



Asset Management Plan 2018



1 April 2018 - 31 March 2028



COUNTIESPOWER

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Plan Summary

Introduction

Counties Power's mission is to provide safe, reliable and cost effective supply to the electricity consumers of Franklin. The purpose of the Asset Management Plan (AMP) is to ensure we manage our assets over their useful life in a smart and sustainable manner in order to provide a level of service our consumers want and for which they are willing to pay. The AMP is a vital planning tool as it focuses our decisions, investments and priorities to ensure our assets provide enduring value and are a reflection of our corporate objectives, mission and values. Investments and priorities are aligned to our long term strategic goals, the dynamic needs of our consumers and our stakeholders and the changing market and technological landscape, all of which we have invested significantly in researching in preparation for completing the AMP.

The 2018 – 2028 AMP sets out the purpose and objective of our asset management practices to assist us in managing our assets over their lifecycle in an efficient, effective and sustainable manner in order to provide a level of service that our customers want and for which they are willing to pay. This is a vital planning document as it focuses our decisions and activities so that our assets provide enduring value to our consumers, our stakeholders and ourselves.

Counties Power has been providing reliable and ubiquitous electricity supply to the consumers of Franklin for over 90 years. It is our intention to do so for at least another 90 years meaning we must, as a minimum, meet our consumer and stakeholder expectations of performance. Demand-side and supply-side technology is developing rapidly and offers consumers and energy providers options for improvement, service transformation and efficiency that are unheralded in the sector. With the largest penetration of smart meters in New Zealand, a range of innovative, on-line applications for consumers and field staff along with investments in electric vehicles (EVs), EV charging stations and solar panels, Counties Power intends to remain ahead of technology change through research, direct investment and by partnering with some of the world's most innovative and proven providers of energy and ICT solutions. We must evolve and continually improve our operations to ensure we are offering, overall, the best service we can to the very consumers who own this company and who, ultimately, have choice over how its assets are best managed.

The AMP covers the period from 1 April 2018 through to 31 March 2028 and was approved by our Board of Directors on 21 March 2018.

About Counties Power

Counties Power owns, manages and operates an electricity distribution network in southern Auckland, Waikato and Hauraki district areas with a system length of 3,200 km covering an area of approximately 2,250 km². The Auckland Council area covers 830 km² (37%) of the Counties Power network, the Waikato District covers 1,340 km² (60%), and the Hauraki District covers the remaining 80 km² (3%). We receive power from the national grid at the Bombay and Glenbrook Grid Exit Points (GXPs) and then transport it to our consumers via eight zone substations and our extensive network of lines, cables, transformers and other equipment.

Counties Power is 100% consumer owned. All shares are held by the Trustees of the Counties Power Consumer Trust (Trust) on behalf of all local power consumers. The Trust has a total of five Trustees, of which two are required to be elected every two years. Counties Power is managed for the benefit of its consumers and their communities. The Trust oversees the performance of Counties Power through the appointment of a Board of Directors (Board). The Board and Management of Counties Power consult the Trust on our strategic direction, business plans, and asset management measures and targets. Information about the Trust can be obtained from www.countiespowertrust.co.nz.

Our operating environment

Network

The Counties Power network is a provincial ‘town and country’ network distributing electricity across a broad geography in Auckland’s south, and the northern Waikato region. Today, over 70% of the Counties Power network is rural overhead, however the urban networks supplying Pukekohe, Waiuku, Tuakau, Pokeno, Drury and parts of Papakura comprise a split of overhead and underground assets. Generally, the eastern part of the network is newer, higher in ICP density and subject to high levels of growth in the areas adjacent to motorway and state highway corridors. The western side of the network is older, more remote, lower density and subject to little growth.

The Counties Power network is exposed to a range of environmental conditions, including weather, particularly the harsh coastal environment around the Awhitu Peninsula and vegetation, most notably in the areas around the Hunua Ranges, but with effects across the entire network.

Growth

The Counties Power network is amongst the fastest growing electricity networks in New Zealand with connection growth in the order of 2.5% per annum. This is largely driven by the growth of Auckland and our location within the ‘golden triangle’ of growth between Tauranga, Hamilton and Auckland.

The population of the area grew by 11.5% between the 2006 and 2013 census periods. Auckland was the fastest growing region, increasing by 8.5% over the same period. Waikato district was ranked in the top 10 territorial areas with a 10.1% population growth. The Hauraki district population decreased slightly overall, however the Kaiaua area population growth increased by 19% (an area which is supplied by Counties Power).

The largest contributor to demand growth in the medium term is expected to be industrial and residential developments around Tuakau, Pokeno, the Drury South Business Park development, and the Special Housing Areas at Hingaia, Drury and Paerata. However, the supply of land for housing and development is an important planning issue for Auckland. Greenfield areas identified in the Auckland Plan Development Strategy, consisting of Hingaia, Opaheke, Drury, Karaka, Paerata and Pukekohe, will collectively see additional capacity of up to 42,000 houses over the long term.

Emerging disruptive technologies

Emerging disruptive technologies are recognised as one of the biggest issues across the electricity industry sector in the medium to long term. Embedded generation, energy storage, energy efficiency measures, demand side management initiatives and new load types such as Electric Vehicles (EVs) may result in modified load growth patterns. We anticipate that only embedded generation will impact load growth in our area in the short term, but as energy storage and EVs becomes a more mature technology and costs reduce, this could have an impact in the medium term.

Counties Power continues to keep a watching brief on demand side technologies and options, along with other new supply side technology and where appropriate undertake or participate in trials to understand how these options could impact on our business. We are trialling new technology options to understand the value they provide as well as actively following international developments in new technology. Should the cost of new technology continue to reduce, these options may become viable alternatives and will be considered as part of investment planning process.

Local Authorities and District Plans

Counties Power serves the area previously known as the Franklin District. This district was split with the formation of the Auckland Council in 2010, and the Auckland Council is responsible for administration of approximately 40% of the area, with the remainder split across Waikato District and Hauraki District Councils.

The Auckland Unitary Plan Operative in part AUP(OP) came into effect on November 2016. Certain parts of the plan have been excluded from being operative, because they are either subject to Environment Court and High Court appeals or they require the approval of the Minister of Conservation. Once all appeals are resolved and approvals given, the Council will notify the date on which the Auckland Unitary Plan will become fully operative. The AUP(OP) has a single infrastructure chapter, designed with network utility operators in mind, which will impose new requirements and restrictions on the way Counties Power builds, operates and maintains its network going forward. Our work processes and practices are being updated for routine work activities to align with the updated requirements in the AUP(OP). Some of the maintenance and network development activities are subject to additional requirements on controls and compliance. These new requirements have potential to add costs and complexity to future maintenance and development of the network. Experience to date has identified these requirements will only apply in exceptional circumstances. These effects are not factored into costs stated in this AMP.

In the Waikato District Council area, a similar review of the Waikato District Plan has continued in 2017 and will be publicly notified in May 2018.

Regulation

Counties Power, as an electricity distribution business, is subject to regulation by the Commerce Commission, under Part 4 of the *Commerce Act 1986*. Due to the ownership structure, it is exempt from the Default Price - Quality Regime, as the consumers are the beneficial owners through the Counties Power Consumer Trust, however it is still required to comply with the Information Disclosure Requirements, of which the AMP is one requirement.

The business is also regulated by the Electricity Authority and is subject to compliance with the *Electricity Industry Participation Code*, both as a distributor and also as a metering equipment provider.

Regulatory changes imposed by the Electricity Authority on other industry participants, such as Transpower, can have a consequential effect on the business, such as the method for determining transmission pricing.

In addition to economic and industry regulation, Counties Power has a range of legislative requirements to meet including the *Electricity Act 1992*, the *Electricity (Safety) Regulations 2010*, *Health and Safety at Work Act 2015*, the *Electricity (Hazards from Trees) Regulations 2003*, amongst others.

Consumer value and cost reflective pricing

Counties Power's capital and operating expenditure is continuing to grow as its network expands at a time when peak demand is growing twice as fast as sales volume and where average usage per consumer is decreasing. The combination of Counties Power's current volume based pricing, and the fact it chose not to increase either line prices or its own distribution prices to its consumers for the 4 years between 2015 and 2018 in an endeavour to improve consumer value, means that distribution revenue per consumer is also decreasing.

As with any electricity lines company, however, most of the company's costs of providing distribution network access are fixed and are associated with building and maintaining infrastructure that can meet peak demand; the variable cost component is driven by the consumer's winter peak demand requiring additional distribution capacity and associated transmission charges. Because consumer volume is increasing at a lower rate than the consumer peak demand is increasing, this creates a mismatch between revenue received and costs incurred. Counties Power's current lines charges to its consumers are not directly cost-reflective.

The Company believes that moving to a more cost reflective structure will enable consumer choice and control and ensure fairer pricing to all consumers. For these reasons, the Electricity Authority has also instructed all line companies to introduce cost reflective pricing. To do this Counties Power introduced prices that are higher at peak times and lower off-peak. This then sends clear price signals to consumers to reduce their peak time use and save money and reduce costs to Counties Power. It also gives the choice to customers that if they use power during peak times they still can but they have to pay more to cover the higher costs to Counties Power.

As a consequence, in 2014 Counties Power introduced smart tariffs that provided peak, off-peak and shoulder pricing options for residential and business customers. No retailers opted to use this tariff, and so on 1 April 2016 Counties Power aligned the tariff to Vector's mass market peak and off-peak tariff to encourage retailer uptake. To date, only one retailer opted to use the tariff but this is expected to change in the future as the industry moves to cost reflective pricing.

Stakeholders

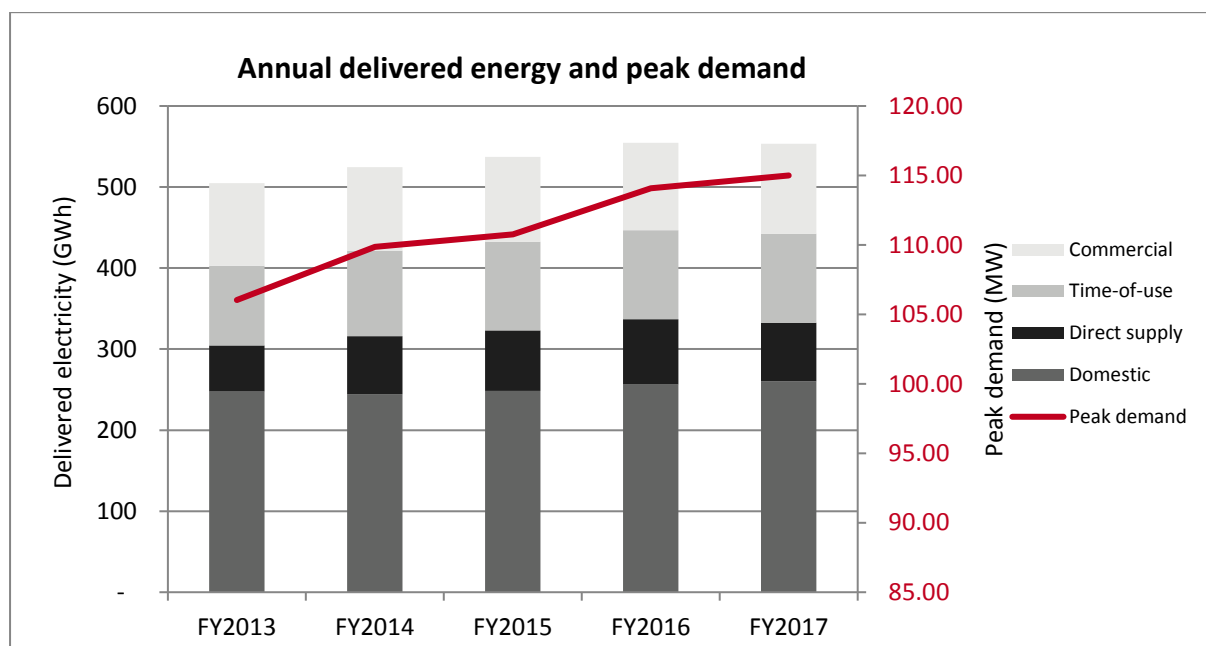
Stakeholder requirements are important to us and we place considerable focus on identifying and meeting stakeholder expectations. As we have a wide range of stakeholders, it is important that conflicting stakeholder requirements are managed appropriately and consistently.

Our stakeholders include consumers, the community and landowners, local authorities, electricity retailers, regulators and government agencies, Transpower, our Board, our employees, our contractors, our suppliers and the Counties Power Consumer Trust.

Our consumers

Our consumers are our owners. As at October 2017, there were 41,697 ICPs connected to the Counties Power network with a maximum demand of approximately 115 MW and annual delivered energy of 553 GWh in the year ending 31 March 2017. In the most recent winter peaks in 2017, peak demand reached 116 MW. The network load profile is winter peaking, with residential loads showing typical morning and evening peaks, and commercial loads generally having a constant daytime load.

This number is increasing daily with new residential, commercial and industrial customers being connected. This is changing the customer mix from a predominantly rural, small town and rural commercial base (e.g. quarries, mines, food production) to an urban residential and industrial mix.



Energy volumes and network demand 2013 to 2017

A breakdown of the ICP type is shown in the table below:

	ICPs	Delivered GWh*
Direct supply	7	72.4
Time-of-use	163	109.7
Commercial	7,397	111.0
Domestic	34,130	260.3
Total	41,697	553.4

* Delivered GWh in FY2016/17.

Our major customers are in a range of industry sectors including steel production, waste product and material handling, food and beverage producers, as well as timber and construction material processing operations. We also supply civic amenities such as streetlights, pumping stations, schools, libraries and emergency service providers. All have differing requirements from their electricity supply which need to be considered.

Counties Power has eight embedded generators greater than 10kW and 538 embedded generators under 10kW. The eight large embedded generators consist of hydro, solar and landfill gas, with the smaller generators being predominantly solar PV installations.

Our network

Counties Power has two points of supply from Transpower's National Grid via Grid Exit Points (GXPs) at Glenbrook and Bombay. The Glenbrook GXP supplies our western substations at 33kV whilst Bombay GXP supplies the eastern substations at 110kV and 33kV. 73% of ICPs are supplied from Bombay GXP at 110kV and 33kV, and the remaining 27% from Glenbrook GXP.

Our subtransmission network consists of a network of 110kV and 33kV subtransmission lines from Bombay and Glenbrook GXPs. The architecture of the network is typically radial subtransmission circuits connecting to 33kV buses, or configured as transformer-feeders where no bus is installed. Our 110kV supply to Pukekohe and Tuakau is operated as a ring with three circuits supplying the two zone substations.

Three zone substations (Pukekohe, Opaheke and Tuakau) operate at 110kV with distribution supply operating at 22kV. The remaining five zone substations (Mangatawhiri, Ramarama, Waiuku, Karaka and Maoro) are supplied via the 33kV subtransmission network with distribution supply operating at 11kV, with some feeders stepped up to 22kV.

Our zone substations supply a total of 53 distribution feeders (operating at 22kV or 11kV) via approximately 3,983 distribution substations (including private substations). The distribution substations connect over 41,690 consumers to the Counties Power network.

Distribution substations have pad mount or pole mount transformers which transform the 22kV or 11kV distribution voltage to 400V/230V reticulation voltage.

A summary of all our network assets is provided in Section 2.6 of the 2018 Asset Management Plan.

Our service levels

Our service levels help link the company vision to the expectations of consumers and to assist us in measuring and improving performance. In particular, they inform our asset management practices by having safety as our top priority.

Customer surveys

Counties Power conducts customer surveys at least once every two years and post-service feedback surveys every month. These customer surveys measure and monitor both residential and commercial customers experience and rating of the power supply service they receive.

Service levels – workplace safety

Our health and safety vision is “no harm for our people, our communities and the environments in which we operate”.

To achieve our health and safety vision, and our corporate mission and values, we have placed health and safety as the highest priority over all our business objectives. We believe that our most important priority is the health and safety of our staff, our contractors, and visitors to our sites and the general public who interact with our assets. To this end, we will always conduct ourselves in a manner that protects the health and safety of our employees and contractors (Counties Power Team Members) visitors to our sites and members of the public who interact with us and our assets.

We acknowledge our responsibilities for maintaining high health and safety standards in the work place and will provide competent resources and effective systems and sufficient capacity within our business to fulfil this commitment. All Counties Power employees are required to adhere to this policy.

Service levels – public safety

Our objective is to ensure that no member of the public is harmed by our network assets, and that hazards introduced by our network assets are controlled so as to not pose a risk to the public.

In order to provide the highest levels of public safety, we have the following initiatives in place:

- Ensuring assets are inspected, maintained and defects repaired in accordance with good industry practice;
- That equipment is designed, selected and installed in a way to promote public safety (safety by design);
- That earthing and protection systems are designed, tested and operate to clear faults quickly to protect members of the public from electric shock;
- Maintain compliance and certification to the requirements of NZS7901 for Public Safety Management Systems, including undertaking periodic external performance assessment;
- Public safety awareness – undertake radio and print media awareness campaigns, as well as providing safety resources on our website www.countiespower.com; and

- Active engagement with Energy Safety in relation to unsafe activity around our network by third parties, or where people have come to harm from our assets, or their own premises.

Service levels – reliability

Our objective is to operate the network to provide a level of performance that meets the expectations of consumers and customers for reliability and value for money, this includes:

- Minimising the number and duration of outages experienced by consumers;
- Restoring power as quickly and safely as possible following an unplanned outage and providing communication to keep consumers informed; and
- Providing consumers with sufficient notice ahead of planned outages required for maintenance.

There are some consumer groups on our network who demand higher levels of reliability, and are prepared to pay more for that benefit, and we accommodate their needs where practicable.

Consumer reliability service levels

We set reliability service levels for our consumer in the Use of System Agreements we have with retailers trading on our network. These outline the target times for restoration of supply following a fault on the network, as well as the timeframes for notifying the consumer that we have to turn them off for planned works.

Description	Target
Restoring electricity supply after the Distributor becomes aware of the fault.	Rural – 6 hours Urban – 4 hours
Notice of pre-planned supply interruption	Not less than 5 days' notice to the electricity retailer unless already agreed with by the Customer

Overall network performance

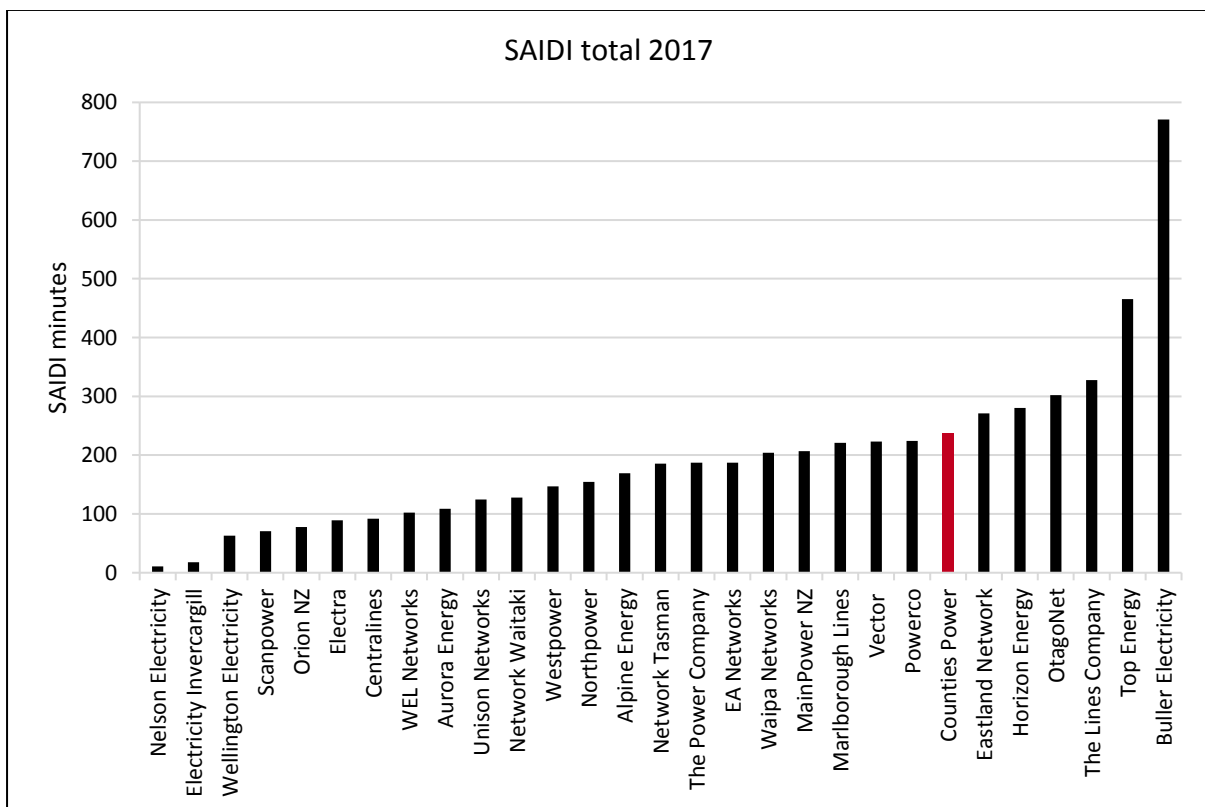
We measure overall network performance using industry standard metrics of SAIDI and SAIFI, which measure the average duration and frequency of interruptions experienced by a consumer on the Counties Power Network. We also measure the number of faults per 100km of circuit length.

Our performance and targets are shown in the table below, and with industry comparisons in the graphs below.

Network SAIDI¹	2015	2016	2017	2018	2019	2020+ Target²
Counties Power	95.7	118.3	236.6	170	205	200
Industry Average	170.1	162.9	194.8			

Network SAIFI¹	2015	2016	2017	2018	2019	2020+ Target
Counties Power	2.23	2.70	3.28	2.55	2.90	2.80
Industry Average	2.18	1.88	2.07			

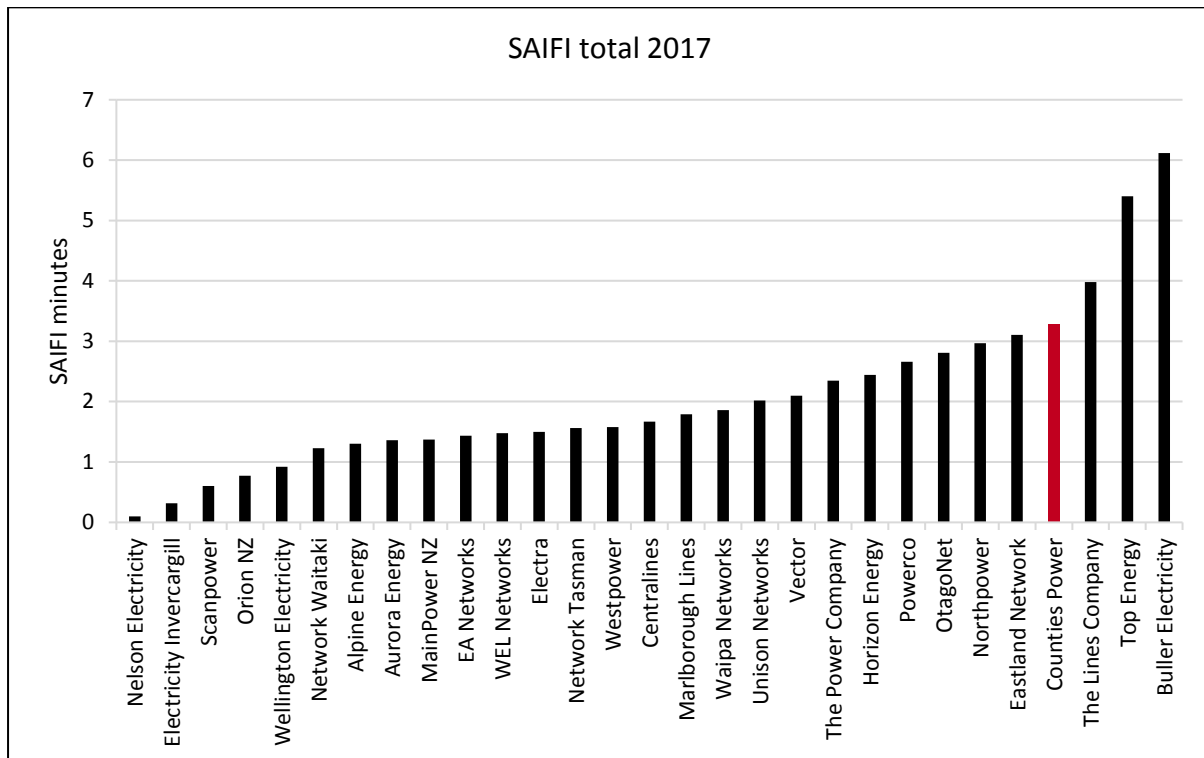
Faults per 100km	2015	2016	2017	2018	2019	2020+ Target
Counties Power	17.56	18.41	16.93	14.50	14.50	14.50
Industry Average	33.03	29.56	16.93			



Network SAIDI – Industry Comparison 2017

¹ Network SAIDI and SAIFI figures from 2015 onwards are normalised figures using the Commerce Commission methodology

² Total SAIDI targets will reduce from 2020 onwards in line with the reliability investments that are made and forecast benefits they will provide. The future level of reliability investment and expected performance benefits will be assessed in the coming year.



Network SAIFI – Industry Comparison 2017

Network performance, as measured by SAIDI and SAIFI, is unfavourable to our own targets, and when compared to industry averages. SAIDI and SAIFI are high relative to similar networks, and reflect the higher feeder customer density resulting from 22kV feeders, changes to live work practices and increased works programme, as well as a notable increase in overhead equipment failure, vegetation faults and vehicle damage in the past two years. The number of faults by these fault types have an upward trend from FY15 to FY17, however from the beginning of FY18 we are starting to see the results of investment and maintenance programmes which started in FY17.

In order to provide appropriate levels of network performance, we have the following initiatives in place:

- Vegetation management – a proactive programme of vegetation surveys and tree trimming to ensure supply is not interrupted by trees coming into contact with overhead lines;
- A focus on worst performing feeders – identifying which feeders have the greatest number of outages, as well as those that have high SAIDI and SAIFI impacts, and undertaking remedial works to ensure the assets on these feeders perform as expected;
- Post fault analysis of all events that cause more than 20,000 customer-minutes to be lost, or affect a major customer, to identify the root cause of the fault and to implement corrective actions to prevent reoccurrence;
- Car vs pole post incident investigation and reporting, and follow up actions with internal and external stakeholders such as Police and local roading authorities;
- Increased maintenance and replacement of overhead components in worst performing areas – as detailed in Section 5; and
- Investigating new tools and technology to identify fault locations to enable quicker restoration of consumers in affected sections of the network.

Our approach to Asset Management

Risk Management

Risk management and asset management are intricately linked. We recognise that risk management is an integral part of good management practice, corporate governance, and it is central to effective asset stewardship. Our risk management framework is aligned to the *ISO 31000:2009 Risk management – Principles and guidelines* standard and it ensures that all our risks are identified, understood and managed consistently across all levels of our business. Our risk management framework strengthens our asset management decision making and practices.

Public Safety Management System

Public safety is a critical component of our risk management framework. We adopt the requirements set out in NZS 7901:2008 *Electricity and gas industries – Safety management systems for public safety* to safeguard the public or their property from safety-related risks arising from the presence or operation of our network distribution assets.

Asset Management Framework

We have developed a high level Asset Management framework for Counties Power, which provides the linkage down the corporate objectives to our asset management activities, as shown below.



Asset Management Framework

Our Asset Management Policy links our Asset Management approach to our corporate objectives and details the Objectives, the Accountabilities and the Implementation considerations.

Our Asset Management Policy Objective is to “optimise the whole of life costs and the performance of the network to sustainably deliver safe, reliable and cost effective supply to our consumers”.

We have developed asset management strategies to deliver the requirements of the Asset Management Policy, these cover maintenance, replacement, and network development.

Maintenance Strategies

Maintenance comprises asset inspection; measurement, recording and assessment of condition and undertaking required corrective or preventative action to minimise risk and/or maximise performance. Our maintenance programme also includes reactive (fault) maintenance and vegetation management.

Replacement Strategies

As we are a rapidly growing network, large parts of the network around growth areas have been rebuilt over the past 20 years, and the eastern part of our network is relatively new compared to many other networks, however the western and southern parts will require significant replacement in the planning period as they have not benefited from growth related renewals.

Many of our major substation assets are approaching the end of their economic service life just as capacity and security constraints are becoming binding. This allows the assets to be replaced at the optimal time to maximise their service life by moving towards condition based replacement, and be upgraded to meet new capacity requirements at the time it is required.

Distribution assets are generally in the public domain and can present a risk to public safety. We inspect these assets to identify defects and undertake condition assessment to forecast when replacement will be required. Our objective is to replace these assets based on condition before they fail or present an unacceptable risk.

Network Development Strategies

As demand on our network grows we have to ensure it is able to meet our consumer's requirements for capacity, security and reliability.

We have developed security and planning criteria and assess the network against these for the reasonable growth forecast. This results in the identification of constraints and timeframes for investment. Our strategy is to ensure that the development options we select do not lead to over investment (too much), premature investment (too soon), or lead to a high risk of asset stranding. We also aim to get as much renewal benefit as possible when upgrading or replacing assets due to growth, and avoid the early write-off of assets before the end of their economic service life.

Investment Planning Process

Our network investment process consists of a sequence of decision making steps, used to ensure we make the correct investment decisions and have adequately considered alternatives. A high level overview of this process is shown below.



Investment planning process overview

When considering options for network risks and constraints, typically addressed by the construction or replacement of network assets, we also consider ‘Network Alternatives’ such as demand side management, distributed generation, and energy storage – an emerging area which is becoming rapidly more economic.

Asset Management Systems

There are a number of key systems used in the asset management process, as well as part of our wider business operation – including our ERP system Microsoft Dynamics NAV, our GE iFix SCADA system and GE Smallworld, our GIS tool. Supporting this are specialist packages such as DlgSILENT Powerfactory, AutoCAD and our suite of Field Computing tools used to capture field activity data.

Asset lifecycle planning

Major capital projects and programmes of work arising from asset lifecycle planning strategies are summarised below, by asset category. These are in addition to routine inspection and maintenance programmes (operational expenditure). Full details are covered in Section 5 of the 2018 Asset Management Plan

Subtransmission

- Refurbishment of the Maioro 33kV line towards the end of the planning period (2025/26), with an estimated cost of \$900,000 (dependent upon the future of the site).

Zone Substations

- Renewal of 33kV circuit breakers at Waiuku and the 11kV switchboards at Waiuku, Maioro and Mangatawhiri substations due to age and condition. Under this plan, these will be addressed through renewal and network development projects;
- Replacement of the 22kV switchboard at Opaheke substation in 2022/23 with an estimated cost of \$2 million due to condition and capacity constraints. Under this plan, this will be addressed through a network development project;
- Replacement of the 11kV switchboard at Maioro substation around 2024/25 with an estimated cost of \$350,000 due to condition;
- Rebuild of the Waiuku substation in 2018/19 and 2019/20 with an estimated cost of \$5.8 million due to condition and seismic risk, but also to address capacity constraints. Under this plan, this will be addressed through a network development project; and
- Disposal of the equipment at the old Tuakau 33kV zone substation in 2018/19 with an estimated cost of \$50,000, which has been superseded by the new Tuakau 110kV substation.

Distribution Overhead Lines

- Replacement of small diameter copper conductors (16mm², 25mm²) over the planning period, continuing in higher risk areas, with an estimated programme cost of \$16.3 million;
- Replacement of Swan ACSR conductor over the planning period, commencing in higher risk areas, with an estimated programme cost of \$10.9 million;

- Replacement of high voltage and urban low voltage overhead networks following condition assessment, commencing high voltage network replacement projects in Mangatawhiri and Waiuku and continuing low voltage network replacement projects in Pukekohe and Waiuku with an estimated programme cost of \$6.8 million; and
- Replacement of poles following inspection, focussing on hardwood, softwood and iron rail poles, and provision for additional replacement needs arising from over 2,200 poles identified in the 2017 survey and the change in policy relating to private HV line ownership from January 2018. An annual allocation of \$3.9 million has been made in 2018/19, decreasing to \$3.5 million from 2020/21 onwards.

Distribution Cables and Underground

- An ongoing condition based replacement programme for distribution cables, with an annual allocation of \$200,000; and
- An ongoing condition based replacement programme for LV distribution pillars and pits, with an annual allocation of \$170,000.

Distribution Substations and Transformers

- An ongoing condition based replacement programme for distribution transformers, with an annual allocation of \$590,000, increasing to \$730,000 in 2020/21 and 2024/25 in conjunction with renewal of Andelec and Hazemeyer Ring Main Units;

Distribution Switchgear

- Replacement of Andelec and Hazemeyer Ring Main Units over a period of 9 years, with a programme budget of \$1.7 million; and
- Replacement of Air Break Switches and remote control units, with a programme budget of \$4.1 million over the planning period.

SCADA and Communications Equipment

- Radio communication, protection and control renewal, with an annual allowance of \$100,000;
- Remote Terminal Unit (RTU) replacement programme, with an estimated cost of at \$75,000 in 2018/19 and \$70,000 in 2019/20 and an annual allowance of \$20,000 to 40,000 throughout the planning period; and
- SCADA Master Station renewal in 2019/20 and 2020/21, with an estimated cost of \$300,000 unless superseded by a new ADMS system or other technology.

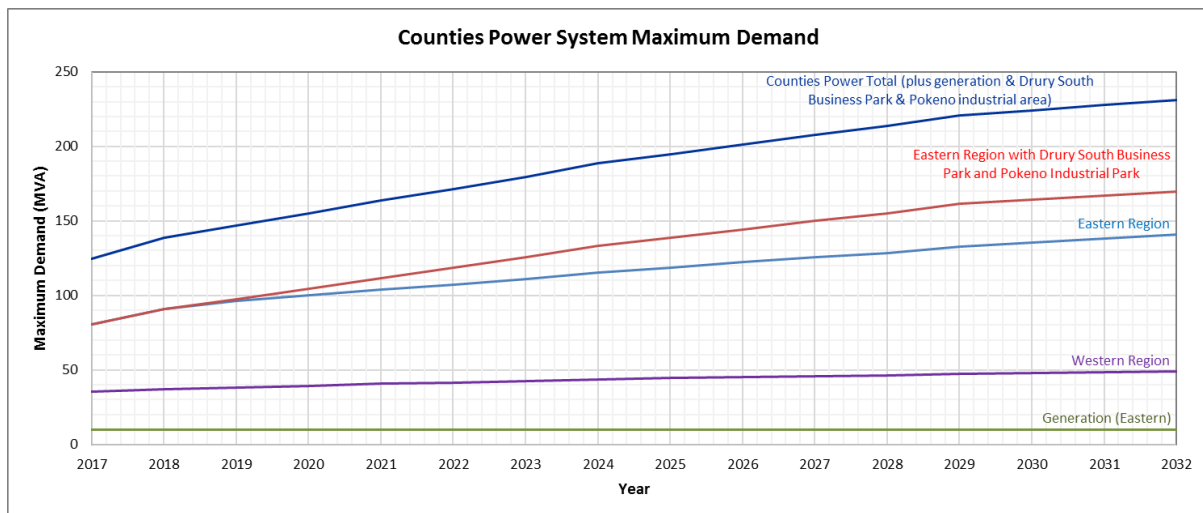
Protection, Load Control and Auxiliary Battery Equipment

- Replacement of under-frequency relays at various sites in 2019/20 with an estimated cost of \$400,000, and feeder protection relays at Karaka substation in 2021/22 with an estimated cost of \$200,000; and
- Replacement of the battery chargers at substations and communication sites in 2018/19 estimated at \$120,000, and annual allowance of \$20,000.

Network development planning

Demand forecast

The maximum demand on our system is the main driver for investing in our network. Our demand forecast defines future network requirements and is a key input into determining the appropriate timing for capacity and security related investment in our subtransmission and distribution networks for the AMP period.



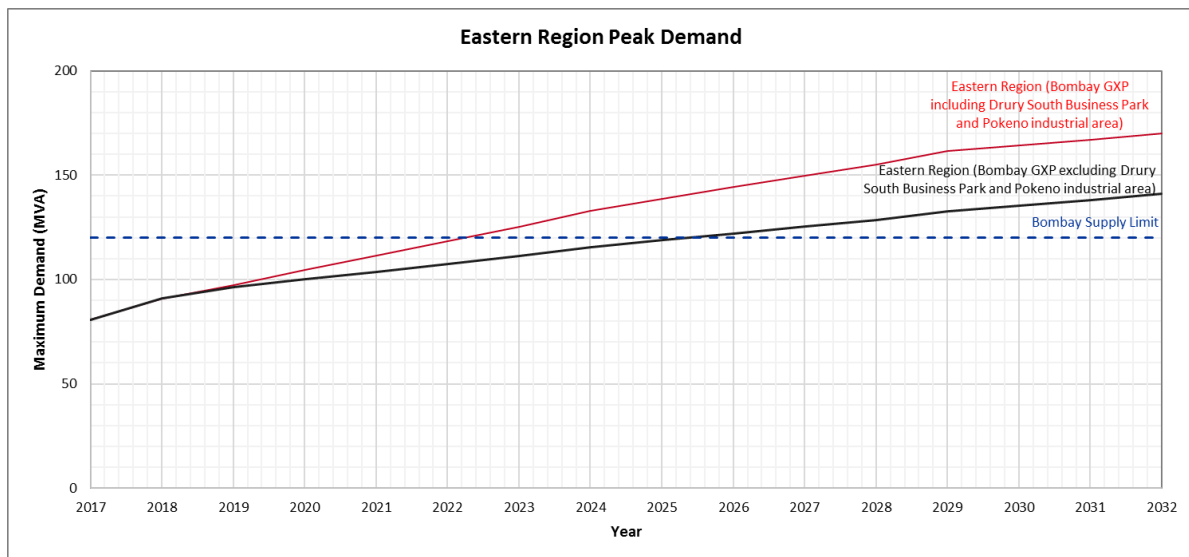
Winter maximum system demand forecast

Of particular note, Auckland Council's Future Urban Land Supply Strategy could result in a significant increase in demand in our area over the next 30 years. We have included the potential impact of Auckland Council's draft plan and any other known development in our area when developing our network development plan, although we have treated the Drury South Business Park development separately given its potential magnitude and sensitivity to assumptions regarding reticulation timeframes and the nature of the load.

Eastern Region Development Plans

The Eastern Region is supplied from Transpower's Bombay Grid Exit Point and covers areas supplied by our Opaheke, Pukekohe, Tuakau, Mangatawhiri and Ramarama Zone Substations.

The figure below shows the demand forecast for the Eastern Region.



Winter maximum demand – eastern region

We currently have three proposed regional development programmes within the Eastern region:

- Drury South Business Park supply (refer to section 6.4.2 of the 2018 Asset Management Plan): relocate a section of the Bombay to Opaheke 110kV East line, develop our network to supply the proposed Drury South Business Park by building a new 110kV Drury South Area Substation and feeders and reconfiguring our network to supply the proposed new development and surrounding area. This is expected to occur in 2018/19 for the line relocation, and 2023/24 for the substation and feeder development at an estimated cost in the order of \$24 million;
- Pokeno Industrial area supply (refer to section 6.4.3 of the 2018 Asset Management Plan): upgrade existing feeders, install a new 22kV feeder from Tuakau substation, and install a third transformer at Tuakau substation. This is expected to occur in stages from 2019/20 at an estimated cost in the order of \$6 million;
- Eastern Supply Project (refer to Section 6.4.7 of the 2018 Asset Management Plan): further development our network area currently supplied by the Mangatawhiri and Ramarama substations. This project is expected to occur in 2021/22 for an estimated cost in the order of \$12 million. The development work includes:
 - converting our subtransmission network in the area to 110 kV;
 - building a new 110 kV Bombay Area Zone Substation in the vicinity of the Bombay GXP to replace the Mangatawhiri and Ramarama substations; and
 - converting our distribution network in the area to 22kV operation.

In addition to these large scale development programmes, there are major projects identified within the planning period at the following locations.

Opaheke

Our development plan for Opaheke Zone substation is to:

- Replace the two existing 20/40MVA transformers with two new 30/60MVA transformers in 2024/25, at an estimated cost of \$2.8 million.

Our development plan for Opaheke Zone Substation Feeders is to:

- Replace two RMUs on the Red Hill feeder with new units including circuit breakers in 2018/19, at an estimated cost of \$160,000 to improve supply reliability through more effective fault isolation;
- Rebalance load between Beach Rd, Blackbridge Road and Hingaia feeders in 2020/21 by utilising existing switches to increase Hingaia feeder backfeed capacity;
- Convert the Papakura South feeder to 22kV operation in 2020/21, at an estimated cost of \$310,000, to be carried out in conjunction with condition based replacement of distribution switchgear on the feeder;
- Install a new 22kV feeder and replace the 22kV switchboard at Opaheke substation in 2022/23, at an estimated cost of \$2 million, which will also address the condition issues of the switchboard;
- Upgrade sections of Drury and Drury Hill feeders for Drury South Business Park development in 2021/22, at an estimated cost of \$2 million;
- Upgrade the Bremner Road to Norrie Road section of the Drury feeder in 2024/25 at an estimated cost of \$170,000 to increase backfeed capacity to Anchor Factory feeder; and
- Upgrade the Hingaia Road section of the Hingaia feeder in 2025/26 at an estimated cost of \$270,000 to increase backfeed capacity to Anchor Factory feeder.

Pukekohe

Our development plan for Pukekohe Zone Substation Feeders is to:

- Utilise existing sectionalisers and upgrade sections of conductor on urban feeders to transfer high density residential load away from rural feeder sections across the planning period, at an estimated cost of \$50,000 per annum;
- Install a new recloser on Railway feeder in 2019/20, at an estimated cost of \$25,000 to improve supply reliability;
- Upgrade a section of Pukekohe West feeder in 2021/22, at an estimated cost of \$300,000 to increase backfeed capacity to Pukekohe Town feeder.

Tuakau and Pokeno

Our development plan for Tuakau Zone Substation Feeders is to:

- Final stage of visual impact mitigation on the Bombay – Tuakau 110kV line, involving planting along the rail corridor and a 110kV pole relocation at a private property, as part of the stakeholder management plan for the 110kV line corridor in 2018/19, at an estimated cost of \$175,000;

- Establish a backfeed to River Road feeder sections from Port Waikato feeder and Church Corner feeders in 2018/19, at an estimated cost of \$635,000 to provide backfeed to industrial load expansions;
- Rebuild front end sections of Whangarata and Hitchen Road feeders along Whangarata Road in 2018/19, at an estimated cost of \$990,000 to improve reliability;
- Rebuild and reroute a section of 22kV line from Tuakau to Pukekawa switching station (new Pukekawa trunk feeder) in 2018/19, at an estimated cost of \$1 million, to improve security to Pukekawa switching station, and to address age and condition concerns of the existing line; and
- Upgrade auto-transformers and install voltage regulators on Port Waikato and Glen Murray feeders in 2019/20, at an estimated cost of \$800,000 to increase backfeed capacity.

Battery Energy Storage Trial

One of the network alternative technologies which has the potential to change how distribution networks traditionally operate is energy storage through the use of grid scale battery storage system.

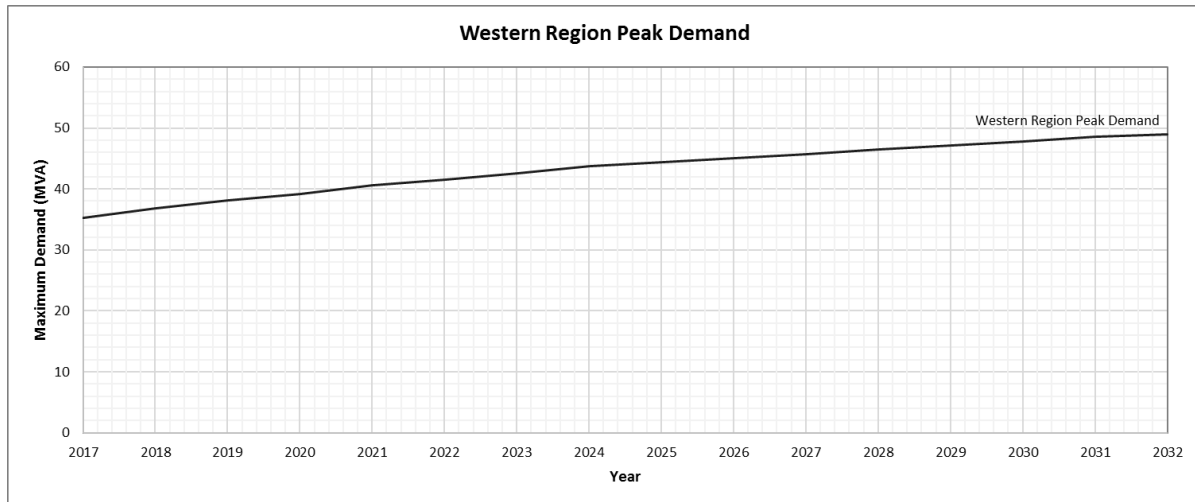
We installed our first grid-scale battery storage system at the Tuakau Zone Substation in 2017. This trial installation is to understand the benefits such systems can provide including management of peak demand, contributing to quality of supply in our network through reactive power support, and to provide ancillary services. While the battery trial has specific objectives, it will more broadly enable better understanding of its impact on the network, its limitations, and the benefits it can provide across the whole network over time.

At the time of writing this AMP, we consider the battery to be able to provide both regulated benefits (in terms of network support and peak demand management on the distribution network), as well as unregulated benefits (such as value from the arbitrage of energy when not used for regulated purposes). As such we discuss the use of the battery in this AMP in the context of our regulated activities however we are working to develop a cost allocation methodology to provide a transparent means of reporting how we use the battery and allocate respective costs and benefits.

Western Region Development Plans

The Western Region is supplied from Transpower's Glenbrook Grid Exit Point and covers areas supplied by our Karaka, Maioiro and Waiuku Zone Substations and a 33kV point of supply at Storey Road.

The figure below shows the total Western Region forecast demand.



Winter maximum demand – western region

Karaka

Our development plan for Karaka Zone Substation Feeders is to:

- Install voltage regulator on Waiau Pa feeder in 2018/19, at an estimated cost of \$130,000 to increase backfeed capacity to Glenbrook Beach;
- Reconductor a section of the Blackbridge feeder and convert to 22kV operation, in 2019/20, at an estimated cost of \$1.15 million. This investment will provide more system flexibility by enabling us to backfeed load from large subdivision developments in the Opaheke and Pukekohe north areas;
- Install a voltage regulator at switch 47 along the Te Hihi feeder in 2021/22, at an estimated cost of \$130,000 to accommodate the identified load growth due to development around Kingseat;
- Convert Waiau Pa feeder to 22kV in 2021/22, at an estimated cost of \$1.0 million to address capacity and voltage constraints due to identified load growth at Clarks Beach and Glenbrook Beach;
- Reconductor a section of the Blackbridge feeder in 2024/25, at an estimated cost of \$400,000 to increase backfeed capacity to large subdivision developments in the area; and
- Convert part of Te Hihi feeder to 22kV in 2026/27, at an estimated cost of \$1.25 million to address identified load growth from development around Kingseat.

Waiuku

Our development plan for the Waiuku Subtransmission network is to:

- To reconductor the 33kV East line from Glenbrook to Waiuku with higher rated Cockroach conductor in 2022/23 at an estimated cost of \$1.2 million.

Our development plan for Waiuku Zone Substation is to:

- Redevelop the Zone Substation which has capacity, age and condition issues with a new substation on the same site over two stages in 2018/19 and 2019/20 at an estimated cost of \$5.8 million.

Our development plan for Waiuku Substation Feeders is to:

- Upgrade a section of Glenbrook feeder and install a voltage regulator in 2018/19, at an estimated cost of \$400,000 to increase backfeed capacity;
- Install a voltage regulator on Manukau Heads feeder in 2018/19, at an estimated cost of \$260,000 to increase backfeed capacity to the end section of the Te Toro feeder;
- Upgrade sections of Te Toro and Manukau Heads feeders, and install a second voltage regulator on Te Toro feeder in 2020/21 at an estimated cost of \$1.04 million to increase backfeed capacity on the front sections of the two feeders;
- Install a second voltage regulator on Glenbrook feeder in 2020/21, at an estimated cost of \$130,000 to address to identified load growth in Clarks Beach and Glenbrook Beach area; and
- Rebuild the tie section of Waiuku Town and Te Toro feeders in 2021/22, at an estimated cost of \$500,000 to increase backfeed capacity to the Waiuku Town feeder.

Maioro

Our development plan for Maioro Substation Feeders is to:

- Install a voltage regulator on the Otatau feeder in 2021/22, at an estimated cost of \$130,000 to address voltage constraints along the feeder.

Investment forecasts

Network and Non-Network CAPEX Forecast

	FY2019	FY2020	FY2021	FY2022	FY2023	FY2024	FY2025	FY2026	FY2027	FY2028
Consumer Connections	10,000	10,000	10,000	10,000	10,000	8,000	8,000	8,000	8,000	8,000
System Growth	6,990	6,460	6,445	10,130	5,925	11,255	7,595	8,895	3,975	725
Asset Replacements	11,295	11,550	11,335	10,080	9,710	10,360	10,910	10,605	10,180	9,150
Asset Relocations	3,225	300	300	300	300	300	300	300	300	300
Reliability, Safety and Environment										
Quality of Supply	1,350	350	350	350	350	350	350	350	350	350
Legislative and Regulatory		400								
Other Reliability, Safety, Environment	295	395	200	200	200	200	200	200	200	200
Subtotal Network	33,155	29,455	28,630	31,060	26,485	30,465	27,355	28,350	23,005	18,725
WIP carry-over from FY2018 to FY2019	2,761									
WIP carry-over from FY2019 to FY2020	-	2,000	2,000							
Non Network	2,450	2,450	2,350	2,350	2,350	2,350	2,350	2,350	2,350	2,350
TOTAL	36,366	33,905	30,980	33,410	28,835	32,815	29,705	30,700	25,355	21,075

Network OPEX Forecast

Asset Category	FY2019	FY2020	FY2021	FY2022	FY2023	FY2024	FY2025	FY2026	FY2027	FY2028
Service interruptions and emergencies	1,900	1,900	1,900	1,900	1,900	1,900	1,900	1,900	1,900	1,900
Vegetation management	1,100	1,100	1,100	1,100	1,100	1,100	1,100	1,100	1,100	1,100
Routine and corrective maintenance and inspection	1,350	1,350	1,350	1,370	1,370	1,380	1,380	1,380	1,380	1,380
Asset replacement and renewal	800	570	500	370	380	280	280	280	290	320
Total	5,150	4,920	4,850	4,740	4,750	4,660	4,660	4,660	4,670	4,700

Note: Forecasts are stated in real (constant) prices

1 Introduction

This chapter introduces our 2018 Asset Management Plan (AMP) and covers:

- **Purpose:** provides the reasons for producing this AMP, the period it covers, the date it was approved by our Board of Directors (Board), and the assets it covers:
- **Key Themes and Initiatives:** A summary of the key themes and initiatives that have been described in this AMP: and
- **Document Structure:** an outline of this AMP and how it is structured.

1.1 Purpose

The purpose and objective of our asset management practices and this AMP is to assist us in managing our assets over their lifecycle in an efficient, effective and sustainable manner in order to provide a level of service that our consumers want and for which they are willing to pay. This AMP is a vital planning document as it focuses our decisions and activities so that our assets provide enduring value to our consumers, our stakeholders and ourselves. It illustrates how our asset management objectives are aligned to our corporate objectives, mission and values.

We apply a disciplined and consistent approach to the management of our assets, so that we can attain our corporate mission of being a progressive and successful community owned electricity distribution business with the aim of delivering safe, reliable, and cost effective electricity to our consumers. Our asset management approach converts our corporate objectives of operating a safe network, meeting consumer needs and maximising shareholder returns; into technical and financial decisions, plans and activities. This AMP links with our other documented plans that are a part of our business planning process. These documents are our Statement of Corporate Intent, Strategic Plan, and our annual budget.

1.2 Period covered

This AMP covers the period from 1 April 2018 through to 31 March 2028 (AMP period). As with any long term planning document, greater detail has been included for the first five years. Planning for the outer period is directional.

1.3 Approval date

This AMP was approved by our Board of Directors on 21 March 2018.

1.4 Scope

This AMP covers all network equipment and non-network solutions involved in the distribution of electricity to consumers who are connected to our network.

1.5 Document structure



Chapter 2 – Overview of Counties Power – this section provides a brief background of Counties Power, our organisation, our operating environment, outlines who our stakeholders and consumers are, and an overview of our network.

Chapter 3 – Service Levels – this section provides an overview of the service levels we expect to provide to our stakeholders, and which inform our asset management decision making.

Chapter 4 – Approach to Asset Management – this section provides an overview of how we go about asset management at Counties Power, and describes our framework and processes for making investment decisions, including our approach to risk management.

Chapter 5 – Renewals and Maintenance – this section provides a more detailed overview of our assets by category, and includes our plans on how we inspect, maintain and replace them.

Chapter 6 – Network Development – this section provides details on how we forecast our network demand, the capacity of our network to manage that demand and the constraints identified, and includes our plans on how we are going to develop the network to address future growth.

Chapter 7 – Non-Network Investment Plan – this section provides details on the investments we will make in non-network equipment such as land and buildings, IT equipment, tools, vehicles and machinery.

Chapter 8 – Expenditure Summary – this section summarises all the operational and capital expenditure identified in Chapter 5, 6, and 7 for the 10-year period covered by this plan.

Chapter 9 – Evaluation of Performance – this section assesses performance against previous plans as part of our continual improvement in asset management and overall business performance.

Appendix A to F provides a glossary of terms, a summary of performance against previous plans, the information disclosure schedules, and director certification.

2 Overview of Counties Power

2.1 Our company

Counties Power owns, manages and operates an electricity distribution network in southern Auckland, Waikato and Hauraki district areas with a system length of 3,200 km covering an area of approximately 2250 km². The Auckland Council area covers 830 km² (37%) of the Counties Power network, the Waikato District covers 1340 km² (60%), and the Hauraki District covers the remaining 80 km² (3%). We receive power from the national grid at the Bombay and Glenbrook Grid Exit Points (GXPs) and then transport it to our consumers via eight zone substations and our extensive network of lines, cables, transformers and other equipment.

2.1.1 Ownership and governance

Counties Power is 100% consumer owned. All shares are held by the Trustees of the Counties Power Consumer Trust (Trust) on behalf of all local power consumers. The Trust has a total of five Trustees, of which two are required to be elected every two years. Counties Power is managed for the benefit of its consumers and their communities. The Trust oversees the performance of Counties Power through the appointment of a Board of Directors (Board). The Board and Management of Counties Power consult the Trust on our strategic direction, business plans, and asset management measures and targets. Information about the Trust can be obtained from www.countiespowertrust.co.nz.

2.1.2 Ownership and governance

Objective

Our objective is to operate Counties Power as a successful electricity distribution and service business, ensuring that the necessary strategies are implemented to maintain an environment of zero harm for our staff, consumers and the communities in which we operate, to provide a reliable service that meets consumer needs and to achieve sustainable and superior shareholder value.

To achieve this objective, we will embrace the concepts of quality, safety and environmental responsibility in all elements of our business. The safety of our staff, our contractors and the communities in which we operate is our top priority. We are committed to continually providing a quality service at competitive prices for the benefit of our consumers. We will continue to invest prudently in developing our assets, focus upon excellence in our core business, deliver on our targets and foster a philosophy of continuous improvement.

Mission

Counties Power's mission is to be a growing and successful consumer-owned electricity company that provides safe, reliable and cost effective electricity to our consumers, always.

Values

Our values drive how we work and interact. They keep us focused and guide our decisions as we deliver on our objectives and mission. Our values are:

Safe: We deliver on our commitment to safety and our duty of care for our people and the public, always.

Dedicated: We take pride in what we do, our expertise and the level of service we offer.

Reliable: We can depend on each other and the community can depend on us.

Smart: We work hard, share ideas and adapt to meet the challenges of our evolving industry.

Dynamic: We are forward thinking and progressive in our approach.

Informing Asset Management Practices

Our objective, mission and values steer our priorities and activities. They also provide the framework for our business and asset management practices. In particular, they inform our asset management practices by having safety as our top priority. Our service levels help link the company vision to the expectations of consumers and to assist us in measuring and improving performance.

2.1.3 Corporate and organisation structure

The Counties Power Board is responsible for the overall governance of the business, including approval of the company strategy, business plans and annual budgets. The Directors are appointed by the Counties Power Consumer Trust. The Board reports to the Trust on a quarterly basis.

The Chief Executive is responsible for leading the business, implementing the company strategy and is accountable for business performance.

The Leadership Team reports to the Chief Executive, and is responsible for specific areas of the business operation as shown in the diagram below.

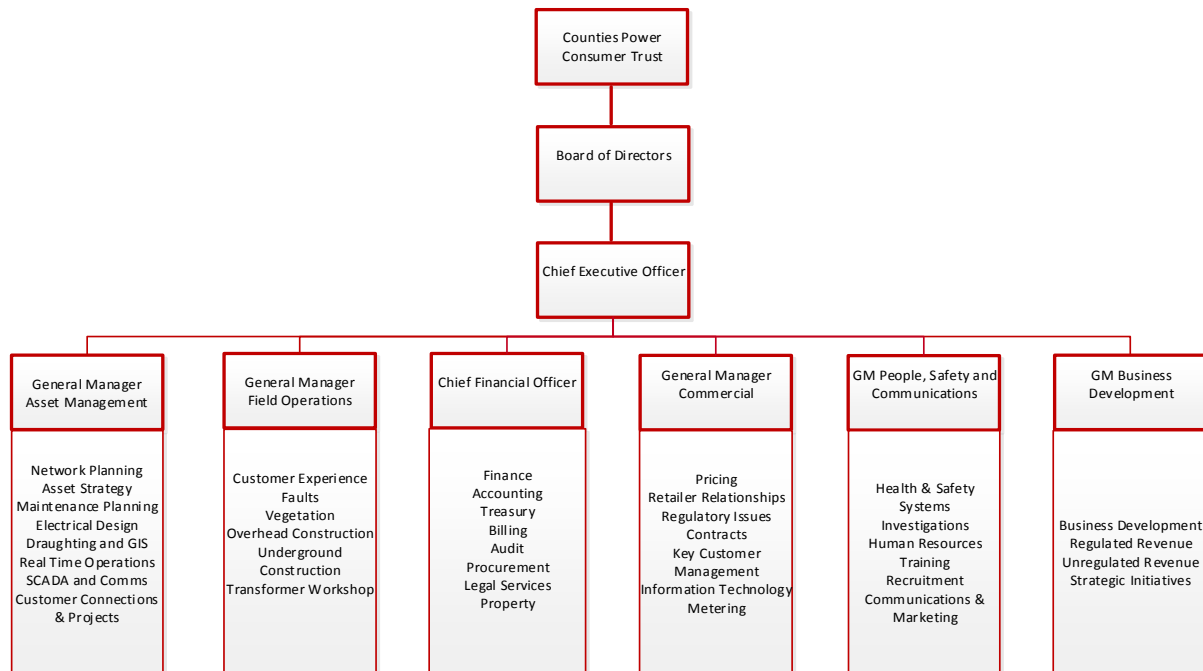


Figure 2-1 Overview of company governance and Management

The General Manager Asset Management is accountable for the asset management function in the business, including developing network planning and asset strategies, compiling and delivering annual plans for operational expenditure and capital investment, as well as the control and operation of the network to ensure the ongoing operation of the network meets safety and reliability expectations.

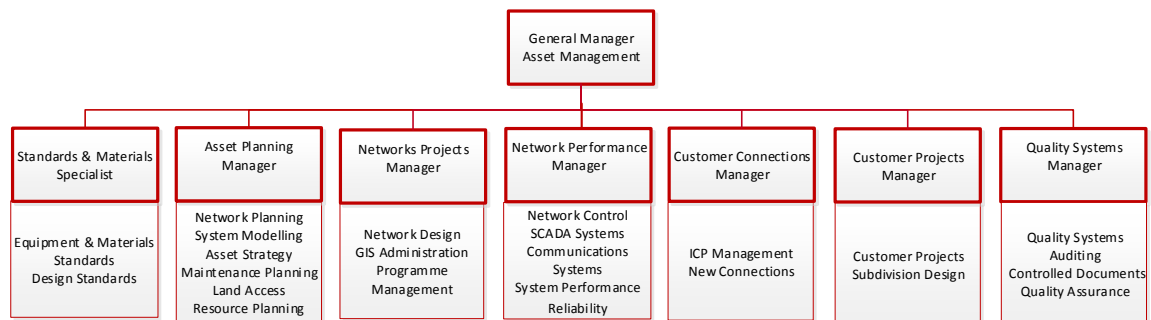


Figure 2-2 Overview of Asset Management Team

The General Manager Field Operations is accountable for the safe and cost effective field delivery of annual plans and work programmes, including routine and corrective maintenance, asset replacement, construction of new network, fault dispatch and response, customer services, and vegetation management.

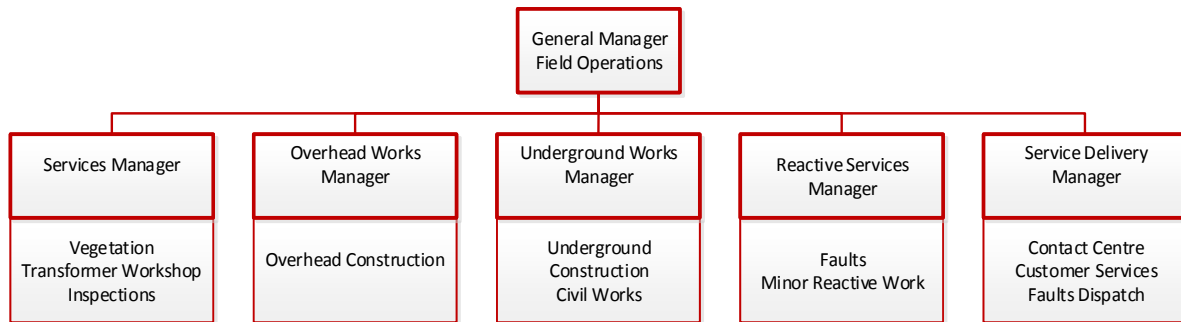


Figure 2-3 Overview of Field Operations Team

2.1.4 Asset management governance

Expenditure Approvals

The Board of Directors approves the annual budgets for operational and capital expenditure and delegates authority to the Chief Executive to approve the expenditure within a delegated authority framework, which is reviewed annually. Each major initiative or project is then subject to a robust business case and options analysis process before being recommended by the sponsoring executive for investment. The Chief Executive delegates authority to management to approve expenditure of a lower level in line with the requirements of the position and responsibilities.

All projects over \$100,000 are reported to the Board on a monthly basis, and all major projects are subject to a post implementation review to ensure objectives and targets have been achieved.

Any project variations which incur a cost increase or material time delay are managed within the approval delegated authority level, and reported to the Board as necessary.

Asset Management Capability

In order to deliver this plan, Counties Power has to ensure that appropriate skills and capability are available within the business.

Counties Power undertakes the majority of asset management activities in-house, using its own employees. As shown in the organisation structure diagrams earlier in this section, the Asset Management and Field Operations teams develop and deliver this plan, with the support of the Finance, Commercial, and People and Performance teams.

Some activities are outsourced to meet peak capacity requirements, or where it is not efficient to have specialist skills within the team. Examples of specialist services sourced externally include land and resource planning, specialist engineering and advisory consultants, and some field services such as specialist equipment repairers and protection technicians. A robust contractor assessment and approval framework provides assurance of safety, technical and capability competency before work commences and forms part of the ongoing contractor performance assessment framework.

Alongside maintaining worker competency, the training and development of staff is critical to the success of the business, and identifying areas where new skills requirements or development pathways exist.

Through the development of a rolling 10-year plan, Counties Power is able to identify the upcoming work types and volume, and assess the requirements for resources, capability and capacity.

2.2 Operating environment

Network Overview

The Counties Power network is a provincial ‘town and country’ network distributing electricity across a broad geography in Auckland’s south, and the northern Waikato region. Today, 70% of the Counties Power network is a rural overhead network by length, however the urban networks supplying Pukekohe, Waiuku, Tuakau, Pokeno, Drury and parts of Papakura comprise a split of overhead and underground assets. Generally, the eastern part of the network is newer, higher in ICP density and subject to high levels of growth in the areas adjacent to motorway and state highway corridors. The western side of the network is older, more remote, lower density and subject to little growth.

Network performance is consistent with a largely rural network topology, largely owing to long restoration times associated with the remote Manukau Heads, Port Waikato and Kaiaua supply areas. Increasing levels of network automation are improving response times. When compared to a peer group of similar networks, the network has historically been one of the better performing rural/urban networks in New Zealand, but in recent years has experienced increasing levels of faults due to aging overhead network assets, the increasing frequency and severity of weather events, and operational decisions which have led to a decrease in live work and changes to reclose rules which have contributed to unfavourable network performance. Programmes of works outlined in this plan are intended to address these identified network performance issues.

The Counties Power network is exposed to normal climatic variation including temperature, wind and rain variances. The severity and frequency of adverse weather events is noted to be increasing, with short sharp bursts of wind and rain causing damage directly to the network, or causing debris to be blown onto lines.

Assets exposed to the harsher weather and environmental conditions of the Awhitu Peninsula are also subject to more frequent failures, and have lower expected life spans. Similarly, in some areas overhead assets are located on exposed ridge lines, or are in difficult terrain to access and maintain.

Vegetation management is another area of concern to Counties Power. Areas such as Ararimu and Hunua are heavily vegetated which leads to high numbers of tree related outages, and in particular blown vegetation over which Counties Power has little control. A common problem in the area is gum bark which is blown onto lines, causing momentary outages. Counties Power and our vegetation management contractors liaise with the relevant local authorities and landowners concerning trimming of trees in accordance with the *Electricity (Hazards from Trees) Regulations 2003*.

Territorial Authorities

Counties Power serves the area previously known as the Franklin District. This district was split with the formation of the Auckland Council in 2010, and the Auckland Council is responsible for administration of approximately 40% of the area, with the remainder split across Waikato District and Hauraki District Councils.

Auckland Unitary Plan

The Auckland Unitary Plan Operative in part AUP(OP) came into effect on November 2016. Certain parts of the plan have been excluded from being operative, because they are either subject to Environment Court and High Court appeals or they require the approval of the Minister of Conservation. Once all appeals are resolved and approvals given, the Council will notify the date on which the Auckland Unitary Plan will become fully operative.

The AUP(OP) has a single infrastructure chapter, designed with network utility operators in mind, which will impose new requirements and restrictions on the way Counties Power builds, operates and maintains its network going forward. Some work will be required in the interpretation of the new requirements at least in the initial stages, and updating our works processes and practices. Our work processes and practices are being updated for routine work activities to align with the updated requirements in the AUP(OP). Some of the maintenance and network development activities are subject to additional requirements on controls and compliance. These new requirements have potential to add costs and complexity to future maintenance and development of the network. Experience to date has identified these requirements will only apply in exceptional circumstances. These effects are not factored into costs stated in this AMP.

Waikato District Plan

In the Waikato District Council and Hauraki District Council areas, the requirements for Counties Power's operations, maintenance and development, and are still based on the former Franklin District Plan. A review of the Waikato District Plan has continued in 2017 and will be publicly notified in May 2018. This will ultimately integrate the Franklin District section into a single plan covering the whole of the Waikato District Council area.

Growth – present and future

The Counties Power network is one of the fastest growing electricity networks in New Zealand with connection growth in the order of 3% per annum. This is largely driven by the growth of Auckland and our location within the 'golden triangle' of growth between Tauranga, Hamilton and Auckland.

The population of the area grew by 11.5% between the 2006 and 2013 census periods. Auckland was the fastest growing region, increasing by 8.5% over the same period. Waikato district was ranked in the top 10 territorial areas with a 10.1% population growth. The Hauraki district population decreased slightly overall, however the Kaiaua area population growth increased by 19% (an area which is supplied by Counties Power).

Population growth trends within the Counties Power area are monitored in terms of building consent applications and new connections. The figures produced by Statistics New Zealand for annual population change support high growth projections in our area.

The largest contributor to demand growth in the medium term is expected to be industrial and residential developments around Tuakau, Pokeno, the approved Special Housing Areas at Paerata Rise, the proposed Drury South Business Park, and the Drury and Hingaia areas.

It has long been recognised that the growing population in Auckland is placing increased demands on land for housing, employment and associated infrastructure in the Auckland and neighbouring regions. To promote efficient urban development, while at the same time protecting natural and physical resources, the AUP(OP) has identified land which is potentially suitable for urban development and has defined its limit by means of the Rural Urban Boundary (RUB). The RUB, which gives effect to the AUP(OP)'s Regional Policy Statement regarding urban growth and form, contains sufficient appropriately zoned land within its boundary to accommodate a minimum of seven years of projected growth at any one time in terms of residential, commercial and industrial demand, as well as corresponding requirements for social facilities. Development of land beyond the RUB such as that proposed at Clarks Beach and Glenbrook Beach can only be achieved through a formal plan change process, thereby providing utility operators the opportunity to comment on the ability to supply the new development and identify any required upgrade. Maps outlining the RUB impact are provided in Section 6 Network Development Planning.

The supply and delivery of development ready land for housing and industrial growth is an important planning issue for Auckland. Figure 2-4 shows the anticipated dwelling capacity in future urban areas from the Greenfield Areas identified in the Auckland Plan Development Strategy, the future urban zoned land identified within the RUB area in the AUP(OP), and both of the large future urban and Rural Settlement in future urban areas identified in the Auckland Future Urban Land Supply Strategy (FULSS)³. While the timing of these developments is still uncertain, this provides information on the order of magnitude for anticipated dwelling capacity in our network development planning.

Anticipated dwelling capacity for future urban areas 2017 - 2042			
New greenfield areas	Auckland Plan growth projections (2015)	Auckland Unitary Plan (AUPOP)	Auckland Future Urban Land Supply Strategy (2017)
South (Hingaia, Opaheke, Drury, Karaka, Paerata, Pukekohe) FLUSS area (Clarks Beach, Glenbrook Beach, Kingseat, Patumahoe, Karaka North)	55,000	33,000 – 42,000	42,900

Figure 2-4 Anticipated dwelling capacity for future urban areas

Special Housing Areas

The Special Housing Areas which were initiated to help maintain a ready supply of housing land during the preparation and development of the Auckland Unitary plan have been progressively disestablished since the Unitary Plan became operative (in part) in September 2016. Construction has already commenced on many of these sites within the Counties Power area including sites at Belmont, Pukekohe and Hingaia, McLarin Road, Glenbrook, Paerata Rise and Bremner Road, Drury. Whilst the final SHA was disestablished in May 2017, private plan changes such as the Bremner Road extension will mean that development sites will continue to be brought forward.

³ The primary purpose of FULSS is to identify the sequencing and timing of the future urban zoned land identified in the AUPOP and how it should be brought forward for development over the next 30 years based on zoning and infrastructure constraints. The FULSS has includes development within rural urban areas of Clarks Beach, Glenbrook Beach, Kingseat, Patumahoe and Karaka North in addition to future urban zones areas within the RUB at Hingaia, Opaheke, Drury, Karaka, Paerata and Pukekohe.

Regulation

Counties Power, as an electricity distribution business, is subject to regulation by the Commerce Commission, under Part 4 of the *Commerce Act 1986*. Due to the ownership structure, it is exempt from the Default Price-Quality Regime, as the consumers are the beneficial owners through the Counties Power Consumer Trust, however it is still required to comply with the Information Disclosure Requirements, of which this AMP is one requirement.

The business is also regulated by the Electricity Authority and is subject to compliance with the *Electricity Industry Participation Code*, both as a distributor and also as a metering equipment provider.

Regulatory changes imposed by the Electricity Authority on other industry participants, such as Transpower, can have a consequential effect on the business, such as the method for determining transmission pricing.

In addition to economic and industry regulation, Counties Power has a range of legislative requirements to meet including *Electricity Act 1992*, the *Electricity (Safety) Regulations 2010*, the *Health and Safety at Work Act 2015*, the *Electricity (Hazards from Trees) Regulations 2003*, amongst others.

2.3 Consumer value and cost reflective pricing

Counties Power's capital and operating expenditure is continuing to grow as its network expands at a time when peak demand is growing twice as fast as sales volume and where average usage per consumer is decreasing. The combination of Counties Power's current volume based pricing, and the fact it has chosen not to increase either line prices or its own distribution prices to its consumers for the 4 years between 2015 and 2018 in an endeavour to improve consumer value, means that distribution revenue per consumer is also decreasing.

As with any electricity lines company, however, most of the company's costs of providing distribution network access are fixed and are associated with building and maintaining infrastructure that can meet peak demand; the variable cost component is driven by the consumer's winter peak demand requiring additional distribution capacity and associated transmission charges. Because consumer volume is increasing at a lower rate than the consumer peak demand is increasing this creates a mismatch between revenue received and costs incurred. Counties Power's current lines charges to its consumers are not directly cost-reflective.

The Company believes that moving to a more cost reflective structure will enable consumer choice and control and ensure fairer pricing to all customers. For these reasons, the Electricity Authority has also instructed all line companies to introduce cost reflective pricing. To do this Counties Power introduced prices that are higher at peak times and lower off-peak. This then sends clear price signals to consumers to reduce their peak time use and save money and reduce costs to Counties Power. It also gives the choice to customers that if they use power during peak times they still can but they have to pay more to cover the higher costs to Counties Power.

As a consequence, in 2014 Counties Power introduced smart tariffs that provided peak, off-peak and shoulder pricing options for residential and business customers. No retailers opted to use this tariff, and so on 1 April 2016 Counties Power aligned the tariff to Vector's mass market peak and off-peak tariff to encourage retailer uptake. To date, only one retailer opted to use the tariff but this is expected to change in the future as the industry moves to the cost reflective pricing.

2.4 Stakeholders

Our stakeholders are the people or organisations that can affect, be affected by, or perceive themselves to be affected by our decisions or activities. Stakeholder requirements are important to us and we place considerable focus on identifying and meeting stakeholder expectations. Our stakeholders are described in Figure 2-5 below, along with their requirements, how those requirements are identified and how they are incorporated into our asset management practices.

Stakeholder	Requirements	Identification of Requirements	Requirements Incorporated into Asset Management Practices
Consumers	Safety; Reliable supply of electricity; at an acceptable quality and price; Effective communication particularly during emergencies and faults; Care of the environment; and Lifelines preparedness.	Meetings; Consumer focus groups; Annual surveys; Special surveys for projects; and Feedback.	Public safety initiatives; Service level targets; Investment in network; Price/Quality trade off; Consumer engagement process; Network development projects for subdivisions and network extensions; and Asset Fleet Management.
Public, Community, Iwi and Landowners	Safety; Lifelines preparedness; Care of the environment; Mana Whenua values and engagement; Protection of property and amenity values; Reconciling land development opportunities with infrastructure routes; and Effective communication regarding access and maintenance.	Meetings; Feedback; and Consultations.	Public safety initiatives; Network Development Planning; Service level targets; and Emergency preparedness planning.
Local Authorities	Alignment with district and regional planning requirements; and Accommodation of population and industrial growth arising from land use changes.	Meetings; and Consultations on appropriate infrastructure development and regional and district plans.	Network Development Planning to ensure planned growth can be accommodated within the identified zones; and Emergency preparedness planning.
Electricity Retailers	Fair contractual arrangements; Transparent, clear billing; suitable tariff structures; and Effective delivery of business to business services.	Industry forums, conferences and seminars Regular consultation; Electricity Industry Participation Code; and Use of System Agreements.	Service level targets; and Network Development Planning.

Stakeholder	Requirements	Identification of Requirements	Requirements Incorporated into Asset Management Practices
Regulators and Governmental Agencies	Statutory and Regulatory Compliance; and Ensure consumers receive a reliable supply of electricity at an acceptable quality and price.	Legislation and Regulations; Consultations; and Industry forums, conferences and seminars.	Network Development Planning; and Service level targets.
Transpower (as Grid and System Operator)	Security of supply; New grid investment and planning provisions; Effective and timely communication; Legislative and Regulatory compliance; and Sustainable earnings from connected and interconnected assets.	Operational standards and procedures; and Regular meetings.	Network Development Planning.
Board of Directors	Governance; Risk Management; Business direction and sustainability; and Performance of Chief Executive and Leadership team.	KPIs; and Regular Board Meetings and Directives.	Risk Management integrated into all business processes; and Monthly reporting.
Employees	Safe and enjoyable work environment; Job satisfaction; Work/life balance; Development opportunities; Fair remuneration; and Effective support.	Employee surveys; and Regular employee briefings and communications.	Forward planning of work; Safety Initiatives and reporting; Integration of Risk Management into all processes; and Training.
Contractors	Safety; Commercial treatment and access; Assurance of work continuity; Visibility of forward workload requirements; and Risk management.	Contractual arrangements; and Regular meetings.	Forward planning of work; Safety initiatives and reporting; and Integration of Risk Management into all processes.
Suppliers	Fair, transparent, unbiased selection; Forecast requirements to optimise supply chain; Commercial sustainability; and Risk management.	Contractual arrangements; and Regular meetings.	Forward planning of work; and Network Standards.
Counties Power Consumer Trust	Fair and reasonable rate of return on equity; Incentives to invest and innovate; Good governance; Risk management; Business sustainability; Good reputation with the community; and Good asset management.	Trustee Meetings; and KPIs,	Network Development Planning; Organisation and governance structures; and Integration of Risk Management Half-yearly and annual reporting.

