rd (Blairs Rd north to end.)		32								
-1086		11kV OH Rebuild - Rakaia Gorge Section 1+2		458	458							
-1017		22kV Conversion - Flemington & Huntingdon		216								
-1089		22kV Conversion - Methven Hwy Springfield Rd to Methven, AForest to Newtons Cnr		201	201							
-1091		22kV OH Rebuild - Allan Smith Rd (Ash Staveley Rd to on property)		82								
-1090		22kV OH Rebuild - Allan Smith Rd		152								
-1092		22kV OH Rebuild - Copley Rd (Chertsey Kyle Rd East to end.)		87								
-1093		22kV OH Rebuild - Crows Rd (Emersons to Dowdings Rds)		110								
-1094		22kV OH Rebuild - Hackthorne Rd (Valetta Westerfield - Frasers Rds)		245								
-1094		22kV OH Rebuild - Hackthorne Rd Section 1 (TWM - Barford Rds)		286								
-1095		22kV OH Rebuild - Harrisons Rd (Dorie School to Acton Rds)		139								
-1096		22kV OH Rebuild - Hollands- TWM Rd		89								
-1097		22kV OH Rebuild - Lismore Mayfield Rd (Hackthorne - Lismore School Rds)		320								
-1098		22kV OH Rebuild - Seafield Rd (Christys - Buckleys Rds)		89								
-1099		22kV OH Rebuild - Stevens Rd (Dowdings Rd South to ET05)		65								
-1101		22kV OH Rebuild - Windermere Rd (Surveyors Rd West)		162								
-1100		22kV OH Rebuild - Valetta Westerfield Rd (Westerfield School to Sheates Rd)		130								
-1102		66kV OH Rebuild - WNU-SFD		1,237								
-1104		UG Conversion - Cracroft St, Hinds (Peters St - Nugent St)		203								
-1105		UG Conversion - Dorie School		67								
-1106		UG Conversion - Gray St, Hinds (Cracroft St - Isleworth Rd)		314								
-1107		UG Conversion - Isleworth Rd, Hinds (Peters St - Nugent St)		281								
-1109		UG Conversion - Methven Hwy (Thompsons Track - Pole Rd)		862								
-1112		UG Conversion - Rolleston Street West HV Only (Cridland St - Mackie St)		88								
-1114		11kV OH Rebuild - Ashburton Gorge - Section 1.			324							
-1117		22kV OH Rebuild - Crows Rd (Dowdings Rd - East to end)			124							
-1116		22kV OH Rebuild - Anama School Rd			539							
-1118		66kV OH Rebuild - PDS-DOR			1,285							
		ANNUAL TOTAL	23,444	15,474	15,395	13,277	12,140	13,091	11,363	14,458	15,203	10,649

Parent	Child	Name	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
-1119		UG Conversion - Fergusson Street (Rakaia Terrace East - Burrowes Rd)			477							
-1120		UG Conversion - McNally St (Range St - McGregor Ln)			83							
-1121		UG Conversion - Methven Hwy (Blands Rd - Thompsons Track)			291							
-1122		UG Conversion - Peter Street (William St - Cass St)			81							
-1123		UG Conversion - Robinson St & Watson St			248							
-1124		UG Conversion - South Town Belt East (Bridge St - Burrowes Rd)			141							
-1125		UG Conversion - Tancred Street, Rakaia (South Town Belt - Dunford St)			430							
-1126		ZSS Montalto Hydro - Inject at 22kV			274							
-1086		11kV OH Rebuild - Rakaia Gorge Section 3 & 4				350						
-1172		22kV Conversion - Montalto/Rangitata				291						
-1088		22kV Conversion - Ruapuna				186						
700		New/Smart Technology Programme				1,991	2,012	1,994	2,027	1,975	1,968	2,042
-1171		UG Conversion - Carters Tce				201						
-1170		UG Conversion - Harland St (Catherine St - Graham St)				320						
-1127		UG Conversion - Johnstone St (McMurdo St - Grove St)				382						
-1128		UG Conversion - Manchester St (McMurdo St - Harland St)				228						
-1129		UG Conversion - Melcombe St (Anne St - Lagmhor Rd)				220						
-1129		UG Conversion - Melcombe St (Anne St - Maronan Rd)				176						
-1130		UG Conversion - Methven Hwy (Shearers - Blands Rd)				284						
-1131		UG Conversion - Michael St (East Side, Bridge St - Burrowes Rd)				271						
-1132		UG Conversion - Oxford St (Beach Rd - Wellington St)				323						
-1133		22kV Conversion - Anama					294					
-1134		UG Conversion - Allens Road (Harrison St-Alford Forest Rd)					296					
-1135		UG Conversion - Allens Road (Racecourse Rd-Carters Rd)					175					
-1136		UG Conversion - Farm Rd (Middle Rd - Racecourse Rd)					297					
-1137		UG Conversion - Mt Hutt Stn Rd (Methven - Holmes Rd)					56					
-1138		UG Conversion - Racecourse Rd (Farm Rd - Russell Ave)					833					
-1139		22kV Conversion - Highbank/McLennans Bush						292				
-1140		UG Conversion - Burrowes Road (Elizabeth Ave - Michael St)						93				
-1141		UG Conversion - Burrowes Road (STB to Elizabeth Ave)						116				
-1142		UG Conversion - Jane St (McMurdo St - Grove St)						326				
-1143		UG Conversion - Mackie Street (Elizabeth Ave - Dunford St)						173				
-1144		UG Conversion - Mackie Street HV Only (Rolleston St - Michael St)						76				
-1145		UG Conversion - Rakaia Huts						436				
-1146		UG Conversion - Rolleston Street West (Mackie St - Cridland St)						158				
-1147		UG Conversion - Wilkin St (McMurdo St - Millibrook Pl)						208				
-1148		ZSS EGN - 33kV Ripple Plant Replacement						392				
-1149		ZSS TIN - New 66/11kV Transformer						1,200				
-1150		22kV Conversion - Mt Hutt/Rakaia Gorge							296			
-1151		UG Conversion - Lower Hakatere Huts Stage 3							277			
-1152		UG Conversion - Rolleston Street (Tancred St - Burrowes Rd)							228			
-1153		UG Conversion - South Town Belt - West (West Town Belt - SH1)							458			
-1151		UG Conversion - Upper Hakatere Huts Stage 2							222			
-1154		22kV Conversion - Ashburton Gorge								289		
-1155		66kV OH New - HTH-LSN								2,094	1,542	
-1156		GXP - New 66kV GXP (+$1.5M T.Charge p.a.)										
-1157		UG Conversion - Grahams Street (McMurdo St - Grove St)								355		
-1158		UG Conversion - Thomson St (Carter Tce - Wilkin St)								185		
-1158		UG Conversion - Thomson St (Grahams St - Hassel St)								669		
-1158		UG Conversion - Thomson St (Wilkin St - Grove St)								960		
-1159		ZSS HTH - New HTH-LSN 66kV Line Bay								181		
-1167		22kV OH New - MON Feeder Integration									764	
-1168		66kV OH New - CRW-MON									1,738	1,803
-1160		UG Conversion - Agnes St (McMurdo St - Grove St)									316	
-1161		UG Conversion - Catherine St (McMurdo St - Grove St)									309	
-1162		UG Conversion - Shearman St									79	
-1163		ZSS MON - New 66/22kV ZSS									1,996	
-1164		ZSS MSM - New MSM-MON 66kV Line Bay									229	
-1166		ZSS CRW & MON - New 66kV Line Bays										475
		ANNUAL TOTAL	23,444	15,474	15,395	13,277	12,140	13,091	11,363	14,458	15,203	10,649

10.3 Appendix C - Forecast Load Growth

Future load estimation is as much art as it is science. There are two main techniques one can use to try and predict future load. The first approach is to look at historical trends and extrapolate these into the future (referred to in this plan as projection). The second approach is to model the loads and estimate the impact of various factors such as the economy, commodity prices, resource availability, legislative changes, weather, etc on the future loads placed on the network (referred to in this plan as estimation). During periods of high load growth, the projection technique appeared to offer a reasonable fit. Now that constraints have come on water for irrigation, the historical information that projection relies upon is no longer valid for load growth prediction. EA Networks have now moved to use the estimation technique which offers more granularity, albeit with less hard data to justify it. The long-term demand graph shown below indicates the correlation between connected irrigation growth and summer peak demand growth. In the last three years there has been zero net increase of connected irrigation.



The estimation approach is more time consuming and detailed, but it does offer the advantage of estimating zone substation maximum demands individually. The model EA Networks has chosen takes each substation and assumes a base load for winter and a base load for summer. The winter base load is assumed to be approximately the winter maximum demand. An irrigation load is available for summer maximum demand calculation. The summer base load and the irrigation load are added together with a diversity factor applied and this gives a summer zone substation maximum demand. Individual subtransmission lines and ultimately Transpower GXP maximum demands can also be calculated. Growth at each substation is estimated from, among other things, localised trends in irrigation pump size and resource consent density. These trends are subjective and are influenced by the opinions of many people involved in the irrigation industry - from well drillers to end use farmers. The chart "Actual and Estimated EA Networks Summer/Winter Maximum Demands" (see section 5.2.4) and the table "Base and Irrigation Loads for Zone Substation Load Predictions" (see below) show the results of this modelling. The estimation technique has been pessimistic in some previous plans (since it cannot accommodate unknown load growth). In the last few years, it has been a reasonably close fit during dry years. It will be used as a realistic/minimum growth curve for the 2021-30 plan.

BASE AND IRRIGATION LOADS FOR ZONE SUBSTATION LOAD PREDICTIONS

		Financial Year	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
SUBSTATION		Year	2019/20	2020/21	2021/22	2022/23	2023/24	2024/25	2025/26	2026/27	2027/28	2028/29	2029/30
Ashburton	Total Summer		12.93	13.09	13.35	13.51	13.68	13.85	14.02	14.19	14.37	14.55	14.73
2 x 10/20 MVA	Total Winter		19.20	19.62	20.05	20.50	20.95	21.41	21.88	22.36	22.85	23.35	23.87
22.0 Firm	Winter Base	2.2% Growth	19.20	19.62	20.05	20.50	20.95	21.41	21.88	22.36	22.85	23.35	23.87
ASH	Summer Base	1.5% Growth	10.63	10.79	10.95	11.11	11.28	11.45	11.62	11.79	11.97	12.15	12.33
	Irrigation Base	100% Diversity	2.30	2.30	2.40	2.40	2.40	2.40	2.40	2.40	2.40	2.40	2.40
Northtown	Total Summer		11.15	11.30	11.46	11.62	11.88	12.05	12.21	12.38	12.55	12.73	12.91
2 x 10/20 MVA	Total Winter		17.20	17.58	17.97	18.36	18.76	19.18	19.60	20.03	20.47	20.92	21.38
22.0 Firm	Winter Base	2.2% Growth	17.20	17.58	17.97	18.36	18.76	19.18	19.60	20.03	20.47	20.92	21.38
NTN	Summer Base	1.5% Growth	10.35	10.50	10.66	10.82	10.98	11.15	11.31	11.48	11.65	11.83	12.01
	Irrigation Base	100% Diversity	0.80	0.80	0.80	0.80	0.90	0.90	0.90	0.90	0.90	0.90	0.90
Carew	Total Summer		16.62	16.65	16.67	16.69	16.72	16.84	16.87	16.89	16.92	16.94	16.97
2 x 10/15 MVA	Total Winter		1.22	1.23	1.24	1.25	1.27	1.28	1.29	1.30	1.32	1.33	1.34
17.0 Firm	Winter Base	1.0% Growth	1.22	1.23	1.24	1.25	1.27	1.28	1.29	1.30	1.32	1.33	1.34
CRW	Summer Base	1.0% Growth	2.32	2.35	2.37	2.39	2.42	2.44	2.47	2.49	2.52	2.54	2.57
	Irrigation Base	100% Diversity	14.30	14.30	14.30	14.30	14.30	14.40	14.40	14.40	14.40	14.40	14.40
Coldstream	Total Summer		16.07	16.19	16.21	16.22	16.34	16.36	16.38	16.39	16.41	16.43	16.45
1 x 10/20 MVA	Total Winter		0.75	0.76	0.77	0.78	0.78	0.79	0.80	0.81	0.82	0.82	0.83
9.0 Firm	Winter Base	1.0% Growth	0.75	0.76	0.77	0.78	0.78	0.79	0.80	0.81	0.82	0.82	0.83
CSM	Summer Base	1.0% Growth	1.67	1.69	1.71	1.72	1.74	1.76	1.78	1.79	1.81	1.83	1.85
	Irrigation Base	100% Diversity	14.40	14.50	14.50	14.50	14.60	14.60	14.60	14.60	14.60	14.60	14.60
Dorie	Total Summer		11.49	11.50	11.52	11.53	11.55	11.56	11.58	11.59	11.61	11.63	11.64
1 x 10/15 MVA	Total Winter		0.95	0.96	0.97	0.98	0.99	1.00	1.01	1.02	1.03	1.04	1.05
9.0 Firm	Winter Base	1.0% Growth	0.95	0.96	0.97	0.98	0.99	1.00	1.01	1.02	1.03	1.04	1.05
DOR	Summer Base	1.0% Growth	1.49	1.50	1.52	1.53	1.55	1.56	1.58	1.59	1.61	1.63	1.64
	Irrigation Base	100% Diversity	10.00	10.00	10.00	10.00	10.00	10.00	10.00	10.00	10.00	10.00	10.00
Eiffelton	Total Summer		9.20	9.32	9.44	9.56	9.67	9.79	9.81	9.83	9.84	9.86	9.88
1 x 10/20 MVA	Total Winter		1.75	1.77	1.78	1.80	1.82	1.84	1.86	1.87	1.89	1.91	1.93
4.0 Firm	Winter Base	1.0% Growth	1.75	1.77	1.78	1.80	1.82	1.84	1.86	1.87	1.89	1.91	1.93
EFN	Summer Base	1.0% Growth	1.70	1.72	1.74	1.76	1.77	1.79	1.81	1.83	1.84	1.86	1.88
	Irrigation Base	100% Diversity	7.50	7.60	7.70	7.80	7.90	8.00	8.00	8.00	8.00	8.00	8.00
Fairton	Total Summer		8.99	9.05	9.12	9.18	9.25	9.31	9.38	9.45	9.52	9.59	9.66
2 x 10/20 MVA	Total Winter		8.99	9.17	9.35	9.54	9.73	9.92	10.12	10.32	10.53	10.74	10.96
20.0 Firm	Winter Base	2.0% Growth	8.99	9.17	9.35	9.54	9.73	9.92	10.12	10.32	10.53	10.74	10.96
FTN	Summer Base	1.0% Growth	6.39	6.45	6.52	6.58	6.65	6.71	6.78	6.85	6.92	6.99	7.06
	Irrigation Base	100% Diversity	2.60	2.60	2.60	2.60	2.60	2.60	2.60	2.60	2.60	2.60	2.60
Highbank	Summer Load		8.40	8.40	8.40	8.40	8.40	8.40	8.40	8.40	8.40	8.40	8.40
Not Firm	Summer Gen		0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
HBK	Winter Gen		-27	-27	-27	-27	-27	-27	-27	-27	-27	-27	-27
Hackthorne	Total Summer		20.08	20.11	20.14	20.16	20.19	20.22	20.25	20.28	20.30	20.33	20.36
1 x 10/20 MVA	Total Winter		2.00	2.04	2.08	2.13	2.17	2.21	2.26	2.30	2.35	2.39	2.44
9.0 Firm	Winter Base	2.0% Growth	2.00	2.04	2.08	2.13	2.17	2.21	2.26	2.30	2.35	2.39	2.44
HTH	Summer Base	1.0% Growth	2.68	2.71	2.74	2.76	2.79	2.82	2.85	2.88	2.90	2.93	2.96
	Irrigation Base	100% Diversity	17.40	17.40	17.40	17.40	17.40	17.40	17.40	17.40	17.40	17.40	17.40
Lagmhor	Total Summer		8.29	8.30	8.40	8.41	8.41	8.41	8.42	8.42	8.43	8.43	8.43
1 x 10/20 MVA	Total Winter		1.25	1.27	1.30	1.33	1.35	1.38	1.41	1.43	1.46	1.49	1.52
5.0 Firm	Winter Base	2.0% Growth	1.25	1.27	1.30	1.33	1.35	1.38	1.41	1.43	1.46	1.49	1.52
LGM	Summer Base	1.0% Growth	0.39	0.40	0.40	0.41	0.41	0.41	0.42	0.42	0.43	0.43	0.43
	Irrigation Base	100% Diversity	7.90	7.90	8.00	8.00	8.00	8.00	8.00	8.00	8.00	8.00	8.00
Lauriston	Total Summer		16.21	16.22	16.23	16.24	16.26	16.27	16.28	16.29	16.31	16.32	16.33
1 x 10/15 MVA	Total Winter		1.73	1.77	1.80	1.84	1.88	1.91	1.95	1.99	2.03	2.07	2.11
7.0 Firm	Winter Base	2.0% Growth	1.73	1.77	1.80	1.84	1.88	1.91	1.95	1.99	2.03	2.07	2.11
LSN	Summer Base	1.0% Growth	1.16	1.17	1.18	1.19	1.21	1.22	1.23	1.24	1.26	1.27	1.28
	Irrigation Base	100% Diversity	15.05	15.05	15.05	15.05	15.05	15.05	15.05	15.05	15.05	15.05	15.05

