Wellington Electricity

10 Year Asset Management Plan

1 April 2015 - 31 March 2025

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Any comments or suggestions regarding the Asset Management Plan can be made to:

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Information, outcomes and statements in this version of the AMP are based on information available to Wellington Electricity that was correct at the time of preparation. Some of this information may subsequently prove to be incorrect and some of the assumptions and forecasts made may prove inaccurate. In addition, with the passage of time, or with impacts from future events, circumstances may change and accordingly some of the information, outcomes and statements may need to change.

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Statement from the Chief Executive Officer

Wellington Electricity welcomes the opportunity to submit an updated Asset Management Plan (AMP) for the period 2015 to 2025. We confirm that this AMP has been prepared for the Commerce Commission's *Electricity Distribution Information Disclosure Determination 2012* requirements.

Our operations over the last 12 months have continued to focus on delivering high levels of safety, reliability and service to our customers, while maintaining a high level of performance from our network assets. We have been fortunate that the major weather events of the past few years have not continued in 2014 which has provided a stable operating period where we have met customer service levels.

The network has performed to expectations. It is pleasing to see continued improvement in areas where engagement with third parties has been instrumental in protecting assets from interference by discussing safer methods to undertake their work.

This will be an important development through the early stage of the plan to align and demonstrate compliance with Work Safe NZ regulations expected to be drafted during 2015.

We continue to invest in the network assets where they require replacement to ensure we operate a safe and reliable electricity delivery infrastructure. This requires good planning from well-defined asset strategies which is central to the role the Asset Management Plan plays in communicating our business drivers and forward work plans to our stakeholders.

The economic outlook for the region still appears relatively flat compared to the national growth and GDP perspectives, which is evident through flat peak network demand and falling energy consumption. However business confidence continues to build which is being supported through lower unemployment figures.

Our reliance on sound risk management practices helps to analyse the various business impacts we face and the controls we have in place to manage our operations effectively. This underlines our approach to evaluating network buildings and their performance during a major earthquake event. We are now well through the evaluation stage of where it would be strategic to have key network equipment protected and available to operate following a major earthquake event, to support the community, business and economic recovery for the region.

We continue to strive for business efficiency and have recently consolidated a number of services from outsourced providers to strengthen the cross functional benefits across our teams and enhance customer service. This also brings the drive and enthusiasm to improve our systems and implement the wider learnings from response to past events so we can build on better delivery of service and value to our consumers. A launch in 2015 of an enhanced website; which delivers updated restoration information is expected to be a well-received improvement in consumer information and communication

1 April 2015 represents the start of a new five year regulatory period. The Commerce Commission released a decision on 28 November 2014 ("DPP decision") which re-sets prices the business can charge consumers based on the regulatory allowances Wellington Electricity will have to operate its business over this five year period.

Unfortunately, the AMP was largely completed and five year plans were set ahead of the receiving the Commerce Commission decision. A new section has been added to the beginning of this AMP to describe the high level impact the DPP decision is expected to have on this plan. Further work is currently underway to identify the specific projects and programmes of work which will be impacted. The Network Planning and Lifecycle Management sections of the Plan outline forecast investment strategies as determined ahead of the DPP decision, while the financial schedules in the appendices (Schedule 11) lower the financial investment plans taking into consideration the DPP decision.

This has created some uncertainty and exposure for consumers as planned work is deferred out to the subsequent regulatory period (2020 and beyond) in order to meet the lower regulatory allowances, for the next five years, while maintaining essentially the same levels of service quality from the assets. This will inevitably lead to a price catch-up in subsequent periods to complete the deferred work, otherwise poorer levels of service would be expected to develop in the longer term.

The Commission and Wellington Electricity remain apart on accepting the appropriate basis for forecasting volume growth over the next five year period. The business's historic volume decline has not been supported in the Commissions model used to forecast future volumes. As a result, the decrease in our prices as of 1 April 2015, is higher than expected. This is a material concern for the Wellington business as lower prices coupled with falling volumes further reduce the funds available for network investment that maintains the current service levels for consumers. In the longer term, consumers will need to consider whether they prefer to pay for the catch-up of deferred expenditure from previous periods or alternatively agree a lower service quality. Neither, in Wellington Electricity's opinion, provides the stability of pricing or incentives for ongoing network investment which deliver on the price-quality regulation objective for providing long term benefit to consumers.

Wellington Electricity will continue to proactively engage with the Commerce Commission on these performance anomalies and continue to encourage Policy changes to address inconsistencies in the Price-Quality regulation outcomes.

We continue to close gaps identified in the output from our Asset Management Maturity Assessment Tool (AMMAT). This has included the implementation of the SAP Plant Maintenance module which supports maintenance prioritisation. This is starting to deliver benefits to our asset management processes for planned, remedial and corrective maintenance of our assets as well as enhanced works order management.

Overall Wellington Electricity is managing a mature set of assets which, when not affected by large natural events, are performing well for the consumers. The challenge is how well this can continue to be the case with reduced allowances and incentives for future investment.

We are also proud to receive re-certification from Telarc, for a further five year period, from the compliance audit of the operation systems we use to ensure ongoing safety of our assets located in public areas. The Public Safety Management System - AS/NZS 7901 is a standard which assists with supporting our strong focus on continuing to develop an engaged health and safety culture.

Being a member of the CKI and Power Assets Group allows Wellington Electricity the ability to access skills and knowledge from our other electricity distribution businesses around the world and have direct access to international best practice in asset management.

In conjunction with our service companies and in alignment with its business strategy, Wellington Electricity will continue to focus on the development of asset management strategies in parallel with the short to long term planning of the network. Subject to the constraints discussed above and further in this AMP, we will continue to work towards a regulatory price-quality process that incentivises appropriate levels of capital and operational expenditures, so we can continue to deliver a safe, reliable and cost effective supply of electricity to consumers within the Wellington region.

We welcome any comments or suggestions regarding this AMP.

Greg Skelton
Chief Executive Officer

Impact of the 2014 Default Price Path (DPP) Decision on this plan

This Asset Management Plan (AMP) was prepared on the basis of project plans and forecasts developed prior to the November 2014 Default Price-quality Path (DPP) reset decision. Due to the limited time available between the reset decision and the disclosure of this AMP, the assumptions made and the project plans and forecasts have not been updated to reflect the impact of the decision and accordingly represent a "pre-reset" view of what Wellington Electricity was expecting to achieve during the planning period.

This section outlines an initial high-level view on the impact of the reset decision and the options for Wellington Electricity in response to the decision. The content of this AMP should be read in the context that a full re-evaluation is underway and changes will be expected.

The DPP Decision

In 2014, the Commerce Commission ("Commission") undertook a reset of the DPP regulatory regime under which Wellington Electricity and other "non-exempt" New Zealand Electricity Distribution Businesses ("EDB") operate. On 28 November 2014, the Commission published its final decision on the DPP applying to Wellington Electricity and other EDB's from 1 April 2015 to 31 March 2020.

This DPP decision determines Wellington Electricity's weighted average prices for the 2015 to 2020 period. Under this weighted average price cap approach, the Commission first calculates Wellington Electricity's revenue requirement based on its view of the company's efficient operating expenditure (OPEX) and capital expenditure (CAPEX). The Commission then applies its forecasts of energy consumption growth, known as constant price revenue growth (CPRG), to determine the 'starting prices' to apply at 1 April 2015. Each year thereafter prices may increase by CPI until the next DPP re-set, which is scheduled to occur in 2020.

Together with the return on investment (known as Weighted Average Cost of Capital or WACC), the forecasts of capex, opex and CPRG are critical to determining the price consumers pay and what maintenance and renewal work Wellington Electricity is able to undertake on its network assets. This of course has a direct impact on the reliability of supply for consumers and Wellington Electricity is required to meet performance standards for this, also set by the Commission.

On 28 February 2015 and following the final DPP decision, Wellington Electricity announced that its prices for delivering electricity supply to its consumers would decrease by an average of 10% as at 1 April 2015.

Whilst a price decrease was anticipated, the magnitude of the final price decrease mandated by the Commission was larger than expected. The reasons and implications of this are discussed further below. As noted, the full impact on specific projects is still being evaluated, however it is clear that Wellington Electricity will be required to defer a significant amount of capital and operating expenditure over the next five years. The expectation is that future periods will require significantly more investment to 'catch up', if the current high level of reliability is to be maintained.

Two critical outcomes from the DPP decision impact on Wellington Electricity's ability to efficiently maintain and renew its network assets, and consequently have the potential to affect Wellington consumers. These are:

- The uncertainty of Wellington Electricity's revenue between 2015 and 2020, caused by a significant gap between the observed ongoing decline in electricity consumption by Wellington consumers and the Commission's assumption that consumers will use more electricity over the next five years. The

Commission's assumption of growth in electricity consumption was used to determine the magnitude of the price decrease as at 1 April 2015; and

- The reduction in the allowable expenditure on OPEX and CAPEX for the period, relative to the forecasts presented by Wellington Electricity in previous AMPs and this AMP. Specifically, the Commission's forecasting methods did not provide for an allowance for the expenditure Wellington Electricity requires to invest in increased earthquake resilience.

The most critical of these issues is the uncertainty in the revenue Wellington Electricity will actually earn over the next five years, which is highly dependent on electricity consumption trends. Each issue is discussed in more detail below.

Uncertainty in forecast electricity consumption

There is considerable uncertainty in the forecast electricity consumption within the Wellington region over the next five years. While the volumes of electricity consumption in many parts of the country continue to grow, since 2010 electricity consumption in the Wellington region has declined by 1.68% p.a. Whilst it is difficult to forecast, there is little to suggest that this decline will not continue. In contrast with the trend of declining consumption, the Commission has set Wellington Electricity's prices at 1 April 2015 on the expectation that there will be a constant growth in electricity consumption of 0.45% p.a.

The divergence between the Commission's growth assumption and a real decline in consumption results in a significant gap between the revenue (fixed prices x consumption volume) the Commission assumes Wellington Electricity will earn and the actual revenue that can be used to fund investment and operational expenditure. Figure A highlights the expected shortfall in revenues over the next five years.

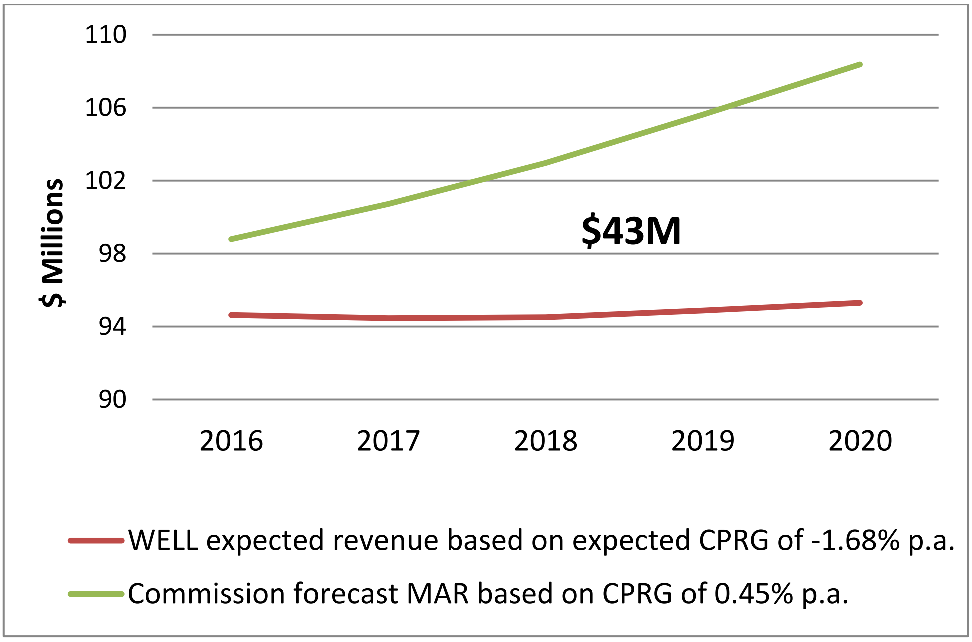


Figure A – Projected Revenue Shortfall 2016-2020

If the historic decline in electricity consumption continues, Wellington Electricity faces an estimated $43 million shortfall in revenue over the next five years. The actual difference could be larger or smaller than this but will only be known as each year passes. The fundamental uncertainty of what revenue will actually be earned to fund investment, necessarily requires an inefficient year by year approach to network maintenance and renewal decisions. $43 million is also a significant amount of expenditure to consider deferring over a five year period.

This uncertainty means that Wellington Electricity will need to determine its ability to fund capital and operating expenditure on a year by year basis, making it very difficult to deliver efficient investment that is optimal for the long term benefit of consumers.

Deferral of Expenditure due to Revenue Uncertainty and Reduced Allowances

The Commission's DPP reset decision capped expenditure allowances (both operational expenditure and capital investment) at a fixed percentage of the historical expenditure level that occurred in specific years. Wellington Electricity submitted that a company's AMP, which is forward looking document based on identified network needs and resourcing requirements over the next 10 years, was the most appropriate basis to use for setting capital investment allowances for the future.

For Wellington Electricity the decision to base forward expenditure on historical circumstances results in significantly lower allowances for the next five years than that forecast in previous AMPs and this document. This gap in expenditure allowances necessarily requires Wellington Electricity to review its planned projects and decide which projects will need to be deferred, given the reduced funding made available by the Commission. Wellington Electricity considers that in the short term it could defer expenditure to live within the allowances set by the Commission and target maintaining the current level of reliability. However, it is expected to result in catch-up investment being necessary in future periods. This is illustrated in Figure B.

However, the expected shortfall in revenue discussed above will require additional capital and operational work to be deferred. Accordingly, there is expected to be a significant gap between Wellington Electricity's own forecasts of required expenditure and the actual level of investment for which funding will be available. As a result, there remains a real risk that the reduced level of CAPEX and OPEX spend on the network will result in poorer levels of service for consumers in the future.

Expenditure Forecast Gap

Figures B and C highlight the differences between the capital and operating allowances set by the Commission for the next five years and the impact to Wellington Electricity's consumers of the catch-up of deferred expenditure in the subsequent five year period to 2025. The gap in funding resulting from the reset decision is illustrated in Figures B and C.

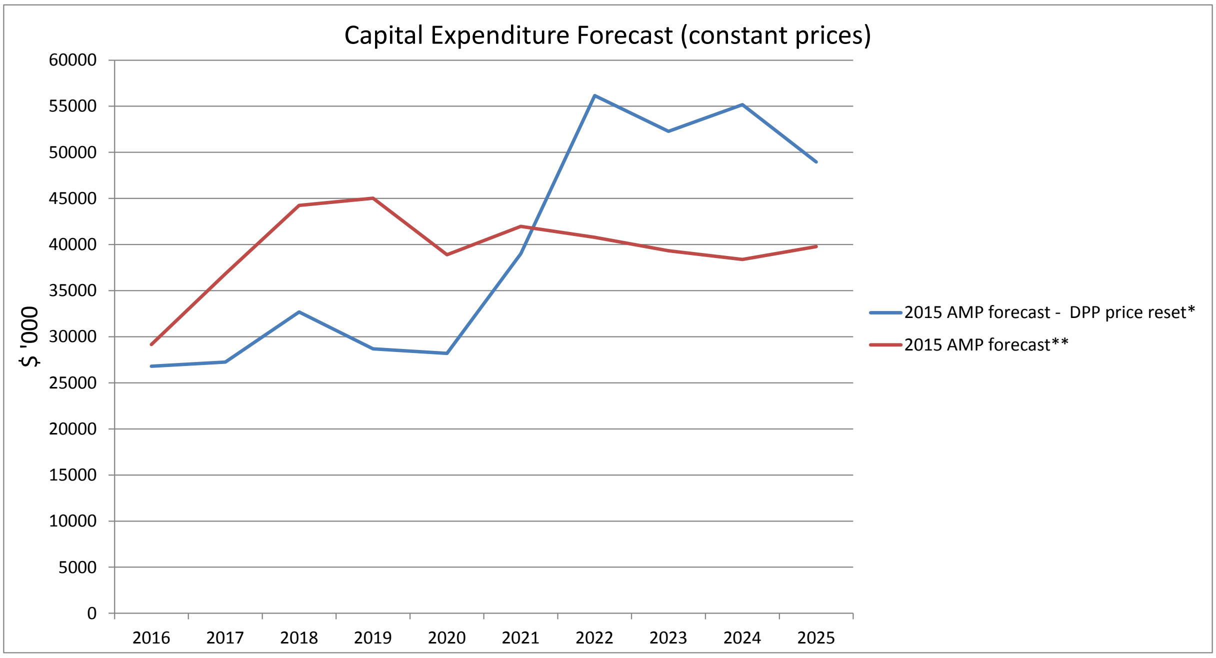


Figure B - Capital expenditure forecast gap

Notes for Figure B

*The blue line represents the expected level of capital expenditure prior to adjusting for any further deferral due to a shortfall in revenues. For the period 2016 to 2020, forecast capital expenditure is limited to the capital expenditure allowance included in the DPP decision. This expenditure is significantly below Wellington Electricity's forecast of the optimal level required to maintain network reliability. Post 2020 it is expected that a significant catch-up of deferred capital expenditure will be needed.

** The red line represents Wellington Electricity's estimate of the optimal level of capital expenditure on the network, to maintain network reliability in a manner that balances price and resourcing requirements to complete the work.

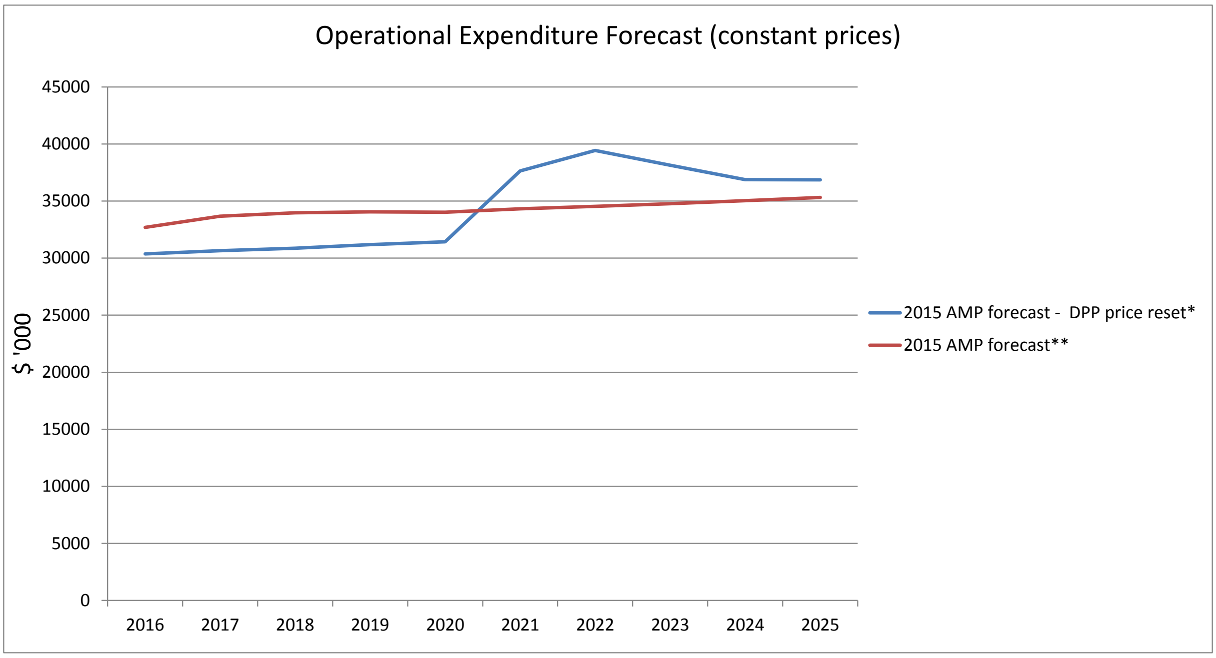


Figure C - Operational expenditure forecast gap

Notes for Figure C

* The blue line represents the expected level of operational expenditure, prior to adjusting for any further deferral due to a shortfall in revenues. For the period 2016 to 2020, forecast operational expenditure is limited to the operational expenditure allowance included in the Commerce Commission 2015 DPP re-set decision. As this expenditure is below Wellington Electricity's forecast of the optimal level required to maintain network reliability, post-2020 there is a catch-up of deferred maintenance.

** The red line represents Wellington Electricity's estimate of the optimal level of operational expenditure to maintain network reliability in a manner that balances price and resourcing requirements to complete the work.

Figure D below highlights the impact of additional deferred expenditure should the above projected shortfall in revenues occur.

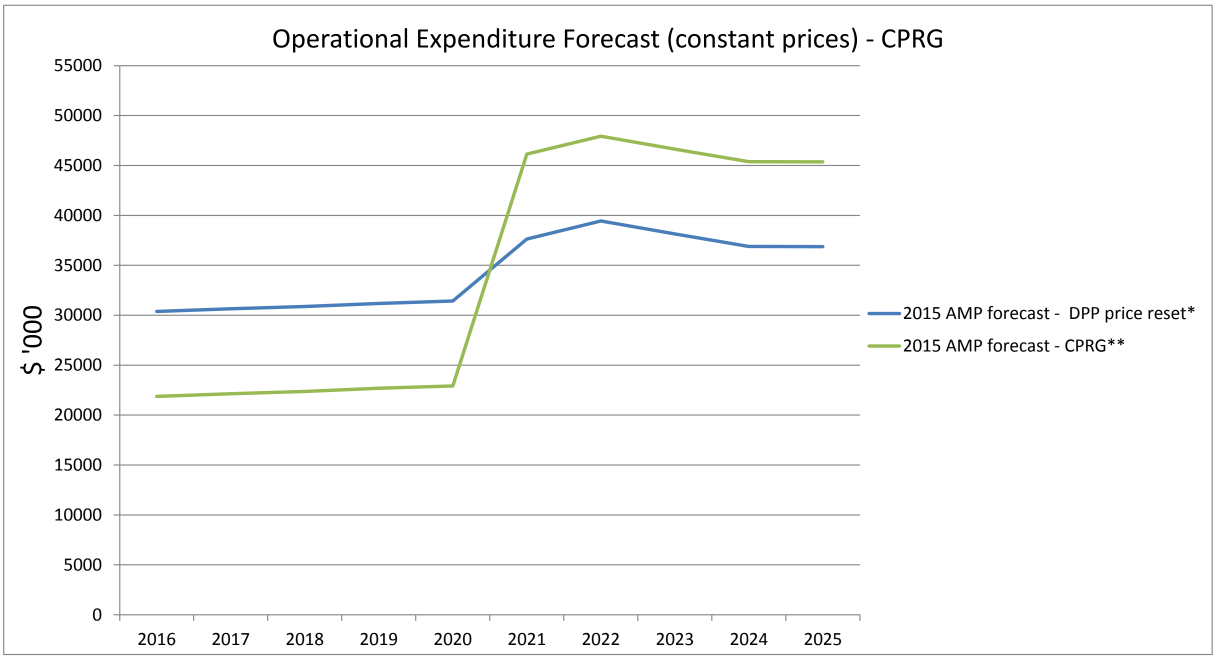


Figure D - Operational expenditure forecast gap – CPRG

Notes for Figure D

* The blue line represents the expected level of operational expenditure, prior to adjusting for any further deferral due to a shortfall in revenues. For the period 2016 to 2020, forecast operational expenditure is limited to the operational expenditure allowance included in the Commerce Commission 2015 DPP re-set decision. As this expenditure is below Wellington Electricity's forecast of the optimal level required to maintain network reliability, post-2020 there is forecast to be a catch-up of deferred maintenance.

** The green line represents Wellington Electricity's estimate of the OPEX funding that would be available should the forecast $43 million shortfall in revenues eventuate due to the difference between the Commission's forecast of CPRG growth and the historic trend of declining energy volumes, discussed above. This shortfall is forecast to result in a greater level of expenditure being necessary in future periods.

Accordingly, the expenditure described in this AMP will need to be re-prioritised and some projects delayed. While there is likely to be little immediate or short term impact for consumers from re-prioritising expenditure, departure from long-term efficient planning will ultimately lead to overall higher prices for consumers. In addition, there is an immediate impact on Wellington Electricity's capability to maintain and operate the network as resource levels are scaled down. The prioritisation of investment will mean that less urgent and non-safety related investments will be delayed. Examples include:

- renewal of assets being delayed or scaled down to address any potential and immediate safety issues only; and
- the timing of capital investment to cater for localised capacity needs are being reconsidered

Options in response to DPP Decision

There are limited alternative options available for Wellington Electricity in addressing the uncertainty arising from the DPP decision. The options include:

- Substantive tariff restructuring to rebalance the fixed and variable tariff prices, with a significantly higher fixed portion. The extent of this option is limited by the *Electricity (Low Fixed Charge Tariff Option for Domestic Consumers) Regulations* which specify that the fixed daily charge for consumers using less than 8,000 kWh per annum must be 15 cents/day;
- Applying for a Customised Price Path (CPP). This option however:
    - requires a significant investment upfront (estimated to be between $2 - $3 million) at a time when revenues are declining and expenditure is being deferred;
    - would take at least two to three years before taking effect at which point the majority of revenue losses have already occurred and cannot subsequently be recovered;
    - provides no guarantee of a better outcome, as the Commission could choose to apply exactly the same approach as it did with the DPP and again not consider concerns raised under submission; and
    - is designed to be the path available to an EDB should it wish to make fundamental changes to its capital and operating expenditure requirements and not a mechanism to address modelling errors in the DPP.
- Applying for a quality only CPP, whereby Wellington Electricity seeks to increase its quality thresholds, resulting in an allowance for more and/or longer power outages to reflect the level of investment that is affordable. This option necessarily requires engaging with consumers to discuss the price-quality trade-off and that the impact of the DPP decision (lower tariffs for consumers) may result in their power supply being less reliable.

Management are evaluating all options available to respond to the impact of the Commission’s final DPP decision for the 2015 – 2020 regulatory period. The analysis and discussion about planned investment throughout the remainder of this document should be read in the context that a full re-evaluation is underway and changes will be expected.

Contents

1 Summary

This section of the AMP is designed to be read as a stand alone overview of the content in the main body of the document. As a result, some key information is subsequently a repeat of detail in later sections while other substantial data is presented as a brief summary only here.

1.1 Introduction

The primary purpose of the Asset Management Plan (AMP) is to communicate Wellington Electricity's strategies, policies, processes and plans for the effective and responsible long-term management of the company's network assets. Subject to the regulatory regime under which Wellington electricity operates, these strategies, policies, processes and plans ensure that electricity supply continues to be delivered at a quality and price sought by electricity consumers connected to the network.

This AMP covers the 10-year period commencing 1 April 2015 and finishing on 31 March 2025. The plans described in this document reflect Wellington Electricity's current business plan and are relatively firm for the next two to three years. Beyond three years the plans are broader and will inevitably need to be adjusted to incorporate internal and external environmental changes as they arise (such as the Commerce Commission's reset of the Default Price-quality Path (DPP) in November 2014).

This AMP was prepared on the basis of project plans and forecasts developed prior to the DPP determination. Due to the limited time available between the reset decision and the disclosure of this AMP, the assumptions made and the project plans and forecasts have not been updated to reflect the impact of the decision and accordingly represent a "pre-reset" view of what Wellington Electricity could have achieved during the planning period. There is expected to be a significant gap between Wellington Electricity's own forecasts of an optimal expenditure profile and the level of investment for which funding will be available.

This AMP was approved by Wellington Electricity's Board of Directors on 27 March 2015.

1.2 Network Overview

Wellington Electricity's distribution network supplies the cities and council jurisdictions of Wellington, Porirua, Lower Hutt and Upper Hutt. A map of the supply area is shown below in Figure 1-1. As of February 2015, there were 165,938 installation control points, ICPs (consumer connections). Over 89% of this number is residential connections and a further 9% is small commercial connections. The total system length (excluding streetlight circuits and DC cable) is 4,680 km, of which 62.7% is underground. The region includes Wellington's Central Business District (CBD) and widespread residential load interspersed with pockets of commercial and light industrial load. The network area does not have large industrial and agricultural loads.

Figure 1-1 Wellington Electricity Network Area

1.3 Asset Management Framework

The asset management framework under which Wellington Electricity operates aligns with the company's corporate mission and objectives and is embodied in this AMP. The framework follows key components of international standards such ISO 55000, and its predecessor, PAS 55. One key component is the Plan-Do-Check-Act cycle of continuous improvement. During 2015, further work will be undertaken on management strategies for each of the main asset categories on the network.This will cover the whole of the asset lifecycle from selection, acquisition and construction, through operations and maintenance to end of life replacement and disposal.

The three main processes that Wellington Electricity uses as part of managing network assets are:

- Planning – e.g., fleet strategies and network development planning;
- Inspection and maintenance; and
- Investment selection.

The interaction of these processes is illustrated in Figure 1-2 below. Long term network and fleet management planning, supported by the inspection regime specified for each asset type and condition, results in identified investments which in turn form the basis for the approved annual Capital Works Plan.

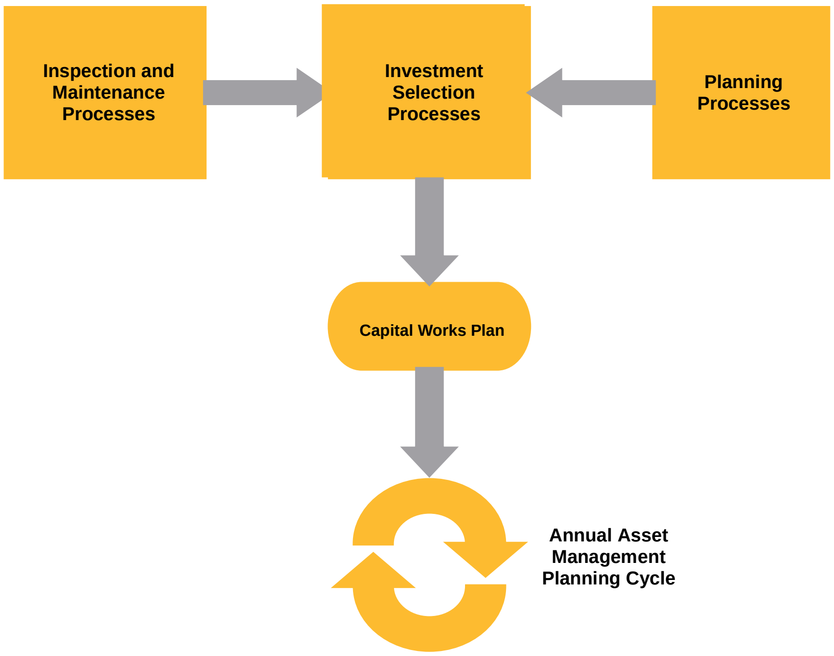


Figure 1-2 Asset Management Processes

A summary of Wellington Electricity's main IT systems, and where they fit in with asset management and network operations processes, is shown in Figure 1-3.

	Physical Attributes	Equipment Ratings	Asset Condition	Connectivity	Customer Service
SCADA / ENMAC		✓		✓	✓
GIS	✓	✓		✓	✓
Project Wise	✓	✓			✓
Power Factory		✓		✓	
Station Ware	✓	✓			
SAP PM	✓		✓		✓
GenTrack				✓	✓
SAP (Financial)					✓

Figure 1-3 IT Systems / Asset Data Repository Summary Table

1.4 Quality, Safety and Environmental Management

Wellington Electricity maintains a comprehensive set of health and safety, environmental and quality policies and procedures and prioritises safety as a core business value. Its employees and contractors are required to both personally manage their own and other people's safety by adhering to safe work practices, making appropriate use of plant and equipment, promptly managing controls for assessed hazards, and reporting of incidents, near misses and accidents.

All reasonable steps are taken to ensure that business activities provide an outcome, which minimises environmental impacts and promotes a sustainable environment for future generations

Safety Initiatives

Wellington Electricity undertakes a range of safety initiatives in the company's workplaces as well as in relation to the community and public safety.

Workplace safety initiatives include:

- Safety breakfasts
- Site safety visits
- Workplace safety
- Safety leadership structure to ensure safety is driven at all levels of the business (see Figure 1-4).

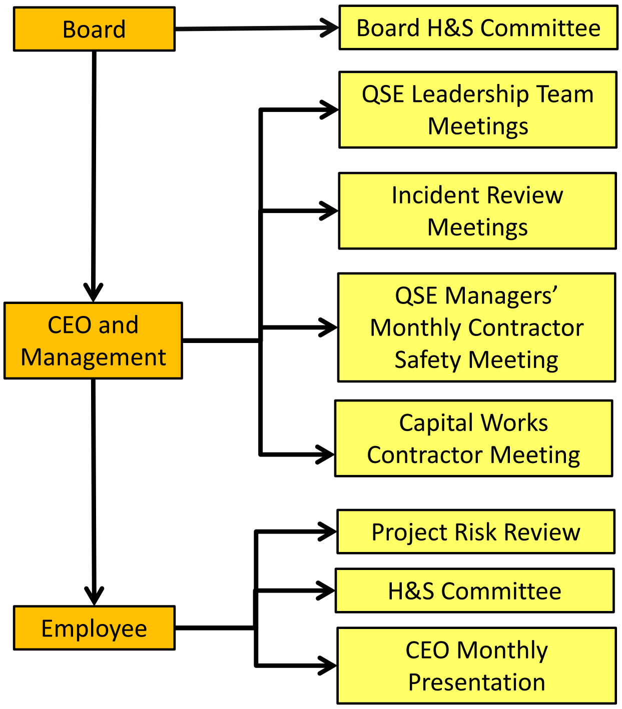


Figure 1-4 Safety Leadership Structure

Community and public safety initiatives include:

- Public safety management system
- School safety programme
- Safety information on the Wellington Electricity website
- Media advertising
- Safety seminars and mail outs
- Contractors safety booklet

Health and Safety and Environmental (HSE) Performance

Wellington Electricity has continued to build on its strong foundations of past HSE performance. Notable performance achievements for 2014 include:

- A positive change in safety culture through an increase in the reporting and investigating of incidents and near misses;

- An improvement in implementing corrective actions from the reported leading indicators so that potential harm incidents are avoided;

- Improving employees ability to identify non-conformances through the field assessment process via a programme of on the job training and development; and
- Working with Service Providers to review and improve their quality assurance processes.
- Wellington Electricity's staff and contractors recorded only one Lost Time Injury (LTI) incident, resulting in a LTI Frequency Rate (LTIFR) of 2.14 per million hours worked.;
- Wellington Electricity received no environmental infringement notices from Territorial Local Authorities (TLAs). Wellington Electricity routinely monitors the activities of contractors working on its network. Inspections or assessments are predominantly undertaken by a Field Assessor and the team of Project Managers.

New Health and Safety Legislation

Changes in health and safety legislation are expected in the latter part of 2015 with the passing of the Health and Safety Reform Act. These changes introduce a higher requirement for due diligence and governance from Board level down and across all parties involved in the supply continuum. Wellington Electricity is actively reviewing processes to ensure the systems and operating standards will reflect the requirements of the new Act..

1.5 Risk Management

As the owner of an asset-intensive business, Wellington Electricity's management of risk directly involves the addressing of risks associated with its network assets. The design of the network has to consider and balance the level of resilience with the associated cost, as it is not practical or economic to have a network which is immune to all risks.

Risk Management Strategy and Framework

Wellington Electricity's Board of Directors is responsible for the governance of all aspects of the business, including risk management. Board oversight of the risk management strategy and framework is delegated to the Audit and Risk Committee. Business risk is managed through regular risk profiling workshops. Risks which cannot be eliminated are assigned controls to minimise or mitigate their impact should the risk eventuate.

Wellington Electricity adopts the Risk Management Standard ISO31000:2009 to provide a structured and robust methodology to managing risk.

Risk-based approach to Asset Management

Management of risks associated with network assets is fundamental to planning the network development, asset maintenance, refurbishment and replacement programmes described in this AMP.

Risks associated with network assets are managed:

- Proactively: Reducing the probability of asset failure through safety-by-design principles, capital and maintenance work programmes, insurance strategies and enhanced working practices; and
- Reactively: Reducing the impact of a failure through business continuity planning and the development of an efficient fault response capability.

Figure 1-5 shows the top ten network risks identified and ranked by residual risk rating.

2014 Rank	2013 Rank	Event	Inherent Rating	Residual Rating
1	(1)	Inadequate management and/or supervision of contracted (i.e. outsourced) activities (including contractor resources).	Extreme	High
2	(11)	Unsustainable starting price adjustment	Extreme	High
3	(2)	Injury or Damage caused or loss suffered to third parties.	Extreme	High
4	(3)	Catastrophic earthquake and/or Tsunami that causes significant damage to Company assets	High	High
5	(4)	Sub-optimal performance or failure of network assets.	Extreme	Medium
6	(5)	A loss of connection supply from transmission assets.	Extreme	Medium
7	(6)	A health and safety incident that affects one or more employees, contractors or visitors while performing work or visiting the Business' properties, assets or worksites.	Extreme	Medium
8	(7)	Release or spread of hazardous materials, Electromagnetic Fields (EMF) or noise to land, ecosystems or atmosphere.	Extreme	Medium
9	(8)	Mismanagement of a crisis and emergency affecting the Network.	Extreme	Medium
10	(9)	Failure of a retailer, customer, supplier or contractor to perform their contracted obligations, including financial obligations.	Extreme	Medium

Figure 1-5 Top Ten Network Risks

Resilience (Business Continuity)

Two major projects currently in progress have been driven by the events associated with the Canterbury earthquakes of 2010 and 2011. These projects are:

- Development of a major event resilience network plan, in particular for emergency overhead subtransmission line routes. Detailed plans for bypassing damaged subtransmission cables are being developed, with all but two of the CBD gas cable subtransmission routes now completed. Discussions with Wellington City Council on the inclusion of these routes within the District Plan will continue in 2015 and a start will also be made on the development of emergency overhead line routes in the Hutt Valley and Porirua areas; and

- Development of a substation building seismic policy. A programme for assessment of 320 network substation buildings started in 2012 and is expected to run through until early 2016. This work identifies a number of earthquake prone buildings that will require seismic reinforcement over the following 10 year period.

As part of its Business Continuity Management Policy, Wellington Electricity has developed a suite of emergency response plans to respond to a number of emergency and high business impact situations which would affect the network. These include Business Continuity, Crisis Management and Major Event Management Plans.

1.6 Network Assets

Wellington Electricity's electricity distribution system comprises the following network assets.

Grid Exit Points (GXPs)

Wellington Electricity's network is supplied from Transpower's national transmission grid through nine GXPs. Central Park, Haywards and Melling GXPs supply the network at both 33kV and 11kV, and Kaiwharawhara supplies at 11kV only. The remaining GXPs (Gracefield, Pauatahanui, Takapu Rd, Upper Hutt and Wilton) all supply the network at 33kV only. The network is grouped into three areas where the GXPs are located, namely the Northeast, Northwest and Southern areas.

Subtransmission

The 33kV subtransmission system is comprised of assets that take supply from the Transpower GXPs and feed 27 Wellington Electricity zone substations, incorporating 52 33/11kV transformers. This 33kV system is radial with each feeder supplying its own dedicated power transformer, with the exception of Tawa and Kenepuru where two feeders supply four transformers (one feeder shared per bank at each substation). All 33kV feeders supplying zone substations in the Wellington area are underground while those in the Porirua and Hutt Valley areas are a combination of overhead and underground. The total length of the 33kV system is 207km of which 143km is underground.

Distribution

The 11kV distribution system is supplied from the zone substations, or directly from the GXP in the case of the 11kV supply points at Central Park, Melling, Haywards and Kaiwharawhara. While some larger consumers are fed directly at 11kV, most consumers are supplied at low voltage through 4,276 distribution substations (11kV/415V) located in commercial buildings, industrial sites, kiosks, berm-side and on overhead poles. The total length of the 11kV system is approximately 1,749km, of which 66% is underground. In the Southern area, the 11kV network is largely underground, whereas in the Northeast and Northwest areas the proportion of overhead 11kV lines is higher. Most of the 11kV feeders in the Wellington CBD[1] are operated in a closed ring configuration with radial secondary feeders interconnecting neighbouring rings or zone substations. This arrangement provides a high level of supply reliability. Most 11kV network outside the Wellington CBD, both in the South and Northeast areas, comprise radial feeders.

There are 1,666 11kV circuit breakers operating within the distribution system. Of this total, 368 are located at the zone substations and control the energy being injected into the distribution system. The remainder

[1] The CBD is defined as the commercial areas supplied by Frederick St, Nairn St, University, The Terrace, Moore St and Kaiwharawhara substations.

are located within distribution substations. These circuit breakers are used to automatically isolate a faulted section of the network and to improve the ability to maintain an uninterrupted supply to all customers not directly connected to the faulted section.

Low Voltage

Low voltage (LV) lines and cables are used for the LV network, which is supplied from the distribution transformers and used to connect individual small consumers to the distribution system. The total LV network length is around 2,724 circuit-km, of which approximately 60% is underground.

Consumers are supplied via a low voltage fuse, which is the installation connection point (ICP) between the low voltage network and an individual consumer's service main. This fusing is either an overhead pole fuse or located within a service pillar or pit near a consumer's boundary. In addition to the service pillars there are 400 link pillars on the network that allow isolation, reconfiguration and back feeding of certain LV circuits. These vary in age and condition and are being replaced where required.

A summary of the population each asset class is shown in Figure 1-6.

Asset Class	Measurement Unit	Quantity
Subtransmission Lines	km	58
Subtransmission Cables	km	136
Zone Substations	number	27
Zone Substation Transformers	number	52
Zone Substation Circuit Breakers	number	368
Distribution and LV Lines	km	1,682
Distribution and LV Poles	number	36,544
Distribution and LV Cables	km	2,791
Distribution Substations	number	3,588
Distribution Transformers	number	4,335
Distribution Circuit Breakers	number	1,300
Distribution Switchgear - Ground Mounted	number	2,218
Distribution Switchgear - Overhead	number	2,627
Protection Relays	number	1,388
Load Control Plant	number	26

Figure 1-6 Asset Population Summary

1.7 Network Performance and Service Levels

SAIDI and SAIFI

Network reliability is measured using two internationally recognised performance indicators - System Average Interruption Duration Index (SAIDI) and System Average Interruption Frequency Index (SAIFI).

- SAIDI is a measure of the total time, in minutes, electricity supply is not available to the average consumer connected to the network in the measurement period; and
- SAIFI is a measure of the total number of supply interruptions that the average consumer experiences in the measurement period. It is measured in number of interruptions.

Network reliability performance (Quality) targets have been set by the Commission's 2014 Default Price-Quality Path determination for SAIDI and SAIFI, and as well as an internally forecasted target for faults per 100km. These are shown in Figure 1-7.

Regulatory Year	2015/16	2016/17	2017/18	2018/19	2019/20	2020/21	2021/22	2022/23	2023/24	2024/25
SAIDI target	35.42	35.42	35.42	35.42	35.42	35.42	35.42	35.42	35.42	35.42
SAIFI target	0.547	0.547	0.547	0.547	0.547	0.547	0.547	0.547	0.547	0.547
Faults/100km target	12.6	12.8	12.9	13.1	13.2	13.3	13.5	13.6	13.8	13.9

Figure 1-7 Network Reliability Performance Targets

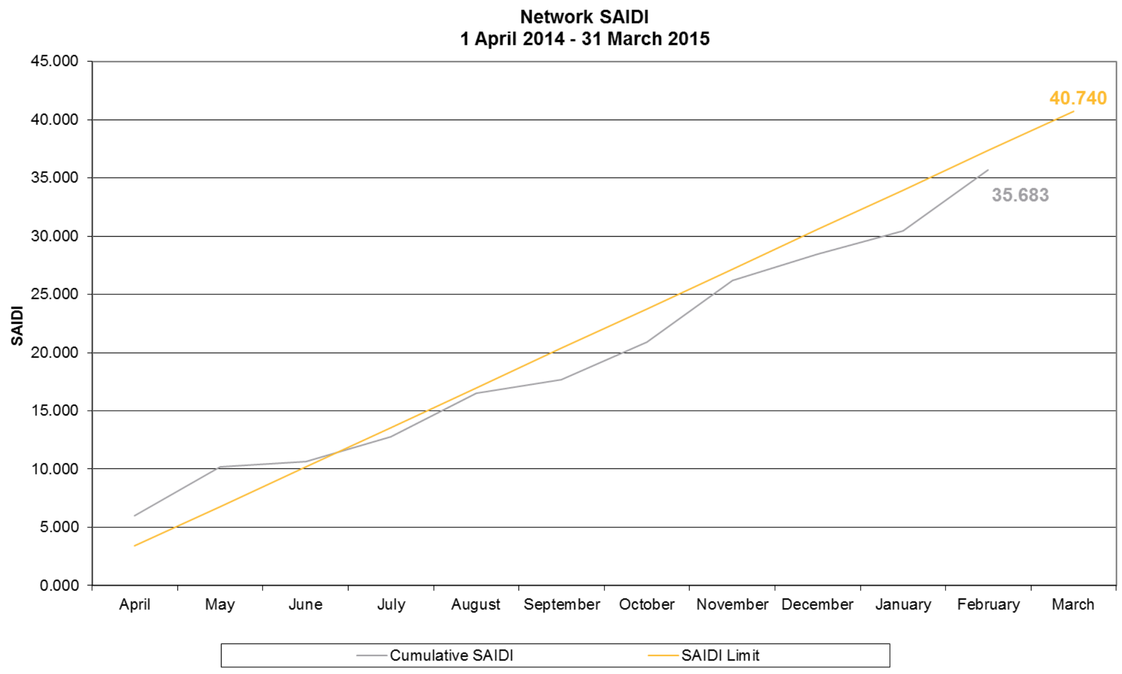
Figure 1-8 shows the actual performance of the network against the reliability targets set by the Commission. The reason for the high SAIDI and SAIFI in the 2013/14 year was the major storm which occurred on 20 June 2013. This storm alone contributed nearly 25 SAIDI minutes and 0.36 SAIFI to the annual totals.

Regulatory Year	2010/11	2011/12	2012/13	2013/14	2014/15[2]
SAIDI target	33.90	33.90	33.90	33.90	31.075
SAIDI limit	40.74	40.74	40.74	40.74	37.345
SAIDI actual	34.74	45.88	43.29	78.88	35.683
Significant Events	0.0	11.51	7.84	36.33	0.0
SAIFI target	0.52	0.52	0.52	0.52	0.476
SAIFI limit	0.60	0.60	0.60	0.60	0.55
SAIFI actual	0.537	0.715	0.573	1.107	0.56

Figure 1-8 Wellington Electricity Reliability Performance

[2] Regulatory Year 2014/15 up to 28th February 2015

Wellington Electricity's network performance from 01 April 2014 to 28 February 2015, with SAIDI and SAIFI numbers of 35.683 and 0.560 respectively, are just below and just above the set limits, but forecast to comply at year end. No storms comparable to that of 2013 occurred in 2014/15 and improvements in network control room (NCR) operations and Field Services response have helped keep the actual reliability performance close to the set limits. The underlying performance of assets continues to be in line with expectations. SAIDI and SAIFI performance to date is illustrated in Figure 1-9.



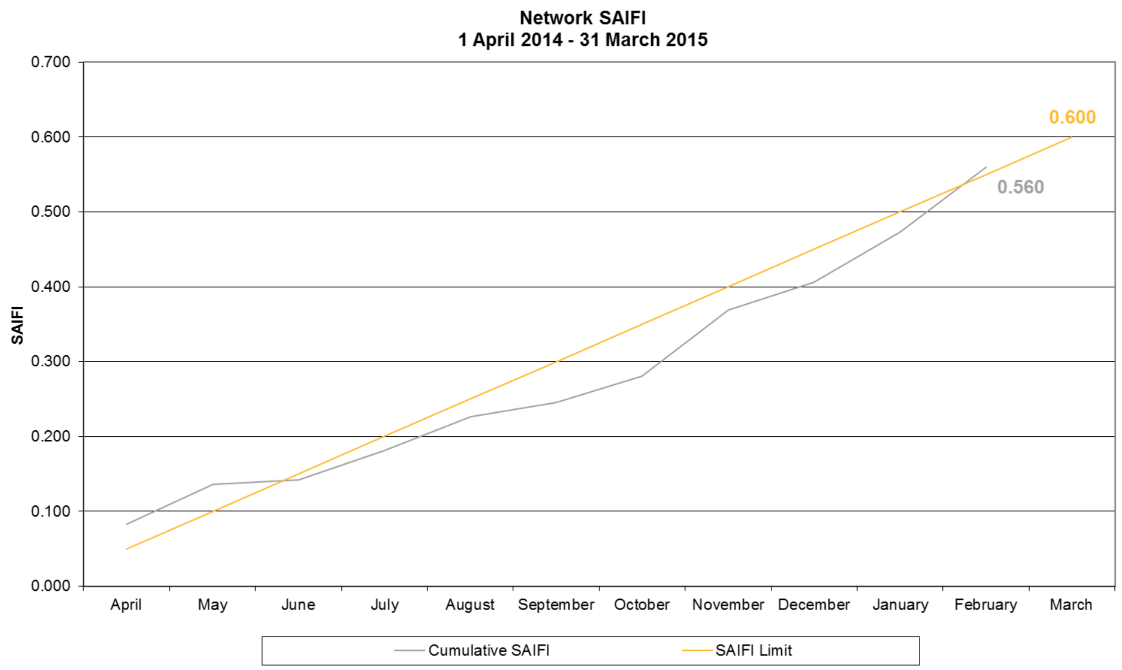


Figure 1-9 Actual SAIDI and SAIFI for 2014/15 (up to 28 Feb 2015)

Reliability Initiatives

As part of Wellington Electricity's Continuous Improvement Process, a key focus for the 2014/15 year was on operational performance improvement. Key components of this process are shown in Figure 1-10.

Reliability Initiative	Details
Incident reporting on all events greater than 0.4 SAIDI minutes	Involves analysis and identification of root cause of outages and recommendations to prevent recurrence. Outage reports are discussed by Network and Operations Managers at weekly incident review meetings to ensure all issues are being addressed.
Post-event operations analysis	Study of field response and repair times for major faults to identify causes of prolonged outages and develop strategies to improve restoration times. Examples include: making additional faultmen available, installation of more fault indicators, and increased ability to sectionalise the network or undertake switching remotely.
Reporting of asset failures on specific asset types (or modes of failure) through the Asset Failure Investigation Process	Reporting from field to network engineers to identify, investigate and monitor recurring trends helps determine whether maintenance practices need to be improved or what assets need to be upgraded.

Figure 1-10 Reliability Initiatives

1.8 Trends in Consumption and Peak Demand

Consumption of electricity (kWh volume) has been decreasing at a rate of approximately 1.7% per annum over the period from 2010 to 2014 and is forecast to continue this trend for at least the next five years. This decline has been driven by a number of factors including the relocation of industries, a greater focus on energy efficiency, some consumers converting their heating and cooking loads to gas, warmer winter weather, and static ICP numbers. Given the underlying economic characteristics and seasonal variances of the region, these trends are expected to continue. Energy consumption determines revenue, and the impact of a decline in this, together with the 2014 DPP determination has been described previously.

Meanwhile peak demand causes the majority of system constraints and drives the need for investment in the network or some alternative means of providing or managing the capacity. Despite the overall decline in energy use, peak demand for the past three years has remained relatively constant, and actually grown in some localised areas. Figure 1-11 shows the peak demand (system maximum demand) and system energy injected for the last six years. This trend in the peak demand is also expected to continue.

Year to	30 Sep 2009	30 Sep 2010	30 Sep 2011	30 Sep 2012	30 Sep 2013	30 Sep 2014
System Maximum Demand (MW)	565	583	585	552	542	546
System Energy Injection (GWh)	2,595	2,594	2,579	2,543	2,480	2,459

Figure 1-11 Peak Demand and Energy Injected

	System Maximum Demand MVA[3] (including DG)											
	2014 Actual[4]	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025
System Maximum Demand (MW)	544	545	547	549	551	549	548	546	545	543	542	545
System Energy Injection (GWh)	2,595	2,551	2,508	2,465	2,423	2,382	2,341	2,302	2,302	2,302	2,302	2,302

Figure 1-12 Network Historic Demand and Forecast

Peak Demand Forecasts

Southern area

Peak demand in the southern network area has declined in recent years and is expected to decline further. However in some localised sites peak demand growth is still forecast, primarily due to new building developments along the waterfront and in the CBD.

Northwestern area

In the Northwestern network area there is a moderate increase in summer peak loading but a static winter peak. This area has the strongest level of residential development in the region with high interest for new residential subdivisions in Whitby, Grenada North and Churton Park. The Aotea subdivision, currently supplied from the Porirua zone substation, is also an area of high growth,.

Northeastern area

Peak demand in the Northeastern network area is expected to remain at the current levels. There are localised areas of peak demand growth in the Upper Hutt area driven by planned residential sub-divisions and expansion plans of industrial customers in the Trentham and Maidstone zone substation supply areas. This is balanced by declining peak demand outside of these areas (i.e. in most parts of Lower Hutt).

1.9 Network Planning

The Network Development Plan (NDP) describes the identified need, options and recommended investment path for the network over the next 10 years. As each of the three network areas are largely electrically independent they are addressed separately. Each is structured in accordance with the network hierarchy of GXP level requirements, sub transmission and zone substations and then distribution level investments. A detailed review of the development plan for the Southern network is currently underway and is planned to be finalised in 2015. Some of the details in this plan could change as the review is finalised. In regard to the

[3] Forecast values are for the normal growth average seasonal temperature case correspond to the 60th percentile deduced from the peak demand range and include step change loading due to planned load transfer or confirmed customer connections
[4] System Maximum Demand forecast is based on the 2014 sustained peak in MVA.

Northwestern and Northeastern network areas, similar reviews are planned for 2015. In the meantime, the existing planning around previously identified issues remains as the development strategy.

Southern Network Area

In order to address the identified constraints in this area, four development path options were identified and analysed. Figure 1-13 shows the comparison of the options, including the pros and cons, as well as the high level cost estimates.

	Option 1	Option 2	Option 3	Option 4
Description	Installation of a new zone substation supplied from Wilton with distribution level interconnections to The Terrace, Frederick St, Kaiwharawhara and Palm Grove	Augmentation of sub-transmission and distribution infrastructure to alleviate constraints and improve transfer capacity	Re-configuration of Nairn St to be supplied from Wilton, initiation of a customer driven project to improve security of supply at CPK and reinforcement of distribution links to adjacent zones	Installation of a new zone substation supplied from Wilton with distribution level interconnections to Frederick St, Kaiwharawhara and Palm Grove and a separate distribution link between The Terrace and Moore St
CAPEX Costs	**$38,410,000**	**$40,332,420**	**$36,627,680**	**$36,280,000**
NPV	**$26,639,101**	**$27,360,170**	**$25,553,226**	**$24,567,168**
Pros	• Reduces the magnitude of load at risk in the event of a Central Park N-2 issue; • Introduces a new point of supply into the network and diversifies supply to the Wellington CBD area at sub-transmission and distribution levels; • Mitigates all distribution level issues by introducing distribution links to highly loaded areas; and • Defers replacement of the Palm Grove transformers by shifting load to the new zone substation.	• Reduces the magnitude of load at risk in the event of a Central Park N-2 issue; • Mitigates all distribution level issues by introducing distribution links to highly loaded areas; and • Improves distribution inter-connectivity allowing large scale load shift during contingency situations.	• Utilises existing infrastructure where possible to introduce additional sub-transmission capacity into the Wellington CBD area as well as diversifying supply by shifting Nairn St to supply from Wilton GXP; • Mitigates all distribution level issues by introducing distribution links to highly loaded areas; and • Reduces the magnitude of load at risk in the event of a Central Park N-2 issue.	• Reduces the magnitude of load at risk in the event of a Central Park N-2 issue; • Introduces a new point of supply into the network and diversifies supply to the Wellington CBD area at sub-transmission and distribution levels; • Improves distribution level inter-connectivity within critical zones within the Wellington CBD; • Mitigates all distribution level issues by introducing distribution links to highly loaded areas; • Reduces load transferred to the new zone substation, potentially allowing for lower rated sub-trans circuits; and • Defers replacement of the Palm Grove transformers by shifting load to the new zone substation.

	Option 1	Option 2	Option 3	Option 4
Cons	• Significant capital investment required to mitigate the issues; • Significant challenges in designating a suitable substation site (or utilising the existing property at Bond St) and complexity during construction; • Significant investment required to introduce distribution links from the new zone substation to The Terrace as well as Frederick St and Palm Grove; and • Zone substation and feeders will be highly utilised due to magnitude of offload from Frederick St, Palm Grove and The Terrace.	• Significant capital investment is required to individually augment the sub-transmission and distribution issues; • Significant capital investment required to replace the Palm Grove transformers which are highly utilised but in good condition; and • Overlay of the Frederick St sub-transmission cables will require significant investment and determination of a cable route will be challenging due to the location of Frederick St.	• Significant capital required to establish a new transformer bay adjacent to Nairn St zone substation; • Establishing a new transformer bay adjacent to the Nairn St switchroom may not be feasible due to the consents and civil/earthworks required; • Significant capital investment required to replace the Palm Grove transformers which are highly utilised but in good condition; and • Significant capital investment required to replace the Palm Grove transformers which are highly utilised but in good condition.	• Significant capital investment required to mitigate the issues; and • Significant challenges in designating a suitable substation site (or utilising the existing property at Bond St) and complexity during construction.

Figure 1-13 Comparison of Options for Wellington CBD Development

Summary of the Southern Area Investment Requirement

Figure 1-14 shows the investment plan for growth and reinforcement projects in the Wellington Southern area for the planning period from 2015-2025. This summary includes investment not included in the Wellington Southern recommended Development Option 4 such as CBD zone substation fault level improvements and introducing increased inter-connectivity between Evans Bay, Ira St and adjacent zone substations. The Wellington Southern NDP assumes that the recommended option is to install a new zone substation in the CBD and replacement of the Evans Bay subtransmission assets.

Year	Reference	Project	Estimated Cost ($M)
2015	14-002	8 Ira St Feeder 2 Reinforcement	0.345
2016	16-001	The Terrace to Moore St Distribution inter-connectivity	3.4
2017	17-001	Establish new 2x30MVA zone substation	8.1
	17-002	Evans Bay Transformer Replacement	5.0
	17-004	Moore St New Feeder	1.2
2018	18-001	Distribution link from new zone substation to Frederick St and Kaiwharawhara	5.3
	18-002	CBD Zone Substation Fault Level Improvements	0.85
	18-006	CBD Zone Substation subtransmission supply	5.0

Year	Reference	Project	Estimated Cost ($M)
2019	19-001	Distribution link from new zone substation to Palm Grove	6.5
	19-002	CBD Zone Substation Fault Level Improvements	0.85
2020	20-001	Reinforcement of The Terrace Zone 2 Ring	4
	20-002	CBD Zone Substation Fault Level Improvements	0.85
2021	21-001	CBD Zone Substation Fault Level Improvements	0.85
2022	22-001	CBD Zone Substation Fault Level Improvements	0.85
	22-005	Evans Bay and Ira St Distribution Inter-connectivity	2.5
2023	22-001	CBD Zone Substation Fault Level Improvements	0.85
2024	24-001	University Subtransmission Reinforcement	3.5
	24-002	Evans Bay 33kV bus	4
Total Investment			**53.95**

Figure 1-14 Summary of Southern Area Investment Requirement

Northwestern Network Area

The Northwestern Network Development Plan (NDP) has been developed from the planned and outstanding projects from previous AMP planning. This will be updated in 2015 as part of reviewing and developing a more comprehensive Northwestern NDP.