Figure 2-5 Stakeholders and their requirements

2.4.1 Balancing stakeholder requirements

As we have a wide range of stakeholders it is important that conflicting stakeholder requirements are managed appropriately and consistently. Safety is a company-wide priority that takes precedence in resolving any conflicting requirements. Balancing differing requirements are managed in the following order:

- Safety and hazard mitigation;
- Regulatory and legal requirements;
- Contractual requirements;
- Consumer price/quality; and
- Investment requirements.

2.5 Our consumers

Our consumers are our owners. We are predominantly a rural network. However our network services one of the fastest growing areas in New Zealand. Consequently, the number of active ICPs has increased significantly over recent years and this growth is expected to continue over the planning period covered by this AMP.

Customer Profiles

As at October 2017, there were 41,697 ICPs connected to the Counties Power network with a maximum demand of approximately 115 MW and annual delivered energy of 553 GWh in the year ending 31 March 2017. In the most recent winter peaks in 2017, peak demand remained steady at 116 MW. This number is increasing daily with new residential, commercial and industrial customers being connected. This is changing the customer mix from a predominantly rural, small town and rural commercial base (e.g. quarries, mines, food production) to an urban residential and industrial mix.

A breakdown of the ICP type is shown in the table below:

	ICPs	Delivered GWh*
Direct supply	7	72.4
Time-of-use	163	109.7
Commercial	7,397	111.0
Domestic	34,130	260.3
Total	41,697	553.4

* Delivered GWh in FY2016/17.

2.5.1 Major customers

Counties Power has three large direct supply customers: Watercare Services Limited, New Zealand Steel Limited and Yashili New Zealand Dairy Company Limited. These three customers comprise 14% of Counties Power's total electricity volume and this percentage will increase if Watercare expands their Waikato pumping operation and Yashili grows its production volume. Counties Power works closely with these companies to meet their electricity requirements and to understand their future expansion plans.

Power demand from Counties Power's other major customers has grown in recent years and has been driven by local economic and population growth. This growth has seen the mix of major customers change in recent years and this is likely to continue in the future as small companies expand and new companies are attracted to the region.

Counties Power's top customers are in following industry sectors:

- Steel production;
- Dairy processing;
- Waste product and material handling;
- Food and produce processing and packing; and
- Timber and construction material processing.

Counties Power's top 11 customers account for 22% of Counties Power's total electricity volume.

Other consumers with significant or strategically-important loads on our network include:

- Council infrastructure such as pumping stations, streetlights, and community facilities;
- Emergency and essential service providers; and
- Large industrial or commercial users in addition to those listed above.

We consider the needs of all our major customers when undertaking Asset Management activities:

- **Safety** – we make sure the assets we own which supply them are safe and well maintained, particularly lines and transformers located on their sites.
- **Reliability** – our network should provide the required level of performance in line with the terms under which the customer has connected.
- **Value for money** – that the price they pay for using our electricity network is competitive
- **Security of Supply** – our network should provide sufficient security of supply to enable maintenance and faults to be managed with acceptable levels of disruption to consumers.
- **Planning** – we make sure to consider their operations when planning network activities such as switching and outages.
- **Communication** – we communicate openly with our major customers to understand their business and what's important to them, as well as providing feedback on events that may have impacted upon their operations.

2.5.2 Distributed generation

Counties Power has eight embedded generators greater than 10kW and 538 embedded generators under 10kW. The eight large embedded generators consist of the following:

- Four hydro schemes operated by Watercare at their Hunua reservoirs. These comprise a 300kW generator at the Wairoa dam, a 300kW generator at the Mangatawhiri site, a 700kW generator at the Mangatangi dam, and a 300kW generator at Cosseys dam;
- A 7MW landfill generation plant at Hampton Downs landfill operated by Envirowaste. This plant comprises seven 1MW containerised landfill generators;

- A 5MW plant in Papakura operated by an electricity retailer (consisting of a 3.5MW gas generator and a 1.5MW diesel generator);
- A 60kW photo voltaic installation at Drury operated by an industrial customer; and
- A 15kW photo voltaic installation at Counties Power's head office, which includes a 3.6kWh battery storage system to support our day-to-day needs and is also part of the learning and development activities associated with the opportunities afforded by solar photo voltaics and electricity storage systems.

The remaining 538 embedded generators under 10kW are nearly all small residential and business photo voltaic installations. The number of photo voltaic installations has grown rapidly over the last two years.

2.5.3 Energy delivered and demand

Counties Power's total delivered electricity in the year to 31 March 2017 was 553 GWh and peak demand was 115 MW. The network load profile is winter peaking, with residential loads showing typical morning and evening peaks, and commercial loads generally having a constant daytime load.

Delivered energy has been growing at 2.5% per annum on average over the last 5 years and peak demand has grown at an average of 4.1% per annum over the same period. The graph below shows the growth split over Counties Power's main customer groups and the peak demand increase.

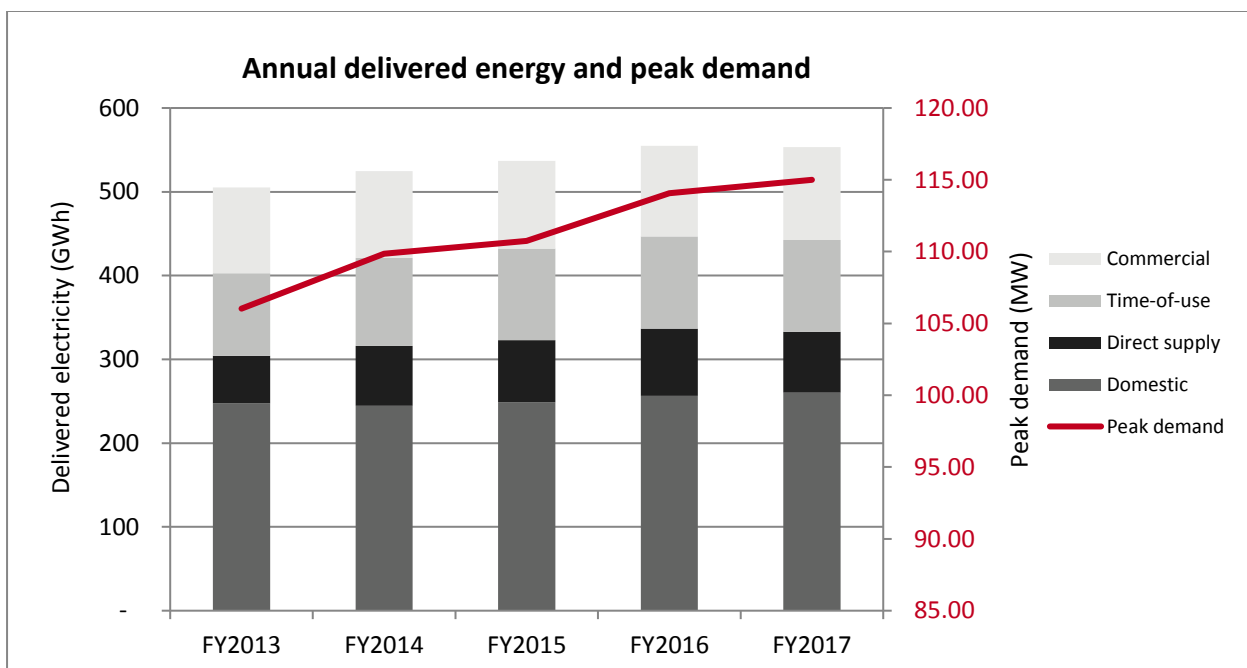


Figure 2-6 Energy volumes and network demand 2013 to 2017

2.6 Our network

Counties Power has two points of supply from Transpower's National Grid via Grid Exit Points (GXP) at Glenbrook and Bombay. The Glenbrook GXP supplies our western substations at 33kV whilst Bombay GXP supplies the eastern substations at 110kV and 33kV. The number of active installations and the installed distribution capacity controlled by each GXP is shown in Figure 2-7. 73% of ICPs are supplied from the Bombay GXP at 110kV and 33kV, and the remaining 27% from Glenbrook GXP. Other details are included in the following sections.

GXP	Zone Substation	No. of Distribution Substations	Distribution Capacity (kVA)	Active ICPs				
				Total	Residential	Commercial	Industrial	% of Total ICPs
Bombay 110 kV	Pukekohe	623	75,955	12083	9948	2072	63	29%
Bombay 110 kV	Opakeke	470	61,040	8327	7334	955	38	20%
Bombay 110 kV	Tuakau	717	44,090	5714	4512	1176	26	14%
Bombay 33 kV	Mangatawhiri	396	20,135	2130	1528	590	12	5%
Bombay 33 kV	Ramarama	345	17,925	2241	1711	522	8	5%
Glenbrook 33 kV	Karaka	445	26,015	3658	2945	708	5	9%
Glenbrook 33 kV	Maioro	112	19,275	525	344	177	4	1%
Glenbrook 33 kV	Waiuku	627	40,300	7019	5808	1197	14	17%

Figure 2-7 Overview of Network Substations and Consumer Information (as at Oct-17)

Figure 2-8 below illustrates the geographical area covered by the network, along with Figure 2-9 which shows the 110 kV and 33 kV subtransmission network, the zone substations and the 22kV switching station. More detailed maps showing the distribution network coverage areas, are included in Appendix E – Network Diagrams.

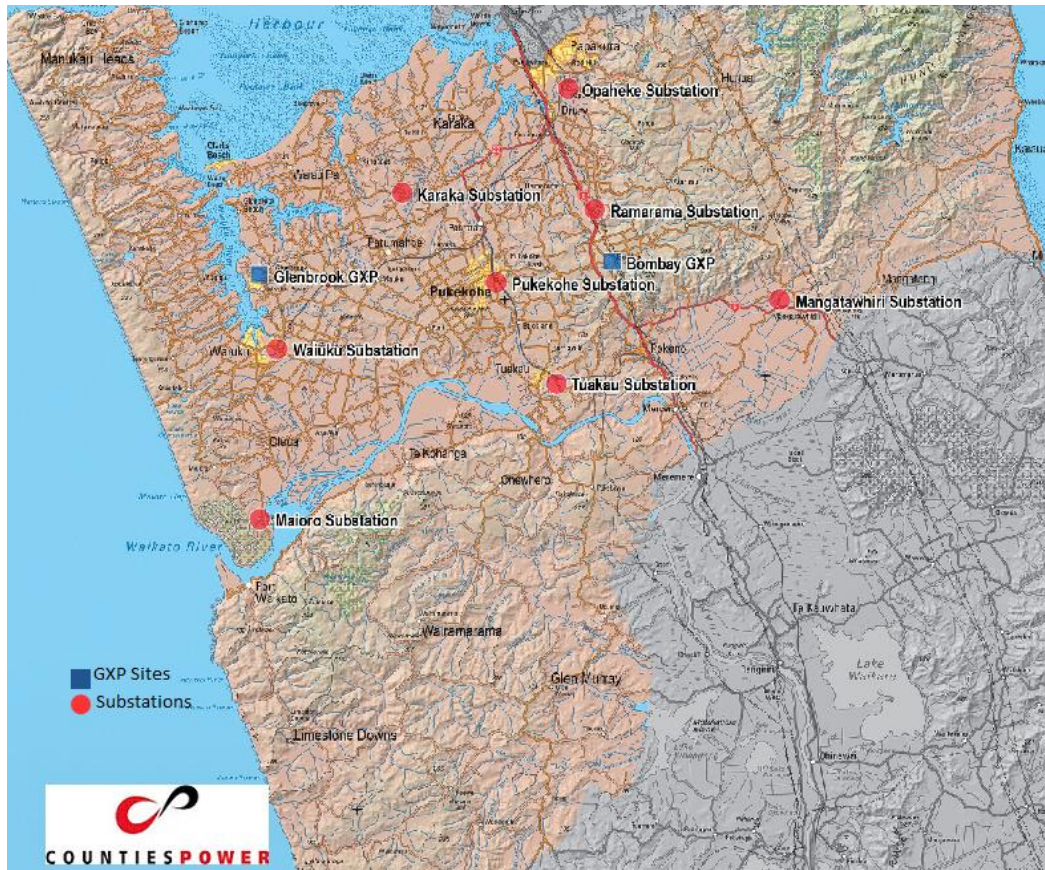


Figure 2-8 Geographic overview of the Counties Power Network Area

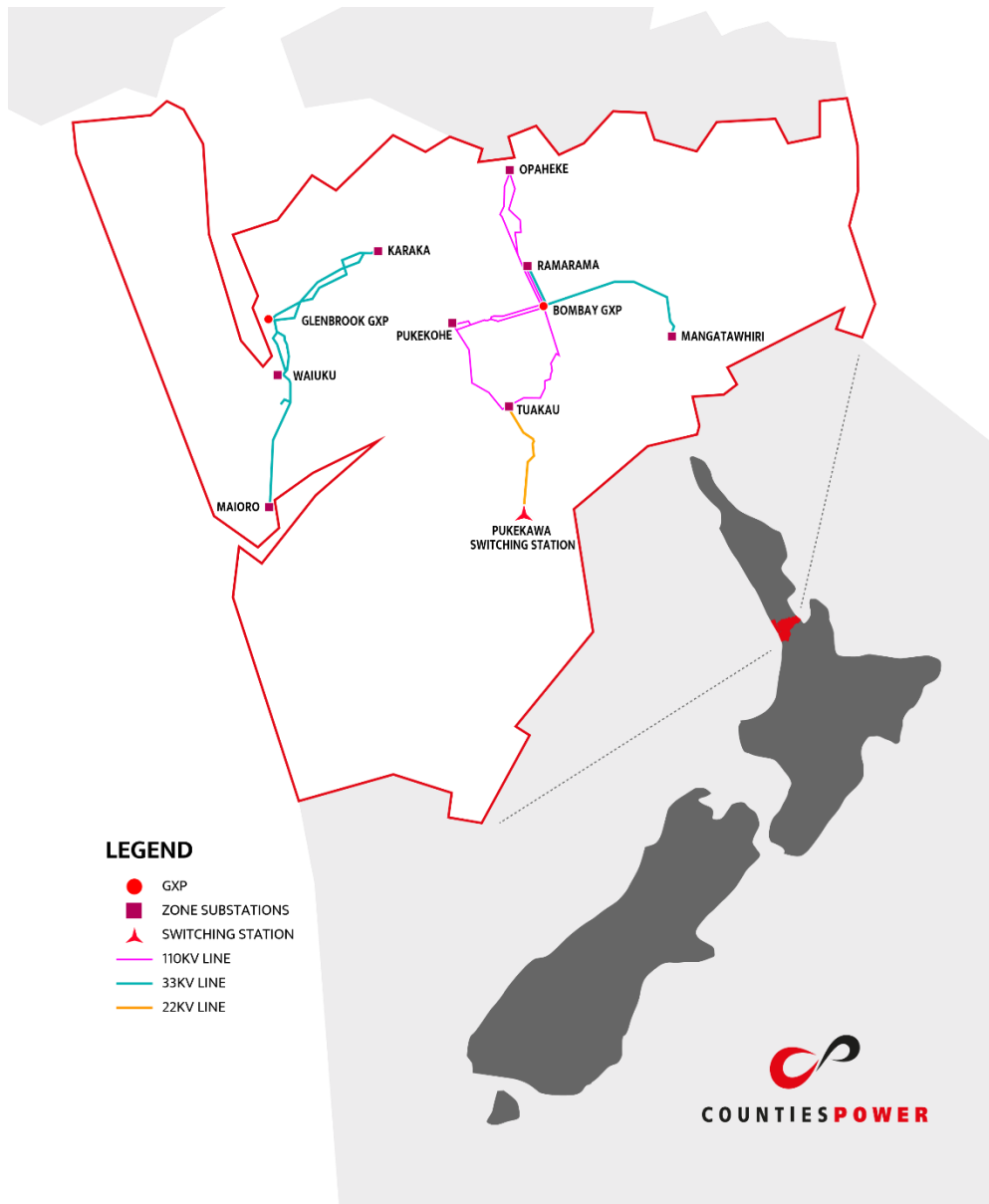


Figure 2-9 Overview of Counties Power Subtransmission Network

2.6.1 The subtransmission network

Our subtransmission network consists of a network of 110kV and 33kV subtransmission lines from Bombay and Glenbrook GXPs. The architecture of the network is typically radial subtransmission circuits connecting to 33kV buses, or configured as transformer-feeders where no bus is installed. Our 110kV supply to Pukekohe and Tuakau is operated as a ring with three circuits supplying the two zone substations.

- The Pukekohe Substation is supplied via two 110 kV lines from Bombay, with a 110kV bus and two 110/22kV transformers rated at 30/60MVA, with the distribution supply operating at 22kV;

- The Opaheke Substation is supplied via two 110 kV lines from Bombay configured as transformer-feeders and has two 110/22kV transformers rated at 20/40MVA, with the distribution supply operating at 22kV; and
- The Tuakau Substation is supplied via two 110 kV lines - one from Bombay and one from Pukekohe - and has a 110kV bus with two 110/22kV 20/40MVA transformers. The distribution supply operates at 22kV.

The remaining five zone substations are supplied via the 33kV subtransmission network with distribution supply operating at 11kV, with some feeders stepped up to 22kV using auto transformers.

The subtransmission system schematics, capacity and demand information is provided in Section 6 Network Development Planning. A summary of the loading and other characteristics of the subtransmission system and zone substations are illustrated in Figure 2-10.

GXP (Grid Exit Point)	Zone Substation	Number of GXP circuits	Circuit Description	Installed Capacity (MVA)	n-1 Capacity (MVA)	Load 2017 [2016] (MVA)	No. of Customers (Oct-17)	Average Forecast Growth Trend (%)
Bombay 110kV	Pukekohe	2	Single 110kV pole line	2 x 30/60	60	35.2 [36.3]	12,083	3.5
Bombay 110kV	Opaheke	2	Single 110kV tower line & pole lines	2 x 20/40	40	23.9 [25]	8,327	8.2
Bombay 110kV	Tuakau	2	Single 110kV pole line	2 x 20/40	40	16.7 [16.9]	5,714	5.7
Bombay 33kV	Ramarama	2	Single 33kV tower & pole lines	1x5+ 5/6.25	5	6.2 [7]	2,241	1.6
Bombay 33kV	Mangatawhiri	1	Single 33kV pole line	1 x 7.5/9.4	--	6.1 [6.0]	2,130	1.6
Glenbrook 33kV	Waiuku	2	Single 33kV pole line	2 x 10/20	15	16.0 [15.9]	7,019	2.6
Glenbrook 33kV	Karaka	2	Single 33kV pole line	2x 10/20	20	10.4 [9.4]	3,658	5.1
Glenbrook 33kV (via Waiuku)	Maioro	1	Single 33kV pole line	2 x 7.5/9.4	--	10.0 [9.4]	525	0.0

Figure 2-10 Summary of Subtransmission and Zone Substations Characteristics

2.6.2 The distribution and LV network

Our zone substations supply a total of 53 distribution feeders (operating at 22kV or 11kV) via approximately 3,983 distribution substations (including private substations). The distribution substations connect over 41,690 consumers to the Counties Power network.

Distribution substations transform the 22kV or 11kV distribution voltage to 400V/230V reticulation voltage.

Distribution substation assets typically include - distribution transformers, high voltage fuses or circuit breakers and low voltage fuses.

A total of 50 22kV/11kV transformers, the earliest of which were installed in 1994, are also in use on the network to facilitate the voltage conversion programme.

Of the total distribution network circuit length (both HV and LV), 75% consists of overhead lines and 25% is underground cable. On the low voltage network, approximately 55% is overhead whilst on the high voltage network, 87% is overhead (see Figure 2-11). Further details about the distribution network, including quantities and age profiles are included in Section 5 Renewals and Maintenance. In addition to our distribution network, there are overhead lines owned by private land owners which connect to our network, and in places third party poles are used to support overhead lines such as those owned by Chorus.

Secondary assets include ripple injection systems, protection, SCADA and telecommunication systems.

	Voltage	Length (km)
Underground	22kV	143
	11kV	70
	LV	619
Overhead	22kV	571
	11kV	903
	LV	755

Figure 2-11 Composition of Distribution Network (as at Oct-17)

If we undertake voltage conversion projects, we increase the system length of 22kV network, and decrease the length of 11kV network. All new network extensions are constructed for 22kV operation however may only be energised at 11kV.

Generally, distribution overhead lines and underground cables feed ground-mounted or pole-mounted transformers via fused switchgear such as drop out fuses (DDOs) and ring main units. These distribution transformers step the voltage down to a low voltage level of 400V or 230V to supply our consumers through our low voltage network.

2.7 Our assets

Asset Category	Type	Quantity ¹
Subtransmission		
Poles	Concrete Pole	1,340
	Wooden/other Pole	16
	Steel Pole	147
	Steel Tower	10
Lines	110kV	65.8 km
	33kV	72.1 km
Cables	33kV	1.1 km
Zone Substation		
Substation Buildings		10
Power Transformers	110/22kV	6

Asset Category	Type	Quantity ¹
	33/11kV	9
Circuit Breakers	110kV CBs	14
	33kV CBs	12
	22kV CBs	44
	11kV CBs	36
Station Disconnectors	110kV Disconnectors	2
	33kV Disconnectors	29
Distribution and LV lines		
Poles	Concrete Pole	25,291
	Wooden Pole	2,019
	Other Pole	118
Cross Arms	Wooden/Steel	48,294
Conductors	22kV	570.7 km
	11kV	902.8 km
	Low Voltage (LV)	754.6 km
Distribution and LV cables		
Distribution Cables 22kV	XPLE	150.5 km
Distribution Cables 11kV	PILC	22.7 km
	XLPE	52.0 km
LV Cables	PVC	87.2 km
	XLPE	493.5 km
	Other	67.3 km
Street Light Cables	PVC	42.7 km
	XLPE	1.4 km
	Other	2.2 km
Distribution Substations and Transformers		
Distribution Transformers	Pole mounted	3,128
	Ground mounted	805
Auto Transformers		50
Distribution Switchgear		
Ring Main Units		198
Air Break Switch	11kV	155
	22kV	109
Gas Insulated Switch ^{*2}	11kV	41
	22kV	50
Spur Line Isolator	11kV	839
	22kV	627
Reclosers ^{*3}	11kV	7
	22kV	20
Grid-scale battery storage system		
Grid scale battery storage system		1
Other System Fixed Assets		
LV Pillars and Pits		12,212
Capacitor banks		29
Voltage Regulators		7
Protection relays		144
Load control relays		3,568

Asset Category	Type	Quantity ¹
Ripple Injection plant		5
Auxiliary battery banks		27
Remote Terminal Units		222
Notes: 1: Asset quantity as at Oct-17. 2: All Gas Insulated Switches are rated at 22kV, operating voltage are as shown in the above table. 3: All Reclosers are rated at 22kV, operating voltages are as shown in above table.		

3 Service Levels

3.1 Stakeholder engagement

3.1.1 Customer surveys

Counties Power conducts customer surveys at least once every two years, and post-service feedback surveys every month. The customer surveys measure and monitor both residential and commercial customers experience and rating of the power supply service they receive. The last customer survey was conducted in December 2017 by an external research company. The respondents surveyed were across four consumer groups, defined by rural or urban location and residential or commercial consumers.

	Residential	Commercial	Total
Rural	128	20	148
Urban	228	24	252
Total	356	44	400

Figure 3-1 Distribution of Consumers Surveyed

The 2017 survey evaluated current satisfaction levels in addition to identifying the key factors that influence overall satisfaction. Reliability of supply remain key to satisfaction, but scored low on the importance to our consumers, reflecting that in general most consumers are satisfied with the reliability of their power supply (79%).

Communication was a key influencer and was the top priority identified by the survey. Consumers are demanding greater insights when power is interrupted to enable them to better manage their needs. A core focus of FY19 is the implementation of real-time updates and the diversification of communication channels to deliver timely and accurate data on outages.

Understanding of the value delivered through line charges is of importance to our consumers and is an area of opportunity for the Company, although given poor recognition of Counties Power as their local lines company suggests consumers do not fully understand the components of their overall electricity bill and the difference between lines and energy charges. Of those surveyed, 68% of consumers were unwilling to pay more for increased reliability, reflecting both the current understanding of how lines charges are invested back into the network and the relatively high satisfaction of current reliability of power supply. Those consumers who experienced more outages were more willing to pay increased line charges for increased reliability.

Communication of unplanned outages and information on the annual Counties Power discount were of equal importance to our consumers as the reliability of power supply. Insight from the 2017 survey questions showing the top five service elements which are of importance to our consumers and the current performance valuation are illustrated below in Figure 3-2.

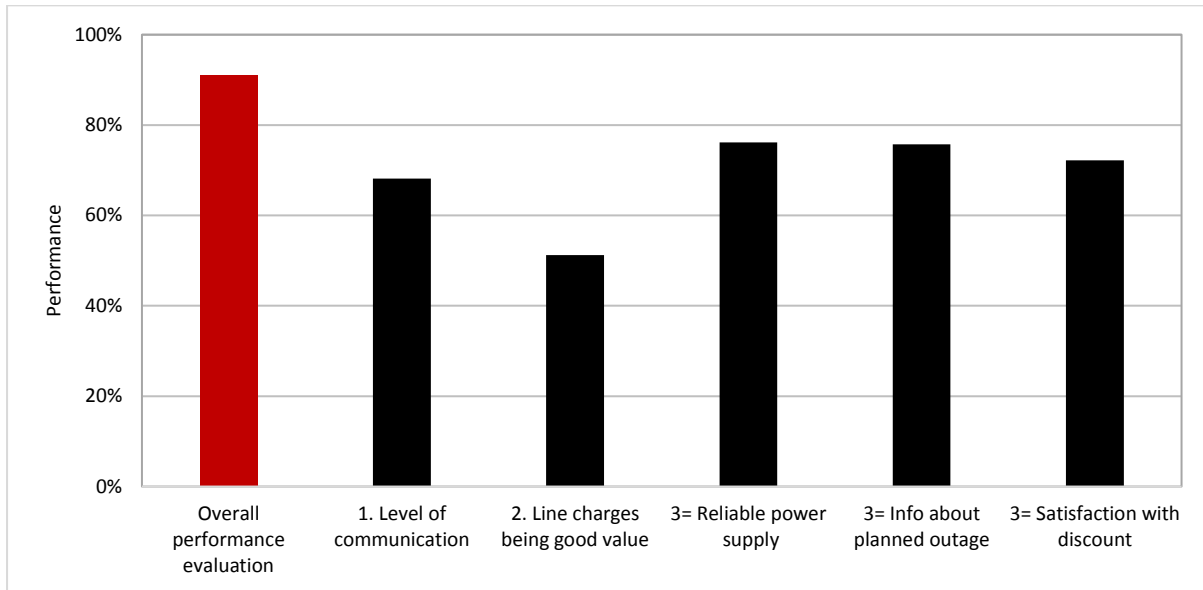


Figure 3-2 Results of 2017 survey questions on top five service elements of importance to our consumers

3.2 Service level: workplace safety

Our health and safety vision is “no harm for our people, our communities and the environments in which we operate”. Our health and safety vision aligns with our corporate mission and values. To achieve our safety vision, our safety culture has continued to improve in the last 12 months due to the implementation of:

- The stronger promotion of reporting and investigation of all near misses, incidents, injuries and damage to plant, equipment or the environment. There has also been emphasis on increasing the number of safety observations and safety conversations on site;
- Strengthening of our staff engagement in safety through a higher profile health and safety committee, with actions and progress reviewed by senior management and the Board;
- The introduction of safety KPIs in all personnel’s performance objectives;
- Leadership training with key leaders across our business with a focus on safety leadership and skill coaching techniques to enable leaders to develop into effective people leaders; and
- Improved accident and incident investigation and analysis by training management representatives in Incident Cause Analysis Method (ICAM) investigation techniques.

Counties Power is an active member of the Business Leaders’ Health and Safety Forum, the Electricity Supply Industry (ESI) Health and Safety Forum, the Electricity Networks Association (ENA), is represented at the Board level of the Electricity Engineers’ Association (EEA), and is a regular contributor to industry working groups on matters concerning staff and public safety and safety by design.

3.2.1 Safety objectives

To achieve our health and safety vision, and our corporate mission and values we have placed health and safety as the highest priority over all our business objectives. We believe that our most important priority is the health and safety of our staff, our contractors, and visitors to our sites and the public who interact with our assets. To this end, we will always conduct ourselves in a manner that protects the health and safety of our employees and contractors (Counties Power Team Members') visitors to our sites and members of the public who interact with us and our assets.

We acknowledge our responsibilities for maintaining high health and safety standards in the work place and will provide competent resources and effective systems and sufficient capacity within our business to fulfil this commitment. All Counties Power employees are required to adhere to this policy.

3.2.2 Safety measures and targets

We have grouped our safety performance targets into two categories; namely lagging indicators through Injury Frequency Rates and leading indicators. These are:

- **Leading Personnel Behaviour Rate Measures.** This includes safety audits in order to improve our safety culture. Under this category we measure Safety Audits, and Safety Observation Reporting.

	Actual 2016/17	Actual 2017/18 (10 months to Jan 18)	Annual Target 2018/19-2027/28
Safety Audits	197	281	132
Safety Observations	936	966	1,500
Leadership Team Safety Observations	83	70	69

- **Lagging Injury Rate Measures.** Under this category we measure total recordable injury frequency rate (TRIFR) which encompasses all lost time, restricted work and medically treated injuries using a calculation based on 1 million hours. We also measure lost time injury frequency (LTIFR) and lost time injury severity (LTISR) which encompasses total number of lost time injuries and total lost days. Our company wide target for each measure is to reduce to zero. The only LTI in the year to date was a fall from height.

	Actual 2016/17	Target 2017/18	Actual 2017/18 (10 months to Jan 18)	Targets 2018/19 to 2027/28
TRIFR	3.49	2.62	7.14	Reduce to 0
LTIFR	3.49	2.62	3.57	

3.2.3 Safety initiatives

In order to achieve these objectives, we are undertaking the following initiatives:

- A reward and recognition scheme for those who make substantial contributions to safety;
- Continuous promotion of worker engagement through an active Health and Safety Committee;
- Redesign of roles and structure of the Health and Safety Committee;
- Continued engagement with the workforce through a strong worker representation at the Health and Safety Committee;
- Evaluating each critical health and safety risk and the associated controls to ensure robust measures are in place;
- Subjecting each high potential incident to a detailed Incident Cause Analysis Methodology (ICAM) investigation by specially trained managers;
- Rolling out Job Safety Analysis (JSAs) to field staff, competency assessments and investigations of high potential incidents to drive process and culture improvement;
- Developing an audit framework to allow for the effectiveness of controls to be assessed on a regular basis;
- An elevated level of Field audits is also to be completed by an external auditor;
- Introduction of an improved quality management system; and
- Introduction of a new Health Safety and Environmental reporting system that is field enabled from tablets.

Safety Culture and Leadership

The Counties Power safety culture has continued to improve in the past 12 months, with the ongoing promotion of near miss reporting and safety observation reporting for all personnel. KPI's are included in each individual's performance objectives.

Leadership training has been undertaken with key leaders across the business not only with a focus on safety leadership but also with a focus on developing capability in the area of skill coaching techniques to enable leaders to develop into effective people leaders. A leadership assessment will be undertaken at regular intervals to evaluate effectiveness.

Critical Risks

Counties Power's six critical safety risks are:

- Working at height;
- Driving;
- Working with electricity;
- Mobile or moving plant;
- Manual tasks; and
- Asset integrity.

3.3 Service level: public safety

3.3.1 Objectives

Our objective is to ensure that no member of the public is harmed by our network assets, and that hazards introduced by our network assets are controlled so as to not pose a risk to the public.

3.3.2 Targets

Leading Indicators

Categories for leading public safety indicators include:

- Number of Asset Inspections and Tests undertaken on,
 - High risk asset categories in the public domain – pillars, transformers, ring main units, poles, zone substations;
 - Safety critical assets – earthing, protection systems; and
 - Assets in special locations – those located around schools, public recreation spaces, commercial and shopping areas.
- Time to repair high risk defects on the network (percentage completed within required timeframes).

Lagging Indicators

In addition to leading indicators, we record lagging indicators including:

- Number of incidents reported with or without harm; and
- Number of damaged property incidents (consumer premises and network property).

Actual Performance for FY 2016 to FY 2018 are shown in the table below.

Details	FY 2016	FY 2017	FY 2018 YTD ⁴
Property Damage to Network Assets	285	273	174
Reported Injuries from Network Assets	1	2	1

Along with introducing targets for leading indicators, we are also going to extend our reporting of lagging metrics, including:

- Number of assets found or reported to be insecure; and
- Number of lines down and unassisted pole failure incidents.

⁴ FY2018 YTD is to Jan-17.

3.3.3 Initiatives

In order to provide the highest levels of public safety, we have the following initiatives in place:

- Ensuring assets are inspected, maintained and defects repaired in accordance with good industry practice;
- That equipment is designed, selected and installed in a way to promote public safety (safety by design);
- That earthing and protection systems are designed, tested and operate to clear faults quickly to protect members of the public from electric shock;
- Maintain compliance and certification to the requirements of NZS7901 for Public Safety Management Systems, including undertaking periodic external performance assessment;
- Public Safety awareness – undertaken radio and print media awareness campaigns, as well as engaging with local primary and secondary schools and providing safety resources on our website www.countiespower.com; and
- Active engagement with Energy Safety in relation to unsafe activity around our network by third parties, or where people have come to harm from our assets, or their own premises.

3.4 Service level: reliability

3.4.1 Objectives

Our objective is to operate the network to provide a level of performance in line with the price consumers are willing to pay, this includes:

- Minimising the number and duration of outages experienced by consumers;
- Restoring power as quickly and safely as possible following an unplanned outage and providing communication to keep consumers informed; and
- Providing consumers with sufficient notice ahead of planned outages required for maintenance.

There are some consumer groups on our network who demand higher levels of reliability, and are prepared to pay more for that benefit, and we accommodate their needs where practicable.

3.4.2 Targets

Consumer Reliability Service Levels

We set reliability service levels for our consumer in the Use of System Agreements we have with Retailers trading on our network. These outline the target times for restoration of supply following a fault on the network, as well as the timeframes for notifying the consumer that we have to turn them off for planned works.

Description	Target
Restoring electricity supply after the Distributor becomes aware of the fault.	Rural – 6 hours Urban – 4 hours
Notice of pre-planned supply interruption	Not less than 5 days' notice to the Retailer unless already agreed with by the Customer

Overall Network Performance

As an exempt EDB, our network performance indices have not been required to be calculated in accordance with the Commerce Commission default price-quality path (DPP) methodology, although we have taken that into account when assessing network performance. We note that the reference period 2004 – 2014 used for the Commerce Commission reliability calculation included a large period of relatively benign weather compared to recent weather trends, the network assets were in places 10 years newer, and the widespread use of live line techniques during that period means that the reference years are not necessarily representative of future network performance. Historic SAIDI and SAIFI is shown in Figure 3-3 and Figure 3-4 below.

With the introduction of the Health and Safety at Work Act in 2015, we have implemented a risk based live work decision framework aligned to the Electricity Engineers' Association's guide to live work which has resulted in an increased number of planned outages to complete our work safely. At present, there is a mixed level of adoption of these live work guidelines across the industry, thus making it difficult to benchmark SAIDI and SAIFI performance against our peers.

Our performance targets have been set based upon recent network performance over the period 2014 to 2017, which has been used to set an internal target of 110 minutes for unplanned SAIDI throughout the planning period, and as described later in this section an internal target of 60 minutes for planned SAIDI in FY18 giving a total target of 170 SAIDI minutes for FY18. We did not adjust our SAIFI target and this remained at 2.55.

Taking in consideration the works plan for FY19, we have increased our internal planned SAIDI target to 95 SAIDI minutes, reducing in subsequent years. We have maintained an internal target for unplanned outage of 110 SAIDI minutes, giving a total of 205 SAIDI minutes for FY19. We have also adjusted our SAIFI target to 2.90 to reflect the increased number of planned interruptions.

By adopting this position on reduced live work, as well as the ability to halve the SAIDI impact of planned outages under the Commission's revised disclosure methodology, we are able to undertake more planned work de-energised, an important safety improvement, as well as reducing the dependence upon generator support. Customer service expectations are being carefully managed, as is engagement with communities in the reasons behind this important safety improvement initiative. We have worked with our main stakeholder, the Counties Power Consumer Trust, to improve their awareness and understanding of the increase in planned outages which, whilst inconvenient in the short term, allows for the maintenance and replacement of assets which will deliver improved performance over the long term.

With our planned SAIDI performance year to date, we have exceeded our target of 60 minutes and a year-end forecast position of 77 planned SAIDI minutes has been determined, which is 17 minutes more than our initial estimate. This is largely due to an increased volume of network maintenance and performance improvement projects underway and a reduction in live work in line with best industry practice.

We also took a decision to align our manual reclosing practices with the industry during 2016, with the main objective being improved public safety particularly in a line down event. This change has led to a higher SAIDI contribution from 'no fault found' events, and this trend can be seen in Figure 3-9. Our unplanned SAIDI performance year to date is unfavourable to target, predominately resulting from 'vehicle' and 'no fault found' events. We forecast a year end position of 170 unplanned SAIDI minutes, and unplanned SAIFI of 2.90 (this is an increase of 0.35 on our initial estimate of 2.55).

Our performance and targets are shown in the table below.

Network SAIDI⁵	2015	2016	2017	2018	2019	2020+ Target⁶
Counties Power	95.7	118.3	236.6	170	205	200
Industry Average	170.1	162.9	194.8			

Network SAIFI⁷	2015	2016	2017	2018	2019	2020+ Target
Counties Power	2.23	2.70	3.28	2.55	2.90	2.80
Industry Average	2.18	1.88	2.07			

Faults per 100km	2015	2016	2017	2018	2019	2020+ Target
Counties Power	17.56	18.41	16.93	14.50	14.50	14.50
Industry Average	33.03	29.56	16.93			

⁵ Network SAIDI figures from 2015 onwards are normalised figures using the Commerce Commission methodology

⁶ Total SAIDI targets will reduce from 2020 onwards in line with the reliability investments that are made and forecast benefits they will provide. The future level of reliability investment and expected performance benefits will be assessed in the coming year.

⁷ Network SAIFI figures from 2015 onwards are normalised figures using the Commerce Commission methodology

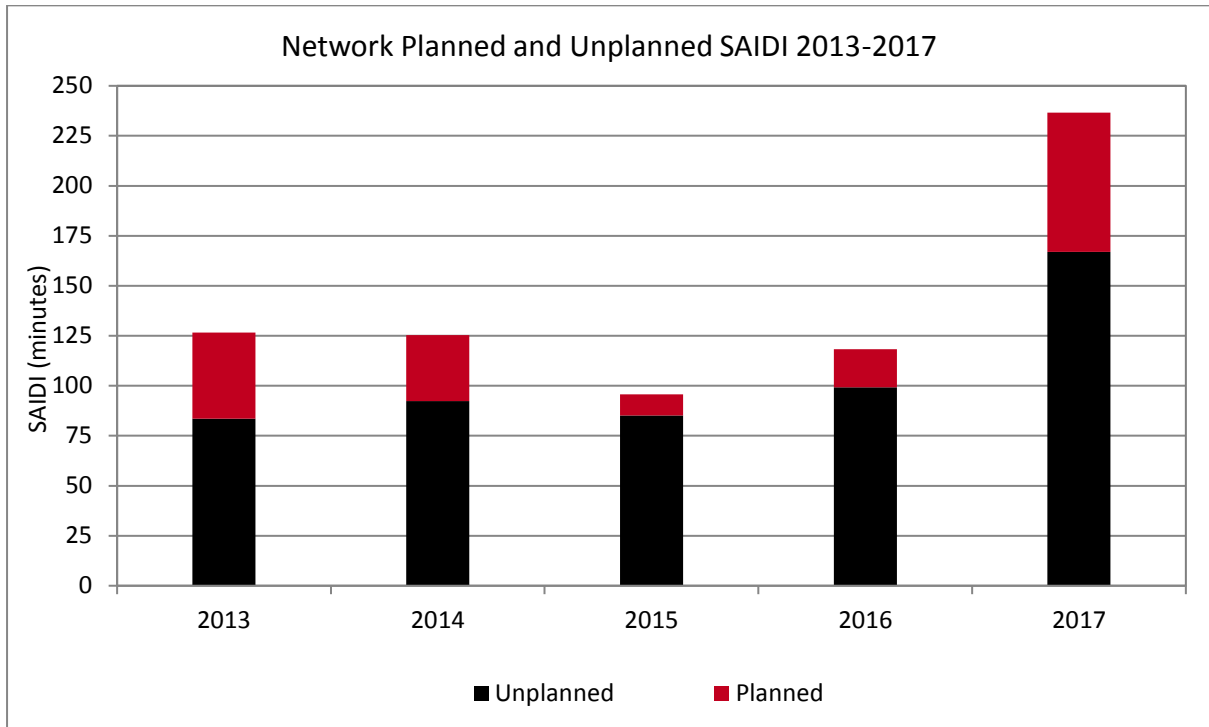


Figure 3-3 Historic Network SAIDI 2013 - 2017

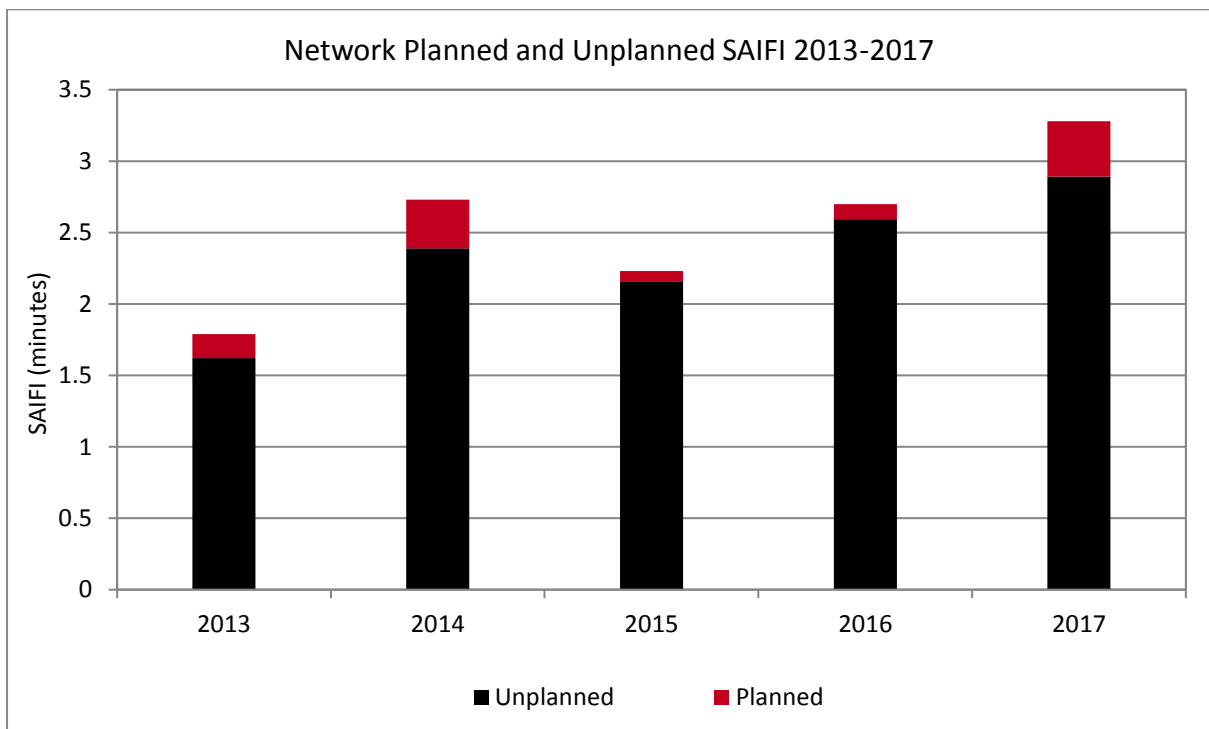


Figure 3-4 Historical Network SAIFI 2013 – 2017

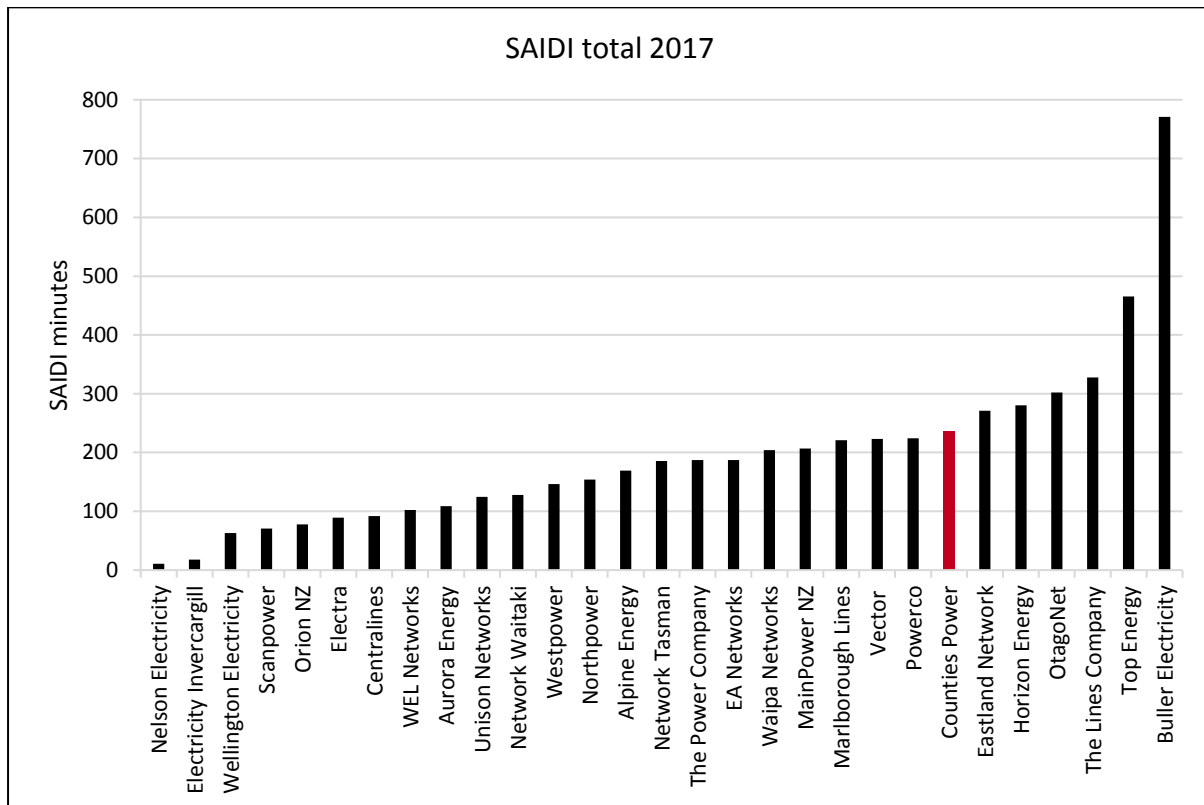


Figure 3-5 Network SAIDI – Industry Comparison 2017

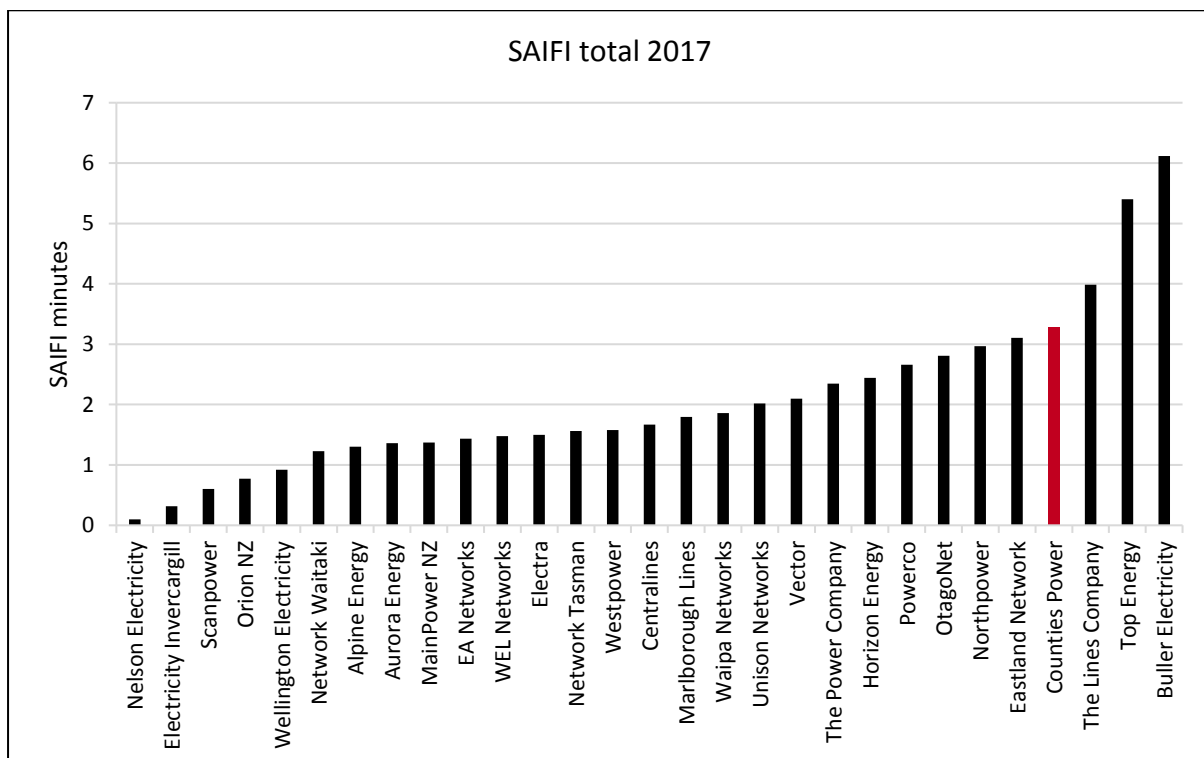


Figure 3-6 Network SAIFI – Industry Comparison 2017

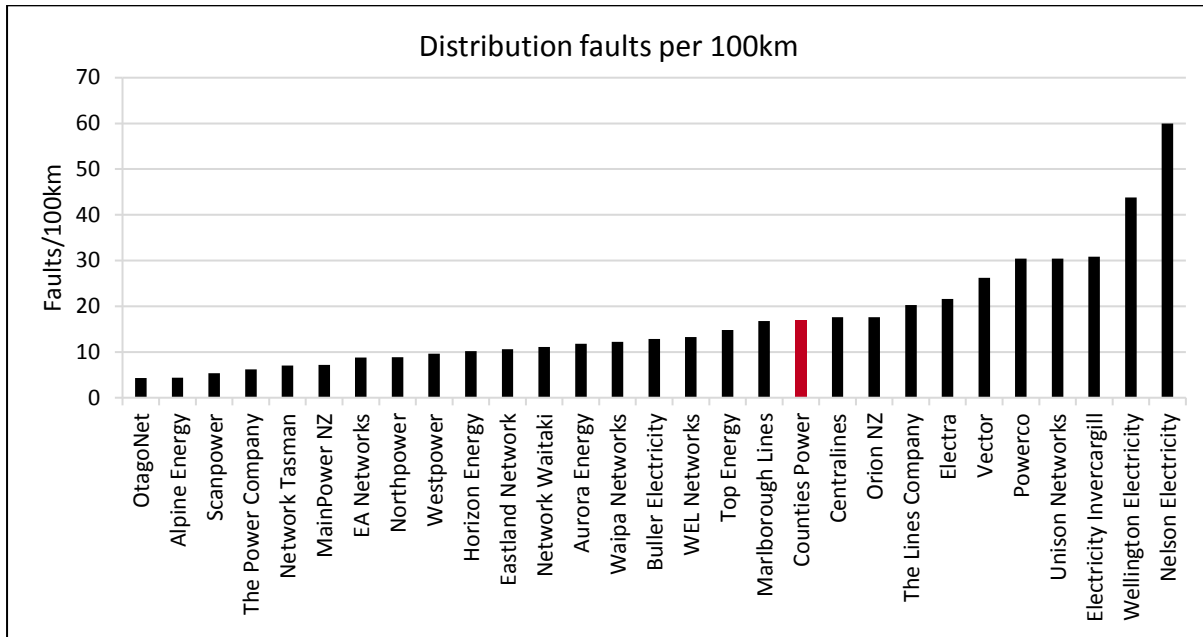


Figure 3-7 Total Faults per 100km – Industry Comparison 2017

3.4.3 Network Performance Analysis

Network performance, as measured by SAIDI and SAIFI, is unfavourable both to our own targets, and when compared to industry averages. SAIDI and SAIFI are high relative to similar networks, and reflect the higher feeder customer density resulting from our 22kV feeders, a notable increase in overhead equipment failure, vegetation faults and vehicle damage in the past two years. This can be seen in Figure 3-8, where the number of faults by type have shown an upward trend from FY15 to FY17, and a gradual change to a downward trend from the beginning of FY18 showing the effects of investment and maintenance programmes which started in FY17. However at the time of writing this AMP, the full year performance is not known and with increasingly stormy weather common in January and February this position may change at year end.

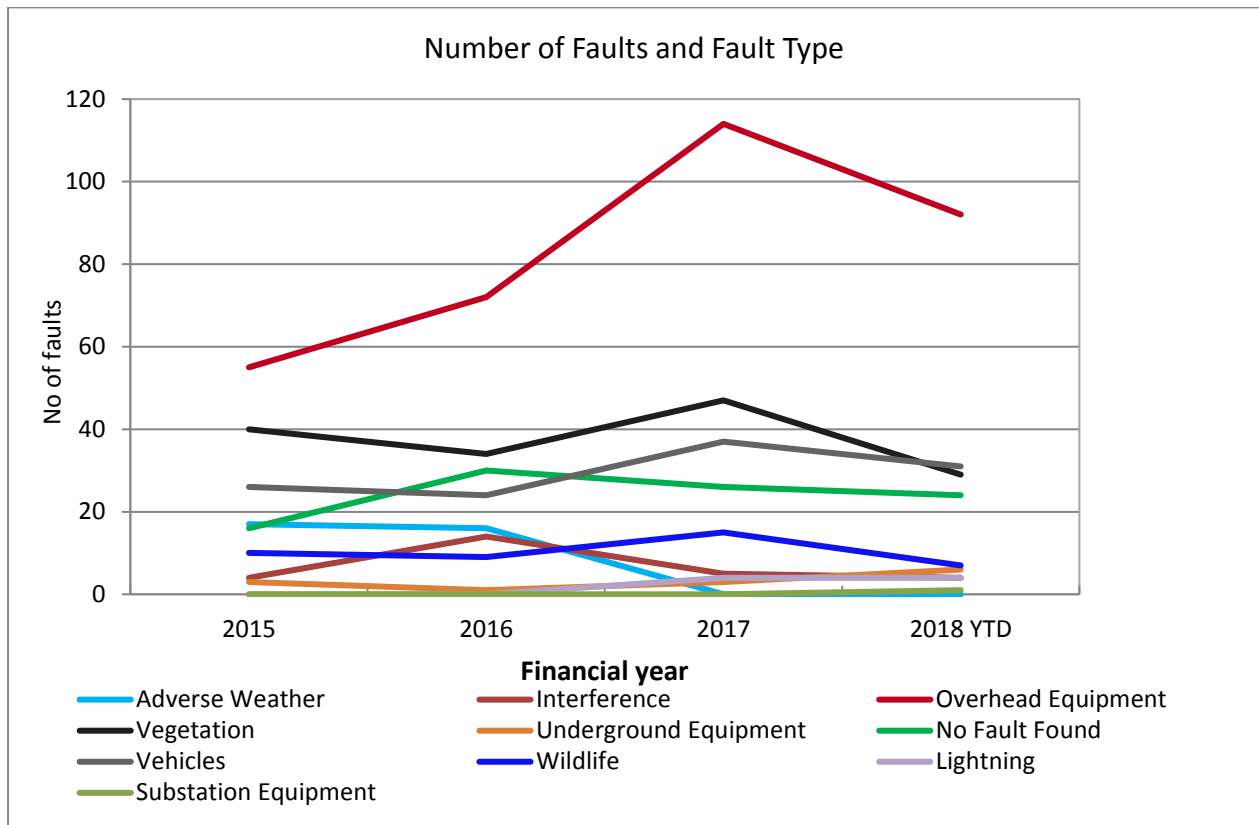


Figure 3-8 Number of faults and fault type (FY18 YTD to Dec-17)

Overhead equipment faults have been largely related to end of life conductor failure in both storm and non-storm situations, broken or defective overhead switchgear, and component failure such as insulators, binders and fuses. To address these issues, increased levels of asset replacement expenditure is planned for short to medium term of this plan. Details are included in Section 5.

When considering the number of faults by type, the SAIDI impact of those faults, as shown in Figure 3-9 shows large contributions from overhead equipment, vehicle damage and vegetation. The impact of vehicle damage is harder to control, and investigation has shown little commonality to vehicle damage sites, although where possible equipment is located to avoid future vehicle damage. Overhead equipment contributes to both the number of faults, as well as the individual impact due to the nature of some fault types. In cases where the fault is caused by a defective switch, the affected area is increased due to reduced ability to isolate consumers. Some equipment failures are difficult to identify in fault patrols, and new technology is being explored to improve that process to reduce the outage time before the fault is located. Vegetation remains a challenge for the business as landowners often do not undertake their obligations under the Tree Regulations, or in many cases experienced, the vegetation is blown debris or trees falling from outside the zone enforceable by the Tree Regulations.

At the time of writing, when considering SAIDI contribution from faults, there is a positive downward trend for overhead equipment and vegetation from the beginning of FY18 to December. This reflects the increased level of automation on the network allowing faster isolation and partial restoration of supply, as well as targeted maintenance and asset replacement in high impact areas. The impact from vehicle incidents remains high. There is however an unfavourable trend in SAIDI impact from 'No Fault

Found' outages as Counties Power changed its practices on manually reclosing following a fault in certain areas. This decision was made on the basis of public safety, particularly in a lines down event, but has led to an increased SAIDI contribution despite steady numbers of these events.

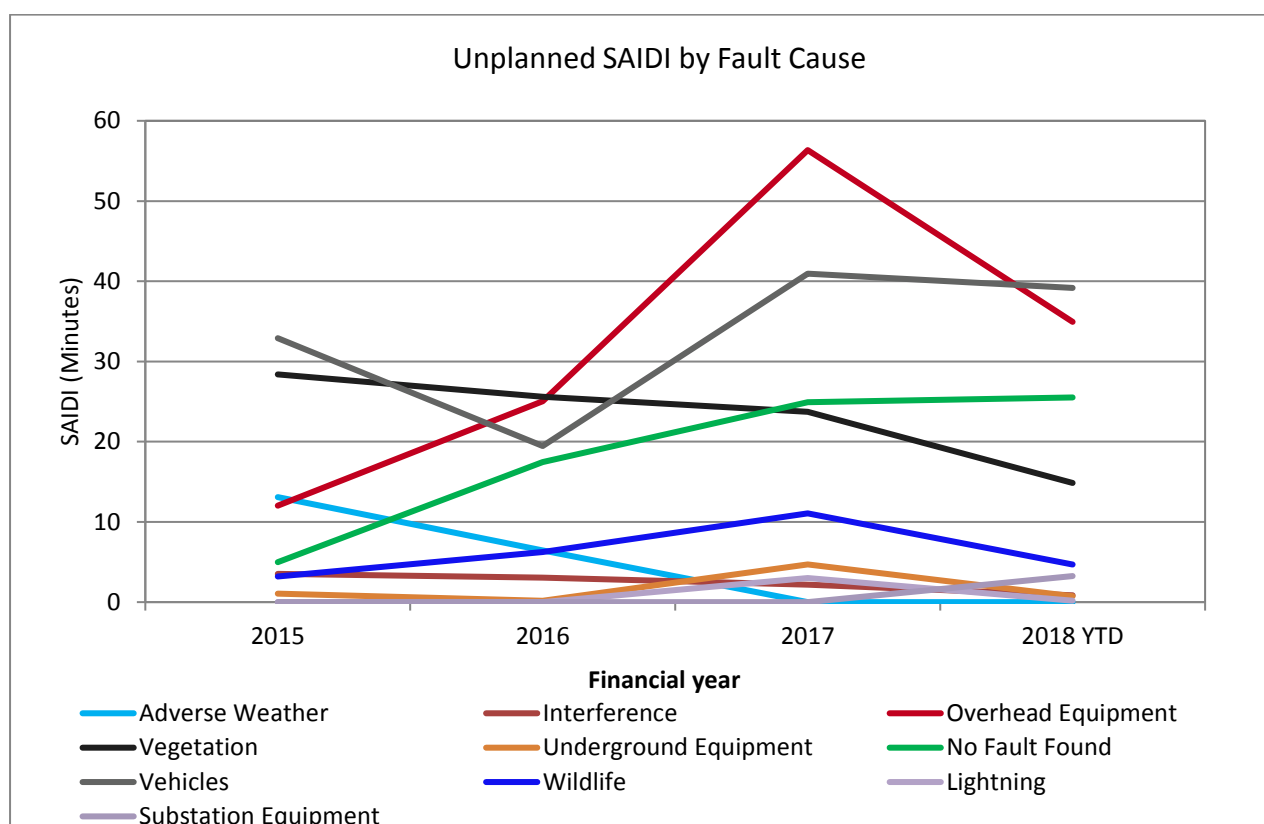


Figure 3-9 Unplanned SAIDI by Fault Cause (FY18 YTD to Dec-17)

In order to provide appropriate levels of network performance, we have the following initiatives in place:

- Vegetation management – a proactive programme of vegetation surveys and tree trimming to ensure supply is not interrupted by trees coming into contact with overhead lines;
- A focus on worst performing feeders – identifying which feeders have the greatest number of outages, as well as those that have high SAIDI and SAIFI impacts, and undertaking remedial works to ensure the assets on these feeders perform as expected⁸;
- Post fault analysis of all events that cause more than 20,000 customer-minutes to be lost, or affect a major customer, to identify the root cause of the fault and to implement corrective actions to prevent reoccurrence;
- Car vs pole post incident investigation and reporting, and follow up actions with internal and external stakeholders such as Police and local roading authorities;
- Increased maintenance and replacement of overhead components in worst performing areas – as detailed in Section 5; and
- Investigating new tools and technology to identify fault locations to enable quicker restoration of consumers in affected sections of the network.

⁸ Part of a 3-year rolling performance improvement plan focusing of top 10 worst performing feeders.

3.5 Service level: customer service

3.5.1 Objectives

- Our customers and consumers are aware of who we are and what we do;
- Customer feedback is easy to give and it can be given across multiple channels;
- Customers and consumers know we will act on their feedback and requests, and they value the services we offer; and
- We aim to deliver our services (including the delivery of electricity) at the levels sought by our customers.

3.5.2 Initiatives

- Ensuring customer feedback is integrated into both our asset management planning process, and AMP;
- Enhanced communication channels to customers for planned and unplanned power outages, including implementation of real-time messaging service for unplanned outages and updated self-service web application;
- Process reviews and continuous improvement of our service offerings to make it more efficient and easier to serve our customers;
- Establish and start to measure the delivery of our services against time, accuracy and satisfaction parameters;
- Surveys of customers, seeking feedback on our service, our price and reliability;
- Achieve 100% compliance with Utilities Disputes (formerly the Electricity and Gas Complaints Commission - EGCC) scheme; and
- Seek and record customer contact information so notifications can be sent out in the event of a fault.

3.5.3 Targets

- Time to answer a call;
- Response times (acknowledgement) of letters and electronic communications from customers and consumers;
- Positive customer and consumer feedback on services we provide;
- Overall customer satisfaction with our services, price and reliability; and
- Complaint handling meets or exceeds Utilities Disputes (and our own) requirements.

Description	Target
Service request – such as providing a new supply for new reticulation; permitting a high load or processing a Distributed Generation approval	On the date agreed with the Customer (or their Retailer) for that service
Voltage Complaint	Acknowledge complaint within 5 Business Days after receipt of the complaint. Advise outcome of investigations and nature and timing of intended remedial action (if required) within 10 Business Days after receipt of the complaint.
Complaint Handling	Acknowledge complaints within 2 working days and close them within 20 working days
Service response	Answer an average 80% of calls within 20 seconds (force majeure events excluded) and acknowledge or resolve customer-driven service requests via email by the next working day

3.6 Service level: economic efficiency

3.6.1 Objectives

- Effectively and efficiently manage the network to have a low cost to serve;
- Reduce losses on network; and
- Ensure high utilisation of assets (load factor).

3.6.2 Initiatives

- Continuous improvement in works delivery model and processes to reduce costs;
- Investigate new technology options for reduced 'whole of life costs';
- Actively manage capacity and asset utilisation; and
- Utilise distribution voltages to reduce technical losses where economic to do so.

3.6.3 Targets

Cost to Serve – Operating Expenditure

To deliver on our vision of having cost effective supply of electricity to our consumers, it is important we have efficient operating costs. We measure operating cost per consumer, and by system length, and aim to be at or below the industry average, and ensure the asset management and business operating decisions we make do not drive unnecessary cost into the business.

Our performance and targets are shown in the table below.

Operating Cost per ICP	2015	2016	2017	2018+ Target
Counties Power	\$293	\$291	\$321	\$295
Industry Average	\$343	\$352	\$367	

Operating Cost per KM	2015	2016	2017	2018+ Target
Counties Power	\$3,642	\$3,631	\$4,042	\$3,600
Industry Average	\$3,463	\$3,583	\$3,780	

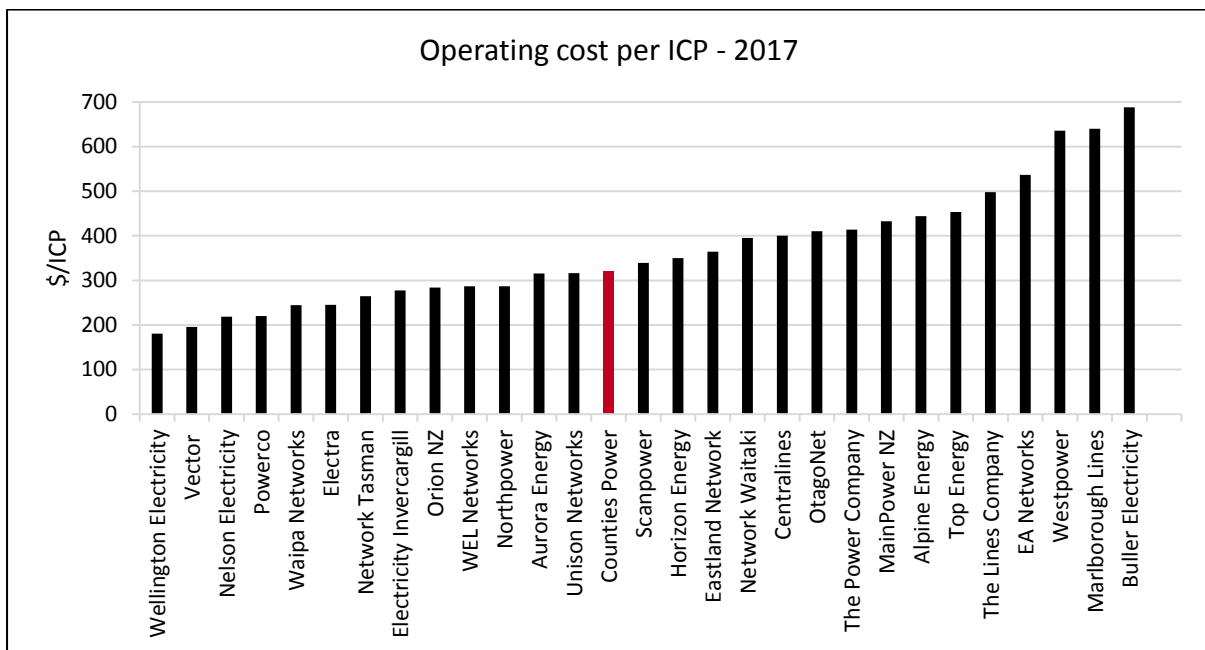


Figure 3-10 Operating Cost per ICP – Industry Comparison 2017

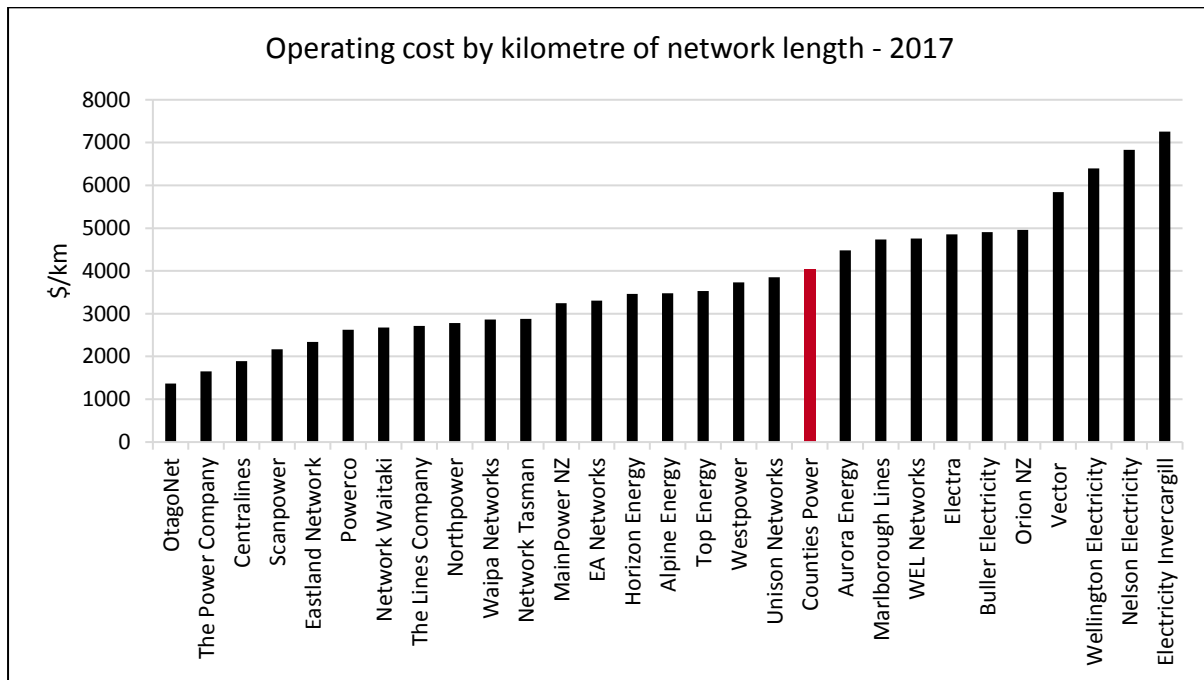


Figure 3-11 Operating Cost per km of Network Length – Industry Comparison 2017

Network Losses

We aim to keep our losses at or below the industry average. As we have predominantly rural network with moderate consumer density, our electricity losses will generally be high. Losses have been kept close to the industry average through the use of higher operating voltages, and the network architecture we have implemented. Our deployment of smart meters, and consequential installation audits have reduced technical and non-technical ‘unaccounted for energy’ on the network over the past three years.

Our performance and targets are shown in the table below.

	2015	2016	2017	2018+ Target
Counties Power	5.3%	4.5%	4.4%	less than 4.5 %
Industry Average	5.9%	6.0%	5.9%	

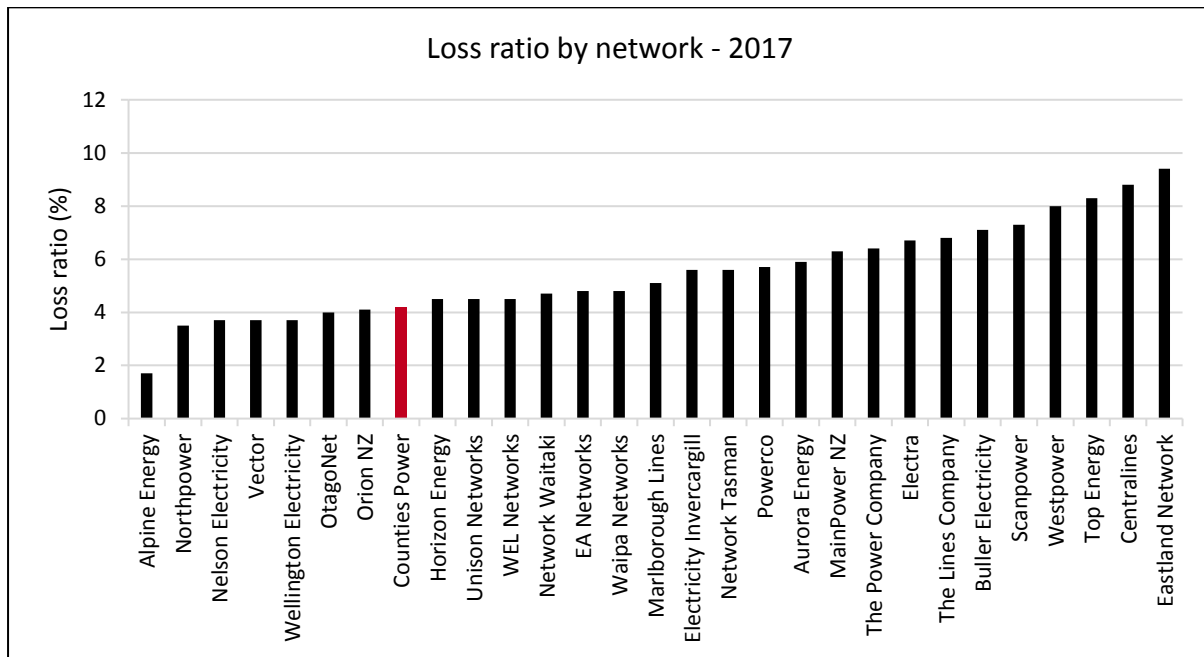


Figure 3-12 Loss Ratios – Industry Comparison 2017

Network Utilisation

Network Utilisation is another important aspect of operating an economically efficient electricity network, and ensuring that our distribution network has been constructed in a way that meets consumer demand, but does not have too much excess capacity built in. The Load Factor is an important measure of utilisation as it compares the installed transformer capacity to the demand at peak times.

Our performance and targets are shown in the table below.

	2015	2016	2017	2018+ Target
Counties Power	56.1	57.8	57.4	60.0
Industry Average	61.7	61.0	60.3	

Due to the high level of growth being experienced on the network, we are undertaking a large number of network extensions and multi stage subdivision reticulation projects which are creating headroom of installed distribution capacity ahead of the uptake in demand. We expect this to change in the coming years, and our utilisation figures to increase as new loads are connected to existing transformers.

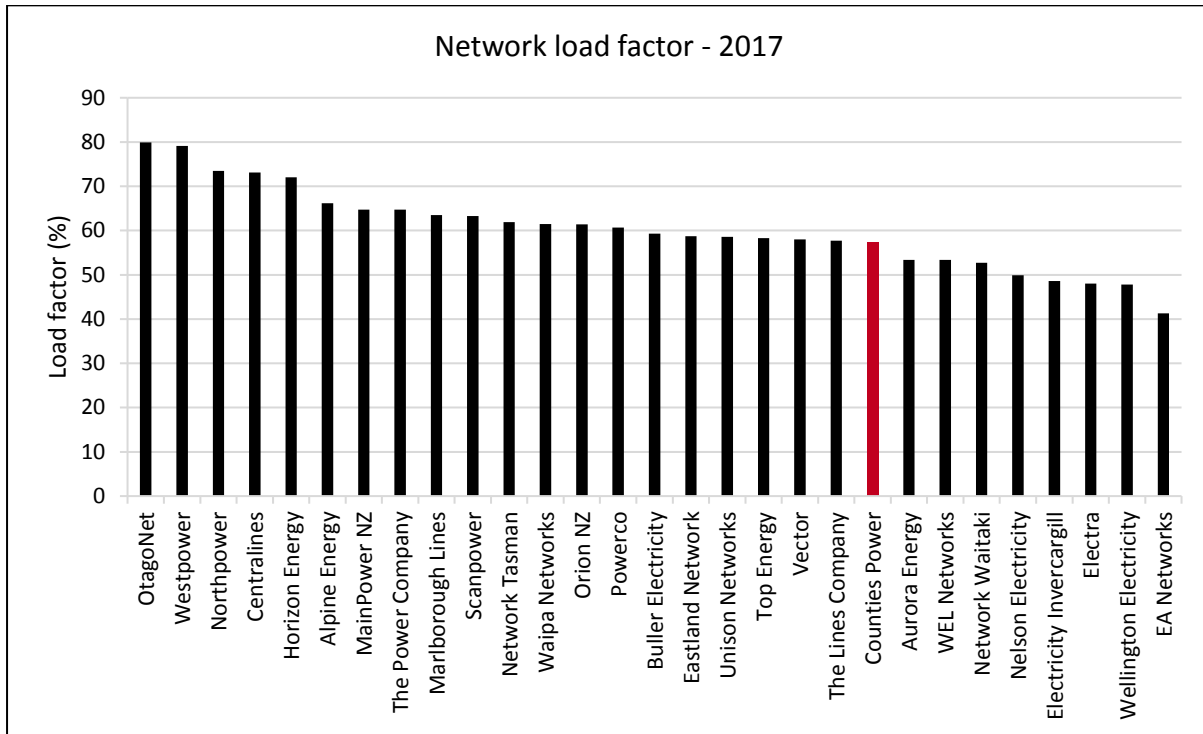


Figure 3-13 Load Factor – Industry Comparison 2017

4 Approach to Asset Management

4.1 Asset Management Framework

4.1.1 Framework Overview

Figure 4-1 below shows the high level Asset Management framework for Counties Power. This has been developed to allow for aligning ourselves with the ISO 55000 framework.