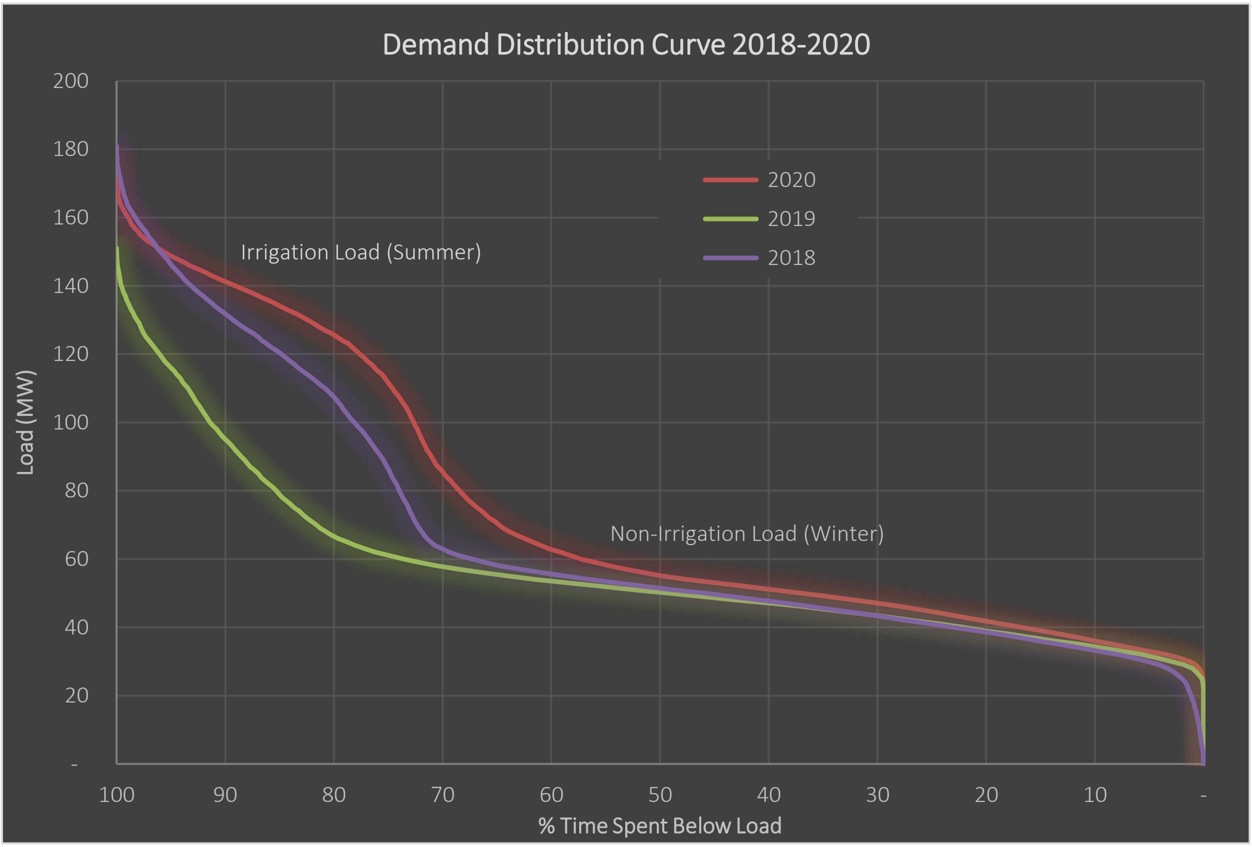
			2019/20	2020/21	2021/22	2022/23	2023/24	2024/25	2025/26	2026/27	2027/28	2028/29	2029/30
Methven 66	Total Summer		5.29	5.40	5.45	5.56	5.62	5.67	5.73	5.78	5.84	5.89	5.95
1 x 10/15 MVA	Total Winter		5.40	5.51	5.62	5.73	5.85	5.96	6.08	6.20	6.33	6.45	6.58
6.0 Firm	Winter Base	2.0% Growth	5.40	5.51	5.62	5.73	5.85	5.96	6.08	6.20	6.33	6.45	6.58
MTV	Summer Base	1.5% Growth	3.39	3.44	3.49	3.54	3.60	3.65	3.71	3.76	3.82	3.87	3.93
	Irrigation Base	100% Diversity	1.90	1.96	1.96	2.02	2.02	2.02	2.02	2.02	2.02	2.02	2.02
Montalto	Summer		-1.00	-1.00	-1.00	-1.00	-1.00	-1.00	-1.00	-1.00	-1.00	-1.00	-1.00
Generation	Winter		-1.50	-1.50	-1.50	-1.50	-1.50	-1.50	-1.50	-1.50	-1.50	-1.50	-1.50
Montalto	Total Summer		2.59	2.60	2.61	2.62	2.63	2.64	2.65	2.66	2.67	2.68	2.69
1 x 2.5 MVA	Total Winter		0.45	0.45	0.46	0.46	0.47	0.47	0.48	0.48	0.49	0.49	0.50
1.0 Firm	Winter Base	1.0% Growth	0.45	0.45	0.46	0.46	0.47	0.47	0.48	0.48	0.49	0.49	0.50
MON	Summer Base	1.5% Growth	0.59	0.60	0.61	0.62	0.63	0.64	0.65	0.66	0.67	0.68	0.69
	Irrigation Base	100% Diversity	2.00	2.00	2.00	2.00	2.00	2.00	2.00	2.00	2.00	2.00	2.00
Mt Hutt	Total Summer		0.56	0.56	0.56	0.56	0.56	0.56	0.56	0.56	0.56	0.56	0.56
1 x 5 MVA	Total Winter		2.30	2.30	2.30	2.30	2.30	2.30	2.30	2.30	2.30	2.30	2.30
2.0 Firm	Winter Base		2.30	2.30	2.30	2.30	2.30	2.30	2.30	2.30	2.30	2.30	2.30
MHT	Summer Base		0.50	0.50	0.50	0.50	0.50	0.50	0.50	0.50	0.50	0.50	0.50
	Irrigation Base		0.06	0.06	0.06	0.06	0.06	0.06	0.06	0.06	0.06	0.06	0.06
Mt Somers	Total Summer		3.33	3.41	3.43	3.45	3.46	3.48	3.50	3.52	3.54	3.55	3.57
1 x 10/15 MVA	Total Winter		2.33	2.35	2.38	2.40	2.42	2.45	2.47	2.50	2.52	2.55	2.57
5.0 Firm	Winter Base	1.0% Growth	2.33	2.35	2.38	2.40	2.42	2.45	2.47	2.50	2.52	2.55	2.57
MSM	Summer Base	1.0% Growth	1.73	1.75	1.77	1.79	1.80	1.82	1.84	1.86	1.88	1.89	1.91
	Irrigation Base	100% Diversity	1.60	1.66	1.66	1.66	1.66	1.66	1.66	1.66	1.66	1.66	1.66
Overdale	Total Summer		13.36	13.37	13.48	13.49	13.51	13.52	13.53	13.54	13.56	13.57	13.58
1 x 10/20 MVA	Total Winter		3.05	3.11	3.17	3.23	3.30	3.36	3.43	3.50	3.57	3.64	3.71
10.0 Firm	Winter Base	2.0% Growth	3.05	3.11	3.17	3.23	3.30	3.36	3.43	3.50	3.57	3.64	3.71
OVD	Summer Base	1.0% Growth	1.16	1.17	1.18	1.19	1.21	1.22	1.23	1.24	1.26	1.27	1.28
	Irrigation Base	100% Diversity	12.20	12.20	12.30	12.30	12.30	12.30	12.30	12.30	12.30	12.30	12.30
Pendarves	Total Summer		19.17	19.19	19.21	19.33	19.34	19.36	19.38	19.40	19.42	19.44	19.46
2 x 10/20 MVA	Total Winter		3.43	3.50	3.57	3.64	3.71	3.79	3.86	3.94	4.02	4.10	4.18
25.0 Firm	Winter Base	2.0% Growth	3.43	3.50	3.57	3.64	3.71	3.79	3.86	3.94	4.02	4.10	4.18
PDS	Summer Base	1.0% Growth	1.77	1.79	1.81	1.83	1.84	1.86	1.88	1.90	1.92	1.94	1.96
	Irrigation Base	100% Diversity	17.40	17.40	17.40	17.50	17.50	17.50	17.50	17.50	17.50	17.50	17.50
Seafield	Total Summer		7.00	7.00	7.00	7.00	7.00	7.00	7.00	7.00	7.00	7.00	7.00
1 x 10/15 MVA	Total Winter		7.00	7.00	7.00	7.00	7.00	7.00	7.00	7.00	7.00	7.00	7.00
5.0 Firm	Winter Base		7.00	7.00	7.00	7.00	7.00	7.00	7.00	7.00	7.00	7.00	7.00
SFD	Summer Base		7.00	7.00	7.00	7.00	7.00	7.00	7.00	7.00	7.00	7.00	7.00
	Irrigation Base		0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Wakanui	Total Summer		12.82	12.84	12.85	12.87	12.88	12.90	12.91	12.93	12.95	12.96	12.98
1 x 10/15 MVA	Total Winter		1.80	1.82	1.84	1.86	1.88	1.90	1.92	1.93	1.95	1.97	1.99
10.0 Firm	Winter Base	1.0% Growth	1.80	1.82	1.84	1.86	1.88	1.90	1.92	1.93	1.95	1.97	1.99
WNU	Summer Base	1.0% Growth	1.52	1.54	1.55	1.57	1.58	1.60	1.61	1.63	1.65	1.66	1.68
	Irrigation Base	100% Diversity	11.30	11.30	11.30	11.30	11.30	11.30	11.30	11.30	11.30	11.30	11.30
Peak Loss	Summer	1.0% Growth	6.20	6.26	6.32	6.39	6.45	6.52	6.58	6.65	6.71	6.78	6.85
(Estimated)													
	Winter	0.1% Growth	2.72	2.73	2.73	2.73	2.74	2.74	2.74	2.74	2.75	2.75	2.75

			2019/20	2020/21	2021/22	2022/23	2023/24	2024/25	2025/26	2026/27	2027/28	2028/29	2029/30
OVERALL	Summer Load	excl Gen	181.4	181.9	182.6	183.2	183.9	184.6	185.3	185.9	186.5	187.2	187.8
TOTALS	220.0 Firm	Diversity	87%	86%	86%	86%	86%	86%	86%	86%	86%	86%	86%
	Irrigation	High	146.4	146.7	147.1	147.3	147.6	147.8	148.6	148.6	148.6	148.6	148.6
		Diversity	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%
		Low	141.2	140.1	139.0	137.7	136.5	135.2	133.7	133.7	133.7	133.7	133.7
		Diversity	96%	95%	94%	93%	92%	91%	90%	90%	90%	90%	90%
	Generation (S)		-1.0	-1.0	-1.0	-1.0	-1.0	-1.0	-1.0	-1.0	-1.0	-1.0	-1.0
	Winter Load	81% of Subs	67.2	68.4	69.5	70.7	71.9	73.2	74.4	75.7	77.0	78.4	79.7
	220.0 Firm	Diversity	77%	77%	77%	77%	77%	77%	77%	77%	77%	77%	77%
		83% of Subs	40.8	42.0	43.2	44.4	45.7	46.9	48.2	49.6	50.9	52.3	53.7
		excl Gen	67.2	68.4	69.5	70.7	71.9	73.2	74.4	75.7	77.0	78.4	79.7
		Diversity	85%	85%	85%	85%	85%	85%	85%	85%	85%	85%	85%
	Generation (W)		-28.5	-28.5	-28.5	-28.5	-28.5	-28.5	-28.5	-28.5	-28.5	-28.5	-28.5

- Load exceeds the current firm capacity of the substation (if a transformer fails).