Summary of the Northwestern Area Investment Requirement

Figure 1-15 shows the investment plan for growth and reinforcement projects in the Northwestern area for the planning period from 2015-2024. An allowance has been included for distribution level development of the Northwestern area and establishment of a new zone substation in Whitby/Pauatahanui and Grenada. These figures will be updated following completion of the Northwestern area NDP.

Year	Reference	Project	Estimated Cost ($M)
2015	15-001	Takapu Road OD-ID Works (Stage 2): OD-ID Conversion	0.025
	15-002	Waitangirua Subtransmission Protection Upgrade (Stage 3)	0.37
	15-003	Ngauranga communications and Subtransmission Protection Upgrade (Stage 3 and 4)	0.8
2016	16-002	Johnsonville Subtransmission Protection Upgrade	0.35

Year	Reference	Project	Estimated Cost ($M)
	16-003	Mana-Plimmerton SPS	0.25
	16-004	Tawa/Kenepuru Subtransmission Protection Upgrade	0.35
	16-005	Porirua Subtransmission Protection Upgrade	0.35
2017	17-003	New Whitby/Pauatahanui Zone Substation – Stage 1 2017	7.5
2018	18-003	Wellington Northwestern Development Strategy 2018 – Distribution Reinforcement Allowance	1.5
	18-005	New Whitby/Pauatahanui Zone Substation – Stage 2, 2018	7.5
2019	19-003	Wellington Northwestern Development Strategy 2019 – Distribution Reinforcement Allowance	1.5
2020	20-003	Wellington Northwestern Development Strategy 2020 – Distribution Reinforcement Allowance	1.5
	20-004	New Zone Substation in Grenada – Stage 1 2020	7.5
2021	21-003	Wellington Northwestern Development Strategy 2021 – Distribution Reinforcement Allowance	1.5
	21-004	New Zone Substation in Grenada – Stage 2 2021	7.5
	21-005	Sub-transmission supply for Grenada via new 33kV bus	4
2022	22-003	Wellington Northwestern Development Strategy 2022 – Distribution Reinforcement Allowance	1.5
	22-004	Pauatahanui Subtransmission Protection Upgrade	0.7
	22-006	Grenada Distribution inter-connectivity	2.5
2023	23-002	Distribution Reinforcement Allowance	5
	23-004	Grenada Distribution inter-connectivity	2.5
	23-005	Ngauranga Distribution inter-connectivity	2.5
2024	24-003	Distribution Reinforcement Allowance	5
	24-004	New Plimmerton 33kV bus	4
2025	25-001	Plimmerton 11kV bus extension	2

Year	Reference	Project	Estimated Cost ($M)
	25-002	2x20MVA Transformers at Plimmerton	2
	25-003	Plimmerton Distribution inter-connectivity	2
Total Investment			**64.2**

Figure 1-15 Summary of Northwestern Area Investment Requirement

Northeastern Area

As indicated previously, the identified constraints and planned projects for the Northeastern area consists of projects brought forward from previous AMP planning. This section will be updated in 2015 as part of the review and further development of the Northeastern NDP. This will provide a more detailed investigation of the area and provide a number of strategies to mitigate the identified issues. These strategies may involve or substitute the currently planned works for the Northeastern area.

Summary of the Northeastern Area Investment Requirement

Figure 1-16 shows the investment plan for growth and reinforcement projects in the Northeastern area for the planning period from 2015-2025. An allowance has been included for distribution level development of the Northeastern area. These figures will be updated following completion of the Northeastern area NDP.

Year	Reference	Project	Estimated Cost ($M)
2015	14-003	Trentham Subtransmission Protection Upgrade	0.416
2016	16-006	New 11kV feeder at Haywards 11kV GXP	0.5
2018	18-004	Wellington Northeastern Development Strategy 2018 – Distribution Reinforcement Allowance	1.5
2019	19-004	Wellington Northeastern Development Strategy 2019 – Distribution Reinforcement Allowance	1.5
	19-005	Gracefield Subtransmission Protection Upgrade	0.5
2020	20-005	Wellington Northeastern Development Strategy 2020 – Distribution Reinforcement Allowance	1.5
	20-006	Upper Hutt Subtransmission Protection Upgrade	0.5
2021	21-005	Wellington Northeastern Development Strategy 2021 – Distribution Reinforcement Allowance	1.5
2022	22-005	Wellington Northeastern Development Strategy 2022 – Distribution Reinforcement Allowance	1.5
	22-006	Hutt area zone substation 33kV bus	4
Total Investment			**13.4**

Figure 1-16 Summary of Northeastern Area Investment Requirement

1.10 Lifecycle Asset Management

Asset lifecycle management consists of the following:

- Routine asset inspections, condition assessments and servicing of in-service assets;
- Evaluation of the results for meeting customer service levels, performance expectations and control of risks;
- Maintenance requirements and equipment specifications to address known issues; and
- Repair, refurbishment or replacement of assets when required.

One of the key assumptions that Wellington Electricity has based its maintenance and renewal programmes on is that the assets are mature, but are generally in fair condition. This is due to sound maintenance programmes early in their service life which has been confirmed by further condition assessment activities undertaken in recent years. Improved condition assessment and reporting has enabled Wellington Electricity to gain a better understanding of the network assets and to target maintenance and renewal activities to the highest priority assets.

Asset Health Analysis

Prior to 2015, Wellington Electricity used a “Stage of Life” analysis to prioritise major asset replacement. Stage of Life gave weightings to asset age and a number of factors influencing condition and utilisation to provide an overall score for each asset, which could then be ranked to give a priority.

In practice, Stage of Life was very sensitive to the weightings given to each attribute, and the method of normalisation meant that scores were not comparable across different asset classes. However, the analysis did provide a useful means of highlighting which assets within a class required closer attention.

During 2014, the Electricity Engineers Association released their draft guide to Asset Health Indicators. This method specifies a number of health indices for each asset class, which are rated on a scale of H5 (new) to H1 (end of life). The overall health score of an asset is determined by its worst health index, further reduced by any indices scoring less than H4.

Asset Health Analysis offers a number of advantages over Stage of Life, particularly in that it does not rely on factors having subjective weightings. However, unlike Stage of Life, Asset Health Analysis does not take any account of asset criticality or consequence of failure. Wellington Electricity has developed an Asset Criticality Indicator using the same methodology as Asset Health Analysis, incorporating factors such as number of customers affected, load type and firm capacity.

The result of this analysis is a health-criticality matrix for each major asset class, with the asset location on the matrix giving an indication of risk.

Projects are identified to either improve the health of an asset, or reduce its criticality. The impact of potential changes to health and/or criticality, whether the result of a project or deterioration in condition, can be clearly shown by the movement of the asset within the matrix.

Accordingly, Wellington Electricity is progressively moving the assessment of asset fleets to the risk based asset health, asset criticality framework to provide an objective and prioritised list of needs to be addressed within the planning period. To date the asset classes that have been addressed are:

- Subtransmission Cables;
- Zone Substation Power Transformers and Tap Changers; and
- Zone Substation Switchboards and Circuit Breakers.

It is expected that the development of asset health and criticality for the remaining asset classes will be completed during the remainder of 2015.

Maintenance Practices

Wellington Electricity currently contracts Northpower as its Field Services Provider to undertake the network maintenance programme under a Field Services Agreement. Within the agreement, the scheduling of inspection and maintenance activities is driven by Wellington Electricity. This arrangement enables Wellington Electricity to lead the overall management of its assets. Maintenance of all assets is undertaken according to standards that have been developed by Wellington Electricity.

Condition-based risk management of assets is achieved through a well-defined condition assessment and defect identification process that is applied during planned inspection and maintenance activities. The condition information is then fed into the SAP-PM maintenance management system by the Field Services Provider and analysed alongside other key network information. This enables Wellington Electricity to prioritise field data to make efficient and optimised asset replacement decisions and maintain visibility and tracking of maintenance tasks in the field.

Vegetation management is provided by Treescape and is carried out in accordance with Wellington Electricity policies and the Electricity (Hazards from Trees) Regulations 2003. Under the regulations, tree owners will now be responsible for maintaining their vegetation to a safe clearance distance.

Asset Replacement Programmes for 2015 - 2020

In addition to the specific projects identified in the fleet summaries, Wellington Electricity also makes provision for replacements that arise from condition assessment programmes during the year. The total projected capital budget for 2015 to 2020 is presented in Figure 1-17. For the period beyond 2015, these projections are less certain in nature. Whether they proceed will depend on the risks to the network and the risks relative to other asset replacement projects. Should the consequence of failure increase, or the asset deteriorates faster than expected, then renewal may need to be brought forward. Conversely, should the risk level decrease then the project may be able to be deferred until later in the planning period, or an alternative found.

Asset Category	2015/16	2016/17	2017/18	2018/19	2019/20
Subtransmission Lines and Cables	0	0	0	0	0
Zone Substations	1,335	1,775	775	1,175	2,125
Distribution Poles and Lines	6,100	5,950	5,500	5,500	5,500
Distribution Cables	1,536	1,750	1,750	1,750	1,750
Distribution Substations	3,263	3,763	38,00	3,783	3,748
Distribution Switchgear	4,578	5,455	5,545	5,448	5,458
Other Network Assets	1,509	1,855	1,165	850	1,405
Total	**18,820**	**21,048**	**19,035**	**19,005**	**20,485**

Figure 1-17 Prospective System Asset Renewal Forecast ($K in constant prices)

This investment profile is to maintain existing service levels. Over time as condition information improves and full asset strategies are developed and refined, the category split may change.

Prospective Asset Replacement Projects for 2021 - 2025

Asset replacement and renewal projects listed in Figure 1-18 are less specific than those shown in Figure 1-17 and are more uncertain in nature. There are few specific projects identified at this time and the prospective investments are broken down only by asset category. As risks and needs change on the network, individual projects will change. However, to ensure safety, and to maintain security and reliability levels that the consumers are presently prepared to accept in their price/quality trade-off decision, the following investment levels are expected to be required over this period.

Investment Driver	Asset Category	Investment
Asset Renewal	Pole & OH Replacement	25,000
Asset Renewal	Load Control Plant Replacement	6,000
Asset Renewal	Power Transformer Replacement	2,000
Asset Renewal	Distribution Switchgear Replacement	19,600
Asset Renewal	SCADA and RTU Replacement	500
Asset Renewal	Distribution Transformer Replacement	14,000
Asset Renewal	Distribution Cable and Conductor Replacement	3,750
Asset Renewal	Zone Substation Switchboard Replacement	4,300
Safety	Earthing Compliance Upgrades	1,500
Reliability	Reliability Improvement Projects	2,500

Figure 1-18 Prospective Asset Replacement Programme 2021-2025 ($K in constant prices)

This investment profile is to maintain existing service levels, over time as condition information improves, and then the category split may change to reflect the changing risks.

Asset Renewal and Replacement Expenditure

For clarity, the forecast provided below does not include non-maintenance related operational expenditure. Asset replacement and renewal costs considered optimal for regulatory periods are shown for the line item on which Wellington Electricity proposes to invest the most capital expenditure - reflecting the increasing age of the asset base.

Category	2015/16	2016/17	2017/18	2018/19	2019/20	2020/21	2021/22	2022/23	2023/24	2024/25
Asset Replacement & Renewal	18,820	21,048	19,035	19,005	20,485	20,565	20,388	19,475	22,275	22,900
Reliability, Safety & Environment (other)	798	988	931	869	838	800	800	800	800	800
Quality of Supply	2,174	1,758	1,458	1,570	1,328	600	600	600	600	600
Subtotal - Capital Expenditure on Asset Replacement Safety and Quality	**21,791**	**23,793**	**21,424**	**21,444**	**22,650**	**21,965**	**21,788**	**20,875**	**23,675**	**24,300**
Service interruptions & emergencies maintenance	4,133	4,136	4,127	4,113	4,100	4,088	4,076	4,065	4,054	4,052
Vegetation management maintenance	1,263	1,273	1,280	1,286	1,291	1,297	1,302	1,308	1,314	1,314
Routine & corrective maintenance and inspection maintenance	8,562	8,590	8,445	8,176	8,199	8,224	8,252	8,279	8,307	8,303
Asset replacement & renewal maintenance	701	707	710	714	716	719	722	727	730	729
Subtotal - Operational Expenditure on Asset Management	**14,658**	**14,705**	**14,562**	**14,288**	**14,306**	**14,328**	**14,353**	**14,379**	**14,405**	**14,397**

Figure 1-19 Optimal Lifecycle Asset Management Expenditure Forecast – 2014/15 to 2023/24 ($000 in constant prices)

Forecast preventative and corrective maintenance expenditure

A breakdown of forecast optimal preventative and corrective maintenance expenditure by asset category is shown in Figure 1-20. These forecasts are based on long-term averages, and year-on-year variances across the different asset categories will occur depending on the nature of the corrective maintenance that is required in any given year. The preventative maintenance component is agreed with the Field Service Provider as part of the Field Services Agreement and remains relatively constant year-on-year.

Service interruptions and emergency maintenance (faults) can only be forecast and reported at a system level as the Field Service Agreement defines the rates for fault response services at a total level and not further broken into asset category detail levels.

Asset replacement and renewal maintenance is similar to corrective maintenance and is not forecast at asset category level at present due to the varying nature of the work required. As Wellington Electricity develops more history on this expenditure category, forecasts and asset category splits will be enhanced.

Routine & Corrective Maintenance & Inspection Maintenance	2015/16	2016/17	2017/18	2018/19	2019/20	2020/21	2021/22	2022/23	2023/24	2024/25
Battery / Secondary Systems	166	165	163	158	159	158	159	160	160	160
Cables (All Voltages)	788	791	779	753	754	758	760	762	765	765
Circuit Breaker	951	954	937	908	910	912	915	919	922	922
Distribution Substation	1,195	1,199	1,178	1,140	1,144	1,147	1,151	1,155	1,158	1,157
Distribution Transformer	2,069	2,077	2,041	1,976	1,981	1,989	1,998	2,001	2,008	2007
Overhead Switch / Recloser	391	393	386	375	375	376	377	379	380	379
Pillar / Pit	201	203	200	194	195	195	196	196	197	197
Pole / Overhead Line	1,661	1,666	1,638	1,587	1,591	1,595	1,601	1,607	1,612	1,611
Power Transformer	231	232	229	221	222	222	222	223	224	224
Ring Main Unit / Ground Mount Switchgear	575	576	567	548	550	552	553	556	558	558
Zone Substation / GXP	333	334	327	317	317	319	319	321	322	322
Total	**8,562**	**8,590**	**8,445**	**8,176**	**8,199**	**8,224**	**8,252**	**8,279**	**8,307**	**8,303**

Figure 1-20 Optimal Preventative & Corrective Maintenance by Asset Category – 2014/15 to 2023/24 ($K in constant prices)

2 Introduction

This Asset Management Plan (AMP) has been prepared in accordance with the Commerce Commission's (the Commission) Information Disclosure (ID) Determination, October 2012. It describes Wellington Electricity's long-term investment plans for the planning period from 1 April 2015 to 31 March 2025.

The AMP is a 'live' document and consequently will change over time as new information is incorporated and our approach to asset management is further refined and optimised to deliver the best price-quality balance recognising the inherent consumer trade-off between price and network constraints, as well as the requirements of the Regulator.

Financial values presented in this AMP are in constant price New Zealand dollars. This AMP includes data relating to Wellington Electricity's financial year (1 January to 31 December) and the regulatory reporting period (1 April to 31 March) – the formats adopted in this AMP are '2014' and '2014/15' respectively.

The document was approved for disclosure by the Wellington Electricity Board of Directors on 27 March 2015.

2.1 Purpose of the AMP

The primary purpose of the AMP is to communicate with consumers and other stakeholders Wellington Electricity's strategies, policies, processes and plans for the effective and responsible long-term management of Wellington Electricity's network assets. Subject to the regulatory regime under which Wellington Electricity operates, these strategies, policies, processes and plans ensure that electricity supply continues to be delivered at a quality and price sought by electricity consumers connected to the network.

The AMP:

- Describes how stakeholder interests are considered and integrated into business planning processes to achieve an optimum balance between the levels of service and cost effective investment. The level of service is reflective of a price/quality trade off where pricing set by the Commission is anticipated to allow Wellington Electricity to upgrade, maintain, and renew the network assets to meet the demand without any material deterioration in quality of supply;

- Addresses the strategic goals and objectives of the business by focusing on prudent life cycle asset management planning, levels of service expected by stakeholders and appropriate levels of network investment to provide a fair return to the shareholders; and

- Explains how Wellington Electricity monitors and is continuously improving its asset management practices and processes based on industry best practice.

The AMP is a key output from the annual business planning, asset management and planning process and is a collectively produced document that draws on information from various internal and external sources.

2.2 Planning Period Covered by the AMP

This AMP covers the 10-year period commencing 1 April 2015 and finishing on 31 March 2025. The plans described in this document reflect Wellington Electricity's current business plan and are relatively firm for the next two to three years. Beyond three years the plans are broader and will inevitably need to be adjusted to incorporate internal and external environmental changes as they arise (such as the Commerce

Commission's reset of the Default Price-quality Path (DPP) in November 2014). Accordingly, plans towards the later part of the 10 year period are not presented in the same level of detail, reflecting the impact of uncertainty over the longer timeframes.

This AMP was prepared on the basis of project plans and forecasts developed prior to the DPP determination. Due to the limited time available between the reset decision and the disclosure of this AMP, the assumptions made and the project plans and forecasts have not been updated to reflect the impact of the decision and accordingly represent a "pre-reset" view of what Wellington Electricity could have achieved during the planning period. There is expected to be a significant gap between Wellington Electricity's own forecasts of required expenditure and level of investment for which funding will be available.

The expenditure and projects presented in this AMP will be continually reviewed in conjunction with the development of asset management strategies driven by:

- A greater understanding of the condition of the network assets and risks;
- Assessment of load growth and network constraints;
- New and emerging technologies;
- Changes to business strategy driven by internal and external factors; and
- The impact of the regulatory regime

It should be noted that Wellington Electricity's internal work planning cycle is based on the financial year as required by the company owners. This is the same as the calendar year. Project timings in the AMP are therefore expressed in calendar years (consistent with the internal planning cycle), however expenditure forecasts are based on regulatory years (1 April to 31 March) to be consistent with information disclosure requirements.

2.3 Capability to Deliver

Wellington Electricity's Board and senior management team review this AMP against the business strategy to ensure alignment with business capability and priorities. Where new business requirements exist beyond current practice, or where non-business as usual items are identified, these will be assessed against the present business capability and, where necessary, further resources will be considered (whether financial, technical, or contractor resource) to achieve these new business requirements.

2.4 Overview of Wellington Electricity

Distribution Area

Wellington Electricity is an electricity distribution business (EDB) that supplies electricity to over 165,000 installation control points (ICPs) in its network area, represented by the orange-shaded area in Figure 2-1. Over 89% of the ICPs are residential connections and a further 9% are small commercial connections. The total system length (excluding streetlight circuits and DC cable) is 4,680 km, of which 62.7% was underground.

Figure 2-1 Wellington Electricity Network Area

Wellington Electricity's distribution network supplies the cities and council jurisdictions of Wellington, Porirua, Lower Hutt and Upper Hutt. The area includes the Wellington Central Business District (CBD),as well as widespread residential load interspersed with pockets of commercial and light industrial load. The network area does not have large industrial and agricultural loads.

In addition to the local authorities, the entire network area comes under the zone of the Wellington Regional Council. The different councils have varying requirements relating to permitted activities for an electrical utility, for example differences exist in relation to road corridor access and environmental compliance.

Historically network development in the region was the responsibility of two separate organisations and consequently in many cases the equipment utilised and the network design standards differ between the areas.

Ownership

The ownership of Wellington Electricity has changed significantly over time as shown in Figure 2-2. At the start of the 1990s, the Wellington City Council Municipal Electricity Department (MED) and the Hutt Valley Electric Power Board merged their electricity assets. As part of the Energy Companies Act 1992 two new companies were formed, Capital Power and Energy Direct. In 1996, the Canadian-owned power company TransAlta acquired both companies to form a consolidated electricity distribution network business. Ownership was passed to United Networks in 1998, which Vector acquired in 2003. Both United Networks and Vector integrated the Wellington based network into their overall operations.

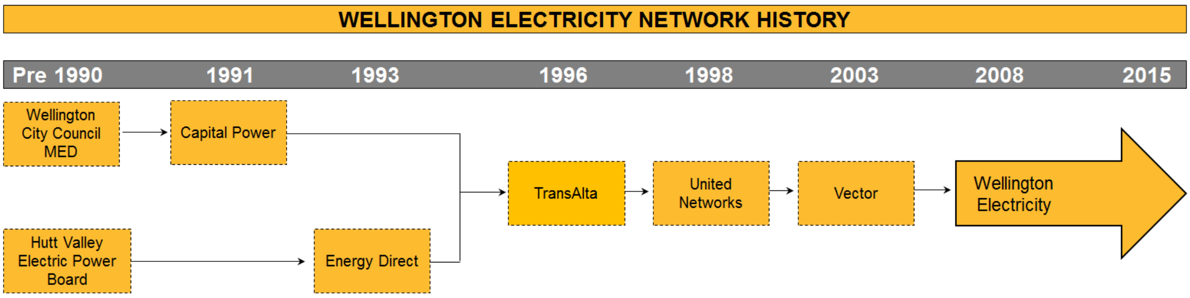


Figure 2-2 Wellington Electricity Ownership History

In July 2008, Cheung Kong Infrastructure Holdings Limited (CKI) and Hong Kong Electric Holdings Limited purchased the network to create Wellington Electricity Lines Limited (Wellington Electricity). Since then Wellington Electricity has established the business systems for the independent operation and control of the network. Hong Kong Electric Holdings Limited changed its name on 16 February 2011 to Power Assets Holdings Limited (Power Assets) to reflect its international portfolio of assets.

CKI and Power Assets together own 100 per cent of Wellington Electricity with both companies being members of the Cheung Kong group of companies, which are listed on the Hong Kong Stock Exchange (HKEx).

Further information on the ownership structure is available on Wellington Electricity's website, www.welectricity.co.nz.

2.5 Wellington Electricity's Stakeholders

Wellington Electricity's stakeholders are described in Figure 2-3. It outlines how stakeholders interests are identified, what their interests and expectations are and how these are accounted for in Wellington Electricity's asset management processes.

How stakeholder interests are identified	Stakeholder interests / expectations	How interests/expectations are accounted for in Asset Management processes
Consumers		
• Customer satisfaction and engagement surveys • Feedback received via complaints and compliments • Media related enquiries and sponsorship • Price / Quality trade-off	• Require a safe and reliable supply of electricity of acceptable quality at a reasonable price • Generally appreciate that delivery of an extremely high quality of supply with no interruptions is unrealistic • Expectations can differ as to the level of reliability and quality considered acceptable	• Planned compliance with reliability and customer service levels • Appropriate investment in the network • Public safety initiatives • Price / Quality trade-off • Consumer engagement initiatives
Retailers		
• Electricity Industry Participation	• Rely on network to deliver energy they	• Planned compliance with the

How stakeholder interests are identified	Stakeholder interests / expectations	How interests/expectations are accounted for in Asset Management processes
Code (EIPC) • Relationship meetings and direct business communications • Via Use of Network Agreement terms	sell to consumers so require network to be reliable and meet agreed service level targets. • Want Wellington Electricity to assist in providing innovative products and services to benefit their customers • Expect to access proposed load control market under the new Electricity Authority Model Use of System Agreement	reliability targets • Achieving customer service levels • Consultation • Development of standard Use of System Agreement taking into account the Electricity Authority Model
Regulators (Commerce Commission and the Electricity Authority)		
• Commerce Act Part 4 and other legislation • Electricity Industry Act 2010 and EIPC • Relationship meetings and direct business communications • Industry working groups • Information disclosure	• To ensure that consumers achieve a supply of electricity at a fair price commensurate with an acceptable level of quality	• Planned compliance with reliability targets and price controls • Compliance with legislation • Engagement in regulatory development process • Preparing information disclosures
Transpower		
• EIPC • Relationship meetings and direct business communications • Annual planning documents • Grid notifications and warnings	• Sustainable revenue earnings from the allocation of connected and inter-connected transmission assets • Wellington Electricity under the EIPC will operate and interface under instruction as and when required • Assurance that all downstream connected distribution and generation will not unduly affect their assets	• Implementation of operational standards and procedures • Appropriate investment in the network • Regular meetings
Central & Local Government		
• Through legislation • Regular meetings and direct business communications	• Local Councils require appropriate levels of investment in the network to allow for projected local growth • Regional Councils require that both	• Compliance with legislation, engagement and submissions as required • Emergency Response Plans

How stakeholder interests are identified	Stakeholder interests / expectations	How interests/expectations are accounted for in Asset Management processes
• Focus working groups	current and new network assets do not affect the environment • Central Government's want to ensure consumers receive a safe, reliable supply of electricity at a competitive price • Appropriate emergency response and contingency planning to manage a significant civil defence event • Legislative obligations such as seismic assessment and reinforcement of earthquake prone buildings	• Environmental Management Plans • Identification of costs associated with the reinforcement of substation buildings • Engagement in policy development processes
Industry Organisations	(e.g. Institute of Professional Engineers NZ (IPENZ); Electricity Engineers Association (EEA) and Electricity Networks Association (ENA))	
• Regular contact at executive level • Attendance at workshops and involvement in working groups	• Expect that Wellington Electricity follows good practice and exhibits continuous improvement..	• Training and development of competencies • Alignment of asset strategies with frameworks and practices established by industry organisations
Staff and Contractors		
• Team and individual direct discussion • Regular meetings and direct business communications • Contractual agreements	• Staff and contractors want job satisfaction, a safe and enjoyable working environment and fair reward for services provided • Contractors also want assurance of work continuity and mitigation of workplace hazards	• Health and safety policies and initiatives • Forward planning of work through asset management practises • Performance reviews • Life balance
Shareholders		

How stakeholder interests are identified	Stakeholder interests / expectations	How interests/expectations are accounted for in Asset Management processes
• Governance and Board mandates • Board meetings and committees • Business plan and strategic objectives	• Shareholders expect the company to meet industry-leading operational and Health, Safety and Environment standards • Shareholders expect a fair return for their investment • Shareholders look to maintain good working relationships with other key stakeholders in the business through meaningful engagement with our consumers and effective management of the network	• Safety is a key driver in asset management decisions • Customer initiated projects produce appropriate revenue levels to meet the cost of capital • Meeting reliability and customer service levels

Figure 2-3 Stakeholder Identification

2.5.1 Consumers as Key Stakeholders

Domestic consumers account for approximately 90% of ICPs in the Wellington Electricity network area with the remainder being mostly small commercial operations. Figure 2-4 sets out the overall consumer mix.

Consumer Type	ICP Count
Domestic	148,648
Large Commercial	382
Medium Commercial	408
Small Commercial	15,356
Large Industrial	39
Small Industrial	500
Unmetered	589
Individual Contracts	16
Total	**165,938**

Figure 2-4 Wellington Electricity's Consumer Mix as at February 2015

Wellington Electricity has a Customer and Retailer Relations Manager who meets face-to-face with major consumers at least once a year to discuss and understand their specific needs and address any concerns they may have. Consumers who have significant electricity use, specific electricity requirements, or are suppliers of essential services are proactively contacted prior to planned outages, and following unplanned outages that impact their supply.

Wellington Electricity's ten largest consumers (by annual consumption) are:

1. Capital and Coast District Health Board (Wellington Hospital)
2. Foodstuffs
3. Chorus
4. Progressive Enterprises
5. Wellington City Council
6. Hutt City Council
7. The Warehouse Ltd
8. Porirua City Council
9. New Zealand Transport Agency (NZTA)
10. Vodafone NZ

Other consumers with significant or strategically-important loads include:

- Parliament
- Kenepuru and Hutt Hospitals
- Council infrastructure such as water and wastewater pumping stations and streetlighting
- Emergency services and civil defence;
- Essential service providers such as NZ Police, Wellington Free Ambulance, NZ Fire Service;
- The Reserve Bank;
- Major infrastructure providers such as Wellington Airport and CentrePort;
- Large education institutions such as Victoria University and Massey University;
- Network security-sensitive customers such as Weta Digital, Datacom, Department of Corrections; and
- Electrified public transport operators.

Line Charges

Network line charges are regulated by the Commission and set out what EDB's charge electricity retailers for provision of line function services. For Wellington business and residential consumers network line charges make up about 30-40% of their overall tariff.

The following list sets out the various line charge categories:.

- Industrial (> 1500 kVA; CBD/Urban/Rural; Fixed/Variable/Capacity/Demand))
- Transformer Connection (different kVA levels; Fixed/Variable/Capacity/Demand)
- Low Voltage Connection (different kVA levels; Fixed/Variable/Capacity/Demand)
- Residential (Single/Dual meters; Controlled/Uncontrolled charges)
- Un-metered (Street/Non-Street lighting; Fixed/Variable charge)

Engagement

Wellington Electricity engages with consumers in a variety of ways including:

- Public notices, for example notification of tariff changes;
- Consumer surveys – from time to time Wellington Electricity surveys a range of customers to get feedback on network performance, as well as to understand their views on issues such as price-quality of supply trade-offs. Consumer satisfaction surveys are also routinely carried out with consumers who have requested the provision of specific services;
- Liaising directly with consumers around specific issues, for example where trees are in close proximity to overhead lines and co-operation is required from land owners to improve tree maintenance; and
- Engaging directly with consumers impacted by planned maintenance work – the goal is to contact all impacted consumers prior to work commencing to try and minimise inconvenience caused.

Engagement Initiatives

Wellington Electricity is implementing a number of initiatives to improve the provision of information and engagement with consumers and electricity retailers. These include:

- Strengthening of its customer service team through appointment of a new Customer Service Manager and establishment of local billing and connections functions (previously outsourced);
- Developing a new website, to include more customer-focused content and the ability for customers to check the status of unplanned electricity outages. Consumers will also be able to provide feedback on the website to help improve the website content;
- Developing a new smartphone application that will provide information and updates on the status of electricity outages; and
- Expanding the programme of consumer research to obtain more feedback from customers on the services provided. An example of this already underway includes liaising with community groups in rural areas where trees are interfering with power lines and causing repeat outages.

2.5.2 Managing Conflicting Interests

Safety will always be a priority attribute when managing a stakeholder conflict. Wellington Electricity will not compromise the safety of the public, its staff or service providers. Other conflicts in stakeholder interests will be managed on a case-by-case basis. This will often involve consultation with the affected stakeholders and the development of innovative “win-win” approaches.

Wellington Electricity is a member of the Electricity and Gas Complaints Commissioner Scheme, which provides a dispute resolution process for resolving customer complaints. Wellington Electricity’s Use of Network Agreements provide a dispute resolution process for managing conflict with retailers.

Wellington Electricity actively engages in consultations undertaken by the Electricity Authority, Commerce Commission and government departments. Wellington Electricity is obliged to follow approved business policy to ensure it meets its obligations and responsibilities to deliver an electrical supply in accordance with all legislative requirements.

2.6 Alignment between Asset Management and Corporate Business Plans

Wellington Electricity's mission is:

> **"To own and operate a sustainably profitable electricity distribution business which provides a safe, reliable, cost effective and high quality delivery system to our customers."**

This mission sets the context for all strategic positioning and business planning and subsequently also drives asset management planning and delivery. In achieving this mission, it is essential that business and asset management practices and policies:

- Operate in the most commercially efficient manner possible within the current regulatory environment;
- Provide a safe environment for both our staff, contractors and the public; and
- Deliver high quality outcomes for consumers.

The AMP incorporates information from internal business and asset management related documents, which cascade down from the business plan and strategy to the asset management policy, asset strategy, network development plans and lifecycle plans through to the annual capital and maintenance works delivery plans and programmes, as shown in Figure 2-5. The asset management plans and works delivery programmes are outputs from the annual business planning processes.

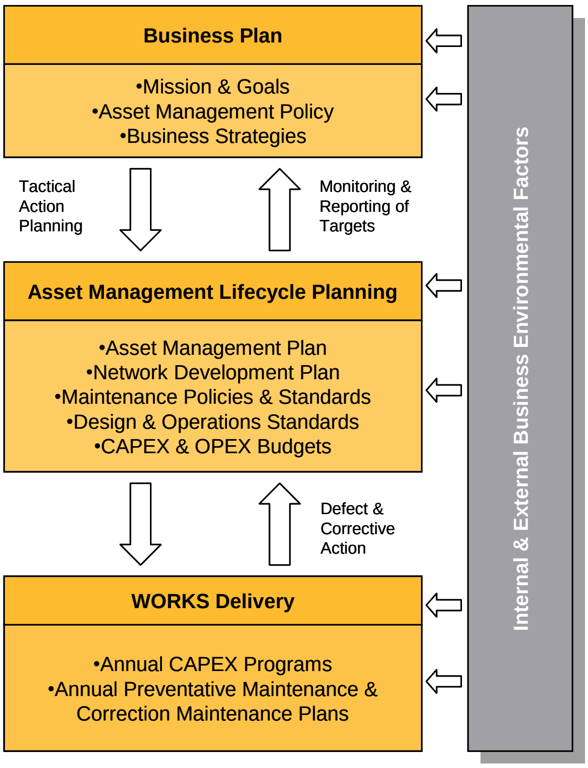


Figure 2-5 AMP Interaction with Business Planning

2.6.1 Business Plan and Strategy

Wellington Electricity's business strategy is supported by the 5-year Business Plan. The Business Plan aims to deliver a long-term sustainable business accounting for the requirements of all stakeholders. Figure 2-6 illustrates the main components of the Business Plan.

WELLINGTON ELECTRICITY BUSINESS PLAN

"To own and operate a sustainably profitable electricity distribution business which provides a safe, reliable, cost effective and high quality delivery system to our customers."

INTERNAL BUSINESS ENVIRONMENT	EXTERNAL BUSINESS ENVIRONMENT
Financial	**Consumers**
Meeting financial targets Manage treasury responsibilities	Over 165,000 reasons to provide effective and efficient service Understand investment in their future for a quality service
People	**Regulatory**
Working safely Developing a great team and organisational culture Employees are aligned with business goals & direction Building strong relationships with service providers Being seen as a reputable employer	Health & Safety in Employment Act and incoming WorkSafe legislation Commerce Act – Price/Quality Path reset and controls Electricity Act, Electricity Industry Act and associated Codes and Regulations **Economic** Business cycles and pressure to maintain price stability
Assets	**Image & Reputation**
Meeting regulatory targets through prudent asset management Effective life cycle management of assets Appropriate risk management Engaged with stakeholders	Well managed media and stakeholder communication Local people managing the business well with high quality service **Political** Responsibility of 4th largest EDB serving New

	Zealand's capital city Government and business leaders interested in affordable and reliable supply Managing local and regional council expectations

Figure 2-6 Wellington Electricity Business Plan

Wellington Electricity's Business Plan is driven by both the internal and external business environments and defines the company's actions and outcomes to meet its business mission.

The Business Plan effectively 'shapes' the AMP, taking into consideration the changing regulatory environment and the needs and interests of Wellington Electricity's stakeholders.

2.7 Organisational Structure

2.7.1 Corporate Governance

The Wellington Electricity Board of Directors is responsible for strategic guidance and the overall governance of the business. Information is provided to the Board monthly as part of a consolidated business reporting that includes health and safety reports, capital and operational expenditure against budget, reliability statistics against targets and consumer satisfaction survey results.

The Board reviews and approves each AMP as well as annual forecasts and budgets.

2.7.2 Financial Oversight, Capital Expenditure Evaluation and Review

Wellington Electricity has a Delegated Financial Authorities (DFA) list, authorised by the CEO, which shows the specific approval limits for the various levels of staff within the business.

Major Project Financial Approval and Governance

The policies for Authorisation and Payment of Project Expenditure together with the Individual and Delegated Financial Authorities, define the procedure for authorisation of Wellington Electricity's capital expenditure.

No expenditure associated with capital projects above $400,000 proceeds until the Capital Investment Committee (CIC) has appraised the project business case and approved the expenditure.

The scope of the CIC is to approve capital expenditure proposals and to ensure that both an appropriate level of diligence has been undertaken and that the investment is in line with Wellington Electricity's strategic direction. The Committee also reviews the annual expenditure programme, and conducts post-implementation reviews.

The CIC can approve projects previously included in the budget or Customer Connections projects not previously included in the budget up to $2 million. Projects of larger value than this need to go to the Board of Directors for approval after receiving CIC approval.

Projects greater than $500,000 not included in the budget (excluding customer connection projects) are also required to go to the Board for approval after receiving CIC approval.

2.7.3 Executive and Company Organisation Structure

The Wellington Electricity CEO leads the business management, implements the company mission and is accountable for overall business performance and direction.

As Wellington Electricity is part of the CKI and Power Assets group of infrastructure companies, it can access skills and experience from across the world. For example, the Australian group of companies (which distribute electricity to over 1.8 million consumers) have considerable knowledge and experience in electricity distribution business asset management, including strategy and planning. This group provides IT systems and platforms to Wellington Electricity to allow synergy gains across the business. Being part of a larger CKI group of companies provides Wellington Electricity with direct access to international best practice systems.

International Infrastructure Services Company (IISC) is a separate infrastructure services company, part of the CKI and Power Assets group, which provides business support services to Wellington Electricity. IISC provides the in house asset management and planning functions.

The overall structure is shown in Figure 2-7 below

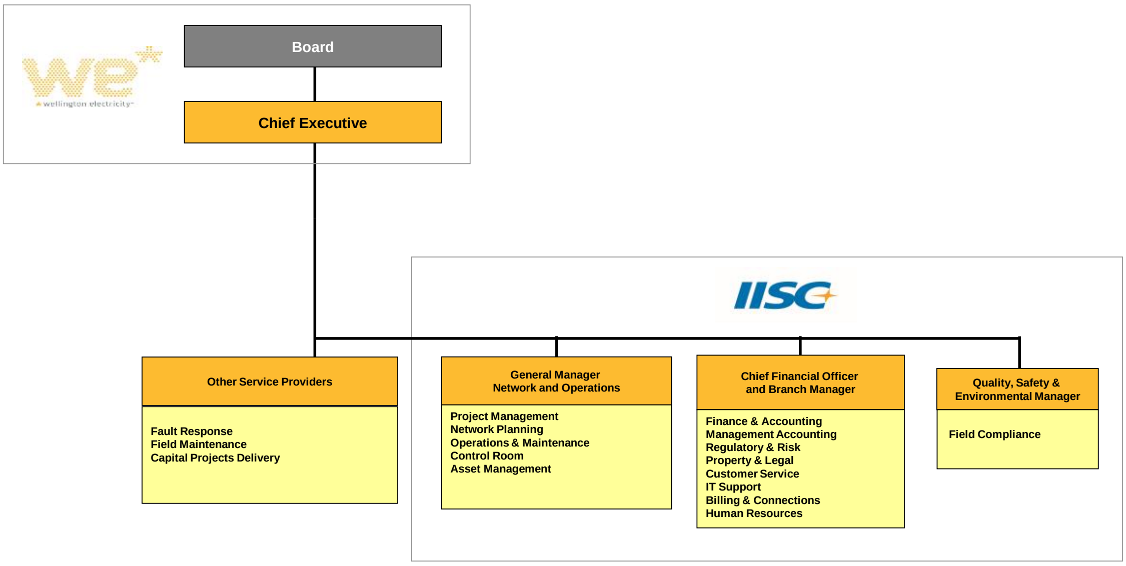


Figure 2-7 Wellington Electricity Organisation Structure

2.7.4 Network & Operations Team Structure and Asset Management Accountability

The IISC Networks and Operations team is responsible for the management of network assets. As established in Wellington Electricity's Asset Management Policy, the General Manager – Network and Operations is accountable for the delivery of asset management. This includes asset planning, project management, capital expenditure delivery, operations and maintenance and safety, quality and environmental performance. Figure 2-8 illustrates the organisational structure.

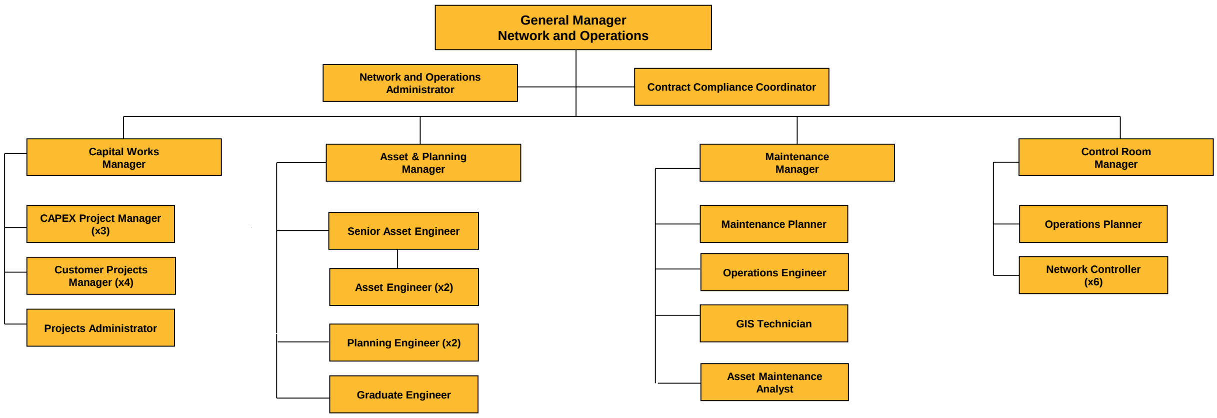


Figure 2-8 IISC Network and Operations Support Structure for Wellington Electricity

2.7.5 Finance and Commercial Team Structure and Asset Management Accountability

The Finance and Commercial team provide financial and accounting support for the management of network assets within the IISC.

The Chief Financial Officer is responsible for all indirect asset management functions including customer service, retail services, regulatory management, legal and property management as well as financial modelling and accounting support services.

Figure 2-9 illustrates the finance and commercial support structure.

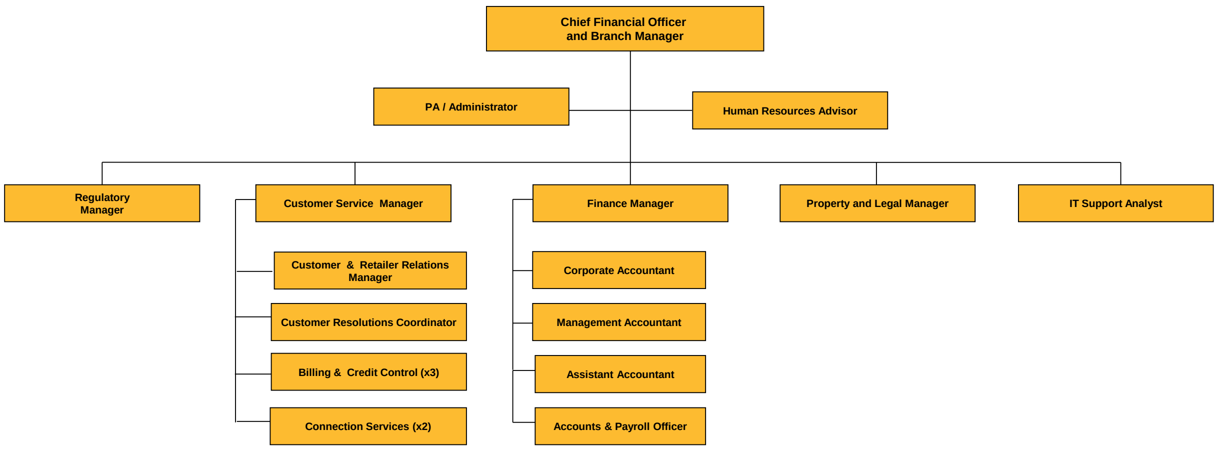


Figure 2-9 IISC Finance and Commercial Support Structure for Wellington Electricity

2.8 External Service Providers

Wellington Electricity outsources a number of network related services both in the field and at the Contact Centre. The outsourced field operations and the approved Wellington Electricity service providers are listed below, along with their contractual responsibilities.

Wellington Electricity manages and audits all service providers and continually reports on network operations and maintenance performance and expenditure, customer satisfaction, safety statistics and network reliability.in order to achieve optimum outcomes for its asset management.

Contractors working on an underground cable

2.8.1 Field Services

Wellington Electricity utilises a number of service providers for core field and network functions. From 2011 Northpower Ltd has been Wellington Electricity's primary field service provider responsible for fault response and maintenance. This was initially for a four-year term, and has been extended for one year through to the end of 2015. During 2015, Wellington Electricity will be completing a process of negotiating a new field services agreement to be effective from January 2016.

The current Field Services Agreement with Northpower delivers a number of strategic outcomes for Wellington Electricity. The agreement is structured to ensure alignment with Wellington Electricity's asset management objectives and to improve the integrity of the asset data held in Wellington Electricity's information systems.

Fault Response and Maintenance (Northpower)

- Fault management – 24/7 response for fault restoration;
- Preventative maintenance – asset inspection and condition monitoring including the capture and storage of asset condition data and reporting this information;
- Corrective maintenance – remedial maintenance on defective assets;
- Value added services – safety disconnects and reconnects, on site cable mark-outs, subtransmission standovers and provision of buried asset plans provided to third parties;
- Minor connection services and livening; and

- Management services – management of network spares, updating of geographical information systems (GIS) and other supplementary services as required.

The Field Services Agreement includes key performance indicators (KPIs) and performance targets that the contractor is required to meet, with penalties for poor performance, as well as incentives for high levels of achievement. The contract is managed with a series of monthly meetings to cover off key functional relationships between Wellington Electricity and Northpower, as well as a leadership committee meeting bi-monthly comprising the senior managers from both businesses. The cost of work undertaken is based on commercially tendered unit rates. It is the responsibility of the Maintenance Manager to ensure the work completed is within agreed budgets and the work is delivered within the required quality and timeliness targets. To achieve financial performance under this contract, and to ensure a strategic balance is achieved between maintenance and renewal activities, expenditure by the contractor is limited under Delegated Financial Authorities, above which Wellington Electricity must provide approval to proceed.

Contestable Capital Works Projects (Northpower, DownerTenix and Connetics)

- Customer initiated works – new connections, subdivisions and substations, undergrounding and relocations; and

- Network initiated works – asset replacement projects and cable/line reinforcements.

Contestable capital works projects are generally competitively tendered. They are delivered under either independent contractor agreements or the Field Services Agreement, dependant on the successful tenderer. These agreements outline the terms and performance requirements the work is to be completed under such as KPIs, defects liability periods, insurance and liability provisions to limit the exposure of Wellington Electricity. All contracts are managed on an individual basis, and include structured reporting and close out processes including field auditing during the course of the works.

In some instances, low value works or in circumstances where only one supplier can provide the required service projects are sole sourced. In the case of sole source supply, pricing is benchmarked against comparable market data. Under the project management framework, work scopes are well defined and there are stringent controls in place for variations to fixed price work.

It is the responsibility of the Capital Works Manager to ensure work undertaken is managed contractually to deliver value to the business.

Vegetation Management (Treescape)

- Vegetation Management – tree clearance programme, tree owner liaison and reactive availability.

This outsourced contract was re-negotiated in 2013. The revised contract provides for effective and efficient second cut and trim management, as well as improved landowner awareness of tree hazards.

Management of this contract is handled in a similar manner to the Northpower Field Services Agreement with monthly meetings and performance incentives in place.

Contact Centre (Telnet)

The Contact Centre provides management of customer and retailer service requests, outage notification to retailers and handling general enquiries. Telnet is currently contracted to provide services to Wellington

Electricity to November 2015. During 2015 Wellington Electricity will complete a process of negotiating a new Contact Centre agreement.

2.9 Legislative and Regulatory Environment

As an electricity operator, pursuant to section 4 of the Electricity Act, Wellington Electricity is subject to a range of legislative and regulatory obligations to ensure its network is safely and efficiently planned, constructed, operated and maintained and that the prices charged for its services fall within regulated allowances. This includes obligations covering:

- Economic regulation under Part 4 of the Commerce Act 1986, including:
  - Information disclosure - the purpose of which is to ensure that sufficient information is readily available so that interested persons can assess whether the purpose of Part 4 is being met. Wellington Electricity is subject to the Commission's Electricity Distribution Information Disclosure Determination, November 2014 ; and
  - Price-Quality regulation - the purpose of which is to regulate the weighted average prices Wellington Electricity is allowed to charge for providing electricity lines services as well as the reliability (quality) of the supply of electricity to consumers. Reliability of supply is measured with reference to the duration of interruptions to supply and the frequency of interruptions to supply[5]. Wellington Electricity is also subject to the Commission's DPP determination of November 2014.
- Price oversight under the Electricity Industry Act 2010 administered by the Electricity Authority. While the Commission regulates the maximum average price Wellington Electricity may charge, the Authority's price oversight relates to price setting and price movements for different consumer classes, including the principles for price development.
- Connection of consumers and embedded generators to the network. These obligations are established under Wellington Electricity's Use of Network Agreements with the retailers using its network, and are compliant with the Electricity Industry Act 2010 and the Electricity Industry Participation Code 2010 (Parts 11 and 6).
- Quality of supply standards. This relates to voltage regulation, harmonic voltages and currents, voltage dips, voltage unbalance and flicker standards as per the Electricity (Safety) Regulations 2010 and AS NZS 61000 Electromagnetic compatibility (EMC).
- Employee and public safety under the Electricity (Safety) Regulations 2010 and the Health and Safety in Employment Act 1992 to ensure that Wellington Electricity's network assets do not present a safety risk to staff, contractors or the public. Wellington Electricity monitors electricity related public safety as well as staff and contractor safety incidents around its assets. Changes in health and safety legislation are expected to be introduced around September 2015 with the Health and Safety Reform Bill currently in Select Committee stage of review. This legislation change is discussed further in Section 4.6.

[5] The duration of interruptions to supply is measured by the System Average Interruption Duration index (SAIDI) and the frequency of interruptions is measured by the System Average Interruption Frequency Index (SAIFI). For a detailed explanation of these measures refer to Section 6.1.

- Environmental obligations under the Resource Management Act 1991, the Building Act 1991, the Local Government Act 1974 (particularly with respect to works on roads), the Dangerous Goods Act 1974 and other relevant local authority bylaws. Wellington Electricity has an Environmental Management Plan which sets out its approach to environmental management of its network including in relation to: noise limits; sediment disposal; dust control; spill management.

- Vegetation management in accordance with Electricity (Hazards from Trees) Regulations 2003. This sets out clearance zones in which Wellington Electricity must notify tree owners to arrange management of their vegetation to prevent further encroachment.

Wellington Electricity has regard to these regulatory and legislative obligations in developing best practice asset management policies and procedures that underpin this AMP. Wellington Electricity regularly engages with the Authority and the Commission through active participation in submissions on various matters and regular information disclosures.

2.10 Impact of the Regulatory Environment

The regulatory environment has a number of financial, technical and reliability impacts on Wellington Electricity's business. For example, the impact of the 2014 DPP Determination which was described at the beginning of this AMP.

Other impacts of the regulatory environment are detailed below.

Price-Quality compliance

Wellington Electricity must comply with the regulated price and quality requirements set by the Commission under Part 4 of the Commerce Act through the DPP. The company is exposed to possible fines and prosecution if found to be non-compliant.

Wellington Electricity's prices are calculated in accordance with a regulatory framework and recovered through charges for the use of the distribution system (otherwise known as Lines charges). These charges are payable by retailers and are included in the price retailers charge consumers for the supply of electricity.

Wellington Electricity's maximum weighted average price for providing regulated lines services is set out in the 2014 Determination and applies for the regulatory control period from 1 April 2015 to 31 March 2020.

Information Disclosure

Wellington Electricity must provide information disclosures on an annual basis and respond to other information requests. During 2012 a new information disclosure regime was implemented by the Commission, taking effect from 2013 and then subsequently updated in 2014. This regime has significantly increased the information required to be disclosed. The preparation of the various disclosure requirements is time consuming and costly and, in order to comply, the business has amended its processes and information systems to ensure that information is available in the prescribed form.

Load Control

Historically, Wellington Electricity has optimised the required network capacity by using load control to shift loads to reduce demand during peak times. This lowers the capital investment required to deliver the reliability and quality of supply at peak times. In September 2012, the Authority published a Model Use of

System Agreement (MUoSA) which, while voluntary, facilitates retailers and load aggregators using load control to meet their own requirements. Wellington Electricity supports consumers' right to choose how they participate in the load control market. However the Authority's approach to enforcing the MUoSA may reduce Wellington Electricity's ability to co-ordinate and manage coincident loads when it is critical to do so.

There is currently uncertainty as to how the load control market will operate under the MUoSA as well as the potential for unregulated participants to enter the market. If Wellington Electricity loses its ability to control the loads connected to its network, the quality of supply at peak times could be compromised. The loss of effective load control may also lead to the need to increase investment in network capacity in order to manage larger loads on the network.

Government Policy - Major Infrastructure projects

Major infrastructure projects driven by Government policy have an impact upon Wellington Electricity's network. While Ultra-fast Broadband (UFB) is a positive initiative for New Zealand, the rollout currently being undertaken by the telecommunications infrastructure provider (Chorus) has created a significant increase in requests for maps and location mark-outs of network assets. Wellington Electricity has continued to work with Chorus on the use of network poles where required to support the UFB rollout.

Requirements driven by local authorities

Wellington Electricity must comply with local authority requirements and so monitors changes to district plans providing comment and submissions when required.

Examples of recent additional requirements include the assessment and strengthening of earthquake prone buildings. There are lessons from Christchurch with regard to resilience of infrastructure that require Wellington Electricity to conduct further technical and economic assessments followed by consultation with stakeholders on seismic resilience.

The Wellington City Council earthquake-prone building assessment process obligates Wellington Electricity to make further resilience investments in engineering and strengthening works on substation buildings.

This AMP includes forecasts of the CAPEX and OPEX which Wellington Electricity estimates to be necessary to provide an adequate level of seismic resilience. This includes the assessment of around 320 pre-1976 buildings, with strengthening works on approximately 10% of these (based upon assessment and failure rates to date), as well as design, consenting and materials procurement for emergency overhead line routes to bypass damaged subtransmission cables. Full details of these programmes are provided in later sections of this AMP.

This requirement for moderate levels of additional OPEX and CAPEX in the forecasts provides benefit to customers for the long-term by avoiding higher recovery costs in the future following a major earthquake.

3 Asset Management Framework

The asset management framework under which Wellington Electricity operates aligns with the company's corporate mission and objectives and is embodied in this AMP. The framework is aligned with the principles of the international standards PAS 55/ISO 55000. The key components of the framework are the asset management policy, strategies and plans as discussed below.

3.1 Asset Management Policy

The Asset Management Policy (the Policy) establishes the formal authority for Asset Management within Wellington Electricity. In alignment with the corporate mission, the Asset Management objective in the Policy states that the business will:

"Optimise the whole of life costs and the performance of the distribution assets to deliver a safe, cost effective, high quality services to our customers.**"**

The policy also states that Wellington Electricity's electricity network shall be designed, constructed, operated and maintained in a safe and efficient manner which:

- Aligns with corporate objectives and plans;
- Conforms with the risk management framework and the asset management objective;
- Is founded on customer service level expectations and engages stakeholders where appropriate on asset-related activities;
- Has a strong safety focus regarding its employees, contractors and members of the public;
- Improves asset management capability through appropriate internal and external resourcing;
- Stays apprised of, and aligned with, national and international asset management standards, trends and best practices;
- Complies with all applicable regulatory and statutory requirements; and
- Maximises the long-term return on investment for shareholders.

3.2 Asset Management Strategy

Wellington Electricity is following an asset management strategy that aligns with the company's asset management policy, business strategies and goals and follows key components of international standards. One such key component is the Plan-Do-Check-Act cycle of continuous improvement. During 2015, further work will be undertaken on management strategies for each of the main asset categories on the network. These strategies will cover the whole of the asset lifecycle from selection, acquisition and construction, through operations and maintenance to end of life replacement and disposal.

The strategies will link together various pieces of existing knowledge and information within the business including technical specifications, maintenance standards, as well as renewal and replacement plans as documented in Section 10 of this AMP. The strategies, when finalised and documented in future plans, will incorporate cost-benefit analysis information supported by risk assessments of the different scenarios.

These strategies will be socialised with a range of stakeholders to ensure they are widely understood and that the asset management practices of the business are aligned.

3.3 Asset Management Process Overview

The three main processes that Wellington Electricity uses as part of managing network assets are:

- Planning – e.g. fleet strategies and network development planning;
- Inspection and maintenance; and
- Investment selection.

The interaction of these processes is illustrated in Figure 3-1 and described in further detail below. Long term network and fleet management planning, supported by the inspection regime specified for each asset type and condition, results in identified investments which in turn form the basis for the approved annual Capital Works Plan (CWP).

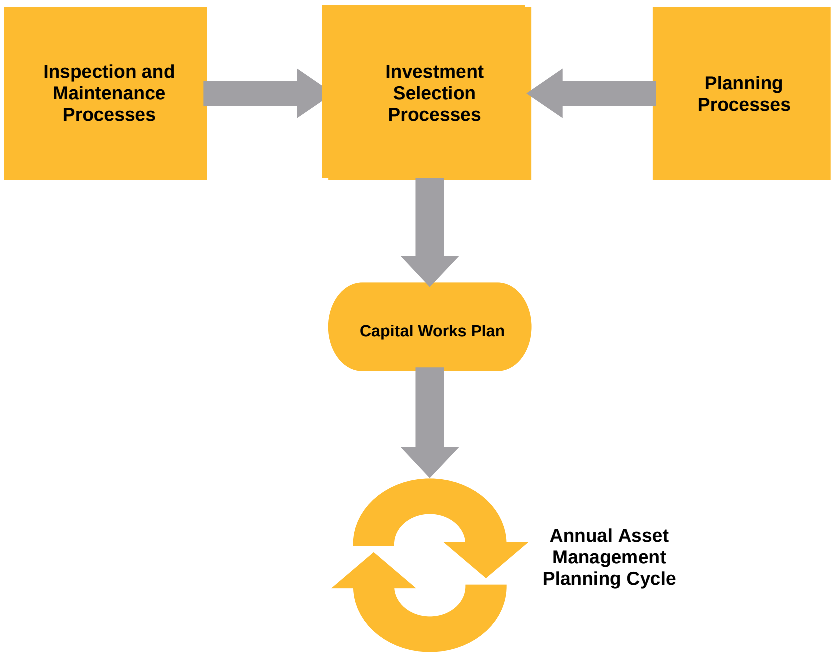


Figure 3-1 Asset Management Processes

3.3.1 Inspection and Maintenance Process

The asset inspection and maintenance process is centred on the Preventative Maintenance plan that is prepared annually by the Wellington Electricity engineering and maintenance groups. Each asset type has an associated standard which details the scope and frequency of the inspection and maintenance required for that asset category. These standards and associated policies are discussed in more detail in Section 10. The timing and scope of these activities are prioritised by a number of factors including:

- Safety (both operational and public);
- Condition (assets that show signs of deterioration may be inspected more regularly);
- Age (older assets may be inspected more regularly than new ones);

- Experience of how often inspections are required (e.g. for substation buildings);
- Type history (assets that have known issues may be inspected more regularly);
- Operation frequency (assets that have operated frequently under fault conditions);
- Risk (likelihood and consequence of asset unavailability); and
- Manufacturers' recommendations.

The details of individual assets requiring inspection and maintenance are stored in a SAP Plant Maintenance system (SAP PM) and are available to the maintenance planners within Wellington Electricity and to the Field Service Provider. The maintenance history, such as date of last activity and the condition assessment outcome, drives the next activity date.

The Preventative Maintenance programme is a function of the following:

- Inspection and maintenance programme conducted by the Field Services Provider;
- Inspection and test results reported to Wellington Electricity on a regular basis via SAP PM; and
- Data analysis by Wellington Electricity engineering staff and recommended corrective maintenance or refurbishment/renewal.