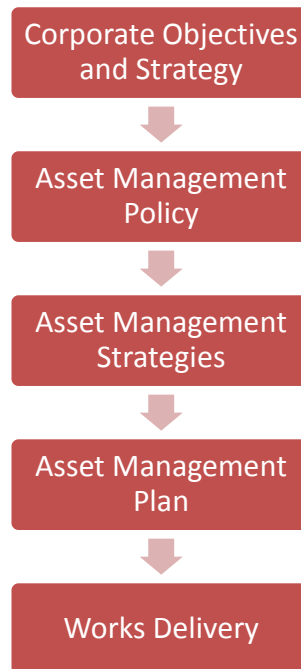


Figure 4-1 Asset Management Framework

4.1.2 Asset Management Policy

Our Asset Management Policy links our Asset Management approach to our corporate objectives and details the Objectives, the Accountabilities and the Implementation considerations.

Our Asset Management Policy Objective is to “optimise the whole of life costs and the performance of the network to sustainably deliver safe, reliable and cost effective supply to our consumers”.

4.1.3 Asset Management Strategies

We have developed asset management strategies to deliver the requirements of the Asset Management Policy, these cover maintenance, replacement, and network development.

Each of these strategies informs this Asset Management Plan and results in proposed programmes of work – comprising operational expenditure and capital investment – which are detailed in Section 5, 6, and 7 of this plan.

Maintenance Strategies

Maintenance comprises asset inspection, measurement, recording and assessment of condition and undertaking required corrective or preventative action to minimise risk and/or maximise performance. In the course of normal business some assets fail in service, often influenced by external factors such as trees, motor vehicles, wildlife, or extreme weather. We have to repair or replace those assets reactively.

Maintenance is required to meet our objectives of providing a reliable service that our consumers value, our obligations under our Public Safety Management System, to meet the requirements of the *Electricity (Safety) Regulations 2010* and to ensure we meet good industry practice.

Our maintenance programme consists of three categories of maintenance activity.

- **Preventative Maintenance** – routine inspection, testing and servicing to ensure our assets are safe, free from defects and meet their service expectations. We also use the inspection process to undertake condition assessment to forecast when the asset will have to be refurbished or replaced. We include vegetation management as a form of preventative maintenance;
- **Corrective Maintenance** – scheduled repairs to assets following inspection or testing, to address known defects, based on the risk they present; and
- **Reactive Maintenance** – unplanned repairs or replacement of assets once a defect or failure has been identified, or where they present an immediate risk to safety or the network.

A key part of our maintenance strategies is to assess the benefits of major repair work against outright replacement or retirement of assets. Although the cost of replacement can be many orders of magnitude greater than a repair, we consider the ‘whole of life’ cost of the asset when contemplating repairs to assets nearing the end of their economic life.

We undertake targeted maintenance in some areas where network performance is poor or the consequence of failure is extreme, and categorise ‘Worst Performing Feeders’ to address reoccurring issues and improve network performance.

Replacement Strategies

As we are a rapidly growing network, a number of areas of the network have been constructed or rebuilt over the past 20 years which means some parts our network are relatively new. Other parts of the network, particularly the older 11kV network in the southern and western areas, are at end of life and are beginning to experience increasing rates of failure, particularly at component level, as well as systematic issues with certain types of conductors. We forecast that a higher level of renewal expenditure will be required over the planning period to address safety, condition and performance risks with this older equipment.

Major substation plant is of high value, has a significant consequence associated with failure, and can present a serious risk to safety, the network, and the environment if poorly managed. We have preventative and corrective maintenance programmes to ensure these assets perform as expected and to ensure we understand their condition to allow us to plan repair and replacement activities. We base replacement of major assets on a detailed condition assessment, as well as an assessment of the risk of failure. Options analysis is undertaken where investment is significant or in an area where major changes in demand forecast are being projected.

Many of our major substation assets are approaching the end of their economic service life just as capacity and security constraints are becoming binding. This allows the assets to be replaced at the optimal time to maximise their service life by moving towards condition based replacement, and be upgraded to meet new capacity requirements at the time it is required. More details of this can be found in Section 6 Network Development Planning.

Distribution assets are generally in the public domain and can present a risk to public safety. We inspect these assets to identify defects and undertake condition assessment, analyse failure rates and causes to forecast when replacement will be required. Our objective is to replace these assets based on condition before they fail or present an unacceptable risk.

Some asset classes have a lower risk to safety and network performance, and have a low consequence of failure. These can be managed with a run-to-failure strategy.

In some cases, where the asset is at end of life and is no longer required or has been superseded, it may be retired from service without replacement.

A detailed description of our replacement programmes is covered in Section 5 Renewals and Maintenance.

Network Development Strategies

As demand on our network grows we have to ensure it is able to meet our consumer's requirements for capacity, security and reliability.

We have developed security and planning criteria and assess the network against these for the reasonable growth forecast. This results in the identification of constraints and timeframes for investment. Our strategy is to ensure that the development options we select do not lead to over investment (too much), premature investment (too soon), or lead to a high risk of asset stranding. We also aim to get as much renewal benefit as possible when upgrading or replacing assets due to growth, and avoid the early write-off of assets before the end of their economic service life.

Details of these network development plans are covered in Section 6 Network Development Planning.

4.2 Investment Planning

Our network investment process consists of a sequence of decision making steps, used to ensure we make the correct investment decisions and have adequately considered alternatives. A high-level overview of this process is shown below.



The key steps in our investment planning process for network initiated projects are:

1. **Identification of the Need** – the need for investment arises from routine business cycle activities such as the network planning process which identifies constraints on the system and the maintenance process which includes asset condition surveys, network fault and performance data. These processes produce outputs of a list of issues which may require investment.
2. **Prioritisation of the Need** – once the Need has been identified, it is prioritised by risk (including safety, security, reliability, environmental, and regulatory) and the timing of when the issue requires resolution
3. **Assess Options** – a long list of possible solutions is developed, with high level order of cost and assessment of benefits. From this a short list of preferred solutions is selected, based on the cost, the benefits they provide, and the alignment with our strategic goals.
4. **Select a Solution** – once the short list of options has been assessed, a preferred solution is selected based on delivering the greatest benefit, which is then scoped and priced to a detailed level to allow a full business case to be developed.
5. **Approvals to Proceed** – the business case outlining the preferred solution is presented for the appropriate level of management approval.
6. **Implementation of the Solution** – once approved, the solution enters the design and delivery phase, where the detailed design is created, the scope of works finalised, and it is handed to the Field Operations group to deliver the solution.

For customer initiated projects such as network extensions and subdivision reticulation, the investment decision making process is simplified and a solution is identified to meet the customer's requirement for capacity and security. The timing of these investments is to suit the customer, and is not discretionary.

A summary of our processes for investment planning are shown in Figure 4-2 and Figure 4-3.

4.2.1 Investment planning process – renewal and replacement

Our process for renewal and replacement investment is shown in the diagram below. Key inputs to this process are Asset Condition Surveys, Known Type Issues and Performance Issues. These are all prioritised by the risk the asset presents, considering public and personnel safety, network security and reliability, regulatory requirements and environmental effects.

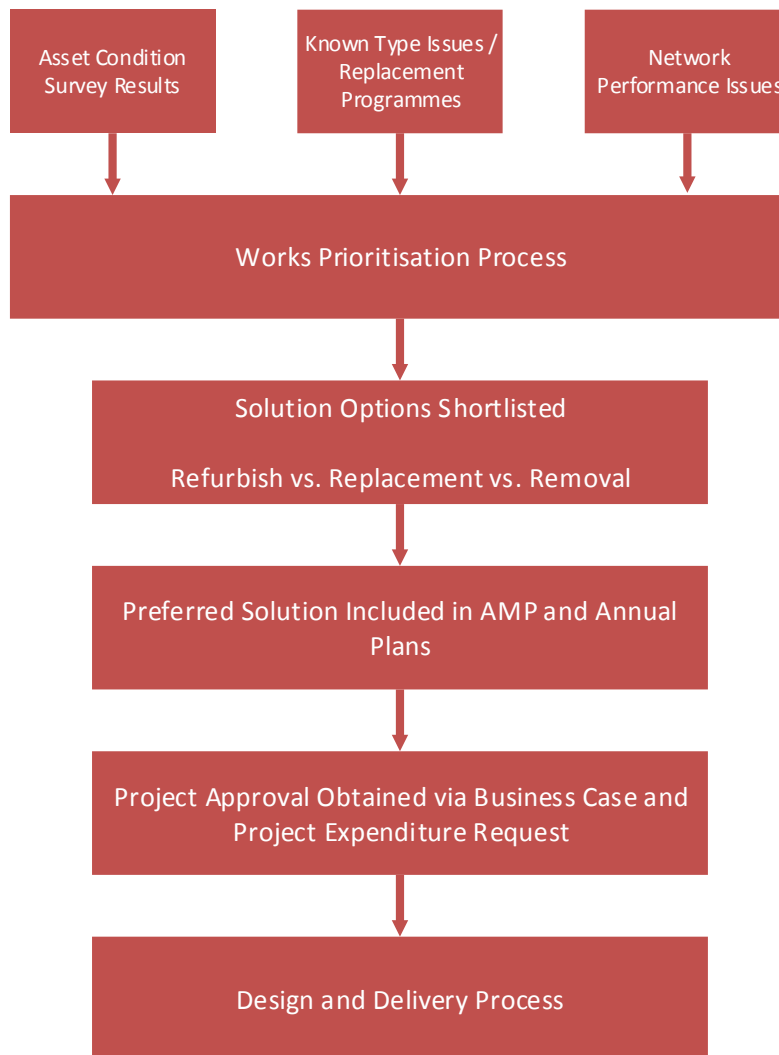


Figure 4-2 Renewal and Replacement Investment Process

4.2.2 Investment planning process – network development

Our process for network development investments is shown in the diagram below. Key inputs to this process are the load forecast, the network model and system capability, and the security and planning criteria. When considered together, these identify constraints on the network which will drive investment. Full details of this process are provided in Section 6 Network Development Planning.

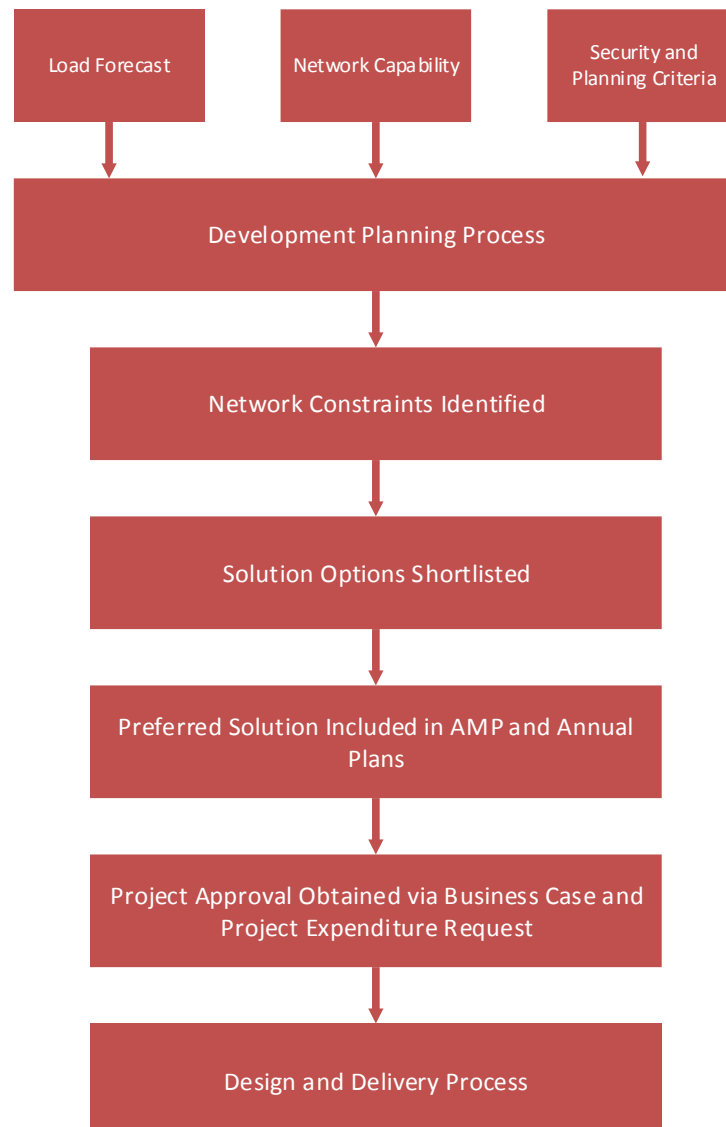


Figure 4-3 Network development investment process

4.2.3 Consideration of network alternatives

Network alternatives (sometimes referred to as non-network solutions) are considered in the options analysis to address a network constraint, particularly a capacity or voltage constraint.

We then consider if network alternatives are feasible such as demand side management, localised storage or generation, and other assets which can be installed to defer the need for investment by reducing the peak demand or supporting the voltage along a feeder.

Where the investment need is driven by poor condition of assets presenting a safety risk, a network alternative is not normally suitable, and investment in replacement network components is required, however consideration is given to the size and configuration of these to determine if the network can be optimised in any way.

Further details around our assessment and selection of Network Alternatives is covered in Section 6 Network Development Planning.

4.2.4 Energy Efficiency Considerations

As part of our network planning process, we make the following considerations for energy efficiency.

- **Voltage and Loading** – we select appropriate operating voltages and operate the network in a configuration that minimises electrical losses;
- **Energy Efficient Equipment** - we ensure that all new equipment, in particular transformers, comply with the required IEC and AS standards for energy efficiency, in particular the Minimum Energy Performance Standard; and
- **Metering** – we ensure our metering equipment is calibrated and compliant with the Code to reduce the ‘unaccounted for’ energy lost on the system.

4.3 Asset Management Information and Systems

4.3.1 Asset Management Systems

There are a number of key systems used in the asset management process, as well as part of our wider business operation. The key systems are listed below with a brief description of the role they play. Some minor systems have not been detailed here.

Geographic Information System (GIS) – Smallworld

We use GE Smallworld to record all our geospatial information relating to network assets, including location, physical and electrical attributes. This platform is also used to record some maintenance attributes relating to the assets.

We have two tools based on the Smallworld platform which are used by the business:

- SIAS which is a version of Smallworld which operates in a web environment, allowing users to access GIS data without needing a full software license; and
- GSA which is a geospatial analysis tool which adds an improved level of analysis and reporting to the Smallworld data.

Supervisory Control and Data Acquisition (SCADA) – iPower

Our GE iPower SCADA system is used for real time operations of the high voltage network, and provides telemetry and remote control of substation and automated field equipment such as ring main units and overhead switchgear. It is used for network switching in planned and unplanned (fault) situations, and provides a representation of the network and all the control points such as switches

and ring main units. It has the capability to record event logs and measurement data for future analysis.

This system also contains the load management functionality we use to manage system peak demands and to operate our load control (ripple) plants.

Microsoft Dynamics NAV

We use Microsoft Dynamics NAV as an enterprise resource planning system and primary system of record, chiefly for financial management and accounting, purchasing, but also for customer service, project management activities such as quoting and estimating, and works management.

This system has been customised to provide a number of Asset Management functions including:

- Faults and Outage Recording and Reporting;
- ICP Management and Billing;
- Asset Survey Records; and
- Vegetation Management Records.

Field Computing Tools

We have developed a range of in-house field tools based on the Google Android platform. These are used as part of our despatch process, as well as for recording job information in the field, and capturing the results of asset surveys. This system has linkages to GIS and NAV.

SharePoint Intranet Sites

The business has a SharePoint based electronic document management system (EDMS) which provides a number of functions to the business, primarily as an intranet containing a range of corporate information and providing a platform for two important Asset Management requirements:

- Public Safety Management System – for recording information on all PSMS activities and reported incidents; and
- Quality Management System – for managing all controlled documents such as policies and standards.

DigSILENT Powerfactory

Powerfactory is used as the main network planning tool for power flow analysis and network simulation. We use it for undertaking systems studies for large scale new connections, assessing network loads and identifying network constraints, and for assessing network performance and operational scenarios. We have a complete network model represented within Powerfactory.

AutoCAD

All of our design work is undertaken in AutoCAD including substation electrical designs, network projects and subdivision reticulation plans. We also create standard drawings in AutoCAD for common construction assemblies. Our network operational diagrams are also maintained in CAD format.

4.3.2 Asset Management Information

To support our asset management processes, we use the following information, some of which is held electronically, and some is held in hard copy. Our expectation is that all asset management information obtained going forward will exist in electronic format in centralised repositories.

Examples of our asset management information includes:

- **Controlled Documents** - as part of our Quality Management System (QMS), these include all Policies, Standards and Procedures;
- **Standard Drawings** – these detail how we build our network, and include standard underground and overhead assemblies used by field crews working on our assets;
- **Network Diagrams** – this information is contained in both AutoCAD drawings, as well as in the GIS system. These are used to plan and operate the network;
- **Test and Inspection Records** – outcomes of these activities are stored for future reference and for regulatory compliance;
- **Fault Records** – following planned and unplanned outages on the HV network (as indicated by SCADA events or customer calls), fault records are created in the NAV system indicating duration, cause and number of customers affected. These are used for calculating our SAIDI and SAIFI figures for regulatory reporting, as well as analysis of network performance trends; and
- **Legacy Information** – we have a range of information contained in hard copy format, particularly older test and inspection records, equipment manuals and technical documentation. Some information has been digitised, however much of it remains in hard copy and there is little benefit in digitising it.

Through our business process, we identify the information we require to make decisions relating to our network, and where necessary introduce new processes to capture this, and identify where systems need to be updated to accommodate this.

As new standards and processes are developed, these are processed through our QMS and socialised with relevant stakeholders through training sessions, toolbox meetings, team meetings and electronic communications such as email.

We have identified opportunities for improvement in how we manage our GIS data, with an improvement programme scoped in 2017 for implementation in 2018.

4.4 Works delivery processes

4.4.1 Key Works processes

An outcome of the Asset Planning process is a range of work that comprises the annual work plan. Once the annual budgets are approved, individual projects and programmes of work gain approval by way of a business case or programme justification. This section describes the key works processes in delivering the plan.

Network Projects

Network projects cover a range of work from system growth and capacity projects, through to asset replacement and renewal programmes.

Once a project has been included in the annual plan, and expenditure approval received from the appropriate authority holder, the work is initiated by the Asset Planning team. A design and specification is created (or a basic work pack for minor jobs) by the Network Projects team. This work is agreed with the Field Operations group, a Works Manager is allocated, the work is scheduled through a mix of internal and prequalified external resources, and the project enters the construction phase.

Once construction is completed the work is audited and accepted by the responsible Designer and the Network Control team, and the assets enter their operational phase.

Customer Projects

Customer projects include new connections to existing network, network extensions or new subdivision reticulation, or other customer initiated work such as street lighting connections, asset relocations or capacity upgrades.

Customer projects are initiated with requests coming through the Connections team, or directly to a Customer Projects Engineer in some cases (larger subdivisions). The customer requirements are identified, a concept and budget price is presented for the customer, and following acceptance of this a detailed design is created and quoted, and an offer is made. When the customer accepts with payment the work is passed to the Field Operations group in the same way a network project is managed.

Preventative maintenance planning

Preventative maintenance is the programme of routine inspections, testing and servicing of network assets to ensure they are performing as expected with regard to public and personnel safety, network reliability, that they are free of defects, and to survey their condition to determine when end of life replacement is required.

The type of activity, and the frequency that it is undertaken, is determined by regulatory requirements, known historic performance, manufacturer's recommendations and good industry practice. We develop maintenance standards for each asset class and these are used to develop the overall Preventative Maintenance Plan.

The Asset Management group develops the annual preventative maintenance plan in conjunction with Field Operations, who then deliver the programme over the course of the year.

Corrective maintenance planning process

Corrective maintenance addresses network defects arising from preventative maintenance surveys, replacement of components following network faults where supply has been restored but further work is required, or to address other network requirements such as dismantling of old assets or refurbishment of equipment.

Corrective maintenance is prioritised based on the following criteria:

- Public and Staff Safety Risk;
- Location of the affected equipment;
- Impact on Network Operations;
- Type and Severity of Defect; and
- Type and Age of Equipment.

The Corrective maintenance programme is developed by the Asset Management group in conjunction with the Field Operations group and the individual work packages are scoped up along with a description of the required work. During the course of the year the programme may be reprioritised to address higher risk defects on the network.

Reactive maintenance process

Our reactive maintenance process handles the situations where network assets have failed in service, or been damaged by external influences, causing an outage or presenting an immediate hazard.

Outages on the Low Voltage system typically result in a customer calling into our Customer Service team, or to our call centre, or are logged using our consumer web application. A service order is created and dispatched to a duty fault crew who then attend to the issue.

Outages on the High Voltage system are notified to a Network Controller through the SCADA system, where a substation circuit breaker or field device such as a recloser has operated. In this situation fault crews are dispatched to attend to the issue by the Network Control team, and undertake the necessary network switching and isolation to restore customers, and complete repairs to the network.

Immediate hazards can be identified by our staff or are reported by members of the public through our Customer Service team. Similar to the Low Voltage outage process, a fault crew is dispatched to attend to the issue.

Vegetation management process

We undertake vegetation management to ensure safety around our network and that network performance meets expectations. Our vegetation management is undertaken in accordance with the *Electricity (Hazards from Trees) Regulations 2003*.

We have a vegetation management team in our Field Operations group which oversees and delivers the vegetation management programme, including undertaking tree surveys, tree owner liaison and undertaking much of the field work. In some cases, external subcontractors are used.

Once a tree has been identified as presenting a hazard to the line, or is within the limit zones, a notice will be issued to the tree owner. First cuts are undertaken by us, and second and subsequent cuts are the responsibility of the tree owner.

The vegetation management strategy is set by the Asset Management group, with a focus on the subtransmission network, backbone distribution feeders, and historically poor performing areas.

Public safety services process

In addition to providing fault response and routine maintenance on the network, we provide a number of public safety services to ensure those working around our network do not come to harm or cause damage to our assets, including:

- **Close Approach Consents** – where third parties wish to operate machinery or undertake other activities within 4.0m of our network they need to be aware of the hazards and have our permission in writing in accordance with ECP34;
- **High Load Permits** – where transport operators wish to move oversized objects, typically houses, along routes which have overhead lines. In some cases, we provide an escort to assist them and reduce the likelihood of harm to people or damage to the network;
- **Plans and Markouts** – we provide plans of our network, and can undertake onsite locates or markouts to show where our buried services are; and
- **Safety Disconnections** – the disconnection of consumer supplies to enable them to undertake work on their property without the hazard of live electricity.

Members of the public or contractors can request these services from Counties Power. These requests are initially handled by our Customer Service team, and the requests are fulfilled by the Network Control or Field Operations teams depending upon the nature of work required.

4.4.2 Field delivery capability

The majority of field work is managed and delivered internally by Counties Power through our Field Operations group.

We have internal capability to undertake fault response, routine network maintenance, construction of overhead and underground networks, substation electrical work, electrical inspections and meter installations, as well as vegetation management.

We outsource some types of work where we do not have the capability and/or the capacity, for example where:

- The tasks require a specialist skill which Counties Power staff do not have and volume of work does not justify having those skills internally – for example some protection and communications work, fibre optic splicing, specialist substation work such as major plant refurbishment;
- To manage peak capacity requirements when our people are fully utilised – for example some civil and electrical construction work; and

- Where the work type is not core business to Counties Power – such as construction of substation buildings.

Using our forward work plans, we can forecast work volumes and balance work programmes to get the best utilisation of our people. Programmes such as preventative and corrective maintenance can be balanced with project work to manage peak capacity constraints and ensure high utilisation.

4.5 Risk management framework

Risk management and asset management are intricately linked. We recognise that risk management is an integral part of good management practice, corporate governance, and it is central to effective asset stewardship. We are committed to maintaining an environment that effectively minimises risk exposure to acceptable levels and ensures compliance with legislation as well as industry and organisational standards and codes. Our Risk Management Framework is aligned to the *ISO 31000:2009 Risk management – Principles and guidelines* standard and it ensures that all our risks are identified, understood and managed consistently across all levels of our business. We assess our risks in accordance with our set consequence and likelihood ratings. We monitor, treat, control and manage all of our known risks. Responsibilities for managing risk are clearly allocated. Our Risk management framework strengthens our asset management decision making and practices. We apply risk management in all our business activities, including policy development, business planning and change management.

Our Risk management framework consists of the following components:

- Risk Management Policy;
- Risk management process;
- Risk management plans;
- Risk registers; and
- Risk reporting.

4.5.1 Risk Management Policy

We have a Risk Management Policy that establishes the context for our risk management activities and ensures that the risk management process is integrated with all organisational policies, processes, and practices to support efficiency and effective management. Our Risk Management Policy also outlines our risk management principles, and the roles and accountabilities for risk management.

Accountabilities and Responsibilities

The following table presents the roles and responsibilities for risk management throughout the company:

Position	Roles and Responsibilities
Board of Directors	Corporate governance Independent review of risks and associated mitigations
Chief Executive	Risk management sponsor Representative to the Board of Directors Oversight of risk management process
Leadership Team (LT)	Ensure risk identified and managed to acceptable levels Risk management framework is in place and continuous Legislative and governance obligations are met Integration of risk management with policies, process and practices
Chief Financial Officer	Risk management administrator, in addition to LT responsibilities Schedule formal review sessions Ensure governance reporting obligations met
Managers and Team Leaders	Promote risk management culture Identify, manage and monitor risks in their groups Participate in risk planning, training and review sessions Assign and undertake responsibilities
Risk Owners	Support risk management within their area of responsibility On-going identification and assessment of risks, and responding appropriately relative to objectives Management of the relevant risk, within acceptable risk tolerance levels
Staff members	Awareness of risk management and process Everyday identification and management of risks and improvement actions to minimise risk events and impacts

Figure 4-4 Overview of Risk Management Accountabilities and Responsibilities

4.5.2 Risk management process

Our risk management process is designed to ensure that risk management decisions are based on a robust approach, assessments are conducted in a consistent manner and a common language is used and understood across our business. Our risk management process comprises the following seven steps:

Establish the context

Many factors are considered including both internal and external parameters such as operating environment, stakeholders, internal structure and capabilities, and the risk appetite of the business.

Risk Identification

Our risks are identified through operational processes including Hazard Identification by employees in the field, team and project meetings, our Health and Safety management process, and our Public

Safety Management System. Risk identification is also undertaken by members of the Leadership Team and senior staff as part of the audit and review process.

For identification purposes, we have grouped our risks into five types. These are:

- **Financial:** Risks with consequential impact on cash flow, balance sheet and financial liability;
- **Safety:** A risk event that adversely impacts on the health and safety of the public, staff or contractors of the Company;
- **Operational:** Risks affecting the efficient operation of the company including service delivery, continuity and recovery of the company. This includes customer relations and reputation;
- **Regulatory:** Risk of the Company failing to meet current or foreseeable legal obligations; and
- **Environment:** Potential or actual negative environmental or ecological impacts, regardless of whether these are reversible or irreversible in nature.

Risk Analysis

We use both qualitative and quantitative methods during the risk analysis stage. All identified risks are analysed in terms of probability, frequency, and consequence criteria in the context of our business objectives. A numeric rating is applied against the criteria of probability, frequency, and consequence. Risk ratings are based on the result of the scoring of these criteria. The probability, frequency and consequence ratings are provided in Figure 4-5 and Figure 4-6 below.

Level	Rating	Probability of the event occurring	Description
10	Almost Certain	1 event in 1 to 2 years, > 50%	The event is almost certain to occur
7	Likely	1 event in 2 to 5 years, 50%	The event is likely to occur within 5 years
1	Possible	1 event in 5 to 10 years, 20%	The event could possibly occur in the next 5 – 10 years
0.5	Unlikely	1 event in 10 to 20 years, 10%	The event is unlikely to occur possibly within 10 – 20 years
0.2	Rare	1 event in 100 years, < 1%	The event may occur only in exceptional circumstances

Figure 4-5 Probability Rating

Level	Rating	Frequency of exposure to the risk of the event	Description
10	Daily/Continuous	> 1 exposure in 24 hours	Exposure expected within a day
6	Weekly/Frequent	> 1 exposure in 7 days	Exposure expected within a week
2	Monthly/Occasional	> 1 exposure per month	Exposure expected within a calendar month
1	Yearly/Seldom	> 1 exposure per annum	Exposure expected within a year
0.2	Rare	< 1 exposure per annum	Exposure expected to be less than once a year

Figure 4-6 Frequency Rating

Level	Description	Examples of Consequence
100	Catastrophic	Major unplanned service outage for over seven days; Very serious irreversible environmental impairment of ecosystem functions; One or more fatalities and or severe injury to staff, customers or public.
40	Major	Major unplanned service outage for up to seven days only; Very serious, long-term environmental impairment to ecosystem functions; Serious injuries and or disability to one or more staff, customers or public.
15	Moderate	Unplanned service outage for up to five days; Serious medium-term environmental effects; Serious injuries to staff, customers or public, requiring hospitalisation and or lost work days.
5	Minor	Unplanned service outage for up to three days unless it affects a key customer or occurs at a significant time (e.g. major sporting event or public holiday); Moderate short-term environmental effects, but not affecting ecosystem functions; Injury to a staff member, customer, or public requiring medical treatment.
1	Insignificant	Unplanned service outage for less than 24 hours unless it occurs at a significant time (e.g. major sporting event or public holiday); No measurable impact on biological or physical environment.

Figure 4-7 Consequence Rating

Risk evaluation

All of our identified risks are evaluated against our probability, frequency, and consequence numeric ratings listed above, to ascertain the residual risk score. This assists us in our decision making to ascertain which risks need treatment and the priority for treatment implementation.

Risk treatment

We treat a risk, depending on the numeric score it has been allocated in the analysis and evaluation stage. Risk treatment involves selecting one or more options for modifying risks, and these can include the following:

- Avoiding the risk by not commencing or continuing the activity;
- Accepting or increasing risk in order to pursue an opportunity;
- Removing the risk source;
- Changing the frequency or probability;
- Changing the consequences;
- Sharing the risk with another party or parties (e.g. contracts and insurance); and
- Retaining the risk by informed decision.

4.5.3 Risk Register

Information from the risk management process is recorded, reported and monitored using our risk register. The Risk Register assists us to monitor and review risks in alignment with our business objectives.

4.5.4 Risk Reporting and Monitoring

All of our risks are periodically reviewed by our Leadership Team and are reported according to the residual risk score in Figure 4-8 below:

Residual Risk Score		Report to
> 400	Extreme	Board of Directors and Leadership Team
200 - 399	High	
70 - 199	Medium	Leadership Team and Operational Managers
20 - 69	Low	
< 20	Insignificant	

Figure 4-8 Risk Reporting Criteria

The Board of Directors receive detailed reviews of specific risks in monthly reports. They also receive a periodic report summarising the top risks that we face and the treatment applied to those risks. The Leadership Team and other senior managers meet periodically to review our risk management position.

4.5.5 Project risk management planning

In addition to corporate level risk management activities, a risk management plan is produced for each activity or project the business undertakes. Each project risk management plan specifies the risks relating to that project and the approach to risk management include the risk treatments, and any relevant task Job Safety Analysis (JSAs) and work standards that apply to the project.

The design and implementation of each project risk management plan is to consider our overall business objectives.

4.6 Public Safety Management System (PSMS)

Public safety is a critical component of our risk management framework. We adopt the requirements set out in NZS 7901:2008 *Electricity and gas industries – Safety management systems for public safety* to safeguard the public or their property from safety-related risks arising from the presence or operation of our network distribution assets.

In 2017, our certification continued after a review audit was conducted by Telarc against NZS 7901:2008 and NZS7901:2014. This follows recertification in 2015 and initial certification in 2012.

4.7 High impact, low probability events (HILP)

We are subject to a number of potential HILP events, which could give rise to a major unplanned service outage for an extended period of time. HILP events can have a widespread impact, but would be incredibly expensive to avoid, if at all. Accordingly, we have a responsibility to plan and manage for HILP events as best we economically and practically are able to. Within this context, our policy is to ensure the timely restoration of power supply; effective communication; a safe environment for staff, contractors and the wider community; and efficient provision of information tools for critical business activities should we be subject to a HILP event.

Our critical business activities relate primarily to power security and reliability, customer service, and quality of supply. Events that could interrupt our critical business functions include natural disasters such as flood, tropical cyclones and windstorms, electrical storms, volcanic eruption, or earthquake; airspace incident; asset failure; communications failure; Information System security breach or loss; and loss of supply from Transpower or generators.

4.8 Emergency response and contingency plans

We place an emphasis on pre-event planning for HILP events. Our assets are designed to provide a certain level of resilience under a normal operating environment. Natural disasters and emergency situations subject our assets and operations to greater stress to what they are designed to withstand, which may result in outages. While our network is not designed to withstand significant HILP events, we have response policies, procedures and contingency plans in place and critical emergency spares are held in stock to ensure that our power supply is restored in as minimum time as possible. Our contingency plans provide details concerning expected events and the necessary response. These include, for example, contingency operational plans for loss of SCADA and communications networks, and switching schedules associated with the loss of transformer banks and subtransmission lines.

Lifeline Utility and Engineering Lifeline Groups

To help make New Zealand resilient to disasters, the Civil Defence and Emergency Management (CDEM) Act 2002 stipulates the responsibilities and roles of key organisations that provide an essential service within New Zealand. Our core business of electricity distribution is an essential service and under the CDEM Act we have been classified as a “Lifeline Utility.” As such, we must:

- Ensure that we are able to function to the fullest possible extent, even though this may be at a reduced level, during and after an emergency;
- Have a plan for functioning during and after an emergency;
- Participate in CDEM strategic planning; and
- Provide technical advice on CDEM when required.

We are members of the Auckland Engineering Life Lines Group and the Waikato Engineering Lifelines Group. Lifeline groups are a voluntary group of organisations with representatives from territorial authorities, major utilities and the transportation sector. The emphasis of these groups is on pre-event planning rather than taking a post-event operational role. Collaborating with other Life Line members provide a much greater understanding of the general vulnerabilities and interdependencies that individual utility response plans need to consider. As well as further developing the preparedness of

lifelines operators for major hazard events, one of the key areas of emphasis is to create and maintain awareness of the importance of lifelines to the community at large.

Civil Defence Plan

We have a Civil Defence Plan in place which details how we respond to a Civil Defence Emergency.

Information System Security Breaches or Losses

We place an emphasis on the security of information within all business systems. We have in place comprehensive data backup and recovery policies. Our operating systems and SCADA systems are particularly critical, therefore they require effective protection from external and malicious access. We participate in the New Zealand Control Systems Security Information Exchange. This organisation is designed to facilitate the exchange of information between its members, in a confidential and trusted environment, concerning threats, vulnerabilities and incidents of electronic attack on control system networks and environments.

4.9 Asset Management Maturity

4.9.1 AMMAT

The Asset Management Maturity Assessment Tool (AMMAT) is a self-assessment required by the Commerce Commission as part of the information Disclosure Schedules, included in Appendix C. It is a set of questions derived from the UK Standard PAS 55 (now superseded by ISO 55000) which requires Distributors to rate their asset management capability through 31 questions.

The purpose of the AMMAT is for Distributors to identify the level of maturity they have in asset management activities and opportunities for improvement, and provide a structured method of benchmarking.

4.9.2 AMMAT Assessment

The completed Asset Management Maturity Assessment Tool is included Schedule 13 of this AMP.

The results from this are shown in the figure below and are consistent with previous years, with scores generally of 2, with some achieving a score of 3, and an average of 2.3.

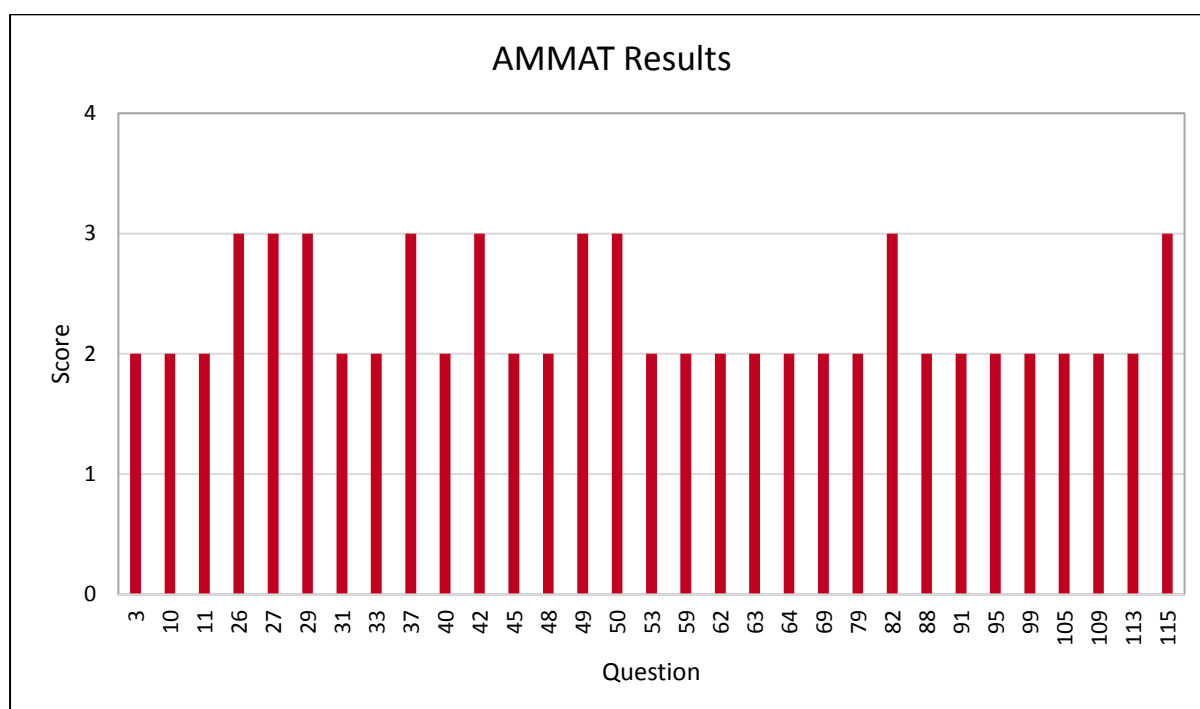


Figure 4-9 AMMAT Results

4.10 Improvement Initiatives / Continuous Improvement

A review of the AMMAT results, along with the wider review of asset management practices in the business currently underway shows there are a number of areas of improvement required, with focus in the following areas. Updates will be provided in future year plans.

- **Asset management policy and strategy** – further development of these documents, including socialising and sharing these within the business and relevant information being provided to stakeholders;
- **Asset management plans** – aside from this AMP which is produced to meet regulatory compliance requirements, more detailed asset management plans for specific asset categories are required to be developed and maintained, including the role different parts of the business play in those plans;
- **Training, awareness and competence** – improved structure and documentation relating to how resources are planned, and for the organisation to have sufficient trained and competent resources to deliver on the requirements for asset management activities. We are continuing to develop our competency framework, with a focus on asset management activities;
- **Information systems and management** – improvements in how the organisation determines the requirements for, and manages the systems for asset management activities. This plan has already identified the need for a major systems review and renewal, and these will be addressed as part of this work;
- **Risk management** – improving how we manage asset specific risk, including further development of asset management strategies focussed on that risk. Additionally, how we manage corrective actions arising from risk assessments of incident reviews;

- **Asset lifecycle activities** – improvements in the development and documentation relating to design, construction and maintenance activities. These are being addressed through standards review and development from 2017, focussing on high risk activities first; and
- **Investigation, audit and corrective actions** – improvement in the documentation and processes around asset management related audit, outcomes and corrective actions. Linking those processes back into business as usual activities.

5 Renewal and Maintenance

This chapter outlines the population profiles, the inspection and maintenance requirements, and the replacement expenditure for each of our asset categories. Our asset categories covered in this chapter are:

- Subtransmission;
- Zone substations;
- Distribution and LV lines;
- Distribution and LV cables;
- Distribution substations and transformers;
- Distribution switchgear;
- Grid scale battery storage system;
- Other network assets;
- Other operational assets; and
- Assets owned by Counties Power at GXPs.

The refinement of our fleet management practices is an ongoing activity within Counties Power. Accordingly, the practices recorded in here are under review and with the further development of comprehensive asset fleet strategies to continue over the next 12 months. We also expect our management planning to continue to evolve over this time.

5.1 Asset quantity summary

Asset Category	Type	Quantity ¹
Subtransmission		
Poles	Concrete Pole	1,340
	Wooden/other Pole	16
	Steel Pole	147
	Steel Tower	10
Lines	110kV	65.8 km
	33kV	72.1 km
Cables	33kV	1.1 km
Zone Substation		
Substation Buildings		10
Power Transformers	110/22kV	6
	33/11kV	9
Circuit Breakers	110kV CBs	14
	33kV CBs	12
	22kV CBs	44
	11kV CBs	36
Station Disconnectors	110kV Disconnectors	2
	33kV Disconnectors	29
Distribution and LV lines		
Poles	Concrete Pole	25,291
	Wooden Pole	2,019

Asset Category	Type	Quantity ¹
	Other Pole	118
Cross Arms	Wooden/Steel	48,294
Conductors	22kV	570.7 km
	11kV	902.8 km
	Low Voltage (LV)	754.6 km
Distribution and LV cables		
Distribution Cables 22kV	XPPE	150.5 km
Distribution Cables 11kV	PILC	22.7 km
	XLPE	52.0 km
LV Cables	PVC	87.2 km
	XLPE	493.5 km
	Other	67.3 km
Street Light Cables	PVC	42.7 km
	XLPE	1.4 km
	Other	2.2 km
Distribution Substations and Transformers		
Distribution Transformers	Pole mounted	3,128
	Ground mounted	805
Auto Transformers		50
Distribution Switchgear		
Ring Main Units		198
Air Break Switch	11kV	155
	22kV	109
Gas Insulated Switch ^{*2}	11kV	41
	22kV	50
Spur Line Isolator	11kV	839
	22kV	627
Reclosers ^{*3}	11kV	7
	22kV	20
Grid-scale battery storage system		
Grid scale battery storage system		1
Other System Fixed Assets		
LV Pillars and Pits		12,212
Capacitor banks		29
Voltage Regulators		7
Protection relays		144
Load control relays		3,568
Ripple Injection plant		5
Auxiliary battery banks		27
Remote Terminal Units		222
Notes: 1: Asset quantity as at Oct-17. 2: All Gas Insulated Switches are rated at 22kV, operating voltage are as shown in the above table. 3: All Reclosers are rated at 22kV, operating voltages are as shown in above table.		

Table 5-1 Asset quantity summary

5.2 Subtransmission

The subtransmission network transports electricity from Transpower's Grid Exit Points to our zone substations. It consists of:

- Overhead lines, which in turn are made up from poles, cross arms and conductors;
- Underground cables;
- Substation buses and support structures; and
- Circuit Breakers.

We have six 110kV subtransmission circuits with a total length of 65.8 km, all of which is overhead line. The total length of 33kV subtransmission circuits on our network is 72.1 km of overhead lines and 1.1 km of underground cables. Portions of our subtransmission network have reached the end of their life expectancy or have capacity constraints and are scheduled to be rebuilt during this AMP planning period. This is discussed further in Section 6 – Network Development.

5.2.1 Quantity and life expectancy of subtransmission assets

Table 5-2 below summarises the construction material, quantity and life expectancy of our subtransmission network by asset type.

Asset	Construction Type	Quantity	Life Expectancy
Subtransmission Poles	Concrete Pole	1,340	80 years
	Wooden/other Pole	16	45 years
	Steel Pole	147	55 years
	Steel Tower	10	55 years
Subtransmission Lines	110 kV	65.8 km	80 years
	33 kV	72.1 km	80 years
Subtransmission Cables	33 kV	1.1 km	55 years

Table 5-2 Subtransmission asset summary (asset quantity as at Oct-17)

The age profile, condition, inspection and maintenance requirements and the 10-year forecast expenditure for each asset class are described below.

5.2.2 Management approach

Our subtransmission assets are critical to provision of services to our stakeholders and are the backbone of our network. The impact of a failure on a subtransmission circuit has the potential to affect a large number of customers for a long duration.

Our approach is to ensure that these assets are subject to robust inspection and corrective maintenance programmes, as well as appropriate asset renewal programmes, to ensure their reliability and availability. Defects are to be addressed with high priority, and investigations into failures undertaken to avoid recurrence of issues given the importance of these circuits.

5.2.3 Subtransmission lines and poles

Our subtransmission network is predominantly overhead line circuits, supported by wood, concrete and steel poles, as well as a section of line supported by steel lattice towers. Older parts of our subtransmission network have copper and ACSR conductors and since the mid-1990s, we have used AAC as the standard conductor for our subtransmission network. We select the most appropriate type and size of conductor on a project specific basis.

Age profile

Figure 5-1 shows the age profile of our subtransmission network.

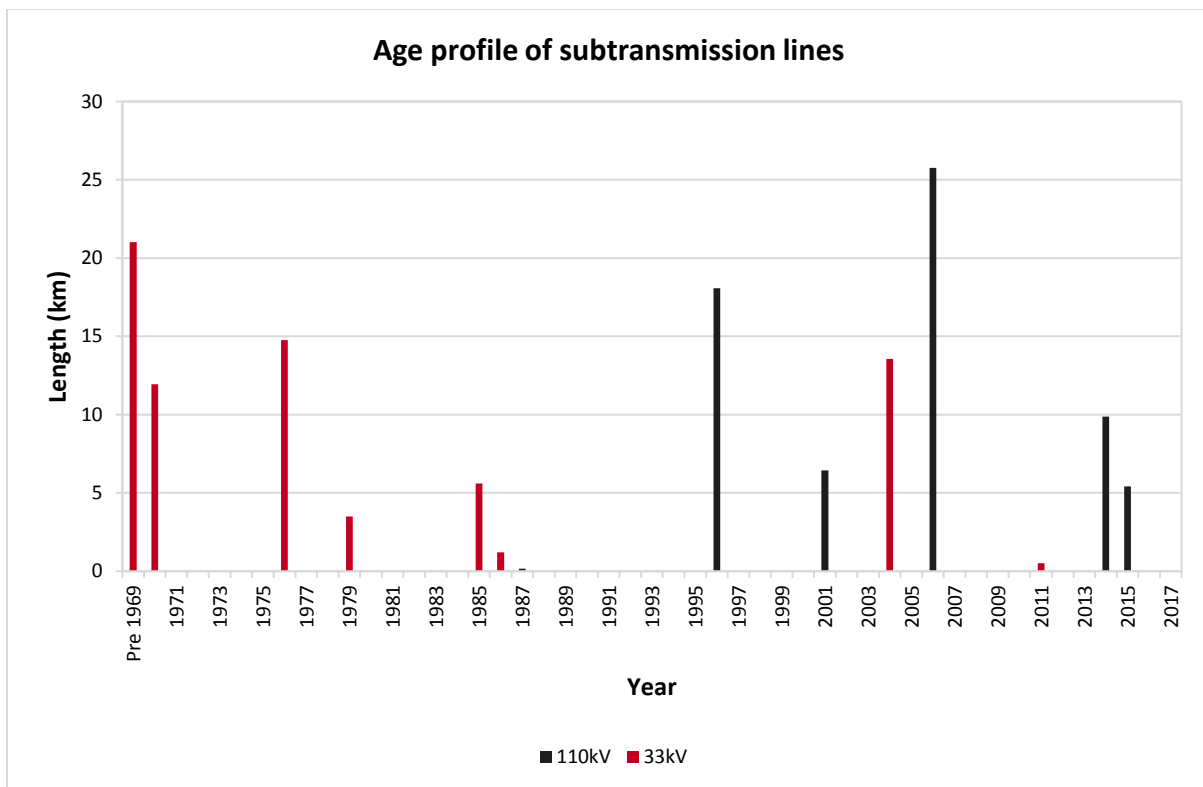


Figure 5-1 Age profile of Subtransmission Lines

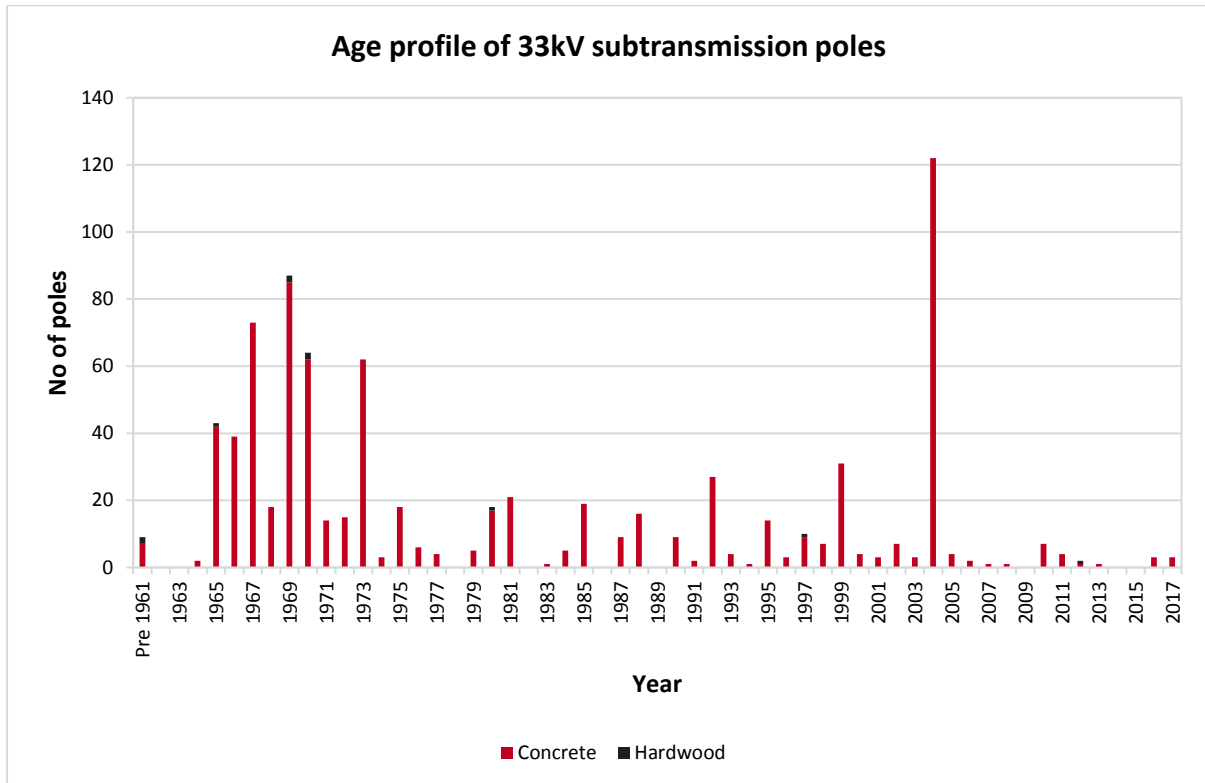


Figure 5-2 Age profile of 33kV subtransmission poles

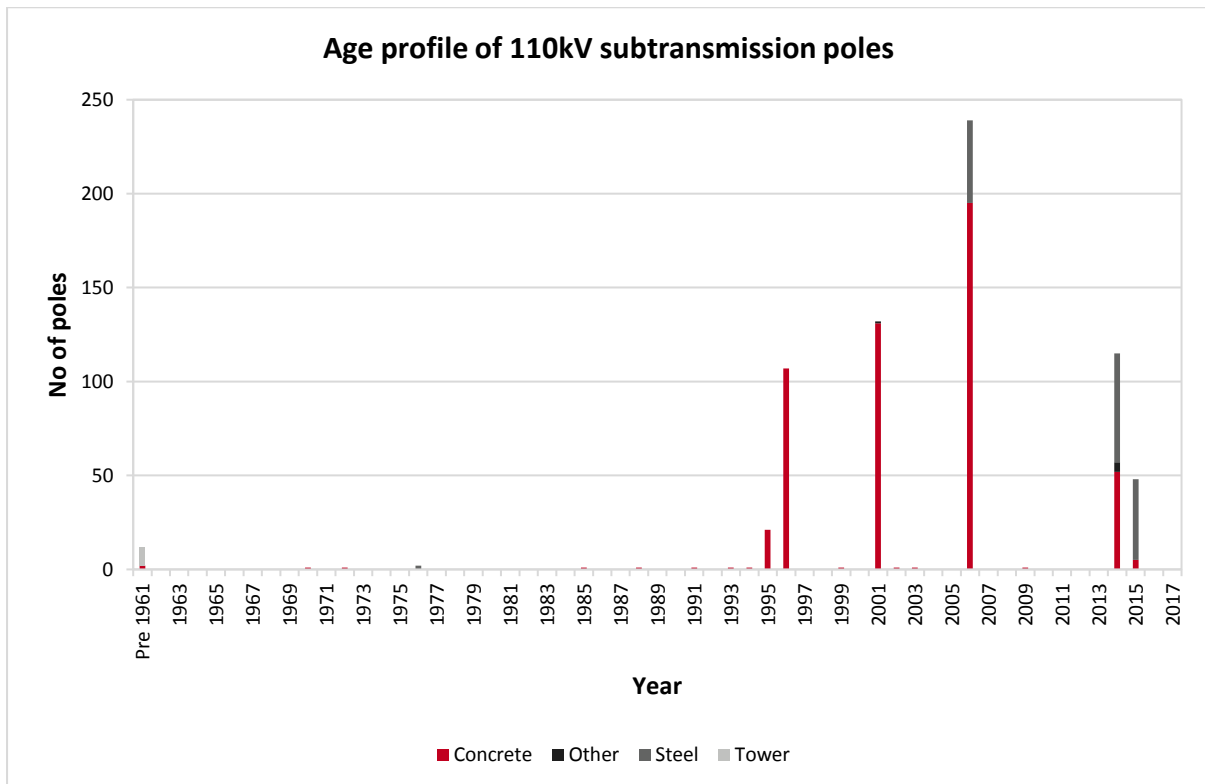


Figure 5-3 Age profile of 110kV subtransmission poles

Inspection and maintenance practices

Our inspection cycles for subtransmission lines and poles are:

Activity	Type	Frequency
Overhead line feeder patrol	Inspection	Annual
Detailed Pole and Line Condition Assessment	Inspection	5 yearly
Insulator Washing – Glenbrook area	Routine Servicing	Annual
Vegetation Survey	Inspection	Area Specific

Table 5-3 Inspection cycles for subtransmission lines and poles

Corrective maintenance is undertaken on overhead subtransmission lines when defects are identified as part of routine asset condition surveys. Examples include insulator and cross arm replacement, replacement of possum guards, stay wires, and other minor components.

In areas subject to heavy pollution, particularly around the Glenbrook steel mill, insulator washing is undertaken periodically to reduce contaminant build up and reduce the likelihood of tracking and flashover.

Renewal programme

Eastern area

The 110kV lines in the Eastern Area supplying Opaheke, Pukekohe and Tuakau are generally in good condition as they have been constructed in the past 20 years, and only require minor maintenance.

One section of line supplying Opaheke and Ramarama is constructed on steel towers which are part of a former transmission line originally constructed by Transpower's predecessors but now owned by Counties Power. These towers are over 85 years old and are at a stage of life where major component replacement will be required in this planning period, as the last major remedial works programme was undertaken in the early 2000s. A detailed condition assessment was undertaken in 2017 and identified 30 insulators with deteriorated condition, and damage to tower leg members at one site. Replacement work was completed in early 2018 to address the identified issues ahead of the line rebuild in 2021/22 which is part of the network development plan for supply to Drury South business park development (see section 6.4.2).

The overhead line to Mangatawhiri is in below average condition, with some components at end of life requiring replacement within this planning period. These issues will be addressed as part of a wider development plan for this area and as such no specific replacement project is included in this section of the plan.

Western area

The 33kV subtransmission line from Waiuku to Maioro is at end of life, with significant maintenance required during the planning period. Given the previous uncertainty around the future of the mine site operated by NZ Steel, the major consumer on this line, the rebuild of the line will only be undertaken once agreed with NZ Steel through appropriate commercial arrangements. A condition based refurbishment will be required if the line remains in service through the planning period. A

budget provision of \$900,000 have allowed for in the later part of the planning period subject to the future of the substation, and customer requirements.

The 33kV East line from Glenbrook to Waiuku has identified capacity constraint within the planning period, and any condition based renewal will be undertaken as part of a larger capacity augmentation project detailed in section 6 Network Development.

Out of service lines

As well as in-service subtransmission lines, we also own lines which are no longer used - however we may use these again in future. We have to inspect and maintain them to ensure they do not present any public safety hazard. Maintenance plans for these are outlined below.

- Orams Rd 110kV line, this line is at end of life. This line has little strategic value now, and is largely inaccessible due to the environmental conditions and land development. Removal of pole structures, conductors and most of the unused steel towers was completed in 2017; Removal of the remaining footings of the unused steel towers is to be completed in early 2018.
- Bremner Road to Karaka 33kV line, this will remain in place and it will be inspected with a detailed condition assessment in 2018/19. This has been allowed for in our corrective works programme; and
- Bombay to Tuakau 33kV line sections along Pokeno Road to Potter Road, and Huia Road to Pokeno Road will be removed in 2018/19 with \$50,000 budget provision in our corrective works programme. The remaining section from Bombay GXP to Huia Road will remain in service as it has strategic value for supply to new developments in the area. This section will be inspected and maintained as part of our preventative maintenance programme.

5.2.4 Subtransmission cables

We have 1.1 km of 33 kV Cross-linked polyethylene (XLPE) cables⁹ installed in our subtransmission network at various locations. The life expectancy of our 33 kV XLPE cables is 55 years, with the first replacement expected well beyond this planning period.

Age profile

Figure 5-4 shows the age profile of our subtransmission cables. The age of XLPE cables ranges from 5 to 37 years old. The weighted average age of the 33 kV subtransmission cables is 11 years.

⁹ Based on operating voltage.

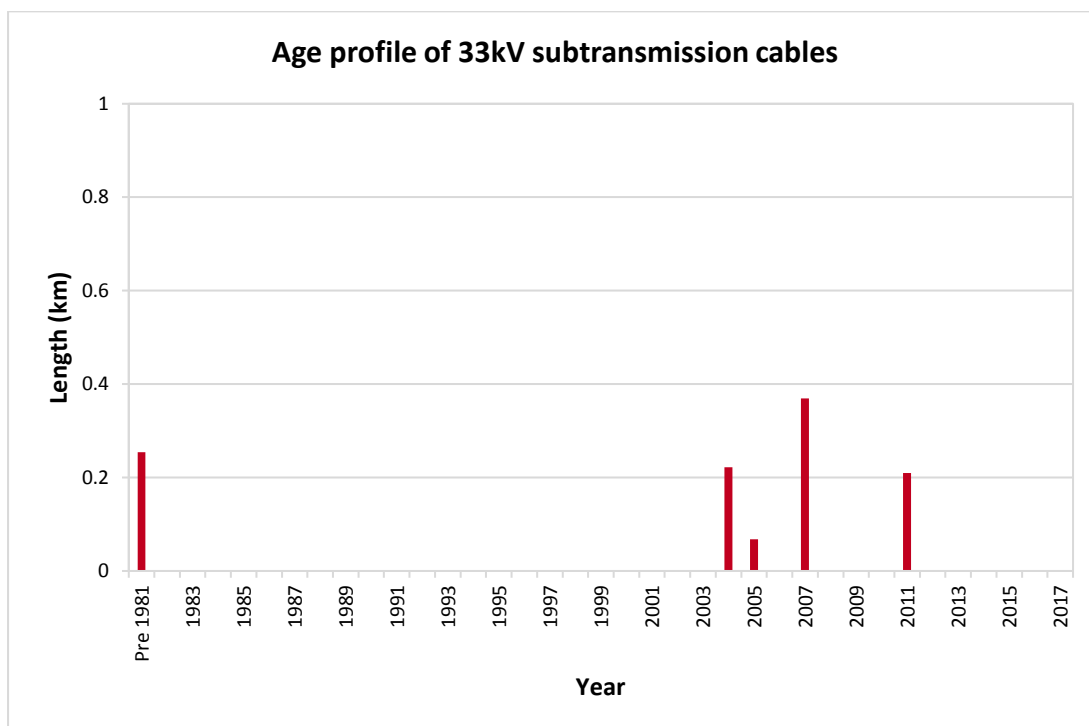


Figure 5-4 Age profile of 33 kV Subtransmission Cables

Inspection and maintenance practices

There are no specific planned maintenance activities on subtransmission cables on our network as we have a small quantity and their construction type is generally very reliable. Cable terminations are inspected as part of the overhead line asset condition survey, and defects remediated as required.

Diagnostic tests can be undertaken on an 'as-required' basis where performance indicates an issue exists or following a fault, such as insulation resistance testing, serving tests and cable partial discharge tests.

Renewal programme

Our management strategy for 33kV cables is to reactively replace them when required. Given the age of the cables we do not expect any renewals will be required within the planning period.

5.2.5 Summary of Subtransmission Expenditure Forecast

Expenditure Forecast (\$000)	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028
Capital Expenditure										
Maioiro line refurbishment	-	-	-	-	-	-	450	450	-	-
Other subtransmission renewal	50	50	50	50	50	50	50	50	50	50
Capital Expenditure Total	50	50	50	50	50	50	500	500	50	50
Operational Expenditure										
Bombay - Tuakau 33kV line section removal	50	-	-	-	-	-	-	-	-	-
Opaheke - Karaka 33kV line condition assessment and repair	10	50	-	-	-	-	-	-	-	-
Subtransmission line maintenance	130	120	120	120	120	120	120	120	120	120
Operational Expenditure Total	190	170	120	120	120	120	120	120	120	120

Table 5-4 Subtransmission expenditure forecast summary

5.3 Zone Substations

Zone substations consist of power transformers, switchboards and substation buildings. Power transformers convert subtransmission voltage (110kV and 33kV) to distribution voltage (22kV and 11kV). Switchboards control and protect the network.

We own eight zone substations of which five operate at 33/11kV and three operate at 110/22kV. The construction dates of our zone substations range from 1956 to 2014. Six of our zone substations have N-1 security and two have N security. Our security standard is discussed in further detail in Section 6 - Network Development. In addition to the eight zone substations, we have one major switching station at Pukekawa and is covered in this section.

5.3.1 Quantity and life expectancy of zone substation assets

Table 5-5 below summarises the construction material, quantity and life expectancy of our Zone Substation assets.

Asset	Construction Type	Quantity	Life Expectancy
Substation Buildings		10	50 years
Power Transformers	110/22kV	6	60 years
	33/11kV	9	60 years
Circuit Breakers	110kV CBs	14	45 years
	33kV CBs	12	45 years
	22kV CBs	44	45 years
	11kV CBs	36	45 years
Station Disconnectors	110kV Disconnectors	2	45 years
	33kV Disconnectors	29	45 years

Table 5-5 Zone substation asset summary (asset quantity as at Oct-17)

The age profile, condition, inspection and maintenance requirements and the 10-year forecast expenditure for each asset class are described below.

5.3.2 Management approach

Zone Substations, like subtransmission assets, are a critical part of our network, and have high impact when they don't perform as expected. They are also prominent parts of the communities in which they are located, and therefore need to be 'good neighbours' – clean, tidy, secure and not causing harm to public.

Key maintenance outcomes for our zone substations are to ensure they are safe and secure, that they meet network and environment performance standards (including seismic compliance, oil containment, discharge controls, noise levels, etc.), that they are free of vermin and nesting animals and are not vandalised. Routine inspections also inform us of when major plant is deteriorating or needs corrective maintenance.

5.3.3 Power transformers

Power transformers at our Zone Substations step down the subtransmission voltage (110 kV or 33kV) to distribution voltage (22kV or 11kV).

We have 15 power transformers at our Zone Substations with installation dates ranging from 1956 to 2014. Power transformers installed prior to 1990 were 33/11kV. Since 2000, six 110/22kV transformers have been installed in line with our plans to develop higher subtransmission and distribution voltages within our network.

Age profile

Figure 5-5 shows the age profile of our power transformers. The weighted average age of the transformers is 32 years.

Based on a life expectancy of 60 years, we expect to be replacing the oldest Zone Substation power transformer in our system (the 33/11kV, 5 MVA transformer at Ramarama) within the next 3 to 5 years. We also anticipate replacing the next batch of power transformers in the mid to late 2020s – these are two located at Maoro, and one at Mangatawhiri. Network Development Plans outlined in Section 6 address these issues.

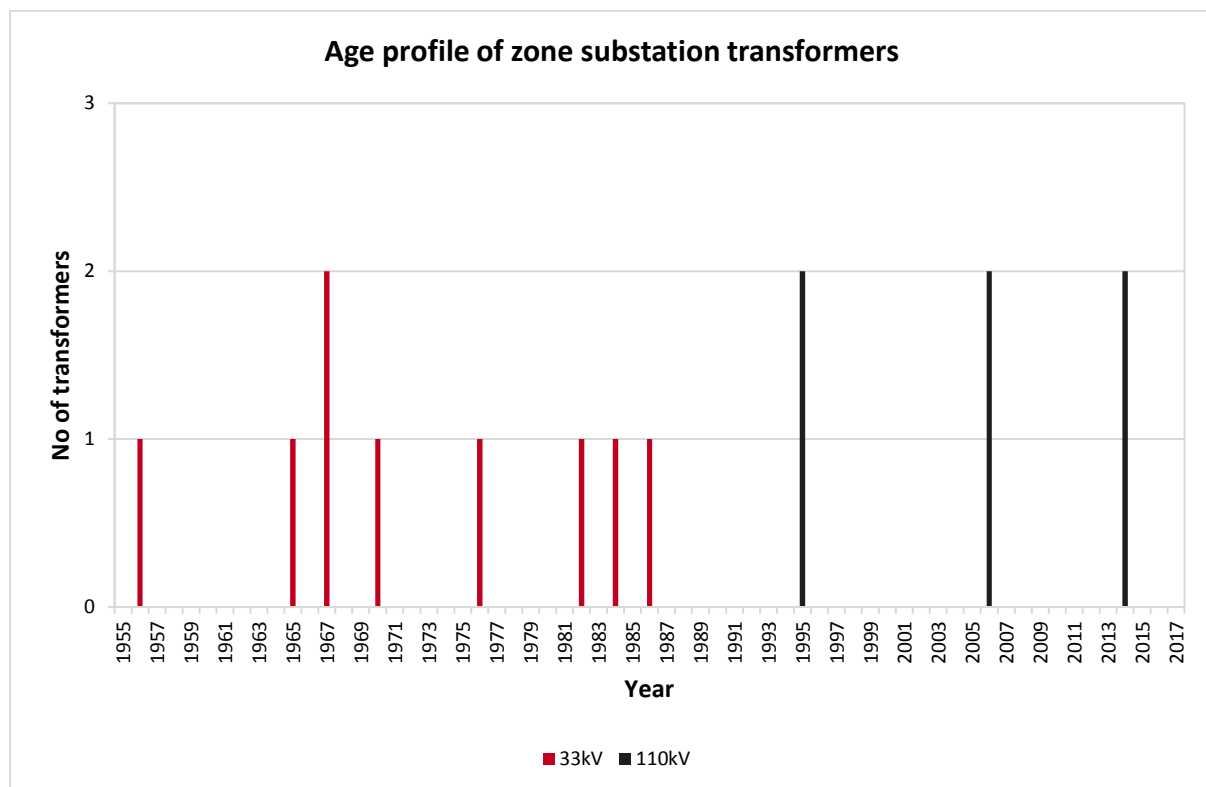


Figure 5-5 Age profile of Zone Substation Transformers

Inspection and maintenance practices

Our inspection cycles for Zone Substation power transformers are:

Activity	Type	Frequency
Routine Visual Inspection	Inspection	Monthly with Sub Visit
Detailed Inspection and Condition Assessment	Inspection	Annual
Transformer oil DGA analysis	Routine Test	Annual
Transformer and Bushing Maintenance	Routine Servicing	3 yearly
Tap changer Maintenance	Routine Servicing	3 yearly / or 10,000 operations

Table 5-6 Inspection cycle for Zone Substation Power Transformers

Renewal programme

Based on age and condition information, replacement of transformers at Ramarama, Maioro (x2), and Mangatawhiri is expected in this planning period. Each of these sites has a development path outlined in Section 6 Network Development which will lead to the transformers being replaced for capacity reasons.

5.3.4 Zone substation switchgear

Age profile

We own 106 circuit breakers and 31 disconnectors at our Zone Substations. Figure 5-6 shows the age profile of our Zone Substation circuit breakers. The weighted average age of the circuit breakers is 25 years.

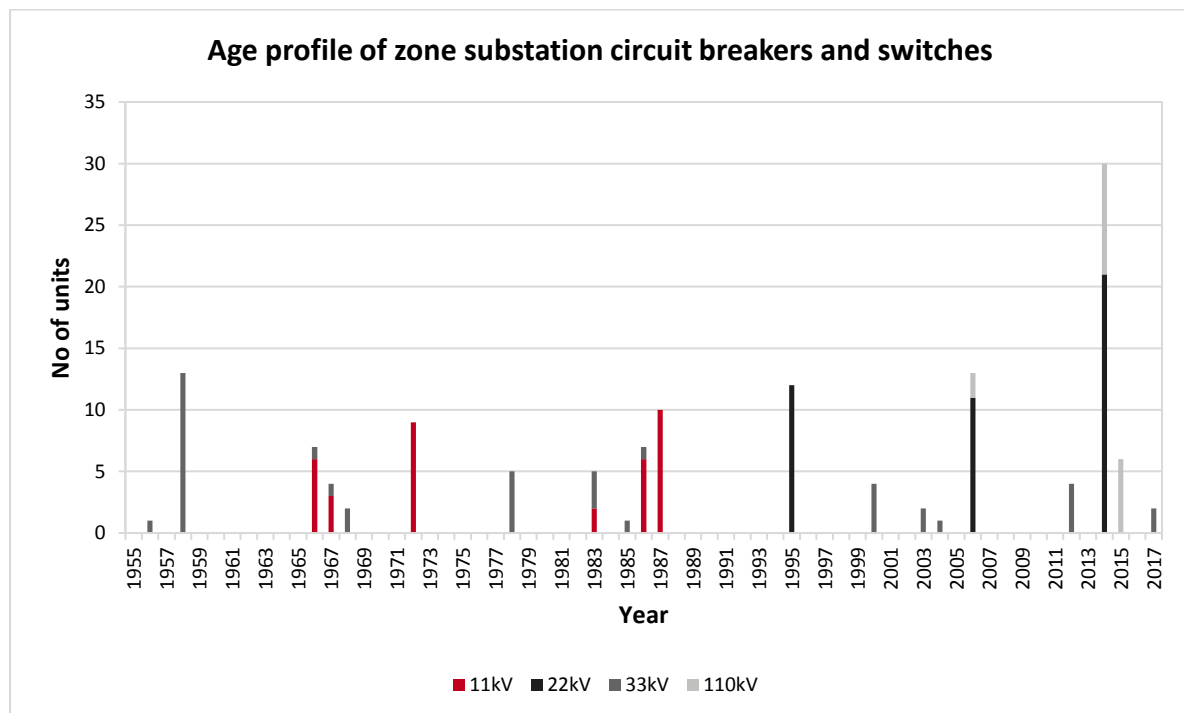


Figure 5-6 Age profile of Zone Substation Circuit Breakers and Switches

Inspection and maintenance practices

Our inspection and maintenance cycles for Zone Substation switchboards and switchgear are:

Activity	Type	Frequency
110kV or 33kV Circuit Breaker Inspection (incl. partial discharge and thermal imaging)	Inspection	Annual
110kV or 33kV Gas Insulated CB Maintenance	Routine Maintenance	5 yearly
33kV Oil Insulated CB Maintenance	Routine Maintenance	3 yearly / or 3 fault operations
22kV or 11kV Switchboard Inspection (incl. partial discharge scan and thermal imaging)	Inspection	Annual
22kV or 11kV Circuit Breaker Maintenance (Gas/Vacuum)	Routine Maintenance	5 yearly
11kV Circuit Breaker Maintenance (Oil)	Routine Maintenance	3 yearly / or 3 fault operations

Table 5-7 Inspection and Maintenance cycles for Zone Substation Switchboards and switchgear

Renewal programme

During the planning period, we will have a need to replace 11kV switchboards at Waiuku, Maioro, and Mangatawhiri due to age and condition. These switchboards are air insulated with oil filled circuit breakers. This expenditure is included in the forecasts, however as the network development plan further progresses, these replacements may be addressed through alternative projects such as area development plans leading to new substation builds.

The last older style 33kV bulk oil circuit breaker on the network at Waiuku will be replaced as part of a substation redevelopment project for Waiuku in the first half of the planning period (see section 6.5.4).

There will be a need to replace the 11kV switchboard at Maioro, due to age and condition, around 2024/25. Annual switchboard partial discharge testing and inspection will continue to be part of the ongoing condition monitoring of the switchboard. An option exists to utilise the switchboard from the existing Ramarama substation if and when it is decommissioned and the timing is right (see Section 6), or to purchase a new switchboard for the site. The expected cost of this project ranges from \$100,000 to \$350,000 depending on the final solution selected. This investment is dependent upon the future of the Maioro site and major customer requirements, however an allowance of \$350,000 has been made in 2024/25.

The 22kV bus section circuit and feeder breakers at Opaheke had additional maintenance carried out in 2017 to address a condition issue associated with partial discharge. While we continue to monitor the condition, additional maintenance will be carried out on an annual basis with an allowance of \$10,000 until switchboard replacement in 2022/23 for capacity reasons (see section 6).

5.3.5 Other primary equipment

This category includes primary equipment at our Zone Substations not covered by other categories such as outdoor bus structures, instrument transformers and earth grids.

Inspection and maintenance practices

Our inspection and maintenance cycles for Zone Substation other primary equipment are:

Activity	Type	Frequency
Instrument Transformer Inspection	Inspection	Annual
Substation Earth Grid Inspection	Inspection	Annual
Substation Earth Grid Test	Routine Test	3 yearly

Table 5-8 Inspection and maintenance cycles for Zone Substation other primary equipment

Renewal programme

There are no identified renewals required for other substation primary plant included in this plan and expenditure forecasts. Any replacement or renewal activity will arise from routine inspection and condition assessment, or as a result of other primary plant upgrade (e.g. new instrument transformers required with a new circuit breaker).

5.3.6 Substation buildings and grounds

Substation buildings provide physical protection for indoor switchgear, metering, control, protection and communications equipment against the environment.

Age profile

Figure 5-7 shows the age profile for our substation buildings. We have 10 buildings at our Zone Substations with installation dates ranging from 1954 to 2014. The weighted average age of our buildings is 39 years.