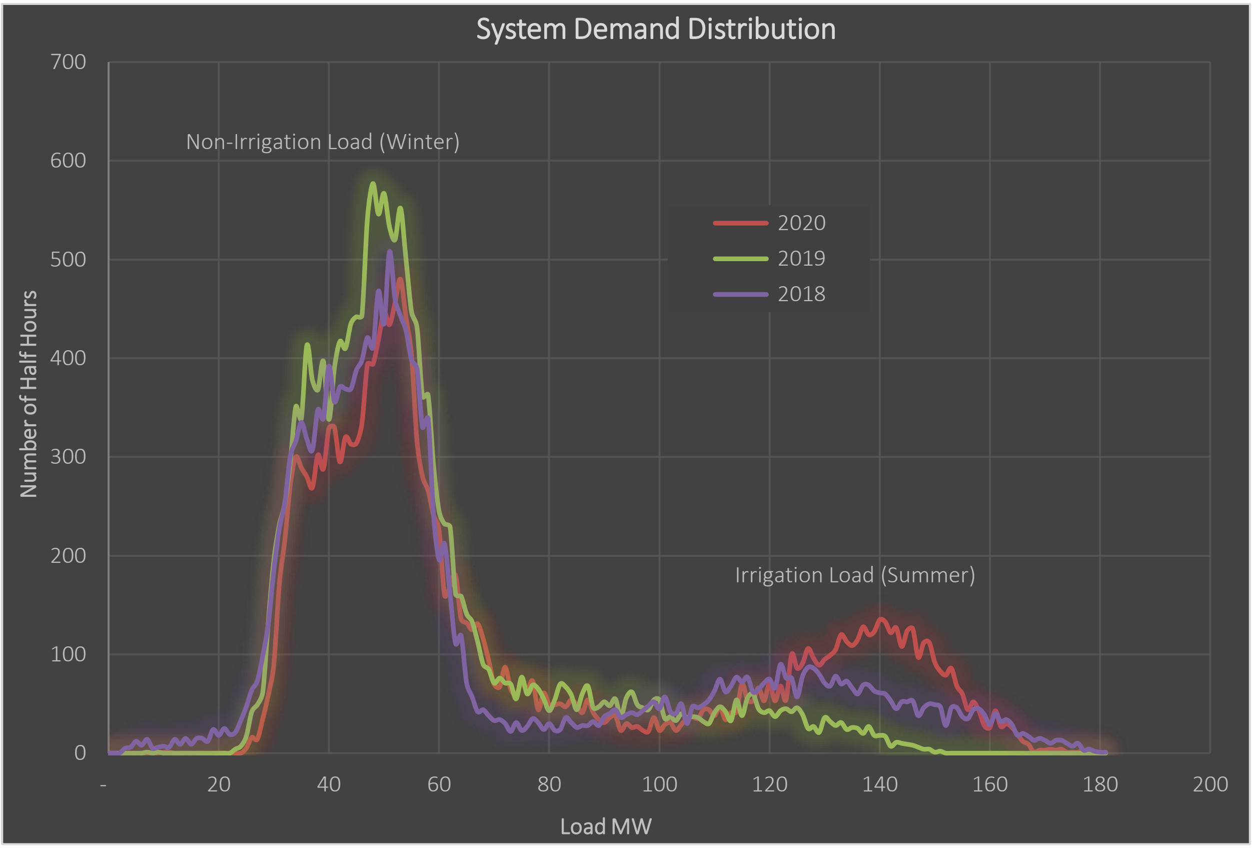
It should be noted that the firm capacity referred to in the table above is the present firm capacity (steady state and switched) and this will change with development in the network (both subtransmission and distribution development). The pink highlight is used to show the point at which peak load will exceed firm capacity if nothing is done. Many of the firm capacity constraints are addressed by network development projects during the plan period.

The load forecasts assume a dry year (low diversity) and a cold winter, as that is the demand the network must cope with and when the irrigation capacity is most needed. The risk of irrigation load either remaining static or falling because of surface irrigation scheme piping has resulted in a change of approach for load estimation. The normal and dry year estimates are averaged, and this is used as the realistic load estimate for subtransmission planning. Future individual zone substation loads are assessed using non-diverse load estimates.



The two charts shown above and below represent demand duration data for the 2018, 2019, and 2020 year so far. The charts show the seasonal sensitivity of the system demand as well as the demand duration sensitivity of rain during summer. A marked transition occurs from summer high demand to base winter demand (where Highbank generation of 20-26 MW is running but is not visible here). The demand below 60 MW is considered winter demand, or summer base demand. The second (frequency distribution) chart has two distinct 'humps' that show the winter demand (25-65 MW) and summer demand (70-181 MW). A considerable amount of productive 'growing' time is spent beyond 150 MW and the irrigation consumers causing this peak have indicated they are prepared to pay for the assets (both EA Networks and Transpower) necessary to avoid load control of the absolute peak demand. The summer of 2017-18 started dry (October-November 2017) and this initially caused a very low irrigation diversity. In December and January regular rain caused the demand to drop significantly. The actual summer peak demand (181MW) was very similar to that previously predicted for a dry year and was not unexpected. 2016-17 peak demand was 162MW. 2018-19 was a "wet" summer and both diagrams show the impact it had on irrigation demand duration and peak (151MW). 2019-20 has been an average to dry summer with a reasonably high peak (177MW) and considerable demand duration above 110MW.

Hours Spent Above Load	2014-15	2015-16	2017-18	2018-19	2019-20
>110MW	2,397	2,349	1,705	595	2,243
>160MW	26	95	167	-	108
>170MW	-	17	44	-	10



EA Networks have reached a point in time where some of the underlying assumptions about summer load growth have changed. The total amount of water that can be abstracted from underground aquifers in much of Mid Canterbury has reached the limit stipulated by ECAN. This limit forces other sources of water to be sought. These other sources are typically obtained from storage regimes and water conservation from existing river abstraction schemes. The piping of existing open race schemes can have a twofold effect:

1) The losses from open race systems are eliminated and that water is now available to the scheme as 'new' water.

2) The pipe system is gravity pressurised for most of its length and this allows existing electrical surface pumps to be relinquished or saved only for a dry year. It also can permit some small hydro generation options.

Some of the farms that have 'new' surface water available are existing deep well irrigators with a water abstraction consent and a large electrical pump. This deep well water consent is to some degree portable in that the water is no longer taken from the aquifer so another farmer can apply for the consent to take water from the same aquifer. Initially, it is likely that the original consent holder will retain the consent and deep well pump to guarantee reliability of water supply during drought conditions (river-based schemes may be restricted). If the piped gravity scheme proves to be reliable, the electrical demand from the deep well pump may shift to a less traditional irrigation area that is less well serviced for this type of demand by EA Networks. Overall, the demand for water from all sources will remain high. It is very unlikely the total electrical pumping demand will fall considerably in the medium term. The growth rate in irrigation demand will be minimal at best.

The other environmental issue that constrains rural intensification is that of nutrient run-off. ECAN have released a decision on a variation to the Regional Water Plan that:

- precludes almost all additional water abstraction south of the Ashburton River,
- places strict limits on groundwater nitrate levels, and
- places strict limits on the quantity of nitrogen run-off from farming operations.

These additional restrictions have resulted in EA Networks revising down the irrigation load growth potential in all areas of the Ashburton District. The area north of the Ashburton River may have some additional irrigation development but it is likely to be delivered via a gravity pressurised scheme and not electric pumping.

EA Networks are planning on the basis that all available deep well consents will be used and some existing surface electrical pumps will be substituted by gravity pressurised pipe schemes. The level of generation provided by piped schemes has been low (of the order of a few MW at best) and will not materially affect the GXP load. It may however affect particular zone substation loads and delay the need for transformer upgrades and similar demand-driven asset intensive solutions.

The prospect of EV (electric vehicle) charging causing significant impacts on the distribution network are real and will occur at some future time. At the moment, the penetration of EVs is low but over the next ten years it will undoubtedly grow. The critical factor for the impact of EVs is the timing of the charging cycle. The cost of energy will initially remain cheapest in the off-peak periods which will encourage charging from 11:00 PM to 6:00 AM. Provided the bulk of charging takes place during this period the impact on peak demand should be low, although at some future time there is the potential for midnight peaks to occur. The impact of EV charging has not yet been factored into the GXP demand. Once EV uptake increases, it will become more apparent how owners choose to operate the charging facilities both at home and elsewhere.

Solar photovoltaic electricity generation is becoming reasonably common (EA Networks have approximately 237 Solar PV installations). The average size of these is about 4.4 kW each and the combined total output is 1,034 kW (much of which will be consumed on the load side of the meter). The impact of Solar PV is not yet measurable in the peak demand of either Transpower grid exit points or EA Networks zone substations. The impact of Solar PV generation has not been factored into the 10-year GXP demand.

The potential for coal or gas process heat to be converted to electrical demand is a strong possibility. Some analysis has been done about the scale of process heat locally, and it is possible 20-25MW electrical demand may eventuate from existing boilers being converted. Until firm proposals are in place, the loads will not be incorporated as additional planned demand. Only one enquiry has been made. The CDHB Ashburton hospital are looking to use groundwater heat pumps (~1MW total) to displace coal fired boilers. This proposal appears to be proceeding (although no confirmation has been received) and may also have a minor impact on summer demand as the system can also be used for cooling.

10.4 Appendix D - Disclosure Cross-References

To assist people reading this plan in relation to the Electricity Information Disclosure Requirements, a cross-reference list of mandatory items is shown here. This allows the reader to find all items listed in "Attachment A" of the Electricity Information Disclosure Determination 2012 without searching the entire plan.

3. The AMP must include the following-

3.1 A summary	Exec. Summary
Background and Objectives	
3.2 Details of the background and objectives of the EDB's asset management and planning processes	s1
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.	s1.3, s1.5
3.3.2 states the corporate mission or vision as it relates to asset management	s1.3, s1.7
3.3.3 identifies the documented plans produced by the annual business planning process	s1.6
3.3.4 how do the different documented plans relate to one another, particularly asset management	s1.6
3.3.5 the interaction of the objectives of the AMP and other corporate goals, business processes, and plans	s1.6, s1.7
3.4 Details of the AMP planning period	s1.5
3.5 The date that it was approved by the directors	I.F.C.
3.6 A description of stakeholder interests identifying important stakeholders and indicates -	s1.4
3.6.1 how the interests of stakeholders are identified	s1.4
3.6.2 what these interests are	s1.4
3.6.3 how these interests are accommodated in asset management practices	s1.4
3.6.4 how conflicting interests are managed	s3.2
3.7 A description of the accountabilities and responsibilities for asset management on at least 3 levels, including-	
3.7.1 governance	s1.2, s1.6
3.7.2 executive	s1.2
3.7.3 field operations	s1.9
3.8 All significant assumptions	s1.10
3.8.1 quantified where possible	s1.10
3.8.2 clearly identified in an understandable manner to interested persons,	s1.10

including	
3.8.3 a description of changes proposed where the information is not based on the EDB's existing business	s1.10.3
3.8.4 the sources of uncertainty and the potential effect of the uncertainty on the prospective information	s1.10
3.8.5 the price inflator assumptions used to prepare nominal New Zealand dollar costs	s1.10.6
3.9 Factors that may lead to a material difference(disclosed vs future actual)	s1.10, s9.1
3.10 An overview of asset management strategy and delivery	s1.7
3.11 An overview of systems and information management data	s1.8
3.12 Any limitations in the asset management data and any data improvement initiatives	s1.8
3.13 A description of the processes used within the EDB for-	
3.13.1 managing routine asset inspections and network maintenance	s6.2.5, s6
3.13.2 planning and implementing network development projects	s5.1.6 – s5.1.7
3.13.3 measuring network performance.	s9
3.14 An overview of asset management documentation, controls and review processes	Not Available
3.15 An overview of communication and participation processes	Not Available
3.16 AMP must present all financial values in constant price NZD except where specified otherwise;	Compliant
3.17 The AMP must be structured and presented to support the purposes of AMP disclosure (clause 2.6.2)	Compliant
Assets covered	
4. The AMP must provide details of the assets covered, including-	
4.1 a high-level description of the service areas covered, including-	
4.1.1 the region(s) covered	s4.1
4.1.2 identification of large consumers that have a significant impact on the network	s4.1
4.1.3 description of the load characteristics for different parts of the network	s4.1
4.1.4 peak demand and total energy delivered in the previous year	s4.1, s1.1
4.2 a description of the network configuration, including-	s4.2
4.2.1 GXPs and any DG greater than 1 MW inc. firm supply capacity and current peak load;	s4.2.1
4.2.2 subtransmission system off each GXP, and security/capacity of zone substations.	s4.2.2, s4.2.3
4.2.3 a description of the distribution system, including the extent to which it	s4.2.4