Additionally, the cyclic review of asset performance (e.g. feeder performance) may initiate either corrective or project works. The maintenance data allows for the monitoring and detailed reporting of defects, which enables the business to plan and implement the appropriate action

3.3.1.1 Review of Inspection and Maintenance Process

Wellington Electricity continually reviews the outcomes from its asset inspection and maintenance processes to ensure they are effective in meeting business and consumer needs.

Increasing the understanding of network assets through the data improvement programmes enables improved asset planning and operations. From an analysis of defects and asset failure modes, maintenance standards are then updated as required to reflect new issues and modes of failure. Where necessary, corrective programmes of work are put in place to address specific risks.

3.3.2 Planning Process

Network investment programmes are developed through both proactive and reactive planning:

- Proactive: The Network Development Plan (NDP) identifies potential constraints, areas of growth or future requirements for network infrastructure; and
- Reactive: Investigation of the current state of the network and identification of constraints or historical deficiencies.

Figure 3-2 provides a flowchart view of the planning process.

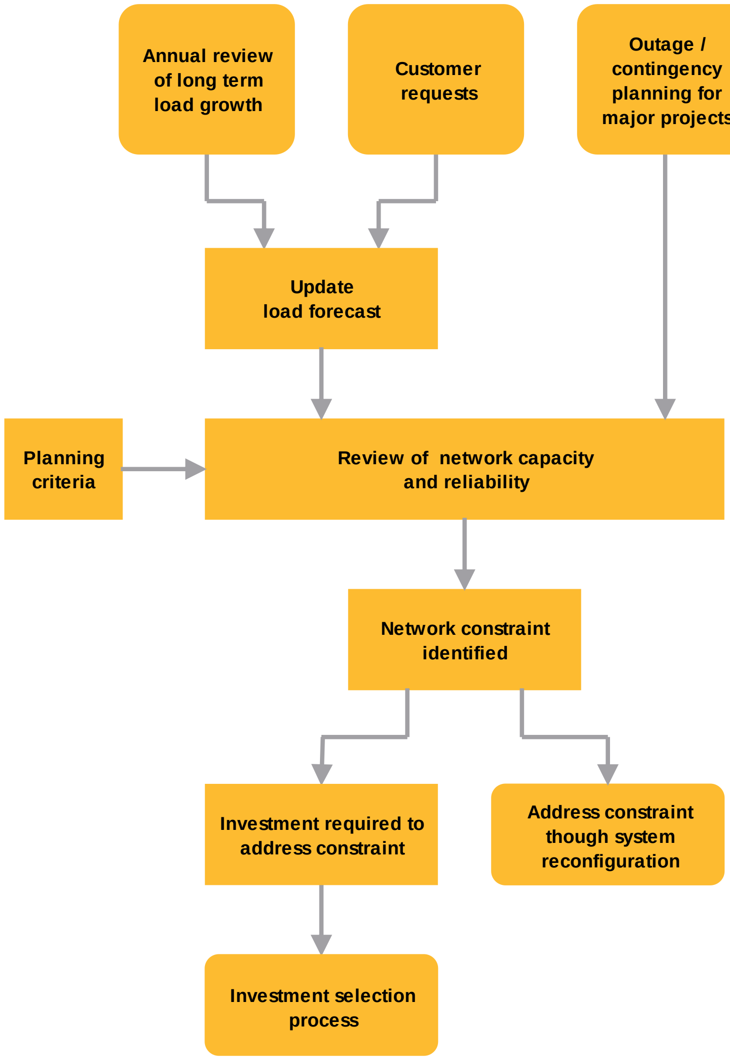


Figure 3-2 Planning Process

Wellington Electricity's approach to planning is as follows:

1. Identification of the need or constraint in the network requiring mitigation: This could be due to organic or step change load growth in an area exceeding available capacity or a historical deficiency in the network.

2. Development of options to mitigate: Multiple options are investigated to determine the optimal solution for mitigating an identified constraint. Costing for each option is also determined by investigating estimates and actual costing for recent projects of similar scope.

3. A recommendation is made for investment: A semi-quantitative analysis is performed to determine the optimal solution with respect to factors such as health and safety, cost to implement, regular maintenance requirements and the level of mitigation achieved.

4. Approval: According to the delegated financial authority process.

5. Project execution: Following approval of a project, the project is executed and commissioned by the installation contractor to Wellington Electricity standards.

In most cases, operational solutions, such as open point shifts, are preferred where possible to relieve the issue and defer investment. If this is not possible then network augmentation is required.

To identify the network constraints within the planning period, the forecast peak demand is compared to the capacity of the network equipment to produce a list of potentially overloaded assets. This is done for both system normal (N) and contingency (N-1)[6] conditions. Options to resolve asset overloads at times of forecast peak load are considered for inclusion in the capital budget submission if the relevant network planning criteria for the asset are breached.

3.3.3 Investment Selection Process

The investment selection process describes the way in which network investments are taken from a high level need through to a preferred investment option that in turn results in a business case or project proposal. It includes consideration of a list of appropriate options, refinement of the list to a short list of practicable options followed by detailed analysis and selection of a preferred option. The Capital Works Plan is the repository for all potential network investments for the year ahead.

The process is as follows:

1. Outputs from the planning process (NDP or reactive), inspection and maintenance process are developed into a project recommendation, justifying the need for investment.

2. Approved recommendations are entered into the Capital Works Plan and prioritised in terms of budget, timelines and network criticality. Customer connection requests are also recorded in the Capital Works Plan.

3. Following prioritisation and budget confirmation, a list of projects for the following year (i.e. the capital works spend plan) is prepared for both CIC and Board approval.

Additional information on the prioritisation process used for capital works projects is provided in Section 9.3.

3.3.4 Measuring Network Performance for Disclosure Purposes

Measuring network performance for disclosure purposes relies on Supervisory Control and Data Acquisition (SCADA)[7] and ICP[8] allocation information stored within the Electricity Network Management and Control (ENMAC) database. Reporting tools are used to extract data which provides the business with fault (unplanned) and planned outage information. All relevant details of each fault are entered into the ENMAC fault log database which calculates the impact of each fault on the network reliability indices, SAIDI and SAIFI. Where supply is restored progressively, the switching sequence is recorded and used as the basis for measuring the actual SAIDI impact on customers. The ENMAC database is also used to measure other performance metrics, for example the faults per 100 circuit-km performance indicator.

Information on network performance is regularly reported both within the business and to the Board through its monthly reports.

[6] N-1 = Available capacity in the event of a single component failure. The majority of sites have redundant capacity by design in the form of a second backup component, i.e. two independent subtransmission circuits supply each zone substation with sufficient capacity for the total load at the zone substation (N+1).

[7] SCADA includes the status of circuit breakers and switches as well as system voltages and currents.

[8] ICP allocation information comprises connections made to each part of the network.

3.3.4.1 Unplanned Outages

The main operating teams that contribute to managing outages are:

- Contact Centre service provider;
- Control room operators and ENMAC; and
- Field Service Provider (fault response and maintenance).

Low Voltage Faults (400V or below)

Notification of a LV fault may be raised through calls from consumers (either direct to the Contact Centre or via the consumer's energy retailer). The majority of retailers have an electronic interface into the Wellington Electricity's ENMAC Calltaker system to directly input the LV fault details from the consumer. Other options available to retailers are email and facsimile. The Contact Centre receives this information and sends it via the ENMAC Calltaker system to the Field Services Provider's dispatching system.

The Field Services Provider dispatches a faultman to the faulted customer(s). Updated information is fed back from the field to the Contact Centre via the outage management systems to enable the consumer (via its energy retailer) to be kept informed of progress of the fault and its restoration.

High Voltage Faults (11kV or above)

The control room via the SCADA system will notify most faults or a tripping on the 11kV network (or above) through an alarm within the ENMAC SCADA system. A dispatch request to the Field Services Provider for field response is automatically generated via the ENMAC Calltaker system.

As the cause of the fault is identified, repairs are carried out, supply restored and the Network Control Room (NCR) operators (via the field crews) progressively update the fault log in ENMAC. Fault logs are available from ENMAC via a reporting tool. These fault logs are interrogated on a regular basis to obtain network performance statistics.

Wellington Electricity manually creates fault logs in ENMAC for HV events that are not telemetered, such as distribution transformer faults and spur line fuses blowing.

3.3.4.2 Planned Outages

Planning of outages for both maintenance and capital works is undertaken by the Field Services Provider and other approved capital works service providers in conjunction with Wellington Electricity.

For both maintenance and capital works the service providers must provide the outage requirements in a prescribed format to comply with the Wellington Electricity Operational Standards. These Standards set out, for example, the minimum notification period for the request to be made to the NCR before the day of work. The NCR will confirm and schedule the planned outage, and develop the switching schedule and relevant test and access permits for return to the service provider before the day of the planned outage.

Maintenance planners use the Preventative Maintenance programme to produce a forward schedule of planned works for the NCR, to assist in the optimisation of planned outages and minimise the number and duration of planned outages on the network.

Wellington Electricity's customer services team discuss major outages, and outages that affect sensitive consumers, directly with those consumers prior to the outage being confirmed. Following confirmation of an outage, the NCR will liaise with the retailers (who notify all affected consumers) to advise them in advance of planned works that will interrupt their supply. As the outage takes place, ENMAC is updated with switching operations. A log of affected consumers, and the duration of the interruption to their supply is then recorded and logged. This log is interrogated to determine network performance.

3.4 Asset Management Systems

Wellington Electricity invests in IT systems, which support the delivery of asset management services to consumers. Figure 3-3 provides an overview of the information systems used by Wellington Electricity as well as where these systems are used as part of the asset management and network operations processes.

	Physical Attributes	Equipment Ratings	Asset Condition	Connectivity	Customer Service
SCADA / ENMAC		✓		✓	✓
GIS	✓	✓		✓	✓
Project Wise	✓	✓			✓
Power Factory		✓		✓	
Station Ware	✓	✓			
SAP PM	✓		✓		✓
GenTrack				✓	✓
SAP (Financial)					✓

Figure 3-3 Asset Data Repositories

3.4.1 Systems for Managing Asset Data

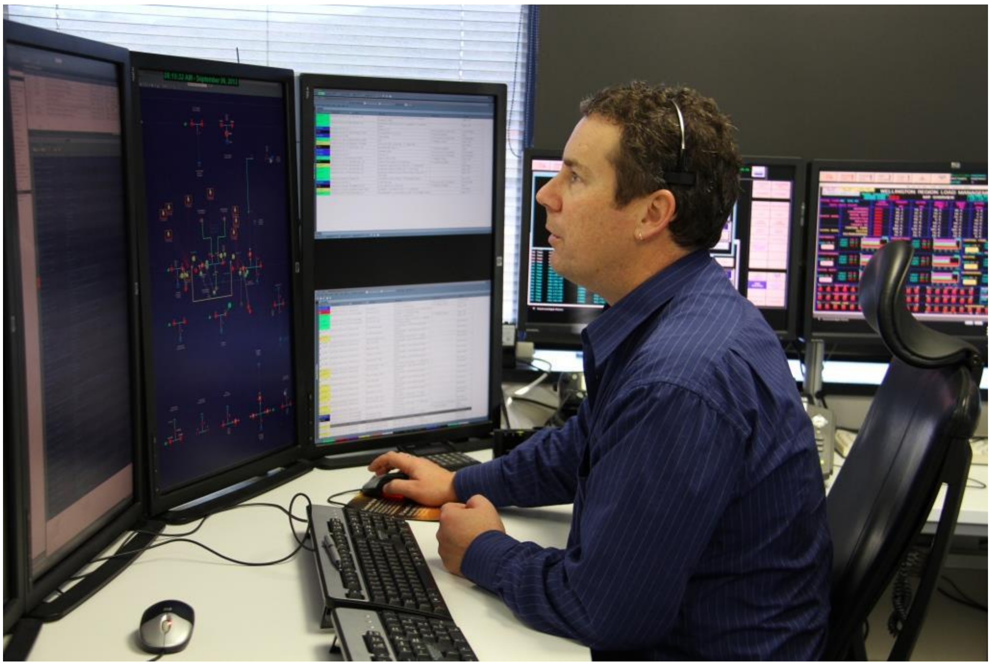
The following information describes the key repositories of asset data used in the asset management process, the type of data held in the repositories and what the data is used for. Areas where asset data is incomplete are identified and initiatives to improve the quality of this data are discussed.

3.4.1.1 SCADA

A GE ENMAC Supervisory Control and Data Acquisition (SCADA) system is used to assist real time operational management of the Wellington Electricity network. SCADA provides for remote control and monitoring of telemetered field devices such as circuit breakers and substation equipment; it also provides HV network connectivity overview. The ENMAC system has the capability to provide a total integrated solution of SCADA, DMS (Distribution Management System) and OMS (Outage Management System).The legacy Foxboro SCADA system that it replaced has been retained to perform automated load control.

The SCADA system provides operation, monitoring and control of the network at 11kV and above. Low voltage (400 volts or below) outages are recorded by the GE ENMAC Calltaker system utilised by the

Outage Manager at the Wellington Electricity Contact Centre. The Calltaker system electronically interfaces with the Field Service Provider's dispatch system to dispatch field staff for fault response.



Main Network Control Room

Wellington Electricity has planned and budgeted for the upgrade of ENMAC to an updated version of the GE system, known as PowerOn Fusion, scheduled for 2015. Staged enhancements following the upgrade will continue to improve functionality of systems such as the Outage Management System.

Two other systems related to the SCADA system are being investigated for upgrade and business cases for their upgrades will be completed in 2015.

- TrendSCADA - a proprietary data historian tool provided with GE ENMAC system, which is used by network operations and for planning purposes. There are a number of shortfalls with this product, such as limitations in the resolution of data that can be stored, limited ability to retrieve large datasets, as well as a limited suite of analysis tools. The business case for an upgrade will consider alternative products, such as OSI-Soft PI, which is widely used by other EDBs, which may offer greater benefits to the business and improve user-friendliness.
- Load Control – currently uses the Foxboro SCADA system, which has remained in service since the conversion to ENMAC. This requires replacement in the short term and options are being investigated, either as an integrated part of the GE system or as a replacement standalone package.

3.4.1.2 Geographic Information System (GIS)

The GIS is a representation of the system's fixed assets overlaid on a map of the supply area. Wellington Electricity uses the GE Smallworld GIS application for planning, designing and operating the distribution system and this is the primary repository of network asset information. Asset condition data in the SAP PM system is linked to the GIS information to further improve asset management outcomes. Information is exchanged from the GIS to the Field Service Provider's systems, as well as to the Wellington Electricity SAP PM system, on a nightly basis ensuring that all systems have the latest asset data. By linking GIS with the SAP PM system, analysis of asset populations is improved and geospatial analysis of defects, maintenance and test history, and asset performance can be undertaken with ease, which will aid engineering decision making.

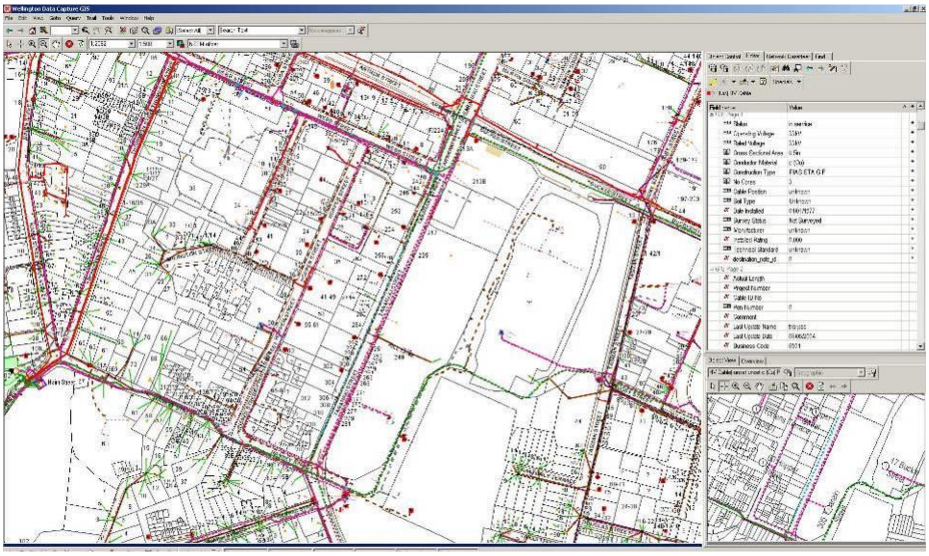


Figure 3-4 Screen Shot of Smallworld GIS system

3.4.1.3 ProjectWise

Wellington Electricity stores all drawings and historic asset information diagrams in ProjectWise, where users can access PDF files of all substation and system drawings.

3.4.1.4 DIgSILENT Power Factory

Power Factory is a leading network simulation tool used to model and simulate the electrical distribution network and analyse load flows for development planning, contingency planning, reliability and protection studies. The Power Factory database contains detailed connectivity and asset rating information. To ensure ongoing accuracy, the model is manually updated every quarter to improve functionality and include recently commissioned network assets and augmentations. Model updates are regularly distributed to design consultants to ensure consistency for commissioned studies. The most recent load forecast is input into the network model to allow future planning and assessment of constraints.

3.4.1.5 Cymcap

Cable rating information is derived via CYMCAP (cable ampacity and simulation tool) which is used to model the ratings of underground cables at all voltages for both existing cables in service as well as for new developments.

3.4.1.6 LVDrop

LV Drop is low voltage modelling tool used to model low voltage electrical networks to ascertain voltage drops and loading of conductors and transformers. LV Drop contains all the relevant LV cable, conductor, transformer and ADMD types and ratings. It is used for new subdivision reticulation designs and forms part of the customer connections and planning process.

3.4.1.7 DIgSILENT Station Ware

Station Ware is a centralised protection setting database and device management tool. It holds relay and device information, parameters and settings files. Station Ware is accessible remotely, via the Citrix environment, to allow input and modification by approved design consultants. Protection settings are uploaded to the Station Ware database for review and approval. The settings are then distributed to commissioning personnel for application in the field.

3.4.1.8 Maintenance Management System

In 2014 Wellington Electricity introduced SAP Plant Maintenance (SAP PM) to plan its maintenance activities and capture maintenance data for both preventative and corrective works. Maintenance workpacks are issued to service providers electronically, with maintenance results being returned electronically via a web interface. Asset data is synchronised with GIS, which allows maintenance tasks to be grouped spatially to increase efficiency.

3.4.1.9 GenTrack

GenTrack is an application designed to manage ICP and revenue data as well as deliver billing services. GenTrack is populated and synchronised with the central ICP registry. It interfaces with the GIS and ENMAC systems to provide visibility of consumers affected by planned and unplanned network outages. GenTrack also interfaces to the SAP financial system for billing.

3.4.2 Financial Systems

SAP is the financial and accounting application used by the business as its commercial management platform. It is an integrated finance system for billing, fixed asset registers, payroll, accounts payable and general accounting.

3.4.3 Identifying Asset Management Data Requirements

Wellington Electricity recognises that robust information is needed to drive asset management activities such as maintenance, refurbishment and replacement. Completeness and accuracy of the data in GIS is required to drive asset decisions, as GIS is regarded as the central repository for network information. Initially data is entered at the time the asset is created and more data is created through the life of the asset in systems such as SAP PM and Station Ware. However, it is recognised that data requirements may vary as asset management strategies change. Identification of asset management data requirements is covered by asset maintenance standards as well as through an evolutionary process where new needs are identified within the business or through changing regulatory requirements. Asset management data requirements and processes are also specified in the Field Service Agreement with Northpower.

3.4.4 Data Quality

Wellington Electricity is routinely reviewing its asset data to check the quality of the records in the IT systems (GIS, GenTrack and SAP PM), as inconsistencies have been found between some of the data in different locations. Ongoing processes are in place to establish one ‘source-of-truth’ for each category of information and the synchronisation of data between the various repositories. Work is well advanced to update data on missing or discovered assets and nameplate information stored in GIS, identify and fix network connectivity in GIS, which is critical to ICP data management, and to improve the quality of the maintenance data reported from the field.

Data quality is managed by the use of system controls such as mandatory fields, fixed selection lists and ongoing Quality Assurance (QA) processes in the major systems (GIS, SAP PM). User training is also provided to ensure users understand what information is required and why particular information is captured and its use within the overall asset management process. Specific areas where there are limitations in the availability or completeness of data are listed in Figure 3-5.

System	Limitation	Control in Place
GIS	Equipment name plate information missing for some assets	Name plate data collected as part of inspection process and GIS data is updated following inspections Periodic reporting of asset categories to identify where gaps exist and follow up with GIS updating process to correct gaps on inspected equipment
	LV connectivity is incomplete in some places	Ongoing project to improve LV connectivity and create accurate representation of LV feeders and open points
GIS/GenTrack	ICP connections to transformers	Historically some ICPs were not connected to the correct transformers in GIS and there is a mismatch between the GenTrack system and GIS. This is progressively being corrected and new processes are in place to ensure new ICPs are connected to the correct transformer (physical connection in the field is correct)
SAP PM	Some required data not collected for early records	Entry forms now have mandatory fields in place to control data being inputted Historic entries being reviewed to fill in gaps
	Condition Assessment (CA) scores incorrect for early inspections arising from misunderstandings of new Field Inspectors	Standardised CA scoring and field training is in place Annual re-inspection will provide correct information from second pass
Power Factory	Historical network augmentations or customer connections may not be captured in the model	Planning engineers update the model to reflect new and updated system components on project completion Project Managers are required to submit relevant information at the completion of projects to allow the models to be updated to reflect actual state
Station Ware	Not all station protection relay settings have been captured in Station Ware	Settings are updated at the time of projects being undertaken, or audited as required to undertake protection and network studies. Settings are intended to be updated following relay testing where the technician can enter as-left settings following the testing
PowerOn Fusion v5.2 (replacing ENMAC SCADA)	Not all network branches have ratings assigned to them in ENMAC leading to possible system overload	System limitations prevent all branch ratings from being stored and displayed. This will be remedied in upgrade versions of ENMAC The NCR utilises a spreadsheet of ratings based on operational scenarios. Alarm limits based on these ratings are assigned as required.

Figure 3-5 Overview of Asset Data Gaps and Improvements

3.5 Asset Management Documentation and Control

Wellington Electricity has a range of documents relating to asset management. These documents include:

- High level policy documents - define how the company will approach the management of its assets;
- Asset fleet strategies - asset maintenance, lifecycle management and renewal strategies for a range of asset groups, from subtransmission cables and power transformers to the various pole types and LV installations;
- Network Development Plans - providing a 15 year plan of forecasted load growth, potential constraints and strategies to mitigate in conjunction with asset renewal and reliability improvement programmes;
- Technical standards for procurement, construction, maintenance and operation of network assets;
- Network guidelines - provide directions and procedures on the construction, maintenance and operation of network assets and processes to achieve a desired outcome; and
- Network instructions - provide further instructions on the construction, maintenance and operation of network assets and processes.

The keystone document is the Wellington Electricity Asset Management Policy, which provides direction for the asset strategies, processes and supporting documents.

3.5.1 Controlled Document Process

All documents such as policies, standards and guidelines follow the structure of the Controlled Document Process adopted by Wellington Electricity, with a robust review and approval process for new and substantially revised documents. Intranets and extranets make the documents available to both internal users and external contractors and consultants. Generally, documents are intended to be reviewed every three years, however some documents, due to their nature or criticality to business function, are subject to more frequent reviews.

A large number of standards relating to network materials, construction (including standard drawings) and operational standards have been updated or developed and approved through the Controlled Document Process. This work will continue in 2015 and future years.

The Controlled Document Process ensures that new or altered documents are released to staff and contractors in a controlled manner. Contractors have access to the Wellington Electricity extranet to obtain the latest copies of controlled documents. Policy documents are used internally within Wellington Electricity to deliver strategy and as a guide to the development of standards, guidelines and network instructions. Where contractors are required to undertake certain tasks or follow procedures, these are provided to them in the form of a controlled document, either as a standard, guideline or network instruction.

3.6 Communication of Asset Management Framework

The umbrella document for detailing Wellington Electricity's asset management policies, procedures and plans is the annually updated 10 year Asset Management Plan (AMP).

This is also the vehicle by which the contents are communicated both internally and externally.

The AMP is issued by Wellington Electricity to the Regulator (Commerce Commission) on an annual basis, and is also available on the company's website as a public document.

People seeking information about Wellington Electricity's assets and plans can and do access the AMP through the website.

Internally, the AMP identifies and drives much of the company's maintenance and project work and the content is well known to the relevant departments and people.

This also has a bearing on the consultants, contractors and field service providers who assist Wellington Electricity to deliver on the design and construction of capital works and the implementation of the annual maintenance programme.

4 Quality, Safety and Environmental (QS&E)

Wellington Electricity is committed to providing excellence in Quality, Safety and Environmental (QS&E) outcomes through application of the following principles:

- All employees and contractors undertake their work in a safe environment using safe work practices;
- Members of the public are not harmed by the operation, maintenance and improvement of Wellington Electricity's assets;
- Controls are effective for minimising impacts to the environment; and
- Processes are in place to ensure high quality outcomes are consistently achieved.

To support these principles, Wellington Electricity maintains a comprehensive set of health and safety, environmental and quality policies and procedures and prioritises safety as a core business value.

Wellington Electricity employees and contractors are required to both personally manage their own and other people's safety by adhering to safe work practices, making appropriate use of plant and equipment (including protective clothing and equipment), promptly managing controls for assessed hazards and reporting of incidents, near misses and accidents.

Wellington Electricity employees and contractors take all reasonable steps to ensure that business activities provide an outcome, which minimises environmental impacts and promotes a sustainable environment for future generations.

Wellington Electricity employees and contractors take all reasonable steps to ensure the delivery of goods, products and services are to an acceptable standard and meet the quality expectations of the business. Likewise, all employees and contractors identify and report any defects or non-conformances to enable improvement in the systems or performance to maintain quality outcomes.

Wellington Electricity's QS&E outcomes and processes are discussed in more detail below. The associated performance objectives and measures is described in Section 7.

4.1 Community and Public Safety

4.1.1 Public Safety Management System (PSMS)

Wellington Electricity has developed a Public Safety Management System (PSMS) framework policy document, which outlines the policies, procedures and guidelines relevant to the safe design and management of the assets. The PSMS includes assets that are installed in public areas and the management of these assets to ensure they do not pose a risk to public safety. The PSMS meets the compliance requirement for electricity distributors to implement and maintain a safety management system for public safety set out in Regulation 47 and 48 of the Electricity Safety Regulations (ESR) 2010.

The PSMS also meets the requirements of New Zealand Standard Electrical and Gas Industries – Safety Management System (NZS 7901:2008). In 2012 the certification body Telarc assessed Wellington Electricity against the requirements of NZS7901. Some minor updates were recommended by the audit report and these were addressed accordingly. A revisit by Telarc in February 2015 confirmed that Wellington Electricity was compliant with annual certification requirements.

Wellington Electricity continues to invest significant resources to raise awareness in the community of the potential risk of living and working near electricity assets.

4.1.2 School Safety Programme

Wellington Electricity developed an education programme for schools which educates children about electrical safety. The Stay Safe programme is aimed at primary school aged children and offered for delivery in schools around the Wellington Region by Wellington Electricity. The programme involves showing a DVD, electrical safety discussion aided by visual props and the presentation of the “stay safe around electricity” workbook to each child. The workbook invites children to visit the *Electricity Safety World* website.

4.1.3 Electricity Safety World Website

Wellington Electricity provides safety information and advice on its website www.welectricity.co.nz. The purpose of the website is to help the community stay safe around electricity and provides information on: electrical shocks, electrical fires, electromagnetic fields, appliance safety, power line safety and fault reporting details.

The website also links to other safety sites and government safety agencies. Of note is a link to the *Electricity Safety World* website which contains interactive safety games and information targeted at young children and parents regarding not only network safety, but also electrical safety around the home.

4.1.4 Media Advertising

Wellington Electricity understands the importance of raising public awareness about the dangers of living and working around network assets. Wellington Electricity undertakes radio safety campaigns which covers issues such as trees in proximity to overhead lines, cable identification and mark out, safety disconnects and advice on protecting sensitive appliances with surge protectors. During 2014 a new radio safety campaign was added which refreshed the message of safety in the event of a power outage.

4.1.5 Safety Seminars and Mail Outs

In order to prevent third party contact with the network, Wellington Electricity works closely with civil contracting companies (third party contractors working around Wellington Electricity assets) and other organisations that, through the nature of their work, need to get closer to the network than normally allowed. This may be in the form of planning discussion or on site safety seminars which raise awareness of safe working practices when working around the network and particular when excavating in the vicinity of existing underground infrastructure.

From time to time Wellington Electricity also mails out letters to various contracting sectors, particularly in response to known infringements, regarding safety around the network.

Wellington Electricity also works closely with Energy Safety to ensure interactions with the network are conducted safely and investigated where appropriate.

4.1.6 Contractors Safety Booklet

Wellington Electricity has produced a safety publication targeted at civil contractors and those working near but not accessing the Wellington Electricity network. This booklet *Wellington Electricity all need to work safely* is handed to those attending safety workshops and in mail outs to various contracting sectors that interface with the network. This booklet will be updated in the 2015/16 year to reflect changes resulting from the new health and safety legislation which is expected to be enacted in 2015. Closer relationships with major contracting groups have been developed over 2014 including monthly coordination meetings with Chorus who are installing the UFB fibre network for Crown Fibre Holdings.

4.1.7 Information and Value Add Services

Wellington Electricity provides an information service to reduce the risk of public safety and damage incident assets or property. The service is available through a 24 hour Freephone number.

Figure 4-1 shows the number and type of information service requests over the last five years.

Information and Value Add Services	Year				
	2010	2011	2012	2013	2014
Service Map Requests	9,088	6,286	9,154	9,926	12,147
Cable Locations	851	2,165	6,149	2,846	2,251
Close Approach	38	95	181	328	80
Standovers	98	123	95	140	182
High Load Permits	16	25	77	35	33
High Load Escorts	4	5	7	3	5

Figure 4-1 Summary of Information Service Requests 2010-2014

Since 2010 there has been a significant increase in calls relating to cable locations. The increase is attributed primarily to commencement of the UFB rollout in the Wellington Region.

4.2 Workplace Safety and Initiatives

4.2.1 Safety Breakfasts

Wellington Electricity regularly arranges safety breakfasts for all its contractors. The aim of these breakfasts is to highlight key safety messages and areas for improvement. The breakfasts are also used to publically recognise and celebrate examples of good safety behaviour and practice. On average over 200 people are catered for at the sessions.

4.2.2 Site Safety Visits

An initiative launched in 2011 provides for Wellington Electricity personnel to undertake familiarisation visits to sites where contractors are working on the network. The Site Safety Visits are used to confirm understanding and implementation of corrective actions and to discuss safety systems and opportunities for improvement.

During 2012, 57 Site Safety Visits were undertaken increasing to 66 site safety visits in 2013. 2014 saw site safety visit numbers increase to 144 visits by non-operational personnel.

4.2.3 Safety Leadership Structure

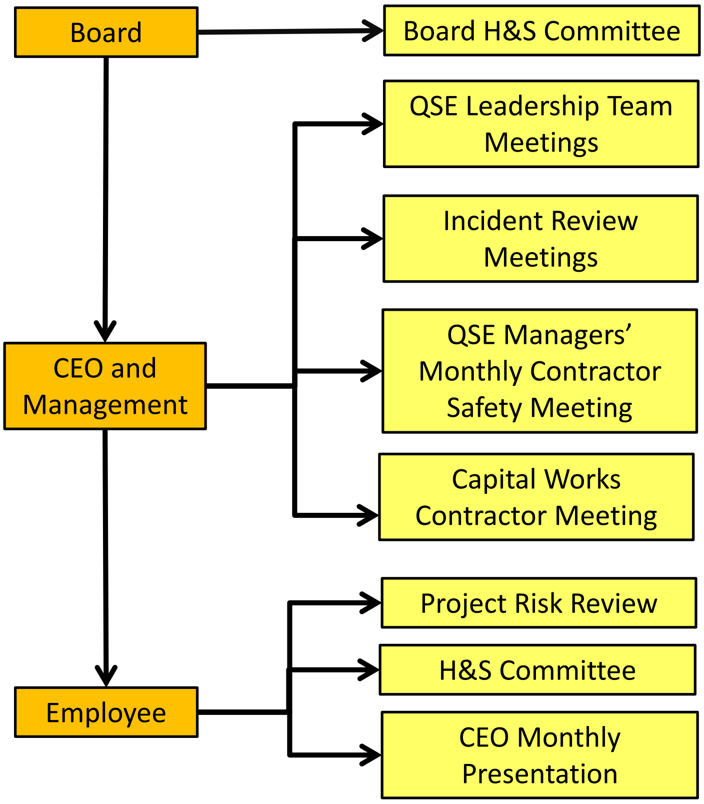


Figure 4-2 Safety Leadership Structure

In 2014, the Board of Directors formed a Health and Safety Committee, which meets each quarter to review issues requiring Board governance or guidance.

Wellington Electricity holds a monthly Safety Leadership Committee meeting to monitor performance, discuss emerging trends or new issues and progress on key improvement areas. The management group and Chief Executive Officer attend this committee.

4.2.4 Workplace Safety

Wellington Electricity operates a Work Type Competency (WTC) process, which categorises different types of activities on the network and sets minimum requirements in terms of qualifications, knowledge and experience. All operational personnel working in the field are required to hold the appropriate competency authorisation for the work being conducted.

Wellington Electricity ensures its employees are trained and competent in safety matters through providing, for example:

- CPR / First Aid refresher sessions every six months;
- Restricted area access training; and
- Defensive driving training for all employees who drive a company vehicle.

4.3 Safety and Quality Performance

4.3.1 Overview

Wellington Electricity has continued to build on its strong foundations of past health and safety performance. Notable performance improvements for 2014 include:

- A positive change in safety culture through an increase in the reporting and investigating (where appropriate) of events which may have the potential to cause harm, before harm occurs (incident and near miss reporting);
- An improvement in implementing corrective actions from the reported leading indicators so that potential harm incidents are avoided;
- Improving employees ability to identify non-conformances through the field assessment process via a programme of on the job training and development;
- Improved management, reporting and trend analysis of the field assessment process resulting in more assessments being undertaken, timelier closure of actions and a reduction in the total number of corrective actions open at any one time; and
- Working with Service Providers to review and improve their quality assurance processes.

4.3.2 Lost Time Injury Frequency

Wellington Electricity's staff and contractors recorded one Lost Time Injury (LTI) incident in 2014. This resulted in a LTI Frequency Rate (LTIFR) of 2.14 per million hours worked. The severity rating of the injury was serious however the injured worker has since been rehabilitated back into the workforce without complication.

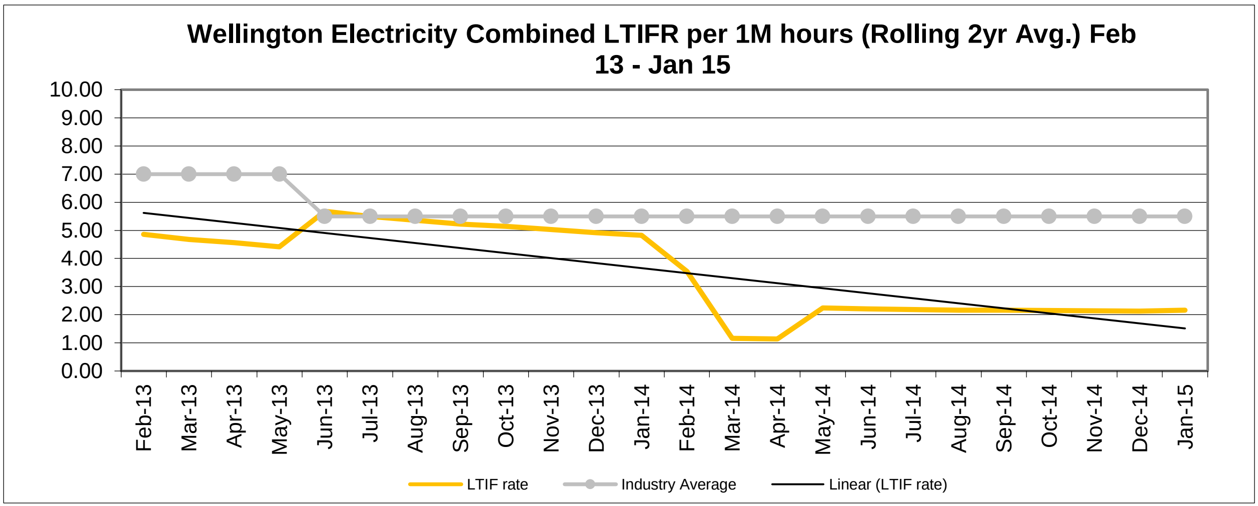


Figure 4-3 Lost Time Injury Frequency Rate

(Industry Average - EEA)

4.3.3 Incident and Near Miss Management

During 2014 Wellington Electricity continued to implement initiatives aimed at increasing reporting rates of "incidents" or "near miss" events. Total event reporting increased again in 2014 to a total of 464 events.

Approximately 70% of all reported events were classified as minor, 25% were classified as moderate, whilst only 1% were of a serious nature. The total number of “near miss” events reported during 2014 was 321, a 17% increase on the previous year’s near miss reports. This increase in near miss reports demonstrates an increased focus on hazard management.

Reporting of loss events (an incident which resulted in some form of loss, damage or injury) during 2014 also decreased with a total of 144 incidents reported. The majority of these were of a minor nature and very few resulted in more than minor loss.

4.3.4 Field Assessment

The revised Wellington Electricity Field Assessment Standard provides for the categorisation of findings from field assessments of worksites by severity and monitoring of close out times.

The majority of assessment findings were a non-conformance with Wellington Electricity technical standards. There was significant focus during 2014 on the quality of project manager field assessments. Actions include one-on-one training with the Wellington Electricity Field Compliance Assessor, attendance of a traffic management course, setting target for the number of assessments to be undertaken by project managers and improved scrutiny of the quality of assessment reports and provision of report writing and corrective action identification guidance.

It is encouraging to see a decrease in the ratio of corrective actions identified per assessment against 2012 levels. Monitoring will continue to ensure that this trend is continued and improved upon.

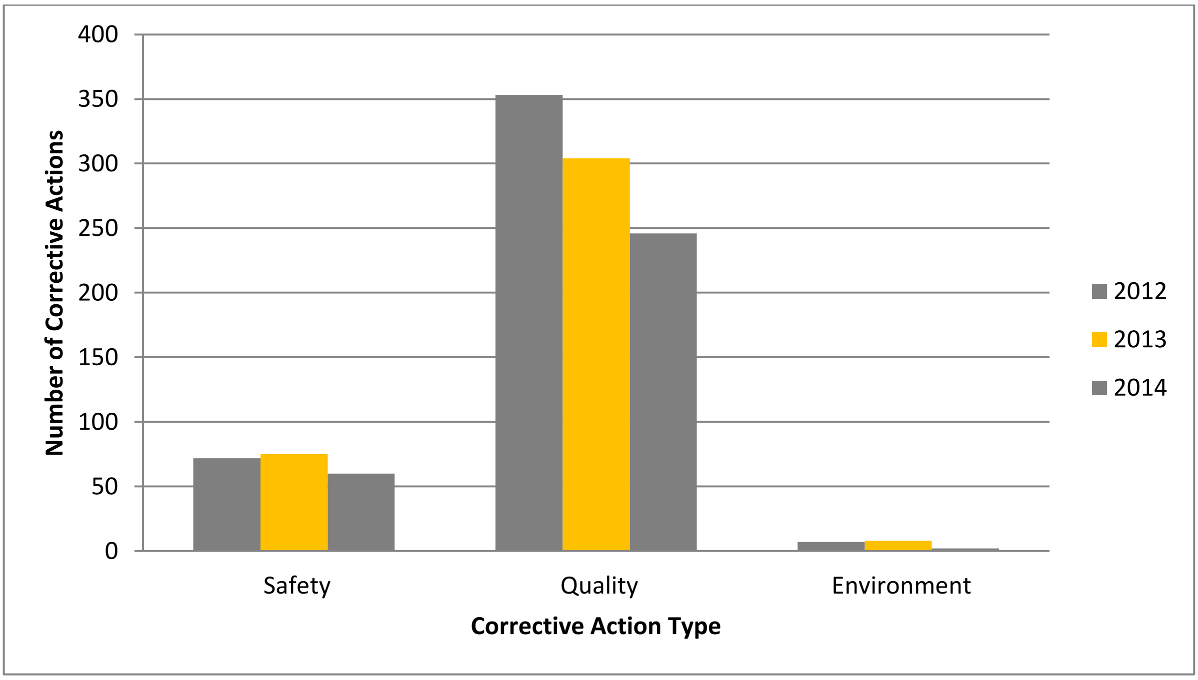


Figure 4-4 Corrective Actions arising from Assessments 2012-2014

The majority of the safety actions were a result of non-compliance with Wellington Electricity PPE requirements. This ratio of event type demonstrates consistency with previous year’s findings. Wellington Electricity is actively addressing this issue with its contractors.

A number of improvements have been made during 2014, these include:

- Implementing the new classification standard and improved reporting;

- Improving contractors' initial review and acknowledgement of assessments and corrective actions;
- Reduction in the timeframe corrective actions remain open; and
- Increasing the number of assessments being undertaken by Wellington Electricity Project Managers.

During 2015 focus will be placed on the following areas to further improve performance:

- Continue to increase the timeliness of close out of assessments;
- Reduce the number of Corrective Actions identified without compromising standards;
- Focus on the reduction of the high classification events;
- Reducing the number of repeat non-conformances; and
- Expanding the risk assessment process and client/contractor communication.

4.3.5 Continual Improvement

Continual improvement in managing health and safety at Wellington Electricity involves ongoing review of health and safety related documents and the document management system to ensure they are aligned to current business practice and requirements. 2014 saw a significant improvement in document and drawing reviews and this would be ongoing in 2015.

4.3.6 Industry Led Safety Initiatives

Wellington Electricity is a member of the Electricity Engineers Association (EEA) and supports the initiatives the EEA undertakes in providing leadership, expertise and information on technical, engineering and safety issues across the New Zealand electricity industry.

During 2012 - 2013 Wellington Electricity supported the Field Service Provider (Northpower) through the EEA led Safety Climate Project (SCP). The SCP is an improvement process based on management engagement with employees around their perception of their safety experience. The SCP has also provided valuable industry safety benchmarks and feedback which is helping the industry drive improvements in work place health and safety.

4.4 Environmental Performance

Wellington Electricity received no environmental infringement notices from Territorial Local Authorities (TLAs) during the period since the last AMP was disclosed. Wellington Electricity routinely monitors the activities of contractors working on its network. Inspections or assessments are predominantly undertaken by a Field Assessor and the team of Project Managers.

Wellington Electricity undertakes field assessments of Contractors work sites as part of the QSE compliance regime. Field assessments comprise both work in progress and completed works for compliance with health safety and quality control standards. These assessments identify areas for improvement for the contractors to comply with Wellington Electricity standards and QSE outcomes.

4.5 Territorial Local Authorities (TLAs)

Wellington Electricity works with TLAs as stakeholders who engage or have some responsibility for contractors and other service providers that interface with the Wellington Electricity network. Wellington Electricity aims to prevent building encroachment on the network, ensure safer reinstatement in road reserves, improve traffic management outcomes and gain a better understanding of where it can mitigate risks to the public.

4.6 New Legislation

Changes in health and safety legislation are expected to be introduced around September 2015 with the Health and Safety Reform Bill currently in select committee stage of review.

The Health and Safety Reform Bill will change the existing duties owed under the Health and Safety in Employment Act 1992 from Employer/Employee and Principal/Contractor to one of a Person Conducting a Business or Undertaking/Worker relationship.

These changes introduce a higher requirement for due diligence and governance from Board level down and across all parties involved in the supply continuum and all personnel including contractors and volunteers become workers for the purposes of the Act.

Wellington Electricity is actively reviewing processes to ensure the systems and operating standards reflect the likely requirements of the new Act.

The fundamental obligation to protect workers, the public and property from harm, remains the core consideration with effective planning and solid communication being paramount to safe and effective work management.

4.6.1 Impact of the New Legislation

The new WorkSafe legislation will bring about a number of changes in the way Wellington Electricity conducts its outsourced field activities. Under the proposed legislation, there will be greater obligations for the Principal to a contract (e.g. Wellington Electricity) to ensure that those contracted to do its work (e.g. Northpower, Treescape, etc), and their subcontractors (e.g. civil and traffic management providers) ensure safety outcomes are achieved and that risk is managed in the workplace.

Building on it's good safety and environmental record, and consistent with the requirements of the new legislation as well as the company's drive for continual improvement (see 4.3.5 above), Wellington Electricity is giving increased focus on areas of potential safety and environmental hazards at the early stages of a project. Rigorous risk assessments are now being conducted prior to the project being approved, with more detailed site assessments and specialist input. Extensive engagement is also taking place with the contractors on the safety and environmental components of their project plans before any site work commences. The cost and time implications of this increased focus are being factored into project budgets and schedules.

A compliance calendar is being implemented by Wellington Electricity that will address the Health and Safety Reform Bill as well as the ASNZS7901 Public Safety Management obligations and timeframes that are quarterly reported to the board.

5 Risk Management

5.1 Introduction

Risk relates primarily to uncertainty, and the effect of this on objectives (ISO 31000:2009). It is typically defined as the chance of something happening, measured in terms of probability and impact.

'For Wellington Electricity, risk management is a structured approach to the identification, assessment, and management of risks. Key risks are listed in risk registers, with the risk ratings related to the impact on the organisation's strategic and business objectives. Risk is evaluated in terms of the impact on the following areas: people, environment, assets, financial and business objectives, and reputation.

As the owner of an asset-intensive business, Wellington Electricity's management of risk directly involves the addressing of risks associated with its network assets. The design of the network has to consider and balance the level of resilience with the associated cost, as it is not practical or economic to have a network which is immune to all risks.

Assessment of the probability and impact of asset failure (whether this results from internal or external causes) and the associated mitigation and control process is a critical component of asset management.

Wellington Electricity's risk management approach is discussed in more detail below.

5.2 Risk Management Strategy and Framework

Wellington Electricity's Board of Directors is responsible for the governance of all aspects of the business, including risk management. Board oversight of the risk management process is delegated to the Audit and Risk Committee. This Committee is updated biannually by the CEO as part of the regular management reporting functions in line with the risk reporting framework.

Business risk is managed through regular risk profiling workshops with the objective of identifying and assessing the risks that may have an impact on the business achieving its strategic objectives. Risks which cannot be eliminated are assigned controls to minimise or mitigate the impact to the business should the risk eventuate.

Wellington Electricity's Senior Management Team (SMT) monitors the effectiveness of the risk controls and provides a report for the CEO to present to the directors. Each individual risk control is allocated to a manager as the risk control owner, who is responsible for ensuring that the control of each risk is clearly understood within the business and the risk control remains effective. Each risk control owner monitors the risk control and contributes towards the risk reporting framework.

Strategic and operational risks categories are reviewed and reported in risk registers, while more detailed operational risks are captured in risk control procedures and processes. The risk management strategy and process is aligned with other CKI and Power Assets group companies ensuring consistency across the wider global business.

Wellington Electricity adopts the Risk Management Standard ISO 31000:2009 to provide a structured and robust methodology to managing risk. The risk framework provides a process for:

- Identification of the risk event, assessment of the potential causes and possible consequences of the event and quantification of the likelihood and consequence to determine the inherent risk ratings for the event;
- Identification of risk controls and assessment of the effectiveness of these controls in reducing or mitigating the risk – this generates the residual risk rating;
- Development of risk treatment plans to address unacceptable residual risk (high and extreme risks) or allow the business to accept a high risk activity; and
- Creation of risk registers to capture the above information.

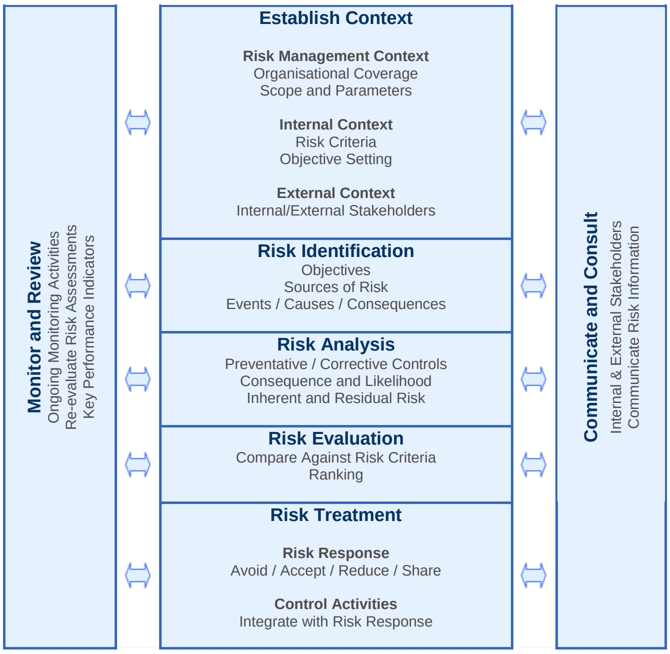


Figure 5-1 Risk Management Process

The objective of the risk treatment plan is to improve the risk control environment and to reduce any residual risk as far as practicable. Appropriate risk treatment plans are developed as required, assigned to business risk owners and monitored to ensure that the business is taking proactive steps to mitigate the risk. These plans include a basic cost analysis to assess the practicability of the improvement options for existing controls and/or additional control initiatives to further reduce the risk to an acceptable level.

All staff members are encouraged to identify risks and hazards and raise these to the appropriate supervisor or manager. Risks are identified as part of the incident management process. New risks are added to the incident management register for evaluation, recommendation, action and close out. All risks that follow the incident management process will undergo root cause analysis to identify the underlying issue and appropriate mitigation action.

5.2.1 Risk Assessment

Assessing risk involves consideration of the possible causes and potential consequences of an event. Ratings for risk probability (likelihood of the event occurring) and impact (consequence of the event occurring) enable risks to be evaluated.

Consequence and likelihood tables have been established with consideration of the Business' long-term objectives and criteria for measuring success. By combining these criteria with a consequence scale, the level of consequence to the Business of a particular risk, should it eventuate, can be described

The scale has been developed by describing levels of consequence for each criteria ranging from: catastrophic, the level that would constitute a complete failure and threaten the survival of the Business to minimal, a level that would attract minimum attention or resources.

In order to obtain a consequence rating, the most likely consequence across a range of consequence categories for a particular risk needs to be identified, and the corresponding likelihood of the event and its associated consequences occurring needs to be estimated.

Wellington Electricity uses the following consequence criteria:

- Health and safety (employees, public and service providers);
- Environment (land, vegetation, waterways and atmosphere);
- Financial (cash and earnings losses);
- Reputation (media coverage and stakeholders);
- Compliance (legislation, regulation and industry codes);
- Customer service / reliability (quality and satisfaction); and
- Employee satisfaction (engagement, motivation and morale).

These criteria are combined with a consequence scale, determining the level of consequence to the business of a particular risk ranging from minimal to catastrophic.

In order to establish the likelihood rating, it is necessary to consider the likelihood that the event occurs and the likelihood of the Business actually incurring the consequences of the magnitude chosen from that event. The risk rating is then determined where the consequence and likelihood ratings intersect.

The risk rating is plotted on a risk chart with its likelihood score on the y-axis and overall consequence on the x-axis.

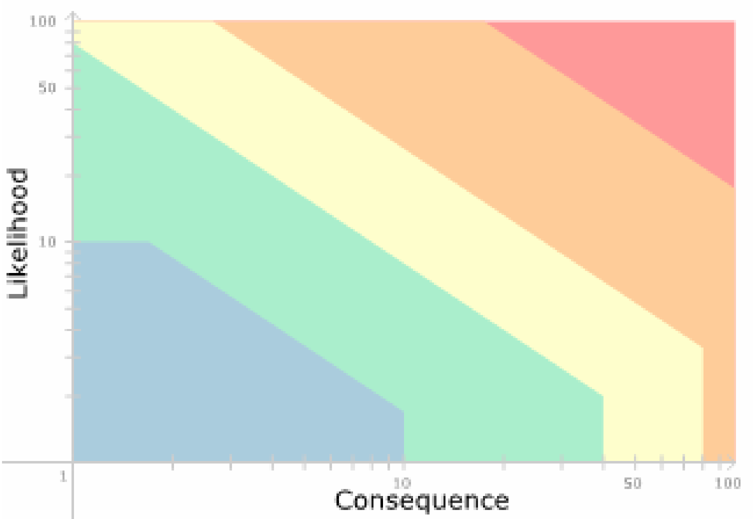


Figure 5-2 Risk likelihood consequence matrix

The consequence and likelihood tables are subject to an annual review process to maintain their relevance to the business. A category is chosen from the likelihood of the Event **and** the probability of the Business incurring the associated consequences.

RATING	DESCRIPTOR	DESCRIPTION	PROBABILITY	INDICATIVE FREQUENCY
95	**Almost Certain**	Is expected to occur	96 – 100%	One or more event per year
25	**Likely**	It will probably occur	81 – 95 %	At least one event every 2 years
10	**Possible**	May occur	21 – 80%	One event per 3 – 10 years
5	**Unlikely**	Not likely to occur	6 – 20%	One event per 11 – 50 years
3	**Rare**	Most unlikely to occur	0 – 5%	One event per 51 – 100 years

Figure 5-3 Risk Profile Matrix

The risk profiling matrix shown below in Figure 5-4 should be used to determine the level of the risk or risk rating. It is a function of Likelihood and Consequence.

Qualitative Values

LIKELIHOOD	CONSEQUENCE				
	Minimal	Minor	Moderate	Major	Catastrophic
Almost Certain	Medium	High	High	Extreme	Extreme
Likely	Low	Medium	High	High	Extreme
Possible	Low	Low	Medium	High	High
Unlikely	Negligible	Low	Low	Medium	High
Rare	Negligible	Negligible	Low	Medium	High

Figure 5-4 Qualitative Risk Matrix

Semi-Quantitative Values

LIKELIHOOD	CONSEQUENCE				
	Minimal 1.8	Minor 5	Moderate 11	Major 50	Catastrophic 90
Almost Certain 95	171	475	1045	4750	8550
Likely 25	45	125	275	1250	2250
Possible 10	18	50	110	500	900
Unlikely 5	9	25	55	250	450
Rare 3	5.4	15	33	150	270

Figure 5-5 Levels of Risk Rating

Risk Rating = Likelihood Score (L) multiplied by Consequence Score (C)

5.2.2 Risk Method Application

Controls are introduced to reduce/mitigate the likelihood or consequence of the risk with varying levels of effectiveness and reliance placed on the particular control. This helps reduce the inherent risk to a more acceptable residual risk.

Risk scoring is undertaken in accordance with the approved corporate Risk Policy, which outlines quantitative measures by which likelihood and consequence are ranked. The risk assessment model then assigns a weighted score in accordance with the ranking selected and the product of the likelihood and the consequence scores determines the overall risk score.

5.3 Risk-based approach to Asset Management

Risk management is an integral part of any business and therefore extends to the asset management process. Assessment of the consequences and likelihood of asset failure and the performance of risk controls that are in place to manage identified risks are understood, reviewed and evaluated as part of the asset management function.

Risks associated with network assets are evaluated and prioritised and, as discussed in Sections 9 and 10, management of these risks is fundamental to planning the network development, asset maintenance, refurbishment and replacement programmes described in this Asset Management Plan

The controls for each risk are considered in developing standard work practices.

Risks associated with network assets are managed:

- Proactively: Reducing the probability of asset failure through safety-by-design principles, capital and maintenance work programmes, insurance strategies and enhanced working practices; and
- Reactively: Reducing the impact of a failure through business continuity planning and the development of an efficient fault response capability.

High probability low impact risks and, conversely, low probability high impact risks are managed through a combination of Wellington Electricity's network planning and design, asset maintenance, fault response and emergency response strategies. The next sections describe these network planning and asset maintenance strategies. In addition, Wellington Electricity's design standards are aligned with industry best practice. They also take particular account of the weather and the seismic environment in the Wellington area. Further, Wellington Electricity has contingency procedures in place to restore power in a timely manner should an asset failure cause a supply interruption.

While it is impractical and uneconomic to design an electricity network that is immune to all risks, high impact low probability events that are either outside the network design envelope or require a response that is beyond the normal capacity of Wellington Electricity and its field contractors can occur. For such events, Emergency Response Plans are in place and these are described later in this section.

The risk of an asset failure is a combination of the likelihood of failure (largely determined by the condition of the asset) and the consequences of failure (determined by the magnitude of any supply interruptions, the repair or replacement time and the extent of any reduction in network operating security while the asset is being repaired). Assessment of this risk assists the process of deciding whether to phase out an asset through a planned replacement programme, or allow it to continue in service, supported if necessary by additional inspection and preventative maintenance activity. Through the mid-term revisions made to the Field Service Agreement, an increased level of condition and risk information is being provided to

Wellington Electricity through the inspection and condition assessment programme. This information is entered into Wellington Electricity's asset management information systems, which in turn feed into the network planning processes. This allows greater analysis of the risks associated with specific assets, or groups of assets, which enables Wellington Electricity to optimise its expenditure to manage risk and the performance of the network.

In addition to this, the prioritisation of capital works (refer to Sections 9 and 10) is based on an assessment of the risk that each potential project carries.

5.4 Specific Network Risks and Controls

Within an electricity distribution network, various assets can exhibit sub-optimal performance, or may deteriorate to an in-service failure point ahead of their expected life. Provided these issues are understood and monitored, the risk of in-service failure can be managed to a point where it is tolerable and controls can be put in place to reduce their impact should they occur.

The following table shows the top ten risks identified for the network.

2014 Rank	2013 Rank	Event	Inherent Rating	Residual Rating
1	(1)	Inadequate management and/or supervision of contracted (i.e. outsourced) activities (including contractor resources).	Extreme	High
2	(11)	Unsustainable starting price adjustment	Extreme	High
3	(2)	Injury or Damage caused or loss suffered to third parties.	Extreme	High
4	(3)	Catastrophic earthquake and/or Tsunami that causes significant damage to Company assets	High	High
5	(4)	Sub-optimal performance or failure of network assets.	Extreme	Medium
6	(5)	A loss of connection supply from transmission assets.	Extreme	Medium
7	(6)	A health and safety incident that affects one or more employees, contractors or visitors while performing work or visiting the Business' properties, assets or worksites.	Extreme	Medium
8	(7)	Release or spread of hazardous materials, Electromagnetic Fields (EMF) or noise to land, ecosystems or atmosphere.	Extreme	Medium
9	(8)	Mismanagement of a crisis and emergency affecting the Network.	Extreme	Medium
10	(9)	Failure of a retailer, customer, supplier or contractor to perform their contracted obligations, including financial obligations.	Extreme	Medium

Figure 5-6 Summary of Top Ten Network Risks

The top 10 risks are ranked above by their residual risk rating and then by the inherent risk rating. The table also indicates the movement in residual risk ratings for the top 10 risks when compared to the December 2013 result. The change to the risk ranking in this period is due to the movement of one risk from a previous ranking of (11 – Medium residual) to a present ranking of (2 – High residual).

The risk profiling process undertaken in December 2014 identified no (current) extreme residual risks and four high residual risks. The average residual risk across the business remains at low. This is the same residual result as assessed in previous years indicating a stable risk environment for Wellington Electricity's business at a network level.

Risk treatment plans include a number of specific controls, and their effectiveness. The following table indicates the top 10 controls used for managing risk across the Business.