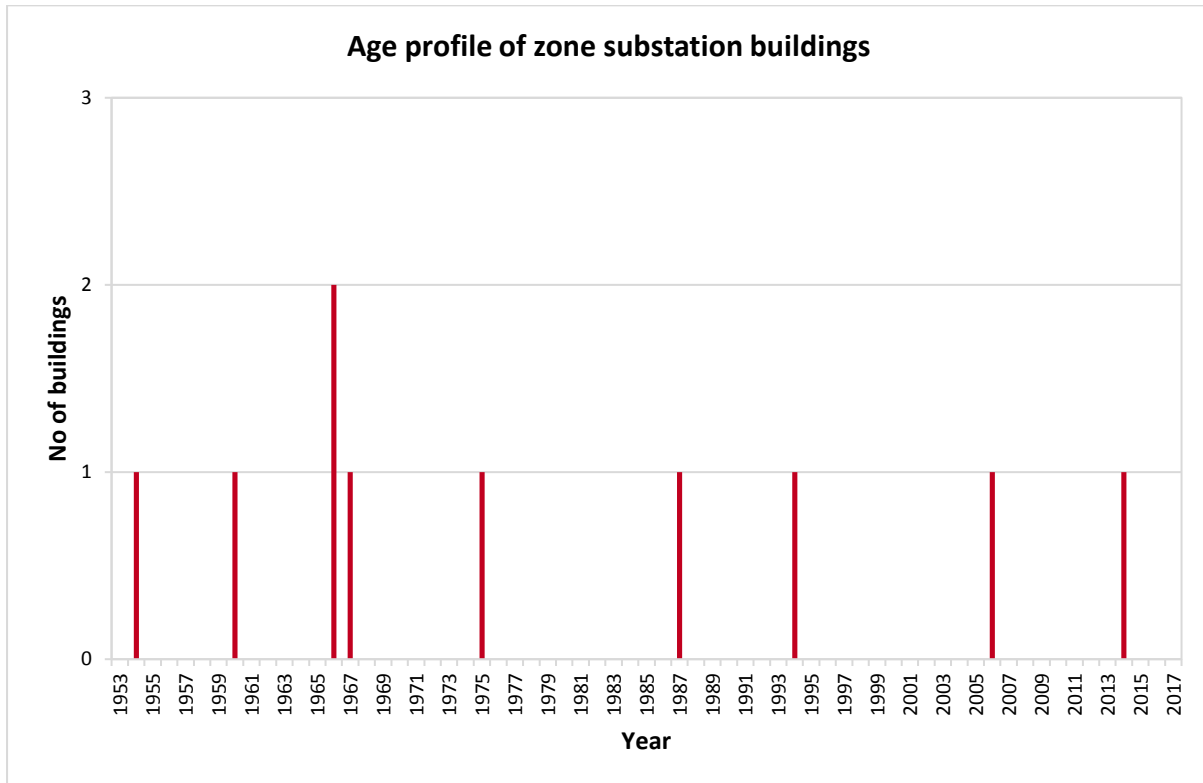


Figure 5-7 Age profile of Zone Substation Buildings

Inspection and maintenance practices

Our inspection and maintenance cycles for Zone Substation buildings and grounds are:

Activity	Type	Frequency
Routine Substation Inspection	Inspection	Monthly
Building and Grounds Maintenance	Routine Maintenance	Monthly

Table 5-9 Inspection and maintenance cycles for Zone Substation buildings and grounds

Renewal programme

The substation buildings are generally in good condition, with minor repair and renewal work undertaken as required.

The Waiuku zone substation building has been identified as having less than 33% of new building seismic standard and will require strengthening if the site is not redeveloped as part of the substation development plan for Waiuku (refer to Section 6 - Network Development). The other zone substation buildings have not yet been assessed for seismic risk. Assessment of the older sites (Mangatawhiri, Pukekawa, Ramarama, Karaka and Maioro) is to be completed in early 2018. Pukekohe, Tuakau and Opaheke have all been constructed within the past 20 years to modern building standards.

The old Tuakau 33kV substation is planned to be disposed of in the short term, as this site is no longer required. Some work is required to clear electrical plant from this site and an allowance of \$50,000 is included in expenditure forecast for 2018/19.

5.3.7 Summary of zone substation expenditure

Expenditure Forecast (\$000)	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028
Capital Expenditure										
Replace Maioro 11kV switchboard	-	-	-	-	-	-	350	-	-	-
Other zone substation renewal	150	50	50	50	50	50	50	50	50	50
Capital Expenditure Total	150	50	50	50	50	50	400	50	50	50
Operational Expenditure										
Power transformers	190	150	140	100	100	100	100	100	100	100
Switchgear	120	120	120	120	110	110	110	110	110	110
Other primary equipment	70	70	70	120	120	120	120	120	120	120
Substation buildings	140	90	90	90	90	90	90	90	90	90
Operational Expenditure Total	520	430	420	430	420	420	420	420	420	420

Table 5-10 Zone Substation expenditure forecast summary

5.4 Distribution and LV lines

We transfer electricity from our zone substations to our consumers through our 22kV or 11kV distribution network and our 400V Low Voltage (LV) network which consists of both overhead lines and underground cables. Lines and Cables have quite different maintenance and renewal requirements, and are treated separately in asset management planning.

We have 570.7 km of 22kV lines, 902.8 km of 11kV lines and 754.6 km of 400V LV lines. Our conductors consist of a mix of copper and aluminium (ACSR¹⁰, AAC¹¹ and AAAC¹²). Overhead lines generally have lower capital and overall lifecycle cost than underground cables.

5.4.1 Quantity and life expectancy of distribution and LV lines

Asset	Construction Type	Quantity	Life Expectancy
Poles	Concrete	25,291	80 years
	Wooden	2,019	45 years
	Other	118	45 years
Cross Arms	Wooden/Steel	48,294	45 years
Conductors	22 kV	570.7 km	80 years
	11 kV	902.8 km	80 years
	Low Voltage (LV)	754.6 km	80 years

Table 5-11 Distribution and Low Voltage lines asset summary (asset quantity as at Oct-17)

5.4.2 Management approach

In our management of overhead lines, our primary focus is on safety, and particular attention is paid to those lines in areas in high risk special locations, such as around schools, playgrounds, public recreation spaces, commercial and high population density areas.

Due to risks identified and increasing failure rates associated with small diameter copper conductors (16mm² or 25mm²) and ACSR conductor (Swan 20mm²), we have extended our structured replacement programme to address both copper and Swan conductor risk in urban areas from 2017/18, with priority given to those around schools and public spaces, as well as in rural areas with

¹⁰ Aluminium Conductor Steel Reinforced

¹¹ All Aluminium Conductor

¹² All Aluminium Alloy Conductor

repeat performance issues. Factors to consider are the fault level of the area, public safety risk (likelihood and consequence), as well as considering other network development needs to address capacity constraints.

Additionally, under the *Electricity (Safety) Regulations 2010*, we have to ensure that the structures that support our lines are capable of withstanding service loads. This requires us to inspect and where necessary test poles and other components, and replace those found to be unsafe within specified periods.

We also have to make sure our lines do not get affected by trees, third parties working on and around our network, and high loads travelling along roads.

5.4.3 Distribution and LV conductors

Age profile

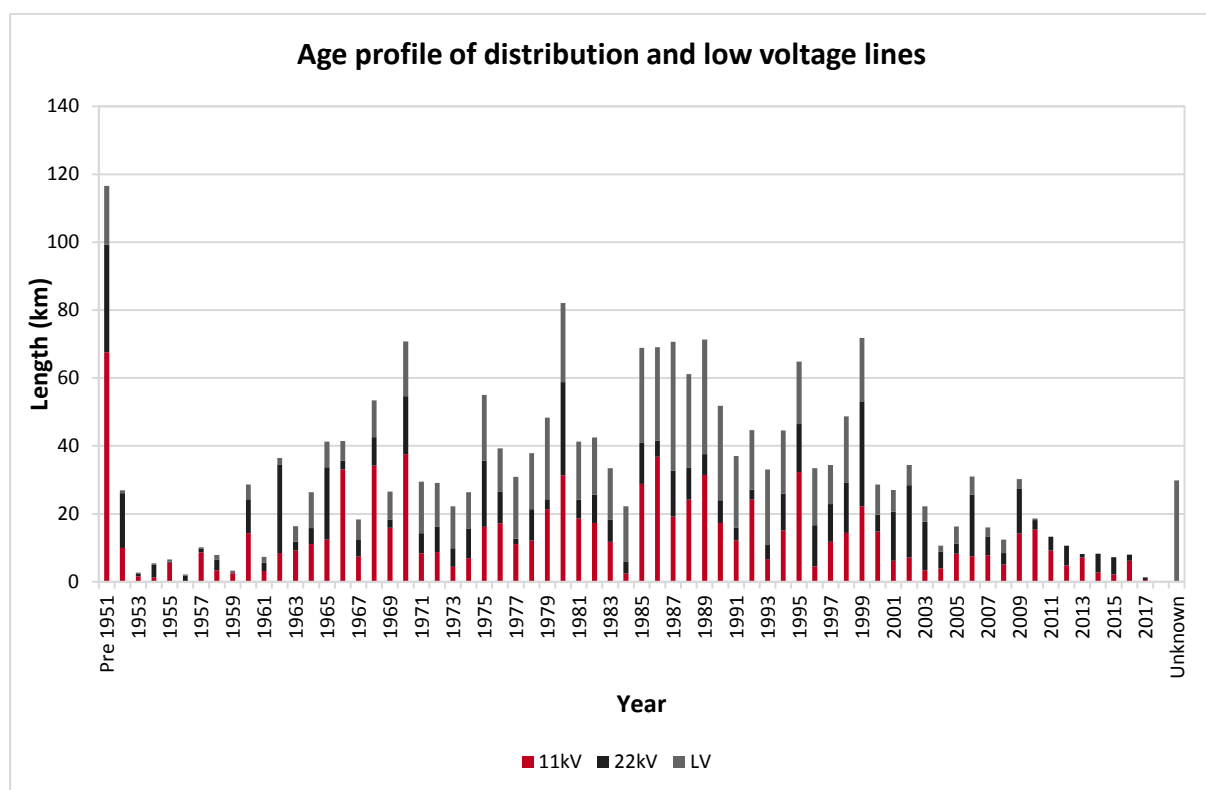


Figure 5-8 Age profile of Distribution and Low Voltage Lines

Inspection and maintenance practices

There are few components of overhead lines requiring routine servicing, and issues are identified through periodic inspections of overhead lines and their support structures, or from failure mode analysis. These surveys include assessing the condition of poles and towers, cross arms, connectors and clamps, clearances from trees, clearances from other components as well as clearance from the ground and buildings.

Defects are noted and addressed in accordance with their priority, particularly when it presents a hazard for public safety or the reliable operation of the network.

Our inspection and maintenance cycles for Distribution and Low Voltage lines are:

Activity	Type	Frequency
Overhead line feeder patrol	Inspection	Annual
Detailed Pole and Line Condition Assessment	Inspection	5 yearly
Vegetation Survey	Inspection	Area Specific

Table 5-12 Inspection and maintenance cycles for Distribution and Low Voltage Lines

Corrective Maintenance is undertaken as required when defects have been identified and includes such activities as cross arm and insulator replacement, pole straightening, conductor resagging, fitment of stay wires, spacers, and possum guards.

We undertake Vegetation Management in accordance with the *Electricity (Hazards from Trees) Regulations 2003*.

Renewal programme

There are some sections of overhead line on the west coast where ACSR conductor has deteriorated prematurely due to the corrosive west coast conditions. These line lengths are relatively short and their condition is being monitored. They are replaced by AAC or AAAC conductor where necessary.

We have two replacement programmes for small diameter overhead conductors which have reached end of life and are presenting safety and reliability issues due to their condition, with increasing failure rates year on year. These two types are copper conductors (16mm² to 35mm²) of which we have a total length of 250 km and Swan ACSR (20mm²) of which we have around 362 km. The forecast costs are based with the currently identified replacement solution and in some locations, we may consider undergrounding as an option where there are significant safety, reliability or community benefits by undergrounding.

Copper conductor replacement programme

A prioritised programme of replacing copper conductor commenced in 2016/17 in areas where there is elevated public risk, where there have been identified repeat failures or performance issues and where there is no other capacity or development need for replacement over the next 3 years.

The overhead copper conductor renewal projects identified for the next 3 years are as follows:

Feeder	Substation	Area	Financial Year	Length (km)	Cost
Kaiaua (township)	MANGATAWHIRI	Urban	2019	2.1	\$1,300,000
Paparata (Paparimu Rd)	MANGATAWHIRI	Rural	2019	1.6	\$200,000
Hunua (Garvie Rd)	OPAHEKE	Rural	2019	2.1	\$550,000
Waiau Pa (Clarks Beach)	KARAKA	Urban	2020	2.9	\$1,500,000
Waiuku West	WAIUKU	Urban	2020	0.5	\$240,000
Blackbridge (Lewis Rd)	KARAKA	Rural	2020	5.5	\$821,000
Pukekohe East (Coulston Rd)	PUKEKOHE	Rural	2020	1.2	\$186,000
Pukekohe East (Tuhimata Rd)	PUKEOKHE	Rural	2020	2.7	\$429,000
Railway (Racecourse)	PUKEOKHE	Rural	2021	0.9	\$131,000

Feeder	Substation	Area	Financial Year	Length (km)	Cost
Kaiaua (Miranda Rd)	MANGATAWHIRI	Rural	2021	7.9	\$1,338,000
				Total:	\$6,695,000

Table 5-13 Prioritised programme of replacing copper conductor

A further \$9.6 million is forecast to be spent for the remainder of the planning period (2022-2027) to replace copper HV conductors.

Swan conductor replacement programme

A prioritised programme of replacing Swan ACSR conductor commenced in 2017/18 in areas where there is elevated public risk, where there have been identified repeat failures or performance issues and where there is no other capacity or development need for replacement over the next 3 years.

Overhead Swan conductor renewal projects identified for the next 3 years are as follows:

Feeder	Substation	Area	Financial Year	Length (km)	Cost
Te Hihi (Ellet Rd)	KARAKA	Rural	2019	3.8	\$600,000
Beach Road	OPAHEKE	Urban	2019	0.5	\$110,000
Pukekohe Hill	PUKEKOHE	Urban	2020	0.5	\$290,000
Pukekohe West	PUKEKOHE	Urban	2020	0.3	\$500,000
Church Corner	TUAKAU	Urban	2020	0.5	\$120,000
Racecourse	WAIUKU	Urban	2020	0.7	\$140,000
Pukekohe West	PUKEKOHE	Urban	2020	1.5	\$500,000
Red Hill	OPAHEKE	Urban	2020	3.5	\$700,000
Tuakau	TUAKAU	Urban	2021	1.0	\$190,000
Waiuku West	WAIUKU	Urban	2021	2.0	\$370,000
River Road	TUAKAU	Urban	2021	3.5	\$640,000
				Total:	\$ 4,160,000

Table 5-14 Prioritised programme of replacing ACSR (Swan) conductor

A further \$6.7 million is forecast to be spent for the remainder of the planning period (2022-2027) to replace Swan conductors.

HV and LV line replacement programmes

In addition to the conductor replacement programmes above, it has been identified that replacement of other overhead lines in poor condition across the network will be required. These were identified from asset condition surveys and post fault investigations. The identified projects for high voltage line replacement in the next 3 years include,

Location	Area	Financial Year	Length (km)	Cost
Victoria Ave, Waiuku (Stage 1)	Urban	2019	0.4	\$500,000
Victoria Ave, Waiuku (Stage 2)	Urban	2020	0.6	\$550,000
Kaiaua Road, Kaiaua	Urban	2021	1.0	\$350,000
			Total:	\$1,400,000

Table 5-15 Prioritised programme of HV overhead conductor replacement

The identified low voltage conductor replacement from 2018/19 are prioritised based on condition and urban locations. The identified areas for low voltage line replacement for the next 3 years include,

Location	Area	Financial Year	Length (km)	Cost
Mason Ave Pukekohe	Urban	2019	0.4	\$280,000
Valley Road Waiuku	Urban	2020	0.3	\$220,000
Queen St Pukekohe	Urban	2021	0.4	\$300,000
			Total:	\$800,000

Table 5-16 Prioritised programme of LV overhead conductor replacement

A further \$1.6 million is forecast to be spent for the remainder of the planning period (2022-2027) to replace low voltage conductors.

We have made an annual budget allocation for other urban overhead network replacement of \$200,000 to address other issues identified in subsequent years, as well as an annual allowance of \$100,000 to address safety other critical issues such as low road crossings and clearances.

5.4.4 Poles

We have 27,428 poles in our distribution system. The majority are concrete poles, as these have been predominantly installed since the mid-1940s, with the remainder made up of hardwood, softwood and other types such as iron rail or steel.

Age profile

The age profile of our distribution and LV poles is shown in Figure 5-9. The age profile portrays a network that has undergone significant expansion and replacement over the last 25 years. The life expectancy is 80 years for concrete poles and 45 for wooden poles.

The quantities and age profile shown is based on distribution and LV poles that we have records of in our system as being Counties Power owned. A pole survey focused on the ownership and usage of all poles in our service area which support electrical equipment was completed in 2017. The survey identified over 2,200 poles that we did not have records of but are deemed to be owned by us. With the increased number of poles, our requirements for pole renewal have increased and an additional 10% budget provision has been made in the renewal and maintenance programmes.

Counties Power recognised that service line ownership, and the range of issues relating to service lines from a safety, reliability and customer service perspective have been a long-term industry issue. Initial assessment indicated that there are over 1,000 private HV lines ('service lines') on our network. A change in our ownership policy came into effect in January 2018 for Counties Power to own new HV lines on private land, and to address existing private HV lines through more systematic clarification of ownership and adoption of private HV lines in a staged and risk assessed approach over the next 2 years. This will increase the number of poles and our requirements for pole renewal and maintenance. An additional annual budget provision of \$1.5 million in the renewal programme and \$230,000 in the maintenance programme has been allowed for in the budget.

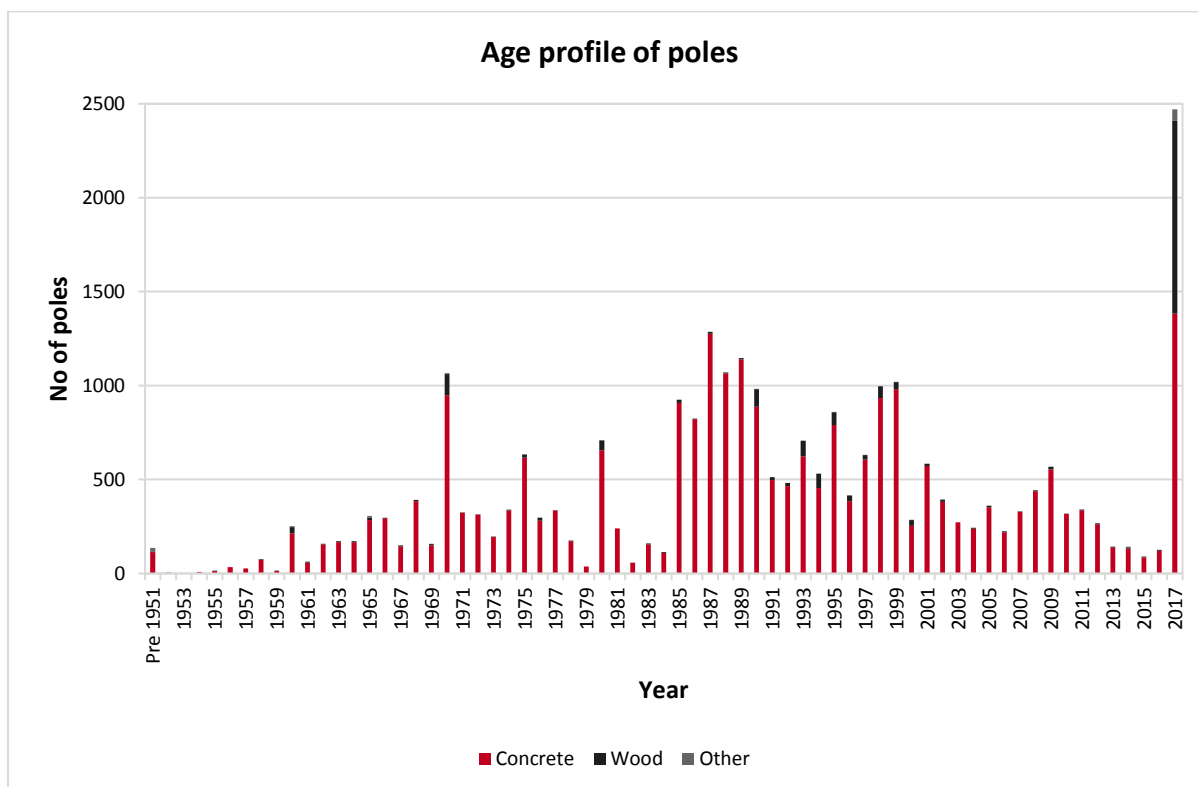


Figure 5-9 Age profile of Distribution and Low Voltage Poles¹³

Inspection and maintenance practices

Our inspection and maintenance cycles for Poles are shared with Overhead Lines (previous section) and are:

Activity	Type	Frequency
Overhead line feeder patrol	Inspection	Annual
Detailed Pole and Line Condition Assessment	Inspection	5 yearly

Table 5-17 Inspection and maintenance cycles for overhead lines

Renewal programme

There is a known issue with concrete poles manufactured around the 1960s not attaining their full life expectancy due to high levels of corrosion on the reinforcing material. This age group represents approximately 2.5% of our total poles population. We are monitoring the condition of these poles and they will be replaced when necessary, but are expecting a higher than average replacement rate. These will be replaced following identification during routine inspections.

Based on age profiles and standard asset lives, a large number of concrete poles are now at end of life, however their condition does not yet justify replacement.

¹³ Poles identified from the pole survey in 2017 were given a default date of 1 January 2017.

Hardwood poles have known issues with ground line and below ground rot which leads to a deterioration of the strength of the pole. Some softwood poles have been found to not reach their full expected life and generally require replacement after approximately 30 years of service.

Specific replacement programmes are planned to replace hardwood, softwood and iron rail type poles from the network as these present safety risks if left in poor condition. Many of these are replaced as part of area line rebuild work, but in some cases individual replacement will be required. Table 5-18 shows the quantity of each type of pole expected to require replacement during the planning period based on age profiles. These will be subject to a targeted condition assessment programme, with replacement driven from poor condition scores and prioritised by safety and network risks.

Type	Quantity	Estimated cost to replace
Hardwood	415	\$4.1 m
Softwood	1,604	\$12.8 m
Iron Rail	72	\$0.6 m
Total	2,091	\$17.5 m

Table 5-18 Number of poles expected to require replacement during the planning period based on age profiles

An increased number of defects have been identified over the past year on poles and overhead hardware, arising from routine inspections. We have allowed an annual budget to replace the worst condition poles and overhead hardware on the network and the adoption of existing private HV lines over the planning period, with an allocation of \$3.9 million in 2019, decreasing to \$3.5 million from 2020 to 2023 and \$3.4 million from 2024 onwards.

Poles are also replaced correctively when found to have poor structural condition, or reactively as a result of vehicle damage.

We expect to replace around 250 poles and overhead hardware at over 360 pole sites per year under the overhead renewal programme, and replace another 30 to 50 poles under other programmes of work.

5.4.5 Cross arms

We have over 48,294 cross arms installed on our poles supporting overhead lines. Multiple cross arms may be installed on a single pole depending on the function of each pole (e.g. whether the pole carries a single voltage or multiple voltages). Figure 5-10 shows the age profile of our cross arms. As they are installed at the same time as the poles, they share a similar age profile. The exception to this is where wooden cross arms are installed on concrete or steel poles. Wooden cross arms have a shorter life expectancy compared to concrete or steel poles so would require replacement at shorter intervals. Increasingly, steel cross arms have been used to achieve longer service lives compared to wooden cross arms.

Age profile

The age profile of our cross arms is shown in Figure 5-10. The average age of our cross arms and conductors are slightly lower than the average age of our poles due to re-conductoring on existing poles.

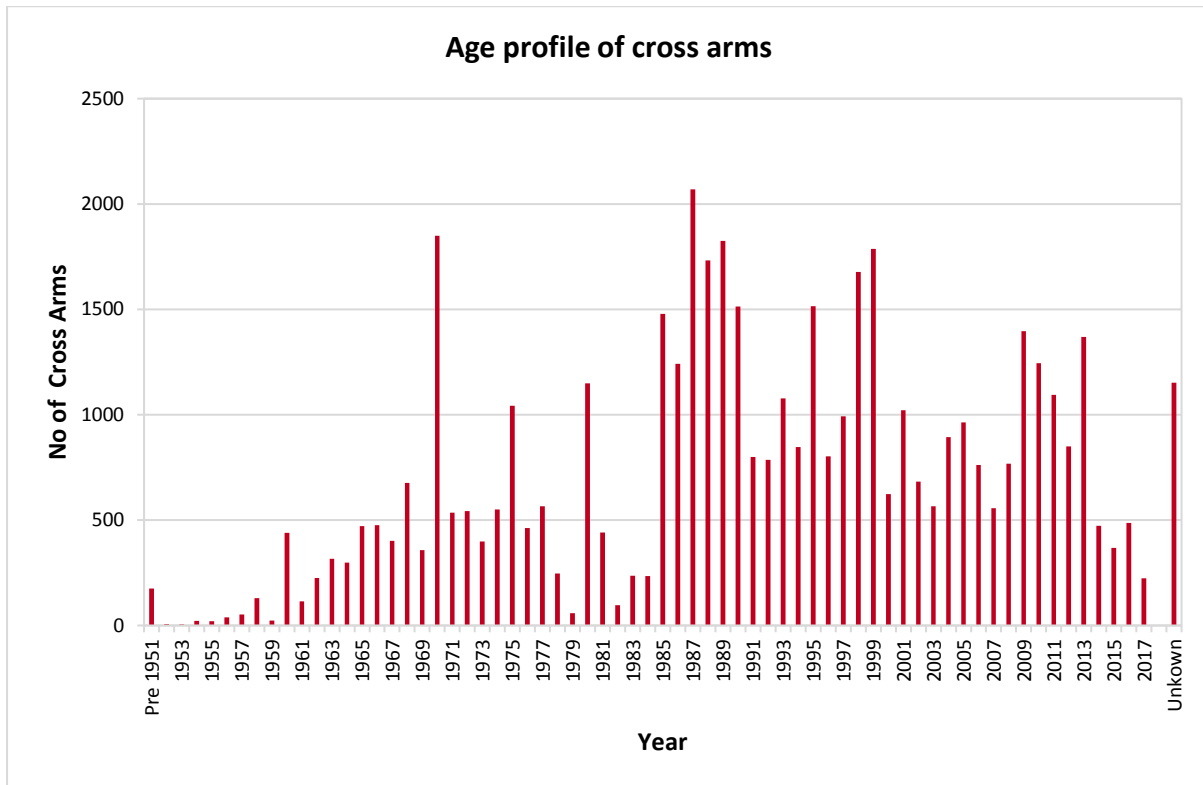


Figure 5-10 Age profile of Cross Arms

Inspection and maintenance practices

Cross arms are inspected as part of the overhead line condition surveys undertaken annually. Defects are raised for those cross arms which are no longer serviceable and they are scheduled for replacement.

Renewal programme

We replace our cross arms that are near the end of their life once identified through routine inspections as opposed to having a specific programme for replacement based on age. Cross arms are also replaced in conjunction with pole replacement or re-conductoring projects.

5.4.6 Summary of distribution and LV lines expenditure forecast

Expenditure Forecast (\$000)	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028
Capital Expenditure										
Overhead renewals	3,910	3,480	3,480	3,480	3,480	3,430	3,430	3,430	3,430	3,430
Copper replacement programme	2,050	1,740	1,440	1,470	1,230	1,660	1,220	1,200	1,580	1,220
Swan replacement programme	710	1,050	1,200	1,200	1,170	1,080	1,110	1,200	920	1,210
HV feeder section replacement	500	550	350	200	200	200	200	200	200	200
Urban LV replacement	280	220	300	280	200	170	260	250	380	300
Overhead safety compliance	100	100	100	100	100	100	100	100	100	100
Capital Expenditure Total	7,550	7,140	6,870	6,730	6,380	6,640	6,320	6,380	6,610	6,460
Operational Expenditure										
Distribution poles and corssarms	840	740	740	640	640	540	540	540	540	540
Distribution conductor	50	50	50	50	50	50	50	50	50	50
Fault indicators and earthing	20	20	20	20	20	20	20	20	20	20
Operational Expenditure Total	910	810	810	710	710	610	610	610	610	610

Table 5-19 Distribution and Low Voltage Lines expenditure forecast summary

5.5 Distribution and LV cables

In addition to our Distribution and LV lines we have Distribution and LV cables. Underground cables have a higher capital and overall lifecycle cost than overhead lines, but have higher reliability and lower ongoing maintenance costs.

Most new construction in the urban area uses underground cables as District Plan rules restrict the installation of new poles and overhead lines, and most land developers require electricity to be supplied underground for new subdivisions.

Our distribution cables (22kV and 11kV) are of XLPE¹⁴ or PILC¹⁵ construction. Our 400V cables are of XLPE, PVC¹⁶ and PILC.

We have 150.5 km of 22kV cables, 74.7 km of 11kV cables and 648 km of 400V LV cables. We also have 46.3 km of street lighting cable which is in a separate trench from our 400V LV cables, however there are significant lengths of street light circuits installed with LV cables which are not recorded on early plans and we do not know the length of these circuits.

5.5.1 Quantity and life expectancy of distribution and LV cables

Asset	Construction Type	Length in KM	Life Expectancy
Distribution Cables 22kV	XPLE	150.5	55 years
Distribution Cables 11kV	PILC	22.7	70 years
	XLPE	52.0	55 years
LV Cables	PVC	87.2	55 years
	XLPE	493.5	55 years
	Other	67.3	70 years
Street Light Cables	PVC	42.7	55 years
	XLPE	1.4	55 years
	Other	2.2	70 years

Table 5-20 Distribution and Low Voltage Cables asset summary (asset quantity as at Oct-17)

¹⁴ Cross linked polyethylene

¹⁵ Paper insulated, lead covered

¹⁶ Polyvinyl Chloride

5.5.2 Management approach

Distribution and Low Voltage cables are generally reliable and maintenance free, and therefore the approach we take to managing these assets is to either repair or replace on failure. We don't have any first generation XLPE cable remaining on the network, which has known type issues and experienced premature failure on many networks due to water treeing¹⁷.

In some parts of the network there is undersized 11kV cabling, particularly around Papakura South and Waiuku area which will be replaced as part of capacity augmentation projects over time. There are also cast metal cable termination boxes on poles which when identified will be replaced as they are known to fail due to water ingress.

5.5.3 Distribution cables

Age profile

Figure 5-11 shows the age profile of our distribution cables. The average age of our XLPE cable is 10 years and the average age of our PILC cable is 34 years.

The life expectancy of XLPE cables is 55 years and PILC cables is 70 years with the first replacement expected beyond this planning period.

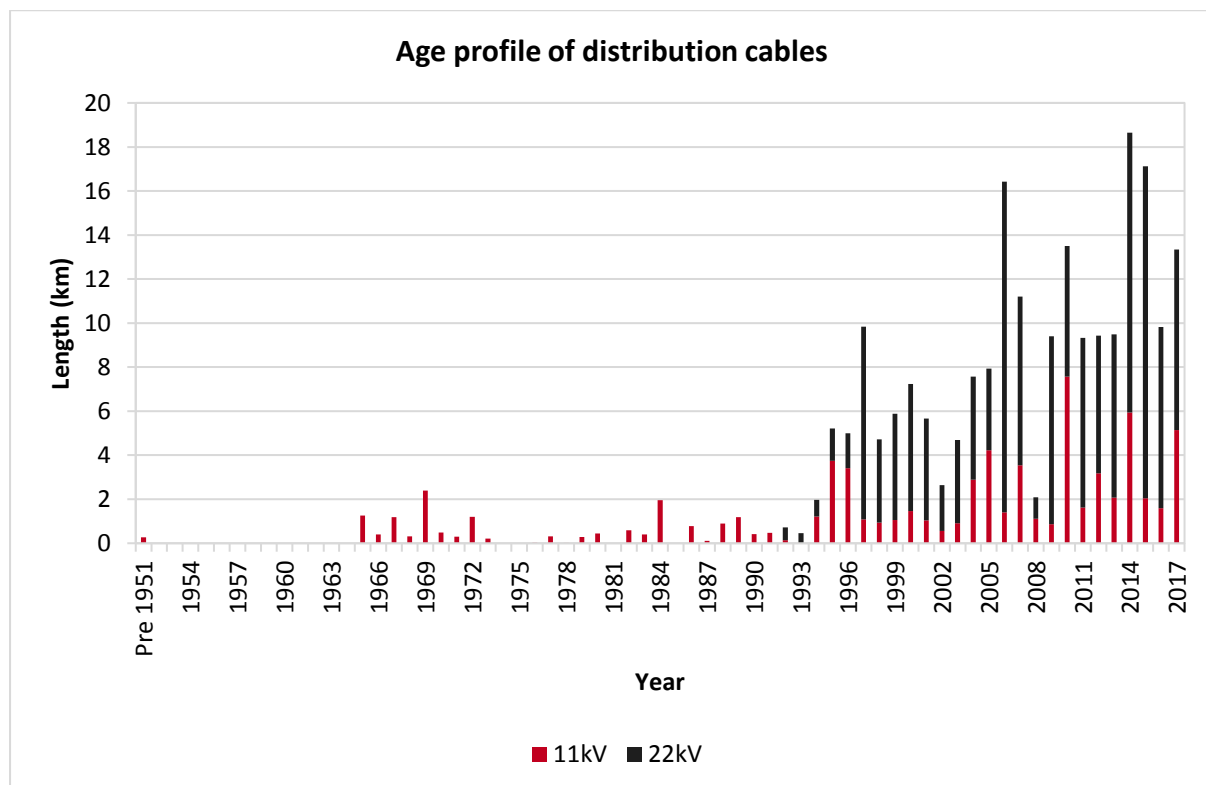


Figure 5-11 Age profile of Distribution Cables

¹⁷ Water treeing is a form of insulation degradation observed on early XLPE cables

Inspection and maintenance practices

Underground distribution cables are not proactively inspected or tested as they are generally maintenance free. Cable terminations and risers on poles are inspected as part of overhead line condition assessment surveys, and repair work is undertaken where defects are found. Cable terminations on ground mounted switchgear are not easily inspected, however the use of thermal imaging and partial discharge location equipment assists in identifying deteriorating cable terminations in these locations.

Renewal programme

There is no proactive renewal programme for this asset type as our management strategy is to replace upon failure or when the level of reliability becomes unacceptable, however an allowance is made each year for replacement of cable sections found to be faulty. We have made an allowance of \$200,000 per year to address these replacements.

5.5.4 LV cables

Age profile

Figure 5-12 shows the age profile of our LV cables in our system which has an average age of 13 years.

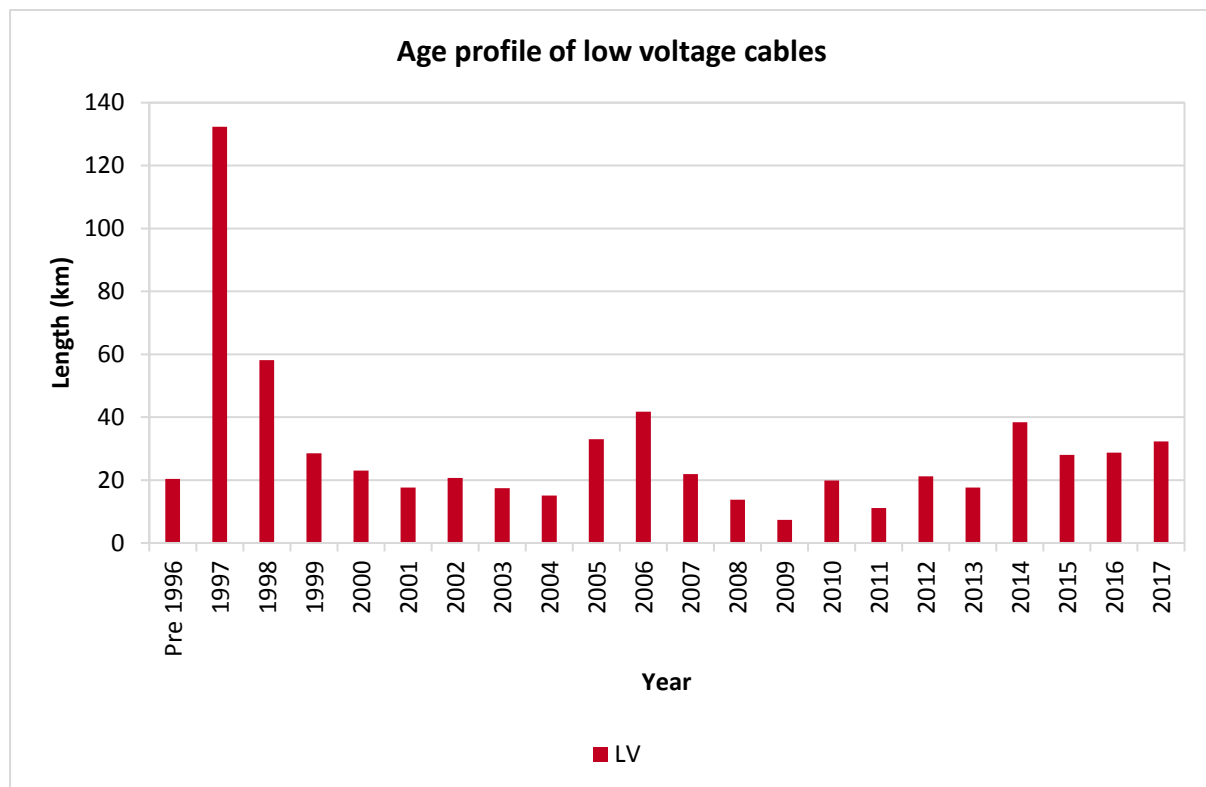


Figure 5-12 Age profile of Low Voltage cables

Inspection and maintenance practices

Underground LV cables are not proactively inspected or tested as they are generally maintenance free. Cable terminations and risers on poles are inspected as part of overhead line condition assessment surveys, and repair work is undertaken where defects are found.

Renewal programme

There is no proactive renewal programme for this asset type, however an allowance is made each year for replacement of cable sections found to be faulty.

5.5.5 LV Pillars and Pits

We have 12,212 LV Pillars and Pits in our network, connected to LV cables. These generally accommodate fusing for consumer supply points, but some pillars are used as link pillars between two adjacent low voltage circuits. Pits are not widely used, and avoided where possible in new build situations.

Age profile

Figure 5-13 shows the age profile of our LV Pillars. The average age of our LV Pillars is 16 years.

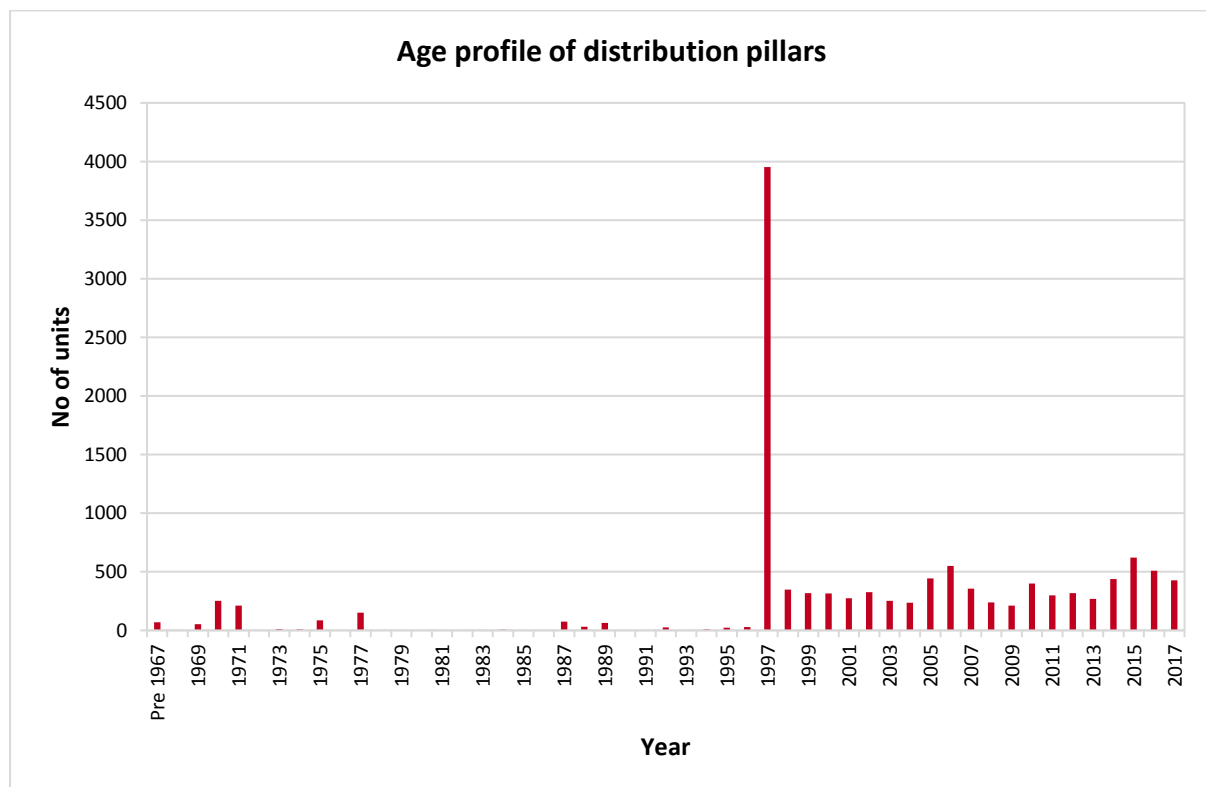


Figure 5-13 Age profile of LV Pillars

Inspection and maintenance practices

We carry out 5 yearly visual inspections and thermographic tests on our LV Pillars to ensure they are safe and secure, and that the components are not overheating which is a common mode of failure.

Corrective maintenance is used to address minor issues such as insecure lids, hot connections, or alignment and siting issues (leaning, etc.). Vehicle damage is common, and entire pillar replacement is the usual remedy depending on the nature of damage.

Renewal programme

There are no specific programmes for pillar replacement, however an allocation is made in the annual plan for corrective repairs and replacements of damaged or defective pillars.

5.5.6 Summary of distribution and LV cables expenditure forecast

Expenditure Forecast (\$000)	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028
Capital Expenditure										
Distribution and LV cable renewal	200	200	200	200	200	150	150	150	150	150
LV pillar renewal	170	180	190	200	210	210	220	230	240	250
Capital Expenditure Total	370	380	390	400	410	360	370	380	390	400
Operational Expenditure										
Distribution and LV cable	150	150	150	150	150	150	150	150	150	150
LV pillar	130	130	130	130	130	130	130	130	130	130
Operational Expenditure Total	280	280	280	280	280	280	280	280	280	280

Table 5-21 Distribution and Low Voltage cables expenditure forecast summary

5.6 Distribution Substations and Transformers

Distribution substations accommodate transformers which step down higher distribution voltages (22kV or 11kV) to low voltage (400V/230V) for distribution to consumers, along with other equipment such as high voltage fusing, low voltage fusing and earth grids.

Distribution switching stations accommodate switchgear such as ring main units or circuit breakers, and are used to control and isolate the network by switching sections of distribution feeders, and to supply and protect transformers. This enables a section of the network to be de-energised for maintenance work, or to isolate faulted sections of the network in order to minimise the impact of faults.

Specially designed 22/11kV transformers connect our 11kV network to our 22kV network and to enable consideration of upgrading to 22kV as one of the options to address identified capacity and voltage constraints in the future. Upgrade to 22kV in each area is assessed on its individual merits, including evaluation of a range of alternatives.

5.6.1 Quantity and life expectancy of Distribution Substations and Transformers

Asset	Type	Quantity	Life Expectancy
Distribution Transformers	Pole mounted distribution transformers	3,128	45 years
	Ground mounted distribution transformers	805	45 years
22/11kV Transformers		50	45 years

Table 5-22 Distribution assets summary (asset quantity as at Oct-17)

5.6.2 Management approach

Public safety is a key driver of the maintenance programme for transformers and ground mounted substations, in particular the security of the units and ensuring members of the public cannot come into contact with live parts. Likewise, protecting the environment is a concern and making sure oil leaks do not occur due to corrosion or damage to tanks.

Some types of equipment, in particular early kiosk type substations have restricted operating space, and live parts, and these require outages to work safely in them. Where justified, these are replaced with modern alternatives.

Transformers are generally low maintenance, requiring little routine servicing, so the maintenance programme is inspection based, with corrective actions taken where required.

In some parts of our network, particularly within 10km of the coast, transformers do not reach their normal service life and are likely to be replaced 10 years earlier than in other locations due to poor condition.

5.6.3 22/11kV auto transformers

We have 50 22/11kV auto transformers, 26 are ground mounted and 24 are pole mounted units.

Figure 5-14 shows the age profile of our 22/11kV auto transformers. The average age of these transformers is 12 years.

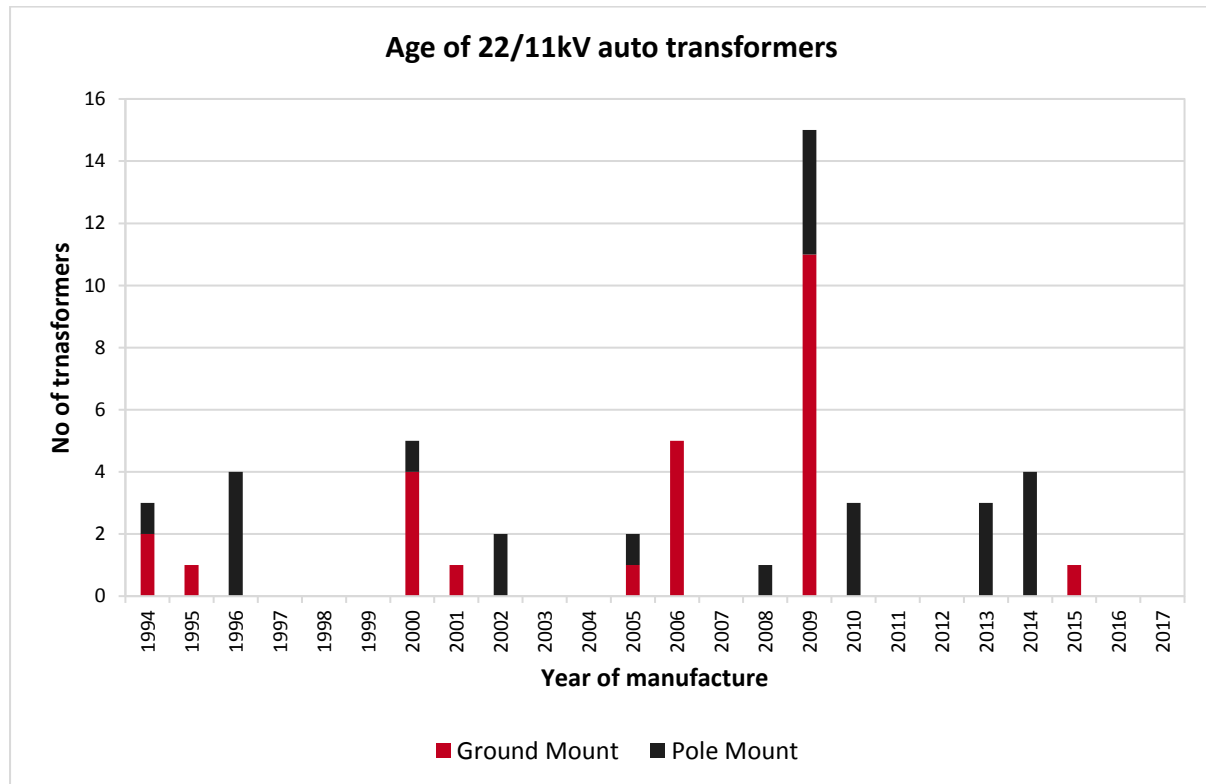


Figure 5-14 Age profile of 22/11kV transformers

5.6.4 Distribution transformers

We have 3,128 pole mounted distribution transformers, 1,152 on the 22kV network and 1,976 on the 11kV network.

Figure 5-15 shows the age profile of our pole mounted distribution transformers. The average age of our 22kV pole mounted transformers is 10 years and our 11kV pole mounted transformers is 28 years. The significant investment made over the last 20 years was driven by a combination of active replacement programme of older transformers in poor condition and development of our 22kV distribution network.

We have 250 pole mounted transformers that are older than the normal expected life of 45 years. This represents 8% of our total pole mounted distribution transformer population.

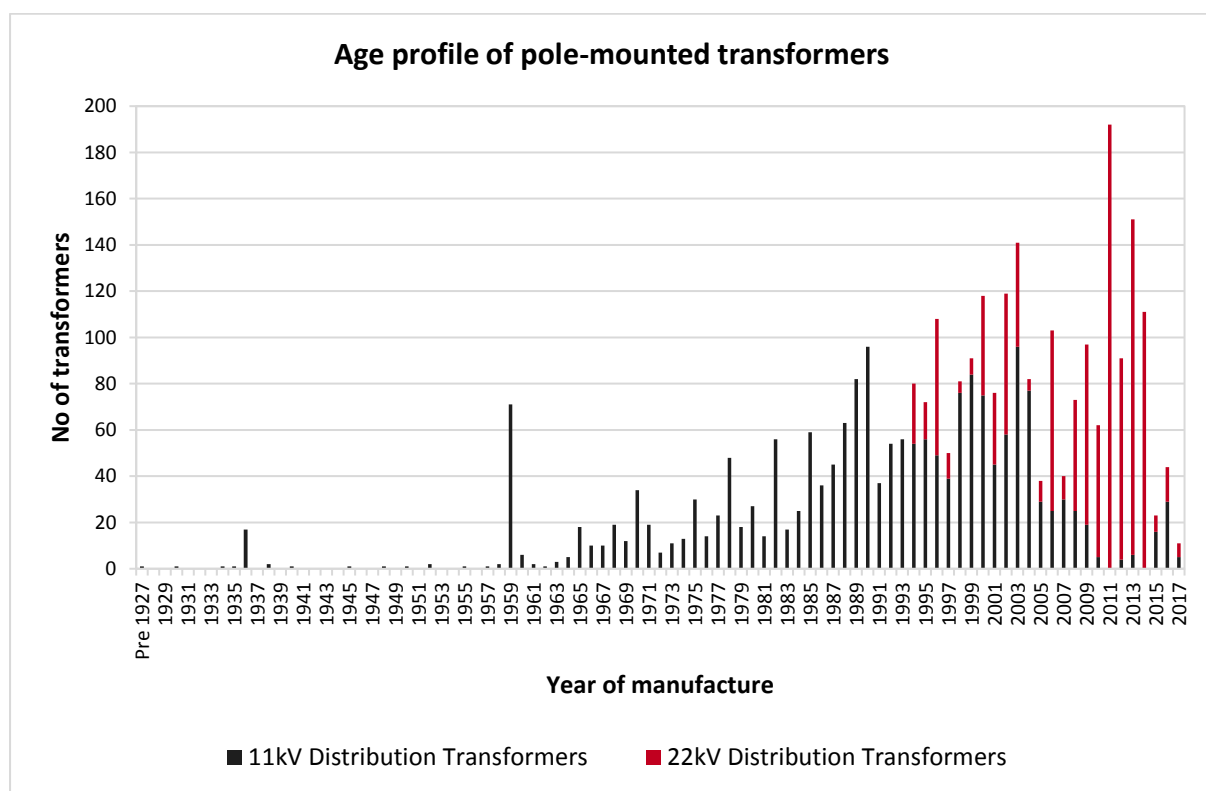


Figure 5-15 Age profile of Distribution pole-mounted transformers

We have 805 ground mounted distribution transformers, 529 on the 22kV network and 276 on the 11kV network.

Figure 5-16 shows the age profile of our ground mounted transformers. The average age of our 22kV ground mounted transformers is 12 years and the average age of our 11kV ground mounted transformers is 21 years. The significant investment made over the last 20 years was driven by significant network growth and development of our 22kV distribution network.

We have 28 ground mounted transformers that are older than the normal expected life of 45 years. This represents 4% of our total ground mounted distribution transformer population.

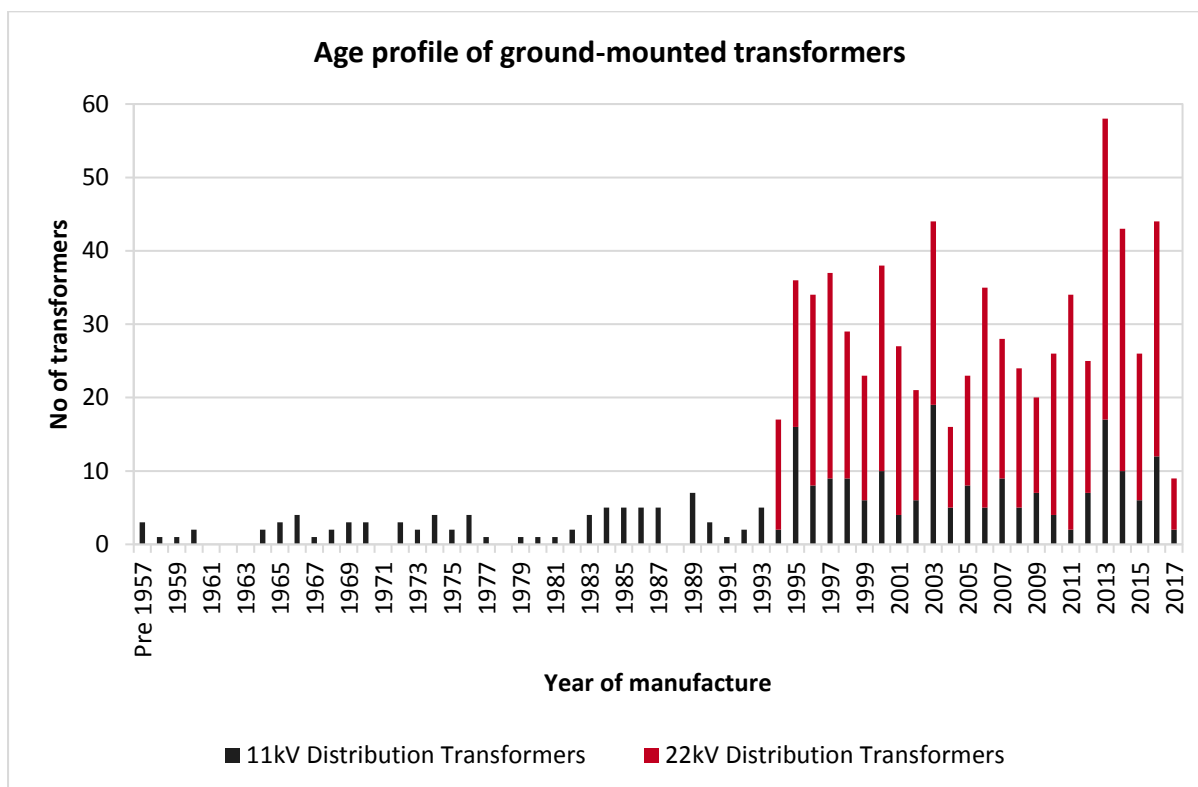


Figure 5-16 Age profile of Distribution ground-mounted transformers

Inspection and maintenance practices

We carry out safety checks, visual inspections and thermographic tests on our distribution transformers annually to ensure that the transformers remain safe, secure and defect free.

Activity	Type	Frequency
Transformer Inspection	Inspection	Annual

Table 5-23 Inspection frequency of distribution transformers

There is no routine servicing required, and any defects found during routine inspections are handled through the corrective maintenance programme.

Renewal programme

We plan to replace our transformers when their condition is unacceptable for continued service, where growth requires a capacity upgrade .

Based on age profiles and quantity in service, we expect to replace around 40 transformers per annum across planned upgrades (capacity and security), and as a result of condition assessment findings or reactive fault repairs. We have allowed \$590,000 in the coming year for the renewal of transformers and associated equipment due to condition.

5.6.5 Expenditure Forecast

Expenditure Forecast (\$000)	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028
Capital Expenditure										
Transformer replacement programme	590	730	590	590	590	730	660	660	660	450
Capital Expenditure Total	590	730	590	590	590	730	660	660	660	450
Operational Expenditure										
Transformer maintenance	250	250	250	250	250	250	250	250	250	250
Operational Expenditure Total	250	250	250	250	250	250	250	250	250	250

Table 5-24 Distribution transformer expenditure forecast summary

5.7 Distribution Switchgear

Distribution switchgear is used to protect and isolate the network. Switchgear minimises the impact of outages arising from faults and planned work by sectionalising affected parts of the network.

On the overhead network, we use Air Break Switches (ABS), Gas Insulated Switches, Reclosers, dropout links and fuses, and spur line isolators.

On the underground network, we use Ring Main Units consisting of load break switches to provide isolation, and fuses or circuit breakers to protect transformers.

5.7.1 Quantity and life expectancy of Distribution Switchgear

Asset	Quantity	Life Expectancy
Ring Main Units	198	40 years
Air Break Switch	264	35 years
Gas Insulated Switch	91	35 years
Spur Line Isolator	1,466	35 years
Reclosers	27	40 years

Table 5-25 Distribution Switchgear assets summary (asset quantity as at Oct-17)

5.7.2 Management approach

Distribution Switchgear should be serviceable, free from defects and safe to operate at all times. It is a key component of operating the network safely and efficiently, and providing necessary isolation of equipment. These devices are generally located in the public domain so safety is our main consideration with regard to inspecting and maintaining these units.

Selection of good quality, low maintenance Ring Main Units (RMUs) has positioned us well, with little ongoing maintenance needed apart from routine safety checks.

A small number of older RMU types are unsafe to operate live, largely due to their age and condition, and this introduces operational restrictions and causes wider area outages than necessary. These units have been identified and will be replaced during the planning period.

A number of issues relating to overhead equipment have been identified, and programmes implemented to address these through the planning period, with priority given to higher risk issues and locations.

5.7.3 Ring main units

Ring Main Units are ground mounted switches for switching distribution cable rings and for connecting distribution transformers, generally through fused switches or circuit breakers, to the distribution network.

We have 198 RMUs in our distribution network, of which 176 are gas insulated, 7 are oil insulated, and 15 are air/resin insulated.

Age profile

Figure 5-17 shows the age profile of our RMUs. The average age of our RMUs is 12 years. We have 12 RMUs that are older than the normal expected life of 40 years. This represents 6% of our RMU population.

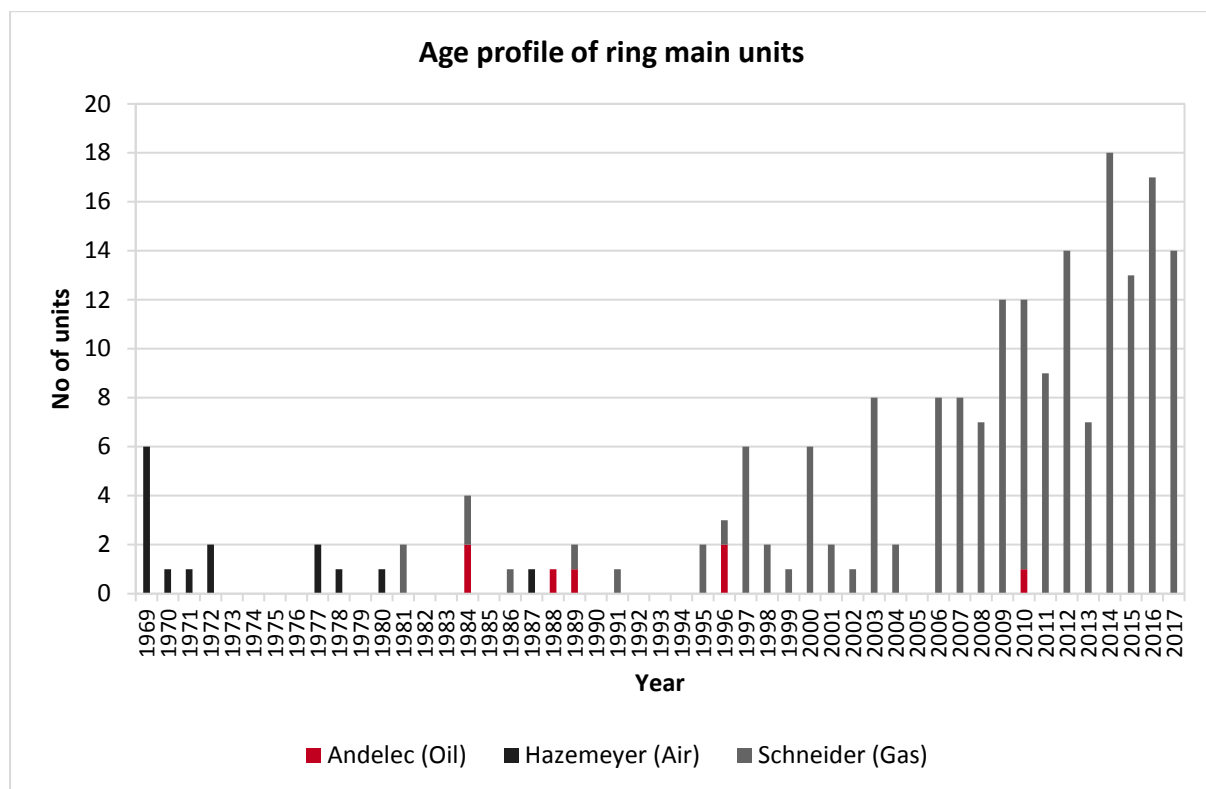


Figure 5-17 Age profile of Ring Main Units

Inspection and maintenance practices

We carry out annual visual inspections on our RMUs to ensure that they are safe, secure and free of defects.

The majority of the RMUs on the network are modern gas insulated Schneider RM6 units, and require very little maintenance. Some of these units have automation fitted, which requires battery replacement every 5 years.

There are some types of RMU of older designs, particularly oil filled units such as Andelec/ABB SD series switchgear and Hazemeyer Magnefix which require higher levels of routine servicing to ensure they operate safely and correctly:

Activity	Type	Frequency
Ring Main Unit – Annual Inspection	Inspection	Annual
Ring Main Unit Maintenance – Oil Filled	Routine Maintenance	5 yearly
Ring Main Unit Maintenance – Hazemeyer	Routine Maintenance	5 yearly
Ring Main Unit Battery Renewal	Replacement	5 yearly

Table 5-26 Inspection frequency for RMUs

Renewal programme

We plan to replace all our air/resin insulated and oil filled RMUs within the next nine years. There are two specific types of RMU which will be targeted for replacement by 2027, namely Hazemeyer Magnefix and Andelec SD-series. These replacements are driven by age, and condition. A standard procedure is in place to restrict operation of this equipment to a de-energised state to manage the operational risks.

There is also a GEC type RMU and an ASEA type RMU located at Raventhorp on the Bombay feeder (Ramarama area). The replacement will be completed in 2018/19 to address condition issues.

There are 21 units identified for replacement, with an estimated replacement cost of \$80,000 each, giving a total programme cost of \$1.68 million. The associated costs for distribution cable and transformer replacement are covered in the respective renewal programmes.

Year	Feeder	Andelec	Hazemeyer	Other	Cost
2019	Waiuku Town	1	1		\$160,000
2020	Papakura South	1	1		\$160,000
2021	Papakura South	1	2		\$240,000
2022	Racecourse		2		\$160,000
2023	Racecourse		2		\$160,000
2024	Beach Rd		3		\$240,000
2025	Beach Rd	2	1		\$240,000
2026	Beach Rd		2		\$160,000
2027	Drury Hills	2			\$160,000
				Total	\$ 1,680,000

Table 5-27 RMU replacement programme

Some of this replacement work will be undertaken in conjunction with network capacity and reinforcement projects.

5.7.4 Overhead distribution switchgear

Distribution switchgear consists of Reclosers, Air Break Switches (ABS), Gas Switches, and Isolators. They are used to protect and isolate the distribution network.

On our 22kV network, we have:

- 109 ABS, with an average age of 21 years. 21 ABS are older than the normal expected life of 35 years;
- 50 Gas Switches with an average age of 11 years. 1 gas switch is older than the normal expected life of 35 years;
- 627 Isolators with an average age of 18 years. 40 Isolators are older than the normal expected life of 35 years; and
- 20 Reclosers and circuit breakers with an average age of 11 years. We have no 22kV Reclosers and circuit breakers older than the normal expected life of 40 years.

On our 11kV network, we have:

- 155 ABS, with an average age of 24 years. 28 ABS are older than the normal expected life of 35 years;
- 41 Gas Switches with an average age of 12 years. No Gas Switches are older than the normal expected life of 35 years;
- 839 Isolators with an average age of 20 years. 78 Isolators are older than the normal expected life of 35 years; and
- 7 Reclosers and circuit breakers with an average age of 16 years. No Reclosers and circuit breakers older than the normal expected life of 40 years.

Age profile

Figure 5-18 shows the age profile of our distribution switchgear and switches.

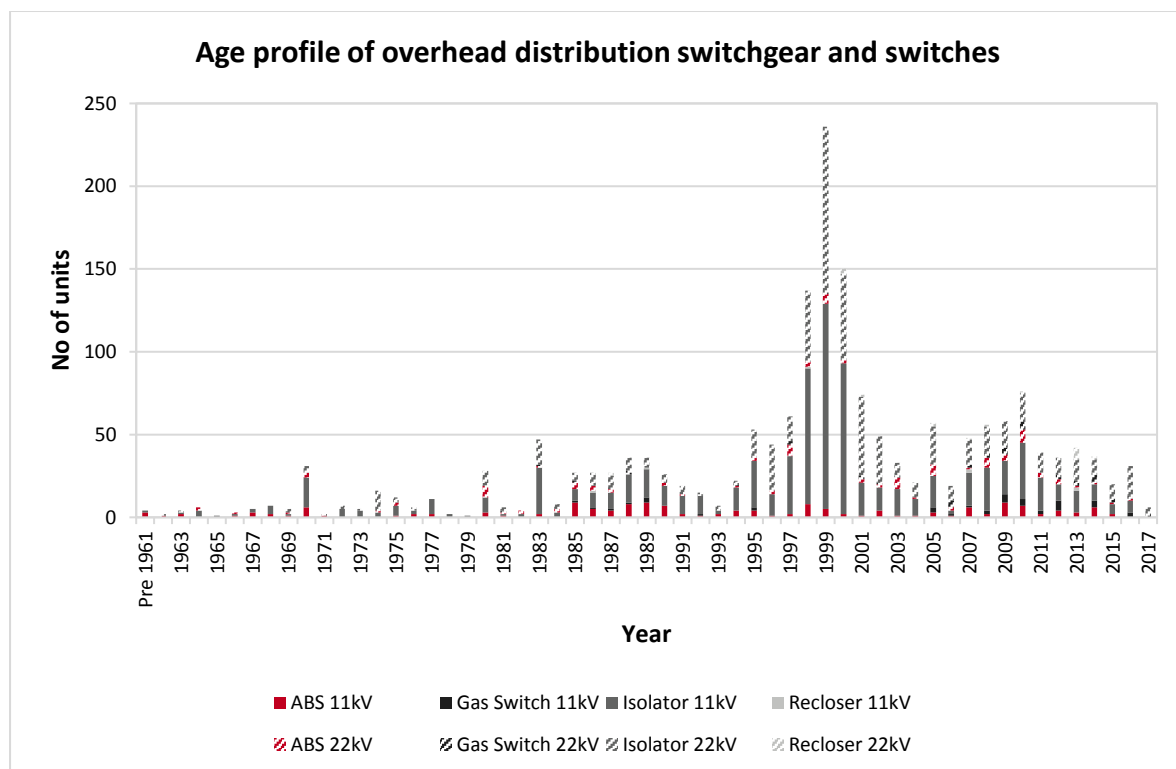


Figure 5-18 Age profile of Distribution switchgear and switches

Inspection and maintenance practices

Our inspection and maintenance cycles for distribution switchgear are:

Activity	Type	Frequency
Overhead Switch – Annual Inspection	Inspection	Annual
Air Break Switch Service	Routine Maintenance	5 yearly
Gas Switch Service	Routine Maintenance	5 yearly
Remote Switch Battery Renewal	Replacement	5 yearly
Recloser Service	Routine Maintenance	5 yearly
Recloser Battery Renewal	Replacement	5 yearly
Overhead Switch Earth Test	Routine Test	5 yearly

Table 5-28 Inspection and maintenance cycles for distribution switchgear

All overhead equipment is part of the annual overhead condition assessment programme, to identify any safety concerns or deterioration which can be addressed through the Corrective Maintenance programme. Overhead switchgear (except DDOs) is also subject to routine servicing to ensure it operates safely and correctly. Automated devices require their batteries to be replaced periodically, which is done in conjunction with routine servicing.

Renewal programme

Issues have been identified with the porcelain insulators on one particular type of air-break switch (ABS) and some types of HV ‘drop out’ style fusing which has led to a very high failure rate.

- A replacement programme commenced in 2017/18 to replace a total of 128 ABS within the next six years. A total of 38 ABS was replaced in 2017/18 and 19 ABS are planned for replacement in 2018/19. The replacement is prioritised based on the switch make and type, switch location and network function each switch provides. There are 46 units of one type of ABS with a particular common reliability issue which are to be replaced within the next three years, and other types of ABS are to be replaced within four to six years. The replacement programme will address the identified condition issues as well as provide operational flexibility; and
- Known types of HV ‘drop out’ style fusing will be identified and replaced where required, as well as some surge arrestors in coastal areas experiencing premature failure due to the harsh environment. These are handled as corrective replacements when found.

We do not forecast any renewal of reclosers during the planning period. However, more may be added for network performance improvements.

5.7.5 Summary of Distribution Switchgear Expenditure Forecast

Expenditure Forecast (\$000)	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028
Capital Expenditure										
Ring main units	750	1,210	1,380	810	810	1,160	1,270	1,280	1,070	400
Overhead switchgear replacement	600	600	600	400	380	300	300	300	300	300
Capital Expenditure Total	1,350	1,810	1,980	1,210	1,190	1,460	1,570	1,580	1,370	700
Operational Expenditure										
Ring main units	110	120	120	130	130	150	150	160	160	170
Overhead switchgear	290	270	270	240	240	240	240	240	240	240
Operational Expenditure Total	400	390	390	370	370	390	390	400	400	410

Table 5-29 Distribution switchgear expenditure forecast summary

5.8 Grid-scale battery storage system

Our first grid-scale battery storage system was commissioned at the Tuakau zone substation in mid-2017. This system consists of the isolating transformer, power converters, battery cells, monitoring and control systems, cooling and auxiliary supply systems.

This is new technology and as such the maintenance regime will initially follow the requirements provided by the system vendor. Over time, we will gain a better understanding from real world operation and system performance, which will allow us to refine the inspection and maintenance practices.

Inspection and maintenance practices

Our proposed inspection and maintenance cycles for grid-scale battery system are:

Activity	Type	Frequency
Routine battery inspection	Inspection	6 monthly
Cooling and auxiliary systems	Routine Maintenance	6 monthly

Table 5-30 Inspection and maintenance cycles for grid-scale battery system

5.9 Other system fixed assets

5.9.1 Quantity and life expectancy of other network assets

Asset	Quantity	Life expectancy
Capacitor banks	29	55 years
Voltage Regulators	7	55 years
Protection relays	144	40 years
Load control relays	3,568	20 years
Ripple Injection plant	5	20 years
Auxiliary Battery Banks	27	8 years
Remote Terminal Unit	222	15 years

Table 5-31 Other system fixed assets summary (asset quantity as at Oct-17)

5.9.2 Capacitor banks and voltage regulators

Due to the electrical impedance of the line, the voltage at the end of feeders is lower than at the supply end, defined as voltage drop along the line. For long distribution feeders, this voltage drop can be significant resulting in unacceptably low voltages at the end of those feeders. We have installed

voltage regulators partway on some of our long distribution feeders to maintain the correct voltage at the end of those feeders.

We have 7 Voltage Regulators in our network operating at 4 sites. One is a three-phase unit, and three sites have two single phase units operating in an open-delta configuration.

Age profile

Figure 5-19 shows the age profile of our Voltage regulators. The average age of our voltage regulators is 15 years.

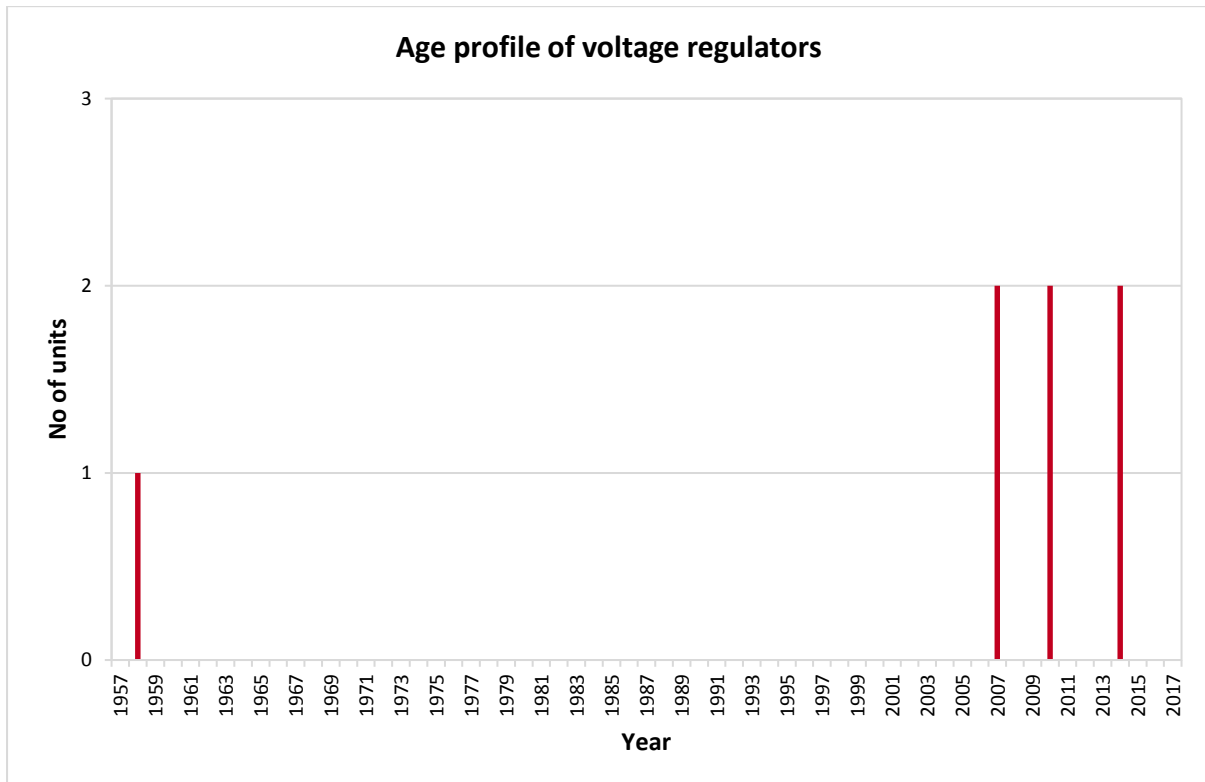


Figure 5-19 Age profile of Voltage Regulators

Capacitors provide power factor correction and help maintain the correct voltage by providing reactive support on long lines with high impedance.

We have 29 capacitors on our distribution network with installation dates ranging from 1998 to 2007. The average age of our capacitors is 17 years.

Figure 5-20 shows the age profile of our capacitors.



Figure 5-20 Age profile of Capacitors

Inspection and maintenance practices

Our inspection and maintenance cycles for our voltage support equipment are:

Activity	Type	Frequency
Capacitor Bank – Annual Inspection	Inspection	Annual
Voltage Regulator – Annual Inspection	Inspection	Annual
Voltage Regulator Servicing	Routine Maintenance	3 yearly

Table 5-32 Inspection and maintenance cycles for our voltage support equipment

Renewal programme

The majority of our voltage regulators and capacitors are in acceptable condition. There is an identified renewal need for the voltage regulator installed in 1958 during this planning period. For parts of the network which have been converted to 22kV operation, some of the voltage regulators and capacitors can be redeployed to other areas to address identified voltage constraints.

5.9.3 Protection relays

Protection relays rapidly detect and initiate the operation of circuit breakers to isolate electrical faults to ensure safety of our staff and the public, and to protect equipment from short circuits and overloads.

We have 144 protection relays installed at our zone substations and at Transpower's Bombay and Glenbrook GXP's. The average age of our protection relays is 17 years.

Age profile

Figure 5-21 shows the age profile of our protection relays.

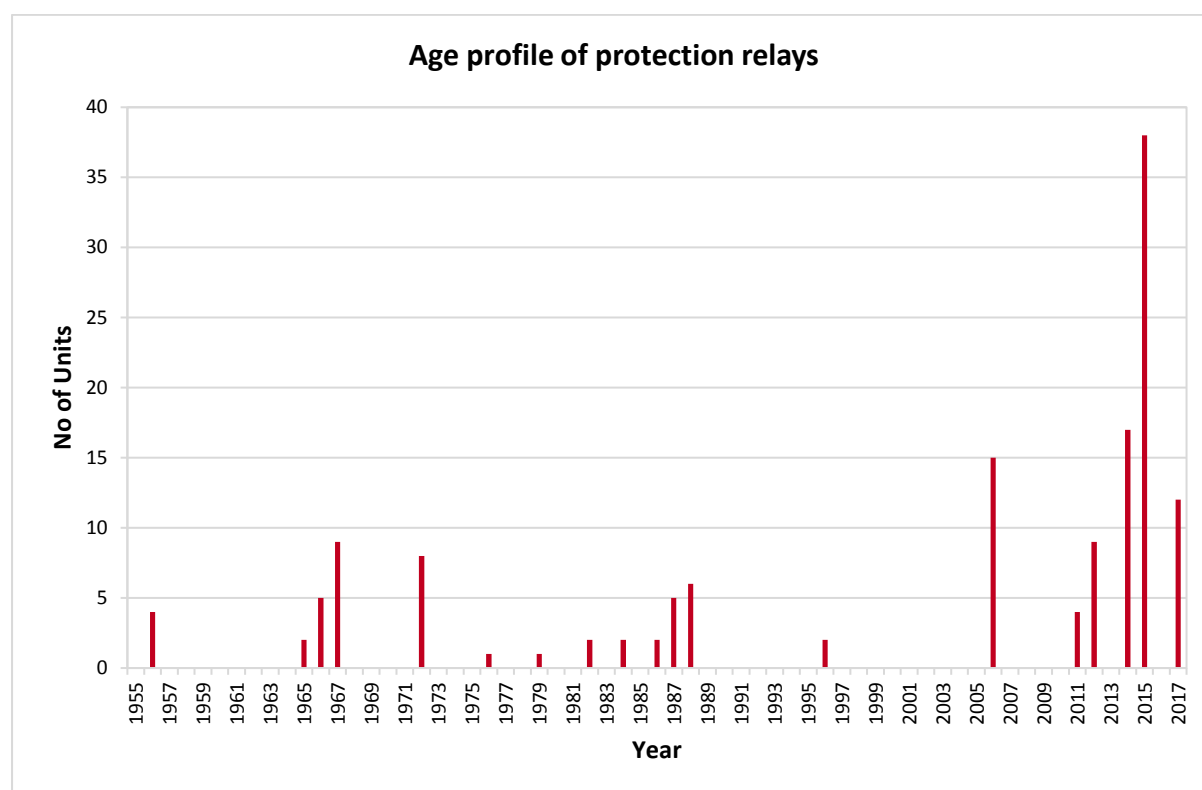


Figure 5-21 Age profile of protection relays

Inspection and maintenance practices

We test our protection relays every 3 years to ensure they operate correctly.