is underground;	
4.2.4 a brief description of the network's distribution substation arrangements;	s4.2.4.2
4.2.5 a description of the low voltage network including the extent to which it is underground; and	s4.2.4.3
4.2.6 assets such as protection relays, ripple injection systems, SCADA and telecommunications systems.	s4.2.5
4.3 sub-networks as per subclause 4.2.	
Network assets by category	
4.4 The AMP must describe the network assets by providing the following information for each asset category-	
4.4.1 voltage levels;	s6.3 – s6.15
4.4.2 description and quantity of assets;	s6.3 – s6.15
4.4.3 age profiles; and	s6.3 – s6.15
4.4.4 condition of the assets	s6.3 – s6.15
4.5 The asset categories discussed in subclause 4.4 above should include at least the following-	
4.5.1 Sub transmission	s6.3
4.5.2 Zone substations	s6.7
4.5.3 Distribution and LV lines	s6.4.1, s6.5.1
4.5.4 Distribution and LV cables	s6.4.2, s6.5.2
4.5.5 Distribution substations and transformers	s6.8, s6.9
4.5.6 Distribution switchgear	s6.10, s6.11
4.5.7 Other system fixed assets	s6.12, s6.13, s6.14, s6.15
4.5.8 Other assets;	s7.1
4.5.9 Assets owned by the EDB but installed at bulk electricity supply points owned by others;	s6.15
4.5.10 Reliability and security mobile substations and generators; and	Not Applicable
4.5.11 Other generation plant owned by the EDB.	Not Applicable
Service Levels	
5. A set of performance indicators.	s3.4
6. Performance indicators SAIDI and SAIFI values for the next 5 disclosure years.	s3.4.1, s3.4.2
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;	s3.4
7.2 Indicators of asset performance, asset efficiency and effectiveness, and service efficiency.	s3.4
8. Basis on which the target level for each performance indicator was determined.	s3.2, s3.3
9. Targets should be compared to historic values where available to provide context and scale to the reader.	s3.4.1
10. Forecast expenditure materially affecting performance vs target - expected change.	s3.4.2
Network Development Planning	
11. AMPs must provide a detailed description of network development plans, including-	
11.1 A description of the planning criteria and assumptions for network development;	s5.1, s5.2
11.2 Planning criteria for network developments should be described logically and succinctly;	Compliant
11.3 Strategies or processes promoting cost efficiency;	s5 By Asset Category
11.4 The use of standardised designs may lead to improved cost efficiencies.	s5.1.4
11.4.1 the categories of assets and designs that are standardised;	s5.1.4
11.4.2 the approach used to identify standard designs.	s5.1.4
11.5 Energy efficiency strategies or processes.	s5.3
11.6 Equipment capacity for different types of assets or different parts of the network.	s5 By Asset Category
11.7 Prioritising network development projects.	s5.1.9
11.8 Demand forecasts - basis, constraint locations;	s5.2, Appendix C
11.8.1 load forecasting methodology and factors;	s5.2, Appendix C
11.8.2 forecasts to zone substation. Uncertain but substantial load accounted in forecasts;	s5.2, Appendix C
11.8.3 network or equipment constraints; and	s5 By Asset Category
11.8.4 DG and demand management impact on the load forecasts.	s5.2, s5.4.12 Appendix C,
11.9 Significant network level development options identified satisfying target levels of service, including-	s5.3
11.9.1 the reasons for choosing a selected option for projects where decisions have been made;	s5.3
11.9.2 alternative options for projects planned within five years and any non-network solutions;	s5 By Project and s5.1.8

11.9.3 planned innovations that improve efficiencies, utilisation, asset lives, and defer investment.	Various locations
11.10 Network development programme inc. DG and non-network with expenditure. Must include-	s5.3, s5.4, Appendix B
11.10.1 detailed description of projects underway or planned to start within the next 12 months;	s5.4 by Project
11.10.2 summary description of programmes/projects for the following four years; and	s5.4 by Project
11.10.3 overview of the big projects being considered for the remainder of the AMP planning period.	s5.4 by Project
11.11 EDB's policies on distributed generation.	s5.4.12
11.12 A description of the EDB's policies on non-network solutions, including-	s5.1.8
11.12.1 economically feasible and practical alternatives to conventional network augmentation; and	s5.1.8
11.12.2 the potential for non-network solutions to address network problems or constraints.	s5.1.8, s5.2.3, s5.4.1, s5.4.3 by Project
Lifecycle Asset Management Planning (Maintenance and Renewal)	
12. The AMP must provide a detailed description of the lifecycle asset management processes, including-	
12.1 The key drivers for maintenance planning and assumptions;	s6.2
12.2 Routine and corrective maintenance and inspection policies/programmes/ actions per asset category, must include-	s6
12.2.1 approach to inspecting/maintaining each asset category - inspection types/tests/monitoring/intervals;	s6.3 – s6.15
12.2.2 systemic problems identified per asset types and proposed actions to address these problems; and	s6.3 – s6.15
12.2.3 budgets for maintenance activities broken down by asset category for the AMP planning period.	s8.2
12.3 Asset replacement and renewal policies/programmes/actions per asset category, inc. expenditure. Must include-	s6
12.3.1 processes used to decide when and whether an asset is replaced or refurbished;	s6.2, s6.3 – s6.15
12.3.2 a description of innovations made that have deferred asset replacement;	s6.2, s6.3 – s6.15
12.3.3 a description of the projects currently underway or planned for the next 12 months;	s6.3 – s6.15
12.3.4 a summary of the projects planned for the following four years (where known); and	s6.3 – s6.15
12.3.5 an overview of other work being considered for the remainder of the AMP planning period.	s6.3 – s6.15

12.4 Asset categories in subclauses 12.2 and 12.3 should include at least the categories in subclause 4.5 above.	Compliant
Non-Network Development, Maintenance and Renewal	
13. Description of material non-network development, maintenance and renewal plans, including-	s7
13.1 a description of non-network assets;	s7.1
13.2 development, maintenance and renewal policies that cover them;	s7.2
13.3 a description of material capital expenditure projects (where known) planned for the next five years;	s7.3, Appendix E
13.4 a description of material maintenance and renewal projects (where known) planned for the next five years.	s7.3, Appendix E
Risk Management	
14. AMPs must provide details of risk policies, assessment, and mitigation, including-	s2
14.1 Methods, details and conclusions of risk analysis;	s2.2 – s2.5
14.2 Strategies to identify areas vulnerable to high impact low probability events;	s2.8
14.3 A description of the policies to mitigate or manage the risks of events identified in subclause 16.2;	s2.6
14.4 Details of emergency response and contingency plans.	s2.8
Evaluation of performance	
15. AMPs must provide details of performance measurement, evaluation, and improvement, including-	
15.1 A review of progress against plan, both physical and financial;	s9.1
15.2 An evaluation and comparison of actual service level performance against targeted performance;	s9.2
15.3 AMMAT evaluation and comparison vs objectives of the EDB's asset management and planning processes.	s9.4
15.4 Gap analysis from AMMAT and performance. Planned initiatives to address the situation.	s9.3, s9.4, s9.5, s9.6
Capability to deliver	
16. AMPs must describe the processes used by the EDB to ensure that-	
16.1 The AMP is realistic and the objectives set out in the plan can be achieved;	s9.7
16.2 Organisation structure and processes for authorisation/business capabilities to support AMP implementation.	s9.7

Please note that this list is does not include explicit references to every passage in the plan that has some relevance to each mandatory item. For readability, EA Networks have chosen to discuss different aspects of some mandatory items in discrete places - where they are relevant. Complete understanding of the plan's concepts and direction requires digestion of the plan as a whole.

10.5 Appendix E - Disclosure Schedules

This appendix contains the schedules that are required to be disclosed to the Commerce Commission and the plan must "Include, in the AMP or AMP update as applicable, the information contained in each of the reports". To ensure all of the information contained in the schedules is in the plan they have been included here. They are also disclosed in the original formats on the EA Networks website.

Schedule	Description
11a	Report on Forecast Capital Expenditure
11b	Report on Forecast Operational Expenditure
12a	Report on Asset Condition
12b	Report on Forecast Capacity
12c	Report on Forecast Demand
12d	Report on Forecast Interruptions and Duration
13	Report on Asset Management Maturity
14a	Mandatory Explanatory Notes on Forecast Information
17	Certification of Year-beginning Disclosures

Notes on the schedules:

11a	• The 12 month forecast values for the current year have been derived by escalating the 10 months of available YTD values by a factor of 1.2.
	• The pages are laid out for A3 portrait printing. The text is small at this scale.
12a	• The data in this schedule represents the best assessment of EA Networks' understanding of the requirements, unique asset categorisation and known condition. The "% of asset to be replaced in next 5 years" is a formulaic assessment based on known age which will be refined over time to reflect actual condition if it is obtained.
12b	• There is a significant increase in switched transfer capacity in +5yrs at many sites, however there is no way of showing this in the schedule.
	• Several sites have changed feeder open points recently and this may lead to variations in quoted "Current Peak Load" values in different parts of the plan for the same site.
13	• The AMMAT report has been presented in a compact manner. If readers wish to see the full template with associated commentary and scoring notes please go to: EDB-ID-determination-templates-for-schedules-11a-13-AMP-v4.1-2017-21-December-2017.xlsx to download the "EDB ID Determination AMP Templates" in Excel format. Warning: the default print layout of Schedule 13 requires 16 pages of A3 with very small text.

Company Name	Electricity Ashburton Limited
AMP Planning Period	1 April 2020 – 31 March 2030

SCHEDULE 11a: REPORT ON FORECAST CAPITAL EXPENDITURE

This schedule requires a breakdown of forecast expenditure on assets for the current disclosure year and a 10 year planning period. The forecasts should be consistent with the supporting information set out in the AMP. The forecast is to be expressed in both constant price and nominal dollar terms. Also required is a forecast of the value of commissioned assets (i.e., the value of RAB additions)

EDBs must provide explanatory comment on the difference between constant price and nominal dollar forecasts of expenditure on assets in Schedule 14a (Mandatory Explanatory Notes).

This information is not part of audited disclosure information.

sch ref				1	1.019	1.0394	1.0602	1.0813	1.103	1.1251	1.1476	1.1705	1.1939
7			Current Year CY	CY+1	CY+2	CY+3	CY+4	CY+5	CY+6	CY+7	CY+8	CY+9	CY+10
8		for year ended	31 Mar 20	31 Mar 21	31 Mar 22	31 Mar 23	31 Mar 24	31 Mar 25	31 Mar 26	31 Mar 27	31 Mar 28	31 Mar 29	31 Mar 30
9	**11a(i): Expenditure on Assets Forecast**		**$000 (in nominal dollars)**										
10	Consumer connection		1,669	3,552	2,780	3,061	2,892	2,902	2,909	2,922	2,898	2,946	3,117
11	System growth		4,805	4,268	3,777	4,332	4,655	4,595	5,969	4,817	7,397	7,809	2,651
12	Asset replacement and renewal		7,547	10,589	6,926	6,115	5,001	3,923	3,904	3,677	5,024	3,558	2,893
13	Asset relocations		-	-	-	-	-	-	-	-	-	-	-
14	Reliability, safety and environment:												
15	Quality of supply		1,409	1,978	1,094	1,284	390	402	507	77	77	2,113	2,802
16	Legislative and regulatory		-	-	-	-	-	-	-	-	-	-	-
17	Other reliability, safety and environment		439	782	269	166	180	185	153	159	158	160	170
18	**Total reliability, safety and environment**		1,848	2,760	1,364	1,450	570	587	660	236	234	2,273	2,972
19	**Expenditure on network assets**		15,869	21,170	14,847	14,958	13,117	12,008	13,442	11,653	15,554	16,585	11,632
20	Expenditure on non-network assets		679	2,274	921	1,043	959	1,119	998	1,131	1,038	1,210	1,082
21	**Expenditure on assets**		16,548	23,444	15,768	16,001	14,076	13,127	14,440	12,784	16,592	17,795	12,714
22													
23	*plus* Cost of financing		-	-	-	-	-	-	-	-	-	-	-
24	*less* Value of capital contributions		389	891	480	268	281	216	210	203	207	211	215
25	*plus* Value of vested assets		-	-	-	-	-	-	-	-	-	-	-
26													
27	**Capital expenditure forecast**		16,159	22,554	15,288	15,733	13,795	12,911	14,230	12,582	16,385	17,584	12,499
28													
29	Assets commissioned		16,159	22,554	15,288	15,733	13,795	12,911	14,230	12,582	16,385	17,584	12,499

sch ref													
30			Current Year CY	CY+1	CY+2	CY+3	CY+4	CY+5	CY+6	CY+7	CY+8	CY+9	CY+10
31		for year ended	31 Mar 20	31 Mar 21	31 Mar 22	31 Mar 23	31 Mar 24	31 Mar 25	31 Mar 26	31 Mar 27	31 Mar 28	31 Mar 29	31 Mar 30
32			**$000 (in constant prices)**										
33	Consumer connection		1,669	3,552	2,729	2,945	2,728	2,684	2,637	2,598	2,526	2,516	2,611
34	System growth		4,805	4,268	3,706	4,168	4,391	4,250	5,411	4,282	6,446	6,671	2,220
35	Asset replacement and renewal		7,547	10,589	6,797	5,883	4,717	3,628	3,539	3,268	4,378	3,039	2,423
36	Asset relocations		-	-	-	-	-	-	-	-	-	-	-
37	Reliability, safety and environment:												
38	Quality of supply		1,409	1,978	1,074	1,235	368	371	460	68	67	1,805	2,347
39	Legislative and regulatory		-	-	-	-	-	-	-	-	-	-	-
40	Other reliability, safety and environment		439	782	264	160	170	171	139	141	138	137	142
41	**Total reliability, safety and environment**		1,848	2,760	1,338	1,395	537	543	598	210	204	1,942	2,489
42	**Expenditure on network assets**		15,869	21,170	14,570	14,391	12,372	11,105	12,186	10,357	13,554	14,169	9,743
43	Expenditure on non-network assets		679	2,274	904	1,004	905	1,035	905	1,006	904	1,034	906
44	**Expenditure on assets**		16,548	23,444	15,474	15,395	13,277	12,140	13,091	11,363	14,458	15,203	10,649
45													
46	**Subcomponents of expenditure on assets (where known)**												
47	Energy efficiency and demand side management, reduction of energy losses		-	105	982	983	996	1,006	1,389	1,014	988	984	1,021
48	Overhead to underground conversion		4,605	6,099	2,522	1,752	2,405	1,658	1,587	1,185	2,169	704	-
49	Research and development		-	-	-	-	-	-	-	-	-	-	-
50													