Ranking	Control Name
1	Work Type Competency
2	Insurance
3	Asset Management Policies, Strategies, Standards and Plans
4	Contractor Management System and Processes
5	Contractor Compliance Audits
6	Health and Safety policies and procedures
7	Incident Reporting & Investigation processes and standards
8	Crisis & Emergency Management System
9	Contract Management and Documentation
10	Auditing and Compliance

Figure 5-7 Summary of Top Ten Network Risk Controls

Example of a Risk Analysis, Treatment and Control Plan

By way of example, the 7th ranked risk in Figure 5.6 above has been selected.

Process Step	Details	
Risk	A health and safety incident that affects one or more employees, contractors or visitors while performing work or visiting the Business' properties, assets or worksites.	
Possible causes	• Hazard not adequately identified • Equipment or asset failure • Lack, or inappropriate use, of safety equipment • Worker not trained for task	• Inadequate induction • Non compliance with policies, procedures and work instructions • Poor supervision
Potential consequences	• Injury to employee • Lost time due to injury • Lost time due to equipment shutdown • Drop in morale / productivity	• Incident investigation required • Negative media attention • Interruption to supply

Risk Analysis

Risk Score	Inherent 8360/Extreme	Residual 120/Medium
Likelihood	95	10
	Almost Certain	Possible
Consequence	88	12
Compliance	Moderate	Minimal
Customer Service / Reliability	Minor	Minimal
Employee Satisfaction	Major	Minimal
Environment	No impact	No impact
Financial	$1m to $5m	<$100k
Health & Safety	Major	Moderate
Reputation	Major	Minimal

Controls

Description	Confidence in Control	Reliance on Control
Asset Failure Investigation Process	Satisfactory	Significant
Auditing and Compliance	Effective	Critical
Contractor Compliance Audits	Satisfactory	Critical
Dial before you Dig Procedures	Effective	Critical
Health and Safety Policy and Procedures (incl. safe work practices)	Effective	Critical
Incident Reporting & investigation processes and standards	Satisfactory	Critical
Insurance	Effective	Critical
Public Safety Culture and Education programmes	Satisfactory	SIgnificant
Work Type Competency	Satisfactory	SIgnificant

Overall Control Effectiveness: Satisfactory

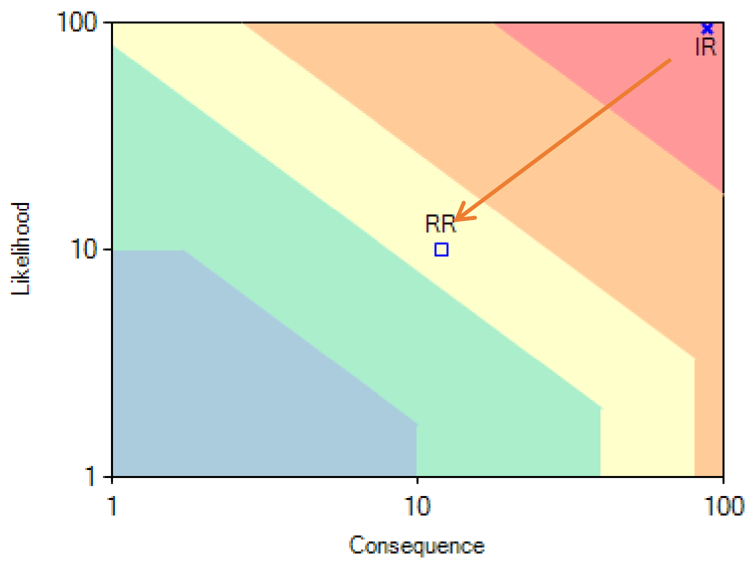


Figure 5-8 Example of Risk Analysis Treatment and Control Plan

As can be seen by this diagram, with the application of the risk controls, the overall risk score moves from the Inherent Risk position in the red area (Extreme) to the Residual Risk position in the yellow area (Medium). This outlines that the controls are effective, however the risks may not be fully eliminated.

5.5 Network Resilience

5.5.1 Resilience to Adverse Events

What is meant by Infrastructure or Network Resilience, why is it important, and who is responsible?

Resilience:

"The ability to prepare and plan for, absorb, recover from, or more successfully adapt to actual or potential adverse events" U.S. National Academy of Sciences

"The ability of assets, networks and systems to anticipate, absorb, adapt to and / or rapidly recover from a disruptive event" U.K. Cabinet Office

"A longstanding commitment to resilience served Christchurch well following the 2010 and 2011 earthquakes." Resilience Lessons: Orion's 2010 and 2011 Earthquake Experiences - Kestrel Group Ltd

The main responsibility for resilience of critical infrastructure lies with the owners of that infrastructure (e.g. Wellington Electricity). However, Government, regulators and industry need to work together to ensure investment in infrastructure considers the needs for security and resilience. Investment to improve the security and resilience of critical infrastructure should be proportionate to the risks.

Significant adverse events (also called High Impact Low Probability – HILP events) fall into different categories, are sometimes unpredictable, and often uncontrollable. Two categories of natural HILP events that occurred in 2013 were the major storm in June that hit Wellington directly, and the two large earthquakes later in the year with their epicentres in the Cook Straight and near the town of Seddon, about 70 km south-west of Wellington.

A description of the impact these events had relating to supply outages and resultant SAIDI numbers is given in Section 7.5.

Major Storm (June 2013)

The storm which occurred on 20 June was described by the National Institute of Water and Atmospheric Research (NIWA) as the worst storm in 37 years, and of a similar magnitude to the "Wahine Storm" of 1968. Wind speeds exceeded 100kph and continued to increase to gusts of 200kph. Wind speeds of over 100kph were continuous for a 30 hour period until they began to reduce later in the evening of 21June.

The storm damaged houses, roads and seawalls, as well as closing schools and rail links. Roads were blocked by fallen trees or were sufficiently damaged to make them impassable. Other roads were closed due to landslips. All flights in and out of Wellington airport were grounded and a ferry broke its mooring.

Wind gusts uprooted trees and flung debris into the 11kV lines. A large number of customer service connections to homes were also damaged. The storm caused widespread damage to the Wellington Electricity network particularly in the Wellington & Porirua areas. At its peak 22,000 customers were without supply, while over the course of the storm around 60,000 customers were impacted by supply interruptions.

Damage caused during June 2013 storm

The majority of the supply interruptions were caused by trees that fell through lines damaging poles and conductors. Other fault causes included airborne debris, conductors breaking or being detached from the insulators and poles breaking due to the very high winds. Even once the storm was subsiding, it was difficult for crews to patrol and clear the lines due to the damage caused to access ways from storm debris. Mobilisation of crews was hampered by blocked roadways and traffic congestion due to the rail link to the Hutt valley being undermined, forcing commuters into private vehicles. The overhead lines and poles damaged due to fallen trees could only be repaired after the trees had been cleared by the City Councils and by Wellington Electricity's vegetation contractor.

Based on the causes of the supply interruptions during the storm, the methods to improve resilience include an increased focus on vegetation management, and condition assessment and maintenance of insulator attachments and other line hardware.

Earthquakes

New Zealand and the Wellington Region in particular, are very seismically active. Running through the Wellington Electricity network area are three major fault lines, two of which run the entire length of the network. Any fault on these would have the potential to damage widespread areas of the network. There is a liquefaction risk in some areas and a tsunami risk in low lying coastal areas. Since the Christchurch earthquakes in September 2010 and February 2011, there has been an increasing social and business awareness of not only the need for a safe and reliable electricity supply but also for a more resilient infrastructure so that power can be expected to be restored safely and quickly following a major event.

In July and August of 2013, two strong earthquakes (magnitude 6.5 and 6.6) occurred in the Cook Strait and near the town of Seddon approximately 70 km south-west of Wellington, causing property damage, tripping of electrical supplies in several areas, and disruption to transport routes with the closure of railway lines pending a safety inspection (which added to the overloading of the road networks).

The quakes caused electro-mechanical protection relays at the Karori zone substation to operate, tripping both supply transformers on both occasions. While the relays responsible for the outage were prioritised for modification following the July earthquake, the work required to prevent a reoccurrence could not be completed prior to the August earthquake 26 days later. This resulted in both transformers tripping again during the second event. The final modifications to the relays were completed on 30 August 2013. It is expected that with the new modifications the relays will be resilient to mid-sized earthquakes of the type experienced in 2013.

The first approach to managing the risks associated with a major event is to improve the resilience of the network to withstand or minimise catastrophic damage.

Resilience is secured through a combination of activities or components. Four key components are:

- Resistance – providing the protection to resist the event.
- Reliability - ensuring that the infrastructure (including all key components) is designed to operate under a range of conditions and hence mitigate damage or loss from an event.
- Redundancy – the design / capacity of the network, providing spare capacity and the ability to supply from more than one source in the event of any disruptions.
- Response / Recovery – a quick, safe and effective response to, and recovery from, disruptive events.

There have been a number of lessons learned from the Canterbury earthquakes regarding the benefits of resilience investment. These include:

- Proactive investment in building reinforcement

Since the mid 1990's Orion has invested $41 million in increasing the resilience of its network. All new structural assets and existing strategic structural assets (including subtransmission lines and zone substations) are designed to withstand a 1 in 500 year seismic event with little service disruption. The seismic strengthening component cost around $6 million, an investment estimated to have saved Orion $30 to $50 million in direct asset replacement costs in the 2010 and 2011 earthquakes.[9] It also significantly reduced the time required to restore supply following the earthquakes. Based on this ratio of 12 to 20%, if applied to the Wellington Electricity network, an investment of up to $30 million now would protect up to $300 million of assets from earthquake damage, and potentially reduce supply restoration times for key substation assets by enabling substation buildings to remain operational following an earthquake. This in turn provides a significant economic benefit to stakeholders.

Other learnings from the Canterbury earthquakes from the Kestrel Report:

- Dealing with damaged subtransmission cables

  The oil-filled 66kV underground cables supplying the eastern suburbs of Christchurch were damaged, cutting supply to this area. The quick construction of an emergency overhead line enabled supply to be restored quicker than attempting to repair the subtransmission cables.

- Access issues

  With the Christchurch CBD area closed off, some substations were inaccessible for switching and isolation of the distribution network.

[9] Resilience Lessons: Orion's 2010 and 2011 Earthquake Experience – Kestrel Group Ltd, September 2011

These learnings have been considered by Wellington Electricity, and as appropriate have been included in our emergency response and restoration planning.

5.5.2 Strategies to manage HILP events

Wellington Electricity applies the following strategies to manage HILP events drawing from the experience of others (such as learnings from Orion following the Canterbury earthquakes):

- Identification – understand the type and impact of HILP events that the network may experience, through individual studies;
- Elimination – minimise the consequence of the HILP event through investment in resilience and network assets;
- Mitigation – investigate options for reduction of the impact of the HILP event, such as diversifying assets or supply paths and improving the resilience of the existing network;
- Response – develop plans to respond to HILP events in terms of business process. This includes practising responses under these plans and improving capability and staff awareness.
- Recovery – understand requirements for contingency plans to invoke a staged and controlled restoration of network assets and supply capability.

5.5.3 Identification and Management of High Impact Low Probability Events

Wellington Electricity identifies HILP events through some of the following methods:

- Transmission risk reviews – participation in the Connection Asset Risk Review (CARR) project undertaken by Transpower. Transpower has undertaken a HILP event study for the Wellington Region at Wellington Electricity's request. The study identified risks on the transmission circuits and substations, and identified, with high level cost estimates, potential upgrades to reduce these risks. This report is in draft at present, and being worked through between Wellington Electricity and Transpower.
- Distribution risk reviews – as part of the network planning process, HILP events are identified. Examples of such events include the simultaneous loss of subtransmission circuits causing a complete loss of supply to a zone substation (e.g. Wainuiomata double circuit 33kV outage, or the protection communications failure coincident with a 33kV fault that caused a loss of supply to the Trentham zone substation in 2013). Substation risks, such as the destruction of a CBD zone substation, can have an even higher impact.
- Environmental risk reviews – understanding and identification of the risk posed by natural disasters such as earthquake and tsunami, and studies undertaken on our behalf by GNS and other external providers.

5.5.4 Seismic Reinforcing of Equipment and Buildings

Wellington Electricity is proactive in surveying and identifying potential seismic issues concerning the assets in network buildings. Major equipment within zone substations, such as transformers, switchgear, service transformers and battery stands, has been seismically restrained. Also heavy loose equipment has been removed from substations and relocated to a centralised store. Ongoing maintenance inspections and notified defects from site visits will continue to identify any assets requiring further seismic support.

Substation building installations generally comply with the relevant building code applicable at the time of construction. Local councils conduct assessments of selected buildings within their region that have been built or strengthened to pre-1976 structural design codes to ensure compliance with their earthquake prone buildings policies. This was driven by changes under the Building Act 2004, which cover all building types and require older buildings to have the performance capacity of at least one third (34%) of that of the New Building Standard (NBS). A building is evaluated using the Initial Evaluation Process (IEP) as set out in the New Zealand Society for Earthquake Engineering Recommendations for the Assessment and Improvement of the Structural Performance of Buildings in an Earthquake.

Wellington Electricity has received approximately 150 notifications from the Wellington City Council (WCC), at least one quarter of which indicate the building may be earthquake prone. Upon receiving council notification, Wellington Electricity must engage a qualified engineer to assess the building and confirm the earthquake prone status and, if required, determine the work needed to bring the building into compliance with the Building Code.

Given the large number of pre-1976 buildings on Wellington Electricity's network (over 320) and their importance to ensuring a resilient power supply, Wellington Electricity embarked on a proactive process of substation building assessment, which it considers is a prudent approach to manage the risk of earthquake damage resulting in significant loss of assets and electricity supply.

The building assessment activity is underway and will be completed during the 2015-20 period. Strengthening works will be undertaken over a longer period of time.

Seismic strengthening at Adelaide Road substation

Wellington Electricity is using independent local structural consultants to do the IEPs and subsequent Detailed Seismic Assessments (DSA's). Figure 5-9 shows the status and local authority location of the assessed buildings.

Building Status	Wellington City Council	Lower Hutt City Council	Upper Hutt City Council	Porirua City Council	Total
Not earthquake prone	132	19	4	13	**168**
IEP result indicates not earthquake prone	71	0	0	0	**71**
Confirmed earthquake prone	9	7	0	2	**18**
Potentially earthquake prone (further assessment required)	10	0	0	0	**10**
Not yet assessed	9	37	11	8	**65**
Total	231	63	15	23	**332**

Figure 5-9 Building Assessment Status

The consultants have assessed and confirmed that 18 buildings are earthquake prone buildings meeting less than 34% of the New Building Standard (NBS).

These 18 have had DSAs completed and strengthening costs estimated. When strengthening work is completed, this will bring the substations' seismic strength (earthquake resistance) to more than 34% NBS and they will no longer be classified as earthquake prone. The strengthening work undertaken is designed to achieve effective reinforcement to minimise the risk to public, personnel and to the electrical plant within the building.

The confirmed sites that require seismic upgrades during the planning period are:

Substation	Building Type	Year Assessed	NBS Result	Budgetary Estimate to Strengthen ($1000's)
Gracefield	Zone Substation	2013	30%	200 - 250
Chaytor St	Distribution Sub	2012	<20%	100 - 150
Evans Bay	Zone Substation	2013	33%	125 - 175
Ghuznee St	Distribution Sub	2013	<20%	175 - 225
Riddiford St	Distribution Sub	2013	9%	125 - 175
21 Tory St	Distribution Sub	2013	8%	300 - 350
176 Wakefield St	Distribution Sub	2013	30%	20 - 30
Boulcott St	Distribution Sub	2014	12%	125 - 175
449 Jackson St	Distribution Sub	2013	26%	50 - 100
Moana Rd	Distribution Sub	2013	33%	20 - 30
204 Naenae Rd	Distribution Sub	2013	23%	75 -100

Substation	Building Type	Year Assessed	NBS Result	Budgetary Estimate to Strengthen ($1000's)
Naenae	Zone Substation	2013	20%	350 - 400
Rutherford St	Distribution Sub	2013	22%	100 - 125
Hartham Towers	Distribution Sub	2013	30%	30 - 50
Porirua Bridge	Distribution Sub	2014	30%	50 - 75
9 Duncan Terrace	DC Station	2012	<20%	150 - 200
Newtown	Distribution Sub	2011	14%	1,000 – 1,250
Total				**2,995 – 4,035**

Figure 5-10 Known Sites that Require Seismic Upgrade

The Cornwell St building was confirmed to be earthquake prone but this substation has been decommissioned, and the building has been demolished.

The first six sites in Figure 5-10 and Newtown Substation have had an Earthquake Prone Building notice attached by the Wellington City Council ("yellow stickered"). This public notice informs the public and users of the building that the building is earthquake prone and the notice must remain affixed to the building until it has been strengthened and is no longer an earthquake prone building. Wellington Electricity has to maintain this sticker and ensure it remains attached, at risk of prosecution by Wellington City Council (WCC). These yellow stickered buildings must, under Council order, be strengthened within 10 years of the notice being attached.

5.5.5 33kV Overhead Emergency Corridors

Underground subtransmission cables utilising gas- and oil-filled technologies can be vulnerable to seismic events. Repairs to extensively damaged gas- and oil-filled cables could take a number of months, which is unacceptable if the repair is necessary to restore supply. There are over 50,000 consumers supplied from zone substations with gas and oil subtransmission cables which are vulnerable to earthquakes. Wellington Electricity has engaged with Wellington City Council to specifically address this issue and to develop the protocols for the emergency installation of overhead 33kV lines should supply become unavailable for an extended period following a major event.

Wellington Electricity engaged a line design consultant to carry out route planning and line design for temporary 33kV overhead lines to supply CBD zone substations from Transpower GXPs. The selection of the proposed routes considers all risks within their immediate vicinity such as earthquake prone buildings, vegetation, topography, ground conditions and ease of access for construction.

The temporary 33kV overhead routes to the majority of the Wellington City zone substations have been designed and surveyed by Wellington Electricity's line design consultant. Each route design provides the pole location and line route along with pole structure design drawings. The planning and design of 33kV overhead routes for the remaining zone substations outside the Wellington City area is underway and will be completed over the period 2015 to 2016. The temporary 33kV overhead line structures are based upon a standard design used across the network, which would involve common materials and use normal construction practices.

The key outcome from the planning and design will be a set of defined 33kV overhead line emergency corridors and appropriate support structures that will be discussed with the relevant local authority with the objective of including the corridors and structures within the District Plan emergency provisions. Engagement with the WCC on the initial routes began in 2014.

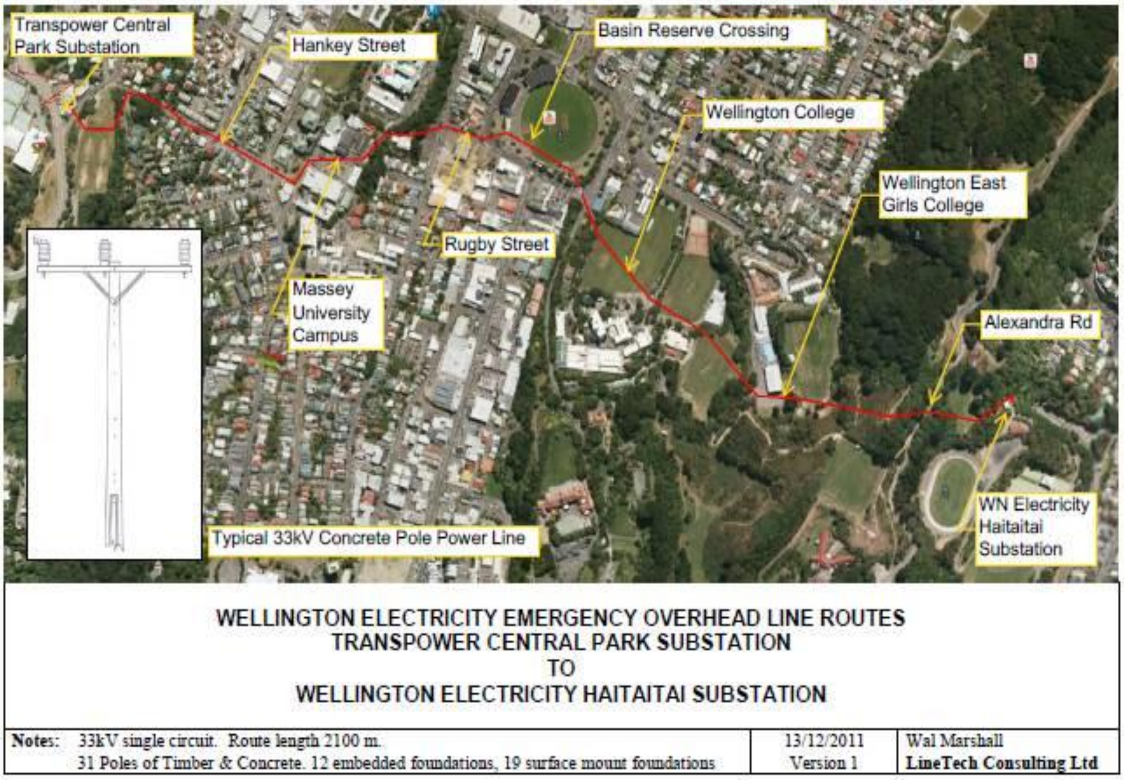


Figure 5-11 33kV Emergency Overhead Line Corridors (Example only)

The prototype of the surface foundation structure has been fabricated and a testing regime is being developed to prove the concept in 2015. Once testing of the concept is completed, a quantity of these will be held at various locations around the Wellington area, along with the required materials such as poles, pole hardware and conductors.

5.5.6 Resilience Investment

Resilience investment can cover the need for seismic reinforcement and for further consideration of network resilience that improves performance to, and response from, a major event. In light of the benefits that improved resilience will deliver, and following the earthquake events in 2013, Wellington Electricity's capital and operational expenditure forecasts in this AMP include seismic resilience expenditure to meet Building Code compliance, which will need to be recovered through future lines charges.

The Building (Earthquake-prone Buildings) Amendment Bill 2013 to "improve the system for managing earthquake-prone buildings", passed its first parliamentary reading in March 2014, and is currently before a Select Committee. If passed into law, this could further increase Wellington Electricity's obligations to assess and strengthen substation buildings, with a corresponding increase in costs to the business.

The expenditure forecasts in this AMP include the additional investment shown in Figure 5-12 to address earthquake resilience improvements for buildings to meet requirements under current legislation and to provide for emergency overhead line corridor development (design and scoping) for restoration of key subtransmission supplies. The resilience investment shown below does not factor in any additional requirements of the Building (Earthquake-prone Buildings) Amendment Bill 2013, should this Bill be passed into law.

Investment Area	2015/16 to 2019/2020 $M
Substation Seismic Assessment (OPEX)	1.4
Substation Seismic Strengthening (CAPEX)[10]	10 to 20[11]
Emergency OH Line Project Planning (OPEX)	0.2
Emergency OH Line Project Strategic Spares (CAPEX)[12]	0.75
Total	**12.35 - 22.35**

Figure 5-12 Overview and Cost Estimate for Resilience Investments

5.6 Response

5.6.1 Wellington Lifelines Group (WeLG)

Wellington Electricity participates in the Wellington Lifelines Group (WeLG). This group brings together various utility and transport operators in the Wellington Region to identify and prepare contingency plans for the region following a major disaster.

During 2012, Wellington Electricity participated in a group led by Civil Defence Emergency Management (CDEM) that compiled a report outlining the resilience and response to a simulated earthquake event in Wellington. This report highlighted the vulnerability of the area following a magnitude 7.5 earthquake on the Wellington fault line and identified that a number of basic services would be unavailable for up to 95 days in some areas and even longer in other areas. Road transport would be affected preventing the movement of personnel, plant and materials to repair failed assets. In addition, corridors into the Wellington Region would be blocked limiting the ability to bring materials into the area and thus increasing dependence on locally held strategic spares.

The report, published in 2013, concluded that, although there is no control over earthquake likelihood, an increase in resilience could help improve response times and reduce the consequences of the event.

As part of its WeLG group participation, Wellington Electricity is involved with the Wellington Region Emergency Management Office, which is a joint council organisation providing Civil Defence functions to the region.

5.6.2 Emergency Response Plans

As part of the Business Continuity Framework Policy, Wellington Electricity has a number of Emergency Response Plans (ERPs) to cover emergency and high business impact situations. The ERPs require annual

[10] The range provided for the substation seismic strengthening capex is due to the number of buildings still requiring initial or further assessment.

[11] Up to $30 million expected over the 10 year planning period

[12] This allows for a limited number of spares to be held locally, and does not reflect the full Capital requirements for construction of all Wellington City emergency overhead lines, which is estimated at around $10 million.

simulation exercises to test the plans and procedures and provide feedback on potential areas of improvement. All ERPs are periodically reviewed and revised to best meet the emergency management and response requirements of Wellington Electricity. Further learnings from the June 2013 storm were also being incorporated into these plans.

The ERPs are described in further detail below. Figure 5-13 shows how the various plans link together through each escalation level, as well as the key personnel involved with each of those stages.

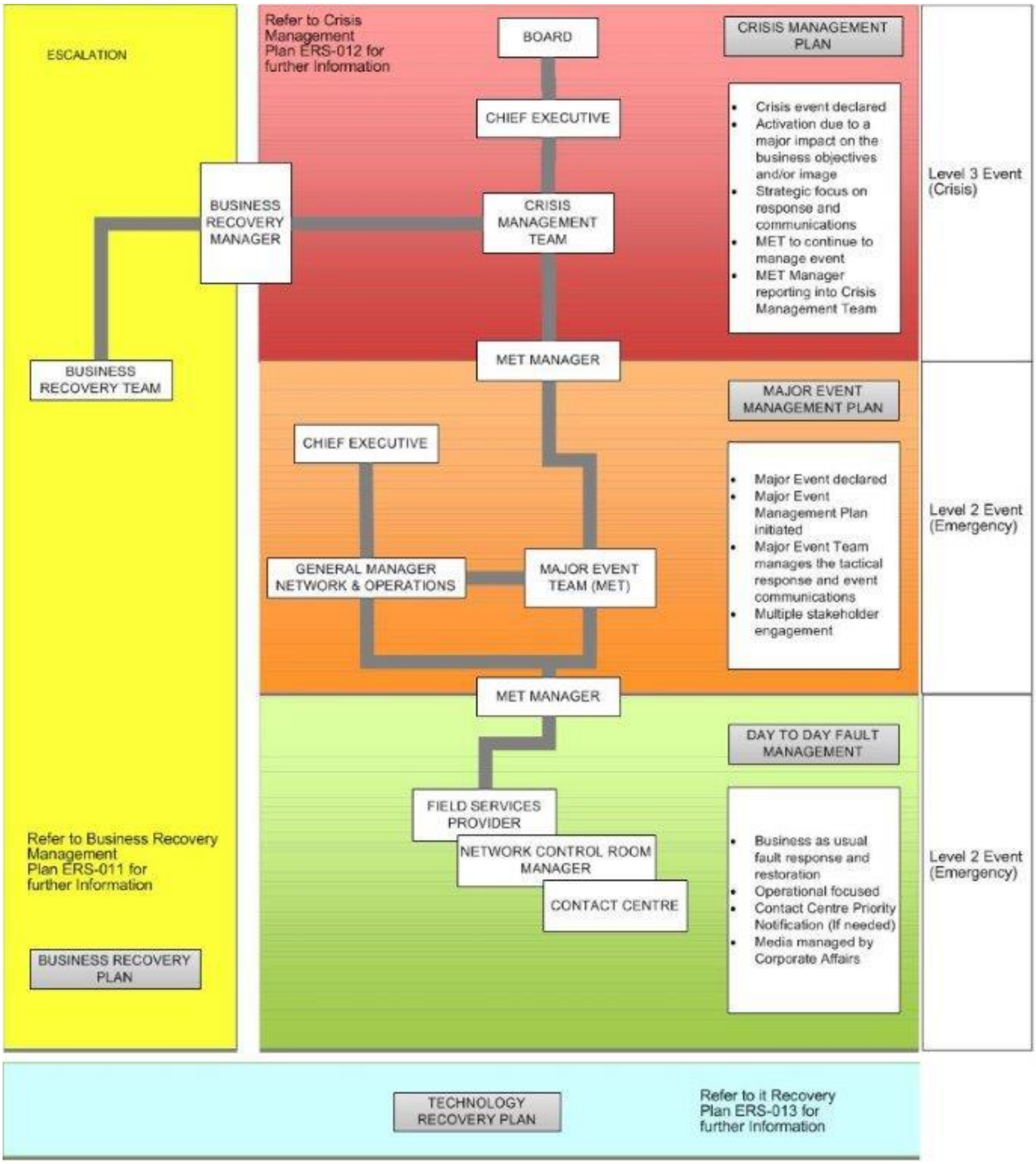


Figure 5-13 Emergency Response Escalation Framework

5.6.3 Crisis Management Plan

The purpose of the Crisis Management Plan (CMP) is to ensure that Wellington Electricity is prepared for, and responds quickly to, any crisis that occurs or may occur on its network. The CMP defines the structure of the Crisis Management Team and the roles and responsibilities of staff during a crisis.

The CMP contains detailed contact lists of all key stakeholders who may contribute to, or be affected by, the crisis.

5.6.4 Major Event Management Plan

The purpose of the Major Event Management Plan (MEMP) is to ensure that Wellington Electricity is prepared for, and responds quickly to, any major event that occurs, or may occur, on its network. The MEMP defines a major event and describes the actions required and the roles and responsibilities of staff during a major event.

A particular focus of the MEMP is how the internal and external communications are managed. The plan contains detailed contact lists of all key stakeholders who may contribute to, or be affected by, the major event.

The MEMP can escalate to a crisis and then be managed in accordance with the CMP.

Major event simulation exercises were carried out during 2012 and 2014 to test the MEMP process and the major event team roles and responsibilities. This plan was not simulated in 2013 however, the major storm in June 2013 put this plan into action in a live situation. Several “real life” learnings from the storm, response, which could not have been foreseen during simulations, have fed back into the ERPs.

5.6.5 Business Recovery Management Plan

The purpose of the Business Recovery Management Plan (BRMP) is to ensure that Wellington Electricity is prepared for, and responds quickly to, any event that interrupts the occupancy of its corporate offices in Petone and clearly states how such a business interruption would be recovered and escalated to a crisis if required. This includes the mobilisation of the Business Recovery Event Centre at the Wellington Electricity Disaster recovery site at Haywards.

The Disaster Recovery site at Haywards is located in the space previously occupied by the Wellington Electricity control room at Transpower’s Haywards substation. This site has meeting and office spaces, as well as functional SCADA terminals and communications equipment, along with the necessary IT equipment, to allow network operations to continue with only a short interruption. Several other key business processes can also be operated from this site should the Petone corporate offices be unavailable.

A simulation exercise was successfully completed in January 2015 which assisted in identification of the necessary business recovery infrastructure provisions and key business recovery timeframes

5.6.6 Information Technology Recovery Plan

The purpose of Information Technology Recovery Plan is to ensure that Wellington Electricity’s IT systems can be restored quickly following a major business interruption affecting these systems. The level of recovery has been determined based on the business requirements. This plan was also tested in January 2015 and improvements were identified, recorded and are being actioned.

5.6.7 Major Event Field Response Plan

The purpose of the Major Event Field Response Plan is to ensure that Wellington Electricity's Field Contractors are prepared for, and can respond appropriately to, a storm or HILP events such as earthquakes and tsunami that may impact the network. The Major Event Field Response Plan describes actions required and responsibilities of Wellington Electricity and Field Contractor Coordination during a storm emergency and focuses on systems and communications (internal and external) to restore supply to customers. A major event field response can escalate to the MEMP if required. This was tested in September 2014.

5.6.8 Emergency Evacuation Plan

The purpose of the Emergency Evacuation Plan is to ensure that the NCR is prepared for, and responds quickly to, any incident that requires the short or long term evacuation of the NCR and re-establishment at the disaster recovery site.

5.6.9 Civil Defence Emergency Management (CDEM) Plan

As an EDB providing essential services, Wellington Electricity belongs to the Lifeline Utilities group. There is an emphasis in the Civil Defence Emergency Management (CDEM) Act 2002 on ensuring that lifeline utilities provide continuity of operation, particularly where their service supports essential CDEM activity.

Wellington Electricity has prepared the CDEM Plan to comply with the relevant provisions of the CDEM Act. It provides information for the initiation of measures for saving life, relieving distress and restoring electricity connections.

This CDEM Plan follows the four 'Rs' approach to dealing with hazards that could give rise to a civil emergency:

- Reduction - identifying risks and developing plans to reduce these risks;
- Readiness - developing emergency operational contingency plans;
- Response - actions taken immediately before, during or after an emergency; and
- Recovery - rehabilitating and restoring to pre-disaster conditions.

Responsibilities relating to the four 'R's fall within various departments of the Network and Operations group, which is responsible for ensuring overall Readiness. The Reduction role is largely the responsibility of the Asset and Planning department. The Response Roles are operational roles being largely the responsibility of the Network Control Room. The Recovery role is the responsibility of the Maintenance and Capital Works Managers with the assistance of Wellington Electricity's Field Services Providers.

Fig 5-15 above shows how these fall iinto the larger emergency response framework.

5.6.10 Pandemic Preparedness Plan

The purpose of the Pandemic Preparedness Plan is to manage the impact of a pandemic-related event by:

- Protecting employees as far as possible from spread of disease;
- Creating a safe working environment; and
- Maintaining essential business functions with reduced staffing levels if containment is not possible.

The Pandemic Preparedness Plan is reviewed annually by the Wellington Electricity QSE manager.

5.6.11 Other Emergency Response Plans

Wellington Electricity has other emergency response plans including:

- Priority notification procedures to key staff and contractors;
- Total Loss of a Zone Substation Plan;
- Loss of Transpower Grid Exit Point Plan (Transpower Plan);
- Emergency Load Shedding Plan;
- Participant Outage Plan (as required under the Electricity Industry Participation Code 2010); and
- Call Centre Continuance Plan.

In addition, contingency plans are prepared as necessary detailing special arrangements for major or key customers.

5.7 Insurance

5.7.1 Insurance Cover

Wellington Electricity renews its insurances in two tranches.

1. Industrial Special Risks (ISR) Insurance: includes Material Damage and Business Interruption cover and is renewed annually as at 30 June; and
2. General Products and Liability Insurance: includes general, products, pollution, electro-magnetic radiation, financial loss (failure to supply), and professional indemnity and is renewed annually as at 30 September.

The renewal process for all insurances commences four to six months prior to the expiry of existing policies in conjunction with the appointed broker and the expertise of the wider CKI and Power Assets group. Insurance is generally placed at least 10 business days prior to the policy expiry date.

The global market for insurance continues to be challenging, following the massive losses from the significant natural events of 2011 and 2012. Therefore, the global insurance industry has adopted a strict technical approach to rating and retention levels in an attempt to recover previous losses.

In 2014, Wellington Electricity commissioned an updated GNS Science (GNS) report to assist in quantifying its insurance risk and requirements and to help mitigate insurance premium increases. GNS estimated losses to insured assets from potential earthquake and tsunami events. This report estimated losses to insured assets were within existing insurance limits.

Wellington Electricity will continue to work with the wider CKI and Power Assets group to obtain market competitive insurance premiums by accessing international market opportunities that could not be achieved on a standalone basis in New Zealand. Due to the earthquake exposure and the Christchurch earthquakes, obtaining insurance capacity for Wellington based risks continues to be a challenge. Wellington Electricity has actively engaged other markets, notably the Australian, Singapore and London markets, to ensure competitive insurance cover is maintained.

5.7.2 Insurable Risks and Increased Insurance Premiums

Wellington Electricity insures around 15% of the estimated asset replacement cost of network assets, covering key strategic assets. The level of insurance cover purchased is based on estimates by GNS to determine maximum foreseeable loss for assets that can reasonably be insured.

Around 85% (by replacement value) of Wellington Electricity's network is not insured, because insurance cover is not available or economically viable. As such, the business retains the risk on the uninsured portion of the network even though the regulated line charges do not include an allowance for the recovery of the cost of retaining the risk. Wellington Electricity does not insure its subtransmission and distribution assets (lines and cables), as insurance cover for these types of assets (poles, cables, wires etc.) is currently only available from a small number of global reinsurers, is very expensive, has high deductibles, and typically excludes damage from windstorm events. Since such costs are not passed on to consumers in the line charges, it is not an economic proposition for the company to obtain such insurance.

Illustrating this by way of example, if Wellington Electricity were to insure poles, cables and wire assets with a policy limit of $500 million, it would need to pay a 10% deductible of $50 million before any insurance payments would be provided. In addition the annual insurance premium for such cover would be in the $40 million to $50 million range.

Ex post recovery of the full costs is therefore the expected regulatory recovery mechanism for managing this risk.

Wellington Electricity would likely seek to recover the fair and reasonable cost for restoring power supplies following a major natural disaster such as a significant earthquake, from consumers in the same way that Orion did following the 2010 and 2011 Canterbury earthquakes.

It is expected that the proposed resilience expenditure identified in this AMP, will assist in lowering the post-event cost of restoration for consumers in such a scenario.

6 Assets Covered

This section describes Wellington Electricity's assets utilised in the delivery of electricity to its consumers. It covers the network configuration and asset fleet, including those assets that are not directly associated with the network itself but important in delivering distribution services to customers.

6.1 Network Configuration

Any electricity distribution system can be broadly categorised into primary and secondary assets. The primary assets form the network that carries energy to consumers. The secondary assets support the operation of the primary assets and include protection and control equipment, as well as communications systems. These secondary assets form an integral part of the distribution system.

The components of Wellington Electricity's network are described below.

6.1.1 Grid Exit Points

Wellington Electricity's network is supplied from Transpower's national transmission grid through nine grid exit points (GXPs). Central Park, Haywards and Melling GXPs supply the network at both 33kV and 11kV, and Kaiwharawhara supplies at 11kV only. The remaining GXPs (Gracefield, Pauatahanui, Takapu Rd, Upper Hutt and Wilton) all supply the network at 33kV only. The network is grouped into three areas where the GXPs are located, namely the Northeast, Northwest and Southern areas.

6.1.1.1 Southern Area

The Southern network is composed of three GXP's, namely Central Park, Wilton, and Kaiwharawhara, which together supply Wellington City and the CBD.

Central Park

Central Park GXP comprises three 110/33kV transformers - T5 (120MVA), T3 and T4 (100MVA units) - supplying a 33kV bus. There are also two Transpower owned 33/11kV (25MVA) transformers supplying local service and an 11kV point of supply to Wellington Electricity.

Central Park is supplied at 110kV by three overhead circuits from Wilton GXP. There is no 110kV bus at the GXP, so an outage on one circuit will cause the loss of the transformer connected to that circuit.

Central Park GXP supplies zone substations at Ira Street, Evans Bay, Hataitai, Palm Grove, Frederick Street, University, and The Terrace. Double circuit 33kV underground cables supply each of these substations. Central Park GXP also supplies the Nairn St switching station at 11kV via two underground duplex 11kV circuits (four cables). The Nairn St site is adjacent to the Central Park GXP.

Wilton

Wilton GXP comprises two 220/33kV transformers operating in parallel, supplying a 33kV bus that feeds to zone substations at Karori, Moore Street, and Waikowhai Street through double circuit underground cables. The transformers at Wilton are each nominally rated at 100MVA.

Kaiwharawhara

Kaiwharawhara is an 11kV point of supply where Wellington Electricity takes bulk 11kV supply from Transpower and distributes this via a Wellington Electricity owned switchboard within the GXP.

Kaiwharawhara is supplied at 110kV two circuits from the Wilton GXP, and has two 38MVA 110/11kV transformers in service.

Kaiwharawhara supplies load at the northern end of the Wellington CBD such as Thorndon and surrounds, and also light commercial and residential load around the Ngaio Gorge and Khandallah areas.

6.1.1.2 Northwestern Area

The Northwestern area is composed of two GXP's, namely Pauatahanui and Takapu Road which supply Porirua City and the Tawa, Johnsonville, and Ngauranga areas of Wellington City.

Pauatahanui

Pauatahanui GXP comprises a conventional arrangement of two parallel 110/33kV transformers each nominally rated at 20MVA. Pauatahanui GXP supplies Mana and Plimmerton zone substations via a single 33kV overhead circuit connection to each substation. The two zone substations have a dedicated 11kV interconnection between them, providing a degree of redundancy when one of the 33kV circuits is out of service.

Takapu Road

Takapu Road GXP comprises a conventional arrangement of two parallel 110/33kV transformers nominally rated at 90MVA each. Takapu Road GXP supplies zone substations at Waitangirua, Porirua, Tawa, Kenepuru, Ngauranga and Johnsonville via duplicated 33kV connections. These circuits leave the GXP as overhead lines across rural land and become underground lines at the urban boundary.

6.1.1.3 Northeastern Area

The Northeastern area is composed of four GXP's, namely Upper Hutt, Haywards, Melling and Gracefield which cover the Hutt Valley with Upper Hutt and Lower Hutt Cities.

Upper Hutt

Upper Hutt GXP comprises a conventional arrangement of two parallel 110/33kV transformers each nominally rated at 37MVA. Upper Hutt GXP supplies Maidstone and Brown Owl zone substations via double circuit 33kV underground cables.

Haywards

Haywards GXP has an unconventional arrangement of a single 110/11kV transformer nominally rated at 20MVA feeding the Haywards 11kV bus, and a single 110/33kV transformer nominally rated at 20MVA supplying Trentham zone substation via two 33kV circuits. These are both overhead lines, although each circuit has short underground sections. A 5MVA 33/11kV transformer supplies the Haywards local service switchboard and also links the 33kV and 11kV switchboards.

Melling

Melling GXP comprises a conventional arrangement of two parallel 110/33kV transformers each nominally rated at 50MVA, which supply zone substations at Waterloo and Naenae via duplicated 33kV underground circuits. Melling also accommodates an 11kV point of supply fed by two parallel 110/11kV transformers each nominally rated at 25MVA.

Gracefield

Gracefield GXP comprises a conventional arrangement of two parallel 110/33kV transformers nominally rated at 85MVA each. Gracefield GXP supplies Seaview, Korokoro, Gracefield and Wainuiomata zone substations via double circuit 33kV connections. The line to Wainuiomata is overhead but underground cables supply the other substations. Wellington Electricity's Gracefield zone substation is located on a separate site adjacent to the GXP with short 33kV cable sections connecting the GXP to the zone substation.

6.1.1.4 GXP Demand and Energy

Figure 6-1 sets out the connection voltages, maximum demand and energy supplied from each GXP for the 2014 year.

Area	GXP	Connection Voltage (kV)	ADMD[1] – 2014 (MVA)	Firm Capacity[2] (MVA)	Energy Injection – 2014 (GWH)
Southern Area	Central Park 33kV	33	155	228	726
	Central Park 11kV	11	23	30	86
	Wilton 33 kV	33	54	106	195
	Kaiwharawhara 11kV	11	33	41	158
Northwestern Area	Pauatahanui 33kV	33	20	24	69
	Takapu Rd 33kV	33	89	123	389
Northeastern Region	Gracefield 33kV	33	63	89	279
	Haywards 33kV	33	17	20	89
	Melling 33kV	33	36	52	138
	Upper Hutt 33kV	33	29	37	128
	Haywards 11kV	11	17	20	66
	Melling 11kV	11	26	27	117

Figure 6-1 Summary of GXP Demand and Energy

6.1.2 Subtransmission

The 33kV subtransmission system is comprised of assets that take supply from the Transpower GXPs and feed 27 Wellington Electricity zone substations, incorporating 52 33/11kV transformers. This 33kV system is radial with each feeder supplying its own dedicated power transformer, with the exception of Tawa and

Kenepuru where two feeders supply four transformers (one feeder shared per bank at each substation). All 33kV feeders supplying zone substations in the Wellington area are underground while those in the Porirua and Hutt Valley areas are a combination of overhead and underground. The total length of the 33kV system is 207km, of which 143km is underground.

Zone substations have N-1 subtransmission supply at 33kV, with one supply from each side of a Transpower bus where this is available. The exception to this is Plimmerton and Mana, which each have a single 33kV supply to a single power transformer; however they are connected together by an 11kV tie cable, and as a result they operate as an N-1 substation with a geographic separation of 1.5km. At certain times, the 11kV tie cable can be constrained, although load control and 11kV network switching can alleviate this constraint.

Figure 6-2, Figure 6-3 and Figure 6-4 show the subtransmission interconnectivity within each the three network areas, Wellington south, northwest and northeast respectively.

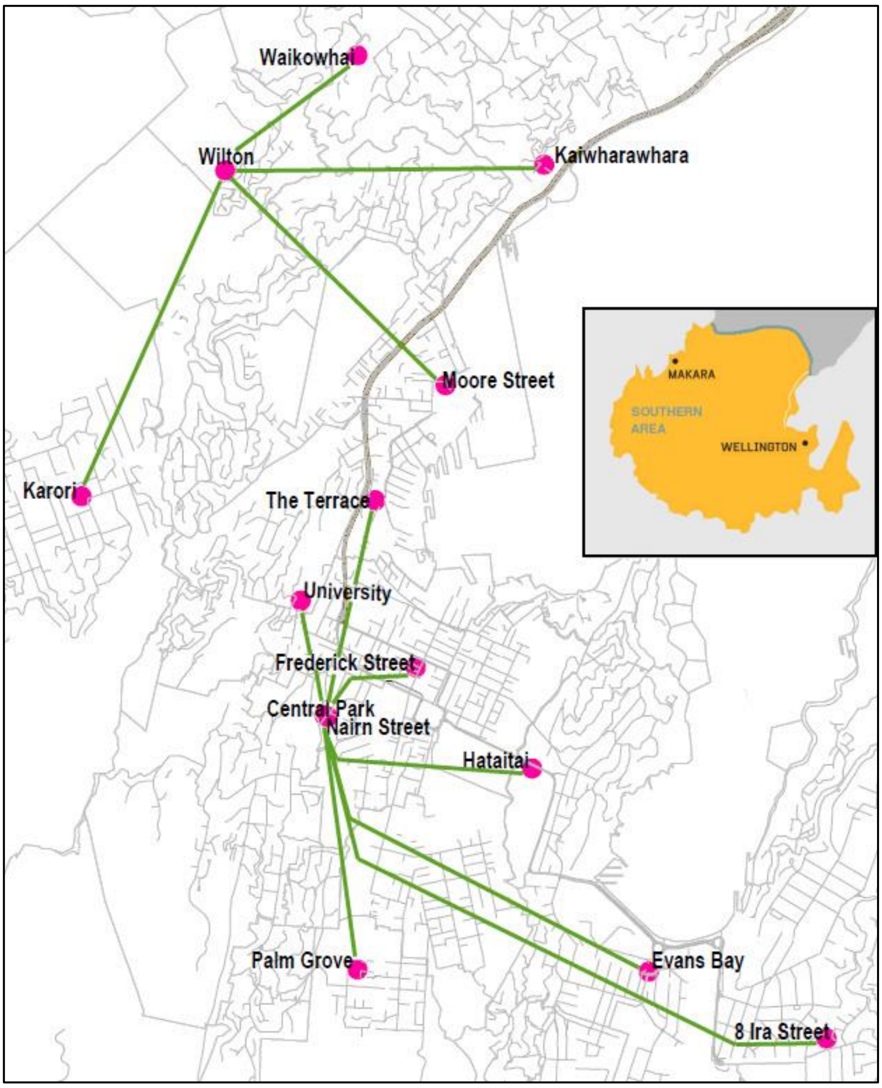


Figure 6-2 Wellington Southern Area Subtransmission Network

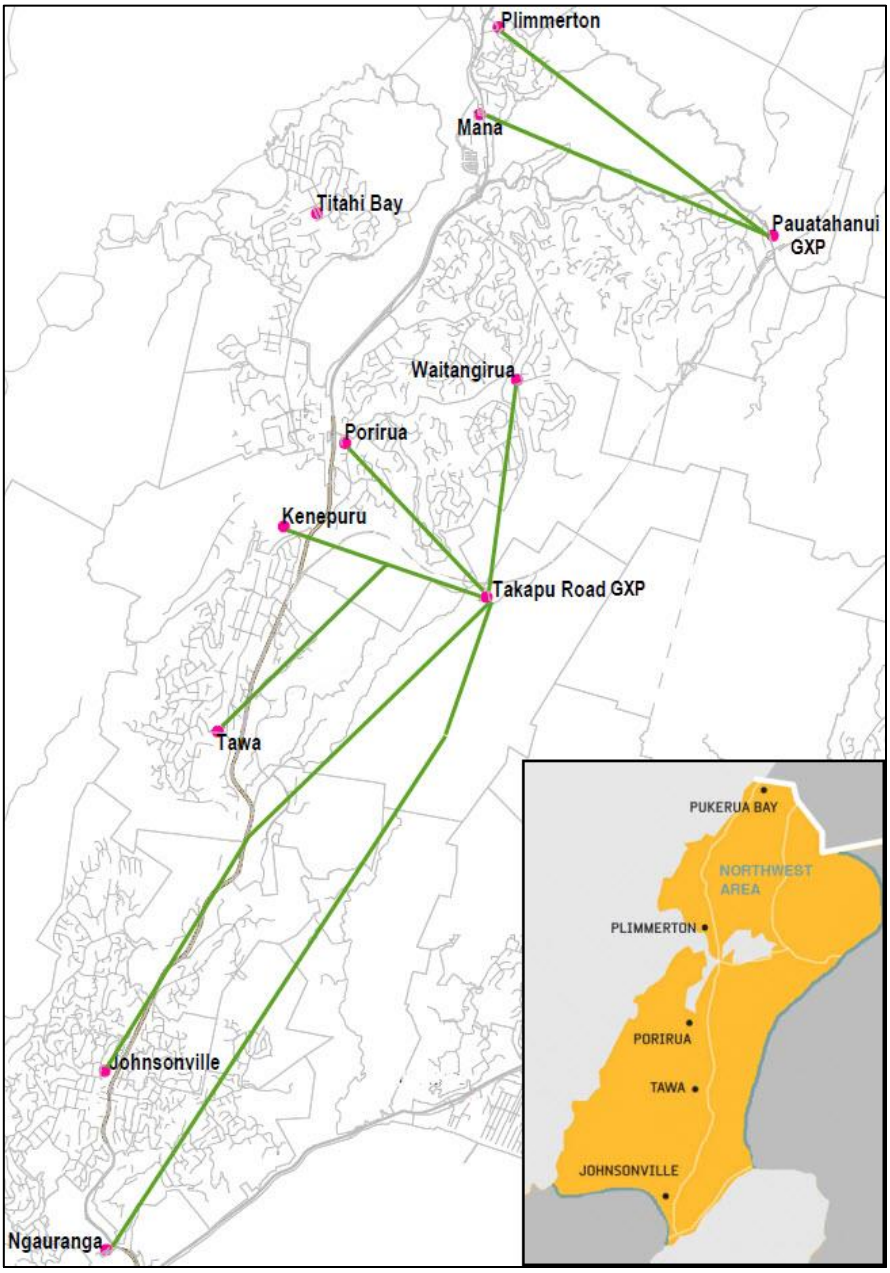


Figure 6-3 Wellington Northwestern Area Subtransmission Network

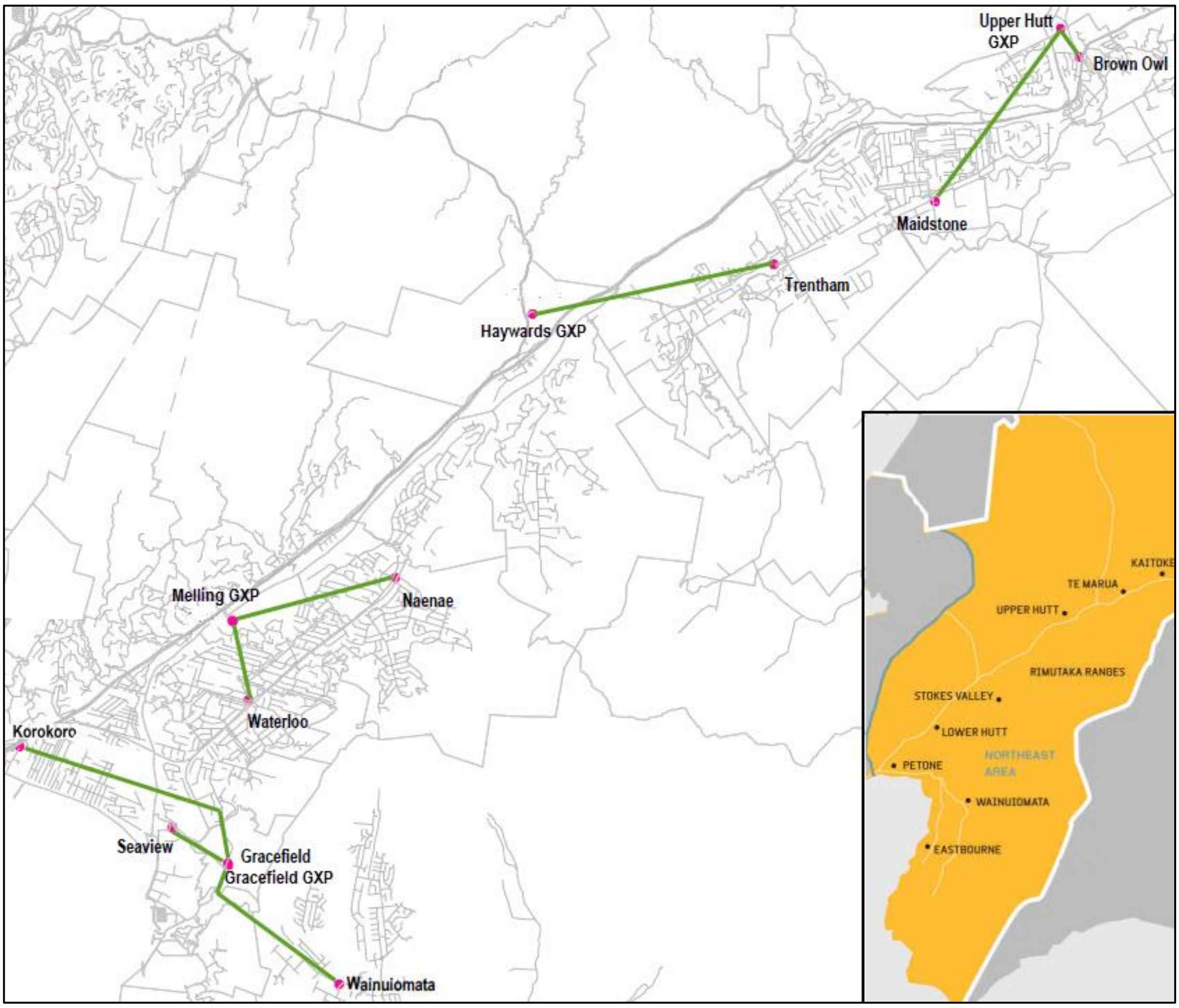


Figure 6-4 Wellington Northeastern Area Subtransmission Network

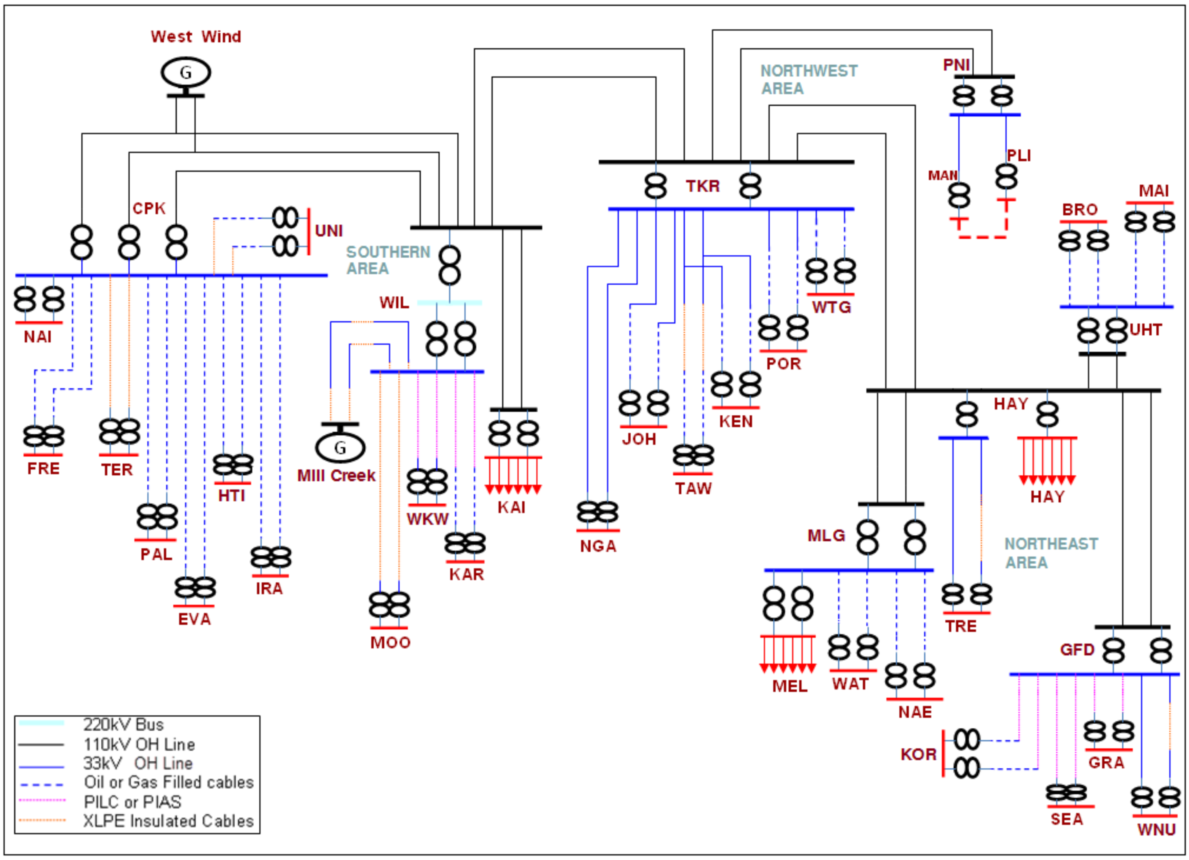


Figure 6-5 Overview of Wellington Electricity Network Connectivity

Note: The 110kV lines and transformers shown in Figure 6-5 are all owned by Transpower and are not covered by this AMP.

6.1.3 Distribution

The 11kV distribution system is supplied from the zone substations, or directly from the GXP in the case of the 11kV supply points at Central Park, Melling, Haywards and Kaiwharawhara. While some larger consumers are fed directly at 11kV, most consumers are supplied at low voltage through 4,276[13] distribution substations (11kV/415V) located in commercial buildings, industrial sites, kiosks, berm-side and on overhead poles. The total length of the 11kV system is approximately 1,749km, of which 66% is underground. In the Southern area, the 11kV network is largely underground, whereas in the Northeast and Northwest areas the proportion of overhead 11kV lines is higher. The varying proportions of overhead and underground distribution on the different parts of the system reflect the different design philosophies of earlier network owners, as well as the geography of the various areas.

Most of the 11kV feeders in the Wellington CBD[14] are operated in a closed ring configuration with radial secondary feeders interconnecting neighbouring rings or zone substations. This arrangement provides a high level of security and hence a high level of supply reliability. Most of the 11kV network outside the Wellington CBD, both in the South and Northeast areas, comprise radial feeders with a number of mid-feeder switches (and in some cases circuit breakers with protection fitted) and normally open interconnectors to other feeders so that, in the event of an equipment failure, supply to customers can be

[13] All succeeding data will be as of October 2014, unless specified.

[14] The CBD is defined as the commercial areas supplied by Frederick St, Nairn St, University, The Terrace, Moore St and Kaiwharawhara substations.

switched to neighbouring feeders. To allow for this, and consistent with normal industry practice, distribution feeders are not operated at their full thermal rating under normal system operating conditions. In rural areas, feeders are generally radial with few interconnections.