Renewal programme

We typically replace protection relays when we replace the primary plant which they relate to, for example replacement of feeder protection when we replace the corresponding circuit breakers. As a result of this, we include relay replacement in the cost of replacing the major primary plant. During this planning period we will replace end of life relays at Maoro, Waiuku, Mangatawhiri and Ramarama zone substations when we replace the switchboards and/or substations.

In some cases, we replace relays due to performance issues, or where we require different functionality. Our replacement programme for protection relays is planned for:

- Replacement of feeder protection relays at Karaka zone substation. These are approximately 17 years old and have been found to have emerging performance and reliability issues at the end of life (20 years). We have recovered spare relays to manage the reliability issues and plan to replace these relays in 2020/21 for an estimated cost of \$200,000; and
- The Electricity Authority issued an amendment to the Electricity Industry Participation Code (the Code) in 2017 which changes the nature of the AUFLS scheme, and replaces it with the

Extended Reserves scheme. Changes to the new system were to start in April 2018 and be completed by mid-2019. The Electricity Authority paused the project in October 2017 to assess options for more reliable delivery of the scheme. Based upon the specified requirements for implementation of this scheme, we will need to change some relays to provide the required functionality to meet new technical requirements. Any new relays we install before then will be compatible with the proposed requirements. We have allowed \$400,000 for new relays in 2019/20, deferred from 2018/19 to reflect the latest update and uncertainty from the Electricity Authority.

5.9.4 SCADA and Communications systems

Our GE iFix SCADA system is in very good condition following server and software upgrades in 2015. We do not expect any replacement in the short term, however in the medium term we will require a version upgrade and server replacement to ensure the system remains current and to reduce the risk of failure.

We operate a digital SCADA radio network, as well as a digital voice radio network, and have repeaters in three locations to provide coverage and redundancy. The digital voice network was installed in 2015 and is in very good condition, the digital SCADA radio equipment is also in good condition. No replacement is expected in the short to medium term on either system, however it will be extended through the addition of more repeater sites to address coverage issues.

We have 222 SCADA remote terminal units (RTUs) installed on our network with 15 located at Grid Exit Points and Zone Substations, and 207 installed on switchgear and devices across the network to provide remote control and indication. An age profile is shown in Figure 5-22.

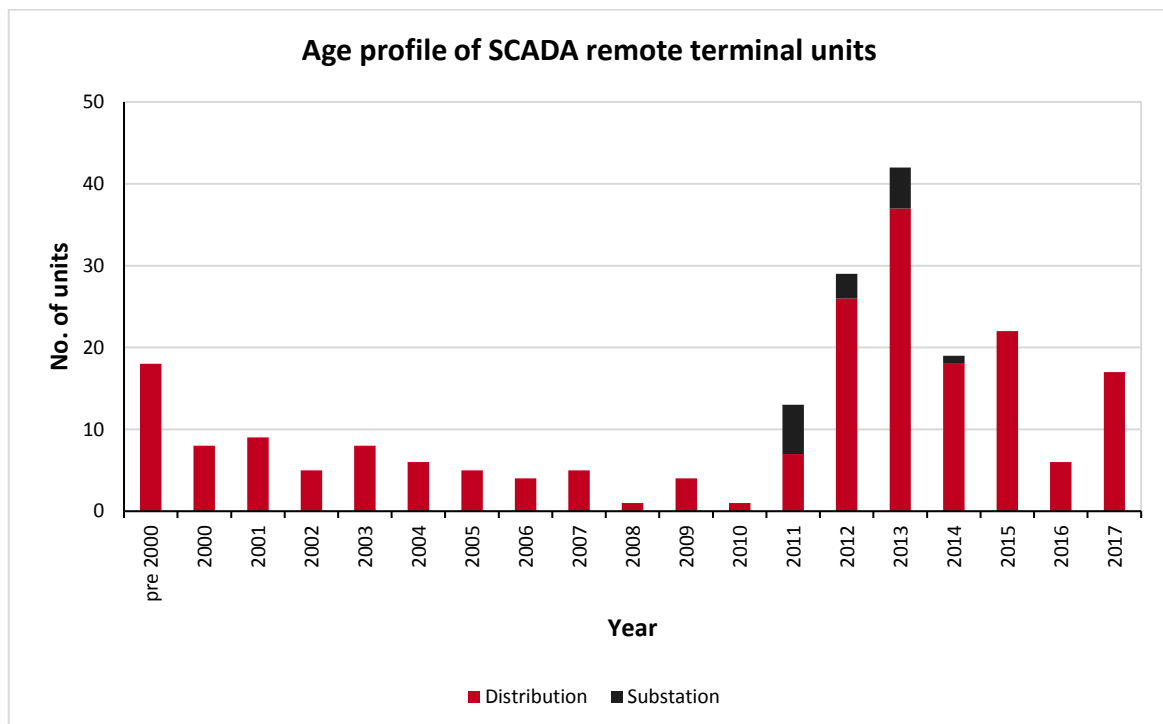


Figure 5-22 Age profile of SCADA Remote Terminal Units

Renewal programme

We plan to replace the communication link between Opaheke and Bombay for an estimated cost of \$60,000 in early 2018, and change-over to the fibre link between Bombay and Pukekohe for the protection communication link at an estimated cost of \$40,000 in 2018/19 due to reliability issues associated with aged and obsolete (unsupported) technology.

We anticipate replacement of the three SCADA servers, and a version upgrade of the software for an estimated cost of \$300,000 around 2019 and 2020.

We are actively investigating alternatives, in particular a fully integrated Advanced Distribution Management System (ADMS), which can utilise information from our smart meter network, and improve call handling and outage management. These systems have considerable cost, and as such we have not included any expenditure in our forecast for such a system, we will update this in future plans.

We have expenditure on the system each year to implement improved functionality. We have a maintenance services agreement with the vendor of the SCADA system for support, with an annual fee.

Based on the age profiles of SCADA RTUs, we expect to replace around 70 units during the planning period as older electronic RTUs tend to become unreliable after 25 years and replaced as part of overhead switchgear replacement programme.

5.9.5 Load control equipment

Load control equipment consists of ripple injection plant located at substations, and load control relays located at each of our consumers premises connected to some form of interruptible load. For residential consumers, the interruptible load is generally hot water heating.

When we need to manage the load on our system, we send a signal from our SCADA master station to the relevant ripple injection plant(s) which in turn send a signal to the assigned load control relays.

We have five Ripple Injection plants installed on the network at Bombay, Glenbrook, Opaheke, Pukekohe and Tuakau with an average age of 19 years. The operating frequency of our load control system is 317 Hz.

Age profile

Figure 5-23 shows the age profile of our Ripple Injection Plant.

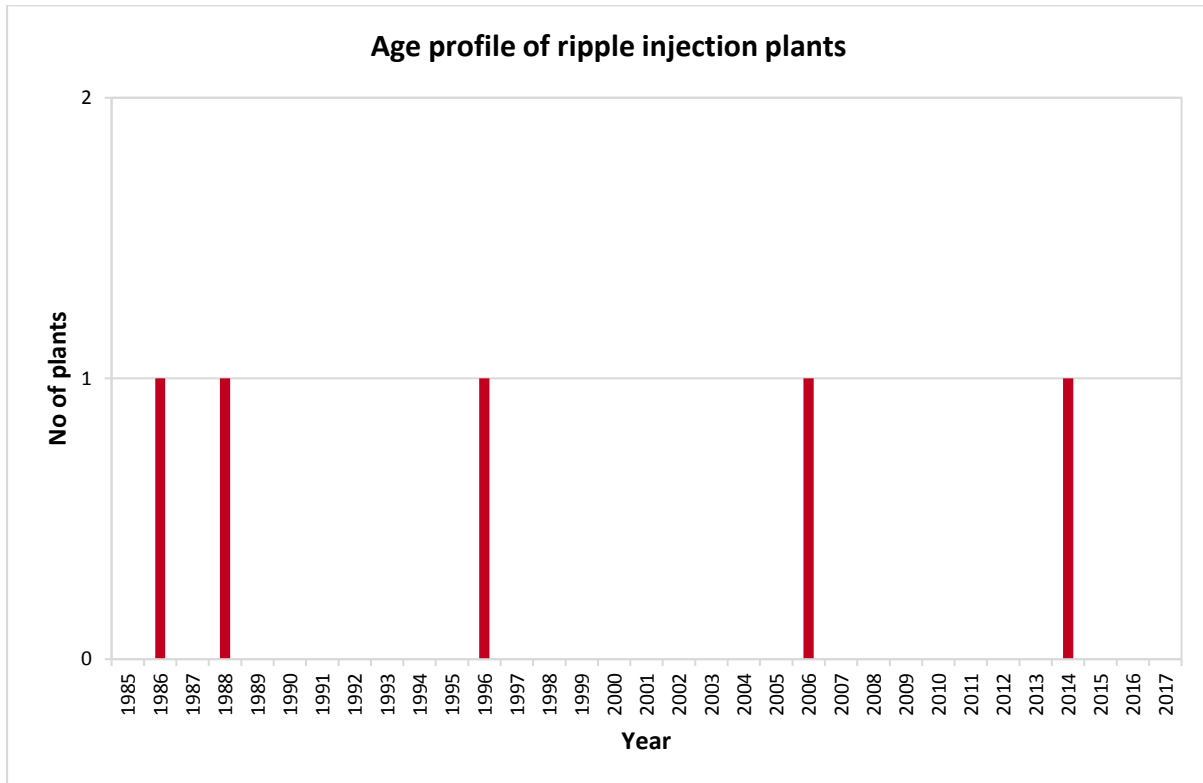


Figure 5-23 Age profile of Ripple Injection Plant

We have over 3,568 load control relays installed on our network associated with legacy meter installations. We have reduced the number of individual load control relays by introducing Smart Meters on our network which have the ripple receiver inbuilt.

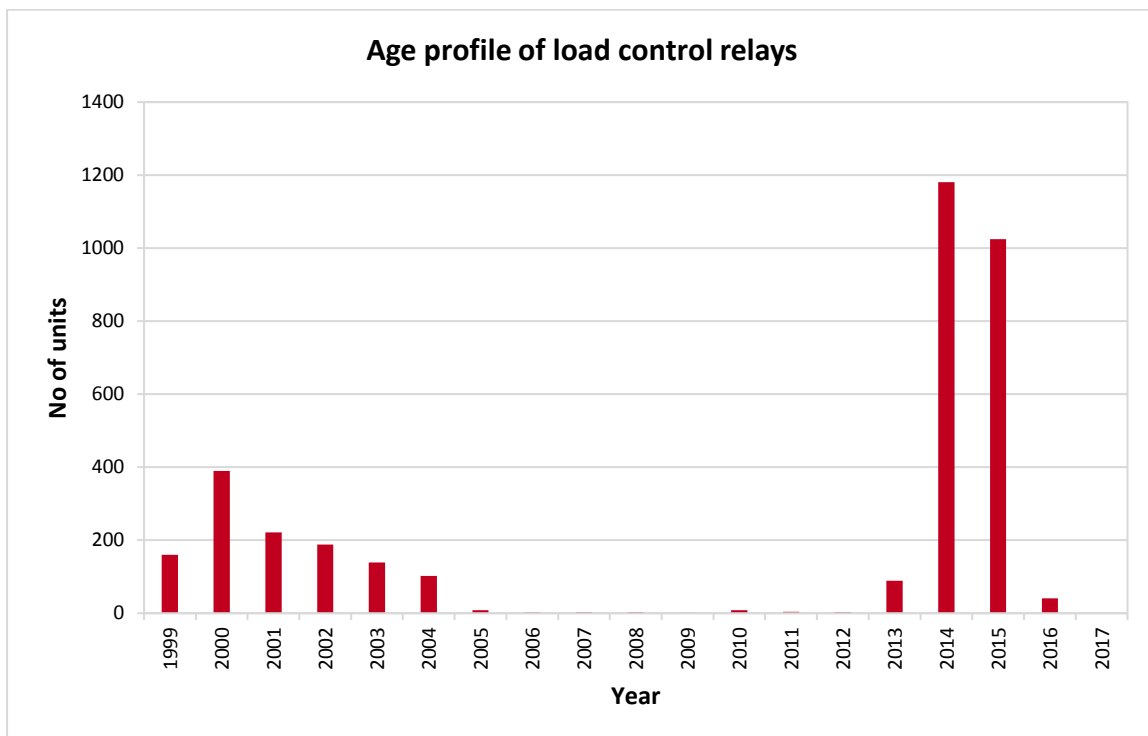


Figure 5-24 Age profile of Load Control Relays

Inspection and maintenance practices

Our inspection and maintenance cycles for our ripple injection plants are:

Activity	Type	Frequency
Ripple Plant – Visual Inspection	Inspection	6 Monthly
Ripple Plant – Test and Service	Routine Maintenance	Annual

Table 5-33 Inspection and maintenance cycles for our ripple injection plants

Renewal programme

Ripple plant at Opaheke and Tuakau is relatively new and no renewal expenditure is forecast in the planning period. Replacement of the ripple plant converter at Pukekohe to address age and reliability issues is to be completed in early 2018.

New ripple plant will be installed with the proposed new Zone Substations at Drury South area and Bombay area, superseding the 33kV plant at Bombay which is in below average condition.

Some expenditure may be required at Glenbrook to renew or replace the existing 33kV ripple plant in the later part of the planning period, this will also be driven by load growth. No allowance has been made for this in the plan due to the uncertainty.

As we upgrade legacy meter installations to smart meters, we will remove the standalone ripple receivers, so no future expenditure is expected on these.

5.9.6 Auxiliary battery banks

110V and 24 VDC battery banks are installed in our network to supply power to protection schemes, control and metering and equipment components (such as circuit breaker operating coils) that need DC supplies to operate.

We have 27 battery banks installed in our network with installation dates ranging from 2009 to 2017. We have 9 units of 110V battery banks and 18 units of 24V battery banks. The average age of our battery banks is 2 years.

Age profile

Figure 5-25 shows the age profile of our auxiliary battery banks.

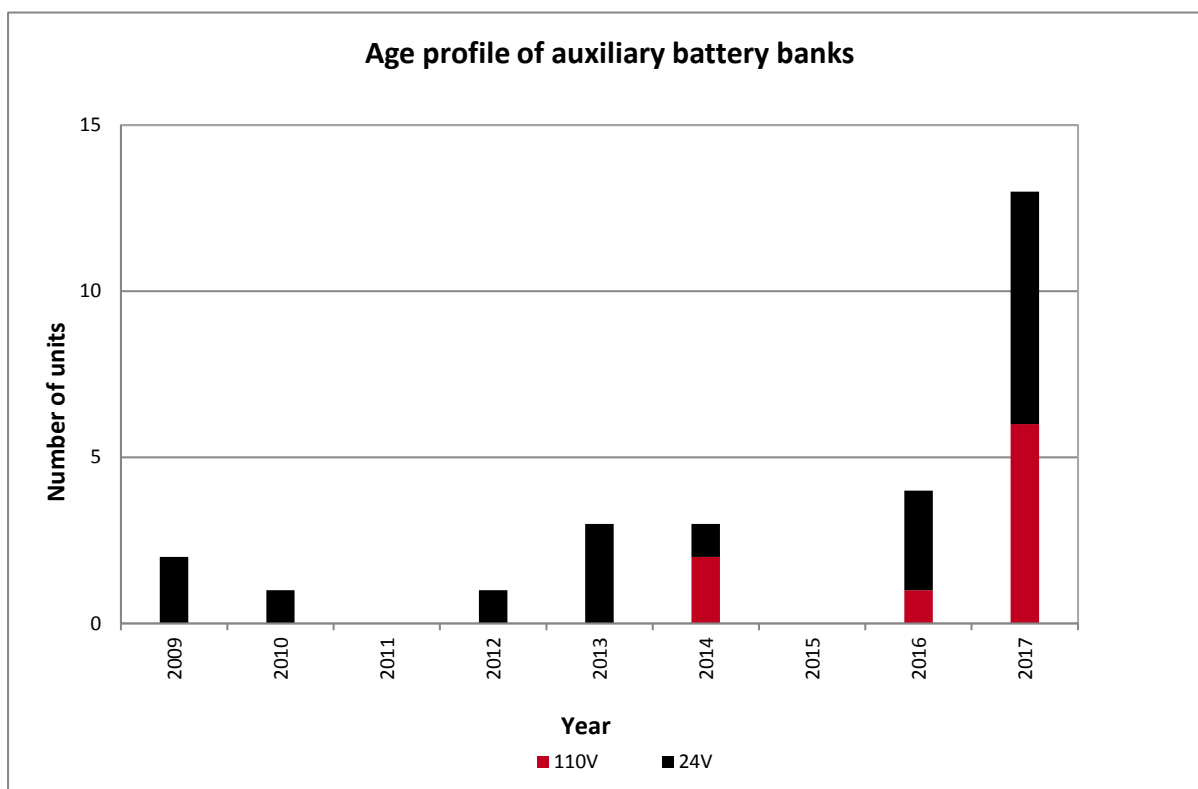


Figure 5-25 Age profile of Auxiliary Battery Banks

Inspection and maintenance practices

We carry out periodic visual inspections and tests ensure that the auxiliary battery cell voltages remain within acceptable ranges and the battery chargers operate as required depending on site criticality.

Activity	Type	Frequency
Battery Inspection and Test - GXP	Routine Test	3 Monthly
Battery Inspection and Test – Zone Sub	Routine Test	3 Monthly
Battery Inspection and Test – Radio Site	Routine Test	12 Monthly

Table 5-34 Inspection cycle for Auxiliary Battery Banks

Renewal programme

As auxiliary battery banks have an expected life of 8 years (80% of their design life of 10 years), conservative financial planning assumes we will replace our entire auxiliary battery bank fleet at least once during this planning period, although actual replacements, particularly as technology improves, may be favourable to this assumption. The trade-off between the relatively low replacement cost and high impact of failure will be considered when planning the renewal programme. Battery banks close to their end of life at the start of the planning period will be replaced twice during this period. We also replace batteries in remote field devices, however these are undertaken as part of their routine maintenance and are not included in this forecast.

5.9.7 Summary of other system fixed asset expenditure forecast

Expenditure Forecast (\$000)	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028
Capital Expenditure										
Voltage regulator replacement	-	150	-	-	-	-	-	-	-	-
New AUFLS/Extended Reserves Relays	-	400	-	-	-	-	-	-	-	-
Protection relays replacement and upgrade	40	-	200	-	-	-	-	-	-	-
SCADA Master Station Renewal	-	150	150	-	-	-	-	-	-	-
RTU Replacement	75	70	25	20	20	40	30	25	30	10
Battery banks	120	20	30	30	20	30	60	30	20	30
Other protection, control, and radio communication renewal	100	100	100	100	100	100	100	100	100	100
Capital Expenditure Total	335	890	505	150	140	170	190	155	150	140
Operational Expenditure										
Capacitors and Voltage regulators	20	20	20	20	20	20	20	20	20	20
Protection	150	140	130	130	150	140	140	130	140	160
Load control equipment	50	50	50	50	50	50	50	50	50	50
Battery banks	20	20	20	20	20	20	20	20	20	20
SCADA and Communications	110	110	110	110	110	110	110	110	110	110
Operational Expenditure Total	350	340	330	330	350	340	340	330	340	360

Table 5-35 Other system fixed asset expenditure forecast summary

5.10 Renewal and maintenance of other assets

5.10.1 Backup Generators

We have 3 mobile generators used to maintain supply during planned and unplanned outages, and 1 fixed generator at our head office to maintain supply to our SCADA and the control room.

Age and size profile

The generators range in size and age from 5 years to 21 years, and from 15kVA to 250kVA.

Inspection and maintenance practices

These are maintained at 250 hours running time, and the fixed generator at our head office is checked every month and run every 6 months.

Renewal programme

We have no firm plans to replace these generators in the short term, however given the age profile, replacement during the planning period is almost certain.

Expenditure forecast

We have no capital expenditure forecast in the short term on generators, and operating costs are allocated to the projects which they are used on or corporate overheads for the building generator.

5.10.2 Emergency critical spares

Description and quantity

We hold a number of critical spares at our main depot in Pukekohe, such as distribution transformers, distribution switchgear, cables, overhead line conductors, poles and cross arms. Some of these are new, and others have been recovered from projects and are now held as spares. Additionally, we have two spare 33/11kV power transformers which can be returned to service should a serious fault develop with one on the network.

We do not hold any spare 110/22kV transformers as the units in service are relatively new, and have n-1 redundancy.

Inspection and maintenance practices

During FY19, we will review our current processes and update our critical spares list and stock requirements. Additionally, we will implement a critical spares management processes, which will look at periodic inspection, refurbishment and maintenance of spares held.

Expenditure forecast

We do not forecast any material expenditure on critical spares in the short term, but will be compiling a plan to ensure sufficient stock levels in the medium term.

5.10.3 Head office and depot

Description

We own the land and buildings used for our Head Office and Depot. We operate all of our activities from this one site, located in Pukekohe.

Our site is approximately 3.2 hectares in size, and we have offices, storage buildings and workshops covering just over 4,000 square meters.

Renewal programme

No significant renewal or upgrade is planned on the existing buildings at this time, however we are developing a Land and Buildings Strategy, which once complete may result in different levels of expenditure or the possibility of a major site redevelopment or relocation to a new site.

5.11 Assets owned by Counties Power at Transpower Grid Exit Points

In addition to the assets we own at our own substations, or as part of our distribution system, we also own asset located at Transpower's GXPs.

These assets are included in the asset category overviews above.

5.11.1 Bombay Substation

Within the substation building, the following equipment is installed:

- 24V DC battery bank;
- 2 sets of overcurrent and earth-fault line protection;
- 3 sets of Line differential protection;
- 3 sets of UHF inter-trip communication links;
- 1 set of metering equipment (33kV only); and
- 1 SCADA RTU and associated equipment.

A 33kV load control plant and an aerial mast are installed within the grounds of the substation, as well as a Disaster Recovery container which has a backup SCADA control terminal.

5.11.2 Glenbrook Substation

Within the substation building, the following equipment is installed:

- 4 sets of Line differential protection;
- 1 set of metering equipment;
- 1 SCADA RTU; and
- 2 fibre optic cables to the Glenbrook Load Control Plant.

The 33kV Glenbrook Load Control Plant is located near the Transpower Glenbrook Substation on land owned by Counties Power.

5.12 Summary of capital and operating expenditure

Replacement and renewal capital expenditure

Asset Category	FY2019	FY2020	FY2021	FY2022	FY2023	FY2024	FY2025	FY2026	FY2027	FY2028
Subtransmission network	50	50	50	50	50	50	500	500	50	50
Maioiro Line Refurbishment	-	-	-	-	-	-	450	450	-	-
Other Subtransmission Renewal	50	50	50	50	50	50	50	50	50	50
Zone Substations	150	50	50	50	50	50	400	50	50	50
Zone Substation switchgear										
Other Zone Substation Renewal	150	50	50	50	50	50	50	50	50	50
Distribution and LV lines	7,550	7,140	6,870	6,730	6,380	6,640	6,320	6,380	6,610	6,460
Distribution poles and crossarms										
Overhead Renewals	3,910	3,480	3,480	3,480	3,480	3,430	3,430	3,430	3,430	3,430
Distribution conductor										
Copper Replacement Programme	2,050	1,740	1,440	1,470	1,230	1,660	1,220	1,200	1,580	1,220
Swan Replacement Programme	710	1,050	1,200	1,200	1,170	1,080	1,110	1,200	920	1,210
HV Feeder section replacement	500	550	350	200	200	200	200	200	200	200
Urban LV Replacement	280	220	300	280	200	170	260	250	380	300
Overhead Safety Compliance	100	100	100	100	100	100	100	100	100	100
Distribution and LV cables	370	380	390	400	410	360	370	380	390	400
Distribution and LV cables Renewal	200	200	200	200	200	150	150	150	150	150
LV Pillar Renewal	170	180	190	200	210	210	220	230	240	250
Distribution substations and transformers	590	730	590	590	590	730	660	660	660	450
Distribution transformers										
Transformer Renewal Programme	590	730	590	590	590	730	660	660	660	450
Distribution switchgear	1,350	1,810	1,980	1,210	1,190	1,460	1,570	1,580	1,370	700
RMU replacement	750	1,210	1,380	810	810	1,160	1,270	1,280	1,070	400
Overhead switchgear replacement	600	600	600	400	380	300	300	300	300	300
Other System Fixed Assets	335	890	505	150	140	170	190	155	150	140
Capacitors and Voltage regulators										
Voltage regulator replacement	-	150	-	-	-	-	-	-	-	-
Protection										
New AUFLS/Extended Reserves Relays	-	400	-	-	-	-	-	-	-	-
Protection relays replacement and upgrade	40	-	200	-	-	-	-	-	-	-
SCADA Master Station Renewal	-	150	150	-	-	-	-	-	-	-
RTU Replacement	75	70	25	20	20	40	30	25	30	10
Battery banks	120	20	30	30	20	30	60	30	20	30
Other protection, control and radio communications re	100	100	100	100	100	100	100	100	100	100
Subtotal	10,395	11,050	10,435	9,180	8,810	9,460	10,010	9,705	9,280	8,250
Capitalised Maintenance	900	900	900	900	900	900	900	900	900	900
Total	11,295	11,950	11,335	10,080	9,710	10,360	10,910	10,605	10,180	9,150

Network operating expenditure

Asset Category	FY2019	FY2020	FY2021	FY2022	FY2023	FY2024	FY2025	FY2026	FY2027	FY2028
Subtransmission network	190	170	120	120	120	120	120	120	120	120
Subtransmission lines	190	170	120	120	120	120	120	120	120	120
Subtransmission cables	-	-	-	-	-	-	-	-	-	-
Zone Substations	520	430	420	430	420	420	420	420	420	420
Zone Substation transformers	190	150	140	100	100	100	100	100	100	100
Zone Substation switchgear	120	120	120	120	110	110	110	110	110	110
Zone Substation other equipment	70	70	70	120	120	120	120	120	120	120
Zone Substation buildings and grounds	140	90	90	90	90	90	90	90	90	90
Distribution and LV lines	910	810	810	710	710	610	610	610	610	610
Distribution poles and crossarms	840	740	740	640	640	540	540	540	540	540
Distribution conductor	50	50	50	50	50	50	50	50	50	50
Fault indicators and Earthing	20	20	20	20	20	20	20	20	20	20
Distribution and LV cables	280	280	280	280	280	280	280	280	280	280
Distribution and LV cables	150	150	150	150	150	150	150	150	150	150
LV Pillars	130	130	130	130	130	130	130	130	130	130
Distribution substations and transformers	250	250	250	250	250	250	250	250	250	250
Distribution transformers	250	250	250	250	250	250	250	250	250	250
Distribution switchgear	400	390	390	370	370	390	390	400	400	410
Ring main units	110	120	120	130	130	150	150	160	160	170
Overhead switchgear	290	270	270	240	240	240	240	240	240	240
Other System Fixed Assets	350	340	330	330	350	340	340	330	340	360
Capacitors and Voltage regulators	20	20	20	20	20	20	20	20	20	20
Protection	150	140	130	130	150	140	140	130	140	160
Load control equipment	50	50	50	50	50	50	50	50	50	50
Battery banks	20	20	20	20	20	20	20	20	20	20
SCADA and Communications	110	110	110	110	110	110	110	110	110	110
Vegetation	1,100	1,100	1,100	1,100	1,100	1,100	1,100	1,100	1,100	1,100
Vegetation	1,100	1,100	1,100	1,100	1,100	1,100	1,100	1,100	1,100	1,100
Public Safety Services	150	150	150	150	150	150	150	150	150	150
Public Safety Services	150	150	150	150	150	150	150	150	150	150
Faults and Reactive Maintenance	1,900	1,900	1,900	1,900	1,900	1,900	1,900	1,900	1,900	1,900
Faults	1,900	1,900	1,900	1,900	1,900	1,900	1,900	1,900	1,900	1,900
Capitalisation	- 900	- 900	- 900	- 900	- 900	- 900	- 900	- 900	- 900	- 900
less Capitalised Maintenance	- 900	- 900	- 900	- 900	- 900	- 900	- 900	- 900	- 900	- 900
Total	5,150	4,920	4,850	4,740	4,750	4,660	4,660	4,660	4,670	4,700

6 Network Development

6.1 Planning approach

Our long-range plan focuses on developing our subtransmission network and zone substations by taking into consideration:

- Plans for new areas of supply (e.g. new subdivisions) and anticipated demand growth in existing areas of supply;
- Adequacy of distribution feeder network to meet future security and capacity requirements; and
- Adequacy of our points of supply, subtransmission network and zone substations to meet future security and capacity requirements.

Our short-range plan focuses on developing our distribution network, in particular feeder performance and capacity to meet our operational objectives. Factors we consider in our short-range plan include:

- Network safety;
- Customer connections;
- Overload relief;
- Voltage correction and control;
- Power factor correction;
- Service quality improvement;
- Operation and maintenance;
- Loss reduction; and
- Operating efficiency improvement.

We have adopted a longer planning timeframe and modified our planning approach to take into account the increasing time required to negotiate and agree on land-rights or new work for upgrades requiring land purchase, designations or easements.

6.1.1 Planning drivers and assumptions

The key drivers and assumptions for our investment plans include:

- The network is to meet all safety requirements;
- Selected options should maintain flexibility for future development if they can be economically justifiable;
- We will invest (where economically feasible) to meet our security standards (see section 6.1.3);
- We will invest to meet the demand forecast (see section 6.2); and
- We will make investment choices that minimise the risk of asset stranding.

6.1.2 Security criteria

Our security criteria have been established based on the historical network requirements and the level of service sought by the consumers connected to our network. When questioned in the annual survey, and from feedback received through other means, consumers are generally satisfied with the level of service they receive (response to faults, and restoration) and are generally unwilling to pay more for a higher level of service. We use the customer service levels outlined in Section 3 to inform our security criteria.

Table 6-1 sets out the security criteria we use to design our network.

Class	Range of Group Peak Demand (GPD) MVA	Examples	Minimum Demand to be met after:	
			First outage (transformer or circuit) ¹	Second outage (transformer or circuit) ²
M	60 - 120	Metropolitan Substation ³	No loss of supply	Demand < 60MVA No loss of supply Demand > 60MVA One line & one transformer No loss of supply Otherwise 50% MD 20 minutes 100% MD 5 hours
S1	12.5 – 60	Large zone substation	No loss of supply	20% MD 20 minutes 100% MD 5 hours
S2	6.3 – 12.5	Medium zone substation	No loss of supply	40% MD 20 minutes 100% MD 5 hours
S3	0 – 6.3	Small zone substation	100% MD in 20 minutes	60% MD 20 minutes 100% MD 5 hours
S4	6.3 – 25	Switching station	No loss of supply	Typically 10% MD 20 minutes 100% 6 hours
D1	6.3 – 25	Trunk feeder (supply to switching stn)	No loss of supply	Typically 10% MD 20 minutes, 100% 6 hours
D2	3.15 – 12.5	Medium loaded feeder	60% MD in 20 minutes 100% 4 hours urban, 6 hours rural	50% MD 30 minutes 100% MD 5 hours
D3	0 – 3.15	Lightly loaded feeder	60% MD in 20 minutes 100% 4 hours urban, 6 hours rural	100% 6 hours
C1	3.15 – 12.5	Large customer	Depends on supply contract	100% 6 hours
C2	1.25 – 3.15 ⁵	Medium customer	100% in 20min off feeder backbone ⁶ 100% 4 hours urban, 6 hours rural when off spur	100% 6 hours
C3	0 – 1.25	Small customer	100% 4 hours urban, 6 hours rural	100% 6 hours

¹Assumes all circuits are in service. Restoration percentage and times do not apply for Transpower outages, civil defence emergency or other extreme situations.

²Assumes maximum of one transformer or incomer cable fault in order to be repaired within target repair time.

³Metropolitan class of substation in this security standard to cater for the increases in demand that will occur because of the Auckland regional growth in the Counties Power's area of supply. A metropolitan substation is connected to the subtransmission network via three 110kV lines and contains three supply transformers. Generally, the three lines will form part of a ring.

⁴Excludes faults on customer owned supply assets.

⁵Includes essential services.

⁶Excludes faults on supply section of line. For these faults, the standard is equivalent to that for supply off a spur.

⁷The restoration of small urban customers inside this timeframe necessitates that underground LV circuits of adjacent transformers are linked via link boxes and associated normally open fuse switch units.

Table 6-1 Counties Power planning security criteria

We have been working on the update of our criteria for security and capacity planning for the next AMP (2019). The update will enable alignment against our industry peer group, recognised national and international standards identified in an earlier baseline review of our current security criteria. Further, the update of our criteria will also provide better line of sight against service expectations from our consumers. We are not expecting a material change of our network development plan as a result.

Criteria for consumers

For larger consumers, we set the security criteria for their supply based on the size of their load, their location, and any special conditions agreed in their supply contracts. Large consumers may make a price-quality trade-off and pay a larger annual amount for higher levels of service compared with the average consumer.

For smaller consumers, we set the maximum customer numbers and installed transformer capacity for each of our feeders according to Table 6-2. This limits the impact of any fault. Although high customer density on feeders provides good utilisation of assets, the network performance impacts (SAIDI, SAIFI) can be unfavourable during faults. We will review our planning criteria for feeder loading as part of the security criteria update for the next AMP (2019).

Feeder section	Max No Customers	Max transformer MVA
Total Feeder	3,000	
1 st Response (Automatic)	1,200	5
2 nd Response (Remote manual)	800	3
3 rd Response (local manual)	400	1.5

Table 6-2 Response levels for feeders

We have three design levels of response to a feeder fault:

- Automatic devices such as circuit breakers and reclosers;
- Operator response by using remotely controlled switches; and
- Sending a technician to operate equipment.

Criteria for feeders

Table 6-3 specifies our feeder service criteria. We assess our feeder performance against this service criteria using load flows. We then identify and prioritise remedial works based on the results of the load flow assessment.

Service Criteria		Benchmark 1	Benchmark 2
Losses	Maximum Demand	81 kW	135 kW
	Maximum Loss	16.0 kW/km	21.6 kW/km
Voltage Drop (VD) at Maximum Demand	Feeder only	0.955 pu for urban feeders (3% regulation) 0.935 pu for rural feeders (4.5% regulation)	1.0% V/km
		0.7% V/km	
	Feeder plus nominally 50% adjacent feeders ¹	0.91 pu	
Loading	Feeder only	0.75 pu	0.9 pu
	Feeder plus nominally 50% of adjacent feeder	1.0 pu	1.15 pu
Note 1: VD is recorded e.g. 0.93/0.91pu with 0.93 referring to voltage at end of feeder and 0.91, the voltage at end of the section of the adjacent feeder			

Table 6-3 Feeder Service Criteria

In addition to the feeder service criteria, assessment will also be undertaken on rural feeder sections with high density residential load. Rural feeders are typically in overhead construction and have lower reliability than urban feeders due to their exposure to external factors such as trees, birds, and strong wind. As urban boundaries of the network extend, some rural feeder sections can be reconfigured to connect the high density residential load to urban feeder sections to improve reliability. These feeder reconfigurations will generally utilise existing switches to change network open points, but may require conductor upgrade and additional switches to provide feeder sectionalisation in some cases.

6.1.3 Design standards

Our distribution network is predominantly rural with older subtransmission built at 33kV and distribution built at 11kV. At these voltages, we experience voltage constraints and high network losses typical of a rural distribution network. To mitigate these issues, where economically feasible, we have been progressively migrating to two new voltage levels:

- 110kV as our standard subtransmission voltage; and
- 22kV as our standard distribution voltage.

Moving to a higher subtransmission and distribution voltage will also enable us to reduce the number of our zone substations that we need on our network as we can supply the demand from fewer sites, leading to lower costs overall. However, we note there is a clear trade-off between the risk of a fault affecting a larger zone substation and the diversity between having a larger number of smaller substations.

Sub-transmission and zone substation design

Our standard 110/22kV zone substation design specifies:

- A 2 bay outdoor structure to allow termination of four circuits (typically two 110 kV lines and two 110 kV transformers) with space provision for a third bay to allow for a third 110 kV circuit and a third 110kV transformer;

- 110kV non-oil disconnecting circuit breakers (to allow for low maintenance and safe operation);
- 60 MVA firm capacity, consisting of two 110/22kV 30/60 MVA transformers. Space is to be provided to allow this to increase this to 120 MVA firm capacity, consisting of a third 110/22kV 30/60 MVA transformer. The transformer impedance shall be designed to limit the 22kV fault level to less than 16 kA¹⁸; and
- One, three-section, 22kV, 2500 A switchboard with:
 - Three incomers each rated at 2500 A;
 - Two bus couplers each rated at 2500 A;
 - Up to fifteen feeders each rated at 630 A;
 - Unit protection throughout the substation; and
 - Where practicable, considering space and cost effectiveness, the switch room should have three fire proof zones, one for each 22kV bus section, or as a minimum active fire suppression.

Distribution network design

We generally run our feeders radially out from the zone substations. Our preferred feeder configuration, where geography allows, is for a Y construction with the bottom of the Y starting near the zone substation and the ends of the two arms of the Y being open parallels with other feeders, normally from another zone substation. In this configuration, we divide our feeders into three by installing reclosers (in rural areas) at the Y junction of the feeder and remotely operable switches at each end arm of the top of the Y. In the urban network, the feeder architecture can differ due to the greater number of switching points, however through the use of ring main units placed in strategic locations, switching of feeders allows for quick isolation and response to faults.

Where possible we will locate main feeder routes off high traffic routes or underground where significant traffic hazards exist. We generally avoid double circuit lines along high traffic routes if possible.

We also use a mix of trunk and distribution feeders on our distribution network to limit the loading on each distribution feeder:

- Our trunk feeders provide n-1 redundancy to small switching stations which in turn typically supply four smaller distribution feeders; and
- Distribution feeders are designed to have sufficient capacity to be able to pick up half the load of an adjacent feeder if it trips.

The power transformer tap changer range at our zone substations defines the minimum voltage levels for our subtransmission network. Table 6-4 specifies our standard distribution network conductor and cable ratings.

¹⁸ three transformers operating in parallel configuration

Feeder Type	Cable	Rating	Design Rating	Overhead Conductor	X-section	Rating	Design Rating	Notes
Trunk	800mm ²	660A	660A					1,2
	630mm ²	590A	590A	Cockroach	256mm ²	560A	560A	3
Distribution				Cockroach	256mm ²	560A	360A	4
	240mm ²	360A	240A	Cricket	160mm ²	420A	280A	3
	95mm ²	200A	140A	Grasshopper	85mm ²	290A	190A	3, 5
				Fluorine	40mm ²	190A	130A	5, 6
Notes to table: 1. Include fibre optic cables in our underground cables for protection, SCADA and cable temperature functions; 2. Use underground cables in urban areas; 3. Use AAC conductor where possible. AAAC may be used as an alternative for long spans; 4. Use maximum span lengths of 80-100 meters; 5. Run spurs for volt drop considerations rather than capacity.								

Table 6-4 Feeder Service Criteria

The design criteria we utilise for our distribution switchgear (RMUs) is that they shall have:

- A minimum fault rating of 16kA;
- A minimum bus rating of 630A;
- 3 phase switching; and
- Remotely operable disconnectors on four function units.

Equipment ratings

We design and operate our network to the following acceptable equipment load limits:

- 100% of OFAF power transformer ratings, with short duration overload to 120% after n-1 operation;
- 100% of the switchgear, line and cable ratings;
- The acceptable load limit on distribution transformers depends on the period of maximum demand and whether it is a winter or summer peak load;
- 100% of the distribution transformer rating where the maximum transformer load is spread over many hours; or
- 150% of the distribution transformer rating where the load is peaky over one to two hours, such as supplying a residential subdivision.

6.1.4 Network development options

Network development philosophy

Our network design philosophy consists of the following elements:

- We make sure any development option we consider has public and personnel safety as a primary requirement;

- Where appropriate, we shall implement phased solutions to defer major subtransmission and distribution investment;
- Our network is primarily radial with the ability to inter link various feeders if the need arises;
- We continually reassess and re-configure our network configuration to respond to load increases and changes in demand patterns to optimise overall performance;
- Upgrade of our distribution feeder network allows better utilisation of tie-lines and alternative feeds. This has also allowed us to defer upgrading some zone substations by temporary re-allocating load to adjacent zone substations;
- Where we identify potential increase in demand (see Section 6.2), we plan for significant line routes and substation sites to serve the demand and seek designations well in advance;
- The security criteria recognises that it is not economic to provide full redundancy on all our network; and
- We continue to improve our network performance by employing effective design and construction techniques, such as triangular line construction and strategic deployment of pole-mounted circuit breakers and fault passage indicators.

Subtransmission development

When identifying subtransmission development options, we consider:

- Long term load and usage forecasts in the area, considering consumer type and needs;
- How the subtransmission system will support new zone substation transformer capacity within growth areas;
- Alternative solutions using existing assets or taking advantage of technological innovations;
- Optimising capital investment on the network;
- Stranding risk; and
- The impact of existing and proposed embedded generation developments.

Distribution Development

When identifying distribution network development options, we consider:

- Industrial, commercial and residential developments affecting specific areas of supply and requiring capacity augmentation;
- The need for feeder reinforcement or distribution tie line construction for security reasons;
- Voltage regulation, particularly on rural feeders, and the need or otherwise for regulators, reactive compensation or voltage conversion;
- Loss reduction through correct conductor selection and optimised switching configurations; and
- The impact of existing and proposed embedded generation developments.

Development on the network boundaries

We share common boundaries with two electricity networks, Vector to the north, WEL Networks to the south, and although not immediately on our border, Powerco's 'Eastern' network is adjacent to the south-east of our network.

When considering development options, including capacity and security projects we will look to share investment with our neighbours as the most economic solution may be one that satisfies a number of mutual needs.

We share interconnection points at 11kV with Vector in two locations, and in one location with WEL Networks.

Conversion to 22kV

Conversion to a 22kV operation can be used to increase our network capacity to meet load growth and service requirements effectively. This involves upgrading the 11kV distribution network to 22kV where there are identified capacity and voltage constraints, and each area for conversion is assessed on its individual merits, including consideration of a range of alternatives. For all new work, we install insulators, cables, switchgear, and transformers (>50kVA) to be capable of 22kV operation. Where practical we will convert the relevant distribution network to 22kV when 11kV capacity constraints occur.

Low Voltage Reticulation

New subdivision developments drive the extent of underground low voltage reticulation augmentation. We liaise closely with local surveyors and property developers who are responsible for the majority of subdivision works in the area to identify their needs. Planning of network augmentation also takes into account the growth plans developed by local councils. The majority of overhead low voltage augmentation work comes from smaller rural subdivision developments.

In the longer term, we expect alternative technologies to change the way in which our LV network is used, ranging from periods where electric car charging systems significantly increase LV demands, through to periods where high levels of distributed generation output could lead to reverse power flows and voltage rise. To assist with network performance under either scenario, we have moved to shorter runs of low voltage feeder, and to use uniform cable sizes for the length of the feeder.

New Equipment types

We regularly investigate new equipment types to determine if they are cost effective in enhancing our network performance. We follow the process identified in Section 4 to ensure that any new equipment meets construction, technical and safety standards. Our teams identify potential new equipment as part of carrying out compliance and safety surveys, asset renewal policies for aging assets and new customer requirements.

6.1.5 Network Alternative Solutions and New Technology

Through our planning processes, we identify possible network alternatives in our solution list. Technology in this space continues to improve and reduce in cost, however to date, the largest network alternative solution we have in place is demand management using our ripple load control system.

Our load management system is integrated with our SCADA system and permits us to switch controllable load during peak periods to maintain our system half-hourly targets, which minimises transmission peak demand, as well as ensures our network equipment operates within its ratings. We also monitor output from large Distributed Generators through our SCADA system, which also assists in managing peak demand.

Embedded generation, energy storage, energy efficiency measures, demand side management initiatives and new load types such as Electric Vehicles (EVs) may result in modified load growth patterns. We anticipate that only embedded generation will impact load growth in our area in the short term, but as energy storage and EVs becomes a more mature technology and costs reduce, this could have an impact in the medium term.

We continue to keep a watching brief on demand side management technologies and options, along with other new supply side technology and where appropriate undertake or participate in trials to understand how these options could impact on our business. We describe later in this section our trial of battery storage on the network.

In the medium term, improved metering technology will enable us to offer tariffs that better reflect delivery cost structures and an increased range of customer options and responses around demand management and energy consumption, as well as providing significant service and operational benefits to customers, network companies and retailers.

Load Control

We currently use ripple load control for network demand optimisation and transmission peak demand management for transmission pricing purposes. We generally limit load control to 5 hours per day on any customer load and only during regional coincident peak demand (RCPD) periods during Upper North Island (UNI) peaks. Our network peak occurs just after the UNI peaks on a typical day.

While the precise maximum load control capacity is measurable, in reality the total amount of load that can be shifted at any one time is based on the prevailing conditions on the network. The effect of load control can vary in different areas and throughout the seasons, but typically over the winter, where Counties Power's maximum demand occurs, controllable load is between 5% and 10% of the total demand. We have approximately 30,000 controlled ICPs on the network, which provide an after diversity maximum demand controllable load of 9MW via Bombay GXP and another 2.2MW via Glenbrook GXP.

The technology deployed to control load is likely to change over time with the advances in consumer technology. Electric vehicles may pose a challenge in the future with the additional loading coming onto the network at times that may differ from traditional peak loading. Our advanced metering

system offers functionality for load control separate to ripple load control, and applications for this will be considered as appropriate.

Distributed Generation

Several of our consumers own distributed generation systems that connect to our 11kV or 22kV distribution network.

Generally, the network can support connection of generation in a specific location of:

- Up to 4MW of generation to our 11kV distribution network;
- Between 4 MW and 12 MW of generation to our 22kV distribution network; and
- Above 12 MW of generation to our subtransmission network.

We have recently connected a small number of photo-voltaic and wind systems, of ratings less than 10kW, to our low voltage network. We record the location of these, but do not have control of these installations.

When assessing an application to connect distributed generation to the network, we consider the following effects on the network

- Reactive power flows – to maintain correct power factor;
- Voltage control range – to ensure compliant voltage is maintained in all load circumstances; and
- Harmonics – to ensure the plant does not create excessive harmonic levels and power quality problems.

Our Distributed Generation Guideline sets out the network connection and technical requirements and is consistent with the Electricity Industry Participation Code, Part 6 – Connection of Distributed Generation. This Guideline can be downloaded from our website at www.countiespower.com.

6.1.6 Smart network programme

We have completed the construction of a meshed communication network (using Silver Spring Networks technology) and installed over 44,000 advanced meters on our network. This has allowed us to achieve a high level of smart meter coverage (over 90% the total number of ICPs), and provides a platform for developing a 'smart network'.

Although we are still developing tools and processes based on this network, having a smart network will help us improve the reliability of the power supply, make it easier for people who have solar power and other energy alternatives to feed them back into the grid and help manage the electricity network in ways that are more efficient. Major network benefits of a smarter network include:

- **Faster fault location and repair.** The meter can send us a signal if it is suddenly out of power – a 'last gasp'. This reports the fault and helps the fault repair team work out exactly where the fault is, so they can get to it and fix it faster;
- **Better information during outages.** The smart network will talk automatically to our Outage Website and Application so that within minutes of a customer's power going on or off the

status will be updated. It also means the fault team will be able to give earlier assessment of likely repair time;

- **Better system data means better engineering choices.** The data from the smart network will help our engineers do more accurate modelling and make more informed choices about when each part of the network will reach capacity and need to be upgraded;
- **Early identification of network issues.** The data from the smart meter can be used to identify voltage issues, quality of supply, and potential defects such as broken neutrals through the use of advanced analytics tools;
- **Improved measurement of energy use.** The data allows us to improve reconciliation and has led to lower 'unaccounted for' energy on the network; and
- **Future proofing for new technologies.** When coupled with other smart network technologies lays the foundation for future proofing our network for two-way power flows and other impacts arising from distributed generation and storage technologies connected to our network.

From a consumer perspective, the half hourly power data that can be provided by smart meters allows more informed choices about power use. Retailers can offer tools, like online usage data, to help consumers manage their power use, and in conjunction with smart pricing plans, it is possible for the power industry to offer incentives to those who can save power at peak times.

To date, expenditure on establishing the smart network and undertaking the meter rollout is over \$15 million. Over the short term, expenditure on meters which can utilise the smart network capability will continue.

6.2 Demand forecast

The maximum demand on our system is the main driver for investing in our network. Our demand forecast defines future network requirements and is a key input into determining the appropriate timing for capacity and security related investment in our subtransmission and distribution networks for the AMP period.

Demand forecasts estimate the amount of electrical load required in different parts of the geographical area served by the network. Forecasting future demand is subjective and uncertain; and only provides an indication of when potential capacity and security issues are likely to occur on our network. As we are a small, predominantly rural distribution network, our total network demand is sensitive to changes in industrial demand within our area. Similarly, large scale housing developments as seen in the eastern part of our network will have a significant impact on demand forecasts. Counties Power recognises the potential changes in demand characteristics from increased energy efficiency in new homes, new energy usage patterns through the use of energy storage systems, and increases in electric vehicle charging over time as the technology matures. Our demand forecast assumptions and approach are based on historical demand data and will be reviewed in coming years as we see new trends emerge for energy consumption on the network.

We accommodate the sensitivity in our demand forecast by monitoring demand trends continuously, revising our forecast periodically and varying the timing of our planned work. If demand growth is slower than forecast, we may defer investment and conversely if the demand growth is faster than

forecast, we may bring forward investment. Figure 6-1 and Table 6-5 show our winter maximum system demand forecast to 2032.

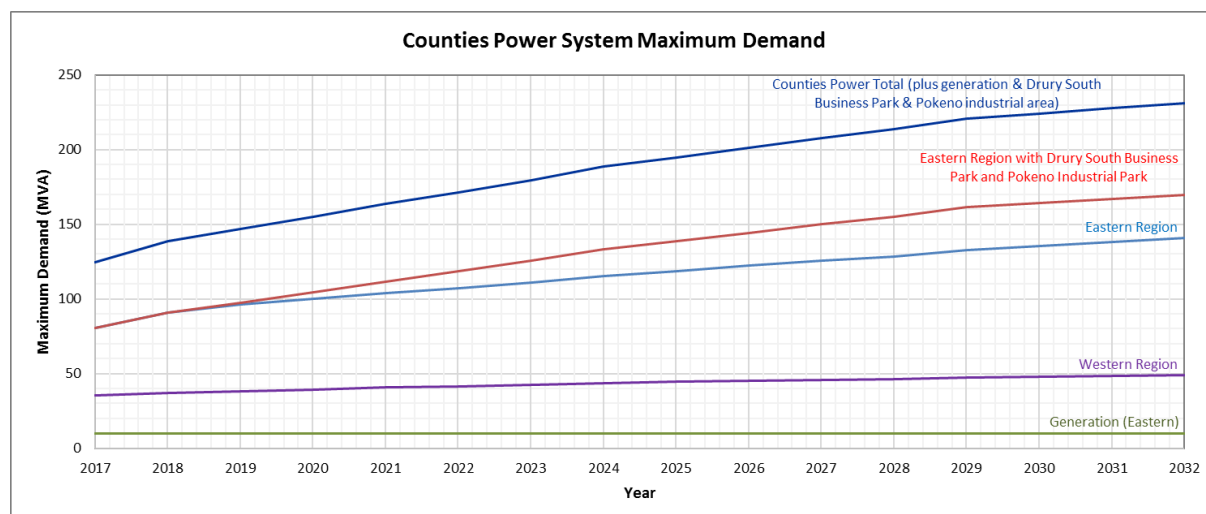


Figure 6-1 Winter Maximum System Demand

Description	Max. Dmd (MVA)	Projected Maximum Demand (MVA): Winter Peak															Avg. Annual Increase %
	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	
Eastern Area	80.8	90.9	96.5	100.3	103.7	107.4	111.1	115.3	118.7	122.1	125.5	128.6	132.6	135.3	138.1	141.1	5.0%
- with Drury South Business Park and Pokeno industrial area	80.8	90.9	97.2	104.5	111.3	118.3	125.4	133.0	138.7	144.3	149.9	155.2	161.4	164.2	166.9	169.9	7.4%
Western Area	35.2	36.8	38.1	39.1	40.6	41.5	42.6	43.7	44.4	45.1	45.8	46.5	47.1	47.8	48.5	49.0	2.6%
Generation (Eastern)	9.7	9.7	9.7	9.7	9.7	9.7	9.7	9.7	9.7	9.7	9.7	9.7	9.7	9.7	9.7	9.7	0.0%
Counties Power Total (plus generation)	124.3	138.9	145.9	150.8	155.8	160.3	165.2	170.5	174.7	178.9	182.9	186.8	191.6	195.0	198.5	202.0	4.2%
Counties Power Total (plus generation & Drury South Business Park & Pokeno industrial area)	124.3	138.9	146.7	155.0	163.4	171.4	179.7	188.4	194.9	201.3	207.6	213.7	220.7	224.2	227.6	231.1	5.7%

Table 6-5 Winter Maximum System Demand¹⁹

Our analysis of the load duration curves, for the period November 2014 to October 2017, indicates that the peak demand on our network exceeds:

- 90% of peak demand 0.6% of the time; and
- 80% of peak demand 5.1% of the time.

6.2.1 Demand forecast methodology

We develop our forecasts internally using a spreadsheet based model to forecast the future demand on our network for the planning period.

We start by developing forecasts for individual feeders based on 10-year historical trends and the anticipated growth of various sectors the feeder supplies. We then roll the individual feeder forecasts up to zone substation and ultimately back to the two Transpower GXPs supplying our network, Bombay and Glenbrook.

¹⁹ We have included any known development that could result in significant increase in demand in our area when developing our network development plan, although we have treated the Drury South business park and Pokeno industrial area developments separately given their potential magnitude and sensitivity to assumptions regarding reticulation timeframes and the nature of the load.

We use the following inputs to develop our demand forecast:

- **Substation Demand Data:** We use fifteen minute average demand data collected from our SCADA system to monitor loads on all incomers and feeders on our network. We use this data to analyse trends, load shifts and power factor for each feeder;
- **Embedded generation:** Every month we collect half-hourly data for generators over 200kW and analyse the data using applications we have developed internally for this purpose;
- **Coincident demands:** We extract the coincident maximum demand from the half-hourly data for our zone substations and embedded generation into our load forecasting spreadsheet.
- **System changes:** We record system changes and network reconfigurations to monitor load transfer between feeders and in various areas. We review these changes and consider spikes in active and reactive demands to verify the maximum demand for each feeder or zone substation;
- **Key Customer Demand:** We review the half-hourly energy data for key customers using demand meters installed at the various premises. We then examine demand trends to see if there is any change in growth at these sites. We also consult with our major customers to identify any planned future expansion and changes in their load demand;
- **Subdivision activity:** We track subdivision activities by feeder for the planning period based on our knowledge of local authority and developer's plans. Where load requirements are unavailable, we assume after-diversity maximum demands of 2.6 kW per lot for new domestic subdivisions and 10 kW per unit for small commercial subdivisions; and
- **General demographic and economic trends:** We collect demographic trend information from publicly available census data and on new connections to our substations²⁰. We use this data to verify our demand forecast.

6.2.2 Load forecasting assumptions

Within the load forecasting model assumptions are made in regard to:

- Demand management;
- Distributed generation;
- Load developments; and
- Other drivers.

Each of these are described below.

²⁰ Obtained from our daily operations

Impact of demand management

Ripple control forms an integral part of our load management strategy and provides a vital network investment deferral option. We assume that peak demand on the network has the most efficient level of load control in place, and thus peak demand observed is exclusive of controllable load.

We incorporate power factor penalty charges in major supply agreements, which encourage our consumers to maintain an efficient power factor. We monitor the impact of this scheme and adjust our future load forecasts accordingly once we determine that a major consumer has lowered their demand through power factor correction.

Impact of distribution generation

We consider how likely a generator will be available when required when deciding if it is to be included in our demand forecast. Factors we consider are:

- **Generation availability:** is it run continuously or is it only run for limited periods at a time; and
- **Generation redundancy:** does the generation connection to our network have an appropriate level of redundancy. For example, if the generation is on radial feeders we do not include it to reduce zone substation maximum demand forecasts (as it is on “n” security). However, we can aggregate a number of such generators into our regional and system maximum demand forecasts as they are spread over a number of feeders and zone substations and not subject to a single common mode failure.

Given the nature of the large scale distributed generation currently on the network, we do not rely upon generation capacity for network support. However, we assume that peak periods include a level of distributed generation operating based on historic operating profiles. With the exception of Hampton Downs and Papakura (Electra) generation, no single generator would have a material impact on network demand at peak times.

Impact of uncertain load developments

Large scale residential subdivisions do not pose the same problems as industrial subdivisions as we can assume their contribution to demand with a reasonable degree of certainty.

For residential subdivisions, we work with the developer to understand the timeframes for subdivision stages to progress and assume that new housing developments will be evenly spread over a number of years. We assume uptake over a period of 18 months following reticulation of the subdivision.

Industrial subdivisions provide a high level of uncertainty as often at development time the eventual occupier of the sites is not known, nor is their load size and type. We provide a standard three phase supply point unless more specific requirements are known. Often, we install dedicated transformers for large consumers as development progresses.

Other assumptions

We have used the following assumptions in developing our demand forecast:

- We have assumed a 2.6 kVA ADMD for each dwelling²¹;
- Power factor – As we know the power factor for most feeders from demand data, our load forecasting is in MVA; and
- Use of power electronic devices and compact fluorescent lamps will cause distortion of supply resulting in poor power factor and higher harmonics (increased feeder loading). As we do not know the impact of these devices, we have not factored them into our demand forecast.

Together our security criteria, design standards and our view on demand growth combine to form the basis for the investment programme over period covered by this plan.

6.3 Development programme

The following sections provide an overview of current development programmes in our network. The development programme is split into the two network regions, the eastern region where the majority of the growth occurs, and the western region which is dominated by rural and industrial consumers. More information on the development programmes for each region is provided below.

6.4 Eastern region development plan

The Eastern Region is supplied from Transpower's Bombay Grid Exit Point and covers areas supplied by our Opaheke, Pukekohe, Tuakau, Mangatawhiri and Ramarama Zone Substations.

Our subtransmission network in the Eastern region consists of:

- A 110kV ring from Bombay to Pukekohe and Tuakau;
- Two 110kV lines from Bombay to Opaheke;
- Two 33kV lines from Bombay to Ramarama; and
- One 33kV line to Mangatawhiri.

Figure 6-2 and Figure 6-3 below show the single line schematic for the subtransmission network supplied from the Bombay grid exit point.

²¹ 2.6kVA ADMD per dwelling is based on historical demand data and is subject to review particularly with changing energy usage in new homes.

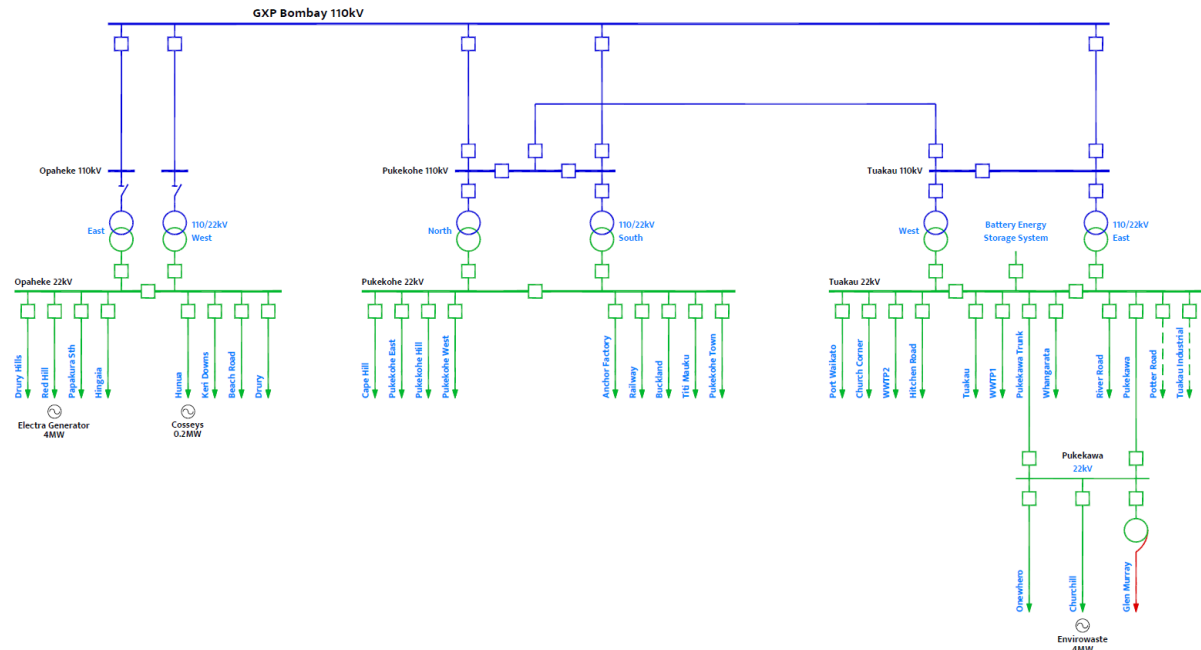


Figure 6-2 Single Line Schematic of the Eastern Region 110kV subtransmission network

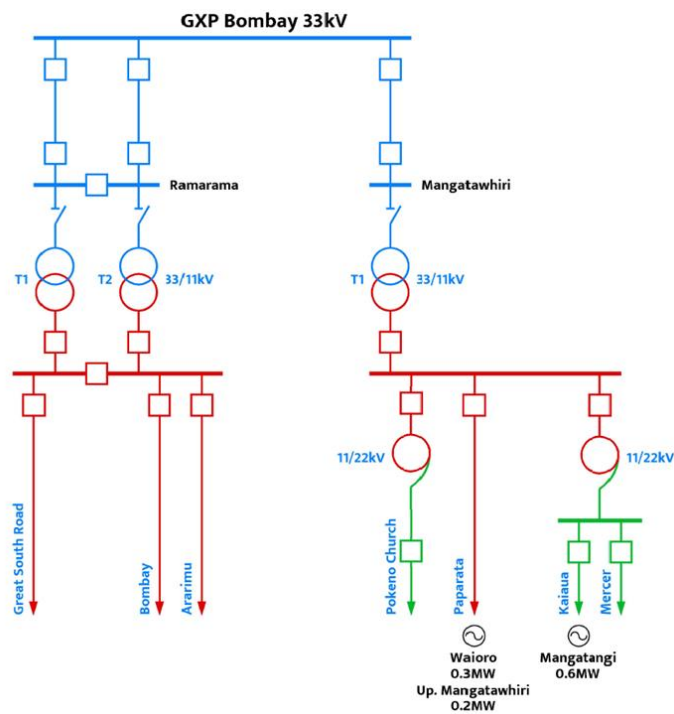


Figure 6-3 Single Line Schematic of the Western Region 110kV subtransmission network

Figure 6-4 and Table 6-6 show the demand forecast for the Eastern Region and the Eastern Region zone substations.

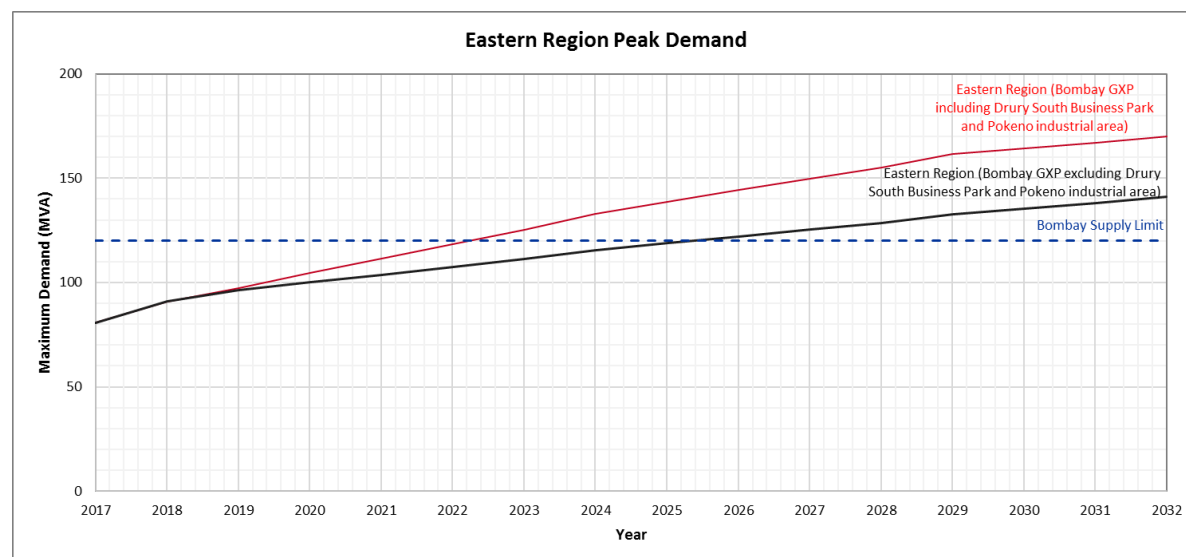


Figure 6-4 Winter Maximum Demand Eastern Region

Zone Substation	Max. Dmd (MVA)	Projected Maximum Demand (MVA): Winter Peak																Avg. Annual Increase %
		2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	
Pukekohe	110/22kV	35.2	37.7	39.0	40.1	41.3	42.4	43.7	45.1	46.2	47.4	48.5	49.6	50.8	51.7	52.6	53.5	3.5%
Opapeke	110/22kV																	
- without Drury South Business Park		23.9	27.2	31.0	33.0	34.5	35.9	37.5	39.7	41.3	42.9	44.5	46.1	48.7	50.0	51.5	53.2	8.2%
- with Drury South Business Park		23.9	27.2	31.0	35.4	39.2	43.1	47.1	51.7	55.6	59.7	63.6	67.6	72.6	74.0	75.4	77.1	14.8%
Tuakau	110/22kV																	
- without Pokono Industrial Park		16.7	21.5	22.3	23.1	23.9	25.1	26.0	26.8	27.6	28.3	28.9	29.3	29.7	30.1	30.6	31.0	5.7%
- with Pokono Industrial Park		16.7	21.5	23.9	26.2	28.6	31.4	33.8	36.1	38.5	40.7	42.2	42.6	43.0	43.4	43.8	44.2	11.0%
Ramarama	33/11kV	6.2	6.4	6.5	6.6	6.8	6.9	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.7%
Mangatawhiri	33/11kV	6.1	6.5	6.6	6.8	6.9	7.1	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	1.1%
Bombay Area	110/22kV	0.0	0.0	0.0	0.0	0.0	13.6	13.8	14.1	14.3	14.6	14.8	15.0	15.3	15.5	15.7	15.9	1.1%
Eastern Region (Bombay GXP including Drury South Business Park and Pokono industrial area)		80.8	90.9	97.2	104.5	111.3	118.3	125.4	133.0	138.7	144.3	149.9	155.2	161.4	164.2	166.9	169.9	7.4%
Eastern Region (Bombay GXP excluding Drury South Business Park and Pokono industrial area)		80.8	90.9	96.5	100.3	103.7	107.4	111.1	115.3	118.7	122.1	125.5	128.6	132.6	135.3	138.1	141.1	5.0%

Table 6-6 Winter Maximum Demand Eastern Region

We expect significant growth in the Auckland Council area over the next 10 years with:

- Continued subdivision developments in the Hingaia Peninsular, Papakura South, the Belmont subdivision and Cape Hill subdivision in Pukekohe, the Hitchen Road subdivision and Pokono subdivisions in Tuakau;
- Designation of special housing accord areas at Paerata Rise, Bremner Road, Jesmond Road and Quarry Road; and
- Additional developments outside the special housing accord areas at Paerata Rise and Bremner Rd area.

Outside the Auckland Council area, we expect continued growth at Pokono and Tuakau.

The Drury South Business Park has now obtained investment approval from Auckland Council for the first stage of development. The earthworks stage of construction commenced in late 2017. However, as the specific timing and maximum demand is unknown, we have assumed development load starting in 2020, with a linear growth of 3 MVA per annum, to maximum anticipated demand of 30 MVA in 2029.

We will continue to review demand growth at the Drury South Business Park, and if it is higher than anticipated, we will bring forward building the 110kV Drury South Area Substation (see Section 6.4.2).

The following sections (Section 6.4.2 to Section 6.4.7) describe the subtransmission and distribution issues and plans for each of the zone substation areas within the Eastern region.

We currently have three proposed regional development programmes within the Eastern region:

- Drury South Business Park supply (refer to section 6.4.2): develop our network to supply the proposed Drury South Business Park by building a new 110kV Drury South Area Substation and feeders, and reconfiguring our network to supply the proposed new development and surrounding area;
- Pokeno industrial area development (refer to Section 6.4.3): develop our network to supply proposed new industrial load connections in the Pokeno area.
- Eastern Supply Project (refer to Section 6.4.7): further development in our network area currently supplied by the Mangatawhiri and Ramarama substations by:
 - Converting our subtransmission network in the area to 110kV;
 - Building a new 110kV Bombay Area Substation in the vicinity of the Bombay GXP to replace the Mangatawhiri and Ramarama substations; and
 - Converting our distribution network in the area to 22kV operation, where there are network constraints.

These developments are explained further in the sections below.

6.4.1 GXP and Eastern area investment requirements

Transpower's Bombay Substation has a transmission capacity limit²² of:

- 170 MW for high north flow into the Bombay bus from the Waikato; and
- 120 MW for high south flow into the Bombay Bus from the Auckland Region.

The south power flow limit could be reached by 2023 and the north power flow limit by 2033 given current demand forecasts.

Distributed generation within our network, approximately 12 MW, could defer the issue by one to two years. However, at present, 7 MW of this generation is connected to our network by a single rural distribution line so may not be relied on to be available if required.

Completion of the eastern supply project will allow us to decommission our 33kV supply from Transpower's Bombay Substation around 2022, to coincide with their need to replace end of life 33kV equipment.

²² There is no apparent seasonal pattern to the high north and south load flows

Options considered

Transpower is considering possible options to address this constraint including:

- Variable line ratings on the Bombay-Wiri circuits to improve south flow capacity, which could defer transmission investment to beyond 2022; and
- Installation of an interconnecting 220/110kV transformer at Bombay to reduce loading on the 110kV circuits into Bombay.

As part of our network development planning, we also consider solutions which provide transmission benefits, including reducing loading or diversification of Grid Exit Points.

6.4.2 Supply to the Drury South Business Park

The Auckland Council has provided investment approval for the first stage of development within the Drury South Business Park. However, as the development is still in the planning stages, we do not know when and how much load will be added to the network from the business park. We expect the business park could, over 10 years, contribute up to 30 MVA of load to our network given a typical mix of industrial use. A section of the Bombay-Opaheke East 110 kV line will need to be relocated to enable earth works and development of the Drury South Business Park.

Considered options

To cater for the uncertainty in demand and timing in the Drury South Business Park we have assumed an initial load of 3 MVA in 2020 with an annual increase of 3 MVA per annum up to a maximum load of 30 MVA in 2029.

With the present network configuration, we would supply this new business park from our Opaheke substation in the short to medium term²³ with upgrade of existing distribution feeders at an estimated cost of \$3 million. We have considered the following three options to meet the total expected load increase from the Drury South Business Park in the medium to long term²⁴ as well as the anticipated additional load from the expansion south of the Auckland City Rural Urban Boundary. Installation of distribution feeders within the business park and interconnection to existing distribution feeder network at an estimated cost of \$4 million, and rebuild of the Bombay to Opaheke 110kV line tower section at an estimated cost of \$1.5 million are common to all options.

- Option 1: Opaheke substation upgrade. This would involve the upgrade of existing transformers and switchgear at Opaheke substation, and the construction of two new distribution feeders from Opaheke substation to reinforce supply to the Drury South Business Park and other anticipated load south of the Auckland City Rural Urban Boundary. The estimated cost of this option is \$10.5 million;
- Option 2: Drury South area substation establishment (Bombay GXP). This would involve establishment of a new substation with supply from Bombay GXP at 110kV and a new section of 110kV line from the rebuilt 110kV tower line section to the new substation. The estimated cost of this option \$18.5 million; or

²³ Up to 10MVA of additional load from Drury South Business Park development and surrounding area

²⁴ 10MVA to 30MVA of additional load from Drury South Business Park development and surrounding area

- Option 3: Drury South area substation establishment (proposed new Drury GXP). This would involve establishment of a new substation with supply from a new 220/110kV Grid Exit Point arising from redevelopment of the Drury 220kV switching station by Transpower. The new substation could also be used to reinforce supply to Opaheke substation, and potentially new developments in the north-eastern part of our network. By supplying this new substation, as well as potentially the Opaheke substation from the new GXP, this would also provide diversity benefits and reducing the high impact, low probability (HILP) risk of all supplies coming from Bombay GXP. This option is estimated to cost \$17 million.

We also considered the following alternative option.

- Use of localised energy storage or distributed generation to reduce peak demand under n-1 scenarios. However, this option is, at present, costly for the level of utilisation and required capacity to supply the additional load at Drury South Business Park development. Counties Power is trialling new technology options to understand the value they provide as well as actively following international developments in new technology. Should the cost of new technology continue to reduce, these options may become viable alternatives and will be considered as part of investment planning process.

Proposed investment

Our proposed investment is to build a new 110kV Drury South Area Substation to supply this additional load at the Drury South Business Park and anticipated additional load south of the Auckland City Rural Urban boundary. This new substation would supply the business park area, reducing the reliance on Opaheke substation and existing distribution feeders, and providing supply diversity.

Our network development plan allows for this proposed new 110kV Drury South Area Substation to be supplied from the proposed new Drury GXP.

Figure 6-5 shows the proposed subtransmission single line diagram for the proposed new Drury South area substation and 110kV supply from the proposed new Drury GXP.

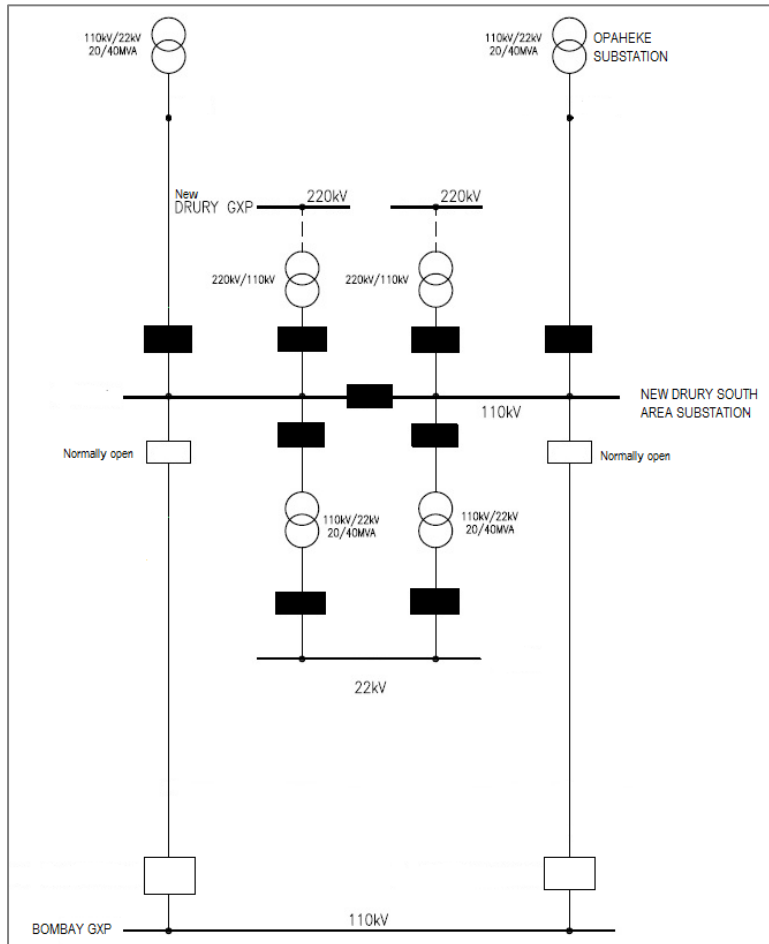


Figure 6-5 Proposed subtransmission configuration for the new Drury South area substation

Our development plan for proposed 110kV Drury South Area Substation is to:

- Upgrade Quarry Road sections of the Great South Road feeder, and convert to 22kV operation to supply the initial stage of Drury South Business Park development, at an estimated cost of \$830,000. This is in progress and is to be completed in early 2018;
- Relocate a section of the Bombay-Opaheke East 110 kV line within the Drury South Business Park development area in 2017/18 and 2018/19, at an estimated cost of \$4 million;
- Purchase land for the substation development in a location suitable for whichever transmission supply option we choose to progress, we have allocated \$2 million for this and plan to acquire the site in 2018/19;
- Install new 22kV distribution feeders from the substation to accommodate new industrial loads and to interconnect with existing distribution feeders over the period 2021/22 to 2030/31, with an estimated cost of \$7.25 million;
- Rebuild the 110kV Bombay to Opaheke East line steel tower section in 2021/22 with an estimated cost of \$1.5 million; and
- Build the new 110kV substation and install subtransmission circuits in 2023/24, with an estimated cost of \$10 million.