sch ref													
51			Current Year CY	CY+1	CY+2	CY+3	CY+4	CY+5	CY+6	CY+7	CY+8	CY+9	CY+10
52		for year ended	31 Mar 20	31 Mar 21	31 Mar 22	31 Mar 23	31 Mar 24	31 Mar 25	31 Mar 26	31 Mar 27	31 Mar 28	31 Mar 29	31 Mar 30
53	**Difference between nominal and constant price forecasts**		**$000**										
54	Consumer connection		-	-	52	116	164	218	272	325	373	429	506
55	System growth		-	-	70	164	264	345	557	536	951	1,137	430
56	Asset replacement and renewal		-	-	129	232	284	295	365	409	646	518	470
57	Asset relocations		-	-	-	-	-	-	-	-	-	-	-
58	Reliability, safety and environment:												
59	Quality of supply		-	-	20	49	22	30	47	9	10	308	455
60	Legislative and regulatory		-	-	-	-	-	-	-	-	-	-	-
61	Other reliability, safety and environment		-	-	5	6	10	14	14	18	20	23	28
62	**Total reliability, safety and environment**		-	-	25	55	32	44	62	26	30	331	483
63	**Expenditure on network assets**		-	-	277	567	745	903	1,255	1,296	2,001	2,416	1,889
64	Expenditure on non-network assets		-	-	17	40	54	84	93	126	133	176	176
65	**Expenditure on assets**		-	-	294	607	799	987	1,348	1,422	2,134	2,592	2,065
66													

sch ref									
67			Current Year CY	CY+1	CY+2	CY+3	CY+4	CY+5
		for year ended	31 Mar 20	31 Mar 21	31 Mar 22	31 Mar 23	31 Mar 24	31 Mar 25
68	**11a(ii): Consumer Connection**							
69	*Consumer types defined by EDB**		**$000 (in constant prices)**					
70	Urban LV		75	169	173	173	175	177
	Urban Transformer		350	950	130	130	132	133
	Urban Alteration for Safety (No new ICP created)		-	-	-	-	-	-
	Urban Capacity Alteration (No new ICP created)		-	2	2	2	2	2
	Rural LV		62	259	266	244	247	250
71	Rural Transformer		526	1,352	1,324	1,325	1,342	1,357
72	Rural Alteration for Safety (No new ICP created)		209	195	191	191	193	185
73	Rural Capacity Alteration (No new ICP created)		181	584	600	541	548	491
74	Other (including large subdivisions)		266	43	44	340	89	90
75	**include additional rows if needed*							
76	**Consumer connection expenditure**		1,669	3,552	2,729	2,945	2,728	2,684
77	*less* Capital contributions funding consumer connection		346	663	180	190	200	200
78	**Consumer connection less capital contributions**		1,323	2,889	2,549	2,755	2,528	2,484
79	**11a(iii): System Growth**							
80	Subtransmission		1,143	83	-	-	-	-
81	Zone substations		1,950	946	-	-	358	362
82	Distribution and LV lines		414	384	122	554	253	162
83	Distribution and LV cables		76	735	579	504	1,247	1,261
84	Distribution substations and transformers		868	1,824	1,025	1,139	1,906	1,842
85	Distribution switchgear		269	48	15	5	327	321
86	Other network assets		86	248	1,965	1,966	299	302
87	**System growth expenditure**		4,805	4,268	3,706	4,168	4,391	4,250
88	*less* Capital contributions funding system growth		-	-	-	-	-	-
89	**System growth less capital contributions**		4,805	4,268	3,706	4,168	4,391	4,250
90								

sch ref								
91			Current Year CY	CY+1	CY+2	CY+3	CY+4	CY+5
92		for year ended	31 Mar 20	31 Mar 21	31 Mar 22	31 Mar 23	31 Mar 24	31 Mar 25
93	**11a(iv): Asset Replacement and Renewal**		**$000 (in constant prices)**					
94	Subtransmission		895	904	990	1,028	-	-
95	Zone substations		154	154	67	67	68	69
96	Distribution and LV lines		2,400	3,328	2,650	2,071	1,355	1,063
97	Distribution and LV cables		3,418	4,898	2,042	1,637	2,324	1,575
98	Distribution substations and transformers		370	786	716	730	646	609
99	Distribution switchgear		203	502	316	334	312	312
100	Other network assets		107	18	16	16	13	-
101	**Asset replacement and renewal expenditure**		7,547	10,589	6,797	5,883	4,717	3,628
102	*less* Capital contributions funding asset replacement and renewal		43	180	291	68	65	-
103	**Asset replacement and renewal less capital contributions**		7,504	10,409	6,506	5,815	4,652	3,628
104								

Company Name	**Electricity Ashburton Limited**
AMP Planning Period	**1 April 2020 – 31 March 2030**

SCHEDULE 11a: REPORT ON FORECAST CAPITAL EXPENDITURE

This schedule requires a breakdown of forecast expenditure on assets for the current disclosure year and a 10 year planning period. The forecasts should be consistent with the supporting information set out in the AMP. The forecast is to be expressed in both constant price and nominal dollar terms. Also required is a forecast of the value of commissioned assets (i.e., the value of RAB additions)

EDBs must provide explanatory comment on the difference between constant price and nominal dollar forecasts of expenditure on assets in Schedule 14a (Mandatory Explanatory Notes).

This information is not part of audited disclosure information.

sch ref 1 1.019 1.0394 1.0602 1.0813 1.103 1.1251 1.1476 1.1705 1.1939

11a(v): Asset Relocations

sch ref		Current Year CY	CY+1	CY+2	CY+3	CY+4	CY+5
106	for year ended	**31 Mar 20**	**31 Mar 21**	**31 Mar 22**	**31 Mar 23**	**31 Mar 24**	**31 Mar 25**
108	*Project or programme**	**$000 (in constant prices)**					
109	N/A	-	-	-	-	-	-
110	N/A	-	-	-	-	-	-
111	N/A	-	-	-	-	-	-
112	N/A	-	-	-	-	-	-
113	N/A	-	-	-	-	-	-
114	**include additional rows if needed*						
115	All other project or programmes - asset relocations	-	-	-	-	-	-
116	**Asset relocations expenditure**	-	-	-	-	-	-
117	*less* Capital contributions funding asset relocations	-	-	-	-	-	-
118	**Asset relocations less capital contributions**	-	-	-	-	-	-
119							

11a(vi): Quality of Supply

sch ref		Current Year CY	CY+1	CY+2	CY+3	CY+4	CY+5
121	for year ended	**31 Mar 20**	**31 Mar 21**	**31 Mar 22**	**31 Mar 23**	**31 Mar 24**	**31 Mar 25**
123	*Project or programme**	**$000 (in constant prices)**					
124	SCADA - Distribution Automation Programme	78	289	296	296	300	303
125	Rural Ring Main Unit Installations	1,023	369	-	-	-	-
	66kV OH Dampers Installation	25	-	-	-	-	-
	Core Network Centres	71	-	-	-	-	-
	OH - Misc. Completion Work	29	-	-	-	-	-
	ZSS - Misc. Completion Work	39	-	-	-	-	-
	ZSS EFN - 66/22kV Conversion	-	53	-	-	-	-
	ZSS MHT - New Local Service RMU	-	105	-	-	-	-
	ZSS MTV - 66kV Line Bay Changes	-	375	-	-	-	-
126	11kV Core Network Centres	-	540	455	671	-	-
127	22kV Conversion - Mvn Hwy Sprgfld Rd to Mvn, AF to Nwtns Cnr	-	-	201	201	-	-
128	ZSS - Synchrophasors - Stage 1 and Stage 2	-	38	-	-	-	-
129	**include additional rows if needed*						
130	All other projects or programmes - quality of supply	144	210	121	66	67	68
131	**Quality of supply expenditure**	1,409	1,978	1,074	1,235	368	371
132	*less* Capital contributions funding quality of supply	-	-	-	-	-	-
133	**Quality of supply less capital contributions**	1,409	1,978	1,074	1,235	368	371
134							

11a(vii): Legislative and Regulatory

sch ref		Current Year CY	CY+1	CY+2	CY+3	CY+4	CY+5
136	for year ended	**31 Mar 20**	**31 Mar 21**	**31 Mar 22**	**31 Mar 23**	**31 Mar 24**	**31 Mar 25**
138	*Project or programme**	**$000 (in constant prices)**					
139	N/A	-	-	-	-	-	-
140	N/A	-	-	-	-	-	-
141	N/A	-	-	-	-	-	-
142	N/A	-	-	-	-	-	-
143	N/A	-	-	-	-	-	-
144	**include additional rows if needed*						
145	All other projects or programmes - legislative and regulatory	-	-	-	-	-	-
146	**Legislative and regulatory expenditure**	-	-	-	-	-	-
147	*less* Capital contributions funding legislative and regulatory	-	-	-	-	-	-
148	**Legislative and regulatory less capital contributions**	-	-	-	-	-	-
149							

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

sch ref		Current Year CY	CY+1	CY+2	CY+3	CY+4	CY+5
150	for year ended	**31 Mar 20**	**31 Mar 21**	**31 Mar 22**	**31 Mar 23**	**31 Mar 24**	**31 Mar 25**
152	*Project or programme**	**$000 (in constant prices)**					
153	Distribution Earthing Upgrades	439	387	80	80	81	82
154	UG Conversion - State Hwy Road Crossings	-	45	-	-	-	-
155	ZSS Security and Surveillance Programme	-	35	23	23	31	31
156	UG Conversion - School Safety	-	37	105	-	-	-
157	UG Conversion - Hinds Hwy. Cracroft St to Coldstream Rd	-	223	-	-	-	-
158	**include additional rows if needed*						
159	All other projects or programmes - other reliability, safety and environment	-	55	57	57	57	58
160	**Other reliability, safety and environment expenditure**	439	782	264	160	170	171
161	*less* Capital contributions funding other reliability, safety and environment	-	48	-	-	-	-
162	**Other reliability, safety and environment less capital contributions**	439	734	264	160	170	171
163							

11a(ix): Non-Network Assets

sch ref		Current Year CY	CY+1	CY+2	CY+3	CY+4	CY+5
165	for year ended	**31 Mar 20**	**31 Mar 21**	**31 Mar 22**	**31 Mar 23**	**31 Mar 24**	**31 Mar 25**
167	**Routine expenditure**						
168	*Project or programme**	**$000 (in constant prices)**					
169	Routine Vehicles	188	570	320	320	320	320
170	Routine Building Work	-	100	-	100	-	100
171	Software - GIS Development	-	53	54	54	55	55
172	ZSS ASH - Building Improvement	-	103	-	-	-	-
	Routine Plant	87	10	10	10	10	10
173	Routine Info Tech	48	772	520	520	520	520
174	**include additional rows if needed*						
175	All other projects or programmes - routine expenditure	-	-	-	-	-	-
176	**Routine expenditure**	323	1,608	904	1,004	905	1,005
177	**Atypical expenditure**						
178	*Project or programme**						
179	Non-Network - DMR Repeater Stations	-	24	-	-	-	-
	ERP/HR Development	113	-	-	-	-	-
180	Non-Network - Software - Distribution Management Software	185	531	-	-	-	-
181	Non-Network - Aerial Photography	-	20	-	-	-	30
182	Non-Network - DMR Unify - Vehicle Mobility & Hospot	-	55	-	-	-	-
183	Website Development	14	-	-	-	-	-
184	**include additional rows if needed*						
185	All other projects or programmes - atypical expenditure	45	37	-	-	-	-
186	**Atypical expenditure**	356	667	-	-	-	30
187							
188	**Expenditure on non-network assets**	679	2,274	904	1,004	905	1,035

Company Name	**Electricity Ashburton Limited**
AMP Planning Period	**1 April 2020 – 31 March 2030**

SCHEDULE 11b: REPORT ON FORECAST OPERATIONAL EXPENDITURE

This schedule requires a breakdown of forecast operational expenditure for the disclosure year and a 10 year planning period. The forecasts should be consistent with the supporting information set out in the AMP. The forecast is to be expressed in both constant price and nominal dollar terms.
EDBs must provide explanatory comment on the difference between constant price and nominal dollar operational expenditure forecasts in Schedule 14a (Mandatory Explanatory Notes).
This information is not part of audited disclosure information.