There are 1,666 11kV circuit breakers operating within the distribution system. Of this total, 368 of these are located at the zone substations and control the energy being injected into the distribution system. The remainder are located within distribution substations. These circuit breakers are used to automatically isolate a faulted section of the network and to improve the ability to maintain an uninterrupted supply to all customers not directly connected to the faulted section. The present network configuration is reviewed from time to time to consider the opportunity for further system optimisation as equipment condition determines the need for replacement. The economics of implementing new smart network technologies is also considered when planning distribution network renewal and reinforcement based on a fair return for the investment in line with the potential for delivering improved customer service.

6.1.3.1 Distribution Substations

Throughout the distribution network there are 4,276 distribution substation sites, of which 3,588 are owned by Wellington Electricity as standalone sites and 688 housed within consumer premises. Within these substations are 4,335 distribution transformers, some sites having multiple transformers installed. Smaller substations (typically 200kVA or less) in areas supplied by overhead lines are generally pole-mounted and are either platform structures or hanging bracket type arrangements. Ground-mounted distribution substations include a range of designs including reinforced concrete block buildings that can accommodate substations ranging from single transformers (typically with an 11kV switch unit and a LV distribution panel) up to larger three-transformer substations with multiple circuit breaker (CB) switchboards and extensive LV distribution switchgear. More compact ground mounted substation designs are also used; these are generally a pad mounted integral style, with an LV distribution panel, transformer and ring main unit enclosed in a metal canopy. Other common styles are standalone, open fenced enclosures or substations located within customer owned buildings. New substations are either metal canopy, pole mounted in rural areas, or indoor substations where the customer provides accommodation within a new or modified building.

Installation of a replacement distribution substation

In Wellington City the majority of the distribution transformers are ground mounted. The Hutt and Porirua areas are a combination of ground mounted and overhead installations. Individual capacities range from 5kVA to 2,000kVA and the average capacity is approximately 300kVA. A summary of the number of substations of each main type is in Figure 6-6.

Enclosure Type	Quantity
Outdoor	272
Indoor	974
Pad mounted	1,209
Pole	1,821
Total	4,276

Figure 6-6 Summary of Distribution Substation Types

6.1.4 Low Voltage

Low voltage (LV) lines and cables are used for the LV network, which is supplied from the distribution transformers and used to connect individual small consumers to the distribution system. The total LV network length is around 2,724 circuit-km, of which approximately 60% is underground.

Consumers are supplied via a low voltage fuse, which is the ICP between the low voltage network and an individual consumer's service main. This fusing is either an overhead pole fuse or located within a service pillar or pit near a consumer's boundary. Some other styles of fuse installation exist; however, these are being progressively replaced following faults or when a non-fault repair is required.

In addition to the service pillars, there are 400 link pillars on the network that allow isolation, reconfiguration and back feeding of certain LV circuits. These vary in age and condition and are being replaced where required

6.1.5 Embedded Generation

There is a wide range of embedded generation connected to the network, including over 400 installations of photovoltaic solar panels averaging 3.3kW per site. Four major customers have significant (>0.5 MW) standby diesel generators. Other embedded generation includes two sites with gas turbines that run on landfill gas, the Brooklyn wind turbine, and small scale hydroelectric generation stations commissioned at some Greater Wellington Regional Council water storage and pumping stations.

A summary of the embedded generation connected to Wellington Electricity's network is in Figure 6-7.

Generation Type	Sites	Installed Capacity (MW)
Known Standby Diesel	Prison	1.2
	Hospitals	6.8
	Others	0.5

	Total	8.5
Landfill Gas	Silver Stream	3.0
	Happy Valley	1.2
	Total	4.2
Hydroelectric	Various	1.3
Photovoltaic	Various	1.3
Wind	Various	60.0
Total		**75.3**

Figure 6-7 Summary of Embedded Generation

6.1.6 Embedded Distribution Networks

Within the Wellington Electricity network area there are a number of embedded networks owned by others, which are typically apartments, commercial buildings, or campuses such as retirement villages.

Wellington Electricity is not responsible for these networks, and generally provides a metered bulk supply point. The management of the assets within these networks, and the associated service levels, are not the responsibility of Wellington Electricity and are excluded from this AMP.

6.2 Asset Fleet - Population and Age Profile

This section describes Wellington Electricity's assets by fleet, including the population of each fleet, in most cases by type, and the age profile.

A summary of the population each asset class is shown in Figure 6-8. Details of condition are presented in Appendix A – Schedule 12a.

Asset Class	Measurement unit	Quantity
Subtransmission Cables	km	136
Subtransmission Lines	km	58
Zone Substation Transformers	number	52
Zone Substation Circuit Breakers	number	368
Zone Substation Buildings	number	27
Distribution and LV Lines	km	1,682
Distribution and LV Poles	number	36,544
Distribution and LV Cables	km	2,791
Distribution Transformers	number	4,335
Distribution Substations	number	3,588

Asset Class	Measurement unit	Quantity
Distribution Circuit Breakers	number	1,300
Distribution Switchgear - Overhead	number	2,627
Distribution Switchgear - Ground Mounted	number	2,218
Protection Relays	number	1,388
Load Control Plant	number	26

Figure 6-8 Asset Population Summary

6.2.1 Subtransmission

6.2.1.1 Subtransmission Cables

Wellington Electricity owns approximately 136 km[15] of subtransmission cables operating at 33 kV. These comprise 52 circuits connecting Transpower GXPs to Wellington Electricity's zone substations. Approximately 30km of subtransmission cable is of XLPE construction and requires little maintenance. This includes the newly installed 33kV from Central Park GXP to Palm Grove zone substation which replaced the old gas-filled cables. The remainder is of paper-insulated construction, with a significant portion of these cables being relatively old pressurised gas or oil-filled, with either an aluminium or lead sheath. A section of the subtransmission circuits supplying Ira St zone substation are oil-filled PIAS (paper insulated aluminium sheath) cables rated for 110kV but operating at 33kV. The lengths and age profile of this asset class are shown in Figure 6-9 and Figure 6-10.

Construction	Design voltage	Percentage	Quantity
Paper Insulated, Oil Pressurised	33kV	31%	42km
Paper Insulated, Gas Pressurised	33kV	34%	46km
Paper Insulated	33kV	7%	9km
XLPE Insulated	33kV	22%	30km
Paper Insulated, Oil Pressurised	110kV	6%	9km

Figure 6-9 Summary of Subtransmission Cables

33kV rated cables that are run at 11kV are not included in the subtransmission circuit length.

[15] This figure doesn't include the subtransmission cables supplying the Petone zone substation which have been de-energised, capped and earthed

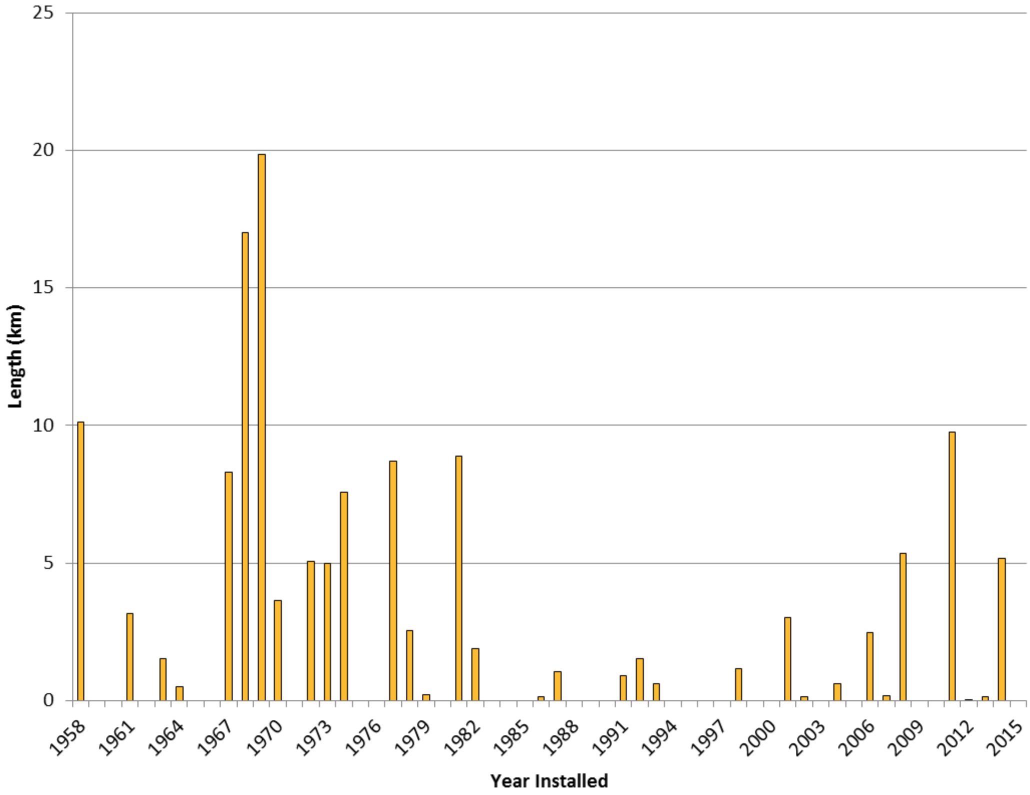


Figure 6-10 Age Profile of Subtransmission Cables

Full details of maintenance, refurbishment and renewal practices are in Section 10.

6.2.1.2 Subtransmission Lines

Wellington Electricity's 58km of 33kV subtransmission overhead lines are predominantly AAC conductor on both wood and concrete poles. Overhead line was used for subtransmission in the former Northern (Hutt Valley) area, converting to underground cable at the urban boundary. Subtransmission overhead lines are typically located on rural or sparsely developed land, although they are also in some other locations where difficult access would have made underground cable installation problematic. A summary and age profile of the subtransmission lines are shown in Figure 6-11 and Figure 6-12.

Category	Quantity
33kV Overhead Line	58km

Figure 6-11 Summary of Subtransmission Lines

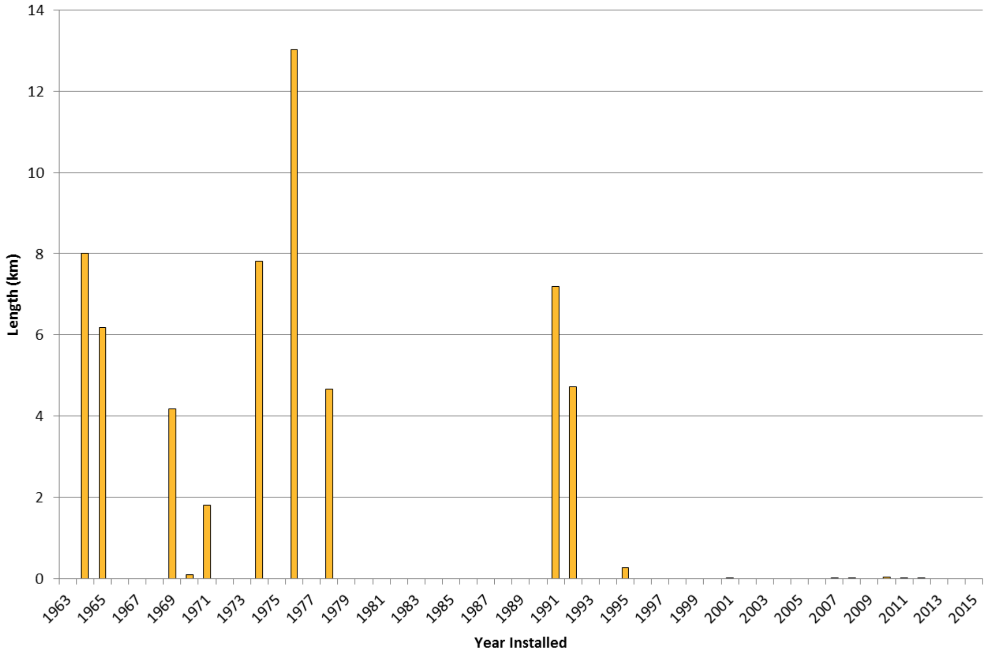


Figure 6-12 Age Profile of Subtransmission Lines

6.2.2 Zone Substations

6.2.2.1 Zone Substation Transformers

Wellington Electricity has 52 33/11kV power transformers in service on the network, and two spare units. All zone substation transformers are operated well within their ratings, are regularly tested and have had condition assessments undertaken.

The age profile for zone substation transformers is shown in Figure 6-13.

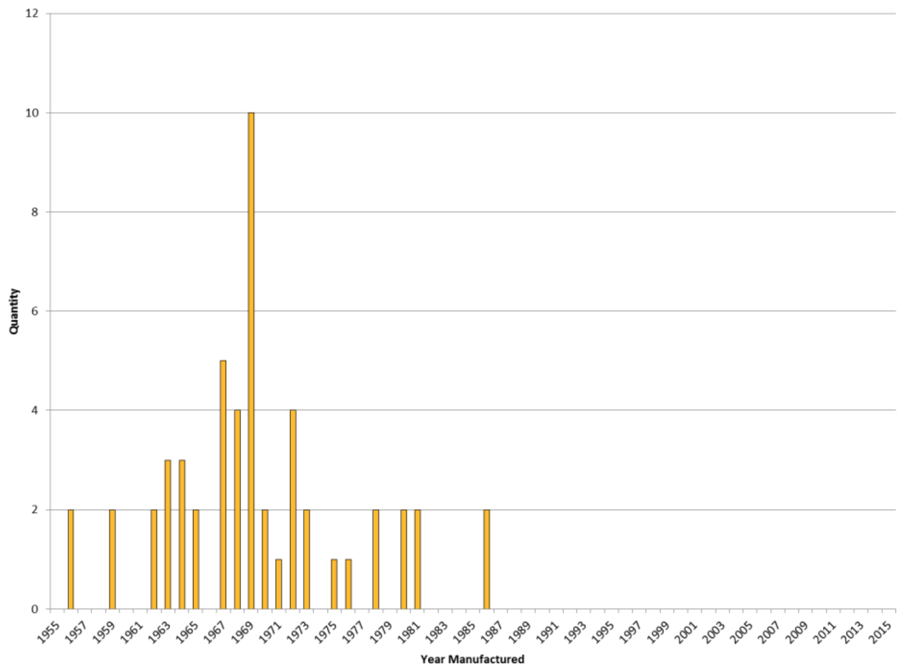


Figure 6-13 Age Profile of Zone Substation Transformers

The age profile indicates that the mean age of the transformer fleet is high (around 45 years). Based on the assumption that zone transformers have a design life of around 55 years then all of the zone transformers have exceeded midlife and four transformers have exceeded an age of 55 years.

6.2.2.2 Switchboards and Circuit Breakers

11kV circuit breakers are used in zone substations to control the power injected in to the 11kV distribution network, and within the network to increase the reliability of supply in priority areas such as in and around the CBD. The most common single type is Reyrolle Pacific type LMT circuit breakers, but other types are also in service in large numbers. There are 1,666 11kV circuit breakers on the Wellington Electricity network.

As shown in Figure 6-14, the number of circuit breakers used in the Wellington Electricity network is high compared to other EDB networks in New Zealand. This is largely as a result of historic design practices with an emphasis on closed-loop arrangements.

EDB Network	ICP Count (approx.)	CB Count (approx.)	ICP/ CB Ratio (approx.)
Vector Networks	538,000	1,445	372
Orion NZ	189,000	1,855	102
Wellington Electricity	**165,000**	**1,666**	**99**
Unison	110,000	277	397
WEL Networks	87,000	364	239
Aurora Energy	85,000	340	250

Figure 6-14 Comparison of number of 11kV Circuit Breakers in various networks

An age profile of the circuit breakers and switchboards is shown in Figure 6-15 and Figure 6-16.

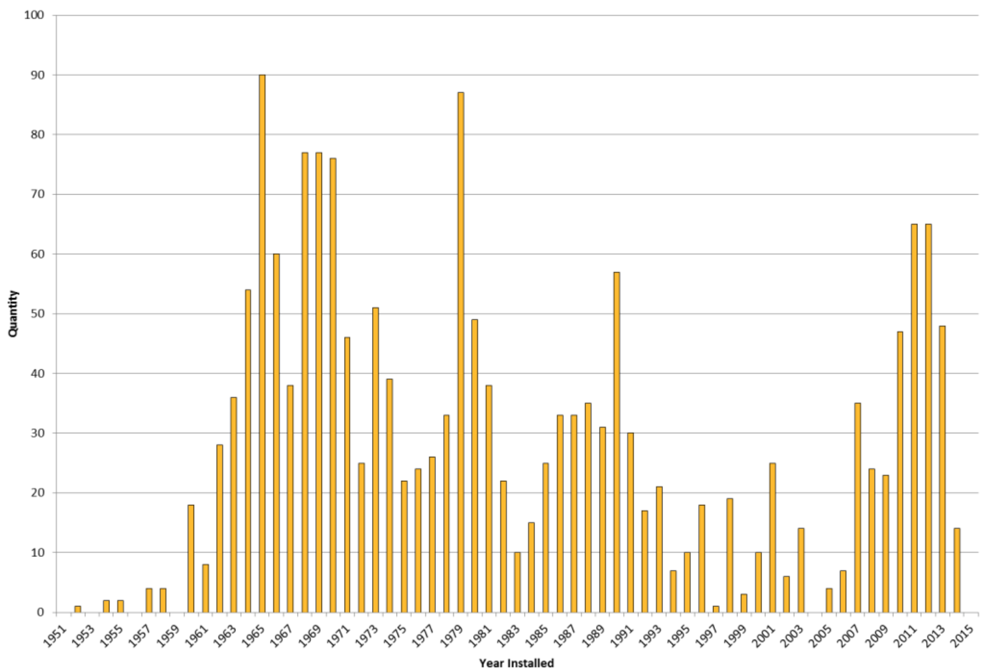


Figure 6-15 Age Profile for Circuit Breakers

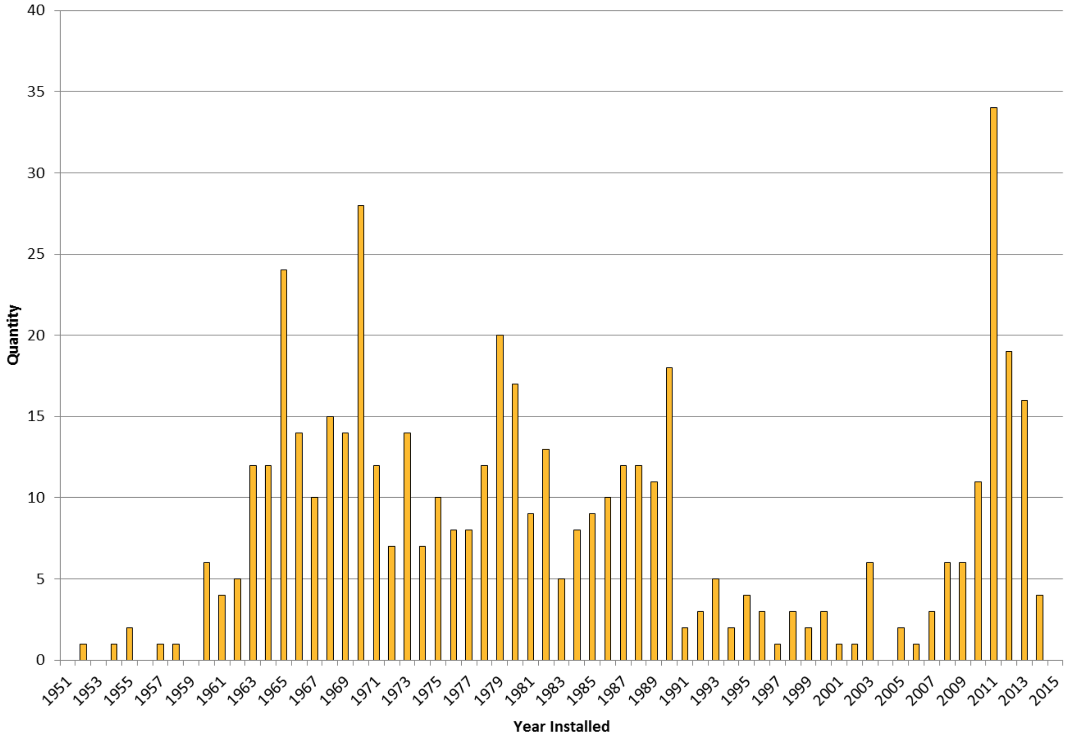


Figure 6-16 Age Profile for Switchboards

The age profile indicates that the average age of circuit breakers in the Wellington Network is around 31 years, with the age of individual breakers ranging from relatively new to more than 50 years. The mix of circuit breaker technologies reflects the age of the equipment. Older circuit breakers are oil filled while newer units have SF_6 and vacuum type interrupters. The majority of circuit breakers are still oil filled and require relatively intensive maintenance regimes.

The use of transformer feeders avoids the need for 33kV circuit breakers at zone substations. However, there are two 33kV Nissin KOR oil circuit breakers at Ngauranga which have been in service at this site for approximately 22 years. Originally manufactured in the 1960s, installation was in 1993 when the substation was constructed.

While large numbers of oil-type circuit breakers are approaching, or have passed, the end of their design life of 40 years, the fleet remains in generally good condition.

Category	Quantity
33kV Circuit Breakers	2
11kV Circuit Breakers	1,666

Figure 6-17 Summary of Circuit Breakers

Manufacturer	Breaker Type	Quantity
ABB	SF_6	11
AEI	Oil	85
BTH	Oil	46

Manufacturer	Breaker Type	Quantity
Crompton Parkinson	Oil	2
GEC/Alstom	Oil	102
Hawker Siddeley	Vacuum	21
Merlin Gerin / Schneider	SF_6	173
Nissin	Oil	2
Reyrolle	Oil	983
	Vacuum	111
Siemens	SF_6	16
South Wales	SF_6	37
Statter	Oil	50[16]
Yorkshire	Oil	29
Total		**1,668**

Figure 6-18 Summary of Circuit Breaker by Manufacturer

6.2.2.3 Zone Substation Buildings

There are 27 zone substation buildings, and three at major 11kV switching stations. The buildings are typically standalone (although some in the CBD are close to adjacent buildings, or in the case of The Terrace located in the basement of a hotel) and have switchgear, secondary systems, local AC and DC supplies installed inside. Some buildings also contain transformers and ripple injection plant. The remaining buildings house kiosk type distribution substations and are not covered in this sub-section as they form part the distribution substation asset class.

The age profile of the major substation buildings is shown in Figure 6-19. The average age of the buildings is 43 years and they are in good condition. From time to time maintenance or replacement of some components such as doors, roofs and spouting is required. There are five locations where Wellington Electricity does not own the land under the zone substation and has a long-term lease with the landowner.

[16] This is for circuit breakers only and excludes the HV switches and ring main units.

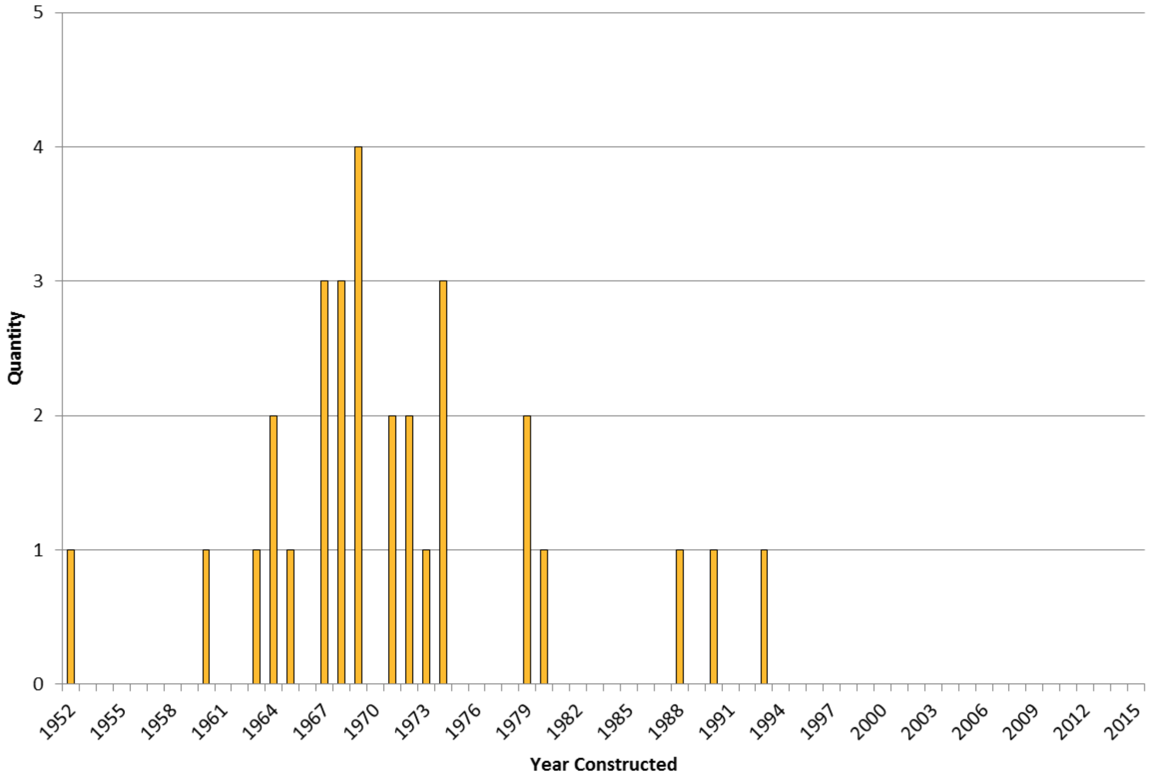


Figure 6-19 Age Profile of Major Substation Buildings

6.2.2.4 Substation DC Systems

The DC auxiliary systems provide power supply to the substation protection, control, metering, monitoring, automation and communication systems, as well as circuit breaker tripping and closing mechanisms. The standard DC auxiliary system comprises batteries, battery chargers, DC/DC converters and a battery monitoring system. Wellington Electricity has a number of different DC voltages: 24, 30, 36, 48, and 110V, largely for historical reasons. However, it has standardised on 24V for all new or replacement installations.

6.2.3 Distribution and LV lines

6.2.3.1 Poles

The total number of poles owned by Wellington Electricity, including subtransmission distribution lines and low voltage lines, is 36,544. Of this number, 26% are wooden poles and 74% are concrete poles. Another 16,447 poles are owned by other parties but have Wellington Electricity assets such as crossarms and conductors attached, for example telecommunication poles owned by Chorus, or the poles for the trolley bus network (owned by Wellington Cable Car Limited). A summary of the poles either owned by Wellington Electricity, or with Wellington Electricity assets attached, is shown in Figure 6-20.

Pole Owner	Wood	Concrete	Total
Wellington Electricity	9,678	26,866	36,544
Customer / Chorus	12,007	2,399	14,406
Wellington Cable Car Limited	1,304	737	2,041
Total	**22,989**	**30,002**	**52,991**

Figure 6-20 Summary of Poles

The average age of concrete poles is 26 years. Although the standard asset life for concrete poles is 60 years there are a number of concrete poles that have been in service for longer than this. The average age of wooden poles is around 38 years and nearly 41% of all wooden poles are older than 45 years (the standard asset life of wooden poles). Crossarms are predominantly hardwood and are generally in a fair condition. An age profile of poles owned by Wellington Electricity is shown in Figure 6-21.

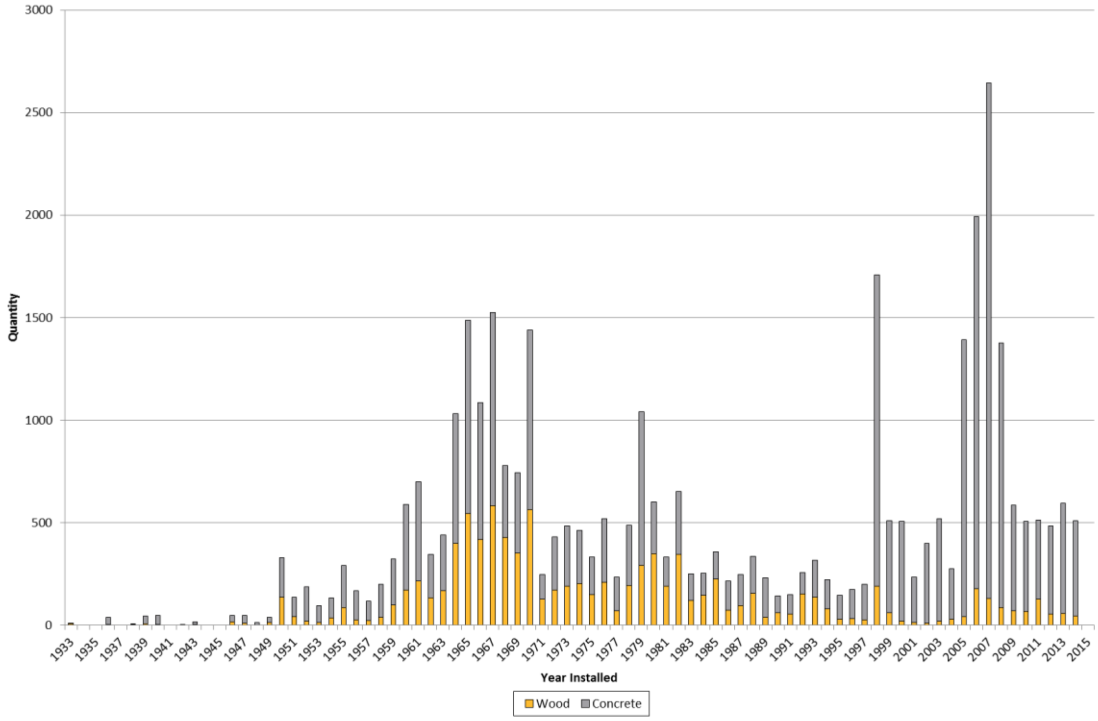


Figure 6-21 Age Profile of Poles

As Wellington Electricity did not purchase customer service lines or poles, there is on-going work required to advise consumers of their responsibilities relating to these privately owned lines. Owners are notified of any identified defects or when hazards are identified on consumer owned poles or service lines.

In addition to electricity distribution services, both Chorus and Vodafone utilise Wellington Electricity's poles for telephone, cable TV and UFB services.

6.2.3.2 Distribution and Low Voltage Conductors

Overhead conductors are predominantly all aluminium conductor (AAC), with older lines being copper (Cu). In some areas aluminium conductor steel reinforced (ACSR) conductors have been used. However, this is not common due to the high salt presence and corrosion experienced in the Wellington Electricity network area. New line reconstruction utilises all aluminium alloy conductor (AAAC). Low voltage aerial bundled conductor (LV ABC) has been used in a small number of tree encroachment areas (subject to District Plan allowances). Figure 6-22 shows the age profile of overhead line conductors.

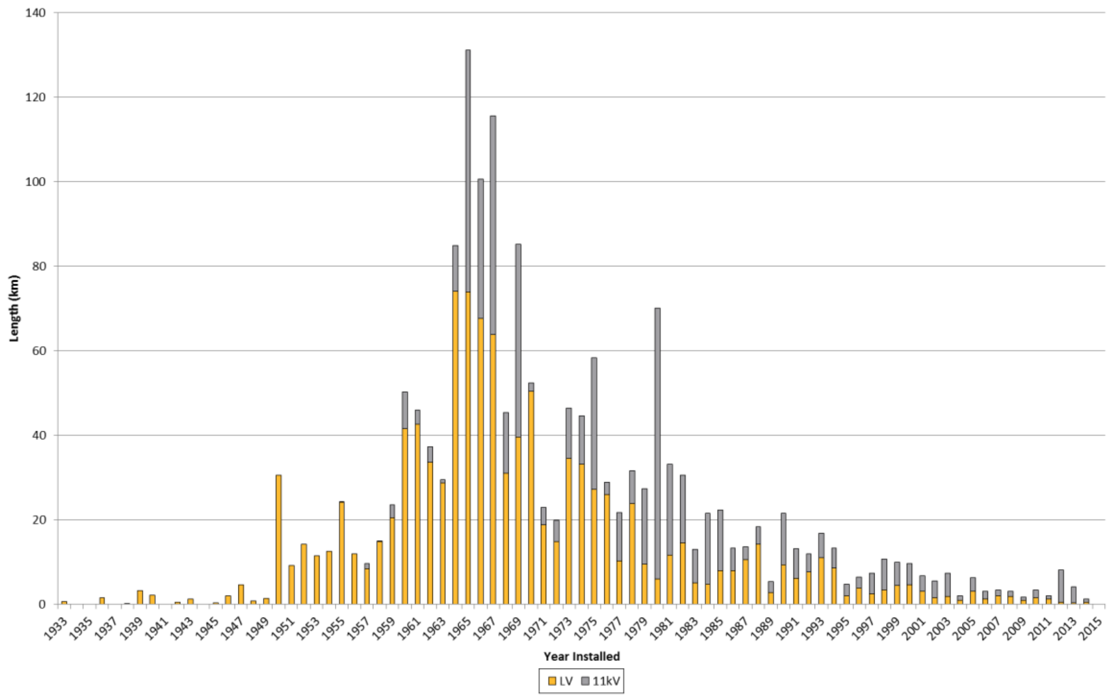


Figure 6-22 Age Profile of Distribution Overhead Line Conductors

Category	Quantity
11kV Line	595km
Low Voltage Line	1,087km

Figure 6-23 Summary of Distribution Overhead Lines

6.2.4 Distribution and LV cables

Wellington Electricity's network has a high percentage of underground cables, which has contributed to a historically high level of reliability during weather-related events but does subject it to increased risks of third party strikes during underground construction work. Outside the Wellington CBD, the 11kV underground distribution system has normally open interconnections between radial feeders, and feeders are segmented into small switching zones using locally operated ring main switches. In the event of a cable fault, the faulted cable section can be isolated, and supply to downstream customers can be switched to neighbouring feeders.

Wellington CBD is operated in a closed primary ring configuration with short, normally open radial feeders interconnecting neighbouring rings or zone substations. This part of the network uses automatically operating circuit breakers, using differential protection between distribution substations, rather than manually operated ring main switches between switching zones. This results in higher reliability as smaller sections of network are affected by cable faults. However due to the nature of the CBD, any repairs required to the distribution system take considerably longer than standard replacement times. CBD repairs also incur considerable costs for traffic management and road surface or pavement reinstatement.

Category	Quantity
11kV cable (incl. risers)	1,154km

Category	Quantity
Low Voltage cable (incl. risers)	1,637km

Figure 6-24 Summary of Distribution Cables

Approximately 91% of the underground 11kV cables are PILC and PIAS and the remaining 9% are newer XLPE insulated cables. PILC cables use a mature technology but are in good condition and have proven to be very reliable.

The majority of low voltage cables are PILC or PVC insulated and a much smaller number are newer XLPE insulated cables. In general, the low voltage cables are in good condition.

An age profile of distribution cables of both voltages is shown below in Figure 6-25.

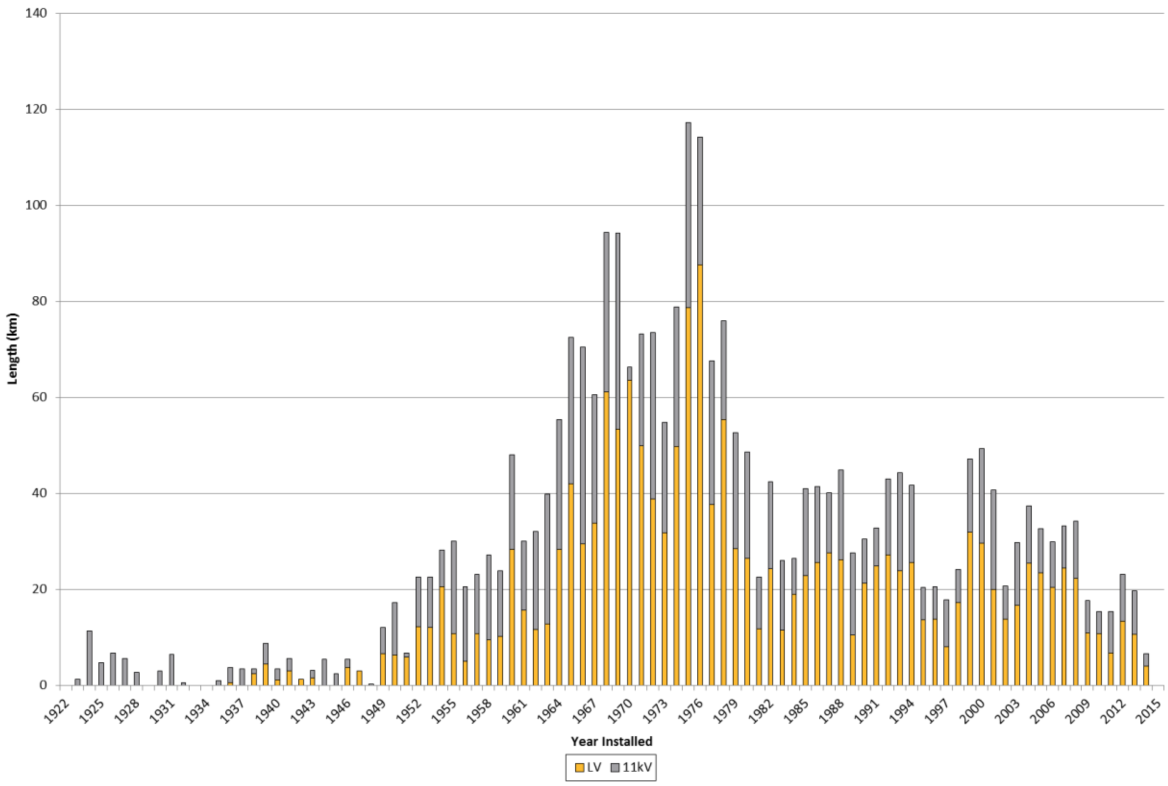


Figure 6-25 Age Profile of Distribution Cables

6.2.5 Distribution Transformers and Substations

6.2.5.1 Distribution Transformers

Of the distribution transformer population, 58% are ground mounted and the remaining 42% are pole mounted. The pole mounted units are installed on single and double pole structures and are predominantly 3 phase units rated between 10 and 200kVA. The ground-mounted units are 3 phase units rated between 100 and 1,500kVA. Wellington Electricity holds a variety of spare distribution transformers, in serviceable condition, to allow for quick replacement following an in-service failure. Other than complete units, few other spares are held for this type of asset. The design life of a distribution transformer is 45 years, although in indoor environments a longer life may be achieved. In some outdoor environments, particularly where exposed to sea salt spray, a transformer will not reach this age due to corrosion. The age profiles of distribution transformers is shown below in Figure 6-26.

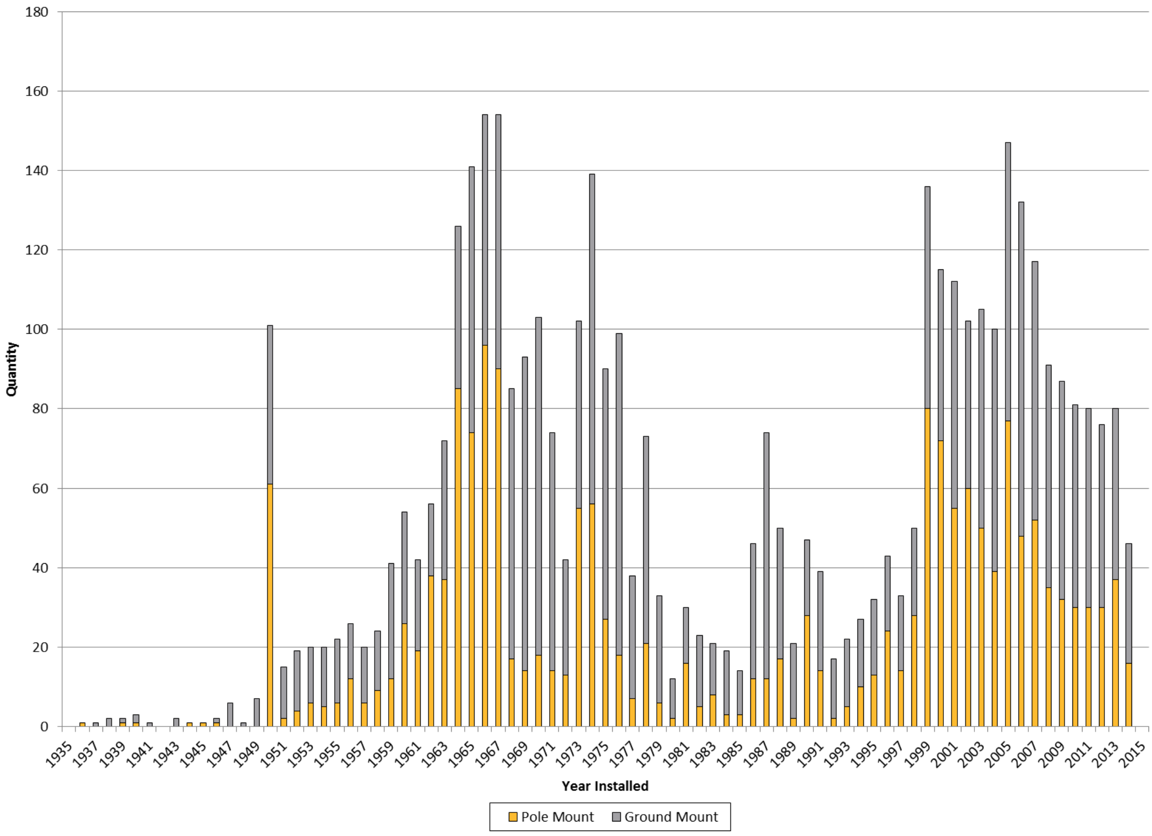


Figure 6-26 Age Profile of Distribution Transformers

6.2.5.2 Distribution Substations

In addition to pole and integral padmount berm substations, Wellington Electricity owns 472 indoor substation kiosks and occupies a further 688 sites that are customer owned (typically of masonry or block construction or outdoor enclosures). These are categorised as substation enclosures, although a large number are quite sizeable and are located on Wellington Electricity owned plots of land. A summary of Wellington Electricity's distribution transformers and substations is shown below in Figure 6-27.

Category	Quantity
Distribution transformers	4,335
Wellington Electricity owned substations	3,588
Customer owned substations	688
Distribution substations – Total	**4,276**

Figure 6-27 Summary of Distribution Transformers and Substations

6.2.5.3 LV Pillars and Pits

Pillars and pits provide the point for the connection of customer service cables to the Wellington Electricity underground LV reticulation. They contain the fuses necessary to isolate a service cable from the network. Pits are manufactured from polyethylene, as are most of the newer pillars. Earlier style pillars were constructed of concrete pipe, steel or aluminium. There are approximately 400 link pillars and pits in service on Wellington Electricity's network. These are used to parallel adjacent LV circuits to provide back feeds during outages, as well as providing the ability to sectionalise large LV circuits. A high-level breakdown of types is listed in Figure 6-28.

Type	Quantity
Customer service pillar	14,336
Customer service pit	1,483
Link pillars and pits	400
Total	**16,219**

Figure 6-28 Summary of LV Pillars and Pits

An age profile of pillars and pits is shown below in Figure 6-29. Approximately 6,500 pits and pillars have unknown ages, and these are not included in the age profile.

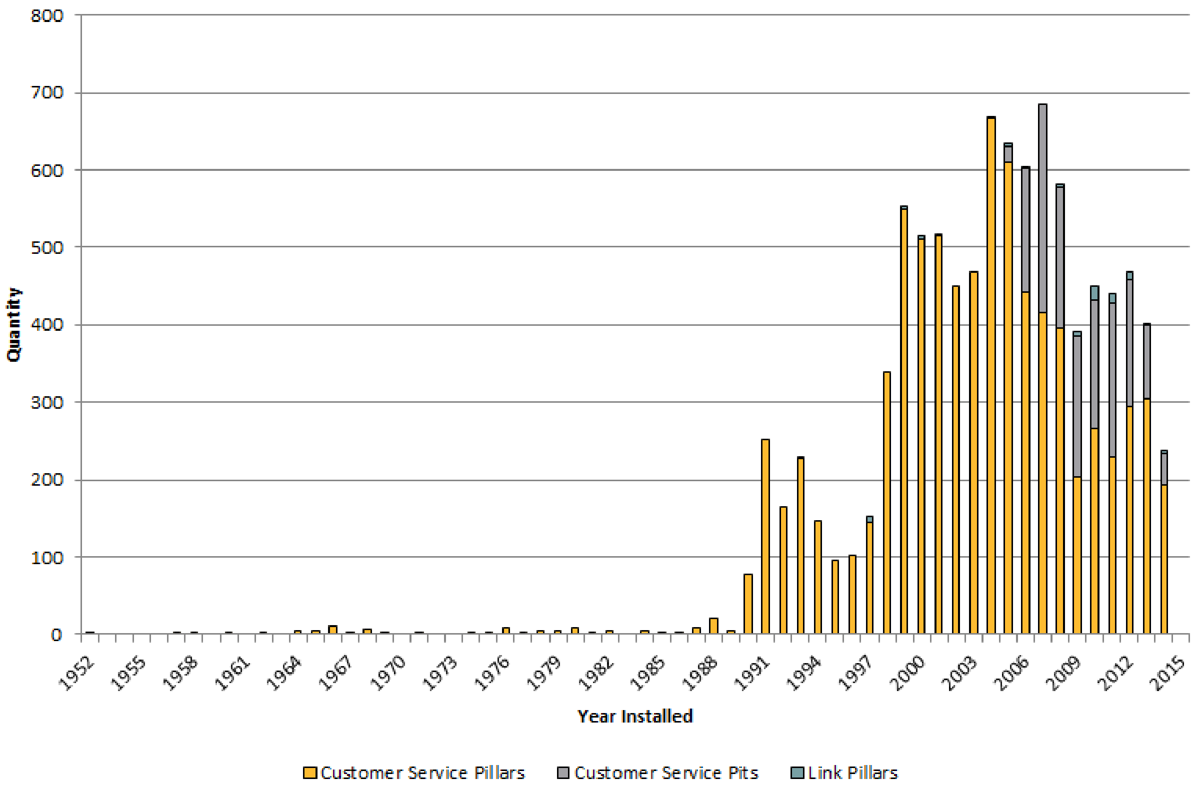


Figure 6-29 Age Profile of Pillars and Pits

6.2.6 Distribution Switchgear

6.2.6.1 Overhead Switchgear

There are 295 air break switches (ABS), 20 auto-reclosers, 173 knife links, 66 gas insulated overhead switches and a mix of expulsion type dropout fuses for breaking the overhead network into sections.

Majority of the ABSs are more than the standard life of 35 years old and are in fair to poor condition. These are not cost effective to refurbish. Each year there is a budget provision for replacement of these switches, which occurs upon receipt of unsatisfactory switch inspection results, or when the poles or crossarms on which a switch is located are replaced. Gas insulated load break switches are being used in strategic areas and are equipped with motor actuation for future automation. New conventional air break switches are also widely used as replacements.

The age profiles of these overhead line devices are shown in Figure 6-30.

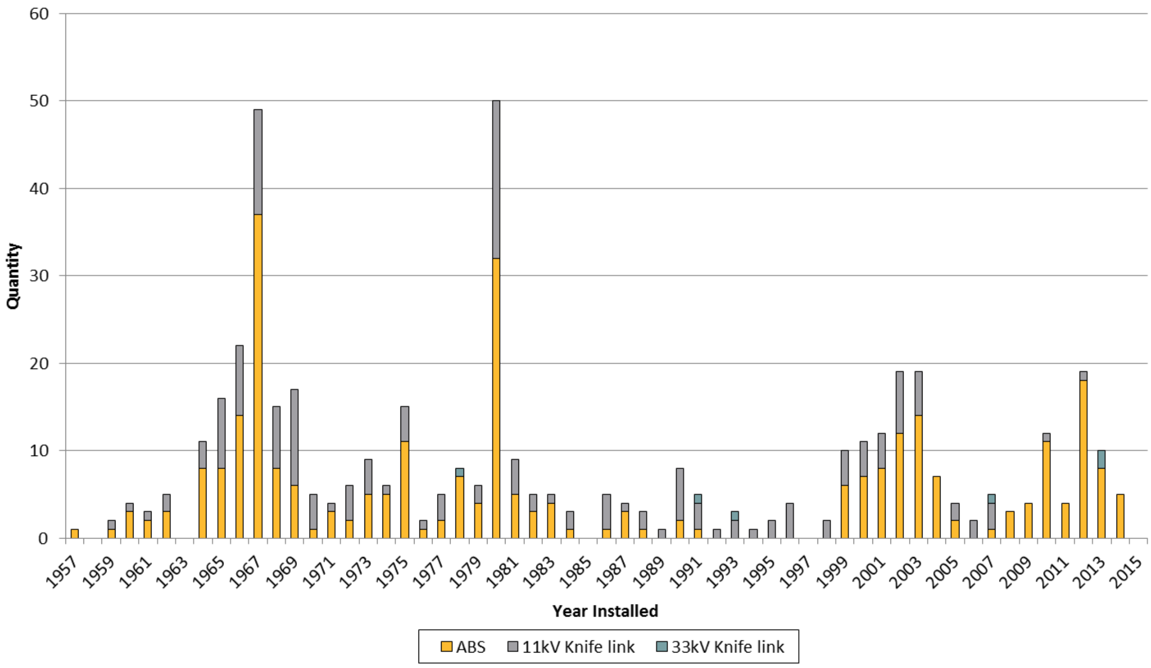


Figure 6-30 Age Profile of Overhead Switchgear and Devices

The majority of the 20 overhead auto-reclosers are oil-filled, with only five having solid insulation and vacuum interrupters. The individual types of auto-reclosers are shown in the Figure 6-31 below.

Manufacturer	Insulation	Model	Quantity
G&W	Solid/Vacuum	ViperS	5
Reyrolle	Oil	OYT	7
Metropolitan Vickers	Oil	UPC	2
McGraw-Edison	Oil	KFE	6
Total			**20**

Figure 6-31 Summary of Auto-Recloser Types

The age profile of Wellington Electricity's auto-reclosers and gas switches is shown in Figure 6-32.

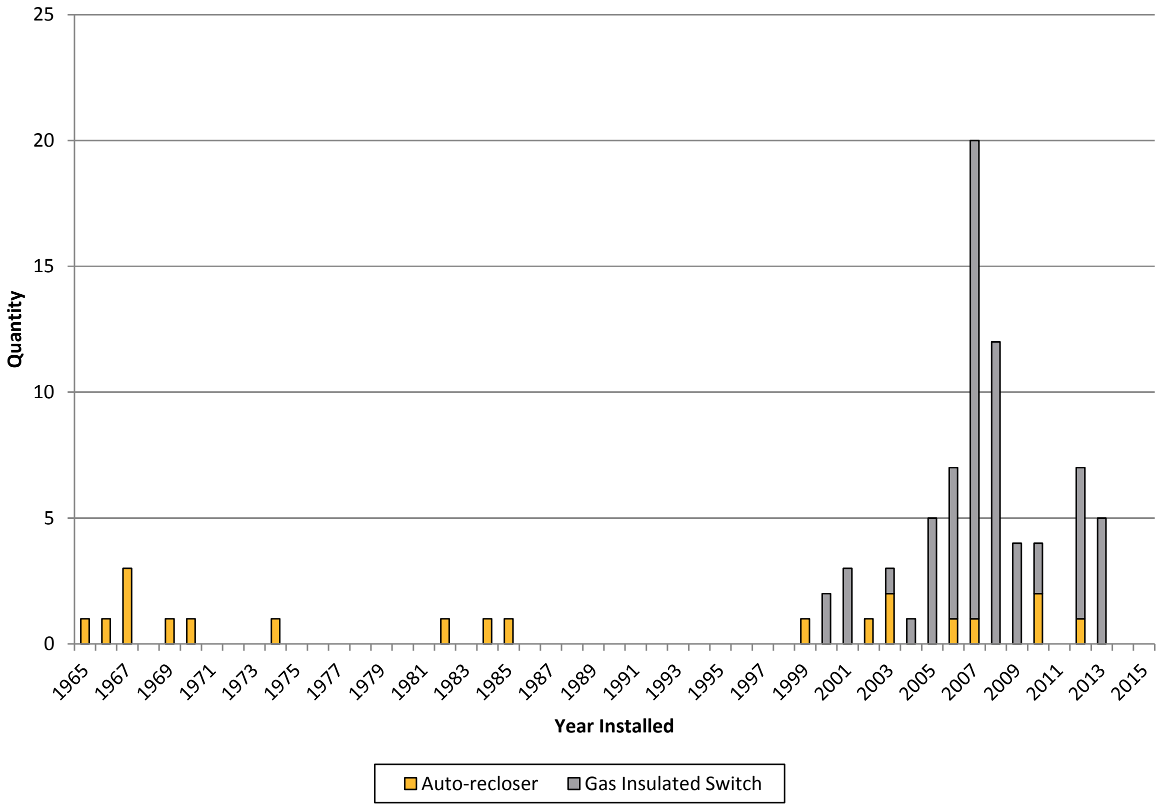


Figure 6-32 Age Profile of Overhead Auto-reclosers and Gas Switches

6.2.6.2 Ground Mounted Distribution Switchgear

This section covers ring main units and similar switching equipment that are often mounted outdoors. It does not include indoor circuit breakers, which are widely used on the distribution network outside of zone substations, as these are included under the category of circuit breaker. There are 2,218 ground mounted switches in the Wellington Electricity network, including the Holec Magnefix resin insulated type, oil insulated ring main switches such as ABB, Long and Crawford, and Statter and newer units that use SF_6 gas as the main insulating medium. The age profile of ground-mounted switchgear (excluding the 1,666 circuit breakers located within the distribution network), is shown in Figure 6-33.

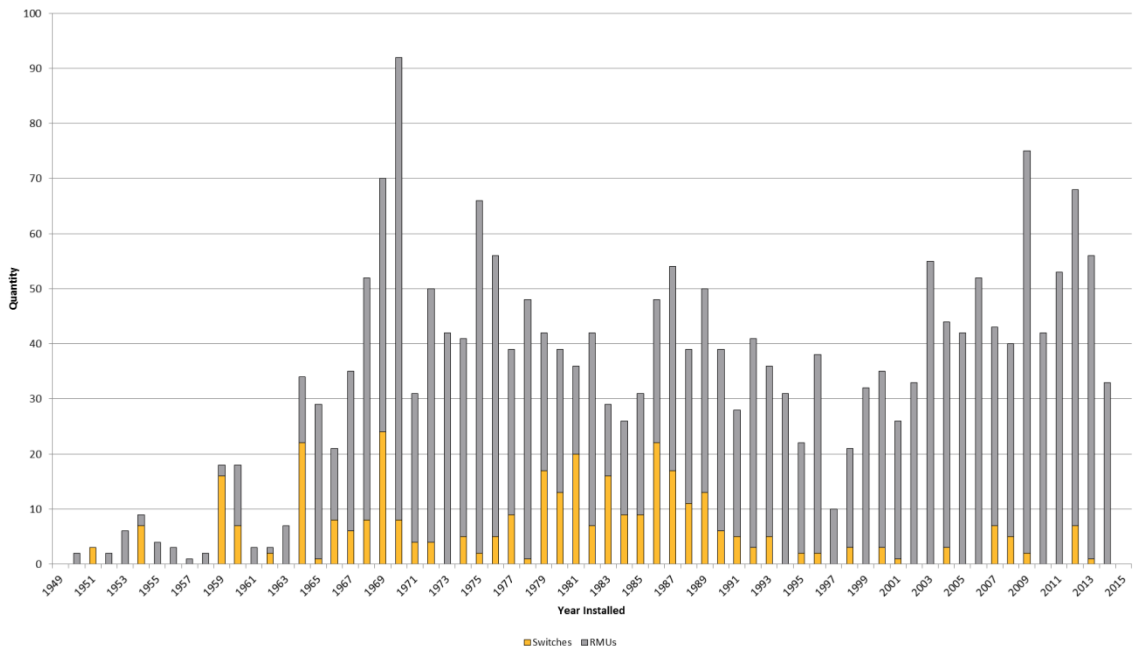


Figure 6-33 Age Profile of Ground Mounted Distribution Switchgear

The average age of the ground mounted distribution switchgear is 25 years. A summary of ground mounted distribution switchgear, of both stand-alone and ring main unit types, is shown in Figure 6-34 below.

Category	Quantity
Oil Insulated Switches	330
Oil Insulated RMUs	248
SF_6 Insulated Switches	21
SF_6 Insulated RMUs	550
Solid Insulated RMUs	1,069
Total	**2,218**

Figure 6-34 Summary of Ground Mounted Distribution Switchgear

6.2.7 Other System Fixed Assets

6.2.7.1 SCADA

The SCADA master station is a GE ENMAC system, which was installed in 2009. It replaced a Foxboro LN2068 system which was initially installed in 1986 and which still provides some functionality with an automated load management package. The Foxboro system will be retained in the short term to provide the automatic load control function until either the GE ENMAC system is upgraded to undertake this function, or an alternative standalone system is implemented.

The SCADA system is used for real time monitoring of system status and to provide an interface to remotely operate the network. SCADA can monitor and control the operation of primary equipment at the zone substations and larger distribution substations, and provides status indications from Transpower-owned assets at GXPs.

More specifically, SCADA is used to:

- Monitor the operation of the network from a single control room by remotely indicating key parameters such as voltage and current at key locations;
- Permit the remote control of selected primary equipment in real time;
- Graphically display equipment outages on a dynamic network schematic; and
- Transmit local system alarms to the control room for action.

System information is collected by remote terminal units (RTUs) at each remote location and is transmitted to a SCADA central master station through dedicated communication links. Control signals travel in the opposite direction over the same communications links.

Wellington Electricity has two NCRs at separate sites, with one set up as a Disaster Recovery site. These sites are interconnected via the Transmission Control Protocol/Internet Protocol (TCP/IP) network.

An age profile of SCADA RTUs is shown in Figure 6-35.

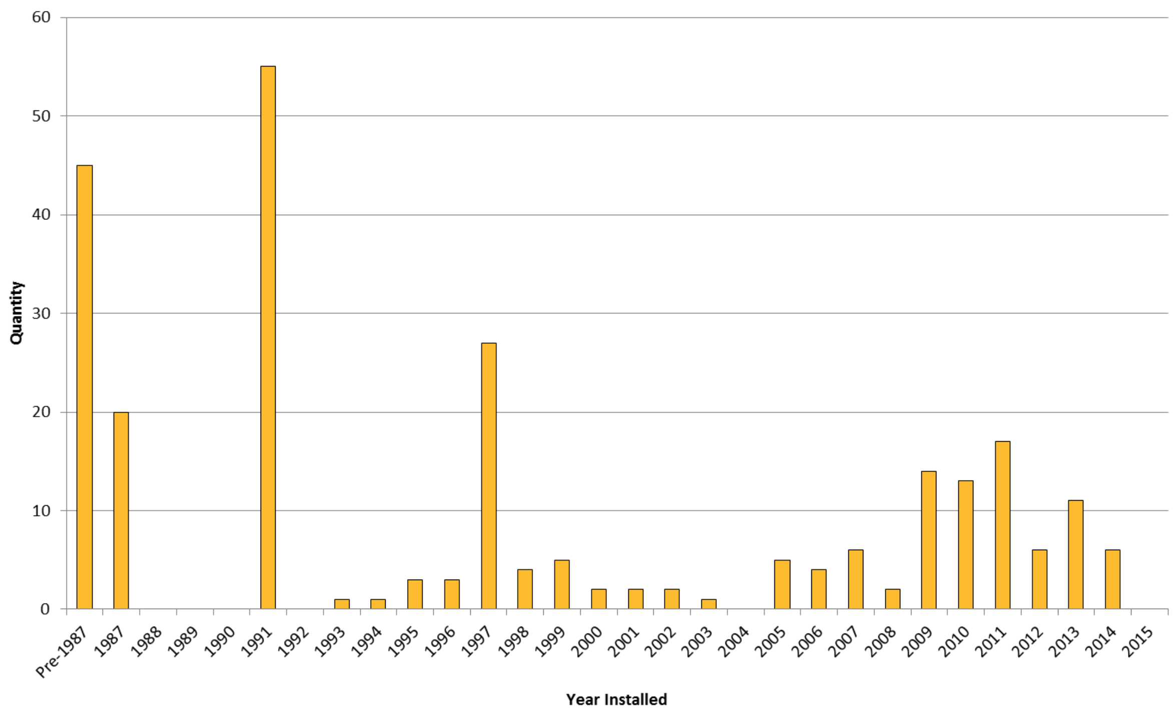


Figure 6-35 Age Profile of SCADA RTUs

As substation sites are being upgraded or developed, and if IP network connections are available, the station RTU is upgraded and moved onto the substation TCP/IP network using the DNP3.0 protocol.