The following table summarises the proposed Drury South Business Park development plan.

Description	Scope	Timing	Estimated Costs (\$'000)
Great South Road Feeder upgrade and 22kV conversion for initial stage of Drury South Business Park development	Conductor upgrade of a total of 300m overhead and cable sections on Great South Road Feeder along Quarry Road and 22kV conversion	Early 2018	830
Bombay-Opaheke 110 kV East line section relocation	Relocate a section of the Bombay-Opaheke 110 kV East line to enable earth works and construction in the Drury South Business Park area	2017/18 2018/19	- 4000
Drury South Area Substation site acquisition	Purchase land in the vicinity of Drury South Business Park for a new Drury South Area Substation	2018/19	2000
Install 22kV distribution feeders	Install 22kV feeders within Drury South Business Park and for interconnection to existing distribution feeders	2021/22- 2030/31	7250
Bombay – Opaheke 110kV East line steel tower section rebuild	Rebuild the steel tower section of the Bombay – Opaheke 110kV East line	2021/22	1500
Drury South Area Substation establishment	Build a new Drury South Area Substation with two 110/22kV 60MVA transformers and 22kV switchboard	2023/24	7000
110kV connection from the new Drury South GXP to Drury South area substation	Build a new 110kV line section from the new GXP to the Drury South area substation	2023/24	3000

Table 6-7 Drury South Business Park development plan

6.4.3 Supply to Pokeno industrial area

Changes in the Pokeno Structure Plan have seen increases in residential and industrial load in the Pokeno area. To date the largest development has been the establishment of the Yashili New Zealand Dairy Company plant, however we are expecting step change loads to be established in the area in the short term. We are aware of known growth plans for new industrial loads such as a new manufacturing plant with an initial load of 3MVA and an ultimate load of 7MVA in the medium term. Recognising that further growth is expected in the area, we are assessing the best way to address and support growth in the area by considering security of supply, reliability, and power quality. We expect the Pokeno industrial area could over 10 years contribute up to 20 MVA of additional load to our network given a typical mix of commercial and industrial use.

Considered options

To cater for the uncertainty in demand and timing of developments in the Pokeno industrial area, we have assumed an initial load of 3 MVA in 2018 with an annual increase of 2 MVA per annum up to 20 MVA of additional load in 2029.

With the present network configuration, we would supply the Pokeno industrial area from Hitchen Road and Whangarata feeders in the short term²⁵ with staged upgrade of sections of the Whangarata feeder at an estimated cost of \$710,000. We have considered three development options to supply the Pokeno industrial area in the medium to long term²⁶:

²⁵ Up to 8MVA of additional load in the Pokeno industrial area.

²⁶ 8MVA to 20MVA of additional load in the Pokeno industrial area.

- Option 1: New Potter Road feeder and a third transformer at Tuakau substation. This would involve constructing a new 22kV feeder (Potter Road feeder) from Tuakau zone substation to Pokeno, upgrade sections of Hitchen Road feeder and install a third 110/22kV transformer at Tuakau substation. The estimated cost of this option is \$3.8 million;
- Option 2: New trunk feeders from the Tuakau substation and establish a switching station in the Pokeno industrial area. This would involve establishing a new switching station in the Pokeno industrial area, constructing two 22kV trunk feeders from Tuakau substation and install a third 110/22kV transformer at Tuakau substation. The estimated cost of this option is \$7 million; or
- Option 3: New Pokeno area substation. This would involve establishing a substation in the Pokeno industrial area and constructing a section of new 110kV line connecting into the Bombay to Tuakau 110kV line. The estimated cost of this option is \$12 million.

We also considered the following alternative development options:

- Localised energy storage or distributed generation to reduce the peak demand under n-1 scenarios, however this option is presently quite costly for the level of utilisation and required capacity in the Pokeno industrial area. Counties Power is trialling new technology options to understand the value they provide as well as actively following international developments in new technology. Should the cost of new technology continue to reduce, these options may become viable alternatives and will be considered as part of investment planning process.

Proposed investment

Our proposed investment is to carry out staged upgrade of Whangarata feeder and followed by construction of a new 22kV feeder (Potter Road feeder) from Tuakau substation. Our development plan for the Pokeno industrial area is to:

- Upgrade Whangarata feeder section along Whangarata Road eastern section and Wellington Road and Huia Road sections to increase backfeed capacity in 2019/20, at a combined estimated cost of \$710,000;
- Upgrade Whangarata feeder overhead sections along Great South Road in 2020/21 and underground sections along Great South Road to increase backfeed capacity in 2021/22 at a combined estimated cost of \$280,000;
- Install a new feeder from Tuakau zone substation to the Pokeno Industrial area (Potter Road feeder) to increase supply capacity in 2022/23 at estimated cost of \$2 million;
- Upgrade Hitchen Road feeder along Hitchen Rd to increase backfeed capacity in 2023/24 at an estimated cost of \$830,000; and
- Install a third 110/22kV transformer at Tuakau zone substation to increase substation n-1 supply capacity in 2026/27 at an estimated cost of \$2 million.

The following table summarises the Pokeno industrial area development plan.

Description	Scope	Timing	Estimated Costs (\$'000)
Whangarata feeder upgrade (Whangarata Road eastern section)	Upgrade 0.6km of overhead section along Whangarata Road eastern section	2019/20	140
Whangarata feeder upgrade (Wellington Road and Huia Road)	Upgrade a total of 2.5km of Whangarata feeder along Wellington Road and Huia Road	2019/20	570
Whangarata Feeder Upgrade (Great South Road overhead)	Upgrade 0.75 km of Whangarata feeder on Great South Road in Pokeno	2020/21	115
Whangarata Feeder Upgrade (Great South Road Cable)	Upgrade 0.3 km of Whangarata feeder on Great South Road in Pokeno	2021/22	165
New Potter Road feeder	Build new feeder from substation to Pokeno Industrial area via Potter Road	2022/23	2000
Hitchen Rd feeder upgrade (Hitchen Rd)	Upgrade 1.3km of Hitchen Rd feeder	2023/24	830
Tuakau zone substation third transformer	Install third 110/22kV 40 MVA transformer at Tuakau zone substation	2026/27	2000

Table 6-8 Summary of Pokeno industrial area development plan

6.4.4 Opaheke Zone Substation (Papakura area)

We expect significant residential growth in the area through the planning period associated with continued residential development in Karaka, Drury, Papakura and business park development in the area, particularly Drury South.

The Opaheke 110/22kV Zone Substation is supplied by two 110kV circuits from Bombay GXP. Opaheke Zone Substation supplies 470 distribution substations in the urban areas of Beach Road, Keri Downs, south of Papakura and Red Hill and some rural areas in Hunua, Drury and Hingaia. The load is predominantly residential, except for the Keri Downs area which is 12% commercial and 72% industrial. Opaheke is classed as a large zone substation (S1) and is fully compliant with our security criteria (Refer to Table 6-1). Major consumers in this area include Independent Liquor, Winstone Aggregates and van den Brink Poultry.

Figure 6-6 below shows the Rural-Urban Boundary (RUB) map for the Opaheke Zone Substation supply area (Papakura area), outlining the areas for future growth (green boundary line).

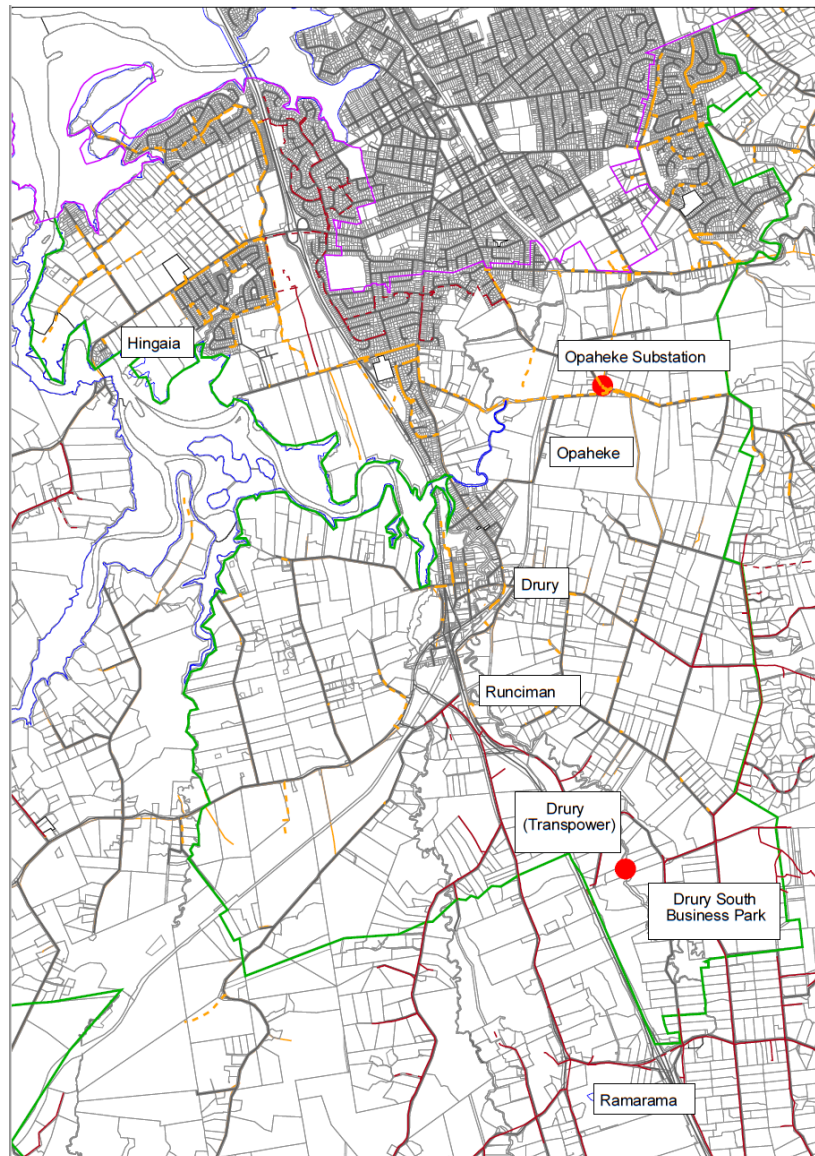


Figure 6-6 Opaheke Zone Substation Rural Urban Boundary (Papakura area)

The Opaheke load is largely residential and has a winter peak. The forecast peak demand for Opaheke Zone Substation and the distribution feeders from the substation is shown in Table 6-9.

22kV Feeders	Max. Dmd (MVA)	Projected Maximum Demand (MVA): Winter Peak															Avg. Annual Increase %
		2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032
		2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032
Beach Road	6.0	7.3	9.1	9.9	8.5	9.0	9.5	11.1	11.6	12.1	12.6	13.2	14.7	15.3	15.9	16.4	11.7%
Drury	3.9	4.1	4.5	4.9	5.4	5.9	6.3	6.7	7.4	7.9	8.3	8.7	9.2	9.6	10.1	10.6	11.6%
Drury Hills	3.5	3.7	3.8	3.8	3.9	3.9	4.0	4.0	4.1	4.1	4.2	4.2	4.3	4.3	4.4	4.4	1.6%
Hingaia	1.8	3.4	5.3	6.0	5.6	5.9	6.5	6.9	7.3	7.8	8.2	8.5	9.1	9.2	9.2	9.5	29.2%
Hunua	4.1	4.3	4.3	4.4	4.5	4.6	4.7	4.7	4.8	4.9	5.0	5.1	5.2	5.2	5.3	5.4	2.1%
Keri Downs	3.5	3.6	3.7	3.7	3.8	3.9	4.0	4.0	4.1	4.2	4.2	4.6	5.1	5.6	6.0	6.5	6.5%
Papakura South	3.5	3.7	4.0	4.3	7.3	7.6	7.8	8.0	8.2	8.5	8.5	8.6	8.6	8.6	8.7	8.9	10.5%
Red Hill	3.9	4.2	4.3	4.3	4.4	4.4	4.4	4.5	4.5	4.5	4.6	4.6	4.6	4.7	4.7	4.7	1.5%
Zone Substation	Max. Dmd (MVA)	Projected Maximum Demand (MVA): Winter Peak															Avg. Annual Increase %
		2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032
		2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032
Opaheke	23.9	27.2	31.0	33.0	34.5	35.9	37.5	39.7	41.3	42.9	44.5	46.1	48.7	50.0	51.5	53.2	8.2%
Opaheke with Drury South Business Park	23.9	27.2	31.0	35.4	39.2	43.1	47.1	51.7	55.6	59.7	63.6	67.6	72.6	74.0	75.4	77.1	14.8%

Table 6-9 Winter Maximum Demand at Opaheke Zone Substation and Feeders

Opaheke Zone Substation Investment

The Opaheke Zone Substation demand forecast is shown in Figure 6-7.

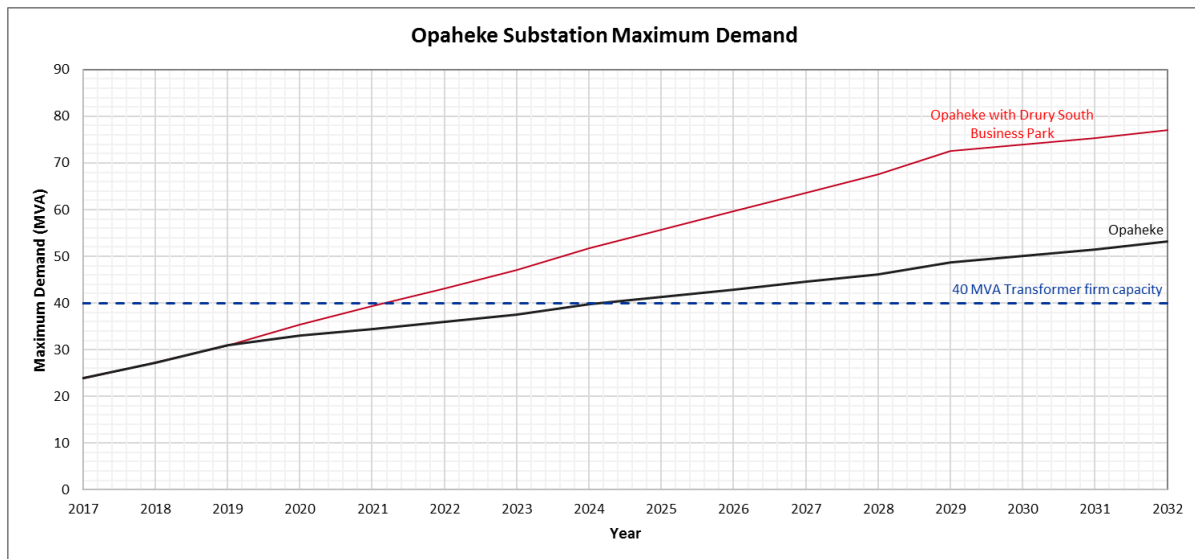


Figure 6-7 Opaheke Zone Substation Demand Forecast

Two 110/22kV, 20/40 MVA transformers supply the load at Opaheke providing n-1 capacity of 40 MVA. The Opaheke maximum winter demand is forecast to exceed the transformers n-1 capacity from 2025, depending on whether Opaheke supplies Drury South Business Park. The proposed investment is to supply the early stages of the Drury South Business Park in the short to medium term (to 2022/23) from existing feeders from the Opaheke substation, and later stages in the medium to long term 2023/24 onwards) from a new Drury South area substation,

In the short to medium term (to 2023), Opaheke will be used to supply the Drury South Business Park through existing distribution feeders:

- The maximum winter demand is forecast to exceed 40 MVA by 2022; and
- The loading on the two 110kV Bombay to Opaheke lines are forecast to exceed their n-1 capacity of 63MVA by 2027 if Drury South is supplied from Opaheke.

In the medium to long term (2023/24 onwards), if the Drury South Business Park will be supplied by a new Drury South Area Substation then:

- The maximum winter demand is forecast to exceed 40 MVA beyond 2025; and
- The loading on the two 110kV Bombay to Opaheke lines are forecast to remain within their n-1 capacity beyond 2032.

Our development plan for Opaheke Zone Substation is to:

- Increase the transformer capacity at Opaheke by replacing the existing 20/40 MVA transformers with two 110/22kV, 30/60 MVA transformers in 2024/25, with an estimated cost of \$2.8 million; and
- Supply the early stages of the Drury South Business Park in the short to medium term before the establishment of a new Drury South Area Substation (see Section 6.4.2).

Opaheke Zone Substation Feeder Investment

The Opaheke area of supply includes the expanded Papakura Rural-Urban Boundary, and this area is characterised by being the area of supply nearest to central Auckland, its proximity to the motorway (SH1) and rail corridors (NIMT). Included in its area is the Hingaia peninsula just west of Papakura and Bremner Road just west of Drury, both of which have been designated as Special Housing Areas (SHA). The area of supply also currently includes that land that will be the future Drury South Business Park as detailed earlier in this section.

- The Hingaia Peninsula has already undergone significant subdivision of approximately 1,050 lots, and the potential for further subdivision developments in excess of 4,900 lots. In the load forecast we have assumed that these will all be developed over the next 15 years;
- The Bremner Road Subdivision has commenced construction of stage one of multi-stage development of around 1,200 lots, and the potential for further subdivision development of over 1,400 lots in the neighbouring Jesmond Road SHA area. These have been assumed to incur demand over the next 10 years and 10 to 15 years respectively. The total area in this vicinity has the potential of the order of 10,000 lots;
- The Quarry Road SHA development, in the southern area of the Drury South Business Park, has around 1,000 lots. These have been assumed to incur demand over the next 5 years; and
- Other smaller subdivisions could be developed around the North Opaheke area. Typical sizes are between 50 and 300 lots. These have been allowed for in the demand forecast.

Figure 6-8 shows the demand forecast for Opaheke substation feeders.

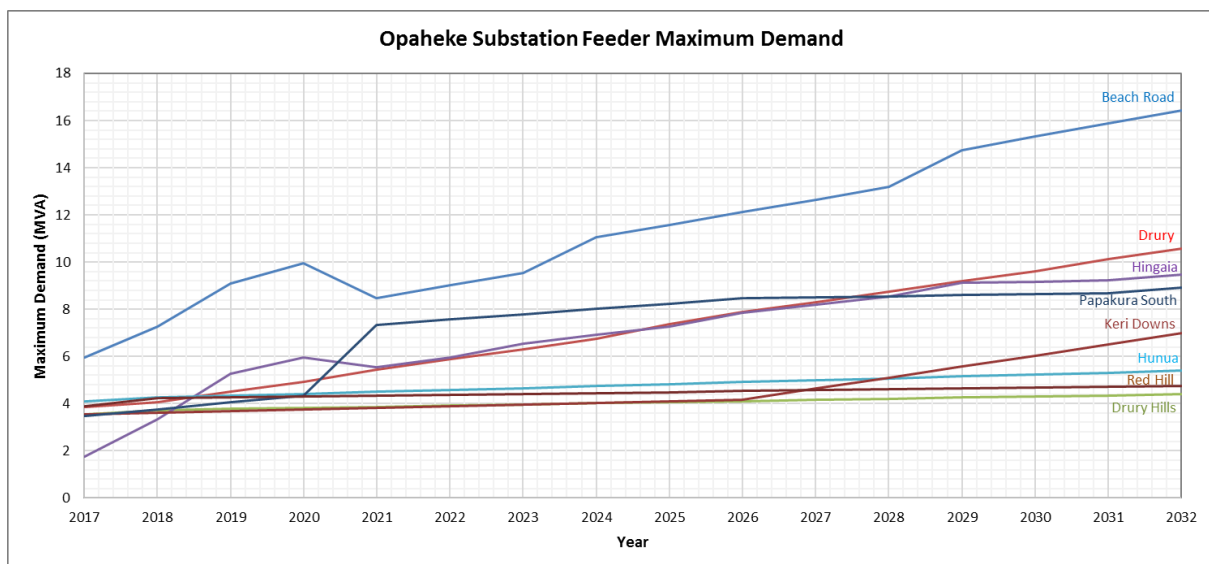


Figure 6-8 Feeder Demand Forecast at Opaheke Zone Substation

Our development plan for Opaheke Zone Substation Feeders is to:

- Upgrade Quarry Road sections of the Great South Road feeder, and convert to 22kV operation to supply the initial stage of the Drury South Business Park development at an estimated cost of \$830,000 for completion in early 2018, see section 6.4.2;
- Replace two RMUs on the Red Hill feeder with new units with circuit breakers in 2018/19 with an estimated cost of \$160,000 to improve supply reliability through more effective fault isolation function;
- Rebalance load between Beach Rd, Blackbridge Road and Hingaia feeders in 2020/21 by utilising existing switches to increase Hingaia feeder backfeed capacity;
- Convert the Papakura South feeder to 22kV operation in 2020/21, with an estimated cost of \$310,000, to be carried out in conjunction with condition based replacement of distribution switchgear on the feeder (section 5.7.3);
- Upgrade sections of Drury and Drury Hill feeders for Drury South Business Park development in 2021/22, with an estimated cost of \$1.3 million;
- Install a new 22kV feeder at Opaheke Substation in 2022/23, with an estimated cost of \$2 million to increase backfeed capacity to Hingaia and Beach Road feeders and to reduce customer numbers on both feeders below the current limit of 3,000 as per our security standard. This will require replacement of the 22kV switchboard at Opaheke, as the existing 22kV switchboard is not extendable, which will also address a known condition issue associated with the switchboard (see section 5.3.4);
- Upgrade Bremner Road, Jesmond Road and Norrie Road sections of the Drury feeder in 2024/25 with an estimated cost of \$170,000 to increase backfeed capacity to Anchor Factory feeder; and
- Upgrade Hingaia Road section of the Hingaia feeder in 2025/26 with an estimated cost of \$270,000 to increase backfeed capacity to Anchor Factory feeder.

We considered the following alternative development options:

- Installing new feeders from Opaheke into the new load centres to reduce existing loading, however the geographic location relative to the substation, and the 22kV operation of the substation, combined with the aged existing 11kV network gives overall benefit to 22kV conversion of existing assets; and
- Localised energy storage or distributed generation to reduce the peak demand under n-1 scenarios, however this option is, at present, costly for the level of utilisation and required capacity to address this constraint. Counties Power is trialling new technology options to understand the value they provide as well as actively following international developments in new technology. Should the cost of new technology continue to reduce, these options may become viable alternatives and will be considered as part of investment planning process.

Summary of Opaheke Area Development Plan

Description	Scope	Timing	Estimated Costs (\$'000)
Improve supply reliability for Red Hill Feeder	Replace existing RMUs with RMUs with Circuit Breakers	2018/19	160
Papakura South feeder upgrade	Complete 22kV conversion of Papakura South feeder	2020/21	310
Drury Feeder upgrade (Quarry Road and Sutton Road)	Upgrade a total of 1.1km of Drury Feeder along Quarry Road and Sutton Road	2021/22	680
Drury Hill Feeder upgrade (Appleby Rd)	Upgrade a total of 1km of Drury Feeder along Appleby Road	2021/22	650
Install a new 22kV distribution feeder at Opaheke substation	Install a new 22kV feeder to increase backfeed capacity to Hingaia and Beach Road feeders and reduce customer numbers on both feeders	2022/23	2000
Drury Feeder upgrade (Bremner Road, Jesmond Road and Norrie Road)	Upgrade a total of 1km of Drury Feeder along Bremner Road, Jesmond Road and Norrie Road	2024/25	170
Opaheke transformer capacity upgrade	Replace the existing 20/40 MVA transformers with two 110/22kV 30/60 MVA transformers	2024/25	2800
Hingaia Feeder upgrade (Hingaia Road)	Upgrade a total of 1.7km of Hingaia feeder along Hingaia Road	2025/26	270

Table 6-10 Summary of Opaheke Area Development Plan

6.4.5 Pukekohe Zone Substation

The 110/22kV Pukekohe Zone Substation is supplied by three 110kV circuits from Bombay GXP, of which two are directly connected to Bombay and the third is connected via Tuakau. Pukekohe supplies 623 distribution substations in the urban areas of Buckland, Cape Hill and Pukekohe and the rural residential loads towards the eastern parts of Pukekohe and Titi Mauku. The load is predominantly residential and commercial load with some industrial load in Buckland. Pukekohe is classed as a large zone substation (S1) and is fully compliant with our security criteria (refer to Table 6-1). Major loads supplied by this substation include the Pukekohe town centre.

Figure 6-9 below shows the Rural-Urban Boundary (RUB) map for the Pukekohe Zone Substation supply area, outlining the areas for future growth (green boundary line).

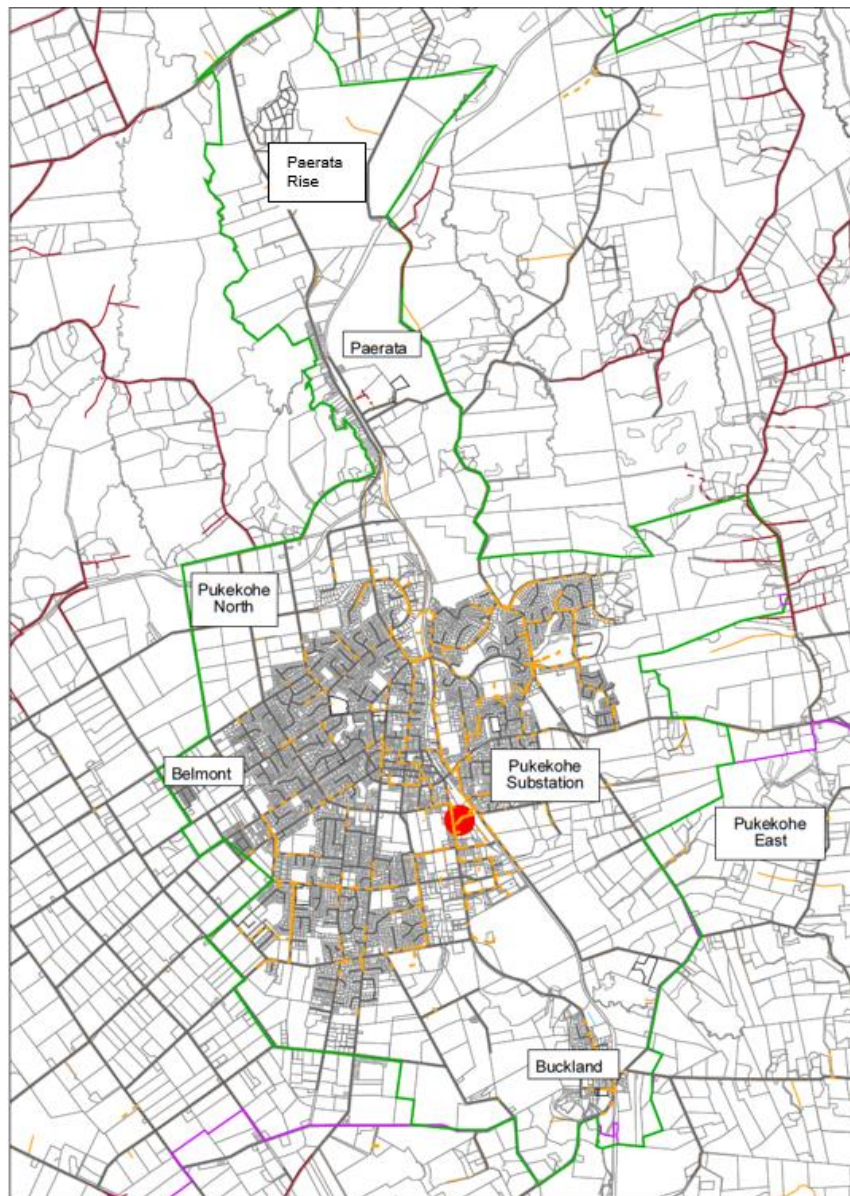


Figure 6-9 Pukekohe Zone Substation supply area

The Pukekohe load has a winter peak. The forecast peak demand for Pukekohe Zone substation and the distribution feeders from the substation is shown in Table 6-11.

22kV Feeders	Max. Dmd (MVA)	Projected Maximum Demand (MVA): Winter Peak															Avg. Annual Increase %
	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	
Anchor Factory	3.6	3.9	4.3	4.7	5.3	5.9	6.4	7.2	7.8	8.4	9.0	9.6	10.2	10.8	11.4	12.0	15.7%
Buckland	2.9	3.0	3.0	3.1	3.2	3.2	3.3	3.3	3.4	3.5	3.5	3.6	3.6	3.7	3.7	3.8	2.0%
Cape Hill	6.6	6.9	7.0	7.1	7.2	7.3	7.6	7.7	7.8	7.9	8.0	8.1	8.2	8.3	8.4	8.5	1.9%
Pukekohe East	1.9	2.1	2.1	2.1	2.2	2.2	2.2	2.2	2.2	2.3	2.3	2.3	2.3	2.3	2.4	2.4	1.7%
Pukekohe Hill	6.9	7.2	7.4	7.5	7.6	7.6	7.7	7.8	7.8	7.9	8.0	8.1	8.1	8.2	8.3	8.3	1.3%
Pukekohe Town	4.9	5.0	5.0	5.1	5.1	5.2	5.2	5.3	5.3	5.4	5.4	5.5	5.5	5.6	5.6	5.7	1.0%
Pukekohe West	6.0	7.4	7.9	8.5	8.8	9.1	9.4	9.7	10.1	10.4	10.7	11.0	11.3	11.4	11.5	11.5	6.2%
Railway	2.9	3.0	3.0	3.0	3.1	3.1	3.1	3.1	3.2	3.2	3.2	3.3	3.3	3.3	3.4	3.4	1.0%
Titimaiku	3.3	3.4	3.4	3.4	3.5	3.5	3.5	3.6	3.6	3.6	3.7	3.7	3.7	3.8	3.8	3.8	1.1%
Zone Substation	Max. Dmd (MVA)	Projected Maximum Demand (MVA): Winter Peak															Avg. Annual Increase %
	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	
Pukekohe	35.2	37.7	39.0	40.1	41.3	42.4	43.7	45.1	46.2	47.4	48.5	49.6	50.8	51.7	52.6	53.5	3.5%

Table 6-11 Winter Maximum Demand at Pukekohe Zone Substation and Feeders

Pukekohe Zone Substation Investment

The Pukekohe Zone Substation demand forecast is shown in Figure 6-10.

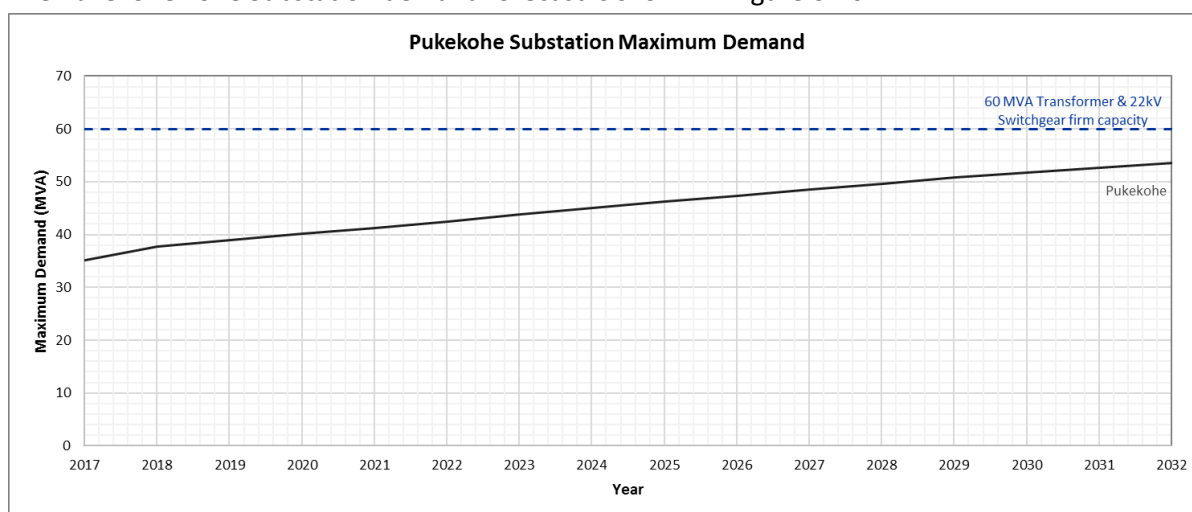


Figure 6-10 Pukekohe Zone Substation Demand Forecast

Two 110/22kV, 30/60 MVA transformers supply the load at Pukekohe providing n-1 capacity of 60 MVA. The Pukekohe maximum winter demand is forecast to exceed the transformers' n-1 capacity beyond 2032.

Given the time horizon of this constraint and the expected growth to the north of Pukekohe, two options have been considered to address these issues.

Option 1 – Extend and Increase Pukekohe Zone Substation Capacity

This option would consist of the following at the existing Pukekohe Zone Substation to raise firm capacity above 60 MVA for n-1 events:

- Increase the transformer capacity at Pukekohe by installing an additional 110/22kV 30/60 MVA transformer, with an estimated cost of \$1.5 million; and
- Extend the control room at the substation to make provision for a third 22kV bus, and install a new 22kV switchboard and related equipment, with an estimated cost in the order of \$3 million;

This option would introduce a number of HILP risks, namely the common mode failure of the 22kV switchboard, the vulnerability due to a fire or explosion in the outdoor yard, and the high customer

numbers served from one site. An engineering solution could be used to reduce the HILP risks to an acceptable level but with an increased level of cost. A cost benefit analysis will be undertaken on the options and respective benefits offered to determine the optimal investment strategy.

Additionally, as the largest areas of growth are to the north of Pukekohe, additional feeder capacity would incur a high cost given the distance (Pukekohe Zone Substation is to the south of the town). This is covered in the following paragraphs relating to feeder constraints.

Option 2 – Development a new ‘Pukekohe North’ substation

This option would develop a new 110kV/22kV Zone Substation to the north or north east of Pukekohe, providing supply into Pukekohe North, Paerata, and the Paerata Rise Special Housing Area.

This option has an estimated cost in the order of \$15 million, which is a higher cost, and added complexity given the need for new 110kV subtransmission corridors and new distribution feeder configurations. It does however provide a number of advantages over extension of the existing substation, specifically:

- Closer to the load centres of Paerata Rise and the future northern development areas;
- Releasing of capacity at Pukekohe to accommodate more localised growth;
- Diversity of supply and provision of interconnection into Pukekohe; and
- Resilience against HILP events.

This option has not been well developed given the horizon for the constraint is beyond the planning period. A full assessment of both options will be undertaken and firmer plans included in future AMPs.

Pukekohe Zone Substation Feeder Investment

We expect significant residential growth in the area through the planning period.

- The Northern Pukekohe area includes the Paerata Rise Special Housing Area of 4,500 dwellings (Anchor Factory Feeder). The Paerata Rise development has announced the first stage of 335 lots, and the potential for further development of around 4,000 lots in future. Indications are that this will only be developed at a rate of 200 dwellings per year, however there is uncertainty around the uptake rates. Subdivision at Paerata Rise outside the SHA is also expected to occur; and
- The Valley Road area (Cape Hill Feeder) continues to be subdivided, 700 lots are proposed in the Belmont development (Pukekohe West Feeder), and the Pukekohe Hill area has just commenced subdivision development. From 2020, further subdivision in the East of Pukekohe (Cape Hill and Buckland Feeders) and in the South (Buckland Feeder) can be expected based on planning information we have received.

Figure 6-11 shows the demand forecast for Pukekohe substation feeders.

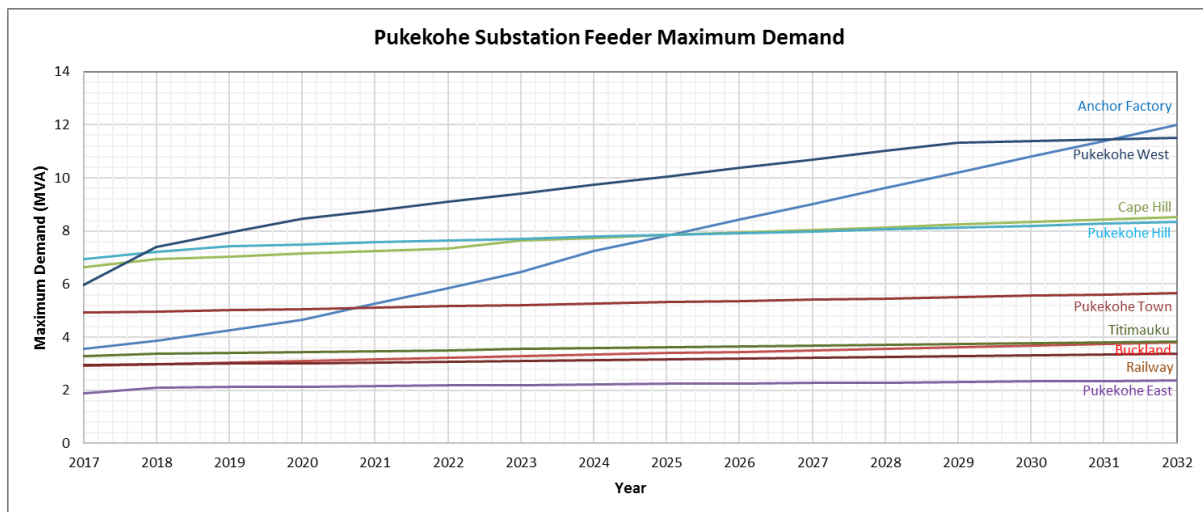


Figure 6-11 Feeder Demand Forecast at Pukekohe Zone Substation

Our development plan for Pukekohe Zone Substation Feeders will be dependent upon the final option selected for the Zone Substation development, and costs and benefits of different feeder and substation scenarios will be considered. Based on the option of extending Pukekohe Zone Substation, the following would be required to address the capacity constraints identified.

- Utilise existing sectionalisers and upgrade conductors on urban feeders to transfer high density of residential load from rural feeder sections between 2018/19 and 2026/27, at an estimated cost of \$50,000 per annum;
- Install a recloser on Railway feeder to improve supply reliability in 2019/20, at an estimated cost of \$25,000;
- Upgrade a section of Pukekohe West feeder to increase backfeed to Pukekohe Town feeder due to residential development in 2021/22, at an estimated cost of \$300,000;
- Upgrade a section of Railway feeder to provide new backfeed interconnection to Buckland feeder after 2029, at an estimated cost of \$200,000;
- Install a new 22kV feeder section to split front end of Cape Hill feeder after 2029, at an estimated cost of \$350,000; and
- Install trunk feeders and develop a switching station in the Paerata Rise and Paerata area located north of Pukekohe, after 2029, with an estimated cost in the order of \$7.9 million.

We considered the following alternative development options:

- Localised energy storage or distributed generation to reduce the peak demand under n-1 scenarios, however this option is presently quite costly for the level of utilisation and required capacity to address this constraint. Counties Power is trialling new technology options to understand the value they provide as well as actively following international developments in new technology. Should the cost of new technology continue to reduce, these options may become viable alternatives and will be considered as part of investment planning process.

Summary of Pukekohe Development Plan

Description	Scope	Timing	Estimated Costs (\$'000)
Improve supply reliability for residential load on rural feeders	Utilise existing sectionalisers and upgrade conductors on urban feeders to connect rural feeder section with high density of residential load.	2018/19 - 2026/27	50 p.a.
Improve supply reliability for Railway Feeder	Install recloser on Railway feeder	2019/20	25
Pukekohe West feeder (Princess Street West) upgrade	Upgrade 1km of swan conductor section of Pukekohe West feeder along Princes Street West	2021/22	300
Increase supply capacity to Paerata Rise and Paerata area	Install trunk feeders and switching station in Paerata Rise and Paerata area located north of Pukekohe	2028/29+	7900
Railway feeder extension	Extend 200m of Railway feeder to provide new backfeed interconnection to Buckland feeder	2028/29+	200
Additional 22kV feeder section on Cape Hill Feeder	Install a new 600m 22kV feeder section to split front end of Cape Hill feeder	2028/29+	350

Table 6-12 Summary of Pukekohe Development Plan

6.4.6 Tuakau Zone Substation

The Tuakau 110/22kV Zone Substation is supplied by two 110 kV circuits from Bombay GXP, of which one is directly connected to Bombay and the other is connected via Pukekohe.

The Tuakau Zone Substation supplies 717 distribution substations in the urban areas of Tuakau, Church Corner, and River Road and the rural areas of Port Waikato and Whangarata. The load is predominantly residential in the Church Corner, Port Waikato and Tuakau areas. The Pukekawa and Pukekawa Trunk Feeders from Tuakau supply the Pukekawa switching station which in turn supplies the Churchill Road, Glen Murray and Onewhero feeders. Tuakau is classed as a medium zone substation (S2) and is fully compliant in accordance with our security criteria (refer to Table 6-1).

Tuakau and Pukekawa supply three of our largest customers, Yashili Dairy, Watercare Waikato Water Treatment Plant and Envirowaste's landfill and generators at Hampton Downs.

The Tuakau residential load is winter peaking. The River Road and Whangarata feeder loads will peak at any time due to industrial loads (processing and quarrying). The forecast peak demand for Tuakau substation and the distribution feeders from the substation is shown in Table 6-13.

22kV Feeders	Max. Dmd (MVA)	Projected Maximum Demand (MVA): Winter Peak															Avg. Annual Increase %
	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	
Church Corner	2.1	2.4	2.4	2.5	2.5	2.6	2.6	2.6	2.7	2.7	2.8	2.8	2.9	2.9	2.9	3.0	2.8%
Port Waikato	1.3	1.3	1.3	1.4	1.4	1.4	1.4	1.4	1.4	1.4	1.5	1.5	1.5	1.5	1.5	1.5	1.0%
River Road	2.0	3.1	3.1	3.2	3.2	3.3	3.3	3.3	3.4	3.4	3.5	3.5	3.5	3.6	3.6	3.7	5.7%
Tuakau	3.9	4.1	4.2	4.2	4.3	4.4	4.5	4.5	4.6	4.7	4.8	4.9	4.9	5.0	5.1	5.2	2.3%
Whangarata	2.6	3.3	3.9	4.4	5.0	6.1	6.7	7.2	7.7	8.3	8.9	9.1	9.3	9.5	9.7	9.9	19.1%
WWTP 1	2.1	2.2	2.2	2.2	2.2	2.3	2.3	2.3	2.3	2.3	2.4	2.4	2.4	2.4	2.4	2.5	1.0%
WWTP 2	1.7	1.7	1.7	1.8	1.8	1.8	1.8	1.8	1.8	1.9	1.9	1.9	1.9	1.9	1.9	2.0	1.0%
Hitchen Road	3.1	6.8	7.0	7.3	7.5	7.7	8.0	8.2	8.4	8.5	8.5	8.5	8.6	8.6	8.6	8.7	11.9%
Tuakau Industrial	0.6	0.6	0.6	0.6	0.7	0.7	0.7	0.8	0.8	0.8	0.8	0.9	1.0	1.1	1.1	1.2	7.4%
Potter Road	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0%
Pukekawa	2.0	2.1	2.1	2.1	2.1	2.1	2.1	2.1	2.1	2.1	2.1	2.1	2.1	2.1	2.1	2.1	0.5%
Pukekawa Trunk	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0%
Zone Substation	Max. Dmd (MVA)	Projected Maximum Demand (MVA): Winter Peak															Avg. Annual Increase %
	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	
Tuakau with Generation	16.7	21.5	22.3	23.1	23.9	25.1	26.0	26.8	27.6	28.3	28.9	29.3	29.7	30.1	30.6	31.0	5.7%
Tuakau with Generation and Pokeno industrial area	16.7	21.5	23.9	26.2	28.6	31.4	33.8	36.1	38.5	40.7	42.2	42.6	43.0	43.4	43.8	44.2	11.0%
Hampton Downs Generation	2.7	2.7	2.7	2.7	2.7	2.7	2.7	2.7	2.7	2.7	2.7	2.7	2.7	2.7	2.7	2.7	0.0%
Tuakau without Generation	19.4	24.2	25.0	25.8	26.6	27.8	28.7	29.5	30.3	31.0	31.6	32.0	32.4	32.8	33.3	33.7	4.9%

Table 6-13 Winter Maximum Demand at Tuakau Zone Substation and Feeders

Tuakau Zone Substation Investment

The Tuakau Zone Substation demand forecast is shown in

Figure 6-12.

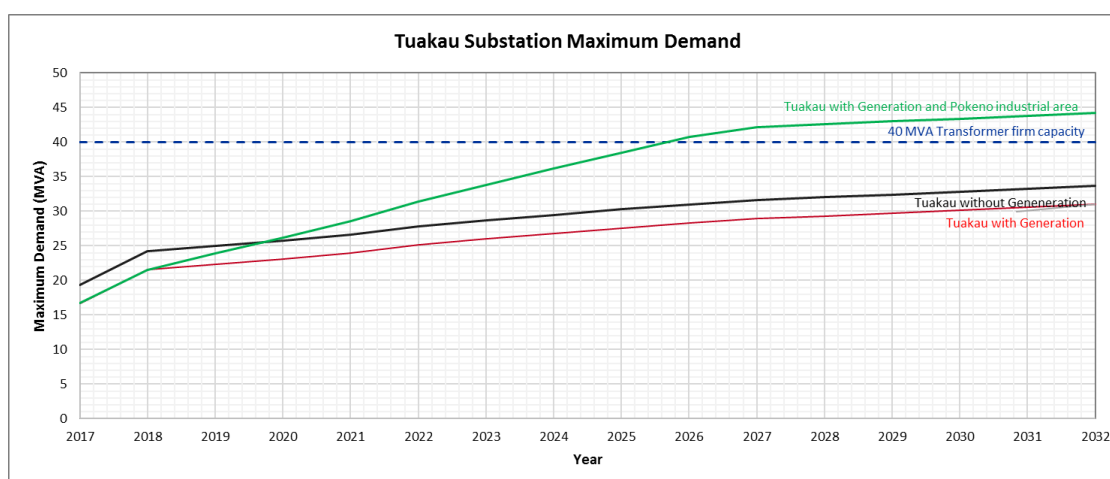


Figure 6-12 Tuakau Zone Substation Demand Forecast

Two 110/22kV, 20/40 MVA transformers supply the load at Tuakau providing n-1 capacity of 40 MVA. As discussed in Section 6.4.3, if load growth in the Pokeno industrial area is as forecast, the maximum demand will exceed 40MVA in 2026/27.

Tuakau Zone Substation Feeders Investment

We expect significant growth in the area through the planning period including.

- Continued residential subdivision developments in the Hitchen Road area and other Pokeno subdivisions; and
- Expansion of the Waikato Water Treatment Plant and the Pokeno residential subdivisions; and
- New load connections in the Pokeno industrial area.

Figure 6-13 shows the demand forecast for Tuakau substation feeders.

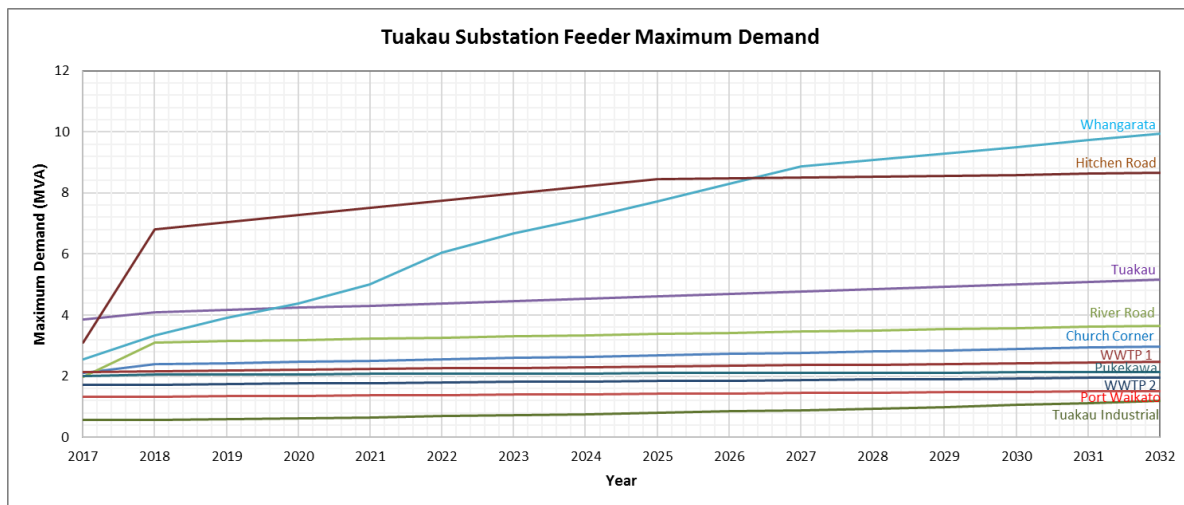


Figure 6-13 Feeder Demand Forecast at Tuakau Zone Substation

Our development plan for Tuakau Zone Substation Feeders which is in progress include:

- Final stage of visual impact mitigation on the Bombay – Tuakau 110kV line on planting along the rail corridor and a 110kV pole relocation at a private property, as part of the stakeholder management plan for the 110kV line corridor in 2018/19, at an estimated cost of \$175,000;
- Establish backfeed to River Road feeder sections from Port Waikato feeder at an estimated cost of \$85,000 and Church Corner feeder at an estimated cost of \$550,000 in 2018/19 to provide backfeed to industrial load expansions;
- Rebuild front end sections of Whangarata and Hitchen Road feeders along Whangarata Road to improve reliability at an estimated cost of \$990,000. This is to be completed in 2018/19;
- Rebuild and reroute a section of 22kV line from Tuakau to Pukekawa switching station (new Pukekawa trunk feeder) in 2018/19, with an estimated cost of \$1,000,000, to improve security to Pukekawa switching station, and to address age and condition concerns of the existing line; and
- Upgrade auto-transformers and install voltage regulators on Port Waikato and Glen Murray feeders to increase backfeed capacity in 2019/20, at an estimated cost of \$800,000.

Several key consumers connected to Tuakau have previously experienced some momentary voltage sags as a result of faults on the rural feeders from Tuakau and Pukekawa substations. We have implemented changes to feeder protection settings to speed up fault clearance time and reduce duration of momentary voltage sags in 2017/18. This measure has improved the momentary voltage sags impact since its implementation. We are investigating options to design out these issues and improve power quality. Options being considered include:

- Primary plant earthing design and improvement measures;
- Consumer side active voltage conditioning on sensitive loads; and
- Substation based STATCOM or similar.

An allocation of \$1 million has been included in the 2018/19 expenditure forecast for improvement of power quality at Tuakau substation.

Battery Energy Storage Trial

One of the network alternative technologies which has the potential to change how distribution networks traditionally operate is energy storage through the use of grid scale battery storage system.

We installed our first grid-scale battery storage system at the Tuakau Zone Substation in 2017. This trial installation is to understand the benefits such systems can provide including management of peak demand, contributing to quality of supply in our network through reactive power support, and to provide ancillary services. While the battery trial has specific objectives, it will more broadly enable better understanding of its impact on the network, its limitations, and the benefits it can provide across the whole network over time.

We see value in the following areas:

- **Peak Demand Management and Reduction** – savings in Transmission Peak Costs;
- **Voltage Support** – the battery, with the appropriate control systems, could be used to assist with voltage support, improving the power quality at Tuakau;
- **Energy Storage** – charge the batteries at lower off-peak rates and discharge at peak times; and
- **Ancillary Services Market** – battery storage may be suitable for instantaneous reserves.

At the time of writing this AMP, we consider the battery to be able to provide both regulated benefits (in terms of network support and peak demand management on the distribution network), as well as unregulated benefits (such as value from the arbitrage of energy when not used for regulated purposes). As such we discuss the use of the battery in this AMP in the context of our regulated activities however we are working to develop a cost allocation methodology to provide a transparent means of reporting how we use the battery and allocate respective costs and benefits.

Summary of Tuakau Development Plan

Description	Scope	Timing	Estimated Costs (\$'000)
Bombay -Tuakau 110kV line corridor visual mitigation measure	Implement landscaping and pole relocation as visual mitigation measures for the Bombay - Tuakau 110kV line corridor.	2018/19	175
Establish backfeed to River Road feeder from Port Waikato feeder	Construct new feeder section from Port Waikato feeder to Roberts road section of River Road feeder	2018/19	85
Establish backfeed to River Road feeder from Church Corner feeder	Construct new feeder section from Church Corner feeder to River Road feeder	2018/19	550
Improve reliability of Whangarata and Hitchen Road Feeders (Front end sections)	Rebuild front end sections of Whangarata and Hitchen Road feeders along Whangarata Road to a new underground feeder section and retain one of the overhead feeders	2018/19	990
New Pukekawa Trunk Feeder	Rebuild and reroute a section of 22kV line from Tuakau substation to Pukekawa switching station to from a new Pukekawa Trunk feeder.	2018/19	1000

Tuakau industrial power quality	Voltage support solution to address power quality issues at Tuakau	2018/19	1000
Increase Port Waikato feeder backfeed capacity	Upgrade auto-transformer and install voltage regulator on Port Waikato feeder	2018/19	400
Increase Glen Murray feeder backfeed capacity	Upgrade auto-transformer and install voltage regulator on Glen Murray feeder	2019/20	400

Table 6-14 Summary of Tuakau Development Plan

6.4.7 Mangatawhiri and Ramarama

Mangatawhiri and Ramarama substations supply the eastern areas of our network from Kaiaua, Paparata and Ararimu in the north to Mercer in the south.

The Mangatawhiri 33/11kV Zone Substation is supplied by one 33kV circuit from Bombay GXP. Mangatawhiri Zone Substation supplies 396 distribution substations in the rural areas of Kaiaua, Mercer, Paparata and Pokeno Church. The load is predominantly rural residential. Mangatawhiri is classed as a small zone substation (S3) and is only compliant for maintaining maximum demand for the first outage in accordance with our security criteria (Table 6-1).

The Ramarama 33/11kV Zone Substation is supplied by two 33kV circuits from Bombay GXP. Ramarama Zone Substation supplies 345 distribution substations in the rural areas of in Ararimu, Bombay and Great South Road. The load is predominantly rural residential. Ramarama is classed as a medium zone substation (S2) and is fully compliant in accordance with our security criteria (Table 6-1).

Proposed Bombay Area Zone Substation

The concept of a single, centralised Zone Substation located in the approximate load centre of the supply area is a valid concept based on the number of identified issues at the two zone substations and the Bombay 33kV supply, however where the substation is located is still being assessed. For the purpose of this section, it shall be referred to as the 'Bombay Area zone substation'. Construction of the substation in the vicinity of the Bombay GXP is a likely outcome of further analysis.

Bombay Area Zone Substation – Options considered

Supply assets are at end of life

We are the primary user of the 33kV assets Transpower operates at the Bombay GXP. These assets are at end of life and will be subject to policy replacement projects by Transpower around 2020.

This work would include the following renewal activities:

- Replacement of outdoor 33kV switchgear, circuit breakers and bus structure;
- Replacement of two 110/33kV supply transformers with 110/33kV or 110/22kV transformers; and
- Replacement of associated secondary equipment.

Additionally, we have assets that are also at end of life, particularly:

- The Bombay 33kV ripple injection plant;
- The Mangatawhiri 33kV line, including poles, crossarms and conductors;

- The Mangatawhiri 33/11kV substation;
- The Ramarama 33kV line is supported on end of life steel towers, which will require replacement and the line corridor is one route that a new 110kV line to supply Drury South Business Park could use; and
- The Ramarama 33/11kV substation is small, and unsuitable for supply to large growth in the area – this will be better accommodated by a new Drury South Area Substation to supply the Drury South Business Park.

We considered the alternative of retaining the existing 33kV supply to Mangatawhiri and Ramarama substations. However, this option would incur significant costs, as most of the existing assets, including the 33kV transmission line to Ramarama, are near the end of their economic life and would need to be replaced within the period of this AMP.

When considering all the issues to address, a single replacement substation capable of supplying both the existing Ramarama and Mangatawhiri load is a viable option to assess further.

This project will:

- Rationalise existing assets;
- Provide a new supply point closer to growth areas, in particular Bombay and Pokeno;
- Save in asset replacement costs by allowing us to decommission a significant number of assets that are nearing the end of their economic life; and
- Provide savings in our Annual Operational Charges with Transpower at the Bombay Grid Exit Point, and allowing them to remove 33kV supply – rationalising their assets.

The project includes:

- Land acquisition in 2018/19, with an expected cost of \$500,000;
- Building a new 110kV substation to replace the Mangatawhiri and Ramarama substations to supply the load in the area by 2021/22, with an expected cost of \$4.5 million;
- Building a new 110kV transmission line from Bombay to the new substation site by 2021/22, with an expected cost of \$1.2 million;
- Connecting existing feeders to the new substation by 2020/21, with an expected cost of \$2.6 million; and
- Contribution to installation of 110kV circuit breakers and protection at Transpower's Bombay Grid Exit Point by 2021/22, with an expected cost of \$2.0 million.

The total cost of this option is in the order of \$12 million. We have allowed for it in the expenditure forecasts.

Since the 2017 AMP, we have assessed the options for replacement of the Mangatawhiri and Ramarama zone substations. The proposed solution is the establishment of a new 110/22kV substation centrally located to replace the two existing substations. The required timing of the substation has not changed and is still required by 2021/22. As part of the options assessment, potential locations for the new substation were also identified. Two sites were identified for the new

substation. The first site is on the Transpower Bombay GXP site adjacent to the 110kV switchyard. The second site is 2.5 km from the Bombay GXP site. Alternative options to use new technology solutions were considered. These were ruled out, as based on present costs, new technology options are not economically justified compared to traditional solutions.

Mangatawhiri and Ramarama area (Bombay Area Substation) demand forecast

Table 6-15 shows the winter maximum demand forecast for Mangatawhiri and Ramarama substations (to be replaced by a new 110 kV substation in 2021/22).

11kV Feeders	Max. Dmd (MVA)	Projected Maximum Demand (MVA): Winter Peak															Avg. Annual Increase %
	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	
Ararimu	1.9	1.9	2.0	2.0	2.1	2.1	2.2	2.2	2.2	2.3	2.3	2.4	2.4	2.4	2.5	2.5	2.2%
Bombay	2.9	3.0	3.0	3.1	3.1	3.2	3.2	3.3	3.3	3.4	3.4	3.5	3.5	3.6	3.6	3.7	1.7%
Great South Road	1.6	1.7	1.7	1.8	1.8	1.8	1.8	1.8	1.9	1.9	1.9	1.9	1.9	2.0	2.0	2.0	1.6%
Kaiaua	2.4	2.5	2.6	2.6	2.6	2.7	2.7	2.8	2.8	2.9	2.9	2.9	3.0	3.0	3.1	3.1	2.0%
Mercer	1.5	1.6	1.6	1.6	1.6	1.6	1.6	1.6	1.6	1.7	1.7	1.7	1.7	1.7	1.7	1.7	0.7%
Paparata	1.2	1.2	1.2	1.3	1.3	1.3	1.3	1.4	1.4	1.4	1.5	1.5	1.5	1.5	1.6	1.6	2.3%
Pokeno	2.3	2.6	2.6	2.7	2.8	2.9	3.0	3.1	3.2	3.3	3.4	3.4	3.5	3.6	3.6	3.7	4.3%
Zone Substation	Max. Dmd (MVA)	Projected Maximum Demand (MVA): Winter Peak															Avg. Annual Increase %
	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	
Bombay Area	0.0	0.0	0.0	0.0	0.0	13.6	13.8	14.1	14.3	14.6	14.8	15.0	15.3	15.5	15.7	15.9	1.6%

Table 6-15 Winter Maximum Demand for Mangatawhiri and Ramarama Substations and Feeders

The Mangatawhiri and Ramarama load is winter peaking and is made up of a mix of commercial and residential load. We anticipate some residential growth around Bombay and on the areas immediately to the north and south along SH1, as far as Pokeno.

Mangatawhiri and Ramarama Zone Substation investment need

Figure 6-14 shows the demand forecast for Mangatawhiri and Ramarama Substations²⁷

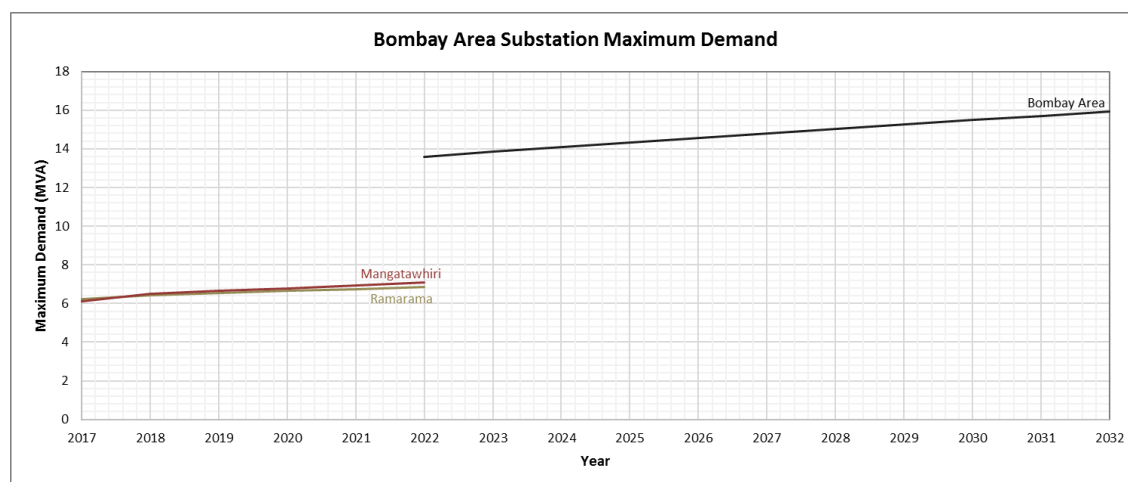


Figure 6-14 Mangatawhiri and Ramarama Substations Demand Forecast

²⁷ The proposed Bombay Area substation replaces Mangatawhiri and Ramarama from 2021/22.

The present supply configuration is made up of:

- One 33/11kV, 7.5 MVA transformer supplying the load at Mangatawhiri with no n-1 capacity; and
- Two 33/11kV, 5 MVA transformers supplying the load at Ramarama providing n-1 capacity of 5 MVA.

Mangatawhiri and Ramarama Zone Substation Feeders Investment need

The supply area of Mangatawhiri covers part of the Pokeno area around the State Highway 1 and 2 junctions. We expect significant growth from the Pokeno subdivisions through the planning period.

Figure 6-15 shows the demand forecast for feeders at Mangatawhiri and Ramarama Substations.

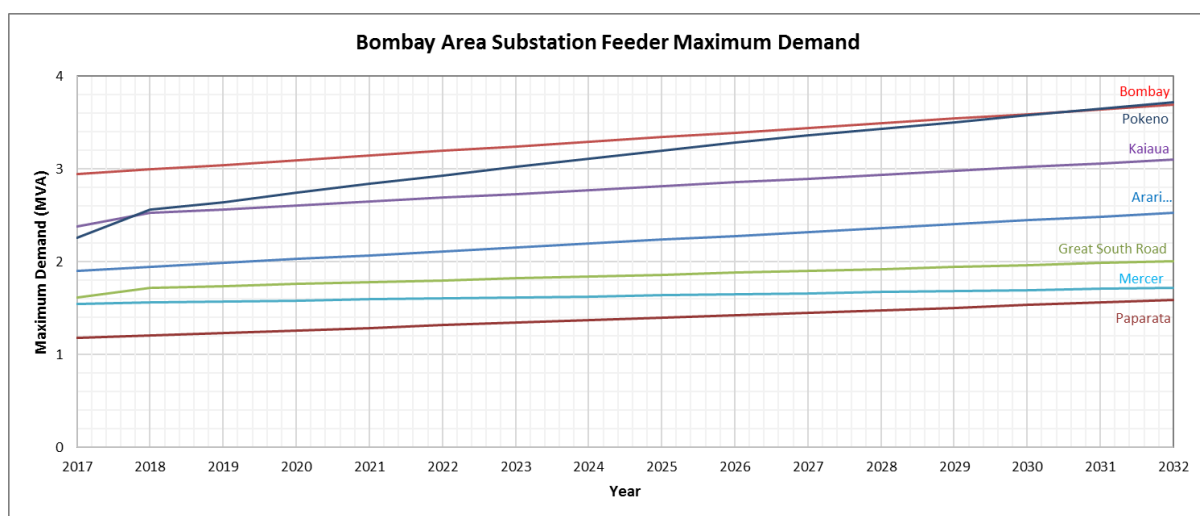


Figure 6-15 Feeder Demand Forecast for Mangatawhiri and Ramarama Substation Feeders

Summary of Bombay Area Development Plan

Description	Scope	Timing	Estimated Costs (\$'000)
Bombay Area Substation site acquisition	Acquire suitable land and line route for new Bombay area substation	2018/19	500
Connection of feeders to existing infrastructure	Build first part of the six new feeders to connect to the existing network	2021/22	2600
Bombay Area Substation establishment	Construct new substation including transformers, switchgear and protection and control to replace existing Ramarama and Mangatawhiri substations	2021/22	4500
Build 110kV subtransmission line to Bombay Area Substation	Build 110kV line from Bombay GXP to Bombay Area Substation	2021/22	1200
Contribution to Transpower for GXP development	Install 110kV circuit breaker control & protection at Transpower Bombay GXP	2021/22	2000

Table 6-16 Summary of Bombay Area Development Plan

6.5 Western region development plan

The Western Region is supplied from Transpower's Glenbrook Grid Exit Point and covers areas supplied by our Karaka, Maioro and Waiuku Zone Substations and a 33kV point of supply at Storey Road. Figure 6-16 and Table 6-17 show the total Western Region forecast demand.

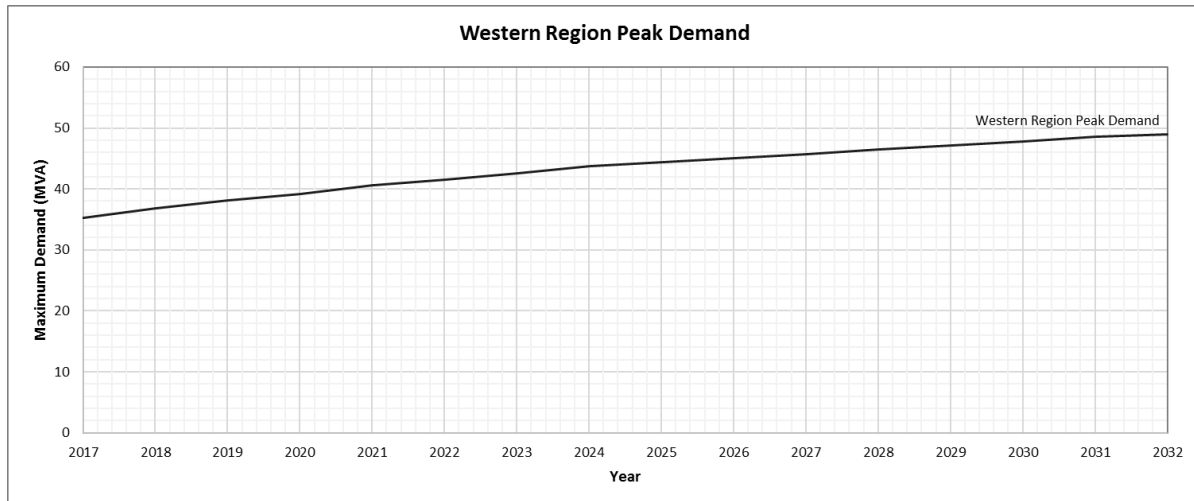


Figure 6-16 Winter Maximum Demand for Western Region

Zone Substation		Projected Maximum Demand (MVA): Winter Peak																Avg. Annual Increase %
		2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	
Waiuku	33/11kV	16.0	16.8	17.1	17.7	18.3	19.0	19.6	20.3	20.5	20.7	21.0	21.2	21.5	21.7	21.9	22.2	2.6%
Karaka	33/11kV	10.4	11.2	12.3	12.7	13.6	13.8	14.3	14.8	15.2	15.7	16.2	16.7	17.1	17.6	18.1	18.3	5.1%
Maioro	33/11kV	10.0	10.0	10.0	10.0	10.0	10.0	10.0	10.0	10.0	10.0	10.0	10.0	10.0	10.0	10.0	10.0	0.0%
NZS (Storey Road)	33/11kV	1.6	1.6	1.6	1.6	1.6	1.6	1.6	1.6	1.6	1.6	1.6	1.6	1.6	1.6	1.6	1.6	0.0%
Western Region		35.2	36.8	38.1	39.1	40.6	41.5	42.6	43.7	44.4	45.1	45.8	46.5	47.1	47.8	48.5	49.0	2.6%

Table 6-17 Winter Maximum Demand for Western Region

Our subtransmission network in the Western region supplies zone substations and the 11kV distribution network via:

- Two 33kV lines from Glenbrook Grid Exit Point to Waiuku;
- One 33kV line from Waiuku to Story Road Pump Station and Maioro; and
- Two 33kV lines from Glenbrook Grid Exit Point to Karaka.

Figure 6-17 shows the single line schematic for the Western region subtransmission network supplied from the Glenbrook grid exit point.

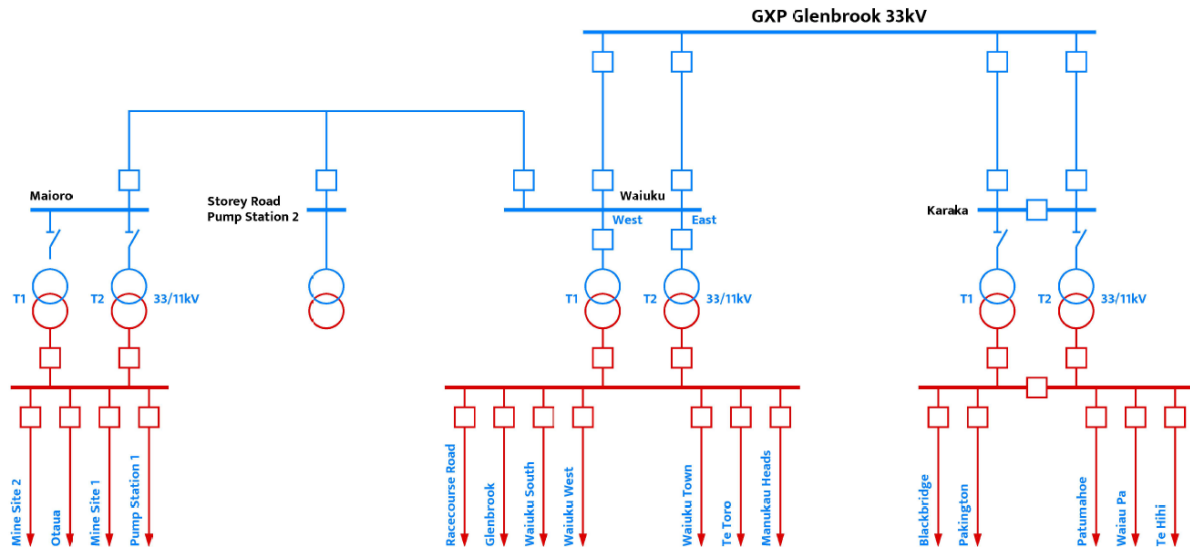


Figure 6-17 Single Line Schematic of the Western Region subtransmission network

This system has the following constraints:

- The distances between the load centres and our substations are too great for efficient 11kV distribution, in particular the distance and demands of Waiau Pa, Clarks Beach and Kingseat from the existing Karaka Substation is too great for 11kV distribution. Similarly, for Glenbrook Beach from Waiuku Substation; and
- The 33 kV network is not suitable for connecting any major wind farms²⁸ to the network, which have previously been consented but not developed. The likelihood of these proceeding during the planning period is very low.

As there is no 110kV supply from Transpower's Glenbrook Grid Exit Point, it would require significant load or generation increase in the area to make it economic to convert to a 110kV subtransmission network and a 22kV distribution network. In the longer term, there are two potential options to increase supply capacity for the area. One option is to continue with the existing 33/11kV network architecture and to upgrade the 11kV to 22kV in places to achieve the required voltage performance on the longer feeders. An alternative is to establish 110/22kV architecture as used in the Eastern Region, however this is harder to achieve as there is no 110kV transmission supply into the area at present.

We expect some growth in the Western region over the next ten years with:

- Designation of special housing accord areas at Glenbrook Beach;
- Proposed developments at Clarks Beach and Kingseat; and
- Subdivisions at Patumahoe, Waiau Pa and Waiuku.

The proposed expansion at New Zealand Steel's mine site at Maoro will only have a minor impact on our network.

²⁸ There is a possibility that a wind farm may eventuate on the Manukau Heads

6.5.1 South Western Subtransmission

South Western Area subtransmission investment need

Two 33kV lines from Glenbrook supply Waiuku and the rest of the South Western Area (Maioiro and Storey Road). The Waiuku West line is strung with Cockroach conductor, which was upgraded in 2017. The Waiuku East line is strung with lower rated Cricket conductor the length of the line.

The loading on the 33kV Glenbrook to Waiuku East line exceeded its n-1 capacity (the rating for the Cricket conductor section) from 2016 during the peak load period, and is forecast to reach 110% of the n-1 rating by 2019. This can be deferred to 2022 if a cyclic rating is applied to the Waiuku East line. Investigations will be required in 2018/19 to confirm that there are sufficient clearances on the line to operate with a cyclic rating. A budget provision of \$1.2 million in 2022/23 is included in the expenditure forecasts.

Our proposed investment to address the identified constraint on the Waiuku East line is to reconductor the 33kV East line from Glenbrook to Waiuku with higher rated Cockroach conductor in 2022/23, at an estimated cost of \$1.2 million.

We considered the following alternative development options:

- Transferring load from Waiuku to the adjacent Karaka substation at 11kV to reduce the loading on the substation, and defer the subtransmission investment, however this is not feasible due to voltage constraints on the interconnecting feeders and significant load transfers have occurred (to both Karaka, but also Maioiro and Pukekohe) in the past leaving little residual capacity able to be transferred;
- Localised energy storage or distributed generation to reduce the peak demand under n-1 scenarios, however this option is, at present, costly for the level of utilisation; and
- Building a third 33kV line from Glenbrook to Waiuku. However, this project was discounted as the cost was significantly greater than our proposed solution of reconductoring the existing line, and would require extensive substation bus modifications.

Summary of south western area subtransmission development

Description		Scope	Timing	Estimated Costs (\$'000)
Reconductor Waiuku East line	Glenbrook to	Reconductor 7.8km of 33kV concrete pole line in cockroach conductor	2022/23	1200

Table 6-18 Summary of south western area subtransmission development

6.5.2 Wind Farm development

Resource consent has previously been granted to build a wind farm on the Manukau Heads, however it is not proceeding at this time and the consents have expired. At the time of writing this plan, it has been indicated that windfarm development in the area may commence again in the short to medium term, although no timeframes are known. Should this valuable wind resource be redeveloped during

the planning period, it would have a significant impact on subtransmission development in the Western area.

We will review our options and finalise a development path to connect any generation in this area in future plans, should the need arise.

6.5.3 Karaka Zone Substation

The Karaka 33/11kV Zone Substation is supplied by two 33kV circuits from Glenbrook GXP. Karaka Zone Substation supplies 445 distribution substations in the mainly rural areas of Blackbridge, Pakington, Patumahoe, Te Hihi and Waiau Pa. The load is predominantly residential. Karaka is classed as a medium zone substation (S2) and is fully compliant with our security criteria (refer to Table 6-1).

The Karaka load is winter peaking. The forecast peak demand for Karaka Zone substation and the distribution feeders from the substation is shown in Table 6-18.