sch ref			1	1.019	1.0394	1.0602	1.0813	1.103	1.1251	1.1476	1.1705	1.1939
7		*Current Year CY*	*CY+1*	*CY+2*	*CY+3*	*CY+4*	*CY+5*	*CY+6*	*CY+7*	*CY+8*	*CY+9*	*CY+10*
8	for year ended	**31 Mar 20**	**31 Mar 21**	**31 Mar 22**	**31 Mar 23**	**31 Mar 24**	**31 Mar 25**	**31 Mar 26**	**31 Mar 27**	**31 Mar 28**	**31 Mar 29**	**31 Mar 30**
9	**Operational Expenditure Forecast**	**$000 (in nominal dollars)**										
10	Service interruptions and emergencies	1,070	1,100	1,126	1,154	1,182	1,210	1,240	1,270	1,300	1,332	1,364
11	Vegetation management	550	590	601	613	626	638	651	664	677	691	704
12	Routine and corrective maintenance and inspection	1,221	1,111	1,160	1,192	1,267	1,293	1,322	1,304	1,330	1,357	1,384
13	Asset replacement and renewal	1,209	1,099	1,122	1,108	1,157	1,124	1,166	1,207	1,214	1,238	1,263
14	**Network Opex**	4,050	3,900	4,010	4,067	4,232	4,265	4,378	4,444	4,521	4,617	4,715
15	System operations and network support	3,580	3,814	3,906	4,004	4,105	4,207	4,313	4,421	4,532	4,646	4,763
16	Business support	5,240	5,574	5,708	5,852	5,999	6,149	6,303	6,462	6,624	6,790	6,960
17	**Non-network opex**	8,820	9,388	9,614	9,856	10,103	10,356	10,616	10,883	11,156	11,436	11,723
18	**Operational expenditure**	12,870	13,288	13,625	13,923	14,335	14,620	14,994	15,328	15,678	16,053	16,438
19		*Current Year CY*	*CY+1*	*CY+2*	*CY+3*	*CY+4*	*CY+5*	*CY+6*	*CY+7*	*CY+8*	*CY+9*	*CY+10*
20	for year ended	**31 Mar 20**	**31 Mar 21**	**31 Mar 22**	**31 Mar 23**	**31 Mar 24**	**31 Mar 25**	**31 Mar 26**	**31 Mar 27**	**31 Mar 28**	**31 Mar 29**	**31 Mar 30**
21		**$000 (in constant prices)**										
22	Service interruptions and emergencies	1,070	1,100	1,105	1,110	1,115	1,119	1,124	1,128	1,133	1,138	1,143
23	Vegetation management	550	590	590	590	590	590	590	590	590	590	590
24	Routine and corrective maintenance and inspection	1,221	1,111	1,139	1,147	1,195	1,195	1,198	1,159	1,159	1,159	1,159
25	Asset replacement and renewal	1,209	1,099	1,102	1,066	1,091	1,039	1,057	1,073	1,058	1,058	1,058
26	**Network Opex**	4,050	3,900	3,936	3,913	3,991	3,944	3,969	3,950	3,940	3,944	3,949
27	System operations and network support	3,580	3,814	3,833	3,852	3,871	3,891	3,910	3,930	3,950	3,969	3,989
28	Business support	5,240	5,574	5,602	5,630	5,658	5,686	5,715	5,743	5,772	5,801	5,830
29	**Non-network opex**	8,820	9,388	9,435	9,482	9,530	9,577	9,625	9,673	9,722	9,770	9,819
30	**Operational expenditure**	12,870	13,288	13,370	13,395	13,521	13,521	13,594	13,623	13,661	13,715	13,768
31	**Subcomponents of operational expenditure (where known)**											
32	Energy efficiency and demand side management, reduction of											
33	energy losses	-	-	-	-	-	-	-	-	-	-	-
34	Direct billing*	-	-	-	-	-	-	-	-	-	-	-
35	Research and Development	34	250	250	250	250	250	250	250	250	250	250
36	Insurance	195	174	174	174	174	174	174	174	174	174	174
37	** Direct billing expenditure by suppliers that direct bill the majority of their consumers*											
38												
39		*Current Year CY*	*CY+1*	*CY+2*	*CY+3*	*CY+4*	*CY+5*	*CY+6*	*CY+7*	*CY+8*	*CY+9*	*CY+10*
40	for year ended	**31 Mar 20**	**31 Mar 21**	**31 Mar 22**	**31 Mar 23**	**31 Mar 24**	**31 Mar 25**	**31 Mar 26**	**31 Mar 27**	**31 Mar 28**	**31 Mar 29**	**31 Mar 30**
41	**Difference between nominal and real forecasts**	**$000**										
42	Service interruptions and emergencies	-	-	21	44	67	91	116	141	167	194	222
43	Vegetation management	-	-	11	23	36	48	61	74	87	101	114
44	Routine and corrective maintenance and inspection	-	-	22	45	72	97	123	145	171	198	225
45	Asset replacement and renewal	-	-	21	42	66	84	109	134	156	180	205
46	**Network Opex**	-	-	75	154	240	321	409	494	582	673	766
47	System operations and network support	-	-	73	152	233	316	403	492	583	677	773
48	Business support	-	-	106	222	341	462	589	718	852	989	1,130
49	**Non-network opex**	-	-	179	374	574	779	991	1,210	1,435	1,666	1,904
50	**Operational expenditure**	-	-	254	528	814	1,099	1,400	1,704	2,016	2,338	2,670

Company Name	**Electricity Ashburton Limited**
AMP Planning Period	**1 April 2020 – 31 March 2030**

SCHEDULE 12a: REPORT ON ASSET CONDITION

This schedule requires a breakdown of asset condition by asset class as at the start of the forecast year. The data accuracy assessment relates to the percentage values disclosed in the asset condition columns. Also required is a forecast of the percentage of units to be replaced in the next 5 years. All information should be consistent with the information provided in the AMP and the expenditure on assets forecast in Schedule 11a. All units relating to cable and line assets, that are expressed in km, refer to circuit lengths.

sch ref					Asset condition at start of planning period (percentage of units by grade)							
7–9	**Voltage**	**Asset category**	**Asset class**	**Units**	**H1**	**H2**	**H3**	**H4**	**H5**	**Grade unknown**	**Data accuracy (1–4)**	**% of asset forecast to be replaced in next 5 years**
10	All	Overhead Line	Concrete poles / steel structure	No.	-	0.76%	0.42%	56.67%	42.15%	-	2	0.76%
11	All	Overhead Line	Wood poles	No.	1.73%	2.06%	11.52%	34.94%	49.75%	-	2	3.78%
12	All	Overhead Line	Other pole types	No.	-	-	-	28.57%	71.43%	-	2	-
13	HV	Subtransmission Line	Subtransmission OH up to 66kV conductor	km	-	0.23%	2.35%	25.93%	71.49%	-	3	5.00%
14	HV	Subtransmission Line	Subtransmission OH 110kV+ conductor	km	-	-	-	-	-	-	N/A	-
15	HV	Subtransmission Cable	Subtransmission UG up to 66kV (XLPE)	km	-	-	-	50.79%	49.21%	-	3	-
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.	-	4.55%	-	27.27%	68.18%	-	2	-
25	HV	Zone substation Buildings	Zone substations 110kV+	No.	-	-	-	-	-	-	N/A	-
26	HV	Zone substation switchgear	22/33kV CB (Indoor)	No.	-	-	-	-	-	-	N/A	-
27	HV	Zone substation switchgear	22/33kV CB (Outdoor)	No.	-	45.45%	31.82%	22.73%	-	-	3	45.45%
28	HV	Zone substation switchgear	33kV Switch (Ground Mounted)	No.	-	-	-	-	-	-	N/A	-
29	HV	Zone substation switchgear	33kV Switch (Pole Mounted)	No.	-	-	34.92%	34.13%	30.95%	-	3	-
30	HV	Zone substation switchgear	33kV RMU	No.	-	-	-	-	-	-	N/A	-
31	HV	Zone substation switchgear	50/66/110kV CB (Indoor)	No.	-	-	-	-	-	-	N/A	-
32	HV	Zone substation switchgear	50/66/110kV CB (Outdoor)	No.	-	-	10.29%	58.82%	30.88%	-	3	-
33	HV	Zone substation switchgear	3.3/6.6/11/22kV CB (ground mounted)	No.	-	0.54%	4.32%	13.51%	81.62%	-	2	0.54%
34	HV	Zone substation switchgear	3.3/6.6/11/22kV CB (pole mounted)	No.	-	-	-	-	-	-	N/A	-

35–36					Asset condition at start of planning period (percentage of units by grade)							
37–38	**Voltage**	**Asset category**	**Asset class**	**Units**	**H1**	**H2**	**H3**	**H4**	**H5**	**Grade unknown**	**Data accuracy (1–4)**	**% of asset forecast to be replaced in next 5 years**
39	HV	Zone Substation Transformer	Zone Substation Transformers	No.	-	13.51%	16.22%	27.03%	43.24%	-	3	13.51%
40	HV	Distribution Line	Distribution OH Open Wire Conductor	km	1.28%	2.34%	12.85%	39.19%	44.33%	-	3	3.63%
41	HV	Distribution Line	Distribution OH Aerial Cable Conductor	km	-	-	-	-	-	-	N/A	-
42	HV	Distribution Line	SWER conductor	km	-	-	-	-	-	-	N/A	-
43	HV	Distribution Cable	Distribution UG XLPE or PVC	km	-	-	0.51%	23.98%	75.51%	-	3	-
44	HV	Distribution Cable	Distribution UG PILC	km	-	3.84%	81.26%	14.89%	-	-	1	3.84%
45	HV	Distribution Cable	Distribution Submarine Cable	km	-	-	-	-	-	-	N/A	-
46	HV	Distribution switchgear	3.3/6.6/11/22kV CB (pole mounted) - reclosers and sectionalisers	No.	-	13.33%	6.67%	50.00%	30.00%	-	2	15.00%
47	HV	Distribution switchgear	3.3/6.6/11/22kV CB (Indoor)	No.	-	-	-	-	-	-	N/A	-
48	HV	Distribution switchgear	3.3/6.6/11/22kV Switches and fuses (pole mounted)	No.	-	-	3.61%	31.21%	65.18%	-	2	-
49	HV	Distribution switchgear	3.3/6.6/11/22kV Switch (ground mounted) - except RMU	No.	-	-	-	-	-	-	N/A	-
50	HV	Distribution switchgear	3.3/6.6/11/22kV RMU	No.	4.51%	8.63%	10.98%	30.78%	45.10%	-	3	1.00%
51	HV	Distribution Transformer	Pole Mounted Transformer	No.	0.32%	8.39%	23.61%	22.82%	44.86%	-	3	5.00%
52	HV	Distribution Transformer	Ground Mounted Transformer	No.	0.09%	4.76%	16.45%	15.01%	63.70%	-	3	1.00%
53	HV	Distribution Transformer	Voltage regulators	No.	-	-	100.00%	-	-	-	3	-
54	HV	Distribution Substations	Ground Mounted Substation Housing	No.	1.37%	3.32%	9.57%	26.76%	58.98%	-	2	4.69%
55	LV	LV Line	LV OH Conductor	km	8.47%	14.87%	13.03%	49.47%	14.16%	-	3	23.34%
56	LV	LV Cable	LV UG Cable	km	0.02%	1.01%	6.60%	35.95%	56.42%	-	3	1.03%
57	LV	LV Streetlighting	LV OH/UG Streetlight circuit	km	1.29%	2.88%	7.85%	38.75%	49.24%	-	2	4.17%
58	LV	Connections	OH/UG consumer service connections	No.	-	-	33.33%	33.33%	33.34%	-	3	-
59	All	Protection	Protection relays (electromechanical, solid state and numeric)	No.	-	-	3.86%	5.41%	63.71%	27.02%	2	3.00%
60	All	SCADA and communications	SCADA and communications equipment operating as a single system	Lot	-	-	30.00%	-	70.00%	-	3	25.00%
61	All	Capacitor Banks	Capacitors including controls	No.	-	-	-	-	-	-	N/A	-
62	All	Load Control	Centralised plant	Lot	-	66.67%	33.33%	-	-	-	3	66.67%
63	All	Load Control	Relays	No.	-	-	-	-	-	100.00%	1	-
64	All	Civils	Cable Tunnels	km	-	-	-	-	-	-	N/A	-

Company Name	**Electricity Ashburton Limited**
AMP Planning Period	**1 April 2020 – 31 March 2030**

SCHEDULE 12b: REPORT ON FORECAST CAPACITY

This schedule requires a breakdown of current and forecast capacity and utilisation for each zone substation and current distribution transformer capacity. The data provided should be consistent with the information provided in the AMP. Information provided in this table should relate to the operation of the network in its normal steady state configuration.