There are currently 54 sites (a mixture of zone and distribution substations) on the substation TCP/IP network.

There are two Siemens Power Automation System (PAS) units that act as a protocol converter between the Siemens IEC61850 field devices located at three sites and that of the DNP3.0 SCADA master station. These units are designed to allow fail-over redundancy to prevent a single point of failure at the PAS. The use of the Siemens PAS unit was part of a previous network owner's protection and control strategy and Wellington Electricity has no plans to add further IEC61850 devices to the PAS system.

6.2.7.2 Protection Systems

Secondary protection assets are relays that automatically detect conditions that indicate a potential primary equipment fault and automatically issue control signals to disconnect the faulted equipment. This ensures that the system remains safe and that damage is minimised. Protection assets are also installed to limit the number of consumers affected by an equipment failure.

On the HV system, there are approximately 1400 protection relays in operation. The majority of these are electromechanical devices. The remainder use solid state electronic and microprocessor technology. Relays are generally mounted as part of a substation switchboard and are normally upgraded at the time of switchgear replacement.

On subtransmission circuits, and in the Wellington City area where the network is comprised of closed 11kV rings, protection relays use differential protection where the power entering a circuit is compared with the power output. As a backup on these circuits, and in situations where differential protection is not required (such as radial feeders with normally open points), overcurrent and earth fault (OC/EF) relays are used where circuit currents are measured and a disconnect signal issued if these move outside an expected range.

The average age of the protection relays on the Wellington Electricity network is around 35 years with approximately 30% of the protection relays are more than 40 years old. Generally, all protection relays are in good condition with the exception of PBO electromechanical and Nilstat ITP solid state relays, which have performance and functionality issues. There are only 10 Nilstat ITP relays still in service, all of which are on a switchboard at Gracefield zone substation, scheduled for replacement in 2015. PBO relays are replaced when their switchboards are replaced.

At distribution level, 11kV fuses are also used for protection of distribution transformers and other equipment. Fuses are used on the LV system for the protection of cables and equipment. Fuses form part of the primary circuit and are not secondary assets.

6.2.8 Other Assets

6.2.8.1 Metering

Wellington Electricity does not own any metering assets as retailers and metering companies own these.

Check meters installed at GXPs and Maximum Demand Indicator (MDI) meters are installed in a large number of distribution substations, predominantly those used for street LV supply. MDIs are used for operational and planning purposes only and are considered part of the distribution substation. In future, there may be benefits from accessing smart metering data from consumer premises to feed into the network planning and asset management processes, as well as for real time monitoring of the performance of the low voltage network.

6.2.8.2 Generators and Mobile Substations

Wellington Electricity does not own any mobile generators or substations but owns a fixed generator supporting the disaster recovery control room site. Wellington Electricity also has shared use of a generator at its corporate office however this generator is owned and maintained by others.

The works contractor provides all generation required for network operations and outage mitigation, where required.

6.2.8.3 Load Control Systems

Wellington Electricity uses a ripple injection signal load control system to inject 475Hz and 1050Hz signals into the network for the control of selected loads such as water heating and storage heaters at consumer premises, to control street lighting and also to provide some tariff signalling on behalf of retailers using the network.

There are 26 ripple injection plants on the network and these are located at GXPs and zone substations. The Southern area has a 475Hz signal injected into the 33kV network with one plant per GXP and two plants injecting at the Kaiwharawhara 11kV point of supply. The Northeast and Northwest areas have a 1050Hz signal injected at 11kV at each zone substation.

All ripple injection is controlled automatically by the Foxboro master station but can also be controlled remotely from the NCR.

The 213 previously used DC bias load control units have now all been either decommissioned or bypassed.

An age profile of ripple plant is shown in Figure 6-36.

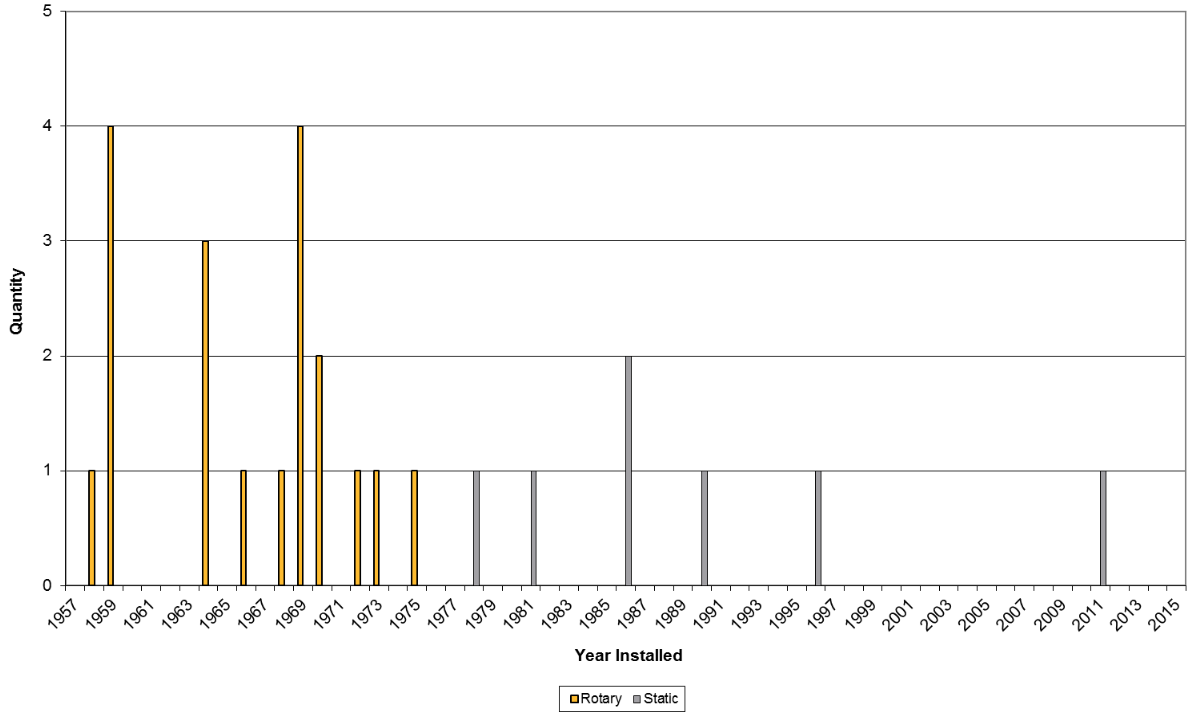


Figure 6-36 Age Profile of Ripple Plant

6.2.9 Assets Located at Bulk Electricity Supply Points Owned by Others

Wellington Electricity owns a range of equipment installed at Transpower GXPs. These assets are included in the asset categories listed above, but are described further below.

6.2.9.1 33kV and 11kV Lines, Poles and Cables

Wellington Electricity owns lines, poles, cables, and cable support structures at all GXPs from which it takes supply. The Wellington City area is fully underground cabled, whereas in the Hutt Valley and Porirua areas many circuits are connected to the GXP via an overhead line.

6.2.9.2 11kV switchgear

Wellington Electricity owns the 11kV switchgear located within the Kaiwharawhara GXP. The 11kV switchboards at all other GXPs where supply is given at 11kV are owned by Transpower.

6.2.9.3 Protection Relays and Metering

Wellington Electricity owns 33kV line and cable protection (differential) and inter-tripping relays at all GXPs except Kaiwharawhara. At Kaiwharawhara, Wellington Electricity owns the relays associated with the 11kV switchgear except those on the incomers, which are owned by Transpower. Wellington Electricity also owns check metering at all GXPs.

6.2.9.4 SCADA, RTUs and Communications Equipment

Wellington Electricity owns SCADA RTUs and associated communications equipment at all GXPs.

6.2.9.5 DC Power Supplies and Battery Banks

Wellington Electricity owns battery banks and DC supply equipment at all GXPs.

6.2.9.6 Load Control Equipment

Wellington Electricity owns load control injection plant at Haywards and Melling GXPs, and also has ripple blocking circuits installed on the 33kV bus at the Takapu Road, Melling and Upper Hutt GXPs.

6.2.10 Non Network Assets

In addition to the network assets described in the sections above, Wellington Electricity also owns a range of non-network assets that are not used for the conveyance of electricity but support the business.

6.2.10.1 Information Technology Assets

Wellington Electricity owns desktop and laptop computers, servers and networking equipment related to the corporate IT network. These are too numerous to detail individually.

The company also owns software and user licenses for a range of packages including Smallworld GIS, SCADA, Power Factory, ProjectWise, MicroStation CAD, and SAP.

Wellington Electricity owns a range of landline and cellular telephones for the corporate office and for staff use. For major event and disaster recovery, a number of Iridium Satellite phones are also owned.

6.2.10.2 Building Improvements and Furniture

The building improvements, signage and major plant installed by Wellington Electricity, including air conditioning upgrades, are considered to be non-network assets. Wellington Electricity does not own the buildings at either the Petone corporate office or the Haywards disaster recovery control room, however lease arrangements with appropriate rights of renewal are in place.

Wellington Electricity owns furniture in the Petone corporate office and the Haywards disaster recovery control room including desks, chairs, shelving, kitchen related equipment and artwork.

6.2.10.3 Plant and Machinery

Wellington Electricity owns very little in the way of plant and machinery due to the outsourced field service arrangements. There are six motor vehicles which are operated under a finance lease and used by the business. There are no vehicles provided for personal use.

Wellington Electricity owns a small range of tools such as test sets relating to the Deuar pole testing system and an UltraTEV+ unit, which is used by both Wellington Electricity and also loaned to the Field Service Provider to undertake specific diagnostic testing. Where possible, the Field Service Provider and capital works contractors are encouraged to purchase and hold specialist test equipment. Tools and equipment owned by Wellington Electricity are tested and calibrated in accordance with the manufacturers' recommendations to ensure reliable and accurate operation.

6.2.10.4 Land and Other Buildings

The land purchased at Grenada in 2012 for the future development of the Grenada zone substation is currently classified as a non-network asset. This is due to the Commerce Commission rules preventing this being added to the network Regulatory Asset Base (asset RAB) until such time as it is used for electricity purposes. Wellington Electricity also owns an undeveloped site at Bond Street in the Wellington CBD, which is intended for future substation use. There are three residential properties located on the same parcel of land that the Karori zone substation is on. These houses are rented at market rents.

7 Network Performance and Service Levels

Wellington Electricity is committed to providing consumers with a reliable and secure electricity supply. This section of the AMP explains the basis for measuring the network's reliability and service level performance It also outlines the reliability performance targets and how Wellington Electricity has performed against the targets.

7.1.1 Consumer Expectations

From time to time Wellington Electricity surveys a range of consumers to get their feedback on network performance, as well as to help understand their views on issues such as the Price-Quality trade-offs they are prepared to make.

Consistent themes from this feedback have been:

- The importance of maintaining continuity of supply and timely restoration following an outage;
- Communication regarding planned and unplanned outages;
- Performance in regard to continuity and restoration is considered favourably; and
- High sensitivity to price changes relating to quality of supply. Survey participants have indicated they are unwilling to pay a higher price for increased levels of service, or to receive a reduction in cost for a lower level of supply reliability.

The consumer engagement initiatives to further improve communication are described in Section 2.5.1. The current contact centre service level targets are described in Section 7.3.

7.2 Reliability Measures

Network reliability is measured using two internationally recognised performance indicators, SAIDI[17] and SAIFI[18].

- SAIDI is a measure of the total time, in minutes, electricity supply is not available to the average consumer connected to the network in the measurement period; and
- SAIFI is a measure of the total number of supply interruptions that the average consumer experiences in the measurement period. It is measured in number of interruptions.[19]

When taken together SAIDI and SAIFI provide an objective basis for judging the quality of supply to the average consumer connected to the network. SAIDI and SAIFI are reported annually to the Commerce Commission (Commission) as part of the information disclosure requirements.

These indicators incorporate both planned and unplanned outages. On average, planned outages on the Wellington Electricity network account for approximately 10% of the total number of outages every year but only contribute to 1.5% of the annual SAIDI minutes. This is due to Wellington Electricity's extensive use of

[17] System Average Interruption Duration Index

[18] System Average Interruption Frequency Index

[19] Due to the effect of averaging, SAIFI is reported as a non-integer number.

temporary network reconfigurations and temporary diesel generation to minimise the number of customers affected by, and duration of, planned outages.

In accordance with the methodology established by the Commission[20], the following supply interruptions are not included in the measured performance indicators:

1. Interruptions caused by the unavailability of supply at a GXP, as a result of automatic or manual load shedding directed by the transmission grid operator,[21] or as a result of some other event external to the Wellington Electricity network;

2. Interruptions lasting less than one minute. In these cases restoration is usually automatic and the interruption will not be recorded for performance measurement purposes, however these interruptions are recorded by Wellington Electricity for planning and operational purposes; and

3. Interruptions resulting from an outage of the low voltage network or a single phase outage of the 11kV distribution network. In practice such interruptions do not have a material impact on measured system reliability, and the business processes required to accurately record these interruptions and measure their impact are not cost effective.

7.2.1 Performance Measure Methodology

As a non-exempt EDB, Wellington Electricity is subject to price-quality regulation under the Commission's Default Price-Quality Path (DPP) regime.[22] Prior to 1st April 2015, this regime set reliability limits based on a reference set of actual network reliability data taken from the period 1 April 2004 to 31 March 2009. The mean reliability over this period, as calculated using the Commission's methodology, was set as the target network reliability with the objective of ensuring that over time there is no deterioration in the underlying reliability of the electricity supply provided by the network. The Commission's compliance limit was set at the mean plus one standard deviation.

From 1 April 2015, the Commission's 2014 Determination (described earlier in this document) includes a revenue-linked quality incentive scheme. The scheme allows distributors to receive financial rewards for reliability outcomes that are better than the targets, and face financial penalties for reliability outcomes worse than the targets. In calculating the quality incentive scheme and quality standards parameters, the Commission has placed a 50% weighting on planned interruptions. The reference set of reliability data (mean annual SAIDI and SAIFI) is the 10 year period from 1 April 2004 to 31 March 2014.

In addition to targets, this regime also sets reliability caps and collars, which are one standard deviation above and below the mean. The caps and collars are the maximum and minimum reliability outcomes for which the rewards and penalties of $95,091 per SAIDI minute and $6,300,301 per SAIFI unit apply. In addition, the Commission has retained a compliance test for reliability which is set at the cap (mean plus one standard deviation). Non-compliance with the cap in multiple years may lead to potential enforcement action and further penalties. The target, caps and collar reliability values for Wellington Electricity calculated using this method are presented in Figure 7-1.

[20] Commerce Commission, Electricity Distribution Services Default Price-Quality Path Determination 2012

[21] The transmission grid operator has the authority to direct electricity distributors to shed load. This is necessary during emergencies to ensure that the power system continues to operate in a secure and stable state.

[22] Commerce Commission, Electricity Distribution Services Default Price-Quality Path Determination 2014.

Regulatory Period	2011-2015	2016-2020
SAIDI Target	33.90	35.42
SAIDI Limit	40.74	-
SAIDI Cap (Target +1 SD)	-	40.63
SAIDI Collar (Target –1 SD)	-	30.24
SAIFI Target	0.520	0.547
SAIFI Limit	0.600	-
SAIFI Cap (Target + 1 SD)	-	0.625
SAIFI Collar (Target -1 SD)	-	0.468

Figure 7-1 Wellington Electricity Regulatory Reliability Targets and Limits

7.3 Reliability Performance Targets

Network reliability performance targets are set by the Commission and shown in Figure 7-2. It is important to note that the data set used to establish these performance targets is now ten years old (2004-2014 reference period). The first five years of the reference period experienced benign weather relative to the last five years. Consequently the targets represent a performance level that is better than what would be expected given recent weather trends.

The targets for SAIDI and SAIFI reflect Wellington Electricity's intention to maintain network reliability at current levels. However this assumes that capital and operational expenditure is not unreasonably restricted by the regulatory environment, as this would have the potential to make these targets hard to meet. As previously mentioned, Wellington Electricity will be reviewing its operating and capital expenditure plans in light on the significant reductions in expected revenue.

The target for faults per 100km for the planning period is based on the historical trend, and shows a gradual increase in the rate of faults over time. This reflects an expectation that there will be an increase in the number of severe weather events, and the impact of an ageing network.

Regulatory Year	2015/16	2016/17	2017/18	2018/19	2019/20	2020/21	2021/22	2022/23	2023/24	2024/25
SAIDI target	35.42	35.42	35.42	35.42	35.42	35.42	35.42	35.42	35.42	35.42
SAIFI target	0.547	0.547	0.547	0.547	0.547	0.547	0.547	0.547	0.547	0.547
Faults/100km target	12.6	12.8	12.9	13.1	13.2	13.3	13.5	13.6	13.8	13.9

Figure 7-2 Network Reliability Performance Targets

While there is potential to further refine these targets to reflect the consumer segments on the network (for example Wellington CBD requires a higher level of security than rural consumers), at this stage this segmentation has not been done. However with the consumer engagement initiatives currently being implemented the potential for further segmentation will be considered.

7.4 Contact Centre Service Levels

Wellington Electricity has developed a set of key performance indicators and financial incentives that provide service level benchmarks for the Contact Centre (Telnet). These service levels have been in place since 2013. Due to the high level of consumer satisfaction with Contact Centre performance (90% to 94%) it is expected the targets and performance measures will remain broadly the same for the planning period from 2015 to 2025. As consumer engagement initiatives progress and contractual arrangements with the Contact Centre provider are renewed, it is likely that future improvements will be made.

7.4.1 Contact Centre Service Levels

There are five service level performance measures for the Contact Centre. These are:

1. Overall Service Level (A1) - This is the measure of calls answered within 20 seconds. The current target is 80% of calls answered within 20 seconds, which is an international standard for utility call centres.

2. Call response (A2) - This is a measure of the average call response waiting time. The target is 20 seconds average wait. This target is an international standard for utility call centres and is continually being updated within the call centre industry by customer survey results.

3. Missed calls (A3) - This is a measure of abandoned calls, where the caller hangs up prior to the call being answered. The target is 4% of calls, or fewer. This target is also an international standard for utility call centres, which recognises that calls may be abandoned for a variety of reasons, including some not related to call centre performance. However an abandonment rate above 4% may be indicative of an issue with the call centre service.

4. Customer satisfaction (C1) - All customer contact should contribute to customer satisfaction in dealings with the service provider when representing Wellington Electricity. Measurement is by way reviewing a random sample of calls with the sample selected by Wellington Electricity.

5. Retailer satisfaction (D1) - All energy retailer contact should contribute to energy retailer satisfaction in dealings with the service provider when representing Wellington Electricity. Measurement is by way of an annual survey.

Figure 7-3 sets out the results for the numeric A1 to A3 measures for the 2014 year.

SL	Service Element	Measure	KPI	2014 Actual
A1	Overall service level	Average service level across all categories	80%	89.6%
A2	Call response	Average wait time across all categories	20 seconds	13 seconds
A3	Missed calls	Total missed/abandoned calls across all categories	4%	2.1%

Figure 7-3 Contact Centre Service Level Performance

Customer satisfaction performance (C1) is shown in Figure 7-4. C1 is measured by reviewing a sample of 10 calls for the quality of interaction with callers. The target is to reach a minimum of 80% based on contact elements that are particularly important to Wellington Electricity. The contact elements primarily relate to the efficient management of fault and emergency calls, effective interaction with energy retailers and representing Wellington Electricity in a responsive and professional manner with the public.

SL	Service Element	Measure	KPI	2014 Actual
C1	Specific Contact Centre experience	Wellington Electricity is properly represented during specific calls	Qualitative assessment 80%	90.9%

Figure 7-4 Customer Satisfaction Service Level Performance

7.4.2 Customer Enquiries and Complaints

Enquiries and complaints are channelled to Wellington Electricity via a number of avenues including retailers, service contractors, contact centres and direct approaches by stakeholders. When an enquiry or complaint is received, it is entered into a central registry. The target response time for enquiries is eight working days and for complaints is 10 working days. Failure to meet these targets results in automatic notification followed by internal escalation.

Wellington Electricity is a member of the Electricity and Gas Complaints Commission (EGCC) and follows its process for dispute resolution. The recent changes under the Consumer Guarantees Act 1993 for goods and services performance related to distribution network outages is expected to increase the number of enquiries and complaints received by all EDBs.

7.5 Asset Management Performance Targets

Other performance targets used by Wellington Electricity relate to the efficiency with which the company manages its fixed distribution assets. The indicators for these performance targets have been selected on the basis that Wellington Electricity considers them particularly relevant to the operation and management of its assets. Some of these indicators are also required for reporting to the Commission under its Information Disclosure regime.

7.5.1 Power Restoration Service Level Targets

Wellington Electricity's published 'Electricity Network Pricing Schedule' provides standard service levels for the restoration of power to three different categories of consumers: CBD/Industrial, Urban and Rural. These service levels reflect previous feedback from our consumers and are agreed between Wellington Electricity and all retailers. They provide Wellington Electricity with financial incentives to not exceed the maximum restoration times detailed in Figure 7-5, provided that safety is not compromised. These targets apply annually for the period 2015-2025.

	CBD / Industrial	Urban	Rural
Maximum time to restore power	3 hours	3 hours	6 hours

Figure 7-5 Standard Power Restoration Service Level Targets 2015-2025

The geographical region by customer category is shown in Figure 7-6.

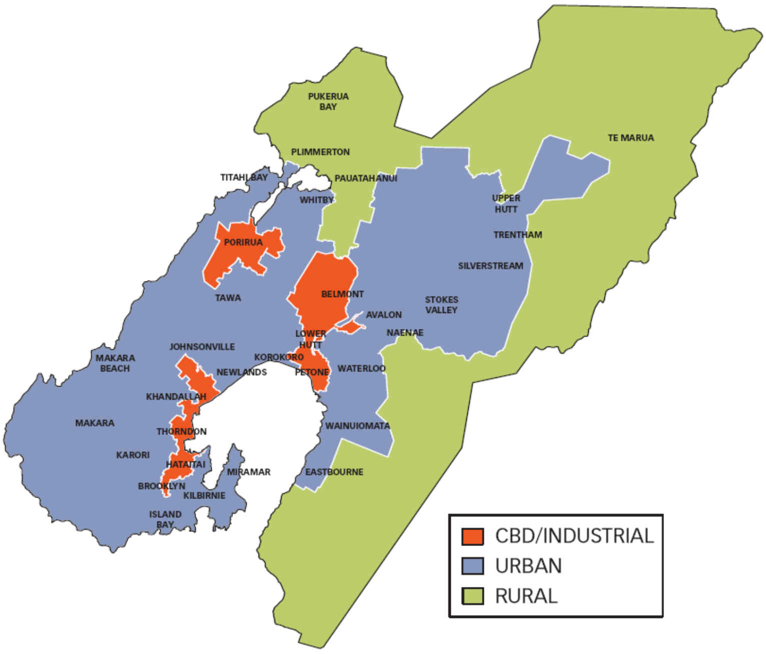


Figure 7-6 Location of Customer Category Areas

7.5.2 Asset Utilisation

The load factor or utilisation of an asset reflects consumer demand profiles, the geography of the region and historic network design and configuration decisions. Wellington Electricity's predominantly urban network results in a higher than average utilisation and load density. Wellington Electricity aims to maintain this high level of utilisation at current levels, in line with other networks that display similar characteristics. Where assets are being replaced, consideration is given to reducing losses through selection of more efficient equipment, in particular transformers. Figure 7-7 provides an overview of the efficiency of the assets utilised by Wellington Electricity compared with the industry average.

	Load factor %	Distribution transformer capacity utilisation %	Loss ratio %	Demand density kW/km	Volume density MWh/km	Connection point density ICP/km	Energy density kWh/ICP
Industry average[23]	61.4	31	5.74	39.8	193	13	16,258
Performance	52.0	41.0	4.8	120.0	520	36	14,609
Targets 2015-2025	>50%	>40%	<5%	-	-	-	-

Figure 7-7 Asset Efficiency and Utilisation

7.6 Network Performance by Reliability

Wellington Electricity's reliability performance has been, and continues to be, one of the best in New Zealand. However, as described previously, over the last two years there have been a number of significant natural events that have impacted the level of network reliability. For the regulatory periods 2012 through 2014, Wellington Electricity has not met both the SAIDI and SAIFI reliability limits and was therefore non-compliant with the DPP quality standards during this period.

Significantly, the reliability limits were calculated by reference to the historical reliability performance from 2005 to 2009, a period that was markedly benign weather compared with more recent weather conditions. The 2013/14 regulatory year featured particularly severe weather with the number of days with wind gusts exceeding 100km/h shown in Figure 7-8.

Maximum Wind Speed	>100 <120 km/h	>120 <130 km/h	>130 <140 km/h	>140 <160 km/h	>160 km/h	Total Days
2012/13	29	12	3	1	0	**45**
2013/14	26	11	4	5	3	**49**
2014/15[24]	30	10	6	7	0	**53**

Figure 7-8 Number of Days of Maximum Wind Speed

Figure 7-9, Figure 7-10 and Figure 7-11 show the actual performance of the network against the reliability targets set by the Commission.

[23] Values as of 2013, Source: PWC Compendium

[24] Regulatory Year 2014/15 up to 28th February 2015

Regulatory Year	2010/11	2011/12	2012/13	2013/14	2014/15[25]
SAIDI target	33.90	33.90	33.90	33.90	31.075
SAIDI limit	40.74	40.74	40.74	40.74	37.345
SAIDI actual	34.74	45.88	43.29	78.88	35.683
Significant Events	0.0	11.51	7.84	36.33	0.0
SAIFI target	0.52	0.52	0.52	0.52	0.476
SAIFI limit	0.60	0.60	0.60	0.60	0.55
SAIFI actual	0.537	0.715	0.573	1.107	0.56

Figure 7-9 Wellington Electricity Reliability Performance

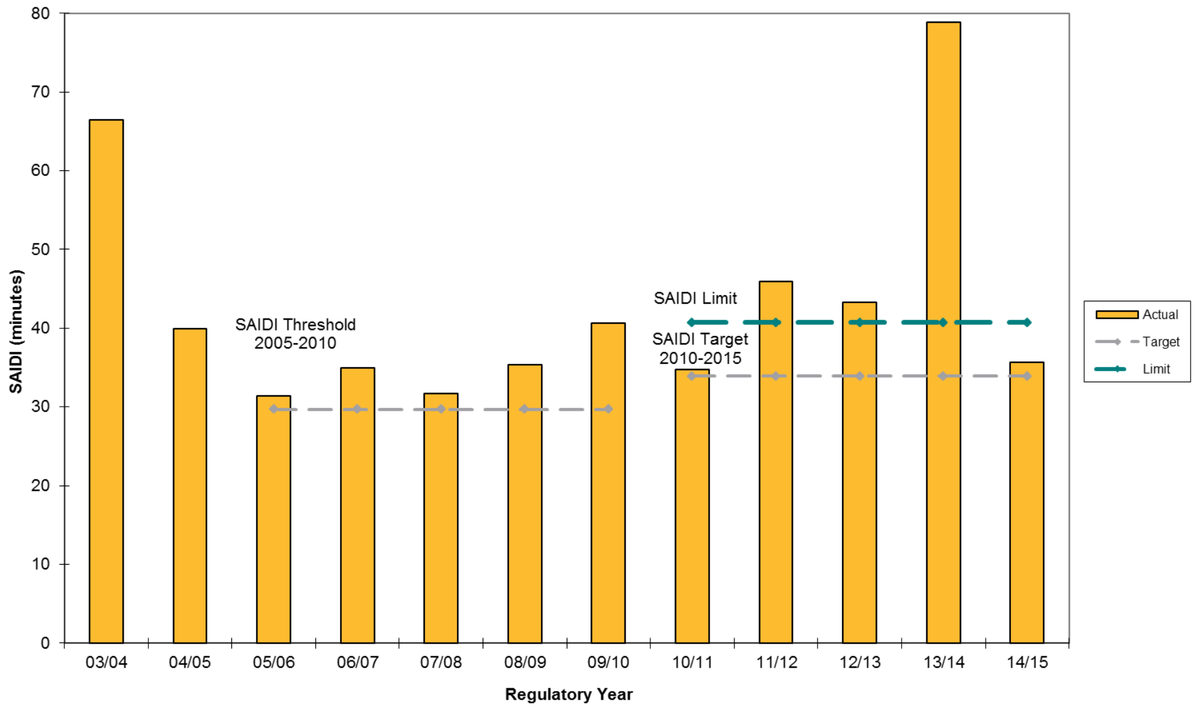


Figure 7-10 Historic SAIDI of the Wellington Electricity Network[26]

[25] Regulatory Year 2014/15 up to 28th February 2015

[26] The 2014/15 year is up to 28 Feb 2015

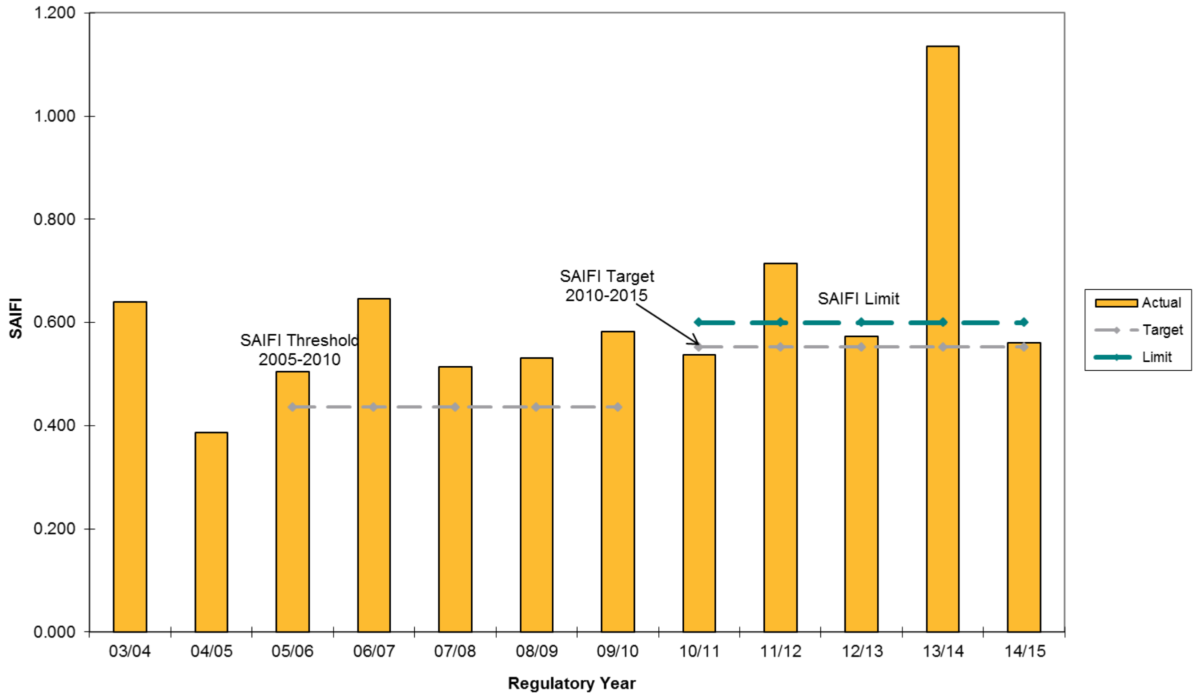


Figure 7-11 Historic SAIFI of the Wellington Electricity Network[27]

7.6.1 Industry Comparison

Wellington Electricity was one of the top five most reliable EDBs in New Zealand in 2013/14. The data presented in Figure 7-12 and Figure 7-13 is sourced from the annual Information Disclosures made by EDBs and made publically available in August 2014.

Wellington Electricity has undertaken a benchmarking analysis of system reliability performance indicators within a peer group of comparable EDBs in New Zealand. The following criteria are applied to establish a comparison using the data from EDB's 2013/2014 Information Disclosures:

- Connection points of over the national average of 64,875 customers;
- Connection point density of over the national average of 13 ICP/km; and
- Percentage circuit length underground of over the national average of 25.4 %.

The benchmarking analysis shows that Wellington Electricity's system reliability indices (i.e. SAIDI, SAIFI) are performing well against comparable networks in New Zealand.

[27] The 2014/15 year is up to 28 Feb 2015

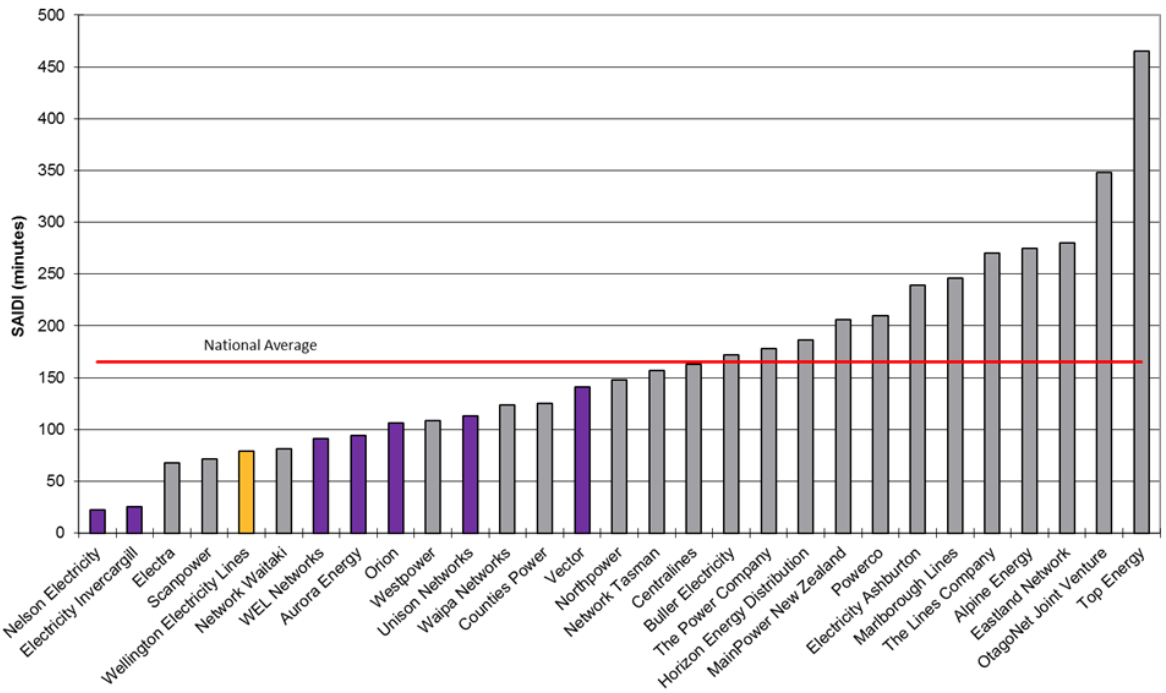


Figure 7-12 National SAIDI by EDB for 2013/14

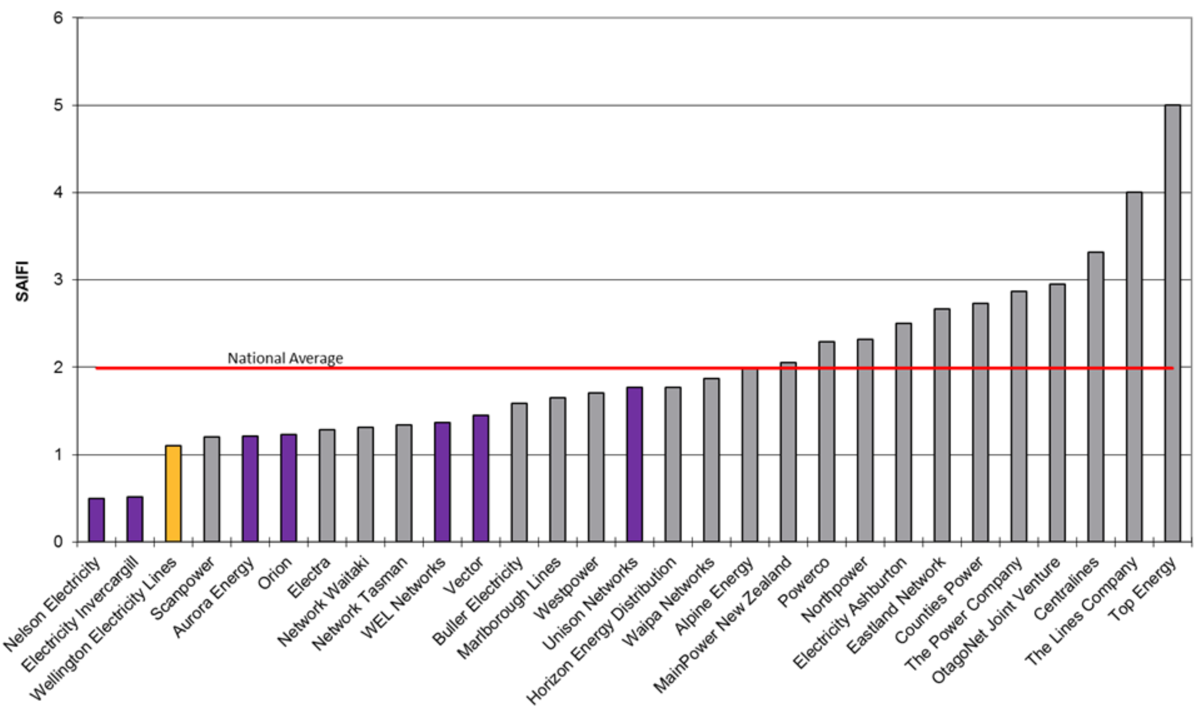


Figure 7-13 National SAIFI by EDB for 2013/14

7.6.2 Faults per 100 Circuit-km

Another indicator of reliability performance is the number of faults per 100km of circuits operated by Wellington Electricity. For the purpose of this performance indicator, a fault is considered an unplanned failure of an in-service line or cable asset on the subtransmission or high voltage distribution systems, irrespective of whether or not it causes a loss of supply to customers. Circuit-km relates to the total circuit length of the subtransmission and high voltage distribution systems, irrespective of whether the circuit is overhead or underground. This indicator is a measure of how well the system is designed and operated from a technical perspective.

Figure 7-14 sets out the faults per 100 circuit-km performance for the six regulatory years. The current target has been set based on the current performance with consideration for performance over the period since Wellington Electricity purchased of the network. Whilst the historic trend indicates an increase in faults per 100 circuit-km over time, this is largely due to an increasing number of major events. This is evident in the significant increase in faults per 100 circuit-km in 2013/14 because of the two major storms that hit Wellington in June and October 2013. The reason for the 2011/12 year being slightly elevated is the snow storm that impacted the Wellington area that year.

Regulatory Year	2009/10	2010/11	2011/12	2012/13	2013/14	2014/15
Target	11.7	11.9	12.0	12.2	12.3	12.5
Actual	12.6	11.9	13.3	12.3	21.8	11.1

Figure 7-14 Performance for Faults per 100 circuit-km[28]

7.6.3 Reliability Performance in 2013/14

While the underlying performance of the network remained solid, a number of major natural events impacted the Wellington Region dominating the performance in the 2013/14 year. The SAIDI and SAIFI for the year are shown in the Figure 7-15.

Reliability Metric	Limit 2013/14	Actual for 2013/14	Variance
SAIDI	40.74	78.876	+38.132
SAIFI	0.60	1.107	+0.505

Figure 7-15 Wellington Electricity Reliability 2013/14

There were four major events that impacted the Wellington Region during 2013:

1. Storm, June 20-22;
2. Earthquake, July;
3. Earthquake, August; and
4. Storm, October 14.

The SAIDI and SAIFI impact of these events is summarised in Figure 7-16.

[28] The 2014/15 year is up to 28 Feb 2015

Event	SAIDI recorded (mins)	Normalised SAIDI (mins)	SAIFI Recorded	Normalised SAIFI
Storm, June 20-22	136.029	24.638	0.359	0.359
Earthquake, July	1.604	1.604	0.045	0.045
Earthquake, August	1.031	1.031	0.036	0.036
Storm, October 14	9.058	9.058	0.080	0.080

Figure 7-16 SAIDI and SAIFI of major events in 2013/14

Each high impact event, along with its reliability implication is described further below.

7.6.3.1 Storm, June 20 - 22

The details of this storm were described in Section 5.5.1. The maximum wind speeds and the number of consumers without power during the three days are shown in Figure 7-17. At the peak of the storm 22,000 consumers were without electricity supply, while over the course of the storm around 60,000 consumers were impacted by supply interruptions.

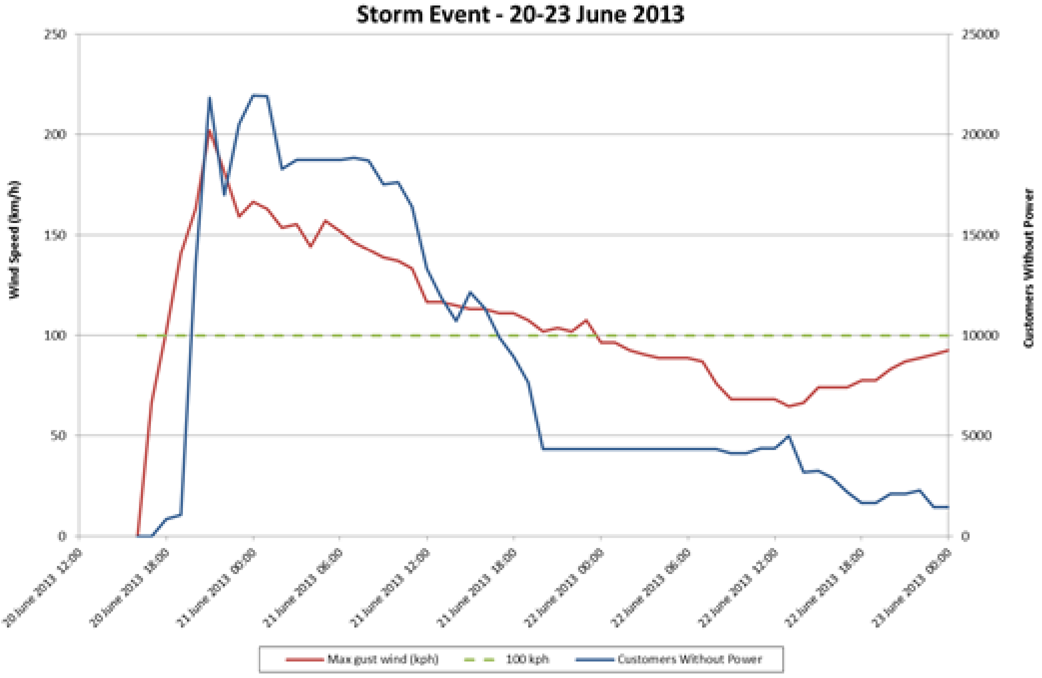


Figure 7-17 Wind Gusts and Outage Extent - Storm, June 20-22

Conditions on the evening of 20 June were so dangerous that Wellington Electricity had to stand down crews due to safety requirements, forcing restoration and repairs to be suspended until the morning of 21 June. Aerial patrols by helicopter could not commence until the third day (22 June), when wind speeds dropped to safe operating levels for power line reconnaissance.

The bulk of the restoration was carried out on 22 June and the days following. To expedite the restoration of supply, Wellington Electricity tripled its normal field crew workforce by bringing in 150 additional staff from around the country. This enabled Wellington Electricity to restore power as quickly as possible without compromising the safety of the crews or the general public.

The total contribution to Wellington Electricity's reliability performance due to the storm is shown in Figure 7-18.

Date	SAIDI	Normalised SAIDI	SAIFI	Normalised SAIFI	No. of HV outages
20-Jun-13	104.702	9.724	0.197	0.197	100
21-Jun-13	26.137	9.724	0.125	0.125	30
22-Jun-13	2.930	2.930	0.013	0.013	12
23-Jun-13 to 5-Jul-13	2.260	2.260	0.024	0.024	30
Total	**136.029**	**24.638**	**0.359**	**0.359**	**172**
MED boundary value	9.724		0.237		

Figure 7-18 Reliability Impact of Storm, June 20-22

The following two graphs (Figures 7-19 and 7-20) show the impact this storm had on SAIDI and SAIFI.

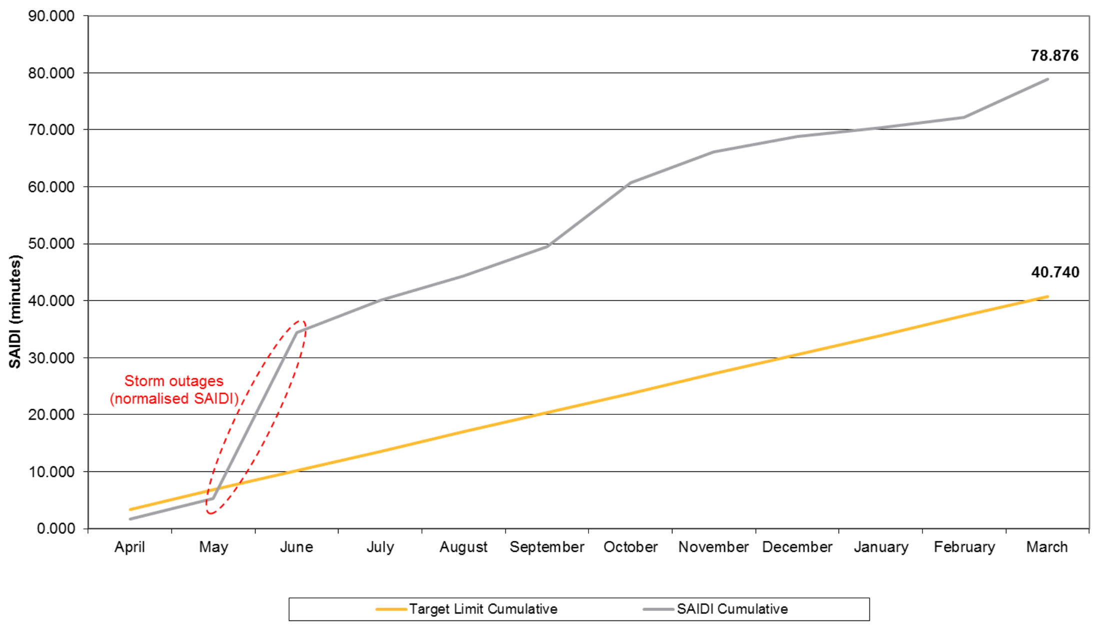


Figure 7-19 Wellington Electricity SAIDI Performance 2013/14 showing June storm

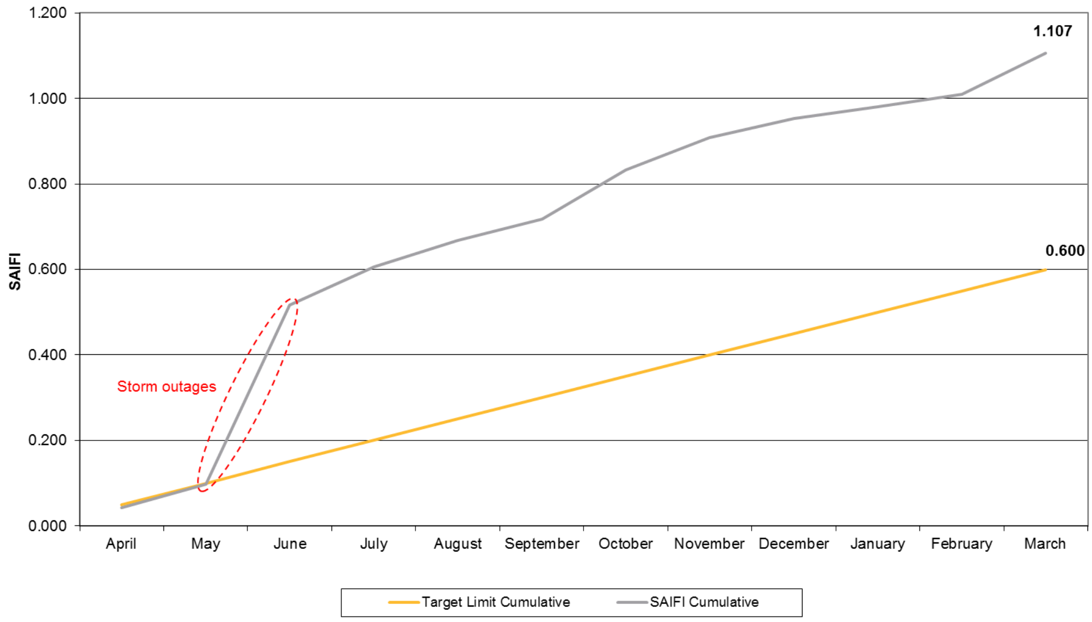


Figure 7-20 Wellington Electricity SAIFI Performance 2013/14 showing June storm

Overall, the single storm contributed 24.638 SAIDI minutes (normalised) and SAIFI of 0.359 with only two out of the three days between 20 June and 22 June able to be categorised as “Major Event Days” (MED). There were thirty 11kV outages still to be repaired after 22 June. These were mostly spur lines in rural areas. Restoration times for these and other non-storm related interruptions in the week following the storm were impacted by various factors. These included:

- Consumers’ misunderstanding of their asset boundaries and their requests for assistance with what were in fact privately owned installations;
- Crews assisting with trees and other problems on consumer premises;
- Provision of goodwill dealing with community impacts, which together with the above two points, used up time that would have been spent on the restoration of damaged network assets;
- Arranging and maintaining adequate resourcing levels, and
    - The need to allow for stand down periods following a period of intense activity in order to manage Health and Safety standards and meet fatigue management protocols.

7.6.3.2 Earthquakes, July and August

The magnitude and impact of these earthquakes were described in Section 5.5.1. The quakes caused mechanical relays at a key zone substation to operate, cutting supply to approximately 7,000 consumers contributing a total SAIDI for both events of 2.635 minutes and a SAIFI of 0.081.

7.6.3.3 Storm, October 14, 2013

Another major storm hit the Wellington Region at 3 am on 14 October 2013 when wind speeds exceeded 100kph. Wind speeds remained above 100kph for approximately 22 hours and peaked at 167kph at 6pm. The sustained high winds resulted in 124 low voltage outages, 24 11kV outages, and two 33kV outages affecting 18,552 consumers. Figure 7-21 plots the wind speeds and number of consumers without power during the storm period.

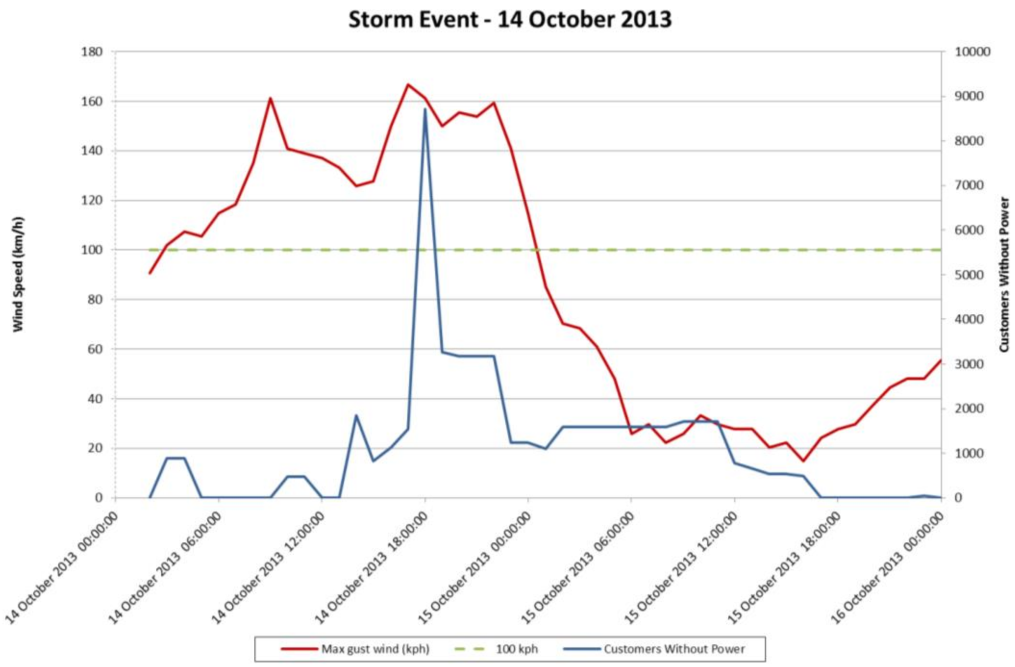


Figure 7-21 Wind Gusts and Outage Extent - Storm, October 14

The total SAIDI and SAIFI recorded from the October storm was 9.058 minutes and 0.080, respectively. The impact of the storm on Wellington Electricity's SAIDI network performance for 2013/14 regulatory year is shown in Figure 7-22.

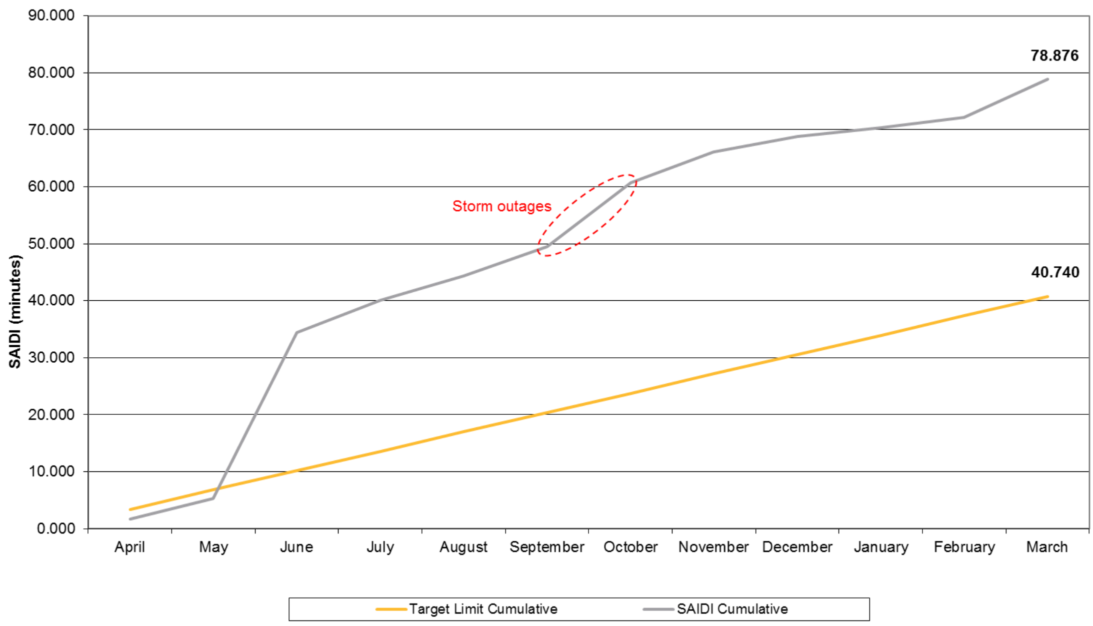
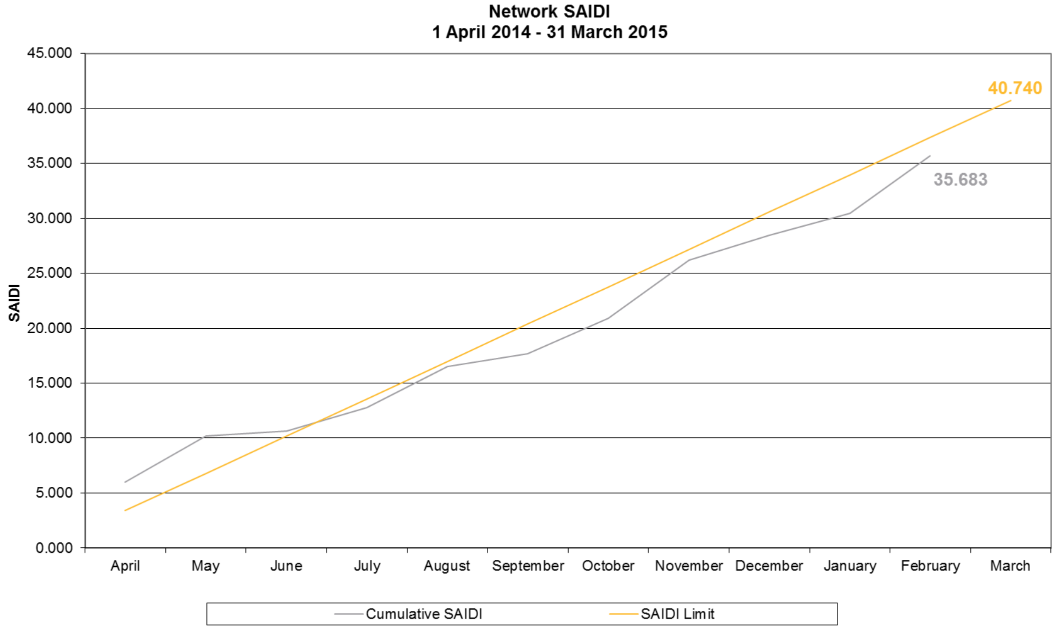


Figure 7-22 Wellington Electricity SAIDI Performance 2013/14 showing October storm

7.6.4 Network Reliability Performance - 2014/15 Regulatory Year to 28 February 2015

The Wellington Electricity network performance from 01 April 2014 to 28 February 2015 with SAIDI and SAIFI numbers of 35.683 and 0.560 respectively are just below and just above the year-to-date limits. Both the values for SAIDI and SAIFI are still under their yearly limits of 40.74 and 0.600 respectively and are forecasted to remain this way at the end of the regulatory year. No storms comparable to the 2013 events have occurred yet in the 2014/15 period and improvements in NCR operations and field services response have helped keep the actual reliability performance close to the set limits. The underlying performance of assets continues to be within expected levels. The 2014/15 performance to date is illustrated in Figure 7-23.