11kV Feeders	Max. Dmd (MVA)	Projected Maximum Demand (MVA): Winter Peak															Avg. Annual Increase %
	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	
Blackbridge	1.3	1.3	1.8	1.9	2.7	2.7	2.7	2.7	2.8	2.8	2.8	2.8	2.8	2.9	2.9	2.9	8.2%
Pakington	2.3	2.4	2.4	2.4	2.4	2.5	2.5	2.5	2.5	2.5	2.5	2.6	2.6	2.6	2.6	2.6	1.0%
Patumahoe	1.9	2.0	2.3	2.3	2.4	2.4	2.4	2.5	2.5	2.6	2.6	2.6	2.7	2.7	2.7	2.8	3.0%
Te Hihi	2.1	2.6	2.9	3.1	3.1	3.2	3.5	3.7	4.0	4.3	4.6	4.9	5.2	5.5	5.7	5.8	11.3%
Waiau Pa	3.1	3.3	3.3	3.4	3.4	3.6	3.7	3.8	4.0	4.1	4.2	4.3	4.5	4.6	4.7	4.8	3.8%
Zone Substation	Max. Dmd (MVA)	Projected Maximum Demand (MVA): Winter Peak															Avg. Annual Increase %
	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	
Karaka	10.4	11.2	12.3	12.7	13.6	13.8	14.3	14.8	15.2	15.7	16.2	16.7	17.1	17.6	18.1	18.3	5.1%

Table 6-19 Winter Maximum Demand at Karaka Zone Substation and Feeders

Karaka Zone Substation Investment

The Karaka Zone Substation demand forecast is shown in Figure 6-18.

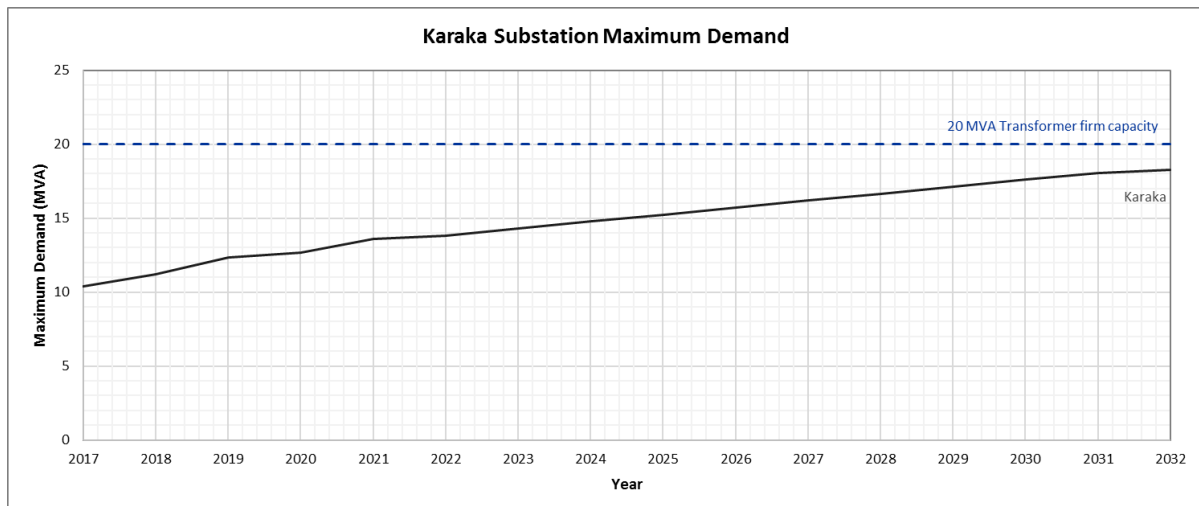


Figure 6-18 Karaka Zone Substation Demand Forecast

There are two 33/11kV 10/20 MVA transformers installed at Karaka substation providing a n-1 capacity of 20 MVA, which will be sufficient to supply the substation load beyond 2032.

Karaka Zone Substation Feeder Investment

We expect significant growth from the Kingseat and Clarks Beach subdivision developments. The Kingseat subdivision has been assumed to incur demand of the first 200 lots over the next 5 years and potentially up to 900 lots from the next 10 to 15 years through the planning period. The Clarks Beach subdivision is expected to add up to 750 lots over the planning period.

Figure 6-19 shows the demand forecast for Karaka substation feeders.

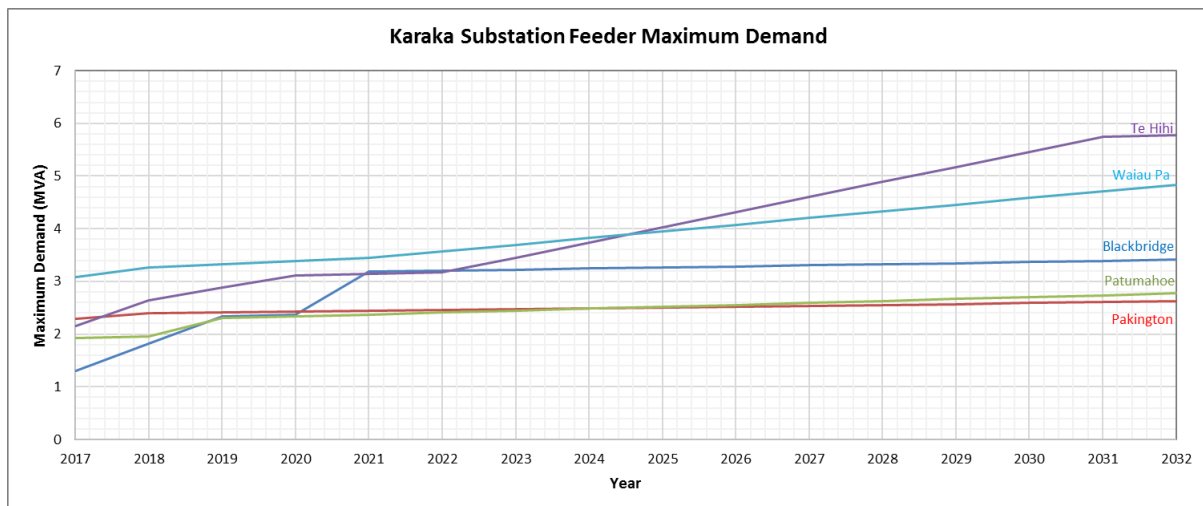


Figure 6-19 Feeder Demand Forecast at Karaka Zone Substation

Some load from our Waiuku substation has been transferred to Karaka substation to relieve the loading on the 33kV Glenbrook - Waiuku circuits. To accommodate this transferred load, as well as to accommodate additional load on the Karaka substation arising from growth, the distribution feeders from Karaka will be reconfigured and upgraded for capacity and voltage performance, particularly those supplying growth in Glenbrook Beach, Clarks Beach and Kingseat areas.

Our development plan for Karaka Zone Substation Feeders is to:

- Install a voltage regulator on Waiau Pa feeder in 2018/19 to increase backfeed capacity to Glenbrook Beach, at an estimated cost of \$130,000;
- Reconductor a section of the Blackbridge feeder and convert to 22kV operation, in 2019/20, with an estimated cost of \$1.15 million. This investment will provide more system flexibility by enabling us to backfeed load from large subdivision developments in the Opaheke and Pukekohe north areas;
- Install a voltage regulator at switch 47 along the Te Hihi feeder in 2021/22, with an estimated cost of \$130,000. This investment is to accommodate the identified load growth on the feeder due to development around Kingseat;
- Convert the Waiau Pa feeder to 22kV, in 2021/22, to address capacity and voltage constraints due to identified load growth at Clarks Beach and Glenbrook Beach, with an estimated cost of \$1.0 million²⁹;

²⁹ To be implemented in conjunction with the 22kV conversion of the Glenbrook feeder from Waiuku Substation. Cost estimate for Glenbrook feeder is listed in section 6.5.4.

- Reconductor 3.4km of Blackbridge feeder from Karaka substation to Charles Road in 2024/25 to increase backfeed capacity to large subdivision developments in the area, with an estimated cost of \$400,000; and
- Convert part of Te Hihi feeder to 22kV, in 2026/27, to address capacity and voltage constraints due to development around Kingseat, with an estimated cost of \$1.25 million.

We considered the following alternative development options:

- Installing new feeders from Karaka or Waiuku into the new load centres to reduce existing loading, however the geographic location relative to the substation, and the combined with the aged existing 11kV network gives overall benefit to 22kV conversion of existing assets; and
- Localised energy storage or distributed generation to reduce the peak demand, however this option is costly for the level of utilisation and required capacity to address this constraint. Counties Power is trialling new technology options to understand the value they provide as well as actively following international developments in new technology. Should the cost of new technology continue to reduce, these options may become viable alternatives and will be considered as part of investment planning process.

Summary of Karaka Development Plan

Description	Scope	Timing	Estimated Costs (\$'000)
Waiau Pa feeder voltage support upgrade	Install second voltage regulator on Waiau Pa feeder	2018/19	130
Blackbridge Feeder upgrade	Complete 22kV conversion of Blackbridge feeder and reconductor 600m feeder section	2019/20	1150
Te Hihi feeder	Install voltage regulator at switch 47	2021/22	130
Waiau Pa Feeder upgrade	Complete 22kV conversion of Waiau Pa feeder	2021/22	1000
Blackbridge Feeder upgrade (Karaka Substation to Charles Road)	Reconductor 3.4km of Blackbridge feeder from Karaka substation to Charles Road	2024/25	400
Te Hihi Feeder upgrade	Complete 22kV conversion of Te Hihi feeder	2026/27	1250

Table 6-20 Summary of Karaka Development Plan

6.5.4 Waiuku Zone Substation

The 33/11kV Waiuku zone substation is supplied by two 33 kV subtransmission lines from Glenbrook GXP. Waiuku Zone Substation supplies 627 distribution substations in the urban areas of Waiuku, Racecourse Road and rural areas of Glenbrook, Te Toro and Manukau Heads. The load is a mix of residential and commercial. Waiuku is classed as a large zone substation (S1), however is not presently compliant with our security criteria due to the rating of the 11kV switchboard (refer to Table 6-1).

The Waiuku load is has a winter peak. The forecast peak demand for Waiuku Zone Substation and the distribution feeders from the substation is shown in Table 6-21.

11kV Feeders	Max. Dmd (MVA)	Projected Maximum Demand (MVA): Winter Peak															Avg. Annual Increase %
	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	
Glenbrook	1.4	2.0	2.0	2.4	2.8	3.3	3.7	4.1	4.1	4.1	4.1	4.1	4.1	4.1	4.1	4.1	12.8%
Manukau Heads	2.2	2.2	2.2	2.2	2.3	2.3	2.3	2.3	2.4	2.4	2.4	2.4	2.4	2.5	2.5	2.5	1.0%
Racecourse	2.6	2.6	2.6	2.7	2.7	2.7	2.8	2.8	2.8	2.9	2.9	2.9	3.0	3.0	3.0	3.1	1.3%
Te Toro	1.7	1.8	1.8	1.8	1.8	1.8	1.8	1.9	1.9	1.9	1.9	1.9	2.0	2.0	2.0	2.0	1.0%
Waiuku South	1.8	1.9	1.9	1.9	2.0	2.0	2.0	2.1	2.1	2.1	2.2	2.2	2.3	2.3	2.3	2.4	2.0%
Waiuku Town	3.2	3.2	3.3	3.3	3.4	3.5	3.5	3.6	3.7	3.7	3.8	3.9	3.9	4.0	4.0	4.1	2.0%
Waiuku West	3.7	3.8	3.9	3.9	4.0	4.1	4.2	4.2	4.3	4.4	4.5	4.5	4.6	4.7	4.8	4.8	2.0%
Zone Substation	Max. Dmd (MVA)	Projected Maximum Demand (MVA): Winter Peak															Avg. Annual Increase %
	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	
Waiuku	16.0	16.8	17.1	17.7	18.3	19.0	19.6	20.3	20.5	20.7	21.0	21.2	21.5	21.7	21.9	22.2	2.6%

Table 6-21 Winter Maximum Demand at Waiuku Substation and Feeders

Waiuku Zone Substation Investment

The Waiuku Zone Substation demand forecast is shown in Figure 6-20.

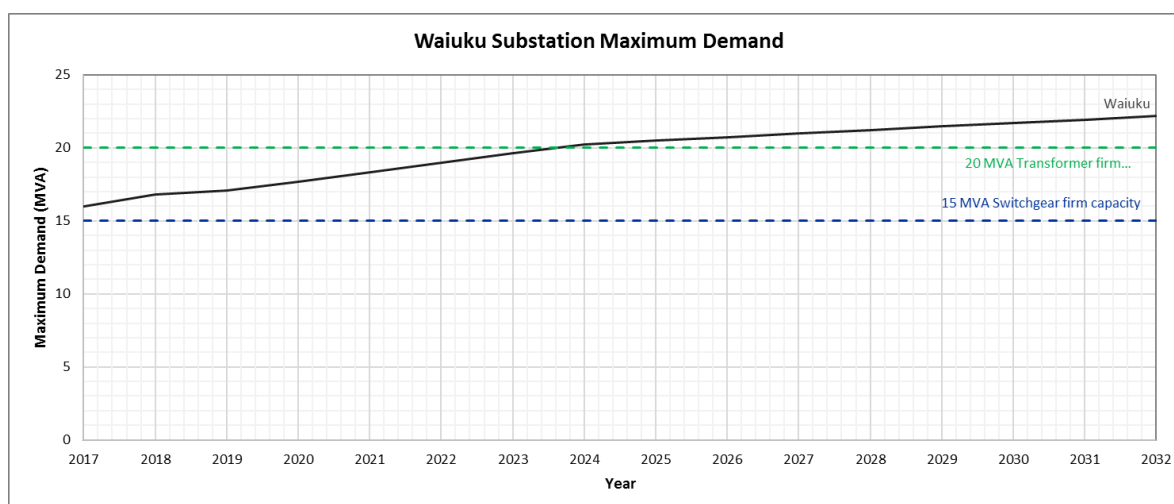


Figure 6-20 Waiuku Zone Substation Demand Forecast

Two 33/11kV, 10/20 MVA transformers supply the load at Waiuku providing n-1 capacity of 20 MVA. The Waiuku maximum winter demand currently exceeds the Waiuku 11kV switchgear n-1 capacity and is managed with operational measures, and will exceed the transformer n-1 capacity by 2025.

The Waiuku Zone Substation building is 65 years old and has been identified as not meeting the new building seismic standard and thus requiring strengthening.

Considered options

Given these constraints all occur within the planning period, a detailed solution for the substation rebuild will need to be in progress by 2020. In the 2017 AMP, two options were considered for our development path. Option 1 was redeveloping the zone substation at the existing site and Option 2 was building a new zone substation at a site approximately 350m from the existing substation. Further work has been undertaken on the two options since the last AMP, and it has been concluded that redevelopment at the existing site is the preferred option. Key considerations for each of the two options are summarised below:

- The existing site has sufficient space for the in-situ redevelopment while the substation remains as a fully operational site, and future expansion. Existing 33kV line entries remain. No additional consents are required, as all work would be covered by existing use rights under

the existing site designation. Existing road frontage access complies with the operational requirement of a substation; and

- The new site will require site purchase, full resource consent and site designation for use as an electricity substation, and full site establishment and civil work. Easements will be required to secure exclusive right of way to meet the operational requirement as a substation. New 33kV line routes will also need to be established for 33kV line diversions to the new site. The associated work is expected to be more complex over a longer delivery timeframe, and incurring a much higher cost compared to the existing site option.

An additional alternative development option was considered involving construction of a new substation at Glenbrook to address growth in demand in the eastern side of Waiuku and Glenbrook, reducing the loading on Waiuku. This option however does not address the age and condition issues with the substation which would still require investment.

Proposed investment

Our development plan for Waiuku zone substation is to redevelop at the existing site in two stages.

- Replace the 11kV switchboard with a new 22kV rated switchboard in a new building in 2018/19 at an estimated cost of \$2 million; and
- Replace the remainder of the substation (33kV switchgear and 33/11kV 10/20 MVA transformers) in 2019/20 at an estimated cost of \$3.8 million.

Waiuku Zone Substation Feeder Investment

We expect significant growth from the Glenbrook Beach subdivision development. It has been assumed to incur demand of approximately 800 lots over through the planning period.

Figure 6-21 shows the demand forecast for Waiuku Substation feeders.

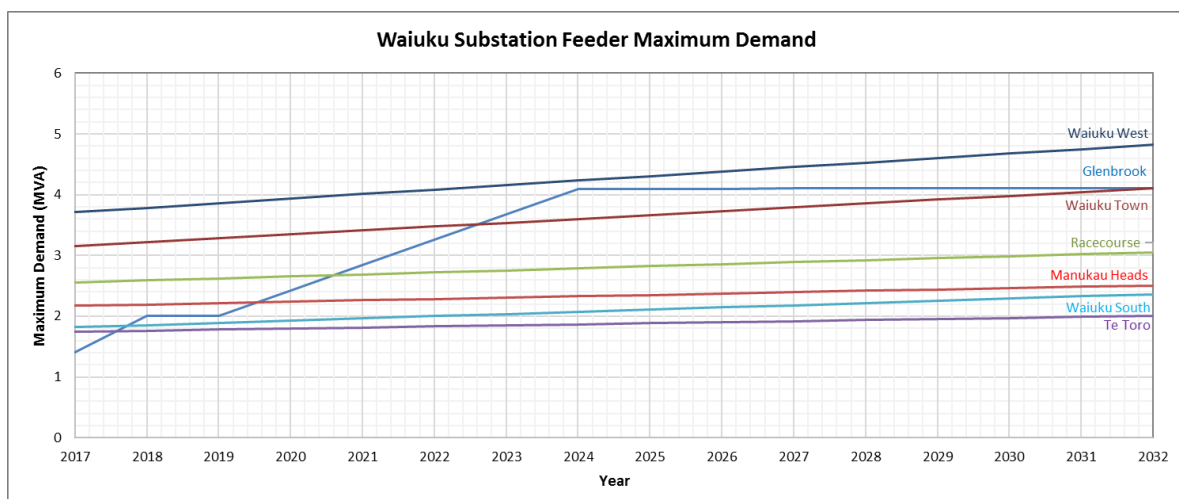


Figure 6-21 Feeder Demand Forecast at Waiuku Substation

Our development plan for Waiuku Substation Feeders is to:

- Upgrade 2.4km section of Glenbrook feeder and install voltage regulator in 2018/19 to increase backfeed capacity, with an estimated cost of \$400,000;

- Install a voltage regulator on Manukau Heads feeder in 2018/19 to increase backfeed capacity to the end section of the Te Toro feeder, with an estimated cost of \$260,000.
- Upgrade a total of 3.6km of Te Toro and Manukau Heads feeders, and install a second voltage regulator on Te Toro feeder in 2020/21 to increase backfeed capacity on the front sections of the two feeders, with an estimated cost of \$1.04 million;
- Install a second voltage regulator on Glenbrook feeder in 2020/21 due to identified load growth in Clarks Beach and Glenbrook Beach area, with an estimated cost of \$130,000;
- Rebuild the tie section of Waiuku Town and Te Toro feeders in 2021/22 to increase backfeed capacity to the Waiuku Town feeder, with an estimated cost of \$500,000; and
- Upgrade Glenbrook feeder to 22kV operation by 2023/24, with an estimated cost of \$1.7 million³⁰.

We considered the following alternative development options:

- Addressing capacity and voltage constraints using network configuration changes and voltage regulators, however these were not as effective as 22kV conversion given the length of the feeders and load centres; and
- Localised energy storage or distributed generation in strategic locations to assist with capacity (peak lopping) and improve voltage support, but this is not currently cost effective. Counties Power is trialling new technology options to understand the value they provide as well as actively following international developments in new technology. Should the cost of new technology continue to reduce, these options may become viable alternatives and will be considered as part of investment planning process.

Summary of Waiuku Development Plan

Description	Scope	Timing	Estimated Costs (\$'000)
Glenbrook feeder upgrade	Upgrade 2.4km of overhead section and install a new voltage regulator on Glenbrook feeder	2018/19	400
Voltage support upgrade on Manukau Heads feeder	Install voltage regulators on Manukau Heads feeder.	2018/19	260
Redevelop existing substation at Waiuku	Rebuild Waiuku zone substation at existing site in two stages	2018/19 – 2019/20	5800
Te Toro and Manukau Heads feeder capacity upgrade	Upgrade a total of 3.6km of Te Toro and Manukau Heads feeders, and install second voltage regulator on Te Toro feeder.	2020/21	1040
Glenbrook feeder voltage support upgrade	Install second voltage regulator on Glenbrook feeder	2020/21	130
Waiuku Town and Te Toro feeder tie section rebuild	Rebuild the tie section of Waiuku Town and Te Toro feeders along Kitchener Road	2021/22	500
Glenbrook feeder upgrade	Complete 22kV conversion of Glenbrook feeder	2023/24	1700

Table 6-22 Summary of Waiuku Development Plan

³⁰ To be carried out in conjunction with the 22kV conversion of the Waiau Pa feeder supplied from Karaka substation. Cost estimate for conversion of Waiau Pa feeder is listed in section 6.5.3.

6.5.5 Maoro Zone Substation

The Maoro 33/11kV Zone Substation is supplied by one 33kV circuit from Waiuku Zone Substation 33kV bus, and ultimately from the Glenbrook GXP. Maoro Zone Substation supplies 112 distribution substations in the rural area of Otaua, with a mix of residential and industrial load. The majority of the demand on this substation is used by a major consumer, NZ Steel, at their iron sands mine. Maoro is classed as a medium zone substation (S2) and is not compliant with our security criteria (refer to Table 6-1) for maintaining maximum demand for both first and second outages. We have a special arrangement with the major customer supplied from this substation for the reduced security on the line, however a transformer outage causes a capacity constraint.

Table 6-23 shows the winter maximum demand for Maoro substation and the distribution feeders from the substation.

11kV Feeders	Max. Dmd (MVA)	Projected Maximum Demand (MVA): Winter Peak															Avg. Annual Increase %
	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	
Otaua	1.4	1.4	1.4	1.4	1.4	1.4	1.4	1.4	1.4	1.4	1.4	1.4	1.4	1.4	1.4	1.4	0.0%
NZS Mine site & Pump Station 1	11.6	11.6	11.6	11.6	11.6	11.6	11.6	11.6	11.6	11.6	11.6	11.6	11.6	11.6	11.6	11.6	0.0%
Zone Substation	Max. Dmd (MVA)	Projected Maximum Demand (MVA): Winter Peak															Avg. Annual Increase %
	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	
Maioero	10.0	10.0	10.0	10.0	10.0	10.0	10.0	10.0	10.0	10.0	10.0	10.0	10.0	10.0	10.0	10.0	0.0%

Table 6-23 Winter Maximum Demand at Maoro Substation and Feeders

We do not anticipate any significant load growth in the area supplied from Maoro over the next ten years. NZ Steel has indicated that increased demand will be required at the mine site in the short term of approximately 650kVA. As such, only minor increases have been allowed for in the demand forecasts and an increase of this magnitude will not lead to any new constraints on the supply assets.

As Maoro is predominantly used for the supply to NZ Steel, and the Otaua feeder can be fully backfed from Waiuku (following conductor upgrades to address capacity and voltage constraints), the future of the NZ Steel site brings uncertainty into future investment decisions. As such any asset replacement will only be undertaken once agreed with NZ Steel through appropriate commercial arrangements, and the nature of work will be done to minimise stranded asset risk should NZ Steel cease their operation. A condition based refurbishment of the 33kV subtransmission line from Waiuku to Maoro will need to be undertaken if the line remains in service in the later part of the planning period as part of an asset renewal project detailed in section 5 Renewal and Maintenance.

Maoro Zone Substation Investment

The Maoro Zone Substation demand forecast is shown in Figure 6-22.

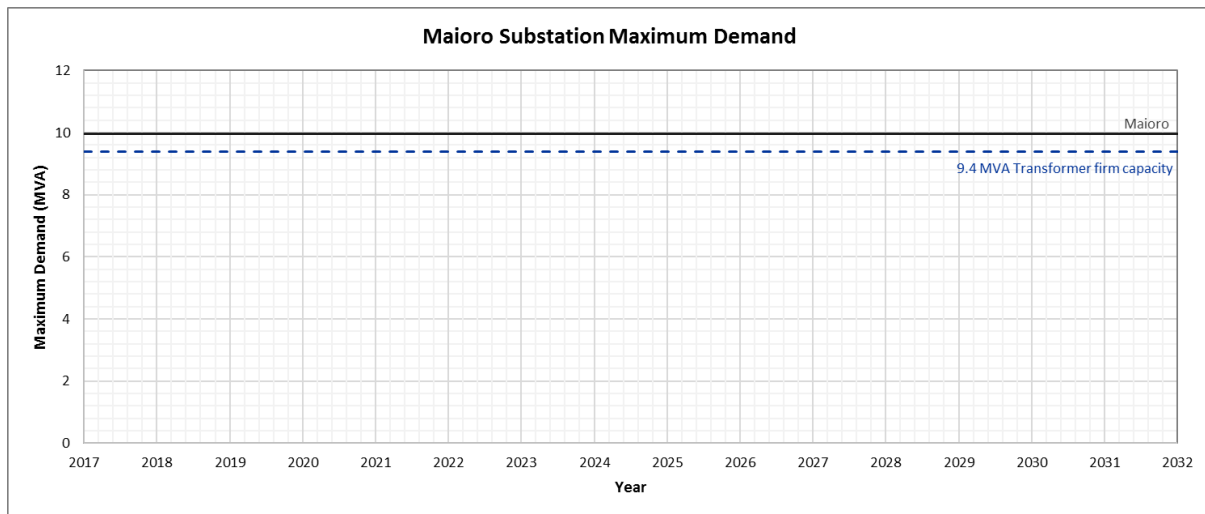


Figure 6-22 Maoro Zone Substation Demand Forecast

Two 33/11kV, 7.5 MVA transformers supply the load at Maoro, providing an n-1 capacity of 7.5 MVA (9.4MVA allowing for 25% short duration overload). The winter maximum demand already exceeds the firm capacity of the transformers.

The only material project in our development plan for Maoro Zone Substation is to replace the 11kV switchboard due to age and condition, which is detailed in Section 5.

Additionally, should the major customer require a higher level of firm capacity, closer to their demand of 10 MVA compared with the existing firm capacity of 9.4 MVA, we could relocate existing transformers to Maoro, most likely from Karaka. This expenditure has not been included in the plan.

We considered the following alternative development options:

- Replace the existing Maoro transformers and switchboard with new transformers and switchboard. This option presents higher risk due to asset stranding, and allows full utilisation of assets recovered from other sites which are not fully depreciated; and
- Installing storage or distributed generation to manage peak demand in n-1 situations where there is a transformer capacity shortfall, however this is not presently economic compared with relocating existing plant, and does not address age and condition risks.

Maoro Zone Substation Feeder Investment

Figure 6-23 shows the demand forecast of Maoro Substation feeders.

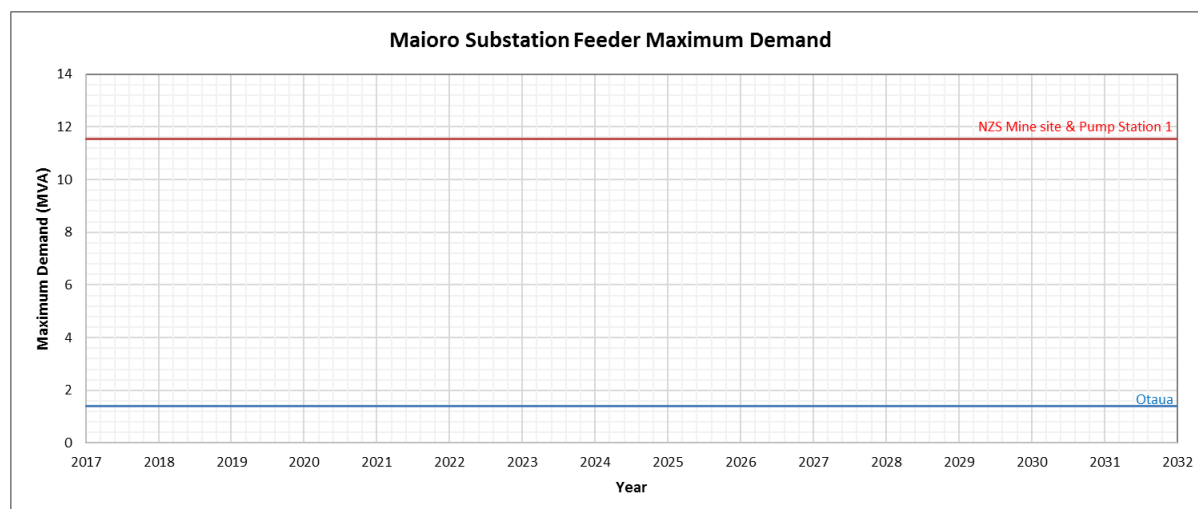


Figure 6-23 Feeder Demand Forecast at Maoro Zone Substation

Our development plan for Maoro Substation Feeders is to install a voltage regulator on Otaua feeder to increase backfeed capacity to Waiuku South feeder in 2021/22 at an estimated cost of \$130,000.

Summary of Maoro Development Plan

Description	Scope	Timing	Estimated Costs (\$'000)
Otaua feeder voltage support upgrade (Hoods Landing Road)	Install a voltage regulator on Otaua feeder	2021/22	130

Table 6-24 Summary of Maoro Development Plan

6.5.6 33kV Storey Road Point of Supply

Storey Road Point of Supply is supplied off the 33kV Maoro-Waiuku line and supplies No. 2 pump station on the New Zealand Steel slurry pipeline. We have no assets on this site apart from a 33kV disconnector. We do not expect any load growth from this point of supply and consider the existing arrangement adequate for the foreseeable future.

6.6 Summary of Capital Expenditure

Table 6-25 below summarises the projected costs for subtransmission and distribution system development.

Significant planning expenditure for the next ten years include:

Over the next five years,

- Feeder conductor upgrades and voltage regulator installations to address capacity and voltage performance constraints driven by load growth;
- Install a new 22kV distribution feeder and replace 22kV switchboard at Opaheke substation to increase backfeed capacity and reduce customer numbers on feeders;

- Upgrade existing 22kV distribution feeders from Opaheke substation to supply the Drury South Business Park;
- Install a new 22kV distribution feeder from Tuakau substation to supply Pokeno industrial area;
- Building a new 110kV Bombay area substation (including decommissioning the existing 33/11kV Ramarama and Mangatawhiri zone substations); and
- Rebuild the Waiuku substation to replace the existing substation due to capacity constraints, age and condition.

Over the following five years,

- Feeder conductor upgrades and voltage regulator installations to address capacity and voltage performance constraints driven by load growth;
- Build a new 110kV Drury South area substation and new 22kV distribution feeders to supply the Drury South Business Park; and
- Increasing transformer capacities at Opaheke and Tuakau substations.

All work programmes, financial profiles and actions described throughout this plan indicate the company's intentions based on the information presently available to it. They may be amended in response to new information. They are also subject to detailed study and verification in accordance with sound engineering practice and, in respect of financial expenditure, established processes for management and Board approval.

	FY2019	FY2020	FY2021	FY2022	FY2023	FY2024	FY2025	FY2026	FY2027	FY2028
Eastern Region										
Eastern Supply Project (Ramarama & Mangatawhiri)	1,000.0	10	4,450	5,850	-	-	-	-	-	-
Drury South Business Park	1,500.0	-	-	725	725	8,725	4,225	725	725	725
Pokeno Industrial Area	-	710	115	165	2,000	830	-	-	2,000	-
Opaheke Substation Supply Area	175.0	10	310	1,330	2,000	-	2,970	270	-	-
Pukekohe Substation Supply Area	-	75	50	350	50	50	50	7,950	50	50
Tuakau Substation Supply Area	2,685.0	900	400	-	-	-	-	-	-	-
Western Region										
Waiuku Substation Supply Area	2,660.0	3,850	1,170	500	1,200	1,700	-	-	-	-
Karaka Substation Supply Area	215.0	1,150	-	1,130	-	-	400	-	1,250	-
Maioiro Substation Supply Area	-	-	-	130	-	-	-	-	-	-
Network Wide										
Network Wide - System Automation	50.0	150	150	150	150	150	150	150	150	150
Quality of Supply - Voltage	350.0	350	350	350	350	350	350	350	350	350
Total	8,635	7,205	6,995	10,680	6,475	11,805	8,145	9,445	4,525	1,275

Table 6-25 Projected Expenditure for Subtransmission and Distribution System Development

Note: Forecasts are stated in real (constant) prices

7 Non-network Investment Plan

In addition to the planned maintenance, renewal and development of network assets detailed in Section 5 and Section 6. We have identified expenditure requirements on Non-Network assets including our Information Technology hardware and software, our tools and equipment, as well as our vehicle fleet.

Information Technology Upgrades and Replacement

The following major systems upgrades have been identified and requiring capital investment in the short to medium term of the plan. Other minor systems are expected to require replacement or upgrade during the planning period, however their cost is not material in terms of the Non-Network Investment Forecast.

Function	System	Year	Estimated Cost ('000s)
ERP Upgrade	Upgrade of the Microsoft NAV Dynamics platform from 2009 to 2017.	2018/19	150
Geospatial Information	Upgrade Smallworld	2018/19	175
Digital & Mobility Transformation	Application of digital technology across all business functions	2018/19	350
Asset Management	System to manage assets through their lifecycle ³¹	2018/19	105
Customer Relationship Management	System to manage and analyse customer interactions and data throughout the customer lifecycle	2018/19	120
Routine Replacement			
Core Network Infrastructure	Network Infrastructure such as switches, servers, UPS, etc. to maintain network reliability.	3-5 year replacement cycle	100 per annum
PCs, Laptops and Field Mobile Devices	Replacement of devices to ensure fit for purpose	2-4 year replacement cycle	65 per annum

³¹ scoping of the Asset Management application system will consider migration of asset survey and vegetation management records from the Microsoft Dynamics NAV system as part of asset lifecycle record consolidation.

Tools and Equipment

Our non-network expenditure forecasts allow for the ongoing replacement of tools and equipment used by our teams. It is also expected that new test and inspection equipment will be purchased in 2018/19 to support the maintenance programme, including thermal imaging equipment.

Vehicle Fleet and Machinery

We own our fleet of light and heavy vehicles, as well as field machinery such as excavators and directional drilling machines, along with their transport trailers.

Our expenditure forecasts allow for the replacement of these as required through the planning period, as well as operational expenditure for the ongoing maintenance to ensure safety and reliability.

Expenditure Forecast (\$000)	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028
Capital Expenditure										
Total	2,450	2,450	2,350	2,350	2,350	2,350	2,350	2,350	2,350	2,350

Note: Forecasts are stated in real (constant) prices

8 Expenditure Summary

This section provides a summary of the forecast expenditure from the three investment sections – Renewals and Maintenance, Network Development and Non-Network.

8.1 Capital Expenditure Summary

8.1.1 Renewal and replacement expenditure

Note: Forecasts are stated in real (constant) prices

Asset Category	FY2019	FY2020	FY2021	FY2022	FY2023	FY2024	FY2025	FY2026	FY2027	FY2028
Subtransmission network	50	50	50	50	50	50	500	500	50	50
Mauro Line Refurbishment							450	450		
Other Subtransmission Renewal	50	50	50	50	50	50	50	50	50	50
Zone Substations	150	50	50	50	50	50	400	50	50	50
Zone Substation switchgear										
Other Zone Substation Renewal	150	50	50	50	50	50	50	50	50	50
Distribution and LV lines	7,550	7,140	6,870	6,730	6,380	6,640	6,320	6,380	6,610	6,460
Distribution poles and crossarms										
Overhead Renewals	3,910	3,480	3,480	3,480	3,480	3,430	3,430	3,430	3,430	3,430
Distribution conductor										
Copper Replacement Programme	2,050	1,740	1,440	1,470	1,230	1,660	1,220	1,200	1,580	1,220
Swan Replacement Programme	710	1,050	1,200	1,200	1,170	1,080	1,110	1,200	920	1,210
HV Feeder section replacement	500	550	350	200	200	200	200	200	200	200
Urban LV Replacement	280	220	300	280	200	170	260	250	380	300
Overhead Safety Compliance	100	100	100	100	100	100	100	100	100	100
Distribution and LV cables	370	380	390	400	410	360	370	380	390	400
Distribution and LV cables Renewal	200	200	200	200	200	150	150	150	150	150
LV Pillar Renewal	170	180	190	200	210	210	220	230	240	250
Distribution substations and transformers	590	730	590	590	590	730	660	660	660	450
Distribution transformers										
Transformer Renewal Programme	590	730	590	590	590	730	660	660	660	450
Distribution switchgear	1,350	1,810	1,980	1,210	1,190	1,460	1,570	1,580	1,370	700
RMU replacement	750	1,210	1,380	810	810	1,160	1,270	1,280	1,070	400
Overhead switchgear replacement	600	600	600	400	380	300	300	300	300	300
Other System Fixed Assets	335	890	505	150	140	170	190	155	150	140
Capacitors and Voltage regulators										
Voltage regulator replacement		150								
Protection										
New AUFLS/Extended Reserves Relays		400								
Protection relays replacement and upgrade	40		200							
SCADA Master Station Renewal		150	150							
RTU Replacement	75	70	25	20	20	40	30	25	30	10
Battery banks	120	20	30	30	20	30	60	30	20	30
Other protection, control and radio communications re	100	100	100	100	100	100	100	100	100	100
Subtotal	10,395	11,050	10,435	9,180	8,810	9,460	10,010	9,705	9,280	8,250
Capitalised Maintenance	900	900	900	900	900	900	900	900	900	900
Total	11,295	11,950	11,335	10,080	9,710	10,360	10,910	10,605	10,180	9,150

8.1.2 Network development expenditure

	FY2019	FY2020	FY2021	FY2022	FY2023	FY2024	FY2025	FY2026	FY2027	FY2028
Eastern Region										
Eastern Supply Project (Ramarama & Mangatawhiri)	1,000	10	4,450	5,850	-	-	-	-	-	-
Drury South Business Park	1,500	-	-	725	725	8,725	4,225	725	725	725
Pokeno Industrial Area	-	710	115	165	2,000	830	-	-	2,000	-
Opaheke Substation Supply Area	175	10	310	1,330	2,000	-	2,970	270	-	-
Pukekohe Substation Supply Area	-	75	50	350	50	50	50	7,950	50	50
Tuakau Substation Supply Area	2,685	900	400	-	-	-	-	-	-	-
Western Region										
Waiuku Substation Supply Area	2,660	3,850	1,170	500	1,200	1,700	-	-	-	-
Karaka Substation Supply Area	215	1,150	-	1,130	-	-	400	-	1,250	-
Maioiro Substation Supply Area	-	-	-	130	-	-	-	-	-	-
Network Wide										
Network Wide - System Automation	50	150	150	150	150	150	150	150	150	150
Quality of Supply - Voltage	350	350	350	350	350	350	350	350	350	350
Total	8,635	7,205	6,995	10,680	6,475	11,805	8,145	9,445	4,525	1,275

8.1.3 Customer programme expenditure

	FY2019	FY2020	FY2021	FY2022	FY2023	FY2024	FY2025	FY2026	FY2027	FY2028
Customer Connections	10,000	10,000	10,000	10,000	10,000	8,000	8,000	8,000	8,000	8,000
Asset Relocations	3,225	300	300	300	300	300	300	300	300	300
Total	13,225	10,300	10,300	10,300	10,300	8,300	8,300	8,300	8,300	8,300
<i>less Customer Contributions of</i>	<i>8,000</i>	<i>8,000</i>	<i>8,000</i>	<i>8,000</i>	<i>8,000</i>	<i>6,400</i>	<i>6,400</i>	<i>6,400</i>	<i>6,400</i>	<i>6,400</i>

8.1.4 Non-network investment

	FY2019	FY2020	FY2021	FY2022	FY2023	FY2024	FY2025	FY2026	FY2027	FY2028
Non Network Total	2,450	2,450	2,350	2,350	2,350	2,350	2,350	2,350	2,350	2,350

8.1.5 Total capital expenditure by disclosure category

	FY2019	FY2020	FY2021	FY2022	FY2023	FY2024	FY2025	FY2026	FY2027	FY2028
Consumer Connections	10,000	10,000	10,000	10,000	10,000	8,000	8,000	8,000	8,000	8,000
System Growth	6,990	6,460	6,445	10,130	5,925	11,255	7,595	8,895	3,975	725
Asset Replacements	11,295	11,550	11,335	10,080	9,710	10,360	10,910	10,605	10,180	9,150
Asset Relocations	3,225	300	300	300	300	300	300	300	300	300
Reliability, Safety and Environment										
Quality of Supply	1,350	350	350	350	350	350	350	350	350	350
Legislative and Regulatory	-	400	-	-	-	-	-	-	-	-
Other Reliability, Safety, Environment	295	395	200	200	200	200	200	200	200	200
Subtotal Network	33,155	29,455	28,630	31,060	26,485	30,465	27,355	28,350	23,005	18,725
WIP carry-over from FY2018 to FY2019	2,761	-	-	-	-	-	-	-	-	-
WIP carry-over from FY2019 to FY2020	-	2,000	-	-	-	-	-	-	-	-
Non Network	2,450	2,450	2,350	2,350	2,350	2,350	2,350	2,350	2,350	2,350
TOTAL	36,366	33,905	30,980	33,410	28,835	32,815	29,705	30,700	25,355	21,075

Note: Forecasts are stated in real (constant) prices

8.2 Operating Expenditure Summary

8.2.1 Network operating expenditure by asset category

Asset Category	FY2019	FY2020	FY2021	FY2022	FY2023	FY2024	FY2025	FY2026	FY2027	FY2028
Subtransmission network	190	170	120	120	120	120	120	120	120	120
Subtransmission lines	190	170	120	120	120	120	120	120	120	120
Subtransmission cables	-	-	-	-	-	-	-	-	-	-
Zone Substations	520	430	420	430	420	420	420	420	420	420
Zone Substation transformers	190	150	140	100	100	100	100	100	100	100
Zone Substation switchgear	120	120	120	120	110	110	110	110	110	110
Zone Substation other equipment	70	70	70	120	120	120	120	120	120	120
Zone Substation buildings and grounds	140	90	90	90	90	90	90	90	90	90
Distribution and LV lines	910	810	810	710	710	610	610	610	610	610
Distribution poles and crossarms	840	740	740	640	640	540	540	540	540	540
Distribution conductor	50	50	50	50	50	50	50	50	50	50
Fault indicators and Earthing	20	20	20	20	20	20	20	20	20	20
Distribution and LV cables	280	280	280	280	280	280	280	280	280	280
Distribution and LV cables	150	150	150	150	150	150	150	150	150	150
LV Pillars	130	130	130	130	130	130	130	130	130	130
Distribution substations and transformers	250	250	250	250	250	250	250	250	250	250
Distribution transformers	250	250	250	250	250	250	250	250	250	250
Distribution switchgear	400	390	390	370	370	390	390	400	400	410
Ring main units	110	120	120	130	130	150	150	160	160	170
Overhead switchgear	290	270	270	240	240	240	240	240	240	240
Other System Fixed Assets	350	340	330	330	350	340	340	330	340	360
Capacitors and Voltage regulators	20	20	20	20	20	20	20	20	20	20
Protection	150	140	130	130	150	140	140	130	140	160
Load control equipment	50	50	50	50	50	50	50	50	50	50
Battery banks	20	20	20	20	20	20	20	20	20	20
SCADA and Communications	110	110	110	110	110	110	110	110	110	110
Vegetation	1,100	1,100	1,100	1,100	1,100	1,100	1,100	1,100	1,100	1,100
Vegetation	1,100	1,100	1,100	1,100	1,100	1,100	1,100	1,100	1,100	1,100
Public Safety Services	150	150	150	150	150	150	150	150	150	150
Public Safety Services	150	150	150	150	150	150	150	150	150	150
Faults and Reactive Maintenance	1,900	1,900	1,900	1,900	1,900	1,900	1,900	1,900	1,900	1,900
Faults	1,900	1,900	1,900	1,900	1,900	1,900	1,900	1,900	1,900	1,900
Capitalisation	- 900	- 900	- 900	- 900	- 900	- 900	- 900	- 900	- 900	- 900
less Capitalised Maintenance	- 900	- 900	- 900	- 900	- 900	- 900	- 900	- 900	- 900	- 900
Total	5,150	4,920	4,850	4,740	4,750	4,660	4,660	4,660	4,670	4,700

8.2.2 Network operating expenditure by disclosure category

Asset Category	FY2019	FY2020	FY2021	FY2022	FY2023	FY2024	FY2025	FY2026	FY2027	FY2028
Service interruptions and emergencies	1,900	1,900	1,900	1,900	1,900	1,900	1,900	1,900	1,900	1,900
Vegetation management	1,100	1,100	1,100	1,100	1,100	1,100	1,100	1,100	1,100	1,100
Routine and corrective maintenance and inspection	1,350	1,350	1,350	1,370	1,370	1,380	1,380	1,380	1,380	1,380
Asset replacement and renewal	800	570	500	370	380	280	280	280	290	320
Total	5,150	4,920	4,850	4,740	4,750	4,660	4,660	4,660	4,670	4,700

Note: Forecasts are stated in real (constant) prices

9 Evaluation of Performance

9.1 Performance against previous plan

Assessing performance against previous plans is a part of our continual improvement in asset management and overall business performance.

This section provides an assessment of performance against the last complete financial year (FY2017) as well as comparing against the forecast performance of the current financial year at the time of writing.

Our financial year runs from 1 April to 31 March, which aligns with the regulatory year.

Network performance and other service levels are compared against previous targets in Section 3 – Service Levels.

9.1.1 Financial performance FY2017 Plan to Actual

Capital expenditure FY2017

Disclosure Categories	Target (\$000)	Actual (\$000)	Variance	Reasons for variance
Consumer Connection	6,300	8,693	38%	Consumer connection expenditure was 38% above forecast. The variance was due to a higher than expected volume of new subdivisions. The forecast was based on the previous year's average and adjusted for known projects.
System Growth	3,700	2,890	(22%)	System growth expenditure was 22% below forecast due to the carryover of the Otua and Waiuku Sth feeder reinforcement projects.
Asset Replacement and Renewal	5,868	5,741	(2%)	Asset replacement and renewal expenditure was 2% below forecast but within expected budget.
Asset Relocations	180	201	12%	Asset relocations expenditure is 12% above forecast due to a higher than expected volume of asset relocation requests. The forecast was based on the expected volumes and adjusted for known major projects.
Other reliability, safety and environment	1,960	872	(56%)	Other reliability, safety and environment was 56% below forecast due to the deferral of Tuakau Industrial Power Quality Project.
TOTAL	18,008	18,397	2%	

Operational expenditure FY2017

Disclosure Categories	Target (\$000)	Actual (\$000)	Variance	Reasons for variance
Service interruptions and emergencies	1,300	1,815	40%	Service interruptions and emergencies was 40% above target due to an abnormally high number of storm events in FY2017.
Routine and corrective maintenance and inspection	2,120	2,654	25%	Routine and corrective maintenance and inspection includes an extraordinary \$500k for the pole audit that was not included in the original budget.
Asset replacement and renewal	600	773	29%	Asset Replacement and Renewal was 11% above forecast due to a one-off transformer relocation at Karaka substation due to condition issues.
System operations and network support	2,201	2,365	7%	System operations and network support increase due to higher than expected network growth and the resources to support it.
Business support	5,654	5,488	(3%)	Variance not material
TOTAL	11,875	13,095	10%	

9.1.2 Project performance FY2017 Plan to Actual

Project	Scope	Project Budget (\$000)	Actual completion
Otaua Road rehabilitation	Feeder reconductoring	376	\$24k completed in FY2017. Carried over and completed in FY2018.
Racecourse Feeder upgrade	Undergrounding of Sandspit Rd	870	\$693k completed in FY2017. Carried over and completed in FY2018.
Port Waikato Feeder Conversion and River Crossing	22kV conversion	490	\$460k completed in FY2017. Carried over and completed in FY2018.
Church Corner feeder conversion	22kV conversion	809	\$770k completed in FY2017. Carried over and completed in FY2018.
Hull Road and Kidd Road rehabilitation	Rehabilitation works	455	\$355k completed in FY2017. Carried over and completed in FY2018.
Onewhero Feeder Conversion St2	22kV conversion	750	Completed in FY2017
Replacement of 33kV CB at Karaka Substation	Replace 33kV CB at Karaka substation	200	\$125k completed in FY2017. Carried over and completed in FY2018.
Pukekohe substation protection relays replacement	Upgrade Protection at Pukekohe Substation. Replacement of Alstom K series relays	250	\$124k completed in FY2017. Carried over and completed in FY2018. Revised budget \$436k.

Project	Scope	Project Budget (\$000)	Actual completion
Bombay -Tuakau 110kV line corridor visual mitigation measure	Landscaping and pole relocation as visual mitigation measures for the Bombay - Tuakau 110kV line corridor.	300	Deferred for completion in FY2019 due to delays in finalising requirements with rail corridor authority and land owner. Revised budget \$175k.
Completion of Tuakau Feeder conversion	Conversion works in Tuakau area	170	Deferred for completion in FY2018. Revised budget \$375k.
Reconductor Glenbrook to Waiuku West line	Reconductor 660m of the concrete pole line	140	Completed in FY2017
Blackbridge School copper conductor rehabilitation	Reconductoring along Blackbridge school	213	Completed in FY2017
Paparimu School copper conductor rehabilitation	Reconductoring along Paparimu school	180	Completed in FY2017
Oram Road Line Stage 1	Decommissioning of the 110kV line (pole sections)	150	Completed in FY2017
Bombay AUFLS relay replacement	Replacement of AUFLS relays at Bombay GXP	60	Deferred to FY2018, but subsequently cancelled due to change in requirements for extended reserves.
Bombay Feeder RMUs replacement	Replacement of RMUs and transformers on Bombay Feeder (Raventhorp site)	570	Deferred for completion in FY2019 due to delay in land owners approval.
Papakura South RMUs replacement	Replacement of RMUs at Papakura South Feeder	645	Completed in FY2017
Karaka T1 transformer replacement	Replace T1 transformer at Karaka with ex-Tuakau transformer	121	Completed in FY2017
Port Waikato (township) underground rehabilitation	Rehabilitation of LV and HV assets along Maunsell Rd, Port Waikato	720	\$656k completed in FY2017. Carried over and completed in FY2018.
Russell Avenue LV rehabilitation	Rehabilitation (undergrounding) of LV network along Russell Ave, Pukekohe	240	\$158k completed in FY2017. Carried over and completed in FY2018.
George Street LV rehabilitation	Rehabilitation (undergrounding) of LV network along George Street, Waiuku	160	Completed in FY2017

9.1.3 Financial performance FY2018 Plan to Forecast

Forecast capital expenditure FY2018

Disclosure Categories	Target (\$000)	Forecast (\$000)	Variance	Reasons for variance
Consumer Connection	7,700	12,035	56%	The expected variance is due to a higher than expected volume of new subdivisions (2,000 lots versus forecasted 1,300 lots) and industrial developments.
System Growth	2,290	1,600	(30%)	The expected variance is due to deferral of the Great South Road Feeder upgrade, and Port Waikato feeder capacity upgrade projects.
Asset Replacement and Renewal	7,459	5,232	(30%)	The expected variance is due to lower levels of asset renewal arising from identified defects, deferral of the Bombay Feeder RMUs replacement (Raventhorp) and low voltage rehabilitation projects, and the Hingaia Feeder conductor replacement project.
Asset Relocations	300	637	112%	Variance is due to the 110kV line relocation for Drury South business park development.
Other reliability, safety and environment	2,625	1,180	(55%)	The expected variance is due to deferral of the Whangarata and Hitchen Road feeders (front end sections) rebuild, and the 110kV line visual impact mitigation project.
WIP (Carry In)	1,302	1,793	38%	The expected variance is due to higher than estimated volume of carried over from FY2017 to FY2018.
Total	21,676	22,477	4%	

Forecast operational expenditure FY2018

Disclosure Categories	Target (\$000)	Forecast (\$000)	Variance	Reasons for variance
Service interruptions and emergencies	1,700	1,939	14%	The expected variance is due to high volumes of faults during winter and high numbers of vehicle versus pole events.
Routine and corrective maintenance and inspection	2,000	2,091	4%	Variance not material
Asset replacement and renewal	806	886	9%	The expected variance is due to additional replacement and renewal of identified asset defects.
System operations and network support	2,836	3,063	8%	The expected variance is due to increased staffing resources to support network growth.
Business support	5,617	5,399	(4%)	Variance not material
Total	12,959	13,378	3%	

9.1.4 Project performance FY2018 Plan to Actual

Project	Scope	Project Budget (\$000)	Expected completion
Otaua Road rehabilitation	Rehabilitation of hard wood poles and copper conductor	476	FY2018
Racecourse Feeder upgrade	Undergrounding of Sandspit Rd	870	FY2018
Port Waikato Feeder Conversion and River Crossing	22kV conversion	490	FY2018
Church Corner feeder conversion	22kV conversion	809	FY2018
Hull Road and Kidd Road rehabilitation	Rehabilitation works	455	FY2018
Hingaia Feeder Swan conductor replacement	Swan conductor replacement	140	Deferred to align with subdivision work in the area
Replacement of 33kV CB at Karaka Substation	Replace 33kV CB at Karaka substation	200	FY2018
Pukekohe substation protection relays replacement	Upgrade Protection at Pukekohe Substation. Replacement of Alstom K series relays	250	FY2018
Cape Hill Swan conductor replacement	Swan conductor replacement	65	FY2018
Tuakau Urban LV replacement (Harrisville Rd & Jellicoe Ave)	Rehabilitation of LV assets along Harrisville and Jellicoe Ave, Tuakau	357	FY2018

Project	Scope	Project Budget (\$000)	Expected completion
Pukekohe Urban LV replacement (Lawrie Ave)	Rehabilitation of LV assets along Lawrie Ave, Pukekohe	250	FY2018
Glen Murray Feeder (Chapman Rd) Swan conductor replacement	Reconductoring along Chapman Rd, Glen Murray	930	FY2018
Pukekohe ripple plant converter replacement	Replacement of ripple plant converter at Pukekohe Substation	100	FY2018
Ararimu Feeder (Sinclair Rd) HV section replacement	Replacement of HV conductor along	150	FY2018
Fibre communication link between Opaheke and Bombay	Establishment of fibre communication link between Opaheke and Bombay substations	60	FY2018
Patumahoe Feeder (Mauku Rd) Copper conductor replacement	Reconductoring along Mauku Rd, Patumahoe	405	FY2018
Blackbridge Feeder (Muir Rd) Copper conductor replacement	Reconductoring along Muir Rd, Blackbridge feeder.	150	FY2018
Bombay Feeder RMUs replacement	Replacement of RMUs and transformers on Bombay feeder (Raventhorp site)	570	\$100k completed in FY2018. Carry over for completion in FY2019 due to delay in land owner approvals.
Whangarata and Hitchen Road Feeders (Front end sections) rebuild	Rebuild front end sections of Whangarata and Hitchen Rd feeders along Whangarata road	990	\$50k completed in FY2018. Carried over for completion in FY2019 due to delay in design to address site specific constraints.
Bombay -Tuakau 110kV line corridor visual mitigation measure	Landscaping and pole relocation as visual mitigation measures for the Bombay - Tuakau 110kV line corridor.	175	\$11k completed in FY2018. Carried over for completion in FY2019 due to delays in finalising requirements with rail corridor authority and land owner.
Rebuild Te Toro feeder (Eastern King Street) replacement	Rebuild Te Toro feeder along swimming pool complex on Eastern King Street	173	FY2018
Bombay AUFLS relay replacement	Replacement of UF relays at Bombay	60	Deferred from FY2017 to FY2018, but subsequently cancelled by utilising functions of existing relays.
Port Waikato feeder backfeed capacity upgrade	Upgrade auto-transformer and install voltage regulator on Port Waikato feeder	400	Deferred to FY2020 due to slower rate of load growth.
Pokeno Church Feeder upgrade	Installation of second Autotransformer at Mangatawhiri Substation	110	FY2018
Waiau Pa Feeder (Waiau Pa Road) upgrade	Upgrade a section of Waiau Pa feeder along Waiau Pa Road	525	FY2018
Improve supply reliability for residential load on rural feeders	Installation of an additional gas switch at Titi Mauku feeder	50	FY2018

Project	Scope	Project Budget (\$000)	Expected completion
Improve supply reliability on Anchor Factory Feeder	Upgrade two sectionalisers and install a third sectionaliser on Anchor Factory feeder	100	FY2018
Improve supply reliability for residential load on Railway Feeder	Install cables between two transformers on Railway feeder to allow transfer of feeder section with high density of residential load to Buckland feeder.	100	Carried over for completion in FY2019. Revised budget of \$100k from \$250k due to change in scope to address site specific constraints from other underground services.
Great South Road Feeder (Quarry Rd and Hillview Rd) feeder upgrade	Reconductoring sections of Great South Road feeder along Quarry Road and Hillview Road	803	\$633k completed in FY2018. Carried over for completion in FY2019 due to delay in landowner approval.
Hingaia Feeder capacity reinforcement	Additional system growth project to install high voltage cable replacement along Hingaia Road to increase Hingaia feeder backfeed capacity	244	\$200k completed in FY2018. Carried over for completion in FY2019 due to dependency with subdivision works along Hingaia Road.
Distribution fault anticipation (DFA) devices at Mangatawhiri, Tuakau, and Pukekawa substations	Install DFA devices to enhance monitoring and fault cause analysis at Mangatawhiri substation	260	\$150k completed in FY2018. Carried over for completion in FY2019 due to a delay in equipment delivery.

10 Appendices

Appendix A – Plan assumptions

Subject	Assumption	Basis for Assumption	Potential Impact of Uncertainty, if any	Level of Impact
Regulatory Environment	We assume for the purpose of this plan, that existing external regulatory and legislative requirements remain unchanged throughout the planning period. Therefore, the external drivers which influence reliability targets and design, environmental, health and safety standards and industry codes of practice are constant throughout the AMP period.	Regulatory requirements are likely to change, requiring Counties Power to achieve different service standards. This could also impact on the availability of funds for asset management arising from changes to allowance revenue, the extent and impact of future changes cannot be assessed at this point and future plans will allow for any updated regulatory requirements. We note new legislation particularly Safety Legislation, Worksafe, and the industry position on Live Work being key changes we have incorporated. We also note that the Input Methodologies (IMs) will be reviewed in the short term which may have an impact on price and quality standards.	It is unlikely that the regulatory and legislative impost will reduce, thus the most likely impact is an increase in forecast expenditure to meet possible increased standards. Changes to Part 4 Regulations, in particular the allowable WACC, and the treatment of expenditure (CAPEX, OPEX, TOTEX) may lead to alternative investment decisions being made.	High
Transpower Policies (Grid owner perspective)	We assume that Transpower will continue to provide grid supply, and undertake projects to meet grid capacity and security requirements, and to meet our development needs and customer service expectations. The costs of maintaining these service levels are passed directly through to customers.	There is no indication of a change of policy or purpose from Transpower. Change is unlikely in the short to medium term. Transpower continues to provide sufficient capacity to meet Counties Power's requirements at the existing GXPs and undertakes the additional investment required to meet additional future demand.	The most likely impact is an increase in Transpower charges to meet possible increased standards.	Low

Subject	Assumption	Basis for Assumption	Potential Impact of Uncertainty, if any	Level of Impact
Demand Side Management and Peak Control	We assume that the industry will increasingly recognise the importance of demand side management and peak control, resulting in the recognition and support for demand-based charging system by regulators.	Increased power system efficiency and minimisation of investment comes largely by minimising peak demand. We see there will be value in demand side management and peak control such as lower transmission and distribution charges. Reduced levels of long term investment are required leading to a lower overall lower cost to serve. This may also provide new revenue streams and opportunities.	Ineffective peak demand management could impact on future transmission pricing if we cannot minimise the offtake from the grid relative to other users. Demand forecasts may be higher or lower than forecast if peak demand management changes, changing the time and nature of investment.	Medium
Distributed Generation	We assume that no newly sited significant embedded generation is commissioned during the planning period and current generators continue to develop based on the existing regulations. We expect to see a steady increase in small scale DG, but not of a significant scale to affect network demand and growth forecasts in the short to medium term.	This assumption is based on current industry position around large-scale generation development (no large-scale developments, closure of some generation plant). Increasing uptake of micro DG (domestic solar) leads to our view that this will continue over the planning period.	Could require significant unplanned capital investment in the network, but would be economically justified by a return on new assets or lower cost alternatives available to address network constraints or alter timing. DG in highly loaded parts of the network, could reduce peak demand, and thus lower future investment requirements. Strong growth in DG in localised areas could also lead to power quality issues.	Medium

Subject	Assumption	Basis for Assumption	Potential Impact of Uncertainty, if any	Level of Impact
Emerging technologies	We assume that there will be no large-scale energy storage systems (batteries) or accelerated uptake of Electric Vehicles (EV) during the planning period. We expect to see a steady increase in small scale energy storage system and low EV uptake as technology continues to improve and costs reduce, but not of a significant scale to affect network demand and growth forecasts in the short to medium term.	This assumption is based on our current understanding around large-scale energy storage system and EV uptake rate.	Could require significant unplanned capital investment in the network, but would be economically justified by a return on new assets or lower cost alternatives available to address network constraints or alter timing. EVs in highly loaded parts of the network, could increase peak demand causing constraints, and thus increase future investment requirements.	Medium
Growth in Demand	Growth in demand at each GXP is predicted to follow a linear growth, with high year on year growth compared to the long-term average. Step change scale growth may occur due to large scale developments.	Recent historical growth shows a linear trend over the long term, but with recent high growth year on year (approx. 2.5% p.a.). Large scale developments could lead to larger than average growth in isolated areas, but not likely to be 'step-change' in scale, unless large industrial and processing loads appear.	Extent of load growth will impact upon demand forecasts and timing of investments (brought forward, or deferred), and the nature of investment made.	Low
Load profiles	Seasonal load profiles remain consistent with recent historical trends, for both winter-peaking and summer-peaking feeders.	No noticeable change in demand type (predominantly residential peak demand) in each network region over the short term. Changes could arise from higher industrial load as a percentage of total demand (less seasonal) and increases of consumer side products such as heat pumps, operating air conditioning in summer and Solar PV installations.	Seasonal shifts in demand could require planned capacity upgrades to be accelerated or delayed. Increased levels of peak demand management required outside conventional periods.	Low

Subject	Assumption	Basis for Assumption	Potential Impact of Uncertainty, if any	Level of Impact
Climate Change	The Counties Power network is exposed to normal climatic variation over the planning period including temperature, wind and rain variances consistent with its experiences since 2000 which have shown an increase in the frequency and severity of weather events.	Forecasts are based on normal climatic variations with an increasing trend of adverse weather.	More extreme weather could result in higher levels of equipment failure and major repairs and replacements required which are not currently provided for in expenditure forecasts. It will also have an impact on network performance metrics (SAIDI, SAIFI, Faults per 100kms)	Medium
Demand Diversity/ New Loads	The demand diversity remains generally unchanged throughout the planning period, with a predominantly residential base. We assume that Drury South Business Park adds 10 to 30MVA and Pokeno Industrial area adds 10 to 20MVA of demand increasing the commercial and industrial load. We assume changing load profiles over time, potentially more 'peaky' if effective demand side options are not implemented	We continue to experience strong residential growth, and an increasing level of commercial and industrial load, but with a relatively constant level of diversity.	New loads will impact on demand growth, and change the timing of development projects. Specific new investments may also be required to meet large new loads. More industrial/commercial could change the load profile of the network.	Medium

Subject	Assumption	Basis for Assumption	Potential Impact of Uncertainty, if any	Level of Impact
Customer Expectations	Establishment of service levels continue to be through consultation with stakeholders and remain a balance between customer needs, price-quality trade-offs and industry best practice. Performance targets are driven by customer consultation indications. We expect increased performance expectations from our consumers for voltage stability, power quality, and minimising the effect of network operations on different equipment installed in customer premises.	Customers could change their demands for reliability or their willingness to pay for different levels of service; it is expected that customers' expectations will increase as the quality of supply improves, and their dependence upon high quality electricity supply increases (particularly industrial customers).	Customers could change their demands for service and willingness to pay resulting in either higher or lower service targets and associated expenditures to deliver those targets.	Medium
Land Zoning	Zoning for land use purposes remains unchanged (from our current knowledge) during the planning period.	The Auckland Unitary Plan, the Rural-Urban Boundaries, and the Waikato District Plan provide clear direction of which areas growth and land re-zoning will be focussed in. We have allowed for changes that are known and publicly available.	Zone changes will impact on demand growth. The implications of uncertainty for demand growth are noted above.	Low
Pricing	It has been assumed that the present pricing structures will be followed in the short term, which will evolve in the medium term to more cost reflective demand and capacity based pricing. This will promote demand side management, encourage distributed generation and reflect asset values/costs.	The assumption is based on the regulators and stakeholders encouraging efficient network development and for revenues to reflect cost drivers.	The present pricing structure does not promote demand side management and a move to capacity based pricing protects revenue against movements in energy demand such as greater uptakes of micro domestic generation and storage technology.	Medium

Subject	Assumption	Basis for Assumption	Potential Impact of Uncertainty, if any	Level of Impact
Inflation Rate	It has been assumed that inflation will affect the annual forecast expenditure though the planning period. (All projections of expenditure are adjusted for inflation.)	The rate of inflation for cost increases has been based on projections sourced from financial institutions, which are based on CPI figures. In reality over time input costs (including those sourced from outside of New Zealand) for asset management activities will change at rates greater or less than the rate of general inflation. As expenditure forecasts are updated annually, this approach is acceptable and consistent with that prescribed.	Forward estimates are based on an inflation rate of 2%. Higher inflation will mean higher costs in dollar terms. Lower inflation will give the reverse. (The inflation referred to is that associated with the renewal and construction of distribution networks, not general inflation).	Medium
Funding for Continued Growth	It has been assumed the cost of developing the network for growth and customer connections will be financed by the additional income from the network customers plus contributions from customers for new connections.	The pricing structure is based on current company policy.	If growth does not go ahead, the expenditure for customer connections and growth as detailed in the long-term plan would reduce. Requirements for network development investment would reduce with lower consumer growth.	Medium

Subject	Assumption	Basis for Assumption	Potential Impact of Uncertainty, if any	Level of Impact
Asset Renewals	We assume that asset replacements will be driven by condition based risk, or asset health indices, rather than outright age. We expect assets in coastal areas to be renewed more frequently than those inland. We expect that increased focus on capital utilisation and consideration of depreciation, asset stranding and asset write downs will be part of our internal, and regulator driven investment process.	The projected Asset Replacement and Renewal programme is based upon the known condition and defect information gathered during annual asset inspections, together with estimated failure rates for assets of a specific age profile. We will improve our condition assessment processes and develop 'Health Index' processes to further refine our renewal investments.	Identification of specific asset issues may cause increased expenditure for certain asset classes within future years in which immediate replacement or removal from operation will incur costs.	Low
Major Customers	We assume all major customers, including NZ Steel (described separately below) continue at similar rates; that Drury South Business park will add 10 to 30MVA and Pokeno industrial area will add 10 to 20MVA of extra demand during the planning period; and that Envirowaste generation will remain at current levels.	Economic conditions are favourable and we make our assumptions based on facts from customers and publicly available information.	Changes to major customer demands will have a material impact on our network demand forecasts, either higher or lower demand, which may change the timing of investments. Decrease in demand will impact on revenue. Reductions in demand will affect network utilisation, may strand assets, and will have an impact on asset replacement decisions (retire rather than replace). A higher portion of transmission costs will be borne by us in this situation.	High

Subject	Assumption	Basis for Assumption	Potential Impact of Uncertainty, if any	Level of Impact
NZ Steel	Our assumption is that NZ Steel, our largest customer, and major contributor to the local economy will remain operating at current levels at both Glenbrook and Maoro.	Information received from NZ Steel, and publicly available information indicates that they will continue operating in the short to medium term.	Business conditions could worsen as a result of foreign exchange rates, demands for steel products changing and emissions controls (new Paris Agreement on climate change) leading to increased compliance and operating costs due to fuel substitution. A closure or downturn in production (or part of production such as iron sand mining at Maoro) would lead to decreased levels of direct consumption (affecting revenues), as well as lead to a regional economic decline affecting overall network demand and growth. A higher portion of transmission costs will be borne by us in this situation.	High
Transmission Pricing	We expect minor changes to the Transmission Pricing Methodology (TPM) which impacts on our transmission pricing but at this stage the exact impact is not known. We have at this time assumed that it will not have a material impact which would lead to a change of the current state. Assessment of RCPD demand using 100 peaks will put more importance on load management and demand side activities.	Transpower has proposed regional transmission prices but consultation has not yet commenced. The EA has put on hold their proposed changes to the TPM guidelines. 100 RCPD peaks have been implemented already.	Significant changes to the TPM now seems less likely. But regional transmission prices would result in customer prices increase to reflect the increased charges from Transpower.	Medium

Subject	Assumption	Basis for Assumption	Potential Impact of Uncertainty, if any	Level of Impact
Embedding or Bypass risk	We have assumed that there will be no embedded network created in our network area, nor any bypass of our network by third parties to supply key loads during the planning period	We have no current evidence that embedding is likely as it is economically unattractive without appropriate scale. We liaise with our key customers and land developers to identify early opportunities and minimise the likelihood of bypass as our network is existing and has capacity to supply with lower incremental cost than any new entrant.	Embedded networks could lead to reduced revenue and ICP growth over time, and potentially stranding of some existing network assets. However, these would still feature as demand on our network. Bypass of our network assets by a third party could lead to reduced revenue from lost supply opportunities and asset stranding and reduced growth in our demand forecasts.	Medium

Appendix B – Information Disclosure Schedule

Company Name **Counties Power Limited**
 AMP Planning Period **1 April 2018 – 31 March 2028**

SCHEDULE 11a: REPORT ON FORECAST CAPITAL EXPENDITURE

This schedule requires a breakdown of forecast expenditure on assets for the current disclosure year and a 10 year planning period. The forecasts should be consistent with the supporting information set out in the AMP. The forecast is to be expressed in both constant price and nominal dollar terms. Also required is a forecast of the value of commissioned assets (i.e., the value of RAB additions).
 EDBs must provide explanatory comment on the difference between constant price and nominal dollar forecasts of expenditure on assets in Schedule 14a (Mandatory Explanatory Notes).
 This information is not part of audited disclosure information.

sch ref		Current Year CY	CY+1	CY+2	CY+3	CY+4	CY+5	CY+6	CY+7	CY+8	CY+9	CY+10
	for year ended	31 Mar 18	31 Mar 19	31 Mar 20	31 Mar 21	31 Mar 22	31 Mar 23	31 Mar 24	31 Mar 25	31 Mar 26	31 Mar 27	31 Mar 28
7												
8												
9	11a(i): Expenditure on Assets Forecast	\$000 (in nominal dollars)										
10	Consumer connection	12,035	10,000	10,200	10,404	10,612	10,824	8,833	9,009	9,189	9,373	9,561
11	System growth	2,366	6,990	6,589	6,705	10,750	6,413	12,426	8,553	10,218	4,657	866
12	Asset replacement and renewal	6,259	11,295	12,189	11,793	10,697	10,510	10,445	11,273	11,148	10,873	9,860
13	Asset relocations	637	3,765	306	312	318	325	331	338	345	351	359
14	Reliability, safety and environment:											
15	Quality of supply	100	1,350	357	364	371	379	386	394	402	410	418
16	Legislative and regulatory	-	-	408	-	-	-	-	-	-	-	-
17	Other reliability, safety and environment	1,081	295	403	208	212	216	221	225	230	234	239
18	Total reliability, safety and environment	1,181	1,645	1,168	572	584	595	607	619	632	644	657
19	Expenditure on network assets	22,478	33,695	30,452	29,787	32,961	28,668	32,642	29,793	31,531	25,900	21,303
20	Expenditure on non-network assets	1,832	2,450	2,499	2,445	2,494	2,544	2,595	2,646	2,699	2,753	2,808
21	Expenditure on assets	24,310	36,145	32,951	32,232	35,455	31,212	35,237	32,439	34,231	28,653	24,111
22												
23	plus Cost of financing	485	704	1,081	1,353	1,724	1,913	2,093	2,205	2,228	2,183	1,823
24	less Value of capital contributions	8,230	8,000	8,160	8,323	8,490	8,659	7,066	7,207	7,352	7,499	7,649
25	plus Value of vested assets											
26												
27	Capital expenditure forecast	16,565	28,849	25,872	25,261	28,689	24,465	30,263	27,437	29,107	23,337	18,285
28												
29	Assets commissioned	30,636	38,880	36,991	34,312	35,455	31,212	35,237	32,439	34,231	28,653	24,111
30												
31												
32												
33												
34												
35												
36												
37												
38												
39												
40												
41												
42												
43												
44												
45												
46	Subcomponents of expenditure on assets (where known)											
47	Energy efficiency and demand side management, reduction of energy losses											
48	Overhead to underground conversion	748	300	300	300	300	300	300	300	300	300	300
49	Research and development											

Company Name	Counties Power Limited
AMP Planning Period	1 April 2018 – 31 March 2028

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 non-current assets (i.e., the value of RAB expenditure).