sch ref

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

sch ref	Existing Zone Substations	Current Peak Load (MVA)	Installed Firm Capacity (MVA)	Security of Supply Classification (type)	Transfer Capacity (MVA)	Utilisation of Installed Firm Capacity %	Installed Firm Capacity +5 years (MVA)	Utilisation of Installed Firm Capacity + 5yrs %	Installed Firm Capacity Constraint +5 years (cause)	Explanation
9	Ashburton 33/11kV [ASH]	-	-	N/A	-	-	-	-	Other	Decommissioned 2019
10	Ashburton 66/11kV [ASH]	19	22	N-1	20	86%	22	91%	Transformer	Two 20MVA 66/11kV transformers, steady state load transfer to/from NTN, and additional fast transfer switched capacity ensure acceptable security.
11	Carew 66/22kV [CRW]	15	17	N-1	9	88%	20	75%	No constraint within +5 years	Second transformer is one of two system spares and provides 100% firm capacity. Transfer capacity increases with additional 22kV conversion.
12	Coldstream 66/22kV [CSM]	13	-	N	9	-	-	-	Transformer	Second Carew transformer provides an increase in transfer capacity. Future EFN 22kV conversion increases transfer capacity.
13	Dorie 66/22kV [DOR]	11	-	N	9	-	-	-	Transformer	Pendarves and Overdale substations offer close to 100% of firm capacity via transfer on 22kV distribution network.
14	Eiffelton 66/11kV [EFN]	9	-	N	4	-	-	-	Transformer	Transfer capacity increases significantly with additional 22kV conversion. When operating at 66/22kV (2022) all load should be able to be back-fed.
15	Elgin 66/22kV [EGN] (Future)	-	-	-	-	-	-	-	Transformer	Existing 66/33kV transformer to be converted to 66/22kV operation by 2022. Will partly unload some 66kV circuits and provide secure back-feeds at 22kV to other sites. Load to be secured by existing switched capacity.
16	Fairton 33/11kV [FTN]	-	-	N/A	-	-	-	-	Other	Decommissioned 2019
	Fairton 66/22/11kV [FTN]	8	22	N-1 Switched	11	40%	20	50%	No constraint within +5 years	New substation (2017) with 1x20MVA 66/22kV, 1x20MVA 66/11kV and 1x8MVA 22/11kV transformers. Station firm capacity is enhanced by adjacent switched transfer capacity at 22kV and 11kV.
	Hackthorne 66/22kV [HTH]	15	-	N	9	-	-	-	Transformer	Second Carew transformer along with additional 22kV conversion provides extra transfer capacity. Future 66kV MSM and MON also significantly increase transfer capacity.
	Highbank 66/11kV [HBK]	8	-	N	-	-	-	-	Subtransmission circuit	Owned by Trustpower. Winter: generation. Summer: pump load. By agreement, EA Networks provide N 66kV subtransmission security beyond Methven.
	Lagmhor 66/22kV [LGM]	9	-	N	6	-	-	-	Transformer	22kV transfer capacity uses HTH, CRW, TIN, plus additional 22kV conversion.
	Lauriston 66/22kV [LSN]	15	-	N	7	-	-	-	Transformer	Transfer capacity uses 22kV from OVD, FTN, & MTV, larger OVD transformer, and increased MTV 22kV supply capability.
17	Methven 33/11kV [MVN]	-	-	N	4	-	-	-	No constraint within +5 years	Load transferred to Methven 66/11kV substation in 2016. Acting as hot standby for Methven 11kV load until 2023.
18	Methven 66/22/11kV [MTV]	5	8	N-1 Switched	5	63%	-	-	Transformer	22/11kV transformer provides significant back-feed from LSN. 66/22kV, 66/11kV & 22/11kV transformers will provide 100% transfer capacity in 2022.
19	Methven 66/33kV [MTV]	5	-	N	5	-	-	-	No constraint within +5 years	Most 33kV load beyond MTV will be converted to 66/22kV. Remaining 33kV load will be supplied by stepping up 22/33kV alleviating constraint (2022).
20	Mt Somers 66/22kV [MSM]	3	5	N-1 Switched	3	58%	-	-	Transformer	Conversion to 66/22kV plus conversion of surrounding distribution network to 22kV permits adequate switched transfer capacity. Additional 66kV circuit in 2022 will provide N-1 subtransmission security (currently N subtransmission security).
21	Mt Hutt 33/11kV [MHT]	2	-	N	2	-	-	-	Transformer	Considered adequate. 33kV and 11kV lines share common poles. Possible 22kV conversion to MTV would increase switched transfer capacity.
22	Montalto 33/11kV [MON]	2	-	N	1	-	-	-	Transformer	Conversion to 22kV distribution network increases transfer capacity in 2024-25. Redundant as 22kV conversion proceeds.
23	Northtown 66/11kV [NTN]	14	22	N-1	20	64%	20	80%	No constraint within +5 years	Currently seasonally constrained by subtransmission network. Fully resolved in 2020 with additional 66kV circuit. Additional 11kV cables in Ashburton increase fast transfer capacity from ASH.
24	Overdale 66/22kV [OVD]	14	-	N	10	-	-	-	Transformer	Transfer capacity has increased with larger 66/22kV transformers at adjacent substations ([PDS] & [LSN]) and with additional 22kV conversion and Fairton 66/22kV construction.
25	Pendarves 66/22kV [PDS]	16	22	N-1	28	73%	20	80%	No constraint within +5 years	Firm capacity limit is N-1 transformer capacity limit. Second transformer is one of two system spares.
26	Seafield 22/11kV [SFD22]	-	-	N	5	-	-	-	Transformer	Decommissioned as 33/11kV and converted to 22/11kV for 5MVA limited transfer back-up supply to SFD66 (several minutes for restoration).
27	Seafield 66/11kV [SFD66]	8	5	N-1 Switched	5	160%	-	-	Transformer	A second transformer and short length of 66kV line would provide 100% firm capacity. Negotiated security with sole industrial customer. Remote-controlled change-over between adjacent 22/11kV and 66/11kV substations.
28	Wakanui 66/22kV [WNU]	13	-	N	10	-	-	-	Transformer	Elgin's 66/33kV transformer conversion to 66/22kV (2020-21) increases 22kV fast transfer capacity significantly.

Company Name	Electricity Ashburton Limited
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SCHEDULE 12C: REPORT ON FORECAST NETWORK DEMAND

This schedule requires a forecast of new connections (by consumer type), peak demand and energy volumes for the disclosure year and a 5 year planning period. The forecasts should be consistent with the supporting information set out in the AMP as well as the assumptions used in developing the expenditure forecasts in Schedule 11a and Schedule 11b and the capacity and utilisation forecasts in Schedule 12b.

sch ref

7 ## 12c(i): Consumer Connections

sch ref		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 20**	**31 Mar 21**	**31 Mar 22**	**31 Mar 23**	**31 Mar 24**	**31 Mar 25**
11	*Consumer types defined by EDB**						
12	Urban LV	80	80	80	80	80	80
	Urban Transformer	7	7	7	7	7	7
	Urban Alteration for Safety (No new ICP created)	-	-	-	-	-	-
	Urban Capacity Alteration (No new ICP created)	5	5	5	5	5	5
	Rural LV	50	50	50	50	50	50
13	Rural Transformer	60	60	60	60	60	60
14	Rural Alteration for Safety (No new ICP created)	25	25	25	25	25	25
15	Rural Capacity Alteration (No new ICP created)	20	20	20	20	20	20
16	Other	45	40	40	40	40	40
17	**Connections total**	292	287	287	287	287	287
18	**include additional rows if needed*						
19	**Distributed generation**						
20	Number of connections	27	30	32	34	36	38
21	Capacity of distributed generation installed in year (MVA)	0	0	0	0	0	0

22 ## 12c(ii) System Demand

sch ref			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 20**	**31 Mar 21**	**31 Mar 22**	**31 Mar 23**	**31 Mar 24**	**31 Mar 25**
25		GXP demand	176	181	183	185	187	189
26	*plus*	Distributed generation output at HV and above	2	2	2	2	2	2
27		**Maximum coincident system demand**	177	183	185	187	189	191
28	*less*	Net transfers to (from) other EDBs at HV and above	(0)	(0)	(0)	(0)	(0)	(0)
29		**Demand on system for supply to consumers' connection points**	177	183	185	187	189	191
30		**Electricity volumes carried (GWh)**						
31		Electricity supplied from GXPs	560	456	457	458	459	460
32	*less*	Electricity exports to GXPs	0	0	0	0	0	0
33	*plus*	Electricity supplied from distributed generation	94	164	164	164	164	164
34	*less*	Net electricity supplied to (from) other EDBs	(0)	(0)	(0)	(0)	(0)	(0)
35		**Electricity entering system for supply to ICPs**	654	620	621	622	623	624
36	*less*	Total energy delivered to ICPs	601	576	577	578	579	580
37		**Losses**	54	44	44	44	44	44
38								
39		**Load factor**	42%	39%	38%	38%	38%	37%
40		**Loss ratio**	8.2%	7.1%	7.1%	7.1%	7.1%	7.1%

Company Name	**Electricity Ashburton Limited**
AMP Planning Period	**1 April 2020 – 31 March 2030**
Network / Sub-network Name	**Electricity Ashburton Limited**

SCHEDULE 12d: REPORT FORECAST INTERRUPTIONS AND DURATION

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

sch ref		*Current Year CY*	*CY+1*	*CY+2*	*CY+3*	*CY+4*	*CY+5*
8							
9	for year ended	**31 Mar 20**	**31 Mar 21**	**31 Mar 22**	**31 Mar 23**	**31 Mar 24**	**31 Mar 25**
10	**SAIDI**						
11	Class B (planned interruptions on the network)	100.0	120.0	115.0	115.0	90.0	85.0
12	Class C (unplanned interruptions on the network)	100.0	110.0	100.0	95.0	90.0	88.0
13	**SAIFI**						
14	Class B (planned interruptions on the network)	0.35	0.40	0.35	0.35	0.35	0.30
15	Class C (unplanned interruptions on the network)	1.54	1.25	1.25	1.25	1.25	1.25

Company Name	Electricity Ashburton Limited
AMP Planning Period	1 April 2020 – 31 March 2030
Asset Management Standard Applied	No Formal Standard Applied

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	Score Description
3	Asset management policy	To what extent has an asset management policy been documented, authorised and communicated?	3	EAN's asset management policy is an inherent part of the AMP. EAN develops policies as the need arises. For example, the rural network harmonic policy is used to address the issues arising out of the irrigation connections. Various operating policies are used to manage the day to day network operational issues. PSMS is used to manage assets to avoid any inadvertent risks to the public. There is also a extensive interaction among the management and the board on a regular basis.		Widely used AM practice standards require an organisation to document, authorise and communicate its asset management policy (eg, as required in PAS 55 para 4.2 i). A key pre-requisite of any robust policy is that the organisation's top management must be seen to endorse and fully support it. Also vital to the effective implementation of the policy, is to tell the appropriate people of its content and their obligations under it. Where an organisation outsources some of its asset-related activities, then these people and their organisations must equally be made aware of the policy's content. Also, there may be other stakeholders, such as regulatory authorities and shareholders who should be made aware of it.	Top management. The management team that has overall responsibility for asset management.	The organisation's asset management policy, its organisational strategic plan, documents indicating how the asset management policy was based upon the needs of the organisation and evidence of communication.	The asset management policy is authorised by top management, is widely and effectively communicated to all relevant employees and stakeholders, and used to make these persons aware of their asset related obligations.
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?	2	EAN's asset management strategies are in line with its asset management policies. Health and safety meetings are regularly held and minutes are circulated to all staff. There is also a regular auditing and interviewing process to identify and resolve any health and safety issues. Biennually, there is a representative survey of customers which provides an input into the asset management strategies of the company. Robust discussion is held at senior management level to ensure the asset management strategies are consistent with other company policies and strategies.		In setting an organisation's asset management strategy, it is important that it is consistent with any other policies and strategies that the organisation has and has taken into account the requirements of relevant stakeholders. This question examines to what extent the asset management strategy is consistent with other organisational policies and strategies (eg, as required by PAS 55 para 4.3.1 b) and has taken account of stakeholder requirements as required by PAS 55 para 4.3.1 c). Generally, this will take into account the same polices, strategies and stakeholder requirements as covered in drafting the asset management policy but at a greater level of detail.	Top management. The organisation's strategic planning team. The management team that has overall responsibility for asset management.	The organisation's asset management strategy document and other related organisational policies and strategies. Other than the organisation's strategic plan, these could include those relating to health and safety, environmental, etc. Results of stakeholder consultation.	Some of the linkages between the long-term asset management strategy and other organisational policies, strategies and stakeholder requirements are defined but the work is fairly well advanced but still incomplete.
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	Life cycle of the assets are regularly checked and reported to management. There is an effective maintenance regime to address life cycle related issues. The age profiles are analysed and conditions of assets are monitored regularly to replace deficient equipment. GIS and other databases are frequently used to maintain an up-to-date knowledge of the assets installation date, categories etc. During 2017, a new asset management system was commissioned to manage all significant assets.		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.	The asset management strategy takes account of the lifecycle of all of its assets, asset types and asset systems.
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	EAN's AMP has been in place for over 20 years and has a 10 year outlook to maintain and develop assets. Major tasks and activities are identified, developed and implemented to optimise the network. Feedback is taken from customer surveys, outage data and public safety inspections to modify the plan as appropriate.		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).	Asset management plan(s) are established, documented, implemented and maintained for asset systems and critical assets to achieve the asset management strategy and asset management objectives across all life cycle phases.

Question No.	Function	Question	Score	Evidence—Summary	User Guidance	Why	Who	Record/documented Information	Score Description
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?	3	Asset management plans are communicated to all those parties involved in implementing the plan. Those involved in implementing the plan are also involved in creating it. High level presentations are made to all staff in company wide meetings.		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.	The plan(s) are communicated to all relevant employees, stakeholders and contracted service providers to a level of detail appropriate to their participation or business interests in the delivery of the plan(s) and there is confirmation that they are being used effectively.
29	Asset management plan(s)	How are designated responsibilities for delivery of asset plan actions documented?	3	AMP responsibilities are defined to appropriate roles/people in the organisation and documented within the AMP.		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.	Asset management plan(s) consistently document responsibilities for the delivery actions and there is adequate detail to enable delivery of actions. Designated responsibility and authority for achievement of asset plan actions is appropriate.
31	Asset management plan(s)	What has the organisation done to ensure that appropriate arrangements are made available for the efficient and cost effective implementation of the plan(s)? (Note this is about resources and enabling support)	3	Over recent years, the company has increased the size of its resource base in order to meet requirements of the plan. General shortages of skilled people hampers implementation of the plan. Where the plan can not be fully implemented in the proposed time frame the priorities are reassed on a risk-based approach.		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.	The organisation's arrangements fully cover all the requirements for the efficient and cost effective implementation of asset management plan(s) and realistically address the resources and timescales required, and any changes needed to functional policies, standards, processes and the asset management information system.
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	Responding to "emergencies" is a common activity within the company. For example, any unplanned outages during an extreme weather condition requires controllers to immediately prepare operating instructions and dispatch fault men to the affected areas. An appropriate risk register is maintained for an on-going health and safety analysis. While not fully documented, plans/resources are in place to respond to an event. In addition, we have a Mutual Aid agreement with other South Island lines companies to assist each other in major events. We also have other arrangements with contracted resource to assist us in emergency situations.		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.	Appropriate emergency plan(s) and procedure(s) are in place to respond to credible incidents and manage continuity of critical asset management activities consistent with policies and asset management objectives. Training and external agency alignment is in place.
37	Structure, authority and responsibilities	What has the organisation done to appoint member(s) of its management team to be responsible for ensuring that the organisation's assets deliver the requirements of the asset management strategy, objectives and plan(s)?	3	There is an enduring process to identify the gaps and delegate tasks to appropriate people. The network manager has overall responsibility to undertake these functions. Appropriate structures, authorities and responsibilities are in place. Current structure is more reliant on matrix management for the best possible outcome.		In order to ensure that the organisation's assets and asset systems deliver the requirements of the asset management policy, strategy and objectives responsibilities need to be allocated to appropriate people who have the necessary authority to fulfil their responsibilities. (This question, relates to the organisation's assets eg, para b), s 4.4.1 of PAS 55, making it therefore distinct from the requirement contained in para a), s 4.4.1 of PAS 55).	Top management. People with management responsibility for the delivery of asset management policy, strategy, objectives and plan(s). People working on asset-related activities.	Evidence that managers with responsibility for the delivery of asset management policy, strategy, objectives and plan(s) have been appointed and have assumed their responsibilities. Evidence may include the organisation's documents relating to its asset management system, organisational charts, job descriptions of post-holders, annual targets/objectives and personal development plan(s) of post-holders as appropriate.	The appointed person or persons have full responsibility for ensuring that the organisation's assets deliver the requirements of the asset management strategy, objectives and plan(s). They have been given the necessary authority to achieve this.