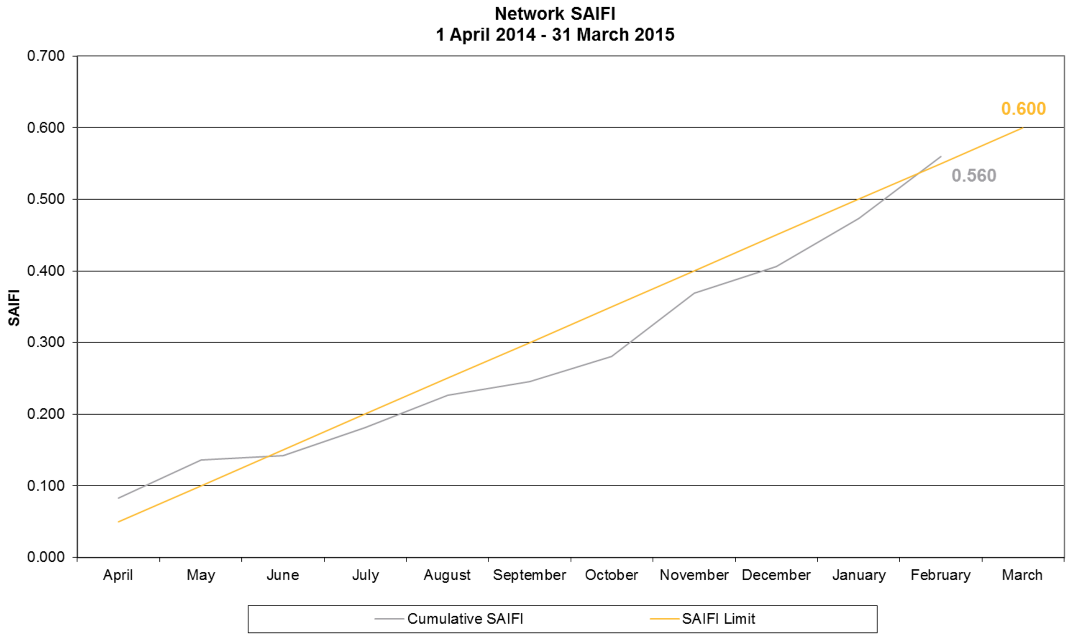


Figure 7-23 Actual SAIDI and SAIFI for 2014/15 (up to 28 Feb 2015)

7.7 Network Performance by Category

7.7.1 Performance by Fault Cause

The network SAIDI performance by fault type, excluding major event days, from 2011/12 to 2013/14 is shown in Figure 7-24. Fault causes are discussed in more detailed below.

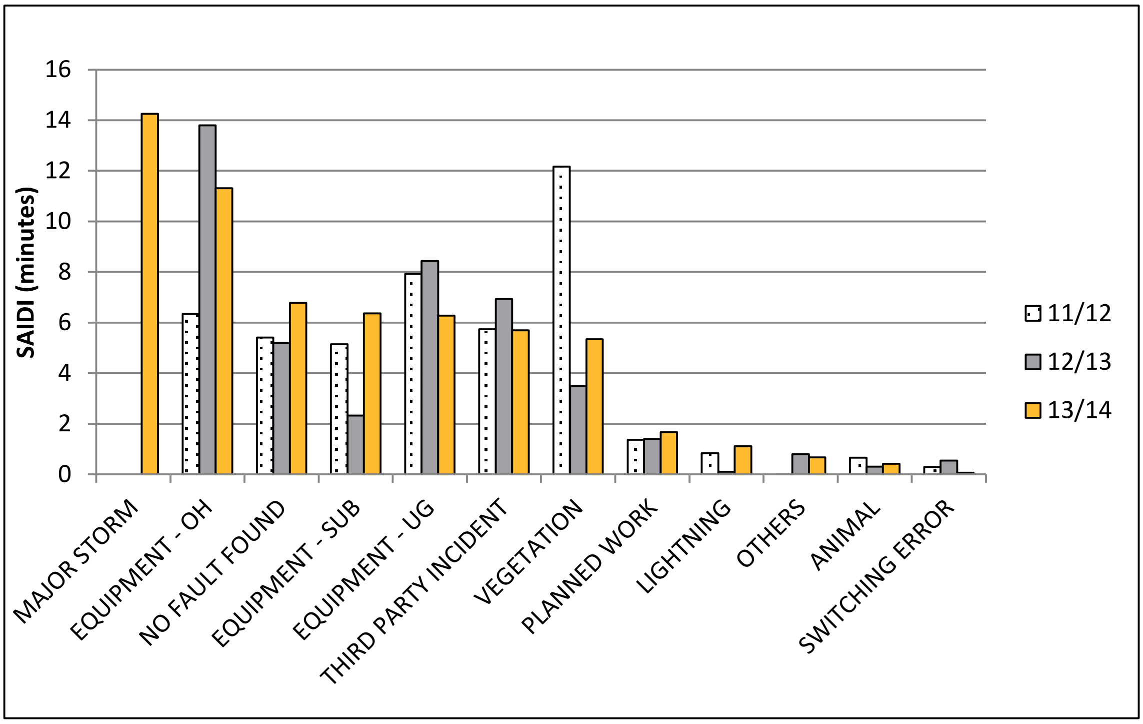


Figure 7-24 SAIDI Performance by Fault Type, 2011 - 2014

7.7.1.1 Overhead Equipment

Overhead equipment outages generally occur during periods of strong winds or stormy weather when components are subject to external debris or loadings beyond design limits. The conductor failure category generally relates to the failure of related components and is rarely a direct failure of the conductor. Faulty insulators are another cause of overhead equipment faults, typically being caused by the failure of pin type insulators in rural areas exposed to high winds.

The relative SAIDI impact of different overhead equipment failure fault causes is shown in Figure 7-25. The number beside the fault causes represents the count of each fault cause.

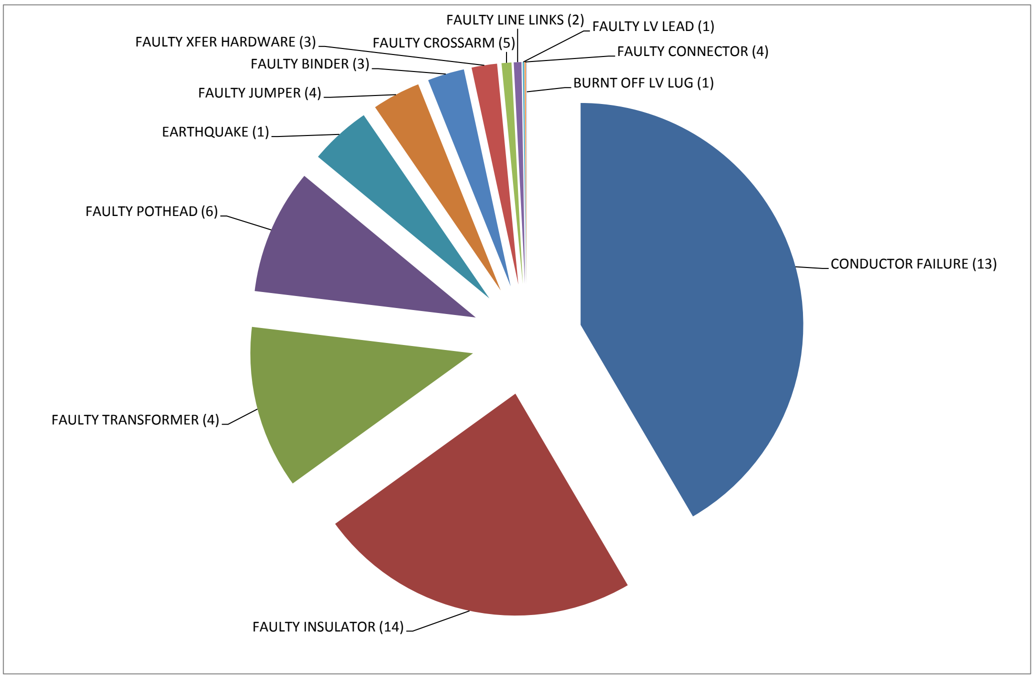


Figure 7-25 SAIDI Impact of the Overhead Equipment Failure (2013/14 Regulatory Year)

7.7.1.2 Substation Equipment

The increase in SAIDI related to substation equipment failure was due to a one off event where nearby changes to land contouring resulted in heavy rain flooding a protection pilot cabinet due to surface water runoff. This led to a communications failure that subsequently tripped a 33kV circuit which occurred while the parallel 33kV circuit was out of service for maintenance. The total SAIDI for this event was 4.123 minutes. This failure has been addressed by a corrective repair and will be addressed entirely with the upgrade of the subtransmission protection in 2015/16.

7.7.1.3 Underground Equipment

Failures in underground equipment are generally due to cable and cable joint failures. Cable systems themselves generally have a long life and high reliability as they are subject to fewer environmental and external impacts.

The performance of Wellington Electricity's underground equipment improved considerably from 2012/13 to the 2013/14 as shown in Figure 7-26. Factors contributing to this improvement include:

- Additional partial discharge tests to identify potential cable insulation issues;
- Replacement of cables which have repeat reliability concerns; and
- Remediation and replacement of faulty cable potheads (terminations).

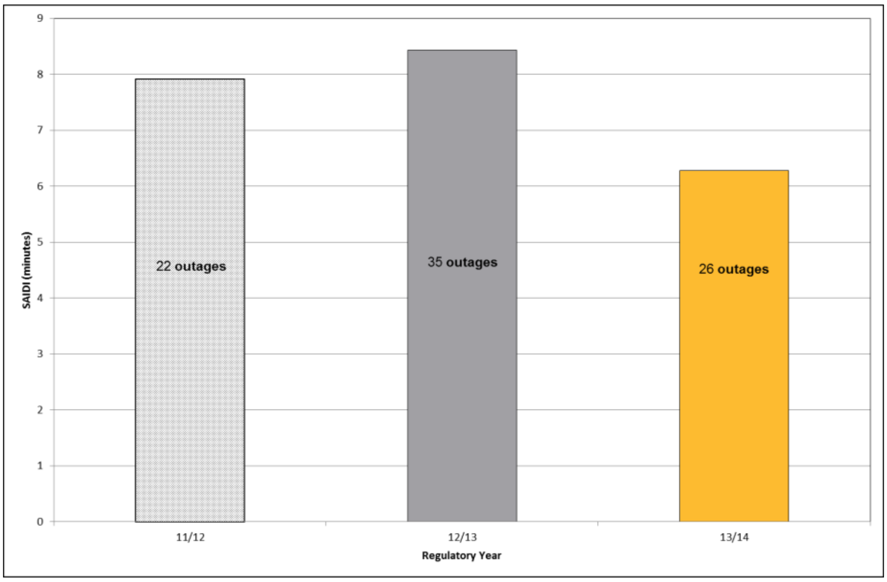


Figure 7-26 SAIDI Impact of Cable Faults, 2011 - 2014

7.7.1.4 Third Party Incidents

Third party incidents contributed 7% or 5.69 minutes of the total SAIDI incurred in 2013/14. These were down by 9% from the previous year. The primary contributors to third party incidents were vehicle collisions (78%), tree cutters (8.5%), and contractors hitting the 11kV conductors (6.5%) and underground cables (7.0%).

In contrast, the number of third party strikes in 2012/13 as a result of the UFB rollout has reduced significantly. Similarly, third party incidents due to landowners felling trees have decreased. The number of third party incidents by cause for the past three years is shown in Figure 7-27.

	2011/12		2012/13		2013/14	
Fault Cause	No. of Incidents	SAIDI	No. of Incidents	SAIDI	No. of Incidents	SAIDI
Vehicle	11	2.91	15	2.09	14	4.44
Tree Contact	5	0.67	6	2.31	3	0.48
Dig In	7	1.96	11	1.96	2	0.40
Overhead Contact	1	0.02	3	0.57	2	0.37
Total	**24**	**5.56**	**35**	**6.93**	**21**	**5.69**

Figure 7-27 Summary of Third Party Incidents

In comparison with 2012/13, the number of outages for most fault causes has decreased, however, the SAIDI impact of vehicle collisions has increased significantly when restoration time is delayed by management of the accident scene.

Figures 7-28 and 7-29 provide visual representations of the number of incidents and SAIDI impact.

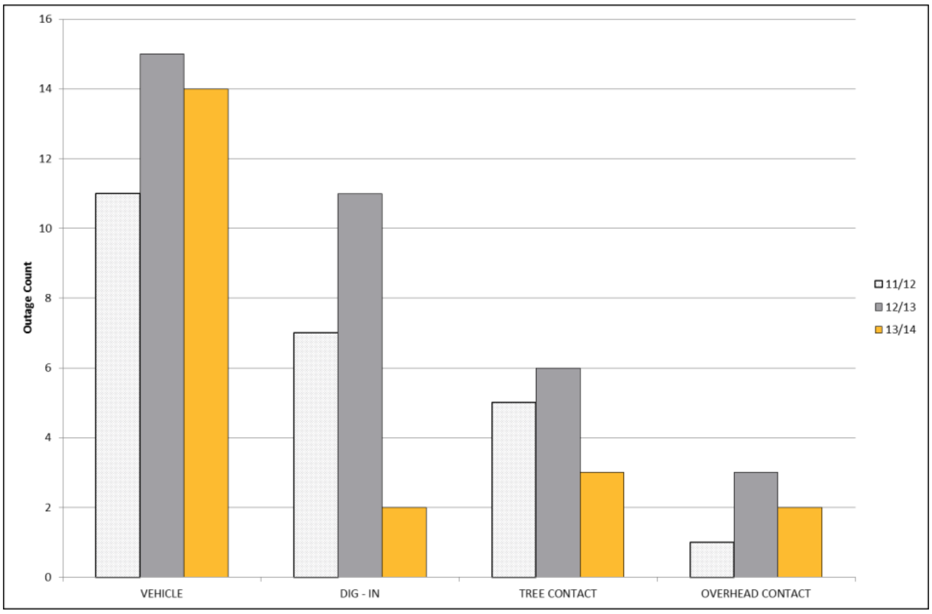


Figure 7-28 Outage Count of Third Party Incident by Fault Cause

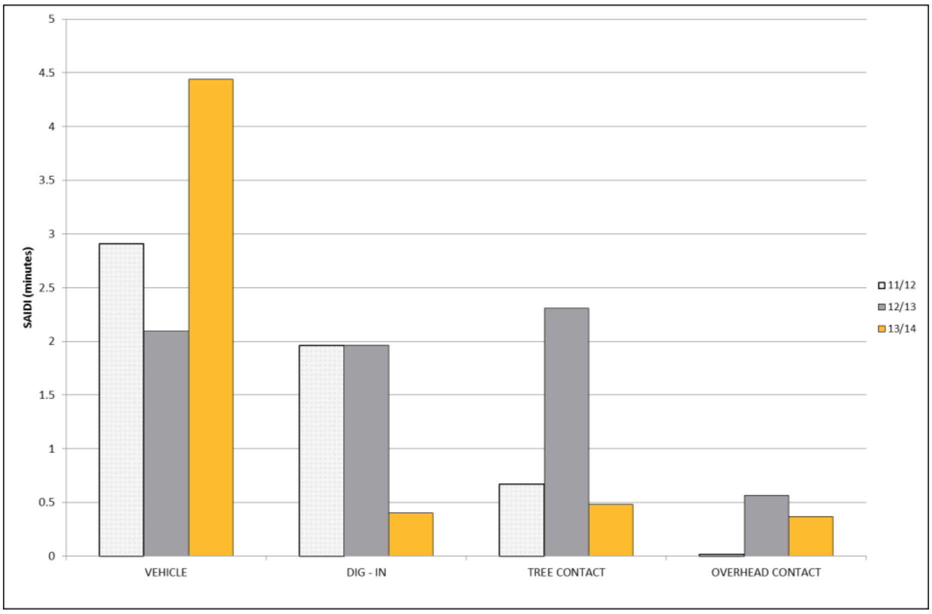


Figure 7-29 SAIDI Impact of Third Party Incident by Fault Cause

While the number and extent of vehicle collisions is generally outside of Wellington Electricity's control, the company has undertaken a number of extensive safety campaigns targeting third party contractors working around the Wellington Electricity network assets to reduce the other fault causes. By way of example Wellington Electricity has:

- Targeted those involved with the UFB roll out;
- Introduced a Key Performance Indicator into its vegetation management contract with Treescape, specifically aimed at maximising the second cut/trim works carried out by Treescape;
- Increased the visibility of poles in identified higher risk areas. Existing poles near intersections have reflectors and white paint at the bottom of the pole, and all new poles installed beside roads are fitted with reflectors;

- Continued the 'Before U Dig' programme which provides free plans and cable mark-outs to third parties during the planning process and prior to field excavation. Consideration is currently being given to extending this programme to include the overhead system assets; and

    - Followed a strategy of positioning new assets away from high traffic areas.

7.7.1.5 Vegetation

Vegetation related outages are generally due to landowners not trimming their trees. Encouragingly, the average SAIDI per vegetation event is trending downwards. The average SAIDI per tree fault for the period 2010/11 to 2013/14 is shown in Figure 7-30.

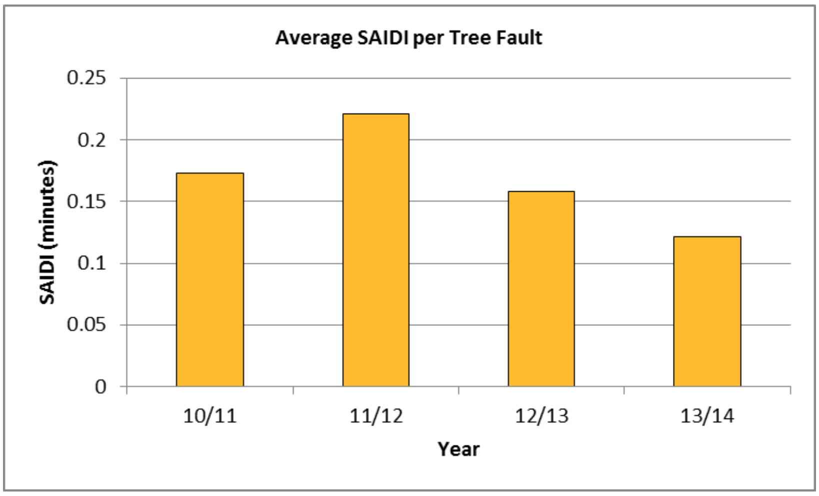


Figure 7-30 Average SAIDI per Tree Fault, 2011 - 2014

To manage the potential for faults Wellington Electricity proactively works with tree owners and provides information on how they can manage their trees for public safety and electricity network reliability. However, there are still significant issues in managing vegetation faults as the current regulations do not permit Wellington Electricity to manage vegetation that poses a risk to the network outside of the Notice Zone.

Contractor performing vegetation management

Vegetation management can take additional time, and incur costs difficult to recover, when disputes occur with tree owners not meeting their legal obligations regarding the “second cut”. Circumstances like this may need to be resolved through the District Court.

Wellington Electricity has considered the use of covered conductors, but concluded these offer little protection against falling trees and significant air-borne debris which often causes catastrophic damage to lines and poles. In order to reduce the impact of vegetation outages in areas with heavy vegetation, the installation of auto-reclosers, line fuses and sectionalisers are considered.

Effective vegetation management around overhead networks is viewed as the more efficient means of controlling vegetation-related outages when compared with alternative asset-intensive network options such as undergrounding circuits.

As such Wellington Electricity will continue to consult with TLAs regarding the current regulations and the reasons for changes to these. In order to further inform such discussion, Wellington Electricity has identified and implemented improvements in the way vegetation-related outages are recorded, and is now recording instances where trees causing outages originate from within the growth limit zone, notice zone, fall zone, or from blown debris.

7.7.1.6 Lightning, Animal and ‘Other’ Fault Causes

Outages due to lightning strikes on 11kV assets mostly occurred on overhead transformers and most commonly in the month of September.

Outages due to animals are typically attributed to birds and possums making contact with the 11kV overhead lines. To reduce the risk of possums contacting live power lines, Wellington Electricity uses possum guards, which are a metallic sheet approximately 600mm wide, wrapped around the mid-section of the pole.

Outages categorised as ‘Others’ are related to outages that have occurred on the feeder or a section of the feeder that was initially restored and had to be interrupted again for the repair.

7.7.1.7 No Fault Found

Faults can occur for which no cause of or reason is able to be determined. Many of these are attributable to transient causes, particularly during storms or high winds. Lines can clash during high wind gusts, and/or debris including tree branches can be blown onto the lines before falling off.

During and after a “No fault found” event, the affected feeders are patrolled and post-fault evaluations done to identify probable causes such as vegetation which may have contributed to the outage. While the number of “No fault found” events is expected to decline over time due to design changes, there will always be instances where the cause of the interruption cannot be identified by field crews at the time.

7.7.2 Worst Performing Feeders

Identification of Wellington Electricity’s worst performing feeders is utilised to target intervention investments and is based on three factors:

- SAIDI – if the feeder has as an annual SAIDI greater than or equal to 0.50 minutes;

- SAIFI – if the feeder has an annual SAIFI greater than or equal to 0.005; and
- Number of interruptions – if the feeder has at least two interruptions in a year.

The ten feeders with the highest SAIDI in any particular year typically contribute approximately 40-50% of annual SAIDI. The particular feeders that make up this group varies significantly from year to year, with only one feeder, Brown Owl 3, being present in the top ten for all of the last three regulatory years.

The 10 worst performing feeders during 2013/14 ranked by a combination of SAIDI and SAIFI are presented in Figure 7-31.

Feeder	13/14 SAIDI	13/14 SAIFI	2013/14 Rank	2012/13 Rank
Johnsonville 10	4.33	0.019	1	3
Porirua 9	2.33	0.036	2	99=
Naenae 2	1.66	0.029	3	80
Waitangirua 5	1.82	0.024	4	5
Korokoro 9	1.90	0.021	5	99=
Brown Owl 3	2.14	0.017	6	6
Mana 6	1.86	0.019	7	43
Melling 4	1.48	0.017	8	33
Wainuiomata 13	1.07	0.023	9	93
Tawa 11	2.03	0.005	10	56

Figure 7-31 Worst Performing Feeders for 2013/14

Historic faults on these feeders have been reviewed to determine whether there is a common root cause that needs to be addressed. Remedial actions identified by this review are fed back into the asset management process where the resulting activities are carried out, either under corrective maintenance or as a network project, depending on the scope of the work required.

7.7.3 Reliability Initiatives

As part of Wellington Electricity's Continuous Improvement Process, a key focus for the 2014/15 year was on operational performance improvement. Key components of this process are shown in Figure 7-32.

Reliability Initiative	Details
Incident reporting on all events greater than 0.4 SAIDI minutes	Involves analysis and identification of root cause of outages and recommendations to prevent recurrence. Outage reports are discussed by Network and Operations Managers at weekly incident review meetings to ensure all issues are being addressed.
Post-event operations analysis	Study of field response and repair times for major faults to identify causes of prolonged outages and develop strategies to improve restoration times. Examples include: making additional faultmen available, installation of more fault indicators, and increased ability to sectionalise the network or undertake switching remotely.
Reporting of asset failures on specific asset types (or modes of failure) through the Asset Failure Investigation Process	Reporting from field to network engineers to identify, investigate and monitor recurring trends helps determine whether maintenance practices need to be improved or what assets need to be upgraded.

Figure 7-32 Reliability Initiatives for 2014/15

8 Peak Demand Forecast

Since 2009 the aggregate volume of energy used by consumers connected to Wellington Electricity's network has been declining. This has been driven by a number of factors including the relocation of industries, a greater focus on energy efficiency, some consumers converting their heating and cooking loads to gas, warmer winter weather, and static ICP numbers. Given the underlying economic characteristics and seasonal variances of the region, these trends are expected to continue. Energy consumption determines revenue, and the impact of a decline in this, together with the 2014 DPP determination has been described at the beginning of this document.

This section focuses on peak demand since this is what causes the majority of system constraints and drives the need for investment in the network or some alternative means of providing or managing the capacity. The areas where the need for additional network is particularly relevant are in the Wellington CBD, with new building developments proposed for the water front and for the subdivision expansions in Whitby and Grenada North. These network development needs, the options identified and the proposed expenditure requirements are described in Section 9.

Despite the overall decline in energy use, the peak demand has remained reasonably constant actually grown in some localised areas. This trend in the peak demand level of the network is also expected to continue reflecting a decoupling between the overall volume of energy consumed and the peak demand on the network.

There is a strong correlation between peak demand and climatic conditions. Demand peaks within the Wellington Region are driven by average winter temperatures. A warmer winter will result in lower peak demand while a colder winter will result in higher peak demand.

8.1 Forecasting Assumptions and Inputs

The peak demand forecast for the current planning period is based on a number of assumptions. In summary these are:

- Load control is available and will be used to manage network peaks;
- The sustained peak demand at any substation is calculated as 'loading that lasts for two hours and occurs at least five times during the year'. This differs from the maximum substation load which is measured over a 30 minute period and can occur as a result of abnormal system operations;
- The peak demand forecast does not factor in any significant demand changes due to a major weather event or unforeseen network condition causing significant outages or abnormal operation of the network;
- Temperature volatility is based on historical temperature data recorded at three NIWA measurement sites based within the three areas of the Wellington network, the Southern, Northwest and Northeast coverage areas;
- Peak demand scenarios are based on a linear extrapolation of recorded historical long term and short term trends accounting for network augmentation, step change loads and load transfers. The scenarios applied to determine the demand forecasts are non-linear to allow for the continuation of any short term trends while also accounting for the longer term historical trend;

- No significant impact is assumed from disruptive technologies such as PV or distributed generation; and
- The forecast peak demand for planning purposes for a particular year is the 60th percentile between the upper and lower range of peak demand scenarios.

These assumptions are reviewed each year and the expected impact incorporated into the peak demand forecast.

The peak demand forecast is based on the following information:

- Half-hourly demand data per zone substation feeder is captured by the SCADA system while the demand at each GXP is metered through the time-of-use revenue metering;
- Step loads changes;
- Diversity factors that provide peak coincident demand are calculated from historical recorded data;
- Typical demand profiles;
- The current year peak demand values and likely step change loads entered into a temperature dependent forecasting tool;
- Population forecasts from NZ Statistics[29]; and
- The base peak demand for the forecasts is the maximum that occurred during the year ended 31 September 2014.

The resultant load forecast is a range of likely peak demand values per feeder, zone substation and GXP per year based on temperature volatility and growth scenarios. This information allows Wellington Electricity to analyse likely future demand at the GXP, zone substation and feeder level and to identify and assess the likelihood of constraints binding in the future for a wide range of scenarios.

8.1.1 Step Change Loads

Highly likely or confirmed step change loads are accounted for in the load forecast. These step change loads may be the result of:

- Major developments that introduce large new loads onto the network;
- New electricity generation that is expected to affect peak demand; or
- Load reductions caused by the movement or closure of businesses.

The magnitude and location of likely step change loads is identified through customer connection requests and likely developments listed in District Plans. A number of property developers and businesses have flagged developments that may create new loads on the network. Demand forecasts are modified if necessary to reflect this information.

[29] NZ Statistics Subnational Population Projections: 2006 (base) – 2031 (October 2012 update)

8.1.2 Typical Load Profiles

Typical annual demand profiles for the CBD and residential loads are shown in Figure 8-1 and 8-2. These graphs illustrate that CBD loads are relatively even throughout the year with a slight trend towards a summer peak whereas residential loads peak in winter .

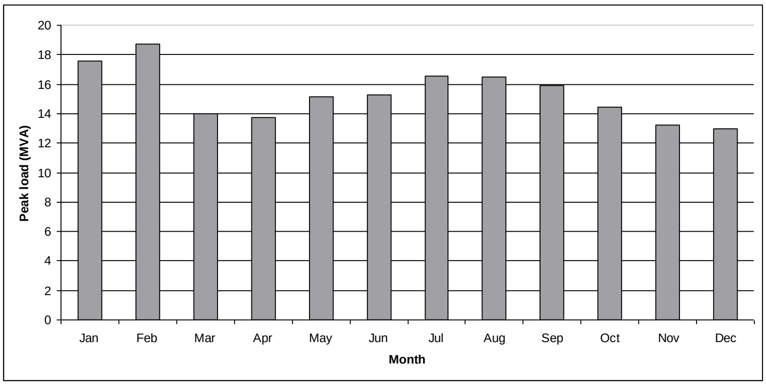


Figure 8-1 Typical CBD Monthly Peak Load Profile

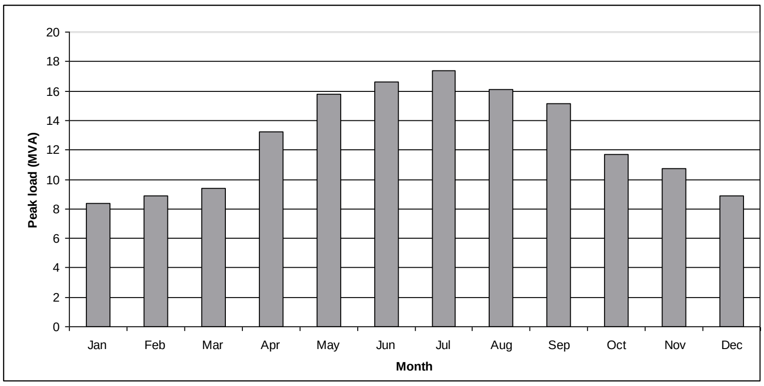


Figure 8-2 Typical Residential Monthly Peak Load Profile

Typical daily demand profiles are shown in Figures 8-3 and 8-4. These graphs illustrate that the CBD daily profile peaks and then remains relatively flat through the day, whereas the residential load profile has the typical morning and early evening peaks.

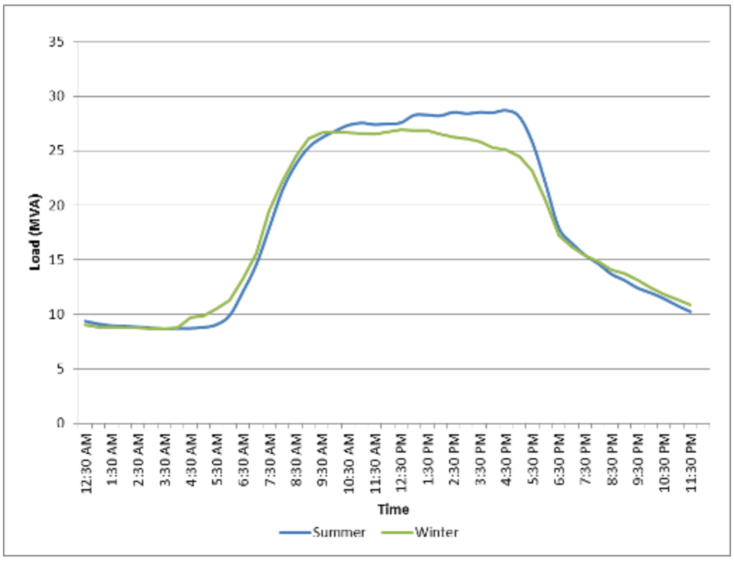


Figure 8-3 Typical CBD Zone Substation Daily Load Profile

Figure 8-4 Typical Residential Zone Substation Daily Load Profile

8.1.3 Peak Demand Forecast Scenarios

Forecast peak demand projections have been based on historical trends. Three forecast scenarios are considered for each feeder, with each scenario consisting of two components - a short term trend (from 0-5 years), and a mid to long term trend (5+ years). The short term trend is the average change in peak demand over the previous two years, allowing for known step change loading. The long term trend is a linear extrapolation of the historical trend recorded over the previous five to 10 years.

The three scenarios are developed for winter temperature volatility (based on weekly average temperatures[30]) and provide an ideal load profile for mild, average and low temperature scenarios.

The output of the forecasting is a peak demand spread over twelve forecast data points per year corresponding to the various peak demand growth and winter temperature scenarios. The forecast scenarios are determined at the zone substation level and are aggregated from “bottom up” to provide the GXP, region and system wide forecasts.

This model is used to determine when subtransmission and feeder level constraints are likely to occur and provides a yearly maximum demand that can be logged into load flow modelling.

8.1.4 Temperature Dependency

Temperature dependency and consequential demand volatility is an important consideration in the peak demand forecast. Historically there is a clear inverse correlation between the temperature during the winter months and the recorded maximum demand. A year with a colder/stormier winter typically results in higher winter peak loading and consequently a higher maximum demand, while a year with a milder winter will experience lower maximum demand. There is also almost no variation in summer loading due to summer temperature variations. As such, the demand model assumes that summer temperature variations have no effect on the annual peak load profile.

[30] Source: NIWA CliFlo climate database

To model this dependency, three scenarios were developed for the three Wellington network areas based on smoothed historical temperature variations provided from monitoring stations within the respective area. These scenarios developed account for a mild (warm), average and low (cold) winter temperature profile. Figure 8-5 shows how the winter temperature volatility correlates the volatility in maximum demand.

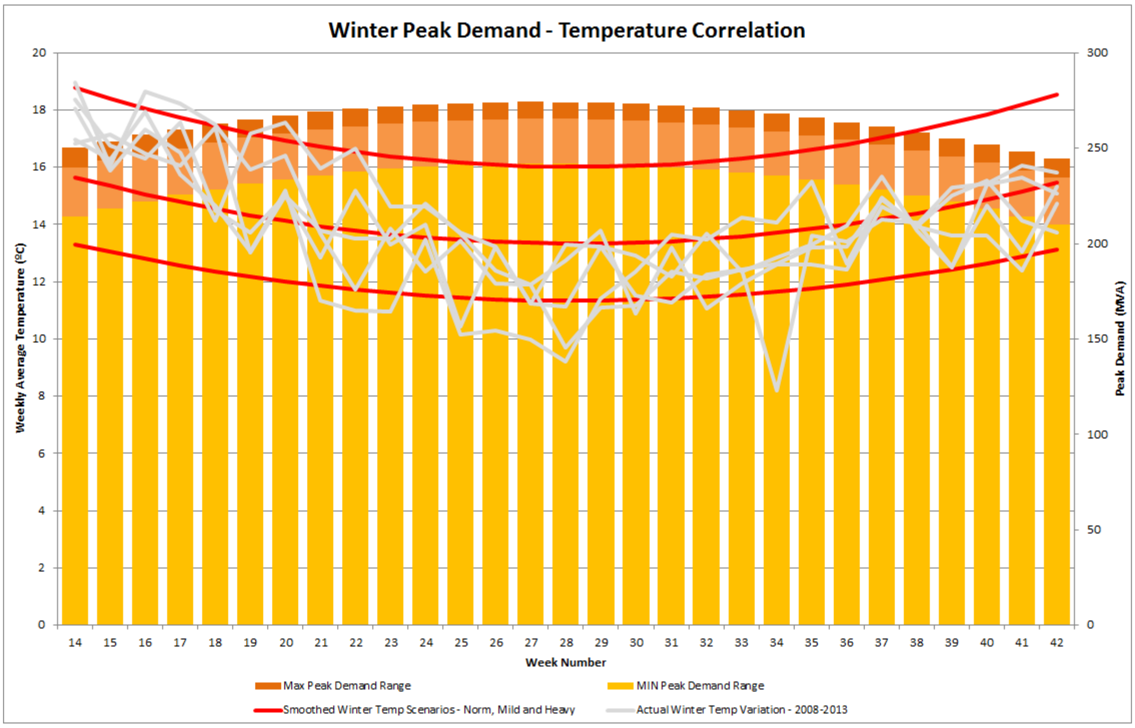


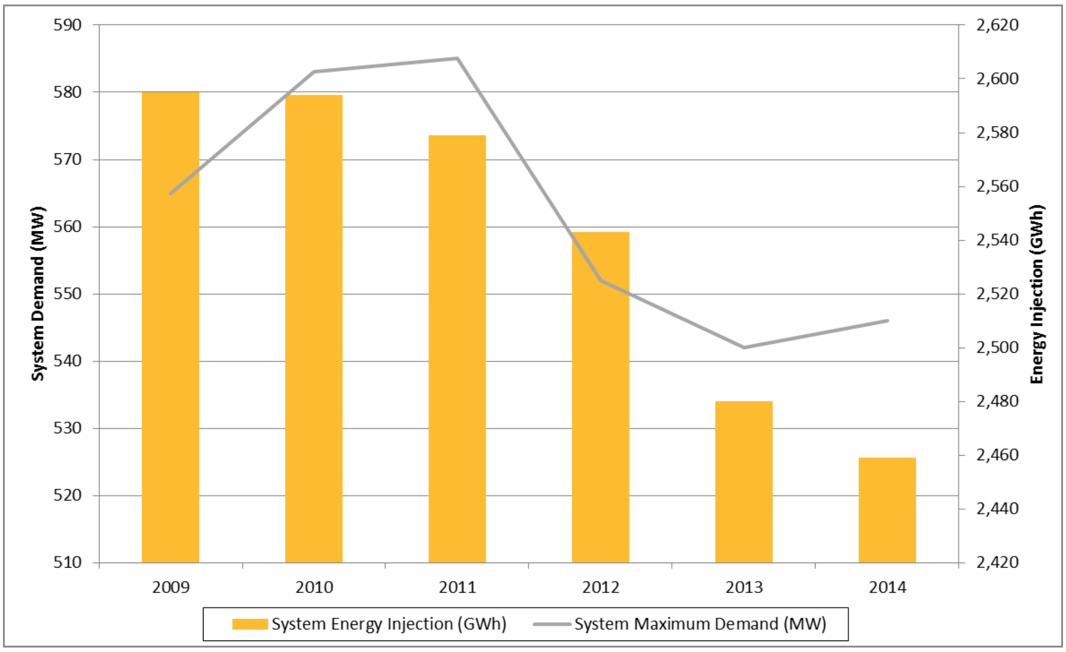
Figure 8-5 Temperature Volatility Correlation to Peak Demand Range

For example, for week 31, there is a high degree of certainty that the temperature for the network area shown will be within the range from 12° C to 15°C. Using the developed correlation between temperature and maximum demand volatility, maximum demand for the network area for week 31 will be between 240MVA and 275MVA. Adjusting this by the demand growth scenarios, the peak demand range for a given week in a given year can be determined to a high level of confidence.

Accounting for the temperature dependency provides for yearly demand profiles for the individual Wellington network areas, which are used to determine the GXP, zone substation, and feeder level demand profile.

8.2 Historical Peak Demand and Consumption

As illustrated in Figure 8-6, since 2011 energy supplied through the network has declined, and the system peak demand has fluctuated.



Year to	30 Sep 2009	30 Sep 2010	30 Sep 2011	30 Sep 2012	30 Sep 2013	30 Sep 2014
System Maximum Demand (MW)	565	583	585[31]	552	542	546[32]
System Energy Injection (GWh)	2,595	2,594	2,579	2,543	2,480	2,459

Figure 8-6 Peak Demand and Energy Injected

Of note is that the average winter temperatures recorded over the last three years indicate that the Wellington Region is in a climatic period of relatively milder winters.

Consumption of electricity (kWh volume) has been decreasing at a rate of approximately 1.7% per annum over the period from 2010 to 2014 and is forecast to continue this trend for at least the next five years. This is consistent with national averages that show declining demand and volumes since 2010.

8.3 Wellington Regional Peak Demand Forecast

Accounting for the forecast scenarios, observed temperature variations and step change demands, the expected system maximum demand forecast to 2025 is shown in Figure 8-7. The spread shown in the yellow band indicates the variation in both forecast assumptions and temperature.

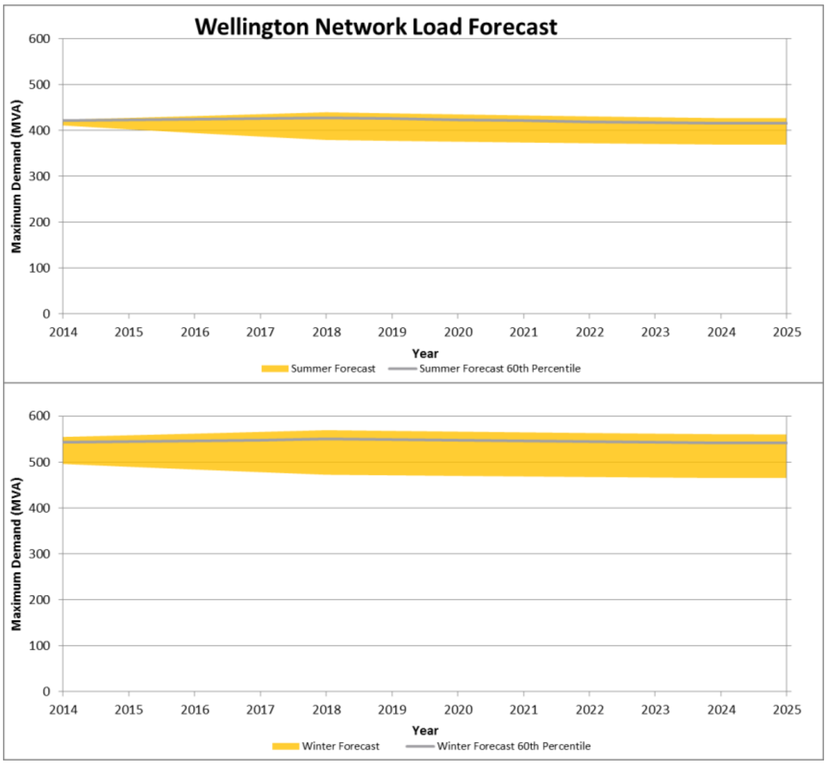
The following assumptions apply:

- The maximum forecast value for a particular year and season indicates the worst case scenario of high growth and colder average temperatures;

[31] During an unusual snowstorm in August 2011 peak demand was over 615MW for a period of half an hour until the load control system was operated to shed 30MW of controllable load (in addition to usual load shedding that is undertaken in winter.). This prevented the overloading of system components and ensured security of supply during a period when Transpower had reduced capacity on the transmission system into the Wellington area.

[32] The System Maximum Demand is the absolute peak coincident real power demand based on half-hourly metered data from Transpower GXPs. The 2014 sustained peak demand for forecasting purposes is 535MW which is equivalent to 546MVA.

- The minimum forecast value for a particular year and season indicates the mild scenario of low to negative growth and warmer average temperatures; and
- The peak demand for planning purposes is for the normal growth, average winter temperature scenario and can be approximated as the 60th percentile of the range of peak demand values resultant from the various load growth and winter temperature scenarios per year.



	System Maximum Demand MVA[33] and Energy Volume (GWh) (including DG)											
	2014 Actual [34]	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025
System Maximum Demand (MW)	544	545	547	549	551	549	548	546	545	543	542	545
System Energy Injection	2,595	2,551	2,508	2,465	2,423	2,382	2,341	2,302	2,302	2,302	2,302	2,302

Figure 8-7 Network Historic Demand and Forecast

[33] Forecast values are for the normal growth average seasonal temperature case correspond to the 60th percentile deduced from the peak demand range and include step change loading due to planned load transfer or confirmed customer connections

[34] System Maximum Demand forecast is based on the 2014 sustained peak in MVA

Notes:

1: Base MD value for the projection is for the year ending 31 December 2014 .

Peak demand is expected to grow at a rate of 0.3 – 0.5% p.a. over the next five years, primarily driven by planned step change loads such as:

- Planned residential developments in the Churton Park, Aotea, Whitby, Grenada North and Upper Hutt areas; and
- Expansion plans of a number of commercial and industrial customers.

However, outside of this short term growth, the peak demand is expected to decline over the long term and return to current levels. This long term decline in peak demand is driven by a number of factors, including:

- A number of buildings within the Wellington CBD are undergoing re-development. High efficiency HVAC systems and better insulation and customer side demand monitoring typically result in a reduction in demand for an existing connection point
- Increased uptake of residential PV generation and gas connections; and
- Observed diversity in peak load coincidence leading to a long term reduction of overall peak demand..

8.4 Network Area Peak Demand Forecasts

Forecast demand in Wellington Electricity's supply area is relatively low compared to demand growth in many other parts of the country. This is consistent with data provided in the 2014 Transpower Annual Planning Report.

8.4.1 Southern Area Forecast

Peak demand in the Southern area has declined in recent years and is expected to decline further, however there are localised sites within the area where peak demand growth is still observable. This is primarily due to expected step changes from new building developments along the water front, around Parliament and the Victoria University campus.

Consumption outside of the Wellington CBD has a declining trend due to factors such as improved energy efficiency as part of building re-developments. Examples include installation of high efficiency HVAC systems, better insulation and customer side demand monitoring.

Due to land development space constraints, the number of new consumer connections within the Wellington CBD is also low. Figure 8-8 shows the summer and winter peak forecasts for the Southern area.

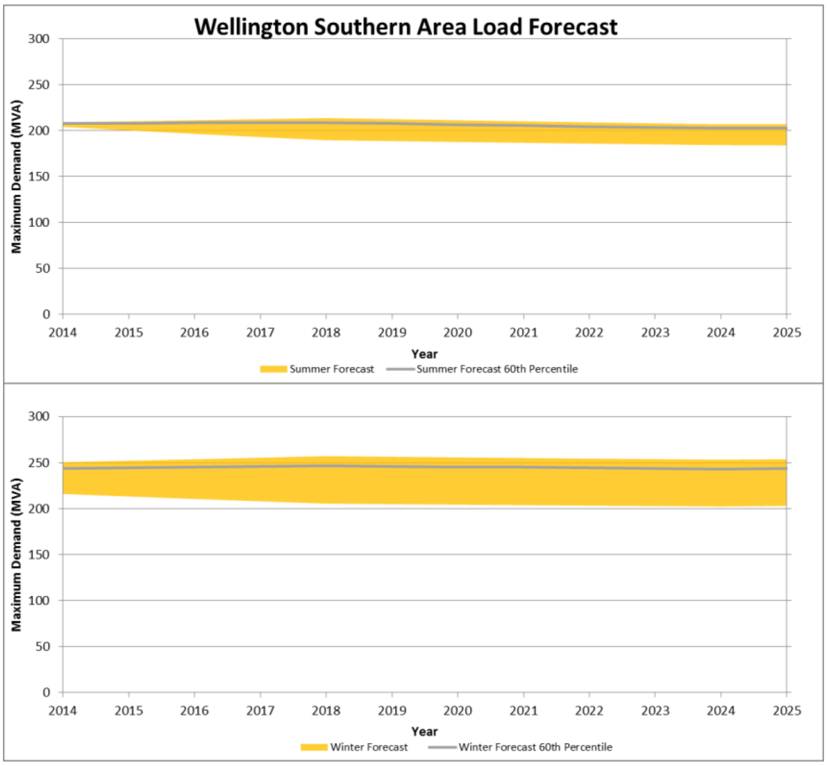


Figure 8-8 Southern Area Forecast

8.4.1.1 Step Change Developments

Examples of developments in the Southern network area that have been highlighted in the District Plan include:

- A new science building with an ADMD of around 2MVA of load at the Kelburn campus of Victoria University and a redevelopment of Rutherford House in the Wellington CBD;
- Approved customer connection requests for a number of developments along Molesworth Street;
- High density residential developments in the Cuba and East Te-Aro precincts;
- High density residential and commercial buildings along the waterfront; and
- A new airport hotel at Wellington International Airport.

There are also other tertiary institutions, hospitals and growth industries, such as businesses supporting the international film industry, which are likely to require future capacity.

While the timing of these developments is not certain, they have been included in the forecast by accounting for step change load growth on feeders supplying the described areas.

8.4.2 Northwestern Network Forecast

The Northwestern network area is continuing to grow organically with the strongest level of residential development within Wellington Electricity's network. More specifically, there is relatively high interest for new residential subdivisions in the suburbs of Whitby, Grenada North and Churton Park. The Aotea subdivision, currently supplied from the Porirua zone substation, is also an area of high growth. Figure 8-9 shows a moderate increase in summer peak loading but a static winter peak.

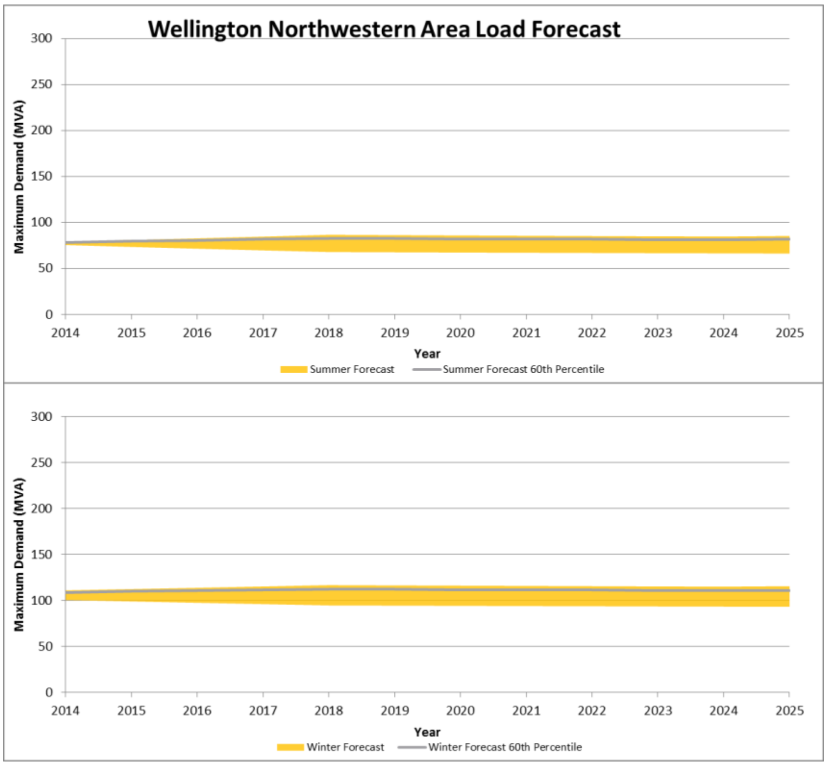


Figure 8-9 Northwestern Area Forecast

8.4.2.1 Step Change Developments

There are no identified major step change loads expected in the Northwestern area. The organic growth in population due to further development of the Aotea and Grenada north residential areas is expected increase peak demand over the short term but remain static over the long term.

8.4.3 Northeastern Area Forecast

Peak demand in the Northeastern area is expected to remain at the current levels. There are localised areas of peak demand growth in the Upper Hutt area driven by planned residential sub-divisions and expansion plans of industrial customers in the Trentham and Maidstone zone substation supply areas. Outside of these areas peak demand is in decline in most parts of Lower Hutt.

There are few constraints arising during the planning period as shown in Figure 8-10.

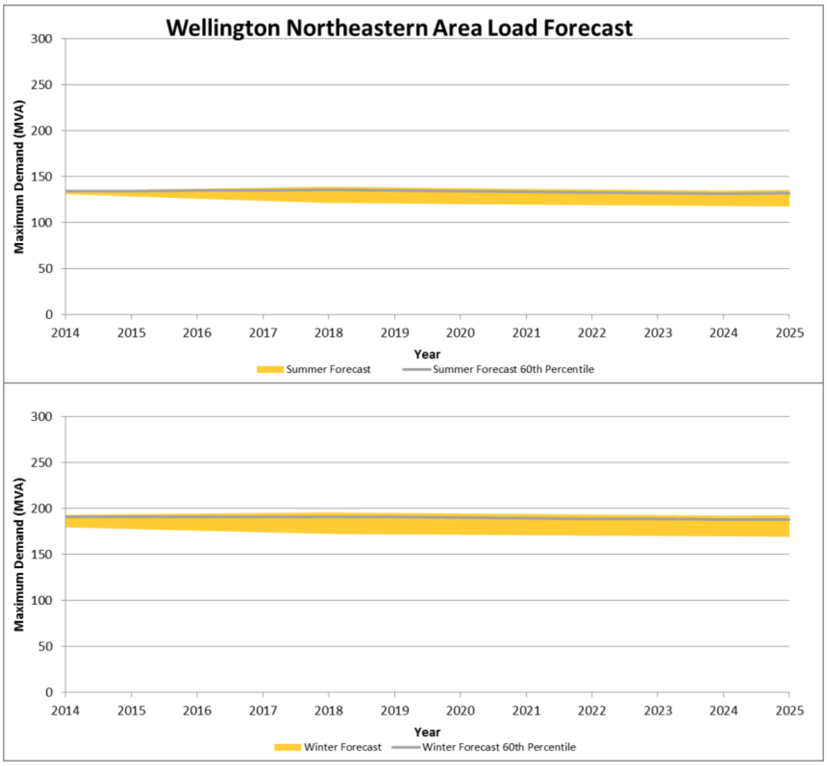


Figure 8-10 Northeastern Area Forecast

8.4.3.1 Step Change Developments

A number of developments are likely within the Northeastern area, confirmed either through requests received for customer connection or for information from developers. The majority of step change loads expected are due to expansion of industrial facilities within the Trentham area.

Examples of developments in the Southern network area that have been highlighted in the District Plan include:

- Expansion of a customer data centre facility which will involve four confirmed stages for a total increase in installed capacity of approximately 4MVA over the next three years. New infrastructure is planned to provide the required capacity and security of supply to these facilities, while also providing increased inter-zone inter-connectivity within the network;

- Redevelopment of an existing industrial premise to house the new Ministry of Agriculture and Forestry research centre. A load increase of 2 to 3MVA is expected within the next two years; and

- A new residential development in the Wallaceville comprising 700 lots with 100-200 lot sections with an installed capacity of 300-500kVA released per year. The total capacity on completion of the residential development will be 2.2MVA with an expected maximum demand of 1.2MVA.

A number of smaller fabricating and manufacturing industries have expressed an interest in developing or expanding facilities within the Petone area. The step change loads expected serve to offset the declining demand in the area.

8.4.4 Regional Aggregate

Figure 8-11 shows the mean forecast of the three areas compared against the aggregate Wellington region forecast. Overall the peak demand is static during the planning period.

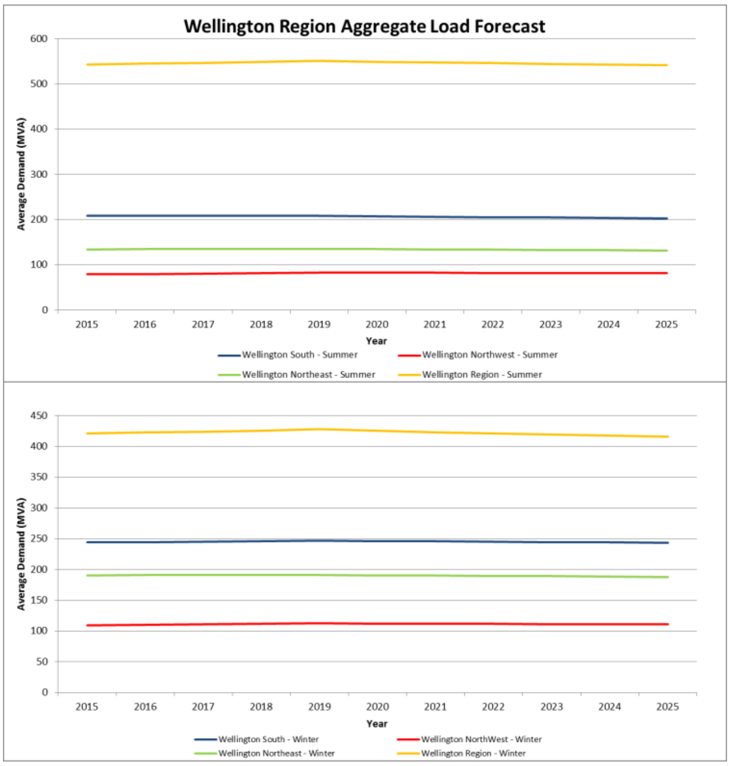


Figure 8-11 Wellington Region Aggregate Forecast

The forecasted peak demand (60th percentile) for each of the three areas of the Wellington Region shows short term peak demand growth in all three. The Northwestern area is forecast to experience the highest growth due to a number of residential developments expected within the short term. Moderate short term peak demand growth is also expected within the Northeastern area. Overall peak demand growth is expected to decline or remain fairly static over the long term.

8.5 GXP and Zone Level Demand Forecasts

The following tables show the GXP and zone substation level forecast for each region within the Wellington network. Figure 8-12 shows the GXP level forecast by region and Figure 8-13 shows the Zone substation level forecast by region.

For both tables, base maximum demand value for the forecast is for the year ending 31 December 2014 and region totals are After Diversity Maximum Demand (ADMD) values.

Area	GXP	Actual and Forecast System Demand MVA[35]										
		2014 Actual	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024
Southern Area	Central Park 33kV	155	153	152	151	150	149	148	147	146	145	145
	Central Park 11kV	23	25	25	25	25	25	25	25	25	25	24
	Wilton 33 kV[36]	54	54	55	55	56	56	56	57	57	58	58
	Kaiwharawhara 11kV	33	34	33	33	33	33	33	33	33	33	33
	Area Total	**244**	**245**	**245**	**246**	**247**	**246**	**246**	**245**	**244**	**244**	**243**
Northwestern Area	Pauatahanui 33kV[37]	20	20	20	20	20	20	20	20	20	20	20
	Takapu Rd 33kV	89	92	93	94	94	95	95	95	95	95	95
	Area Total	**109**	**110**	**111**	**112**	**112**	**112**	**112**	**112**	**111**	**111**	**111**
Northeastern Area	Gracefield 33kV	63	62	61	61	60	59	58	58	57	56	56
	Haywards 33kV	17	17	17	17	17	17	17	17	18	18	18
	Melling 33kV	36	36	36	36	36	36	36	36	36	36	36
	Upper Hutt 33kV	29	28	28	28	29	29	29	29	30	30	30
	Haywards 11kV	17	17	17	17	17	17	17	17	17	17	17
	Melling 11kV	26	26	26	26	26	26	26	26	26	25	25
	Area Total	**191**	**191**	**191**	**191**	**191**	**191**	**190**	**189**	**189**	**188**	**188**

Figure 8-12 Wellington Area GXP Level Forecast

[35] Forecast values are for the normal growth average seasonal temperature case correspond to the 60th percentile deduced from the peak demand range and include step change loading due to planned load transfer or confirmed customer connections.
[36] Forecast for Wilton 33kV is inclusive of the reduction in load due to Mill Creek export.
[37] Kaiwharawhara GXP has a summer peak. All other stations are winter peaking.

Area	Zone	Actual and Forecast System Demand MVA[38]										
		2014 Actual	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024
Southern Area	Palm Grove	25	25	25	25	25	25	25	25	24	24	24
	Frederick St	28	28	28	27	27	27	27	27	26	26	26
	Evans Bay	15	15	15	15	15	16	16	16	16	16	16
	Hataitai	19	20	20	20	20	20	20	19	19	19	19
	University	26	24	25	25	25	24	24	24	24	23	23
	The Terrace[39]	27	27	27	27	28	28	28	28	28	28	28
	8 Ira St	18	16	16	16	16	16	16	16	16	16	16
	Nairn St	23	25	25	25	25	25	25	25	25	25	24
	Karori	17	17	17	17	17	17	17	17	16	16	16
	Moore St[39]	24	25	25	25	26	26	26	27	27	27	27
	Waikowhai St	16	16	16	16	17	17	17	17	17	17	17
Northwestern Area	Mana-Plimmerton	20	20	20	20	20	20	20	20	20	20	20
	Johnsonville	17	17	17	17	17	17	16	16	16	16	15
	Kenepuru	12	12	12	12	12	11	11	11	11	11	11
	Ngauranga	13	14	14	14	14	14	14	14	14	14	14
	Porirua	19	20	20	20	20	21	21	21	21	21	21
	Tawa	14	15	16	16	17	17	17	17	17	17	17
	Waitangirua	15	16	16	16	17	17	17	17	17	18	18
Northeastern Area	Gracefield	12	11	11	11	11	10	10	10	10	10	9
	Korokoro	19	19	19	18	18	18	18	17	17	17	17
	Seaview	16	16	16	16	16	16	16	15	15	15	15
	Wainuiomata	17	17	17	17	16	16	16	16	16	16	16
	Trentham	17	17	17	17	17	17	17	17	18	18	18
	Naenae	18	18	18	18	17	17	17	17	17	17	17
	Waterloo	19	19	19	19	19	19	19	19	19	20	20
	Brown Owl	15	15	15	15	16	16	16	16	16	16	17
	Maidstone	14	13	13	14	14	14	14	14	14	14	14

Figure 8-13 Wellington Area Zone Substation Level Forecast

[38] Forecast values are for the normal growth average seasonal temperature case correspond to the 60th percentile deduced from the peak demand range and include step change loading due to planned load transfer or confirmed customer connections.
[39] The Terrace and Moore St zone substations have a summer peak. All other stations are winter peaking.