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

[illegible]

		Current Year CY	CY+1	CY+2	CY+3	CY+4	CY+5
	for year ended	31 Mar 18	31 Mar 19	31 Mar 20	31 Mar 21	31 Mar 22	31 Mar 23
67	11a(ii): Consumer Connection						
68							
69	<i>Consumer types defined by EDB*</i>						
70	Urban residential	6,018	5,000	5,000	5,000	5,000	5,000
71	Urban commercial	2,407	2,000	2,000	2,000	2,000	2,000
72	Rural residential	2,046	1,700	1,700	1,700	1,700	1,700
73	Rural commercial	1,565	1,300	1,300	1,300	1,300	1,300
74							
75	<i>*include additional rows if needed</i>						
76	Consumer connection expenditure	12,035	10,000	10,000	10,000	10,000	10,000
77	less Capital contributions funding consumer connection	8,230	8,000	8,000	8,000	8,000	8,000
78	Consumer connection less capital contributions	3,805	2,000	2,000	2,000	2,000	2,000
79	11a(iii): System Growth						
80	Subtransmission	-	-	-	-	1,200	1,200
81	Zone substations	78	2,000	3,800	3,150	3,350	
82	Distribution and LV lines	1,899	2,035	1,860	2,855	3,260	2,000
83	Distribution and LV cables	211	-	-	-	1,190	2,725
84	Distribution substations and transformers	37	455	800	440	1,130	
85	Distribution switchgear	88	-	-	-	-	
86	Other network assets	52	2,500	-	-	-	
87	System growth expenditure	2,366	6,990	6,460	6,445	10,130	5,925
88	less Capital contributions funding system growth	-	-	-	-	-	
89	System growth less capital contributions	2,366	6,990	6,460	6,445	10,130	5,925

Company Name **Counties Power Limited**
AMP Planning Period **1 April 2018 – 31 March 2028**

SCHEDULE 11a: REPORT ON FORECAST CAPITAL EXPENDITURE

This schedule requires a breakdown of forecast expenditure on assets for the current disclosure year and a 10 year planning period. The forecasts should be consistent with the supporting information set out in the AMP. The forecast is to be expressed in both constant price and nominal dollar terms. Also required is a forecast of the value of commissioned assets (i.e., the value of RAB additions)
EDBs must provide explanatory comment on the difference between constant price and nominal dollar forecasts of expenditure on assets in Schedule 14a (Mandatory Explanatory Notes).
This information is not part of audited disclosure information.

sch ref

		Current Year CY	CY+1	CY+2	CY+3	CY+4	CY+5
	for year ended	31 Mar 18	31 Mar 19	31 Mar 20	31 Mar 21	31 Mar 22	31 Mar 23
91							
92							
93	11a(iv): Asset Replacement and Renewal	\$000 (in constant prices)					
94	Subtransmission	86	54	54	54	55	55
95	Zone substations	487	163	54	54	55	55
96	Distribution and LV lines	3,332	8,204	7,722	7,463	7,390	7,032
97	Distribution and LV cables	1,266	402	411	424	439	452
98	Distribution substations and transformers	378	641	789	641	648	650
99	Distribution switchgear	522	1,467	1,957	2,151	1,329	1,312
100	Other network assets	189	364	562	549	165	154
101	Asset replacement and renewal expenditure	6,259	11,295	11,550	11,335	10,080	9,710
102	less Capital contributions funding asset replacement and renewal	-	-	-	-	-	-
103	Asset replacement and renewal less capital contributions	6,259	11,295	11,550	11,335	10,080	9,710
104							
105		Current Year CY	CY+1	CY+2	CY+3	CY+4	CY+5
106	for year ended	31 Mar 18	31 Mar 19	31 Mar 20	31 Mar 21	31 Mar 22	31 Mar 23
107	11a(v): Asset Relocations	\$000 (in constant prices)					
108	<i>Project or programme*</i>						
109	AT road widening	102	150	150	150	150	150
110	Others	-	150	150	150	150	150
111	Bombay to Opaheke 110kV East line section relocation	535	3,465				
112							
113							
114	<i>*Include additional rows if needed</i>						
115	All other project or programmes - asset relocations						
116	Asset relocations expenditure	637	3,765	300	300	300	300
117	less Capital contributions funding asset relocations	-	-	-	-	-	-
118	Asset relocations less capital contributions	637	3,765	300	300	300	300
119							
120		Current Year CY	CY+1	CY+2	CY+3	CY+4	CY+5
121	for year ended	31 Mar 18	31 Mar 19	31 Mar 20	31 Mar 21	31 Mar 22	31 Mar 23
122	11a(vi): Quality of Supply	\$000 (in constant prices)					
123	<i>Project or programme*</i>						
124	Voltage quality resolution	100	350	350	350	350	350
125	Tuakau industrial power quality improvement		1,000				
126							
127							
128							
129	<i>*Include additional rows if needed</i>						
130	All other projects or programmes - quality of supply						
131	Quality of supply expenditure	100	1,350	350	350	350	350
132	less Capital contributions funding quality of supply	-	-	-	-	-	-
133	Quality of supply less capital contributions	100	1,350	350	350	350	350
134							

Company Name **Counties Power Limited**
 AMP Planning Period **1 April 2018 – 31 March 2028**

SCHEDULE 11a: REPORT ON FORECAST CAPITAL EXPENDITURE

This schedule requires a breakdown of forecast expenditure on assets for the current disclosure year and a 10 year planning period. The forecasts should be consistent with the supporting information set out in the AMP. The forecast is to be expressed in both constant price and nominal dollar terms. Also required is a forecast of the value of commissioned assets (i.e., the value of RAB additions)
 EDBs must provide explanatory comment on the difference between constant price and nominal dollar forecasts of expenditure on assets in Schedule 14a (Mandatory Explanatory Notes).
 This information is not part of audited disclosure information.

sch ref

		Current Year CY	CY+1	CY+2	CY+3	CY+4	CY+5
	for year ended	31 Mar 18	31 Mar 19	31 Mar 20	31 Mar 21	31 Mar 22	31 Mar 23
135							
136							
137	11a(vii): Legislative and Regulatory						
138	<i>Project or programme*</i>	\$000 (in constant prices)					
139	New AUJLS/Extended Reserve Relays	-	-	400	-	-	-
140							
141							
142							
143							
144	<i>*Include additional rows if needed</i>						
145	All other projects or programmes - legislative and regulatory						
146	Legislative and regulatory expenditure	-	-	400	-	-	-
147	less Capital contributions funding legislative and regulatory						
148	Legislative and regulatory less capital contributions	-	-	400	-	-	-
149							
150							
151	11a(viii): Other Reliability, Safety and Environment						
152	<i>Project or programme*</i>	\$000 (in constant prices)					
153	Energy storage trial	680					
154	Improve reliability of Whangarat and Hitchen Road feeders (front end sections)	50	-	-			
155	Te Toro feeder upgrade (Eastern King Street)	164					
156	Pukekohe - Tuakau 110kV line corridor visual mitigation measures	11	-				
157	Improve reliability of various feeders	176	295	395	200	200	200
158	<i>*Include additional rows if needed</i>						
159	All other projects or programmes - other reliability, safety and environment						
160	Other reliability, safety and environment expenditure	1,081	295	395	200	200	200
161	less Capital contributions funding other reliability, safety and environment						
162	Other reliability, safety and environment less capital contributions	1,081	295	395	200	200	200

Company Name **Counties Power Limited**
 AMP Planning Period **1 April 2018 – 31 March 2028**

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

166	11a(ix): Non-Network Assets						
167	Routine expenditure						
168	<i>Project or programme*</i>						
169	Replacement - Vehicles, Plant, Tools, Computing and Office	1,832	2,450	2,450	2,350	2,350	2,350
170							
171							
172							
173							
174	<i>*Include additional rows if needed</i>						
175	All other projects or programmes - routine expenditure						
176	Routine expenditure	1,832	2,450	2,450	2,350	2,350	2,350
177	Atypical expenditure						
178	<i>Project or programme*</i>						
179							
180							
181							
182							
183							
184	<i>*Include additional rows if needed</i>						
185	All other projects or programmes - atypical expenditure						
186	Atypical expenditure	-	-	-	-	-	-
187							
188	Expenditure on non-network assets	1,832	2,450	2,450	2,350	2,350	2,350

Company Name **Counties Power Limited**
AMP Planning Period **1 April 2018 – 31 March 2028**

SCHEDULE 11b: REPORT ON FORECAST OPERATIONAL EXPENDITURE

This schedule requires a breakdown of forecast operational expenditure for the disclosure year and a 10 year planning period. The forecasts should be consistent with the supporting information set out in the AMP. The forecast is to be expressed in both constant price and nominal dollar terms. EDBs must provide explanatory comment on the difference between constant price and nominal dollar operational expenditure forecasts in Schedule 14a (Mandatory Explanatory Notes). This information is not part of audited disclosure information.

sch ref

	Current Year CY	CY+1	CY+2	CY+3	CY+4	CY+5	CY+6	CY+7	CY+8	CY+9	CY+10
for year ended	31 Mar 18	31 Mar 19	31 Mar 20	31 Mar 21	31 Mar 22	31 Mar 23	31 Mar 24	31 Mar 25	31 Mar 26	31 Mar 27	31 Mar 28
Operational Expenditure Forecast	\$000 (in nominal dollars)										
Service interruptions and emergencies	1,939	1,900	1,938	1,977	2,016	2,057	2,098	2,140	2,183	2,226	2,271
Vegetation management	1,088	1,100	1,122	1,144	1,167	1,191	1,214	1,239	1,264	1,289	1,315
Routine and corrective maintenance and inspection	1,003	1,350	1,377	1,405	1,454	1,483	1,524	1,554	1,585	1,617	1,649
Asset replacement and renewal	886	800	581	520	393	411	309	315	322	340	382
Network Opex	4,916	5,150	5,018	5,046	5,030	5,142	5,145	5,248	5,353	5,472	5,617
System operations and network support	3,063	3,717	3,791	3,867	3,945	4,023	4,104	4,186	4,270	4,355	4,442
Business support	5,399	5,582	5,808	6,042	6,286	6,540	6,804	7,079	7,365	7,663	7,972
Non-network opex	8,462	9,299	9,599	9,909	10,231	10,564	10,908	11,265	11,635	12,018	12,415
Operational expenditure	13,378	14,449	14,617	14,955	15,261	15,705	16,053	16,513	16,988	17,490	18,032
	Current Year CY	CY+1	CY+2	CY+3	CY+4	CY+5	CY+6	CY+7	CY+8	CY+9	CY+10
for year ended	31 Mar 18	31 Mar 19	31 Mar 20	31 Mar 21	31 Mar 22	31 Mar 23	31 Mar 24	31 Mar 25	31 Mar 26	31 Mar 27	31 Mar 28
	\$000 (in constant prices)										
Service interruptions and emergencies	1,939	1,900	1,900	1,900	1,900	1,900	1,900	1,900	1,900	1,900	1,900
Vegetation management	1,088	1,100	1,100	1,100	1,100	1,100	1,100	1,100	1,100	1,100	1,100
Routine and corrective maintenance and inspection	1,003	1,350	1,350	1,350	1,370	1,370	1,380	1,380	1,380	1,380	1,380
Asset replacement and renewal	886	800	570	500	370	380	280	280	280	290	320
Network Opex	4,916	5,150	4,920	4,850	4,740	4,750	4,660	4,660	4,660	4,670	4,700
System operations and network support	3,063	3,717	3,717	3,717	3,717	3,717	3,717	3,717	3,717	3,717	3,717
Business support	5,399	5,582	5,694	5,808	5,924	6,042	6,163	6,286	6,412	6,540	6,671
Non-network opex	8,462	9,299	9,411	9,525	9,641	9,759	9,880	10,003	10,129	10,257	10,388
Operational expenditure	13,378	14,449	14,331	14,375	14,381	14,509	14,540	14,663	14,789	14,927	15,088
Subcomponents of operational expenditure (where known)											
Energy efficiency and demand side management, reduction of energy losses											
Direct billing*											
Research and Development											
Insurance	247	272	280	289	297	306	315	325	335	345	355
* Direct billing expenditure by suppliers that direct bill the majority of their consumers											
	Current Year CY	CY+1	CY+2	CY+3	CY+4	CY+5	CY+6	CY+7	CY+8	CY+9	CY+10
for year ended	31 Mar 18	31 Mar 19	31 Mar 20	31 Mar 21	31 Mar 22	31 Mar 23	31 Mar 24	31 Mar 25	31 Mar 26	31 Mar 27	31 Mar 28
Difference between nominal and real forecasts	\$000										
Service interruptions and emergencies	-	-	38	77	116	157	198	240	283	326	371
Vegetation management	-	-	22	44	67	91	114	139	164	189	215
Routine and corrective maintenance and inspection	-	-	27	55	84	113	144	174	205	237	269
Asset replacement and renewal	-	-	11	20	23	31	29	35	42	50	62
Network Opex	-	-	98	196	290	392	485	588	693	802	917
System operations and network support	-	-	74	150	228	306	387	469	553	638	725
Business support	-	-	114	235	363	498	641	793	953	1,123	1,301
Non-network opex	-	-	188	385	590	804	1,028	1,262	1,506	1,761	2,027
Operational expenditure	-	-	287	581	880	1,196	1,513	1,850	2,199	2,562	2,944

Company Name **Counties Power Limited**
 AMP Planning Period **1 April 2018 – 31 March 2028**

SCHEDULE 12a: REPORT ON ASSET CONDITION

This schedule requires a breakdown of asset condition by asset class as at the start of the forecast year. The data accuracy assessment relates to the percentage values disclosed in the asset condition columns. Also required is a forecast of the percentage of units to be replaced in the next 5 years. All information should be consistent with the information provided in the AMP and the expenditure on assets forecast in Schedule 11a. All units relating to cable and line assets, that are expressed in km, refer to circuit lengths.

sch ref

Asset condition at start of planning period (percentage of units by grade)											
	Voltage	Asset category	Asset class	Units	Grade 1	Grade 2	Grade 3	Grade 4	Grade unknown	Data accuracy (1-4)	% of asset forecast to be replaced in next 5 years
7											
8											
9											
10	All	Overhead Line	Concrete poles / steel structure	No.	0.08%	3.63%	50.45%	45.78%	0.06%	3	3.95%
11	All	Overhead Line	Wood poles	No.	23.38%	13.12%	55.27%	7.77%	0.46%	3	9.90%
12	All	Overhead Line	Other pole types	No.	-	-	-	100.00%	-	3	-
13	HV	Subtransmission Line	Subtransmission OH up to 66kV conductor	km	4.78%	-	75.70%	19.52%	-	3	25.18%
14	HV	Subtransmission Line	Subtransmission OH 110kV+ conductor	km	-	-	0.26%	99.74%	-	3	-
15	HV	Subtransmission Cable	Subtransmission UG up to 66kV (XLPE)	km	-	-	22.72%	77.28%	-	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.	28.57%	28.57%	42.86%	-	-	3	42.86%
25	HV	Zone substation Buildings	Zone substations 110kV+	No.	-	-	33.33%	66.67%	-	3	-
26	HV	Zone substation switchgear	22/33kV CB (Indoor)	No.	-	-	-	-	N/A	-	-
27	HV	Zone substation switchgear	22/33kV CB (Outdoor)	No.	25.00%	33.33%	-	41.67%	-	3	75.00%
28	HV	Zone substation switchgear	33kV Switch (Ground Mounted)	No.	-	-	-	-	N/A	-	-
29	HV	Zone substation switchgear	33kV Switch (Pole Mounted)	No.	48.28%	34.48%	3.45%	13.79%	-	3	48.28%
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.	-	-	-	100.00%	-	3	-
33	HV	Zone substation switchgear	3.3/6.6/11/22kV CB (ground mounted)	No.	11.25%	21.25%	27.50%	40.00%	-	3	24.69%
34	HV	Zone substation switchgear	3.3/6.6/11/22kV CB (pole mounted)	No.	-	-	-	-	N/A	-	-
35											

Company Name **Counties Power Limited**
 AMP Planning Period **1 April 2018 – 31 March 2028**

SCHEDULE 12a: REPORT ON ASSET CONDITION

This schedule requires a breakdown of asset condition by asset class as at the start of the forecast year. The data accuracy assessment relates to the percentage values disclosed in the asset condition columns. Also required is a forecast of the percentage of units to be replaced in the next 5 years. All information should be consistent with the information provided in the AMP and the expenditure on assets forecast in Schedule 11a. All units relating to cable and line assets, that are expressed in km, refer to circuit lengths.

sch ref

Asset condition at start of planning period (percentage of units by grade)												
	Voltage	Asset category	Asset class	Units	Grade 1	Grade 2	Grade 3	Grade 4	Grade unknown	Data accuracy (1-4)	% of asset forecast to be replaced in next 5 years	
36												
37												
38												
39	HV	Zone Substation Transformer	Zone Substation Transformers	No.	-	35.29%	29.42%	35.29%	-	3	33.33%	
40	HV	Distribution Line	Distribution OH Open Wire Conductor	km	1.98%	14.00%	49.76%	34.26%	-	3	3.99%	
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	0.13%	-	11.04%	88.83%	-	3	0.13%	
44	HV	Distribution Cable	Distribution UG PILC	km	-	24.37%	42.35%	33.28%	-	3	-	
45	HV	Distribution Cable	Distribution Submarine Cable	km	-	-	-	100.00%	-	3	-	
46	HV	Distribution switchgear	3.3/6.6/11/22kV CB (pole mounted) - reclosers and sectionalisers	No.	0.84%	13.45%	15.13%	70.58%	-	3	0.84%	
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.	25.58%	19.60%	37.84%	16.98%	-	3	4.35%	
49	HV	Distribution switchgear	3.3/6.6/11/22kV Switch (ground mounted) - except RMU	No.	-	-	-	-	N/A		-	
50	HV	Distribution switchgear	3.3/6.6/11/22kV RMU	No.	5.03%	7.54%	16.08%	71.35%	-	3	5.03%	
51	HV	Distribution Transformer	Pole Mounted Transformer	No.	7.77%	12.72%	35.44%	44.07%	-	3	7.77%	
52	HV	Distribution Transformer	Ground Mounted Transformer	No.	3.11%	4.97%	32.80%	59.12%	-	3	3.11%	
53	HV	Distribution Transformer	Voltage regulators	No.	-	14.29%	-	85.71%	-	3	14.29%	
54	HV	Distribution Substations	Ground Mounted Substation Housing	No.	10.15%	8.65%	37.09%	44.11%	-	3	10.15%	
55	LV	LV Line	LV OH Conductor	km	0.51%	4.13%	63.32%	28.09%	3.95%	3	0.51%	
56	LV	LV Cable	LV UG Cable	km	0.07%	1.45%	31.02%	67.46%	-	3	0.04%	
57	LV	LV Streetlighting	LV OH/UG Streetlight circuit	km	-	-	0.16%	99.84%	-	3	-	
58	LV	Connections	OH/UG consumer service connections	No.	-	-	-	-	N/A		-	
59	All	Protection	Protection relays (electromechanical, solid state and numeric)	No.	19.44%	13.19%	11.81%	55.56%	-	3	27.66%	
60	All	SCADA and communications	SCADA and communications equipment operating as a single system	Lot	18.02%	12.61%	21.62%	47.75%	-	3	22.71%	
61	All	Capacitor Banks	Capacitors including controls	No.	-	-	3.45%	96.55%	-	3	-	
62	All	Load Control	Centralised plant	Lot	40.00%	20.00%	20.00%	20.00%	-	2	20.00%	
63	All	Load Control	Relays	No.	21.61%	12.30%	0.54%	65.55%	-	1	21.61%	
64	All	Civils	Cable Tunnels	km	-	-	-	-	N/A		-	

Company Name	Counties Power Limited
AMP Planning Period	1 April 2018 – 31 March 2028

SCHEDULE 12b: REPORT ON FORECAST CAPACITY

This schedule requires a breakdown of current and forecast capacity and utilisation for each zone substation and current distribution transformer capacity. The data provided should be consistent with the information provided in the AMP. Information provided in this table should relate to the operation of the network in its normal steady state configuration.

sch ref

12b(i): System Growth - Zone Substations

[illegible]

¹ Extend forecast capacity table as necessary to disclose all capacity by each zone substation

Company Name **Counties Power Limited**
 AMP Planning Period **1 April 2018 – 31 March 2028**

SCHEDULE 12C: REPORT ON FORECAST NETWORK DEMAND

This schedule requires a forecast of new connections (by consumer type), peak demand and energy volumes for the disclosure year and a 5 year planning period. The forecasts should be consistent with the supporting information set out in the AMP as well as the assumptions used in developing the expenditure forecasts in Schedule 11a and Schedule 11b and the capacity and utilisation forecasts in Schedule 12b.

sch ref

12c(i): Consumer Connections

Number of ICPs connected in year by consumer type

Consumer types defined by EDB*

Mass market business
Business 3-tier rate
Standard domestic
Low user domestic
Prepaid domestic
Time of use business
Streetlights
Direct charge

Connections total

*include additional rows if needed

Distributed generation

Number of connections

Capacity of distributed generation installed in year (MVA)

12c(ii) System Demand

Maximum coincident system demand (MW)

GXP demand

plus Distributed generation output at HV and above

Maximum coincident system demand

less Net transfers to (from) other EDBs at HV and above

Demand on system for supply to consumers' connection points

Electricity volumes carried (GWh)

Electricity supplied from GXPs

less Electricity exports to GXPs

plus Electricity supplied from distributed generation

less Net electricity supplied to (from) other EDBs

Electricity entering system for supply to ICPs

less Total energy delivered to ICPs

Losses

Load factor

Loss ratio

		Number of connections				
	Current Year CY	CY+1	CY+2	CY+3	CY+4	CY+5
for year ended	31 Mar 18	31 Mar 19	31 Mar 20	31 Mar 21	31 Mar 22	31 Mar 23
	(270)	(250)	200	100	50	55
	(6)	(5)	(20)	(80)	-	-
	(404)	(400)	(100)	(50)	-	-
	1,522	1,520	1,000	1,080	1,080	1,107
	(50)	(50)	(50)	-	(50)	(50)
	14	15	20	20	20	20
	18	-	5	5	5	5
	2	-	2	1	1	1
	826	830	1,057	1,076	1,106	1,138
	90	100	120	120	120	120
	0.3	0.4	0.5	0.5	0.5	0.5
	Current Year CY	CY+1	CY+2	CY+3	CY+4	CY+5
for year ended	31 Mar 18	31 Mar 19	31 Mar 20	31 Mar 21	31 Mar 22	31 Mar 23
	110	115	119	122	126	130
	7	5	5	5	5	5
	117	120	124	127	131	135
	-	-	-	-	-	-
	117	120	124	127	131	135
	553	565	577	589	602	614
	-	-	-	-	-	-
	44	44	44	44	44	44
	-	-	-	-	-	-
	596	608	620	633	646	658
	570	581	593	604	616	628
	27	27	28	28	29	30
	58%	58%	57%	57%	56%	56%
	4.5%	4.5%	4.5%	4.5%	4.5%	4.5%

Company Name	Counties Power Limited
AMP Planning Period	1 April 2018 – 31 March 2028
Network / Sub-network Name	

SCHEDULE 12d: REPORT FORECAST INTERRUPTIONS AND DURATION

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

sch ref		for year ended	Current Year CY	CY+1	CY+2	CY+3	CY+4	CY+5
			31 Mar 18	31 Mar 19	31 Mar 20	31 Mar 21	31 Mar 22	31 Mar 23
8								
9								
10	SAIDI							
11	Class B (planned interruptions on the network)		60.0	95.0	90.0	90.0	90.0	90.0
12	Class C (unplanned interruptions on the network)		110.0	110.0	110.0	110.0	110.0	110.0
13	SAIFI							
14	Class B (planned interruptions on the network)		0.35	0.45	0.40	0.40	0.40	0.40
15	Class C (unplanned interruptions on the network)		2.20	2.45	2.40	2.40	2.40	2.40

						Company Name	Counties Power Limited	
						AMP Planning Period	1 April 2018 – 31 March 2028	
						Asset Management 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/document Information
3	Asset management policy	To what extent has an asset management policy been documented, authorised and communicated?	2	The Asset Management Policy had previously been captured and detailed in the Asset Management Plan, with sections of the plan outlining the high level company policy. A standalone Policy was developed and approved by management in 2016, with alignment to the requirements of PAS 55 / ISO 55000 however its circulation and understanding by the wider organisation is limited to those directly involved in the management of network assets.		Widely used AM practice standards require an organisation to document, authorise and communicate its asset management policy (eg, as required in PAS 55 para 4.2 i). A key pre-requisite of any robust policy is that the organisation's top management must be seen to endorse and fully support it. Also vital to the effective implementation of the policy, is to tell the appropriate people of its content and their obligations under it. Where an organisation outsources some of its asset-related activities, then these people and their organisations must equally be made aware of the policy's content. Also, there may be other stakeholders, such as regulatory authorities and shareholders who should be made aware of it.	Top management. The management team that has overall responsibility for asset management.	The organisation's asset management policy, its organisational strategic plan, documents indicating how the asset management policy was based upon the needs of the organisation and evidence of communication.
10	Asset management strategy	What has the organisation done to ensure that its asset management strategy is consistent with other appropriate organisational policies and strategies, and the needs of stakeholders?	2	There is clear linkage between the organisation's vision and goals, approved policies, and the consideration of stakeholder needs (through service levels) when determining the asset strategy (through this AMP). Work is ongoing to develop individual lifecycle strategies for all assets, and to ensure all strategies meet the organisations objectives.		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 policies, strategies and stakeholder requirements as covered in drafting the asset management policy but at a greater level of detail.	Top management. The organisation's strategic planning team. The management team that has overall responsibility for asset management.	The organisation's asset management strategy document and other related organisational policies and strategies. Other than the organisation's strategic plan, these could include those relating to health and safety, environmental, etc. Results of stakeholder consultation.
11	Asset management strategy	In what way does the organisation's asset management strategy take account of the lifecycle of the assets, asset types and asset systems over which the organisation has stewardship?	2	Treatment of all parts of the asset lifecycle is set out in the AMP for major asset categories including planning, construction, operation, maintenance and disposal. Asset lifecycles are well understood for major asset categories but further development is required for all asset categories.		Good asset stewardship is the hallmark of an organisation compliant with widely used AM standards. A key component of this is the need to take account of the lifecycle of the assets, asset types and asset systems. (For example, this requirement is recognised in 4.3.1 d) of PAS 55). This question explores what an organisation has done to take lifecycle into account in its asset management strategy.	Top management. People in the organisation with expert knowledge of the assets, asset types, asset systems and their associated life-cycles. The management team that has overall responsibility for asset management. Those responsible for developing and adopting methods and processes used in asset management	The organisation's documented asset management strategy and supporting working documents.
26	Asset management plan(s)	How does the organisation establish and document its asset management plan(s) across the life cycle activities of its assets and asset systems?	3	Currently, the AMP details lifecycle asset management plans for all major asset classes and maintenance and life-extension activities for the planning period. This is supported by working documents created by the Asset Management team. Lifecycle management plans take into account the long term optimisation of asset investments and trade-offs required. In the medium term, these will be better documented as standalone lifecycle management plans to be summarised in the AMP for disclosure purposes.		The asset management strategy need to be translated into practical plan(s) so that all parties know how the objectives will be achieved. The development of plan(s) will need to identify the specific tasks and activities required to optimize costs, risks and performance of the assets and/or asset system(s), when they are to be carried out and the resources required.	The management team with overall responsibility for the asset management system. Operations, maintenance and engineering managers.	The organisation's asset management plan(s).

						Company Name	Counties Power Limited	
						AMP Planning Period	1 April 2018 – 31 March 2028	
						Asset Management Standard Applied		
SCHEDULE 13: REPORT ON ASSET MANAGEMENT MATURITY (cont)								
Question No.	Function	Question	Score	Evidence—Summary	User Guidance	Why	Who	Record/document Information
27	Asset management plan(s)	How has the organisation communicated its plan(s) to all relevant parties to a level of detail appropriate to the receiver's role in their delivery?	3	The AMP is made available to all Asset Management staff, and those within the business who rely upon key information in it such as commercial, finance, field operations management and customer services. Major customers, territorial authorities and other utilities receive updates relating to plans in their areas, some within formally minuted account management meetings. Internal circulation is supplemented with briefings during monthly meetings; team meetings; and presentations of work programmes, key projects and other asset management initiatives.		Plans will be ineffective unless they are communicated to all those, including contracted suppliers and those who undertake enabling function(s). The plan(s) need to be communicated in a way that is relevant to those who need to use them.	The management team with overall responsibility for the asset management system. Delivery functions and suppliers.	Distribution lists for plan(s). Documents derived from plan(s) which detail the receivers role in plan delivery. Evidence of communication.
29	Asset management plan(s)	How are designated responsibilities for delivery of asset plan actions documented?	3	The team structure set out in the AMP, job descriptions, business plan responsibilities and personal performance plans establish responsibilities for delivery of AM actions.		The implementation of asset management plan(s) relies on (1) actions being clearly identified, (2) an owner allocated and (3) that owner having sufficient delegated responsibility and authority to carry out the work required. It also requires alignment of actions across the organisation. This question explores how well the plan(s) set out responsibility for delivery of asset plan actions.	The management team with overall responsibility for the asset management system. Operations, maintenance and engineering managers. If appropriate, the performance management team.	The organisation's asset management plan(s). Documentation defining roles and responsibilities of individuals and organisational departments.
31	Asset management plan(s)	What has the organisation done to ensure that appropriate arrangements are made available for the efficient and cost effective implementation of the plan(s)? (Note this is about resources and enabling support)	2	The AMP establishes financial estimates and resourcing arrangements for implementation. Plans may be adjusted for timing to ensure efficient utilisation of resources (e.g. bringing forward, or deferring programmes of work to match resource capacity within an acceptable risk profile). Medium and Long Term plans inform the organisation of future skills requirements and allow training or external contractors to be found to deliver on those requirements.		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. Where appropriate the procurement team and service providers working on the organisation's asset-related activities.	The organisation's asset management plan(s). Documented processes and procedures for the delivery of the asset management plan.
33	Contingency planning	What plan(s) and procedure(s) does the organisation have for identifying and responding to incidents and emergency situations and ensuring continuity of critical asset management activities?	2	The AMP considers network and environmental risk, including disaster response and assessment of HILP events. Participation in CDEM and Engineering Lifelines activities ensures alignment with other infrastructure operators for regional events. Contingency plans for operation of the network assets are being developed. A review of emergency preparedness undertaken in 2017 indicates improvements to be made to major event management and business continuity plans, which will be a focus for 2018.		Widely used AM practice standards require that an organisation has plan(s) to identify and respond to emergency situations. Emergency plan(s) should outline the actions to be taken to respond to specified emergency situations and ensure continuity of critical asset management activities including the communication to, and involvement of, external agencies. This question assesses if, and how well, these plan(s) triggered, implemented and resolved in the event of an incident. The plan(s) should be appropriate to the level of risk as determined by the organisation's risk assessment methodology. It is also a requirement that relevant personnel are competent and trained.	The manager with responsibility for developing emergency plan(s). The organisation's risk assessment team. People with designated duties within the plan(s) and procedure(s) for dealing with incidents and emergency situations.	The organisation's plan(s) and procedure(s) for dealing with emergencies. The organisation's risk assessments and risk registers.

					Company Name	Counties Power Limited		
					AMP Planning Period	1 April 2018 – 31 March 2028		
					Asset Management Standard Applied			
SCHEDULE 13: REPORT ON ASSET MANAGEMENT MATURITY (cont)								
Question No.	Function	Question	Score	Evidence—Summary	User Guidance	Why	Who	Record/documented information
37	Structure, authority and responsibilities	What has the organisation done to appoint member(s) of its management team to be responsible for ensuring that the organisation's assets deliver the requirements of the asset management strategy, objectives and plan(s)?	3	As outlined by the Asset Management Policy, the responsibility for AM activities sits with the GM Asset Management. The GM Field Operations has responsibility for delivery of the physical implementation of work programmes and projects relating to core network assets. Accountabilities are established through job descriptions and assigned activities. Appropriate delegations are in place.		In order to ensure that the organisation's assets and asset systems deliver the requirements of the asset management policy, strategy and objectives responsibilities need to be allocated to appropriate people who have the necessary authority to fulfil their responsibilities. (This question, relates to the organisation's assets eg, para b), s 4.4.1 of PAS 55, making it therefore distinct from the requirement contained in para a), s 4.4.1 of PAS 55).	Top management. People with management responsibility for the delivery of asset management policy, strategy, objectives and plan(s). People working on asset-related activities.	Evidence that managers with responsibility for the delivery of asset management policy, strategy, objectives and plan(s) have been appointed and have assumed their responsibilities. Evidence may include the organisation's documents relating to its asset management system, organisational charts, job descriptions of post-holders, annual targets/objectives and personal development plan(s) of post-holders as appropriate.
40	Structure, authority and responsibilities	What evidence can the organisation's top management provide to demonstrate that sufficient resources are available for asset management?	2	The development of the programmes of work presented in this AMP consider resourcing - financial, and physical resources - required to deliver the expected outcomes in the timeframes required. When developing the annual plan, consideration is given to the type of work, the skills sets required, and other resource constraints to ensure efficiency and sustainability in the long term. Consideration is given to outsourcing some activities where physical resource capacity is not available. Significant effort has been made to resource the team to deliver on asset management objectives including an increase in engineering, field delivery and support functions within the business.		Optimal asset management requires top management to ensure sufficient resources are available. In this context the term 'resources' includes manpower, materials, funding and service provider support.	Top management. The management team that has overall responsibility for asset management. Risk management team. The organisation's managers involved in day-to-day supervision of asset-related activities, such as frontline managers, engineers, foremen and chargehands as appropriate.	Evidence demonstrating that asset management plan(s) and/or the process(es) for asset management plan implementation consider the provision of adequate resources in both the short and long term. Resources include funding, materials, equipment, services provided by third parties and personnel (internal and service providers) with appropriate skills competencies and knowledge.
42	Structure, authority and responsibilities	To what degree does the organisation's top management communicate the importance of meeting its asset management requirements?	3	The significance of core asset management activities and meeting stated AM requirements is emphasised in newsletters, management communication, team meetings, company meetings, celebrations of particular programme successes, detailed reviews of issues and other asset related communications.		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 walkabouts would assist an organisation to demonstrate it is meeting this requirement of PAS 55.
45	Outsourcing of asset management activities	Where the organisation has outsourced some of its asset management activities, how has it ensured that appropriate controls are in place to ensure the compliant delivery of its organisational strategic plan, and its asset management policy and strategy?	2	The organisation has an internal workforce so has limited outsourcing of asset management activities. Contractors have to meet the requirements of the "Preapproved Contractor Scheme" which covers safety, competence and commercial requirements. Work is supervised by internal resources where necessary, and the scope of work is typically very prescribed (e.g. civil works, tree felling, etc). Audits and contract reviews are used to ensure compliance and expected progress with corrective actions noted and addressed.		Where an organisation chooses to outsource some of its asset management activities, the organisation must ensure that these outsourced process(es) are under appropriate control to ensure that all the requirements of widely used AM standards (eg, PAS 55) are in place, and the asset management policy, strategy objectives and plan(s) are delivered. This includes ensuring capabilities and resources across a time span aligned to life cycle management. The organisation must put arrangements in place to control the outsourced activities, whether it be to external providers or to other in-house departments. This question explores what the organisation does in this regard.	Top management. The management team that has overall responsibility for asset management. The manager(s) responsible for the monitoring and management of the outsourced activities. People involved with the procurement of outsourced activities. The people within the organisations that are performing the outsourced activities. The people impacted by the outsourced activity.	The organisation's arrangements that detail the compliance required of the outsourced activities. For example, this this could form part of a contract or service level agreement between the organisation and the suppliers of its outsourced activities. Evidence that the organisation has demonstrated to itself that it has assurance of compliance of outsourced activities.

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SCHEDULE 13: REPORT ON ASSET MANAGEMENT MATURITY (cont)

Question No.	Function	Question	Score	Evidence—Summary	User Guidance	Why	Who	Record/document Information
48	Training, awareness and competence	How does the organisation develop plan(s) for the human resources required to undertake asset management activities - including the development and delivery of asset management strategy, process(es), objectives and plan(s)?	2	Resource requirements are evaluated during annual planning activities and in the course of asset management delivery. In-house resource competency planning and skills development is managed via formal training plans, personal development plans and specific business plan objectives. HR plans consolidate resource requirements and gaps.		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	Senior management responsible for agreement of plan(s). Managers responsible for developing asset management strategy and plan(s). Managers with responsibility for development and recruitment of staff (including HR functions). Staff responsible for training. Procurement officers. Contracted service providers.	Evidence of analysis of future work load plan(s) in terms of human resources. Document(s) containing analysis of the organisation's own direct resources and contractors resource capability over suitable timescales. Evidence, such as minutes of meetings, that suitable management forums are monitoring human resource development plan(s). Training plan(s), personal development plan(s), contract and service level agreements.
49	Training, awareness and competence	How does the organisation identify competency requirements and then plan, provide and record the training necessary to achieve the competencies?	3	Competency requirements are identified through the job descriptions for different roles, as they relate to Asset Management, as well as company standards for certain competencies for specified activities. Through the performance review and development plan process, new skills and competency requirements are identified and training is provided as necessary. Training and competency records are kept by HR.		Widely used AM standards require that organisations to undertake a systematic identification of the asset management awareness and competencies required at each level and function within the organisation. Once identified the training required to provide the necessary competencies should be planned for delivery in a timely and systematic way. Any training provided must be recorded and maintained in a suitable format. Where an organisation has contracted service providers in place then it should have a means to demonstrate that this requirement is being met for their employees. (eg, PAS 55 refers to frameworks suitable for identifying competency requirements).	Senior management responsible for agreement of plan(s). Managers responsible for developing asset management strategy and plan(s). Managers with responsibility for development and recruitment of staff (including HR functions). Staff responsible for training. Procurement officers. Contracted service providers.	Evidence of an established and applied competency requirements assessment process and plan(s) in place to deliver the required training. Evidence that the training programme is part of a wider, co-ordinated asset management activities training and competency programme. Evidence that training activities are recorded and that records are readily available (for both direct and contracted service provider staff) e.g. via organisation wide information system or local records database.
50	Training, awareness and competence	How does the organization ensure that persons under its direct control undertaking asset management related activities have an appropriate level of competence in terms of education, training or experience?	3	Formal competency processes are in place for external providers and field service staff however are being revised to align to wider industry practice. Internal asset management staff competency and training is managed via formal training plans and professional development planning in conjunction with the relevant body (eg, IPENZ for professional engineering qualifications).		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.

SCHEDULE 13: REPORT ON ASSET MANAGEMENT MATURITY (cont)						Company Name AMP Planning Period Asset Management Standard Applied		Counties Power Limited 1 April 2018 – 31 March 2028	
Question No.	Function	Question	Score	Evidence—Summary	User Guidance	Why	Who	Record/documented Information	
53	Communication, participation and consultation	How does the organisation ensure that pertinent asset management information is effectively communicated to and from employees and other stakeholders, including contracted service providers?	2	The AMP is made available to all staff, and other stakeholders via the website. Internal circulation is supplemented with briefings during monthly meetings; team meetings; and presentations of work programmes, key projects and other asset management initiatives. Beyond the AMP and programme specific information, some improvement is required in two way communication and feedback processes. Improvements are occurring in the provision of forecast information to service providers.		Widely used AM practice standards require that pertinent asset management information is effectively communicated to and from employees and other stakeholders including contracted service providers. Pertinent information refers to information required in order to effectively and efficiently comply with and deliver asset management strategy, plan(s) and objectives. This will include for example the communication of the asset management policy, asset performance information, and planning information as appropriate to contractors.	Top management and senior management representative(s), employee's representative(s), employee's trade union representative(s); contracted service provider management and employee representative(s); representative(s) from the organisation's Health, Safety and Environmental team. Key stakeholder representative(s).	Asset management policy statement prominently displayed on notice boards, intranet and internet; use of organisation's website for displaying asset performance data; evidence of formal briefings to employees, stakeholders and contracted service providers; evidence of inclusion of asset management issues in team meetings and contracted service provider contract meetings; newsletters, etc.	
59	Asset Management System documentation	What documentation has the organisation established to describe the main elements of its asset management system and interactions between them?	2	Main systems and functions are detailed in the AMP. There is no clear documentation outlining the relationships between different systems and processes. This has been identified and will be addressed with the introduction of a new asset management information system (whole process mapping) which is expected to be completed during 2018.		Widely used AM practice standards require an organisation maintain up to date documentation that ensures that its asset management systems (ie, the systems the organisation has in place to meet the standards) can be understood, communicated and operated. (eg, s 4.5 of PAS 55 requires the maintenance of up to date documentation of the asset management system requirements specified throughout s 4 of PAS 55).	The management team that has overall responsibility for asset management. Managers engaged in asset management activities.	The documented information describing the main elements of the asset management system (process(es)) and their interaction.	
62	Information management	What has the organisation done to determine what its asset management information system(s) should contain in order to support its asset management system?	2	The asset management information systems have limited capability but support core business function. As per Q.59 a review of the asset management system and IT requirements, along with process and standards review is underway with key deliverables completed during 2018.		Effective asset management requires appropriate information to be available. Widely used AM standards therefore require the organisation to identify the asset management information it requires in order to support its asset management system. Some of the information required may be held by suppliers. The maintenance and development of asset management information systems is a poorly understood specialist activity that is akin to IT management but different from IT management. This group of questions provides some indications as to whether the capability is available and applied. Note: To be effective, an asset information management system requires the mobilisation of technology, people and process(es) that create, secure, make available and destroy the information required to support the asset management system.	The organisation's strategic planning team. The management team that has overall responsibility for asset management. Information management team. Operations, maintenance and engineering managers	Details of the process the organisation has employed to determine what its asset information system should contain in order to support its asset management system. Evidence that this has been effectively implemented.	
63	Information management	How does the organisation maintain its asset management information system(s) and ensure that the data held within it (them) is of the requisite quality and accuracy and is consistent?	2	Asset information is primarily maintained within the company ERP. This provides access controls and auditing. GIS is used to provide the geographic context of assets and also to a lesser degree to record some asset information. An initiative is underway to review and improve asset data quality in this system, which may lead to specific programmes to update and improve quality. A variety of other disparate databases and spreadsheets are in the process of being incorporated within the ERP (or its replacement).		The response to the questions is progressive. A higher scale cannot be awarded without achieving the requirements of the lower scale. This question explores how the organisation ensures that information management meets widely used AM practice requirements (eg, s 4.4.6 (a), (c) and (d) of PAS 55).	The management team that has overall responsibility for asset management. Users of the organisational information systems.	The asset management information system, together with the policies, procedure(s), improvement initiatives and audits regarding information controls.	

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SCHEDULE 13: REPORT ON ASSET MANAGEMENT MATURITY (cont)

Question No.	Function	Question	Score	Evidence—Summary	User Guidance	Why	Who	Record/document Information
64	Information management	How has the organisation's ensured its asset management information system is relevant to its needs?	2	The AMP outlines the core business systems relating to asset management. Following review it has been identified that the systems are no longer providing the required functionality and a project has been included for the replacement of the ERP system and improvement of the asset management system (implementation of a CMMS).		Widely used AM standards need not be prescriptive about the form of the asset management information system, but simply require that the asset management information system is appropriate to the organisations needs, can be effectively used and can supply information which is consistent and of the requisite quality and accuracy.	The organisation's strategic planning team. The management team that has overall responsibility for asset management. Information management team. Users of the organisational information systems.	The documented process the organisation employs to ensure its asset management information system aligns with its asset management requirements. Minutes of information systems review meetings involving users.
69	Risk management process(es)	How has the organisation documented process(es) and/or procedure(s) for the identification and assessment of asset and asset management related risks throughout the asset life cycle?	2	The corporate risk framework and audit programme identifies a number of risks relating to asset management activities with corresponding controls in place. These are assessed periodically for effectiveness. Asset specific risk is addressed through the planning process and maintenance programmes in place and detailed in the AMP. Some of these are still in development and are not yet fully documented, or documentation is out dated.		Risk management is an important foundation for proactive asset management. Its overall purpose is to understand the cause, effect and likelihood of adverse events occurring, to optimally manage such risks to an acceptable level, and to provide an audit trail for the management of risks. Widely used standards require the organisation to have process(es) and/or procedure(s) in place that set out how the organisation identifies and assesses asset and asset management related risks. The risks have to be considered across the four phases of the asset lifecycle (eg, para 4.3.3 of PAS 55).	The top management team in conjunction with the organisation's senior risk management representatives. There may also be input from the organisation's Safety, Health and Environment team. Staff who carry out risk identification and assessment.	The organisation's risk management framework and/or evidence of specific process(es) and/or procedure(s) that deal with risk control mechanisms. Evidence that the process(es) and/or procedure(s) are implemented across the business and maintained. Evidence of agendas and minutes from risk management meetings. Evidence of feedback in to process(es) and/or procedure(s) as a result of incident investigation(s). Risk registers and assessments.
79	Use and maintenance of asset risk information	How does the organisation ensure that the results of risk assessments provide input into the identification of adequate resources and training and competency needs?	2	Actions arising from risk assessments relating to training, competency development and resourcing are captured in training and development plans, as well as updating job specific competencies and position descriptions.		Widely used AM standards require that the output from risk assessments are considered and that adequate resource (including staff) and training is identified to match the requirements. It is a further requirement that the effects of the control measures are considered, as there may be implications in resources and training required to achieve other objectives.	Staff responsible for risk assessment and those responsible for developing and approving resource and training plan(s). There may also be input from the organisation's Safety, Health and Environment team.	The organisations risk management framework. The organisation's resourcing plan(s) and training and competency plan(s). The organisation should be able to demonstrate appropriate linkages between the content of resource plan(s) and training and competency plan(s) to the risk assessments and risk control measures that have been developed.
82	Legal and other requirements	What procedure does the organisation have to identify and provide access to its legal, regulatory, statutory and other asset management requirements, and how is requirements incorporated into the asset management system?	3	The business has established a compliance framework, and through active monitoring of the regulatory environment, along with participation in industry bodies such as the EEA and ENA identifies ongoing requirements, and new or amended requirements. Practices and processes are updated as required to ensure ongoing compliance. Senior Management team members report on compliance issues periodically.		In order for an organisation to comply with its legal, regulatory, statutory and other asset management requirements, the organisation first needs to ensure that it knows what they are (eg, PAS 55 specifies this in s 4.4.8). It is necessary to have systematic and auditable mechanisms in place to identify new and changing requirements. Widely used AM standards also require that requirements are incorporated into the asset management system (e.g. procedure(s) and process(es)).	Top management. The organisations regulatory team. The organisation's legal team or advisors. The management team with overall responsibility for the asset management system. The organisation's health and safety team or advisors. The organisation's policy making team.	The organisational processes and procedures for ensuring information of this type is identified, made accessible to those requiring the information and is incorporated into asset management strategy and objectives

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SCHEDULE 13: REPORT ON ASSET MANAGEMENT MATURITY (cont)

Question No.	Function	Question	Score	Evidence—Summary	User Guidance	Why	Who	Record/document Information
88	Life Cycle Activities	How does the organisation establish implement and maintain process(es) for the implementation of its asset management plan(s) and control of activities across the creation, acquisition or enhancement of assets. This includes design, modification, procurement, construction and commissioning activities?	2	Procedures for planning, design and construction exist in varying forms, with some not as current as others. A major project to review the standards framework (including policies and procedures) will continue during 2018.		Life cycle activities are about the implementation of asset management plan(s) i.e. they are the "doing" phase. They need to be done effectively and well in order for asset management to have any practical meaning. As a consequence, widely used standards (eg, PAS 55 s 4.5.1) require organisations to have in place appropriate process(es) and procedure(s) for the implementation of asset management plan(s) and control of lifecycle activities. This question explores those aspects relevant to asset creation.	Asset managers, design staff, construction staff and project managers from other impacted areas of the business, e.g. Procurement	Documented process(es) and procedure(s) which are relevant to demonstrating the effective management and control of life cycle activities during asset creation, acquisition, enhancement including design, modification, procurement, construction and commissioning.
91	Life Cycle Activities	How does the organisation ensure that process(es) and/or procedure(s) for the implementation of asset management plan(s) and control of activities during maintenance (and inspection) of assets are sufficient to ensure activities are carried out under specified conditions, are consistent with asset management strategy and control cost, risk and performance?	2	Procedures for maintenance and inspection of assets exist in varying forms, with some not as current as others. A major project to review the standards framework (including policies and procedures) will be continue during 2018.		Having documented process(es) which ensure the asset management plan(s) are implemented in accordance with any specified conditions, in a manner consistent with the asset management policy, strategy and objectives and in such a way that cost, risk and asset system performance are appropriately controlled is critical. They are an essential part of turning intention into action (eg, as required by PAS 55 s 4.5.1).	Asset managers, operations managers, maintenance managers and project managers from other impacted areas of the business	Documented procedure for review. Documented procedure for audit of process delivery. Records of previous audits, improvement actions and documented confirmation that actions have been carried out.
95	Performance and condition monitoring	How does the organisation measure the performance and condition of its assets?	2	The routine inspection process captures information relating to defects and hazards, but not a specific, objective assessment of asset condition. Mobile technology is used for inspection records and the quality of information for decision making has improved. As part of the maintenance standards review, a more specific condition assessment regime will be introduced.		Widely used AM standards require that organisations establish implement and maintain procedure(s) to monitor and measure the performance and/or condition of assets and asset systems. They further set out requirements in some detail for reactive and proactive monitoring, and leading/lagging performance indicators together with the monitoring or results to provide input to corrective actions and continual improvement. There is an expectation that performance and condition monitoring will provide input to improving asset management strategy, objectives and plan(s).	A broad cross-section of the people involved in the organisation's asset-related activities from data input to decision-makers, i.e. an end-to-end assessment. This should include contactors and other relevant third parties as appropriate.	Functional policy and/or strategy documents for performance or condition monitoring and measurement. The organisation's performance monitoring frameworks, balanced scorecards etc. Evidence of the reviews of any appropriate performance indicators and the action lists resulting from these reviews. Reports and trend analysis using performance and condition information. Evidence of the use of performance and condition information shaping improvements and supporting asset management strategy, objectives and plan(s).
99	Investigation of asset-related failures, incidents and nonconformities	How does the organisation ensure responsibility and the authority for the handling, investigation and mitigation of asset-related failures, incidents and emergency situations and non conformances is clear, unambiguous, understood and communicated?	2	An incident reporting process in place, and asset-related failures, worksite incidents and emergency situations all initiate processes for investigation and mitigation. Outcomes of audits and investigations are available to all staff. The Intranet is used as a common internal communication system. Non-conformances with processes and procedures are routinely reported, with an emphasis on health and safety impacts. More formal processes relating to asset failure and network performance investigations are being developed.		Widely used AM standards require that the organisation establishes implements and maintains process(es) for the handling and investigation of failures incidents and non-conformities for assets and sets down a number of expectations. Specifically this question examines the requirement to define clearly responsibilities and authorities for these activities, and communicate these unambiguously to relevant people including external stakeholders if appropriate.	The organisation's safety and environment management team. The team with overall responsibility for the management of the assets. People who have appointed roles within the asset-related investigation procedure, from those who carry out the investigations to senior management who review the recommendations. Operational controllers responsible for managing the asset base under fault conditions and maintaining services to consumers. Contractors and other third parties as appropriate.	Process(es) and procedure(s) for the handling, investigation and mitigation of asset-related failures, incidents and emergency situations and non conformances. Documentation of assigned responsibilities and authority to employees. Job Descriptions, Audit reports. Common communication systems i.e. all Job Descriptions on Internet etc.

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Question No.	Function	Question	Score	Evidence—Summary	User Guidance	Why	Who	Record/document Information
105	Audit	What has the organisation done to establish procedure(s) for the audit of its asset management system (process(es))?	2	Procedures for audit exist in some aspects of the AM systems and processes, such as safety, quality and financial. Some areas of process and systems do not yet have established audit procedures and these are developed on a case by case basis to address identified issues or risks.		This question seeks to explore what the organisation has done to comply with the standard practice AM audit requirements (eg, the associated requirements of PAS 55 s 4.6.4 and its linkages to s 4.7).	The management team responsible for its asset management procedure(s). The team with overall responsibility for the management of the assets. Audit teams, together with key staff responsible for asset management. For example, Asset Management Director, Engineering Director. People with responsibility for carrying out risk assessments	The organisation's asset-related audit procedure(s). The organisation's methodology(s) by which it determined the scope and frequency of the audits and the criteria by which it identified the appropriate audit personnel. Audit schedules, reports etc. Evidence of the procedure(s) by which the audit results are presented, together with any subsequent communications. The risk assessment schedule or risk registers.
109	Corrective & Preventative action	How does the organisation instigate appropriate corrective and/or preventive actions to eliminate or prevent the causes of identified poor performance and non conformance?	2	Results of inspections and investigations of failures are reviewed by subject experts and used as inputs into the AM programme. Follow-through is recorded in action plans, minutes and the contents of related documentation.		Having investigated asset related failures, incidents and non-conformances, and taken action to mitigate their consequences, an organisation is required to implement preventative and corrective actions to address root causes. Incident and failure investigations are only useful if appropriate actions are taken as a result to assess changes to a businesses risk profile and ensure that appropriate arrangements are in place should a recurrence of the incident happen. Widely used AM standards also require that necessary changes arising from preventive or corrective action are made to the asset management system.	The management team responsible for its asset management procedure(s). The team with overall responsibility for the management of the assets. Audit and incident investigation teams. Staff responsible for planning and managing corrective and preventive actions.	Analysis records, meeting notes and minutes, modification records. Asset management plan(s), investigation reports, audit reports, improvement programmes and projects. Recorded changes to asset management procedure(s) and process(es). Condition and performance reviews. Maintenance reviews
113	Continual Improvement	How does the organisation achieve continual improvement in the optimal combination of costs, asset related risks and the performance and condition of assets and asset systems across the whole life cycle?	2	Exploration of improvement is evident in action; in the execution of innovative projects and process improvements; and in recognition within the industry. Specific initiatives are recorded in the business plan for development; with opportunity registers regularly reviewed by senior management.		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 than reviews and audit (which are separately examined).	The top management of the organisation. The manager/team responsible for managing the organisation's asset management system, including its continual improvement. Managers responsible for policy development and implementation.	Records showing systematic exploration of improvement. Evidence of new techniques being explored and implemented. Changes in procedure(s) and process(es) reflecting improved use of optimisation tools/techniques and available information. Evidence of working parties and research.
115	Continual Improvement	How does the organisation seek and acquire knowledge about new asset management related technology and practices, and evaluate their potential benefit to the organisation?	3	Participation in industry forums ; conferences; joint initiatives; participation in relevant industry groups; international data gathering and research and inclusion of appropriate goals in personal development and business plans. Business case assessment for new technologies and operating arrangements/partnerships is actively undertaken.		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.

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.

Box 1: Commentary on difference between nominal and constant price capital expenditure forecasts

The difference between nominal and constant prices reflects inflation of 2% per annum

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.

Box 2: Commentary on difference between nominal and constant price operational expenditure forecasts

The difference between nominal and constant prices reflects inflation of 2% per annum

Appendix C – Assessment against Information Disclosure Requirements

Information Disclosure Requirements 2015 clause	AMP Section
3 The AMP must include the following -	
3.1 A summary that provides a brief overview of the contents and highlights information that the EDB considers significant	Plan Summary
3.2 Details of the background and objectives of the EDB's asset management and planning processes	4
3.3 A purpose statement which-	
3.3.1 makes clear the purpose and status of the AMP in the EDB's asset management practices. The purpose statement must also include a statement of the objectives of the asset management and planning processes	1.1
3.3.2 states the corporate mission or vision as it relates to asset management	1.1
3.3.3 identifies the documented plans produced as outputs of the annual business planning process adopted by the EDB	1.1
3.3.4 states how the different documented plans relate to one another, with particular reference to any plans specifically dealing with asset management	1.1
3.3.5 includes a description of the interaction between the objectives of the AMP and other corporate goals, business planning processes, and plans	1.1
3.4 Details of the AMP planning period, which must cover at least a projected period of 10 years commencing with the disclosure year following the date on which the AMP is disclosed	1.2
3.5 The date that it was approved by the directors	1.3
3.6 A description of stakeholder interests (owners, consumers etc.) which identifies important stakeholders and indicates-	2.4
3.6.1 how the interests of stakeholders are identified	2.4
3.6.2 what these interests are	2.4
3.6.3 how these interests are accommodated in asset management practices; and	2.4
3.6.4 how conflicting interests are managed	2.4
3.7 A description of the accountabilities and responsibilities for asset management on at least 3 levels, including-	2.1.3; 2.1.4
3.7.1 governance—a description of the extent of director approval required for key asset management decisions and the extent to which asset management outcomes are regularly reported to directors	2.1.3

Information Disclosure Requirements 2015 clause	AMP Section
3.7.2 executive—an indication of how the in-house asset management and planning organisation is structured and	2.1.3
3.7.3 field operations—an overview of how field operations are managed, including a description of the extent to which field work is undertaken in-house and the areas where outsourced contractors are used	2.1.3;2.1.4
3.8 All significant assumptions	Appendix A
3.8.1 quantified where possible	Appendix A
3.8.2 clearly identified in a manner that makes their significance understandable to interested persons, including	Appendix A
3.8.3 a description of changes proposed where the information is not based on the EDB's existing business	Appendix A
3.8.4 the sources of uncertainty and the potential effect of the uncertainty on the prospective information; and	Appendix A
3.8.5 the price inflator assumptions used to prepare the financial information disclosed in nominal New Zealand dollars in the Report on Forecast Capital Expenditure set out in Schedule 11a and the Report on Forecast Operational Expenditure set out in Schedule 11b.	On forecasts; Appendix A
3.9 A description of the factors that may lead to a material difference between the prospective information disclosed and the corresponding actual information recorded in future disclosures	Appendix A
3.10 An overview of asset management strategy and delivery	4.1; 4.2; 4.4
3.11 An overview of systems and information management data	4.3
3.12 A statement covering any limitations in the availability or completeness of asset management data and disclose any initiatives intended to improve the quality of this data	4.3.2
3.13 A description of the processes used within the EDB for-	
3.13.1 managing routine asset inspections and network maintenance	4.4.1
3.13.2 planning and implementing network development projects	4.4.1
3.13.3 measuring network performance.	4.3.2
3.14 An overview of asset management documentation, controls and review processes	4.3.2
3.15 An overview of communication and participation processes	4.3.2
3.16 The AMP must present all financial values in constant price New Zealand dollars except where specified otherwise;	Throughout AMP

Information Disclosure Requirements 2015 clause	AMP Section
3.17 The AMP must be structured and presented in a way that the EDB considers will support the purposes of AMP disclosure set out in clause 2.6.2 of the determination.	Throughout AMP
Assets covered	
4 The AMP must provide details of the assets covered, including- 4.1 a high-level description of the service areas covered by the EDB and the degree to which these are interlinked, including- 4.1.1 the region(s) covered 4.1.2 identification of large consumers that have a significant impact on network operations or asset management priorities 4.1.3 description of the load characteristics for different parts of the network 4.1.4 peak demand and total energy delivered in the previous year, broken down by sub-network, if any. 4.2 a description of the network configuration, including- 4.2.1 identifying bulk electricity supply points and any distributed generation with a capacity greater than 1 MW. State the existing firm supply capacity and current peak load of each bulk electricity supply point; 4.2.2 a description of the subtransmission system fed from the bulk electricity supply points, including the capacity of zone substations and the voltage(s) of the subtransmission network(s). The AMP must identify the supply security provided at individual zone substations, by describing the extent to which each has n-x subtransmission security or by providing alternative security class ratings; 4.2.3 a description of the distribution system, including the extent to which it is underground; 4.2.4 a brief description of the network's distribution substation arrangements; 4.2.5 a description of the low voltage network including the extent to which it is underground; and 4.2.6 an overview of secondary assets such as protection relays, ripple injection systems, SCADA and telecommunications systems.	2.1 2.1; Appendix E 2.5.1 2.5.3 2.7 2.5.2; 2.6 2.6; 6.4 2.6 2.6 2.6
4.3 If sub-networks exist, the network configuration information referred to in subclause 4.2 must be disclosed for each sub-network.	N/A
Network assets by category	
4.4 The AMP must describe the network assets by providing the following information for each asset category- 4.4.1 voltage levels;	2.6.1; 2.6.2

Information Disclosure Requirements 2015 clause	AMP Section
4.4.2 description and quantity of assets; 4.4.3 age profiles; and	5.1 - 5.10 5.1-5.10
4.4.4 a discussion of the condition of the assets, further broken down into more detailed categories as considered appropriate. Systemic issues leading to the premature replacement of assets or parts of assets should be discussed.	5.1-5.10
4.5 The asset categories discussed in subclause 4.4 should include at least the following-	5.1-5.10
4.5.1 The categories listed in the Report on Forecast Capital Expenditure in Schedule 11a (iii)	5.1-5.10
4.5.2 Assets owned by the EDB but installed at bulk electricity supply points owned by others	5.1
4.5.3 EDB owned mobile substations and generators whose function is to increase supply reliability or reduce peak demand	5.9
4.5.4 Other generation owned by the EDB.	N/A
Service levels	
5 The AMP must clearly identify or define a set of performance indicators for which annual performance targets have been defined. The annual performance targets must be consistent with business strategies and asset management objectives and be provided for each year of the AMP planning period. The targets should reflect what is practically achievable given the current network configuration, condition and planned expenditure levels. The targets should be disclosed for each year of the AMP planning period.	3.2-3.6
6 Performance indicators for which targets have been defined in clause 5 must include SAIDI values and SAIFI values for the next 5 disclosure years.	3.4
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;	3.4
7.2 Indicators of asset performance, asset efficiency and effectiveness, and service efficiency, such as technical and financial performance indicators related to the efficiency of asset utilisation and operation.	3.6
8 The AMP must describe the basis on which the target level for each performance indicator was determined. Justification for target levels of service includes consumer expectations or demands, legislative, regulatory, and other stakeholders' requirements or considerations. The AMP should demonstrate how stakeholder needs were ascertained and translated into service level targets.	3
9 Targets should be compared to historic values where available to provide context and scale to the reader.	3

Information Disclosure Requirements 2015 clause	AMP Section
10 Where forecast expenditure is expected to materially affect performance against a target defined in clause 5, the target should be consistent with the expected change in the level of performance.	3
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;	6.1
11.2 Planning criteria for network developments should be described logically and succinctly. Where probabilistic or scenario-based planning techniques are used, this should be indicated and the methodology briefly described;	6.1
11.3 A description of strategies or processes (if any) used by the EDB that promote cost efficiency including through the use of standardised assets and designs;	6.1.3; 6.1.4
11.4 The use of standardised designs may lead to improved cost efficiencies. This section should discuss—	
11.4.1 the categories of assets and designs that are standardised;	6.1.3
11.4.2 the approach used to identify standard designs.	6.1.3
11.5 A description of strategies or processes (if any) used by the EDB that promote the energy efficient operation of the network.	4
11.6 A description of the criteria used to determine the capacity of equipment for different types of assets or different parts of the network.	6.1.3
11.7 A description of the process and criteria used to prioritise network development projects and how these processes and criteria align with the overall corporate goals and vision.	6.1; 4
11.8 Details of demand forecasts, the basis on which they are derived, and the specific network locations where constraints are expected due to forecast increases in demand;	6
11.8.1 explain the load forecasting methodology and indicate all the factors used in preparing the load estimates;	6.2
11.8.2 provide separate forecasts to at least the zone substation level covering at least a minimum five-year forecast period. Discuss how uncertain but substantial individual projects/developments that affect load are taken into account in the forecasts, making clear the extent to which these uncertain increases in demand are reflected in the forecasts;	6.4; 6.5

Information Disclosure Requirements 2015 clause	AMP Section
11.8.3 identify any network or equipment constraints that may arise due to the anticipated growth in demand during the AMP planning period; and	6
11.8.4 discuss the impact on the load forecasts of any anticipated levels of distributed generation in a network, and the projected impact of any demand management initiatives.	Appendix A
11.9 Analysis of the significant network level development options identified and details of the decisions made to satisfy and meet target levels of service, including-	6.4; 6.5
11.9.1 the reasons for choosing a selected option for projects where decisions have been made;	6.4; 6.5
11.9.2 the alternative options considered for projects that are planned to start in the next five years and the potential for non-network solutions described;	6.4; 6.5
11.9.3 consideration of planned innovations that improve efficiencies within the network, such as improved utilisation, extended asset lives, and deferred investment.	6.1.4; 6.1.5; 6.4; 6.5
11.10 A description and identification of the network development programme including distributed generation and non-network solutions and actions to be taken, including associated expenditure projections. The network development plan must include-	6.4-6.6
11.10.1 a detailed description of the material projects and a summary description of the non-material projects currently underway or planned to start within the next 12 months;	6.4-6.6
11.10.2 a summary description of the programmes and projects planned for the following four years (where known); and	6.4-6.6
11.10.3 an overview of the material projects being considered for the remainder of the AMP planning period.	6.4-6.6
11.11 A description of the EDB's policies on distributed generation, including the policies for connecting distributed generation. The impact of such generation on network development plans must also be stated.	6.2; Appendix A
11.12 A description of the EDB's policies on non-network solutions, including-	4.2.3
11.12.1 economically feasible and practical alternatives to conventional network augmentation. These are typically approaches that would reduce network demand and/or improve asset utilisation; and	6.1.5
11.12.2 the potential for non-network solutions to address network problems or constraints.	6.1.5
Lifecycle Asset Management Planning (Maintenance and Renewal)	
12 The AMP must provide a detailed description of the lifecycle asset management processes, including—	

Information Disclosure Requirements 2015 clause	AMP Section
12.1 The key drivers for maintenance planning and assumptions;	4.1
12.2 Identification of routine and corrective maintenance and inspection policies and programmes and actions to be taken for each asset category, including associated expenditure projections. This must include-	5.2-5.8
12.2.1 the approach to inspecting and maintaining each category of assets, including a description of the types of inspections, tests and condition monitoring carried out and the intervals at which this is done;	5.2-5.10
12.2.2 any systemic problems identified with any particular asset types and the proposed actions to address these problems; and	5.2-5.10
12.2.3 budgets for maintenance activities broken down by asset category for the AMP planning period.	8.1.1; 8.2.1
12.3 Identification of asset replacement and renewal policies and programmes and actions to be taken for each asset category, including associated expenditure projections. This must include-	4;5
12.3.1 the processes used to decide when and whether an asset is replaced or refurbished, including a description of the factors on which decisions are based, and consideration of future demands on the network and the optimum use of existing network assets;	4
12.3.2 a description of innovations that have deferred asset replacements;	4.1.3; 4.2
12.3.3 a description of the projects currently underway or planned for the next 12 months;	5.2-5.8
12.3.4 a summary of the projects planned for the following four years (where known); and	5.2-5.8
12.3.5 an overview of other work being considered for the remainder of the AMP planning period.	5.2-5.8
12.4 The asset categories discussed in clauses 12.2 and 12.3 should include at least the categories in subclause 4.5.	5.2-5.8
Non-Network Development, Maintenance and Renewal	
13 AMPs must provide a summary description of material non-network development, maintenance and renewal plans, including—	7
13.1 a description of non-network assets;	7
13.2 development, maintenance and renewal policies that cover them;	7
13.3 a description of material capital expenditure projects (where known) planned for the next five years;	7
13.4 a description of material maintenance and renewal projects (where known) planned for the next five years.	7
Risk Management	
14 AMPs must provide details of risk policies, assessment, and mitigation, including—	
14.1 Methods, details and conclusions of risk analysis;	4.5

Information Disclosure Requirements 2015 clause	AMP Section
14.2 Strategies used to identify areas of the network that are vulnerable to high impact low probability events and a description of the resilience of the network and asset management systems to such events;	4.5-4.8
14.3 A description of the policies to mitigate or manage the risks of events identified in clause 14.2;	4..5-4.8
14.4 Details of emergency response and contingency plans.	4.8
Evaluation of performance	
15 AMPs must provide details of performance measurement, evaluation, and improvement, including—	9
15.1 A review of progress against plan, both physical and financial;	9
15.2 An evaluation and comparison of actual service level performance against targeted performance;	3.2-3.6
15.3 An evaluation and comparison of the results of the asset management maturity assessment disclosed in the Report on Asset Management Maturity set out in Schedule 13 against relevant objectives of the EDB's asset management and planning processes.	Schedule 13 attached to AMP
15.4 An analysis of gaps identified in clauses 15.2 and 15.3. Where significant gaps exist (not caused by one-off factors), the AMP must describe any planned initiatives to address the situation.	3.2-3.6; 4.10
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;	Throughout AMP
16.2 The organisation structure and the processes for authorisation and business capabilities will support the implementation of the AMP plans.	2.1

Appendix D – Director Certification



Schedule 17 Certification for Year-beginning Disclosures Clause 2.9.1 of section 2.9

We, Vernon John Dark and Douglas John Troon, being directors of Counties Power Limited certify that, having made all reasonable enquiry, to the best of our knowledge:

1. The following attached information of Counties Power 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.
2. 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.
3. The forecasts in Schedules 11a, 11b, 12a, 12c and 12d are based on objective and reasonable assumptions which both align with Counties Power's corporate vision and strategy which are documented in retained records.



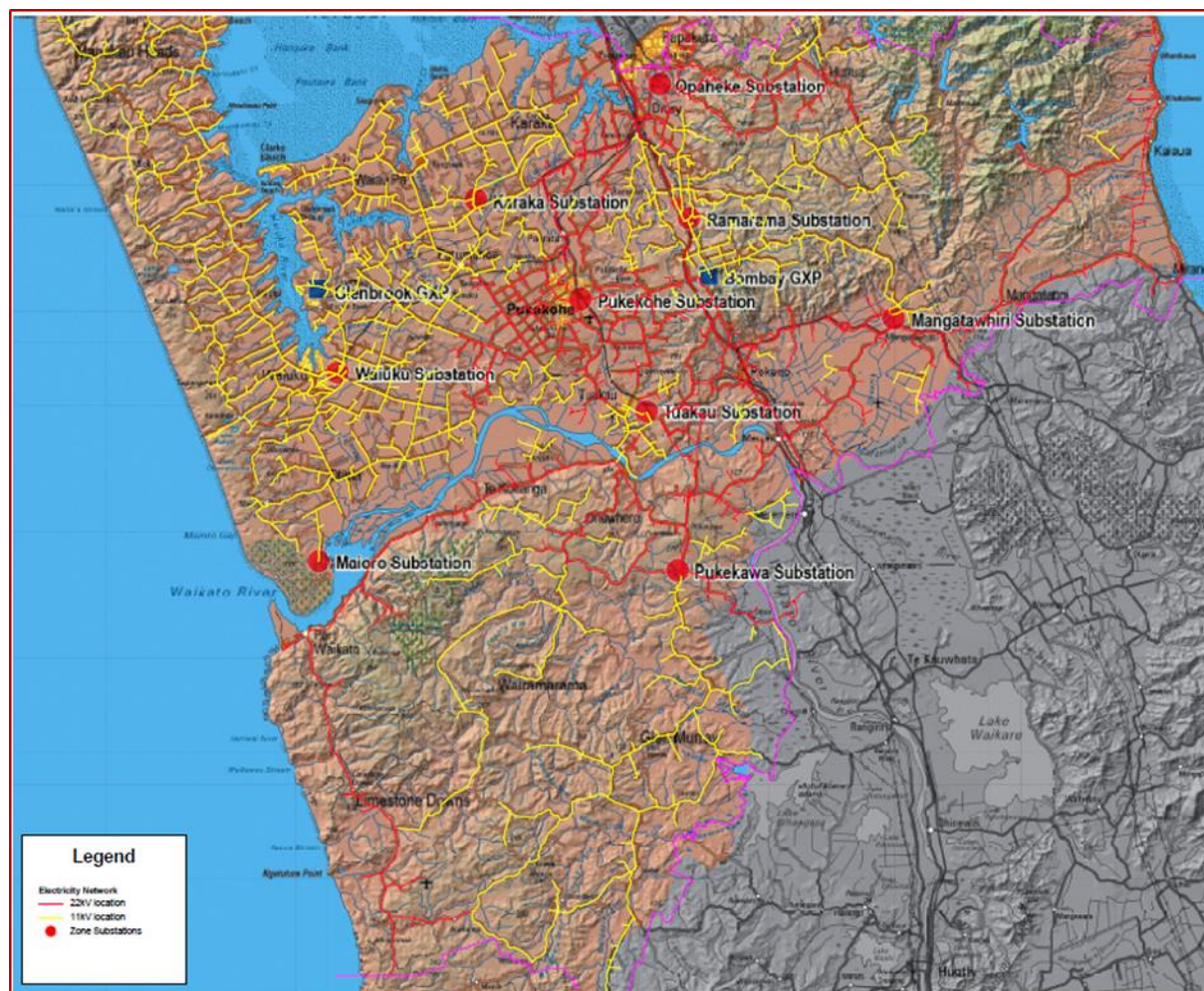
VJ Dark (Director)



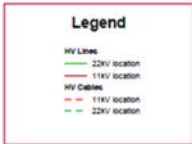
DJ Troon (Director)

Certified at Pukekohe this 21/03/2018 day of March 2018

Appendix E – Network overview diagrams



Overview of network feeders with operating voltages figure



Overview of network feeder coverage areas

Appendix F – Glossary

Term	Description
AAC	All Aluminium Conductor
AAAC	All Aluminium Alloy Conductor
ABS	Air Break Switch
ACSR	Aluminium Conductor Steel Reinforced
ALARP	As Low As Reasonably Practicable
AMMAT	Asset management maturity assessment tool
AMP	Asset Management Plan
Ampere (A)	Unit of electrical current flow, or rate of flow of electrons.
Bus	(Busbar) A common connection point between multiple circuits and equipment.
Bushing	An electrical component that insulates a high voltage conductor passing through a metal enclosure.
Buchholz protection	A Buchholz relay is a safety device sensing the accumulation of gas in large oil-filled transformers, which will alarm on slow accumulation of gas or shut down the transformer if gas is produced rapidly in the transformer oil.
CAIDI	Customer Average Interruption Duration Index is the average total duration of interruption per interrupted customer.
Capacity	The greatest amount of load a circuit can carry.
CB	Circuit Breaker
CBD	Central Business District
Conductor	'Wire' that carries the electricity and includes overhead lines which can be covered (insulated) or bare (not insulated) and underground cables which are insulated.
CT	Current Transformer
Demand	The amount or energy sought by the consumers.
DCIU	Data Concentrator Interface Unit used in SCADA
DNP3	Distributed Network Protocol: A set of communications protocols used between components in SCADA
DO	Drop-out Fuse Switch or Disconnect/Isolator
Disconnect	Also known as a disconnecting switch, isolator, or drop-out
Distribution Line	[Ref NZECP 34] Means works that are owned by Counties Power used for the conveyance of electricity to one or more electrical installations.
Distribution Pillar	A plastic ground mounted enclosure, usually found on a properties boundary containing the fuses for a service supply.
Easement	An easement is a right given to another person or entity to trespass upon land that person or entity does not own
Earth-fault	A circuit conductor unintentionally grounded.
EDB	Electricity Distribution Business
EEA	Electricity Engineers' Association (EEA)
EIPC	Electricity Industry Participation Code 2010 (the "Code")
FY	Financial Year e.g. FY2013 is Financial Year 2014 which covers 1 st April 2013 to 31 st March 2014
Fault	means a physical condition that causes a device, component or network element to fail to perform in the required manner
Feeder	A physical grouping of conductors that originate from a district/zone substation circuit breaker.
Fixed Asset	A purchase normally over \$500 with an intended life cycle of at least over one year.
Flashover	A disruptive discharge around or over the surface of an insulator.
GIS	The Geographic Information System used for electronic mapping of the network.
Grid Exit Point (GXP)	The point at which Counties Power Equipment is deemed to connect to the Transpower Grid System.
GWh	giga-watt hour

Term	Description
Harmonic distortion	Distortion of the sine wave which represents ideal AC power. Usually by super imposed higher frequencies.
High Voltage (HV)	Any voltage exceeding 1000 V a.c. or 1500 V d.c. but usually pertaining to the 11kV or 33kV distribution system.
ICP (Installation Control Point)	A number that uniquely identifies each connection to an electrical lines network that is recorded in a national registry.
Kiosk	A small structure, often open on one or more sides.
kV	kilo-volt
Lines	The LV and HV network of overhead and underground electricity conductors and cables and their associated equipment such as insulators, poles, crossarms etc.
Load Break Switch	A switch that can be operated under load.
Injection Plant	Injects a signal onto 50Hz network, for controlling ripple relays.
Low Voltage (LV)	Any voltage exceeding 32 V a.c. or 115 V d.c. but not exceeding 1000 V a.c. or 1500 V d.c.
MV circuit breakers	Medium voltage circuit breaker
MW	mega-watt
Maximum Demand	The highest value of the power or apparent power taken within the account period, such as, month or year.
MVA	mega-volt-ampere
n-1 security	A load is said to have n-1 security if for the loss of any one item of equipment supply to that load is not interrupted or can be restored in the time taken to switch to alternate supplies. Network Utility reticulation system or asset owned by the utility Company, Trust or other body having control and/or ownership in the utility reticulation system including the land, buildings, installations, individual customer connections up to the point of supply, and other improvements on or under which the utility reticulation system is located.
NAV	ERP and accounting software package; version used in Counties Power is Microsoft Dynamics NAV R2 2009
NZEC35	New Zealand Electrical Code of Practice for Power System Earthing
ODRC	Optimised Depreciated Replacement Cost
ODV	Optimised Deprival Value
ONAN	Abbreviation denote the cooling method used for a transformer: Oil natural, Air natural –no fans or pumps are running, cooling uses natural convection through radiators
ONAF	Abbreviation denote the cooling method used for a transformer: Oil Natural, Air Forced - no oil pump running, fans running forcing air across radiators
OFAF	Abbreviation denote the cooling method used for a transformer: Oil forced (pumped), Air Forced (Fans)
Outage	an interruption to electricity supply
Overcurrent	Current in excess of the rated current of a conductor.
Overhead	Above ground, pole mounted conductor
PSMS	Public Safety Management System
QMS	Quality Management System
RAB	Residual asset base
Recloser	A piece of equipment on the distribution network work which automatically trips when a fault is detected (typically a tree touching the line) and recloses after a set time (minutes).
Reliability	The ability of an item to perform a required function under stated conditions for a stated period of time.
Remaining economic life	The likely future period during which an Asset is expected to generate a positive contribution to value.
Residual Risk	The remaining level of risk after risk treatment measures has been taken.
Retailer	An electrical energy supplier who has a User Supply Agreement with Counties Power.
Risk	Probability (likelihood) and consequences, positive or negative, of an event. In some situations, risk is a deviation from the expected.

Term	Description
Risk Management	AS/NZS 4360 defines risk management as a term applied to a logical and systematic method of identifying, analysing, evaluating, treating, monitoring and communicating risk associated with any activity, function or process in a way that enables maximisation of benefits or minimisation of losses or detrimental effects.
RMU	Ring Main Unit
RTU	Remote Terminal Unit – Communications device used for relaying data from the field.
SAIDI	System Average Interruption Duration Index is the average total duration of interruption per connected customer.
SAIFI	System Average Interruption Frequency Index is the average number of interruptions per connected customers.
SCADA	Counties Power's computerised System Control And Data Acquisition System being the primary tool for monitoring and controlling access, and switching operations for Counties Power's Network
Smallworld	GIS-based system for mapping of the network
Stakeholder	People and organisations who may affect, be affected by, or perceive themselves to be affected by a decision or activity.
Standard	The document that prescribes the requirements with which the product or service has to conform. The criteria for acceptable levels of safety performance/behaviours set by Counties Power, industry codes or relevant legislation.
Standard Operating Procedure (SOP)	A locally controlled work method statement or 'desk top' file.
Substation	Electrical facility where the voltage of incoming and outgoing circuits is changed and controlled.
Supplier	Organisation that provides a service or product to the customer:
Test Permit	The permit for access to HV equipment which has been removed from service to enable testing and where procedures are required to control hazards created by the testing.
Transpower	The national grid operator.
UHF	Ultra High Frequency.
User	Any person or organisation using the Distribution System, but excluding Transpower. It includes all Customers, embedded generators, and where appropriate, Electricity Retailers acting on behalf of their customers.
Vegetation	Any trees or other plants threatening the Counties Power Networks overhead lines.
VHF	Very High Frequency
Voltage regulators	A voltage regulator is an electrical regulator designed to automatically maintain a constant voltage level.
VT	Voltage Transformer
WIP	Work in Progress
WWTP	Waikato Water Treatment Plant
XLPE	Type of cable insulation – Cross-linked Polyethylene
Zone Substation	Includes HV substations, switching stations, voltage regulators, ground mounted HV switchgear, large industrial/commercial distribution substations, ripple control plant, and associated protection and controls.