Question No.	Function	Question	Score	Evidence—Summary	User Guidance	Why	Who	Record/documented Information	Score Description
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	Resources are allocated based on the needs of the organisation. Generally, issues are identified and resources are evaluated/ allocated/contracted in after discussions with the relevant parties. Last year, significant effort has been made to complete Items identified in the plan within the appropriate finacial year to the point some areas were ahead of the plan for the year.		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.	An effective process exists for determining the resources needed for asset management and sufficient resources are available. It can be demonstrated that resources are matched to asset management requirements.
42	Structure, authority and responsibilities	To what degree does the organisation's top management communicate the importance of meeting its asset management requirements?	3	Asset management requirements are regularly communicated to people as per their responsibilities. For example, annual safety sessions are held and all staff are updated on the current asset management projects, practices and requirements. Our commitment to public safety has been ecognised and praised by our PSMS auditor.		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.	Top management communicates the importance of meeting its asset management requirements to all relevant parts of the organisation.
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?	3	Most projects are carried out by our own field services department. Additional resources have been applied to the process of contracting work which is managed jointly between the network and field services. Most of our civil works is now subject to competitive tendering. We have a representative who monitors contracted work while it is occuring to ensure conformity with our requirements. Alternatively, we place our own people within contracted resource to guide contractors to ensure conformity.		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.	Evidence exists to demonstrate that outsourced activities are appropriately controlled to provide for the compliant delivery of the organisational strategic plan, asset management policy and strategy, and that these controls are integrated into the asset management system
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	Training plans are identified on an individual basis. There is no specific training application as such. Regular meetings are held with staff to discuss training and personal development opportunities. Staff and various departments are encouraged to come up with their own training, awareness and competence requirements. We have an ongoing commitment to developing competencies and work procedures directly relating to job positions and job tasks. We have "signed up" to ENA's common competency framework initiative.		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.	The organisation can demonstrate that plan(s) are in place and effective in matching competencies and capabilities to the asset management system including the plan for both internal and contracted activities. Plans are reviewed integral to asset management system process(es).

Question No.	Function	Question	Score	Evidence—Summary	User Guidance	Why	Who	Record/documented Information	Score Description
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?	3	There is a competency register to capture competency levels of all staff and appropriate contractors. It is kept up to date where possible, but it is aimed more at operational competencies. Refer Q 48.		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.	Competency requirements are in place and aligned with asset management plan(s). Plans are in place and effective in providing the training necessary to achieve the competencies. A structured means of recording the competencies achieved is in place.
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	Competency register exists as mentioned above but, to date, review and assessment has concentrated on operational staff. Where appropriate, the company will send staff to conferences, forums, workshops etc to increase awareness and knowledge of asset management activities. Refer Q 48.		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.	The organization is in the process of putting in place a means for assessing the competence of person(s) involved in asset management activities including contractors. There are gaps and inconsistencies.
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	Majority of work is done by the in-house field services department contractor. Regular staff meetings are held where AMP projects are discussed. Asset management plans and policies are published on internet and intranet. Formal after board meeting briefing is held on a monthly basis to inform the key staff about the asset management expectations and requirements. Customers are also engaged on a regular basis to refine the company's asset management strategies.		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.	Two way communication is in place between all relevant parties, ensuring that information is effectively communicated to match the requirements of asset management strategy, plan(s) and process(es). Pertinent asset information requirements are regularly reviewed.
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?	3	The company has several repositories of asset management information - finacial system, asset management sytem, GIS etc. We are currently in the process of mapping our process within the asset sections of the company. This mapping will detail the interactions between the various systems.		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.	The organisation has established documentation that comprehensively describes all the main elements of its asset management system and the interactions between them. The documentation is kept up to date.

Question No.	Function	Question	Score	Evidence—Summary	User Guidance	Why	Who	Record/documented Information	Score Description
62	Information management	What has the organisation done to determine what its asset management information system(s) should contain in order to support its asset management system?	2	We have recently purchased a new asset management system for storing asset information. At the time considerable effort was put into determining what information is required. Information is regularly captured to support the AMP processes. For example, the assets database captures asset condition information relating to assets such as CBs, and transformers. GIS captures location, types and other technical information relating to many other assets within the network.		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.	The organisation has developed a structured process to determine what its asset information system should contain in order to support its asset management system and has commenced implementation of the process.
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	We have just installed a new asset management system. Part of this process, which is ongoing, involves improving the quality of the data incuding field audits. Engineering meetings are held to discuss and address any relevant issues. Additional resource has beeen employed to ensure the asset management information systems are up to date and accurate.		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.	The organisation has effective controls in place that ensure the data held is of the requisite quality and accuracy and is consistent. The controls are regularly reviewed and improved where necessary.
64	Information management	How has the organisation's ensured its asset management information system is relevant to its needs?	3	We have installed a new asset management system which has centralised some of our information systems. Likewise our new GIS system is now on stream and is being updated. Both the asset management and GIS systems share data with each other. To date we have not identified significant areas where the asset management information sytems fall short in any significant way.		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.	The organisation's asset management information system aligns with its asset management requirements. Users can confirm that it is relevant to their needs.
69	Risk management process(es)	How has the organisation documented process(es) and/or procedure(s) for the identification and assessment of asset and asset management related risks throughout the asset life cycle?	3	Our risk management systems has just been overhauled to provide better risk analasysis. Continual improvement process also identifies and deals with the assets at risk. Identified risks are regularly investigated and resolved as soon as practicable. External consultants are also engaged to provide their opinion on some specific risks. Staff have been trained on risk management procedures and are in the process of implementing processes.		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.	Identification and assessment of asset related risk across the asset lifecycle is fully documented. The organisation can demonstrate that appropriate documented mechanisms are integrated across life cycle phases and are being consistently applied.
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?	3	Risks and dangers are considered continually through the existing asset management processes. Continuous improvement processes are also used for this purpose. Health and safety, and public safety risks are continuously monitored and updated to reflect the correct risk matrix.		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.	Outputs from risk assessments are consistently and systematically used as inputs to develop resources, training and competency requirements. Examples and evidence is available.

Question No.	Function	Question	Score	Evidence—Summary	User Guidance	Why	Who	Record/documented Information	Score Description
82	Legal and other requirements	What procedure does the organisation have to identify and provide access to its legal, regulatory, statutory and other asset management requirements, and how is requirements incorporated into the asset management system?	3	Compliance issues are regularly considered and applied in the day to day operation of the network. Organisational, legal, regulatory, statutory and other asset management requirements are discussed in regular engineering meetings as well. Responsible people are encouraged to participate in industry events which also helps to keep up to date knowledge of the legal and other requirements.		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	Evidence exists to demonstrate that the organisation's legal, regulatory, statutory and other asset management requirements are identified and kept up to date. Systematic mechanisms for identifying relevant legal and statutory requirements.
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?	3	AMP has been developed over 20 years with good feedback from reviewers. Various life cycle plans have been implemented with no major issues. Feedback is taken from many sources to ensure we are creating, acquiring and maintaining assets for their intended use.		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.	Effective process(es) and procedure(s) are in place to manage and control the implementation of asset management plan(s) during activities related to asset creation including design, modification, procurement, construction and commissioning.
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?	3	See Q88.		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.	The organisation has in place process(es) and procedure(s) to manage and control the implementation of asset management plan(s) during this life cycle phase. They include a process, which is itself regularly reviewed to ensure it is effective, for confirming the process(es)/ procedure(s) are effective and if necessary carrying out modifications.
95	Performance and condition monitoring	How does the organisation measure the performance and condition of its assets?	2	With additional resource being applied to our maintenace programs, better sytems are being developed to inspect and record the condition and performance of our assets.		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).	The organisation is developing coherent asset performance monitoring linked to asset management objectives. Reactive and proactive measures are in place. Use is being made of leading indicators and analysis. Gaps and inconsistencies remain.
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?	3	Regular inspections, feedback from reliability reports,and other measures such as survey and real time SCADA information are collected and analysed. Investigation into failures is extensive and feeds back into our asset management processes		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.	The organisation have defined the appropriate responsibilities and authorities and evidence is available to show that these are applied across the business and kept up to date.

Question No.	Function	Question	Score	Evidence—Summary	User Guidance	Why	Who	Record/documented Information	Score Description
105	Audit	What has the organisation done to establish procedure(s) for the audit of its asset management system (process(es))?	1	We do not formally audit the asset management process but they are subject to review internally at management and board level		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.	The organisation understands the need for audit procedure(s) and is determining the appropriate scope, frequency and methodology(s).
109	Corrective & Preventative action	How does the organisation instigate appropriate corrective and/or preventive actions to eliminate or prevent the causes of identified poor performance and non conformance?	3	The organisation has a strong record of investigation and applying change as a result of our continuous improvement programs. Equipment or public safety incidents are evaluated and fed back into the asset management process.		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	Mechanisms are consistently in place and effective for the systematic instigation of preventive and corrective actions to address root causes of non compliance or incidents identified by investigations, compliance evaluation or audit.
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?	3	The company has a well developed and strong commitment to continual improvement. Where continual improvement processes have implications for asset management there is rigurous discussion resulting in agreed actions that, if appropriate, are included in future iteration of the AMP		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.	There is evidence to show that continuous improvement process(es) which include consideration of cost risk, performance and condition for assets managed across the whole life cycle are being systematically applied.
115	Continual Improvement	How does the organisation seek and acquire knowledge about new asset management related technology and practices, and evaluate their potential benefit to the organisation?	3	The company has a commitment to encourage staff to explore new ideas and has a track record of innovation. Regular supplier visits are organised to learn about the new technologies and advances.		One important aspect of continual improvement is where an organisation looks beyond its existing boundaries and knowledge base to look at what 'new things are on the market'. These new things can include equipment, process(es), tools, etc. An organisation which does this (eg, by the PAS 55 s 4.6 standards) will be able to demonstrate that it continually seeks to expand its knowledge of all things affecting its asset management approach and capabilities. The organisation will be able to demonstrate that it identifies any such opportunities to improve, evaluates them for suitability to its own organisation and implements them as appropriate. This question explores an organisation's approach to this activity.	The top management of the organisation. The manager/team responsible for managing the organisation's asset management system, including its continual improvement. People who monitor the various items that require monitoring for 'change'. People that implement changes to the organisation's policy, strategy, etc. People within an organisation with responsibility for investigating, evaluating, recommending and implementing new tools and techniques, etc.	Research and development projects and records, benchmarking and participation knowledge exchange professional forums. Evidence of correspondence relating to knowledge acquisition. Examples of change implementation and evaluation of new tools, and techniques linked to asset management strategy and objectives.	The organisation actively engages internally and externally with other asset management practitioners, professional bodies and relevant conferences. Actively investigates and evaluates new practices and evolves its asset management activities using appropriate developments.

Schedule 14a Mandatory Explanatory Notes on Forecast Information

1. This Schedule requires EDBs to provide explanatory notes to reports prepared in accordance with clause 2.6.6.

2. This Schedule is mandatory—EDBs must provide the explanatory comment specified below, in accordance with clause 2.7.2. This information is not part of the audited disclosure information, and so is not subject to the assurance requirements specified in section 2.8.

Commentary on difference between nominal and constant price capital expenditure forecasts (Schedule 11a)

3. In the box below, comment on the difference between nominal and constant price capital expenditure for the current disclosure year and 10 year planning period, as disclosed in Schedule 11a.

The difference is 0.0% for the 2020-21 year. Costs have been prepared using 2020-21 values for labour, plant and materials. Years after 2020-21 have been escalated by the "Half Year Economic and Fiscal Update 2019" CPI Forecast by the New Zealand Government Treasury published in December 2019. When the forecast ends, the final year CPI value has been used until the period end.

(https://treasury.govt.nz/publications/efu/half-year-economic-and-fiscal-update-2019-html)

Commentary on difference between nominal and constant price operational expenditure forecasts (Schedule 11b)

4. In the box below, comment on the difference between nominal and constant price operational expenditure for the current disclosure year and 10 year planning period, as disclosed in Schedule 11b.

The difference is 0.0% for the 2020-21 year. Costs have been prepared using 2020-21 values for labour, plant and materials. Years after 2020-21 have been escalated by the "Half Year Economic and Fiscal Update 2019" CPI Forecast by the New Zealand Government Treasury published in December 2019. When the forecast ends, the final year CPI value has been used until the period end.

(https://treasury.govt.nz/publications/efu/half-year-economic-and-fiscal-update-2019-html)

Financial Year (ending March)	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
Treasury CPI Forecast (%)	1.9	2.0	2.0	2.0	2.0	2.0	2.0	2.0	2.0	N/A
Cumulative CPI Price Inflator	1.000	1.019	1.0394	1.0602	1.0813	1.103	1.1251	1.1476	1.1705	1.1939

Schedule 17 Certification for Year-beginning Disclosures

Clause 2.9.1

We, Philip John McKendry and Paul Jason Munro, being directors of Electricity Ashburton Limited certify that, having made all reasonable enquiry, to the best of our knowledge:

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

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

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

Paul Jason Munro

Philip John McKendry

28 March 2020

EA networks

connecting our community