9 Network Planning

9.1 Introduction

The purpose of network development planning is to safely deliver the required network capacity and security of supply:

- Ensuring the health and safety of the public, staff and contractors is not compromised;
- In an economic, sustainable and profitable manner; and
- At a price and quality level acceptable and expected by consumers.

This section sets out how Wellington Electricity approaches network development planning, the assumptions used and the resulting needs, options and proposed network investments for the next 10 years. The projects presented in this section are to maintain current network security and reliability service levels, and address historical and future capacity constraints as described in the performance objectives in Section 7.

9.2 Planning Criteria, Assumptions and Policies

The principles that underpin Wellington Electricity's network planning are:

- Network assets will not present a safety risk to staff, contractors or the public;
- All network assets will be operated within their design rating;
- The network will be designed to meet all statutory requirements including voltage and power quality (PQ) levels;
- Consumers' expectations for supply capacity and security requirements will be met;
- Network augmentations will be designed to include a prudent capacity margin to cater for foreseeable near-term load growth;
- Network augmentation shall be planned in such a way as to reduce energy losses;
- Constraints are defined as the point at which load flow through a piece of equipment exceeds its long term cyclic rating;
- Varying security standards will apply to different network areas (CBD/industrial, urban, rural) and consumer segments, reflecting the price/quality trade-offs sought by consumers; and
- Network investment will provide an appropriate commercial return for the business.

These principles create competing priorities that must be balanced to find the best outcomes for stakeholders in each specific case.

9.2.1 Planning and Security Criteria

Wellington Electricity has a number of key policies and standards underpinning its network planning and security approach. These policies and standards cover the following areas:

- Service level – established as part of the Use of Network Agreement with retailers and consumers. The service levels reflect expected restoration timeframes and fault frequencies;
- Technical standards – ensure optimum asset life and performance is achieved (i.e. capital cost, asset ratings, maintenance costs and expected life are optimised to minimise lifecycle cost). Standardisation also reduces design costs and minimises spare equipment holding costs, leading to lower overall project and maintenance costs;
- Network operating parameters – including acceptable fault levels, voltage levels, power factor, etc., providing an appropriate operating framework for the network; and
- Network security – specifies the minimum levels of network capacity (including levels of redundancy) to ensure the required level of supply reliability is maintained.

The design of Wellington Electricity's network is based on the security criteria shown in Figure 9-1 (subtransmission criteria) and Figure 9-2 (distribution criteria).

The security criteria are consistent with industry best practice[40] and are designed to:

- Match the security of supply with customers' requirements and what they are prepared to pay for;
- Optimise capital expenditure (CAPEX) without a significant increase in supply risks; and
- Increase asset utilisation.

The planning standards accept there is a small risk that customer supplies may be interrupted when a network fault occurs during peak demand times[41]. The length of time (defined as a percentage) when the subtransmission network cannot meet N-1 security, and the distribution network did not have full backstop, is defined with different durations for each category of customers. However, even in the event that an interruption should occur, limits are set on the maximum load that would be lost.

Figure 9-1 shows the applicable security criteria for the subtransmission network.

Type of Load	Security Criteria
CBD	N-1 switching switching[42] for 99.5% of the time in a year For the remaining time, supply will be restored within 3 hours following an interruption.
Mixed commercial / industrial / residential substations	N-1 switching[43] for 98% of the time in a year For the remaining time, supply will be restored within 3 hours following an interruption.

[40] *Guide for Security of Supply*, Electricity Engineers' Association, August 2013.

[41] A true deterministic standard, such as N-1, implies that supply will not be lost after a single fault at any time. Wellington Electricity's security standard accepts that for a small percentage of time, a single fault may lead to outages. By somewhat relaxing the deterministic standard, significant reductions in required asset capacity and redundancy levels become possible, with corresponding reductions in the cost of supply.

[42] A brief supply interruption of up to 1 minute may occur following an equipment failure while the network is automatically reconfigured.

[43] A brief supply interruption of up to 5 minutes may occur following an equipment failure while the network is reconfigured.

Type of Load	Security Criteria
Predominantly residential substations	N-1 switching[43] for 95% of the time in a year For the remaining time, supply will be restored within 3 hours following an interruption.

Figure 9-1 Security Criteria for the Subtransmission Network

Figure 9-2 shows the applicable security criteria for the distribution network.

Type of Load	Security Criteria
CBD or high density industrial feeders	N-1 switching[44] for 99.5% of the time in a year For the remaining times, supply will be restored within 3 hours following an interruption.
Mixed commercial / industrial / residential feeders	N-1 switching[45] for 98% of the time in a year For the remaining times, supply will be restored within 3 hours following an interruption.
Predominantly residential feeders	N-1 switching[45] for 95% of the time in a year For the remaining times, supply will be restored within 3 hours following an interruption.
Overhead spurs supplying up to 1MVA urban area	Loss of supply upon failure. Supply restoration dependent on repair time.
Underground spurs supplying up to 400kVA.	Loss of supply upon failure. Supply restoration dependent on repair time.

Figure 9-2 Security Criteria for the Distribution Network

While the reliability of Wellington Electricity's distribution system is high, notwithstanding the difficult physical environment in which the system must operate[46], it is uneconomic to design a network where supply interruptions will never occur. Hence, the network is designed to limit the amount of time over a year when it is not possible to restore supply by reconfiguring the network following a single unplanned equipment failure. This approach recognises that electricity demand on the network varies according to the time of day and season of the year, and that the time over which the system is exposed to its peak demand is very small. It also recognises that equipment must at times be taken out of service for planned maintenance and that, when this occurs, parts of the network are exposed to a lower level of security and, as a consequence, a higher risk of interruption. The security criteria and assumptions detailed above also highlight that some areas are supplied by spur lines, as this is the most efficient supply configuration, and these areas will lose supply on failure until the repair is completed. Network planning guidelines indicate the potential for unserved load based on physical constraints and determines possibilities for additional supplies or back feed points where practicable.

[44] A brief supply interruption of up to 1 minute may occur following an equipment failure while the network is automatically reconfigured.

[45] In areas other than the CBD an operator may need to travel to the fault location to manually operate network switchgear, in which case the supply interruption could last for up to 1 hour.

[46] Much of Wellington Electricity's supply area is renowned for its high winds. There can also be a high concentration of salt in the atmosphere, blown in from the sea.

Wellington Electricity's network design and asset management systems also have regard for the time taken to restore supply following an interruption. When an unplanned equipment outage does occur, considerable effort is made to restore supply to customers not directly affected by the equipment fault by switching load to other parts of the network. However, at times of peak demand, or where equipment is out of service for maintenance at the time of the unplanned outage, it may not be possible to switch all load in this way and maintain supply quality. In these instances an extended outage may occur with maximum restoration times as shown in Figure 9-1 and Figure 9-2.

The security criteria generally do not apply to faults on distribution transformers, the low voltage network or to failures of connection assets used to supply individual customers, which are typically designed for 'N' security. In such situations an interruption will last for the time taken to make a repair.

The security criteria also does not apply when multiple equipment outages affect the same part of the network or when major storms or other severe events have a high impact on the system and can stretch the capacity of Wellington Electricity or its contractors to respond in a timely manner. Wellington Electricity has emergency plans in place to prioritise response and repair efforts to assist mitigating the impact of such situations but, when they occur, longer supply interruptions than shown in the tables are possible.

Most of the 11kV feeders in the Wellington CBD, in some locations around Wellington's eastern suburbs, and in the Porirua commercial centre are operated in a closed ring configuration with radial secondary feeders interconnecting neighbouring rings or zone substations. This arrangement provides a high level of security and hence a high level of supply reliability. The urban 11kV network outside these areas typically comprises radial feeders with a number of mid-feeder switchboards with circuit breakers. The radial feeders are connected through normally open interconnectors to other feeders so that, in the event of an equipment failure, supply to customers can be switched to neighbouring feeders. To allow for this, distribution feeders are not operated at their full thermal rating under normal system operating conditions. The maximum feeder utilisation factor at which Wellington Electricity currently operates the distribution feeders during normal and contingency operation is identified in the table in Figure 9-3.

Feeder Operation	Normal Operation Loading (%)	Contingency Operation Loading (%)
Two Feeder Mesh Ring	50	100
Three Feeder Mesh Ring	66	100
Four Feeder Mesh Ring	75	100
Five Feeder Mesh Ring	80	100
Radial Feeder	66	100

Figure 9-3 11kV Feeder Utilisation during Normal and Contingency Operation

A consumer may desire a level of security above that offered by a standard connection. Should this arise, Wellington Electricity can offer a range of alternatives that provide different levels of security at different prices (price/quality trade off). The consumer can then choose to pay for a higher level of security to meet their needs for the load they are being supplied.

Given the declining demand growth in most supply areas, and the potential for further change to the Commission's regulatory framework, it is unlikely that Wellington Electricity would expose itself to future optimisation risk by installing asset capacities greater than indicated by the above approach.

9.2.2 Distributed Generation Policy

Example of distributed generation

There is a small amount of generation embedded within the network. Wellington Electricity welcomes enquiries from third parties interested in installing embedded generation. Where it is identified that a third party scheme may have the potential to defer the need for capital investment on the network, the extent to which the proposal meets the following requirements will be considered in developing a technical and commercial arrangement with stakeholders:

- The risk of non-provision of service needs to be managed. There is little point in paying a third party for a service such as generation or load reduction if availability of the service cannot be guaranteed at the time that network demand is at a peak;
- The service must comply with relevant technical codes and not interfere with other consumers;
- Any payments made to third parties must be linked directly to the provision of a service that gives the required technical and commercial outcomes;
- Commercial arrangements must be consistent with avoided cost principles; and
- Commercial agreements must be reached on other issues not directly related to any benefit provided to Wellington Electricity. These can include the cost of connection and payment of use of network charges.

If the above issues can be managed, and the dispatch of generation can be co-ordinated with system peaks or constraints, then the use of embedded generation as part of a demand side management programme could bring real benefits to Wellington Electricity.

Wellington Electricity has developed a distributed generation connection policy and has different procedures for the assessment and connection of distributed generation up to 10kW and over 10kW. These are in line with the Electricity Industry Participation Code 2010, Part 6.

As per Section 6.1.6 the magnitude and quantity of distributed generation currently installed within the network is minimal and there are no indications that this will change within the planning period. It is assumed that distributed generation has a negligible impact to the network demand forecast or future planning. This assumption shall be re-assessed in the event of large scale uptake of distributed generation in the future.

Information about connecting distributed generation is available on the Wellington Electricity website – www.welectricity.co.nz or by calling 0800 248 148.

9.2.3 Energy Efficiency

The processes and strategies used by Wellington Electricity that promote the energy efficiency of the network are:

- Network planning – to design systems that do not lead to high losses or inefficient conveyance of electricity by selecting the correct conductor types and operating voltages in order to minimise total costs (including the cost of losses) over the lifetime of the asset;

- Equipment procurement – to select and approve the use of equipment that meets recognised efficiency standards; for example, selecting distribution transformers that meet recognised AS/NZS standards. For large items such as zone substation power transformers, the purchase decision includes lifecycle loss analysis (copper and iron) to determine the relative economics of the different units offered; and

- Network Operations – to operate the network in the most efficient manner available given current network constraints and utilise the load management system to optimise the system loadings (which in turn affects the efficiency of the network).

9.2.4 Voltage Levels

Subtransmission voltage is nominally 33kV in line with the source voltage at the supplying GXP. The voltage used at the distribution level is nominally 11kV. The LV distribution network supplies the majority of customers at nominally 230V single phase or 400V three phase. By agreement with consumers, supply can also be connected at 11kV or 33kV depending upon the load requirements.

Regulation 28 of the Electricity (Safety) Regulations 2010 requires that standard LV supply voltages (230V single phase or 400V three phase) must be kept within +/-6% of the nominal supply voltage calculated at the point of supply, except for momentary fluctuations. Supplies at other voltages must be kept within +/-5% of the nominal supply voltage except for momentary fluctuations, unless agreed otherwise with consumers.

Design of the network takes into account voltage variability due to changes in loading and embedded generation under normal and contingency conditions. All Wellington Electricity zone substation transformers are fitted with on-load tap changers (OLTC) to maintain the supply voltage within acceptable limits. Distribution transformers typically have an off-load tap changer which can be manually adjusted to maintain acceptable voltage at different network locations.

9.2.5 Non-Network Solution Policy

Wellington Electricity's load control system is actively used to reduce peak demand on the network by moving load to off-peak periods, and therefore has the effect of deferring demand-driven system augmentation. Wellington Electricity's tariff structure provides benefits if retailers mirror its pricing structure to provide an incentive for consumers to shift electricity consumption away from periods of peak network demand. Historically use of the load control system has resulted in the significant deferral of network investment, as well as providing an effective means of dealing with network loading during outages.

Other potential non-network solutions include demand response, where consumers may be incentivised to switch off demand at certain times when the network is approaching a period of constraint. An example of the type of demand that could prove useful in deferring network investment is air conditioning plant in the CBD. Demand response is less likely to provide benefit in suburban areas as controllable loads are individually small and spread amongst a large number of consumers. Generally, these loads are already controlled through the load control system.

Wellington Electricity has not actively pursued demand response to date because its load control system has provided the sufficient demand reductions. Demand response will however be included as a long list option in any major network investment options analysis where it may provide potential network benefit and will be adopted where there is a positive business case for such an option.

To date the costs of implementing demand side management initiatives have been found to be significantly higher than the alternative network based solutions. However Wellington Electricity continues to explore demand side initiatives. For example there is a possibility that large scale photovoltaic generation may be deployed at a number of commercial premises within the Wellington CBD. The scale and capacity of this potential development is not currently known however the assumption is made that this capacity will only serve to offset the load of the respective commercial premises. This assumption based on the following factors:

- Peak solar generation occurs during peak loading (due to HVAC systems) at commercial premises (summer peaking load profile); and
- The potential capacity of the solar plant will not exceed the maximum demand at the commercial premises, thus will not be exporting into the network.

Any potential large scale deployment of PV at commercial premises within the Wellington CBD may not be sufficient to alleviate current and expected network capacity constraints and is not considered in network development planning in this AMP. Further investigation will be required to determine if there will be any significant network impact of large scale commercial PV deployment, which would then be considered in future as a possible long list option for network investment.

Where distribution capacity constraints are identified, the default method of mitigation is to identify open point shifts which may be utilised to shift a portion of load from an overloaded feeder to a less loaded feeder, thereby optimising utilisation of the existing network. Where this is not possible, network solutions such as construction of new network infrastructure are required.

9.2.6 Emerging Technologies and Practices

There continues to be much industry interest around smart grids and smart technologies that will find their way into transmission and distribution networks, metering, and retail space, as well as at consumer level within homes and businesses.

By design, the Wellington Electricity network has a number of features which allow for “smart” network management. These features are:

- Closed ring feeders with segmented differential protection to isolate faults while leaving healthy sections in service;
- Remote indication and control via SCADA at over 230 sites, which allows for network management from the Wellington Electricity NCR; and
- On demand load management via the existing ripple control system.

Technologies that emerge that may improve the way in which Wellington Electricity could design, build, maintain or operate the network will be thoroughly investigated. Wellington Electricity also has access to considerable intellectual property and learnings through the wider group of CKI and Power Assets companies across Australia, Hong Kong and the United Kingdom, where the outcome of investigations into best practice and trials of new technology are shared and considered in a local context. New technologies will be implemented if the benefits to the network and stakeholders meet or exceed the additional costs incurred in installing and using them. Wellington Electricity specifies equipment for future use that incorporates future technologies where this is practicable and economic. Wide scale replacements of existing assets with new technology capable equipment is not economic and such equipment is only introduced as existing assets reach their end of life or are replaced due to a requirement for a change in capacity or functionality.

The availability of affordable electric vehicles has the potential to significantly alter electricity delivery and usage patterns. It is expected that the adoption rate in New Zealand will increase over longer term based on:

- New Zealand’s high level of renewable energy generation (over 70%) is an ideal match for electric vehicles and will be seen as the most appealing option for environmentally conscious consumers;
- Constantly evolving energy storage systems, electric drives and charging technologies will improve efficiency and range of electric vehicles. Electric vehicles now satisfy the daily commuting needs of regular consumers; and
- Electric vehicles offering lower running costs than traditional internal combustion engines due to the increasing cost of fossil fuels and the higher efficiency of energy conversion from battery storage.

The expected uptake of electric vehicles in future years and resultant increase in usage volumes will be investigated further to determine the likely network impact. At present, insufficient data exists to determine the rate of uptake of electric vehicles, usage habits and charging patterns, as such, has been omitted from current network planning.

9.2.7 General Planning Assumptions and Inputs

Further inputs to the planning process include:

- District Plans;
- Customer connection requests and high level queries,
- Historical demand forecasts;
- Local knowledge of deficiencies in the network;
- Equipment capacities including nameplate capacity and cyclic/seasonal ratings; and
- Equipment age.

These inputs to the planning process ensure that all current and prospective constraints are planned for and mitigated using the most optimal strategies in order to maintain or improve network security and reliability.

9.2.8 Standardised Designs

The implementation of standardised designs for common developments allows for significant reduction in design expenditure and substantially reduces the requirement for review and assessment. Standardised designs also aid in consistency in installation, commissioning and maintenance processes, thus improving familiarity for field staff and potentially reducing the cost of implementation.

Standardised designs are implemented for the purpose of asset and installation specification. At present, design standards are utilised for zone substation and distribution level earthing and LV reticulation. These standardised designs improve efficiency by minimising the design component for commonly performed projects.

Due to the quantity of residential sub-divisions completed in recent years or planned, an underground subdivision design standard has been developed in recent years. A protection standard is also in progress which will aim to provide standardised designs for a variety of schemes and equipment standardisation.

At present, there is no standardisation of HV network augmentations. These are performed as needed specific to the requirements of each planned project.

9.2.9 Asset Capacity

Asset capacity is determined as follows:

- Transformers – The transformer nameplate rating determines asset capacity. For planning purposes, only cyclic capacities[47] (or firm capacity) are considered. Short duration (2 hour) emergency overload ratings, based on nameplate values, are only accounted for during contingency operation;
- Subtransmission Cables – Subtransmission cable capacity is determined through CYMCAP modelling, considering the effect of soil resistivity, the prospective load profile and resulting thermal inertia, mutual

[47] Cyclic rating based on a 24 hour load profile (typical or measured) and resulting thermal inertia allows for loading above normal ratings. This is due to the rate at which the asset temperature reaches its thermal rating during peak times and allowing for sufficient cooling at off peak.

heating due to adjacent conductors and configuration of installation. Soil and ambient temperature variations between seasons are also allowed for providing a set of normal, cyclic and emergency ratings. For planning purposes, the cyclic summer and winter ratings are considered. Short duration emergency overload ratings, based on nameplate values are only accounted for during contingency operation;

- Subtransmission Circuit Capacity – This is determined based on the lowest rated component of the subtransmission circuit, i.e. a transformer may be rated to 36MVA cyclic while the supplying subtransmission cable is only capable of 21MVA cyclic and 17MVA cyclic during winter and summer respectively. Thus the effective rating of the subtransmission circuit is limited to the seasonal cyclic rating of the subtransmission cable; and

- Distribution Cables – Distribution feeders are rated based on the capacity of the cable at the point of connection to the zone substation. Distribution cable capacity is the capacity of the lowest rated segment of the cable, thus a constraint may not be apparent at the feeder supply point, but an undersized section of cable on a particular feeder may constrain capacity at a certain point along the feeder.

The capacity of all network elements is modelled in the DIgSILENT PowerFactory network model, providing ready analysis of network demand vs available capacity.

9.3 Prioritisation of Capital Works Projects

Budgets and other resource constraints are typically a limiting factor in achieving all the programmes and projects identified in this AMP.

Hence, every year, as part of the capital works planning and budgeting process, the list of projects is reviewed and prioritised accordingly. Following the completion of risk analysis or benefit-cost ratio studies on potential projects, a less formal weighting process based on the nature of the project is applied to discretionary and non-discretionary projects in finally selecting projects for inclusion in the works programme.

The following sequence is generally used for prioritising the projects to be included in the capital expenditure programme for that year:

- Safety benefits to the public and personnel;
- Non-discretionary projects;
- Quality of supply and stakeholder satisfaction;
- Company policies and standards;
- Risk to the network;
- Strategic benefit; and
- Commercial returns and investment recovery.

A subset of non-discretionary projects outside of the prioritisation process includes:

(i) HSE and Legal Compliance

Wellington Electricity's top priority is to operate a safe and reliable network, and thus projects needed to address safety concerns and/or meet legal requirements are given high priority.

(ii) Customer-initiated Projects

Provided Wellington Electricity has received sufficient advanced notice, it will give appropriate priority to planning, designing and implementing projects required to meet the needs of commercial and industrial customers.

Under this approach, legal compliance, the need to meet customer requirements, and risk mitigation tend to be the main drivers for the inclusion of projects in the works programme. Wellington Electricity's top priority is to operate a safe and reliable network, and it prioritises those projects that provide safety benefits or are needed to meet legal requirements above others.

Customer driven growth projects generally result from the development of new subdivisions, commercial or industrial projects. Where possible, these projects are prioritised to meet customers' needs. These customer priorities (where Wellington Electricity has been advised in advance) are incorporated into Wellington Electricity's project execution schedules. Related to customer driven projects are those that are implemented to ensure that Wellington Electricity can meet the load capacity requirements on all parts of its network. In general, no shortfalls in supply capacity under normal operating conditions are tolerated. Network integrity projects are those that address the continued effective operation of the distribution network and include renewal and refurbishment projects.

Reliability and security of supply projects are focused on ensuring that the required reliability standards on the network are met and that security of supply standards are maintained.

9.4 Overview of the Network Development Plan (NDP)

The NDP describes the identified need, options and investment path for the network over the next 10 years. As each of the three network areas are largely electrically independent and have a different set of challenges, they are addressed separately. Each is structured in accordance with the network hierarchy of GXP level requirements, sub transmission and zone substations and then distribution level investments.

The GXP level discussion has been developed with reference to Transpower's Annual Planning Report and formal discussions Wellington Electricity has held with Transpower as to their proposed development plans. For Wellington Electricity's subtransmission and distribution networks detail is provided on identified constraints and development plans.

While planning for each network area is approached using a consistent methodology, they are not all equal in terms of the level of development. Specifically, a detailed review of the development plan for the southern network is currently underway and is planned to be finalised in 2015. Accordingly, for the purposes of this AMP, a high level recommendation has been made on the network development plan adopted for this AMP. However, some of the details within this plan are likely to change as the review is finalised. In regard to the Wellington Northwestern and Northeastern areas similar reviews are planned for 2015. In the meantime, for the purpose of this AMP, the existing planning around previously identified issues remains as the development strategy and is the best information available at present.

The NDP for each of network area is described the in the following sections.

9.5 Wellington Southern Area NDP

This section provides a summary of the Southern area NDP. As noted above these plans are currently subject to a detailed review, to be completed in 2015. There are four development paths being investigated, consisting of a sequence of operational and non-operational solutions with specific timing of application to mitigate the identified issues. These four development paths form the foundation for the material in this section. The proposed expenditure profile is based on the development path that is at this stage considered the most economic.

This section is structured as follows:

- Identified GXP level capacity constraints and security of supply issues;
- Identified subtransmission and distribution level capacity constraints and security of supply issues;
- The long term network development options that address the identified network needs and the recommended development path; and
- A summary of the expenditure profile for the next 10 years.

Detail is also provided for the projects currently in progress or completed in the previous year.

9.5.1 Development Needs

9.5.1.1 GXP Level Constraints

The Southern network is supplied from three GXPs. Central Park GXP consists of both a 33kV and 11kV bus which supply separate zone substations. The transformer capacity and the maximum system demand are set out in Figure 9-4.

GXP	Installed Capacity (MVA)	Transformer Cyclic N-1 Capacity (Firm Capacity, MVA)	System Maximum Demand (MVA)	
			2015	2024
Central Park 33kV	2x100 + 1x120	228	153	145
Central Park 11kV	2x25	30	25	24
Wilton 33kV	2x100	106	54	58
Kaiwharawhara 11kV	2x40	41	34	33

Figure 9-4 Southern Area GXP Capacities

The Southern NDP has identified two critical but related issues that impact on the security of supply to the Wellington CBD area:

- The security of supply at Central Park GXP (for an N-2 event); and
- The lack of diversity of supply into the CBD (single point failure risks).

These issues are discussed within further detail regarding the Southern area GXPs.

Central Park GXP

The following network elements are detrimental to security of supply at Central Park GXP:

- Two of the 110kV lines from Wilton to Central Park are terminated on a single bus section at the Wilton 110kV bus, thus a loss of this bus section would compromise available capacity;
- The configuration of the 33kV switchroom presents a substantial single point failure risk as there is no active fire suppression installed. Additionally, there is no segregation or blast wall between the individual 33kV bus sections and all 33kV cabling is installed in a common trench prior to termination to the switchgear;
- The circuits supplying T4 and T5 share a common structure for the entire route between Wilton and Central Park. Additionally, all three 110kV lines are installed on common structures for a portion of the route prior to entry to Central Park. A failure of these four structures will completely interrupt supply to Central Park. This has been identified as a risk in the Transpower High Impact Low Probability Event plan;
- There is minimal segregation between T3 and T4 and a lack of blast protection. Catastrophic failure of one of these units has the potential to damage the adjacent unit, potentially reducing the supply capacity to a single transformer for a potentially lengthy duration for repair and restoration works; and
- The age and condition of the T3 and T4 110/33kV single phase banks is of concern to Wellington Electricity due to their criticality. The transformers are approximately 38 years old and are in relatively good condition. However historical distributed gas analysis results have indicated that the transformers were in need of replacement. Transpower have since revisited the results and determined the DGA results were due to a defect with the tap changers and the determination is that replacement is no longer warranted. Wellington Electricity is currently in discussions with Transpower over this issue.

While the capacity at Central Park is sufficient to support the loss of a single 110kV circuit, the loading will exceed available capacity on loss of a second 110kV circuit. Consequently, the System Operator requires the post-contingency (N-2) loading be restricted to the capacity of the lowest rated 110kV circuit (T3 & T4 post-contingency rating: 109MVA) due to the lack of a 110kV bus at Central Park.

In 2010, a special protection scheme (SPS) was implemented to provide automatic load management should two of the 110kV circuits be out of service. Transpower have operational control of this SPS. This system is armed when one circuit is out of service and once activated will automatically shed load such that capacity of the remaining 110kV circuit is not breached.

During N-2 operation, the SPS will be required to shed load of up to 50 MVA following loss of two 110kV circuits for approximately 14.4% of the time in a year. Due to the lack of diversity of supply in the CBD and the lack of inter-connectivity between GXPs, the load unserved during a Central Park N-2 event is unable to be transferred to adjacent zones and as such will remain unserved until Central Park is restored. Given the forecasted changes in peak demand discussed in Section 8, the magnitude of load at risk is expected to decrease to 40MVA or approximately 22% of the total peak demand at Central Park by 2024.

In addition to this, the 110kV double circuit line supplying T4 and T5 is installed on the same structure, us a double circuit outage is a possibility and accordingly the N-2 rating of Central Park is of particular interest.

To address these issues Wellington Electricity is in discussions with Transpower over the single point failure issues, and a High Level Request (HLR) was submitted to Transpower in October 2014 to examine the feasibility and costing to implement the following:

- Investigate installation of blast walls to provide adequate segregation for the existing transformers;
- Replacement of one of the single phase 109MVA transformer banks with a modern three phase equivalent, rated to 146MVA;
- Mitigation of the risk of catastrophic failure of the 33kV switchroom in the event of a fire by implementation of active fire suppression; and
- Investigation into the feasibility of construction of a 110kV bus within the Central Park switchyard.

Transpower provided a response to the HLR in early 2015 stating the feasibility of the discussed options and approximate costing to achieve the desired outcome. The majority of load within the Wellington CBD is currently supplied from Central Park. A catastrophic failure at this station will result in an outage to over 55,000 customers including a number of critical services such as:

- Wellington Hospital and a number of private hospitals;
- Water treatment and pumping stations;
- Parliament and Civil Defence facilities;
- Traffic lights, trolley bus supply and street lighting;
- The Stock Exchange, Treasury, Banking, and financial institutions; and
- Data centres and customers with sensitive load requirements..

While mitigation of the security of supply risks at Central Park will improve the reliability of supply to the Wellington CBD, it is still preferable to have diversity of supply provided by subtransmission and distribution inter-connectivity to provide:

- Flexibility in post-contingency load restoration;
- A reduction of the load unserved for a Central Park N-2 event; and
- Redundant capacity for supply of critical services following catastrophic failure at Central Park.

The existing Wellington CBD network has insufficient inter-connectivity at the subtransmission and distribution levels to satisfy these requirements. In many cases the marginal cost of meeting these diversity requirements is comparatively small if considered in context of the network development required due to other factors such as capacity constraints or risks to security of supply. As such the plans presented in this AMP have been developed with these resilience drivers as an additional requirement in mind.

Wilton GXP

The majority of the Wellington CBD is supplied from the Wilton 110kV bus which has been identified as a high risk by Transpower in its HILP study. Catastrophic failure of the Wilton 110kV bus will result in a loss of supply to all customers in the Southern area for a substantial duration.

Transpower have identified that the Wilton 110kV bus does not meet grid reliability standards and has an investment proposal underway to rebuild the 110kV bus as a three-section bus (tentatively commencing 2015 following approval). This will adequately address the supply diversity concerns at Wilton as each of the three Central Park circuits will be terminated to an individual bus section.

During 2014, Transpower completed replacement of the outdoor 33kV switchyard with an indoor switchboard as part of Transpower's ongoing programme of outdoor-indoor conversions.

Kaiwharawhara GXP

Based on the demand forecasts in Section 8.4.1 the loading will not breach the firm capacity at Kaiwharawhara during the planning period. Transpower have no planned works at this site.

9.5.1.2 Subtransmission Level Constraints

This section describes the existing subtransmission network and identifies where the network topography and capacity does not meet Wellington Electricity's security criteria. The options for mitigation of the constraints are also discussed.

The Southern area network consists of 22 subtransmission 33kV circuits supplying 11 zone substations. Each zone substation supplies the respective 11kV distribution network with inter-connectivity via switched open points to adjacent zones. The characteristics of each zone substation are listed in Figure 9-5.

Zone Substation	Firm Capacity (MVA)	Single Incoming Circuit Capacity (MVA)		Peak Season	Forecast Peak Demand (MVA)		Date Constraints are Binding	ICP Counts as at 2014
		Winter	Summer		2015	2024		
Palm Grove	24	34	32	Winter	25	24	Existing	11,226
Frederick St	36	21	17	Winter	28	26	Existing	10,613
Evans Bay	24	19	15	Winter	15	16	N/A	5,382
Hataitai	23	22	13	Winter	20	19	N/A	7,413
University	24	26	20	Winter	24	23	Existing	8,277
The Terrace	24	34	32	Summer	27	28	2020	2,844
8 Ira St	24	21	15	Winter	16	16	N/A	5,164

Zone Substation	Firm Capacity (MVA)	Single Incoming Circuit Capacity (MVA)		Peak Season	Forecast Peak Demand (MVA)		Date Constraints are Binding	ICP Counts as at 2014
		Winter	Summer		2015	2024		
Nairn St	30.1	25	25	Winter	25	24	N/A	5,478
Karori	24	21	11	Winter	17	16	N/A	6,271
Moore St	36	36	31	Summer	25	27	2018	1,521
Waikowhai St	19	21	13	Winter	16	17	N/A	5,777

Figure 9-5 Southern Area Zone Substation Capacities

At the subtransmission level, Wellington Electricity's planning security criterion is to maintain N-1 capacity down to 11kV feeders. A typical subtransmission circuit in the area is configured in the following manner:

- Cabling at 33kV to the zone substation supply transformers. Typically this consists of a double circuit arrangement terminating to separate supply transformers. These cables are operated at the cyclic (temporary overload) rating. The magnitude of cyclic rating is determined by the ambient temperature (Summer and Winter) and pre-event loading;

- Zone substation 33kV/11kV supply transformers, in the 20-40MVA range, fitted with oil circulation pumps and cooling fans to provide a higher cyclic (temporary overload overload) rating[48]; and

- 11kV cabling from the LV terminations of the transformers to the incomers on the switchboard can potentially constrain the subtransmission circuit rating if undersized, thus is also considered a component of the subtransmission circuit.

There are a number of issues at the subtransmission and distribution level that have been identified as part of the Southern NDP. These are outlined in the following sections.

Subtransmission constraints can be quantified in terms of a duration of breach and assessed against the security criteria in Figure 9-6, using a load duration curve (based on load data for October 2013 to October 2014). Forecasted constraints are quantified in terms of when the breach is likely to occur given the expected value in the range of possible forecast values for a given year.

Frederick St

The peak load supplied by Frederick Street is currently in breach of the cyclic N-1 capacity of the subtransmission supply cables. The cyclic N-1 capacity is constrained due to a de-rating of approximately 8MVA (on summer and winter cyclic rating) caused by the proximity of adjacent cables. Greater levels of constraint exist in summer than winter. Consequently at peak demand periods, the post contingency

[48] For standardised transformer sizes operated by Wellington Electricity refer to Section 6.1.3.

response is to partially off-load Frederick St following closing of the bus section to avoid overloading the remaining subtransmission cable. This is illustrated in Figure 9-6.

Circuit	Season	Constraining N-1 Cyclic capacity (MVA)	Peak Demand @ 2014 (MVA)	Minimum off load for N-1 @ peak (MVA)
Frederick St 1	Winter	21	28	7
	Summer	17	26	9
Frederick St 2	Winter	21	28	7
	Summer	17	26	9

Figure 9-6 Current Frederick Street Subtransmission Constraints

The available capacity at a distribution level is sufficient to back-feed sufficient load post contingency to avoid overloading the remaining subtransmission cable. There is a risk that future step change loading on feeders inter-connecting with Frederick St will reduce the available transfer capacity and providing sufficient post contingency offload will not be possible.

The magnitude of load at risk and duration is summarised in the load duration curves in Figure 9-7. The subtransmission N-1 capacity constraints that are breached are plotted for comparison.

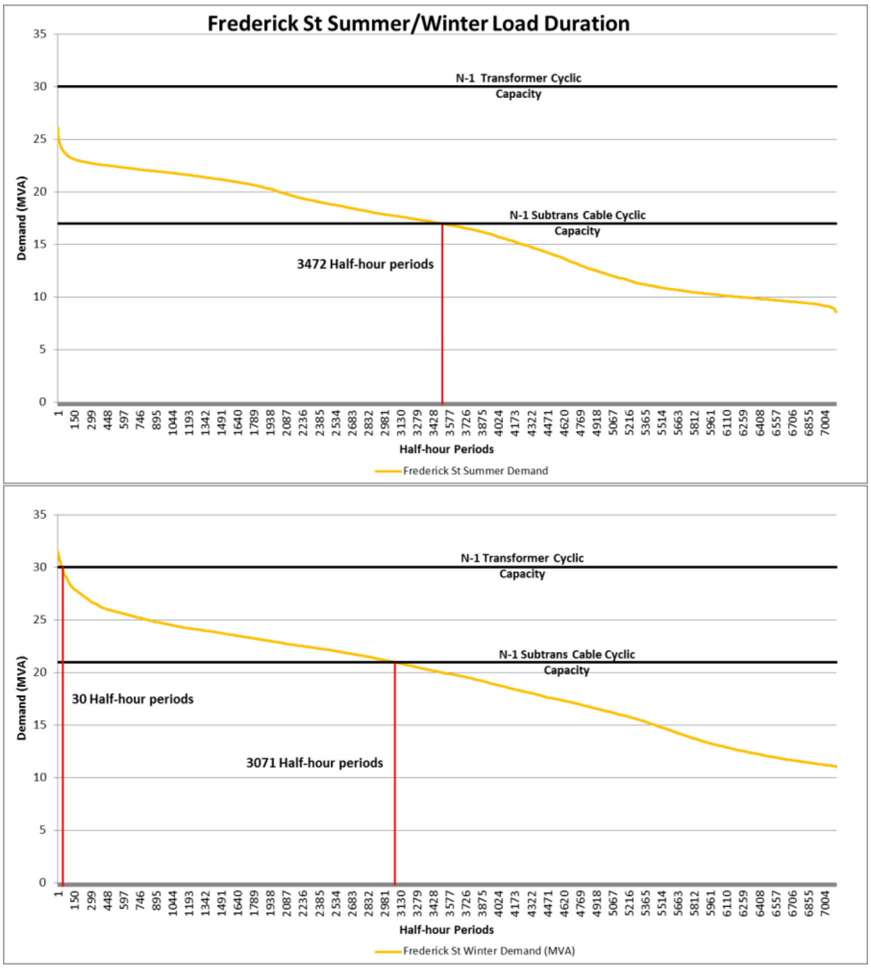


Figure 9-7 Frederick Street Load Duration

The load duration curve shows that a significant proportion of load is at risk during the summer and winter. The immediate concern is that loading exceeds the N-1 Cable Summer Cyclic rating for approximately 19.8% of the time in a year and the N-1 Cable Winter Cyclic rating for approximately 17.5% of the time in a year which is in breach of security criteria discussed in Section 9.2.1. Winter loading is predicted to breach the N-1 Transformer Cyclic ratings however the duration of breach is currently minimal. The load forecast in Section 8 shows that peak demand is expected to decline. The magnitude of peak demand load at risk is expected to decline from 8MVA at present to 6MVA in 2024, in breach of planning criteria for the duration of the planning period. There is a risk that unforeseen step change growth in the planning period will further increase the magnitude of this breach. Network development planning identifies that the most cost effective solution is to partially offload Frederick St to a new zone substation in 2018 as discussed in Section 9.5.3.

Palm Grove

The peak load supplied by Palm Grove is currently in breach of the N-1 capacity of the zone substation supply transformers. This is illustrated in Figure 9-8. Greater levels of constraint exist in winter than summer.

Circuit	Season	Constraining N-1 Cyclic capacity (MVA)	Peak Demand @2014 (MVA)	Minimum off load for N-1 @ peak (MVA)
Palm Grove 1	Winter	24	25	1
	Summer	24	18	0
Palm Grove 2	Winter	24	25	1
	Summer	24	18	0

Figure 9-8 Current Palm Grove Subtransmission Constraints

At present, following a loss of a single subtransmission circuit at Palm Grove, the standard response is to partially offload a portion of loading to adjacent zones before closing the bus tie. The entire Palm Grove bus is then supplied from the healthy subtransmission circuit. The subtransmission cables supplying Palm Grove were replaced in 2014 with high capacity XLPE cables.

Therefore, subtransmission faults may require a substantial length of time to mitigate for the faulted circuit to be returned to service. There are a number of switching operations required following closing the bus section. Back-feed switching must be sequenced to maintain supply to Wellington Hospital at all times.

However, the pre-contingency loading at University, Nairn St and Hataitai needs to be considered before enacting back-feeds at Palm Grove due to distribution level constraints that may be breached.

At times the available distribution level transfer capacity can be insufficient to allow the bus-tie to be closed and backfeed the total load at Palm Grove to the remaining subtransmission circuit. Thus there will be a portion of unserved load even after contingency procedures are enacted.

Installation of new 33 kV cables to Palm Grove substation

The magnitude of load at risk and duration is summarised in the following load duration curves (typical half-hourly averages based on load data for October 2013 to October 2014). The applicable subtransmission N-1 capacity constraints (cyclic ratings of transformer and cable) are plotted for comparison.

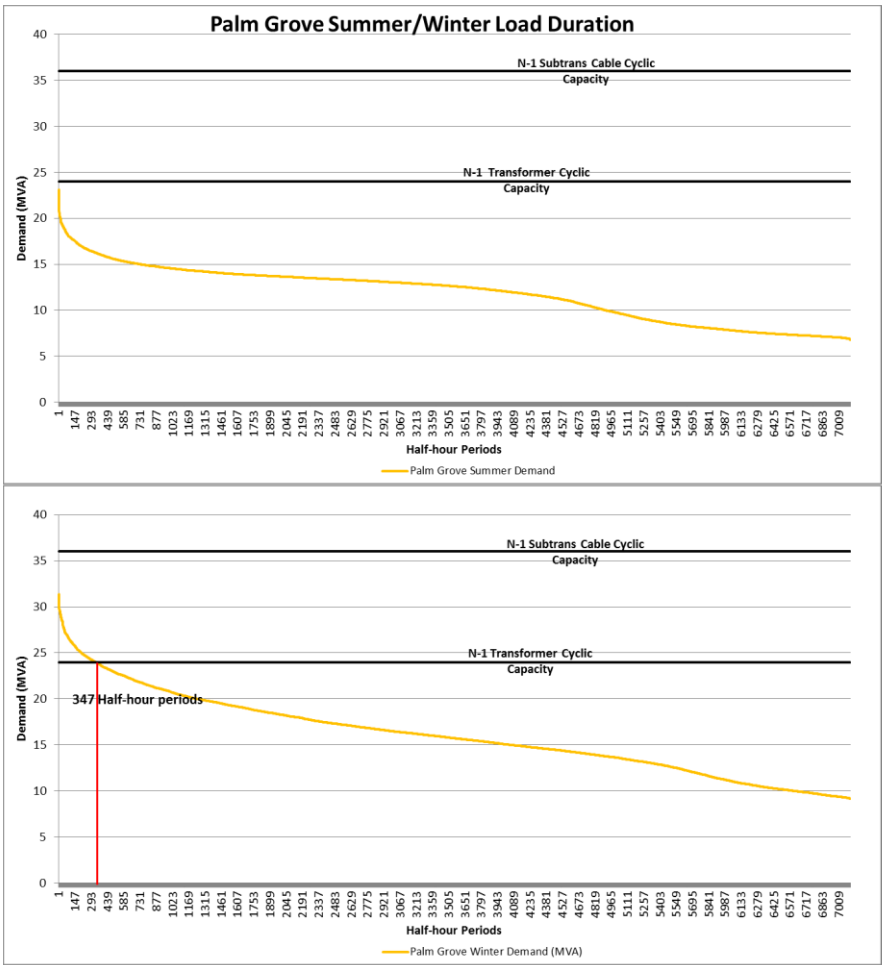


Figure 9-9 Palm Grove Load Duration

While the magnitude of sustained peak demand at Palm Grove in breach of subtransmission capacity is minimal, peak half hourly average demand (non-sustained peak) is in breach for an unacceptable duration of time during a year. The immediate concern is that peak demand loading during winter exceeds the N-1 Transformer Normal and Cyclic ratings for approximately 1.98% of the time in a year respectively which is in breach of security criteria as discussed in Section 9.2.1. The magnitude of this breach is expected to increase due to organic and step change load growth as shown in Section 8. Network development planning identifies that the most cost effective solution is to partially offload Palm Grove to a new zone substation in 2018/19 as discussed in Section 9.5.3.

The Terrace

The peak load supplied by The Terrace is currently within the available N-1 capacity of the subtransmission circuits supplying the zone substation. This is illustrated in Figure 9-10.

Circuit	Season	Constraining N-1 Cyclic capacity (MVA)	Peak Demand @ 2014 (MVA)	Minimum off load for N-1 @ peak (MVA)
The Terrace 1	Winter	36	26	0
	Summer	30	27	0
The Terrace 2	Winter	36	26	0
	Summer	30	27	0

Figure 9-10 Current Terrace Subtransmission Constraints

The load forecast for The Terrace zone substation in Figure 9-11 shows the expected peak demand range based on the estimated growth scenarios and confirmed step change loads for the next 15 years. In 2014, the University Reinforcement project was commissioned to balance loading across the two University bus sections and relieve the loading on feeder 8 and 11. The load forecast shown includes this step change.

While not currently exceeding N-1 capacity, there is a high likelihood that by 2020 the loading at The Terrace will breach the N-1 Cable Summer cyclic ratings. This breach is expected to increase further based on projected peak demand growth in the mid to long term. Network development planning identifies that the most cost effective solution is to introduce new 11kV infrastructure to inter-connect The Terrace and Moore St zone substations at the distribution level. Monitoring of peak demand growth over the short term will be required to ascertain when the recommended works, discussed in Section 9.5.3, should be applied.

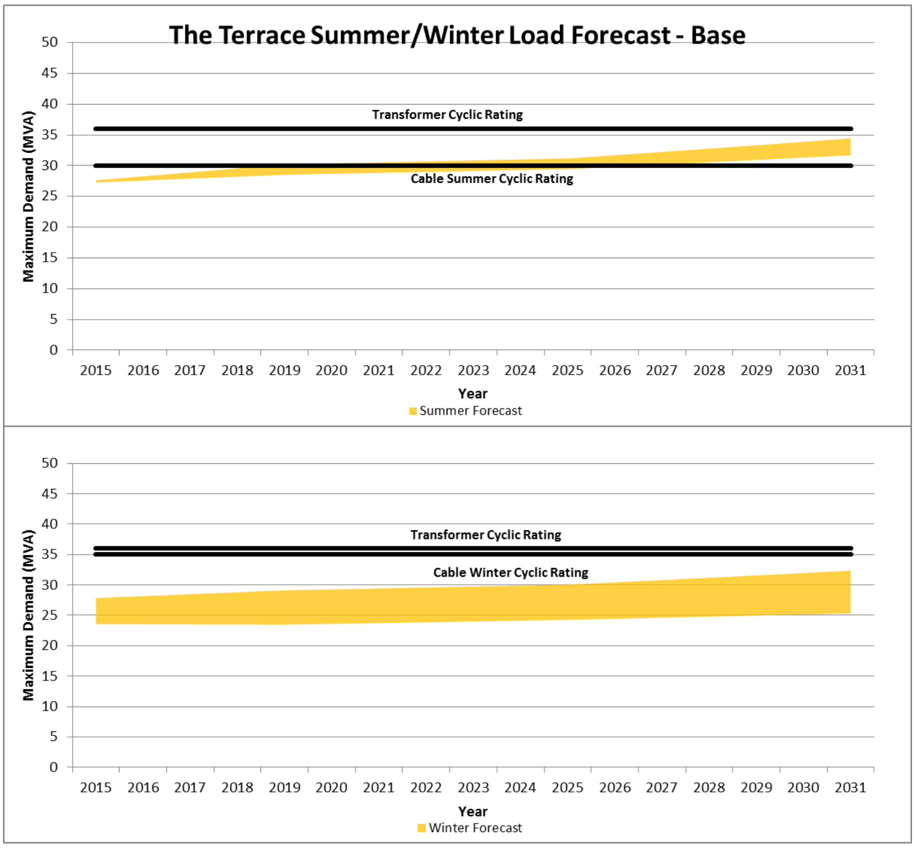


Figure 9-11 The Terrace Load Forecast

University

The peak demand at University is forecasted to increase. As discussed in Section 8, it is also expected that the University facilities will expand at the latter end of the planning period.

During peak demand there is a shortfall in capacity which requires a portion of load to be transferred to an adjacent zone following closing in the bus section breaker. This is illustrated in Figure 9-12.

Circuit	Season	Constraining N-1 Cyclic capacity (MVA)	Peak Demand @ 2014 (MVA)	Minimum off load for N-1 @ peak (MVA)
University 1	Winter	24	26.37	1-2MVA
	Summer	20	19.82	-
University 2	Winter	24	26.37	1-2MVA
	Summer	18	19.82	1-2MVA

Figure 9-12 Current University Subtransmission Constraints

The 11kV interconnection with Karori via Chaytor St can also be used to back-feed a portion of load at University. This will be required in the event that loading at University breaches the N-1 cyclic capacity of the remaining subtransmission circuit.

The magnitude of load at risk and duration can summarised in the load duration curves (typical half hourly averages based on load data for June 2013 to June 2014) shown in Figure 9-13. The subtransmission N-1 capacity constraints that are breached (cyclic ratings of transformer and cable) are plotted for comparison. An approximation of the step change demand due to development at Victoria University has also been plotted.

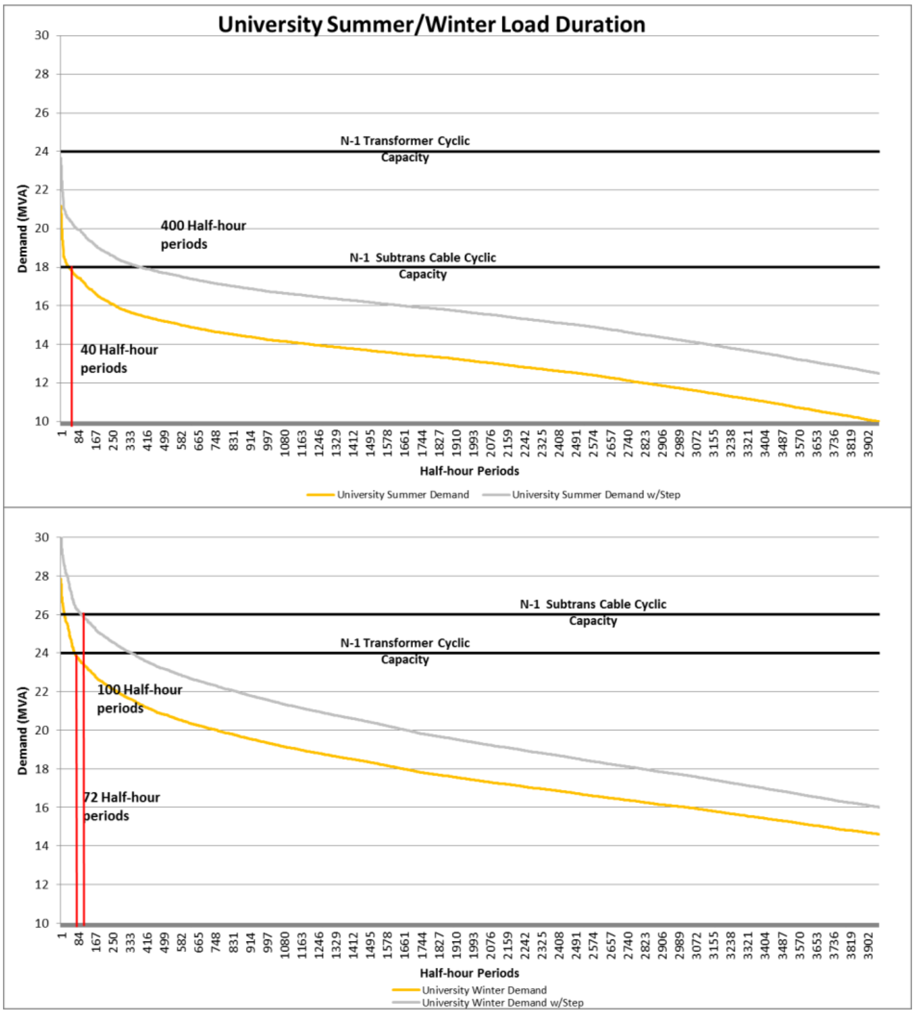


Figure 9-13 University Z/S Load Duration Curve

The loading at University is shown to exceed the available N-1 capacity for approximately 0.41% of the time in a year (or 0.57% of the time in a year when considering the expected step change demand due to development at Victoria University). The duration load is at risk is currently within the applicable security criteria discussed in Section 9.2.1. The expected step change loading at University will increase the magnitude of peak demand load at risk to 3-4 MVA. Network development planning identifies the most cost effective strategies for mitigation are non-network solutions, such as demand side management or load shifts using existing infrastructure. The constraining segments of the subtransmission circuits will be replaced by 2024 due to age which will improve subtransmission capacity and minimise the expected peak demand load at risk due to step change growth.

Moore St

The organic load growth at Moore St is forecasted to increase the peak demand to 28MVA by 2024. There are a number of step change loads expected during the planning period as discussed in Section 8.

The peak demand supplied by Moore St is currently within the available N-1 capacity of the subtransmission circuits supplying the zone substation. This is illustrated in Figure 9-14 below.

Circuit	Season	Constraining N-1 Cyclic capacity (MVA)	Peak Demand @ 2014 (MVA)	Minimum off load for N-1 @ peak (MVA)
Moore St 1	Winter	36	21	0
	Summer	31	24	0
Moore St 2	Winter	36	21	0
	Summer	31	24	0

Figure 9-14 Current Moore St Subtransmission Constraints

The configuration of Moore St feeder 12 and 14 feeding the stadium and CentrePort was modified during 2014. Cornwell St substation is to be removed and a portion of load is to be transferred to Kaiwharawhara. The Moore St Reinforcement will introduce a new feeder into the CentrePort area and thus will not impact on loading on the Moore St subtransmission circuits.

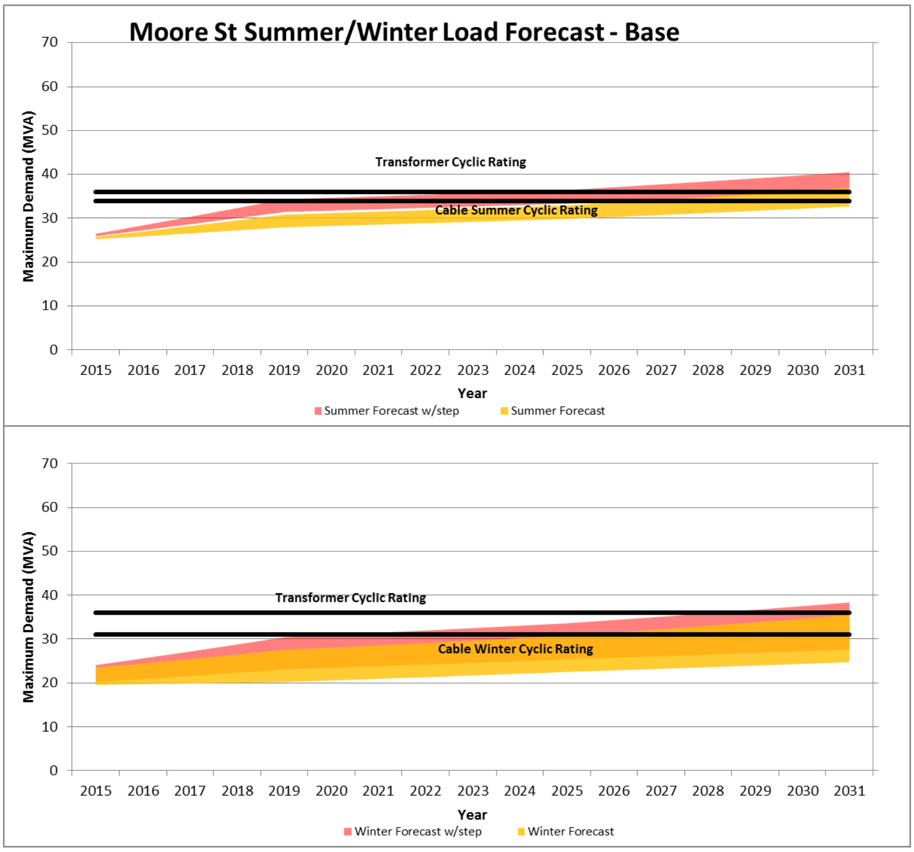


Figure 9-15 Moore St Load Forecast

Load growth at Moore St is expected to breach the ratings of a single subtransmission circuit by 2022. A more immediate concern is that the summer peak loading is forecasted to breach the cable summer N-1 cyclic rating by 2018.

The timing of step change loading, due to development in the Waterfront and Parliament precincts, is unconfirmed at this stage. The impact of step change loading will be to delay or bring forward the time at which N-1 subtransmission constraints will be binding.

9.5.1.3 Distribution Level

The most critical distribution level issues are those associated with overload of meshed ring feeders supplying a high number of customers- or links between zones, which can be used for load transfer. Figure 9-16 shows where the applicable planning criteria for the various feeder configurations shown in Figure 9-2 breached within the distribution network and an estimation of when the constraints bind.

Feeder		Zone Substation	Present Loading	+5 years	+10 years	Feeder ICP Count
FRE CB04	106 Tory St	Frederick St			93%[1]	1,279
FRE CB13	21 Tasman St	Frederick St	79%	79%	70%	1,342
PAL CB02[5]	312 Adelaide Rd	Palm Grove		88%[1]	86%	1,376
PAL CB03[5]	415 Adelaide Rd	Palm Grove		69%	68%	1,101
PAL CB06[5]	Mansfield St	Palm Grove		85%[1]	84%	1,436
PAL CB12	The Parade	Palm Grove	66%	70%	67%	867
UNI CB13	33 Kelburn Pde	University	77%	70%	70%	[6]
IRA CB02	Inglis St	8 Ira St	78%	81%	84%	1,399
IRA CB12	Devonshire Rd	8 Ira St	67%	70%	73%	[6]
KAR CB02	Dasent St	Karori	90%[3]	82%	76%	535
KAR CB04	Burrows Ave	Karori	73%[3]	66%		2,238
WAK CB04	Orari St	Waikowhai	69%[2]	73%	79%	1,647
KAI CB06	Abbatoirs West	Kaiwharawhara	100%[4]	100%	100%	429
MOO CB09	47 Thorndon Quay	Moore St		67%	74%	150
MOO CB12	55 Aotea Quay	Moore St		67%	70%	76
MOO CB14	50 Thorndon Quay	Moore St		90%[1]	94%	522
TER CB15	88 Boulcott St	The Terrace	66%	69%	71%	269

Figure 9-16 Distribution Level Issues

Notes to Figure 9-16

1. Due to potential step change in the area
2. Undersized cable segment
3. Due to 9 Parkvale Road switchgear replacement and network reconfiguration
4. Recommendation has been developed for customer to alleviate works – Taylor Preston project.
5. Palm Grove 2/3/6 ring supplies the Wellington Hospital
6. Recent reconfiguration of feeders, ICP count are not available.

Overloads on feeders supplied from Nairn St, Karori and Evans Bay decline from year to year due to the declining growth rate in these areas. Non-network solutions, such as open point shifts, are recommended to mitigate these specific issues.

Cascade tripping of ring feeders for a loss of a single component feeder is a possibility due to the overcurrent settings applied at the zone substation. Settings are typically set for protection of the feeder breaker and an allowable short time overload of the cables. On certain meshed rings within the Wellington CBD network, the sudden loss of a single feeder will result in the transfer of sufficient load to the remaining feeders to cause a trip of the feeder protection relays at the zone substation. Each subsequent trip results in further overload of the remaining feeders. The result is the possible loss of the entire mesh ring and possible equipment and cable damage due to overloading prior to the protection devices clearing.

Figure 9-17 shows the results of the contingency analysis performed on all meshed ring feeders. Scenarios with overloading feeder segments for each contingency scenario are shown as well as the prospective location and loading. The contingency loading calculation is based on the peak demand for each feeder recorded for 2014.

Meshed Ring	N-1 Case	Feeder	To	From	Contingency Loading
FRE 3/4/5/6	FRE CB03 Out	FRE CB04	21 Tory St	200 Wakefield St	115.18%
	FRE CB08 Out	FRE CB04	106 Tory St	21 Tory St	106.34%
FRE 13/14	FRE CB13 Out	FRE CB14	Frederick St CB14	19 College St	116.26%
	FRE CB13 Out	FRE CB13	Frederick St CB13	21 Tasman St	128.10%
PAL 2/3/6	PAL CB02 Out	PAL CB03	130 Rintoul St	Newtown	119.20%
	PAL CB03 Out	PAL CB02	Palm Grove CB02	312 Adelaide Rd	105.15%
	PAL CB06 Out	PAL CB02	Palm Grove CB02	312 Adelaide Rd	102.44%

Meshed Ring	N-1 Case	Feeder	To	From	Contingency Loading
		PAL CB03	Riddiford Rd	74 Riddiford Rd	105.42%
PAL 8/10/12	PAL CB08 Out	PAL CB10	Herald St	37 Mersey St	125.20%
UNI 8/10	UNI CB08 Out	UNI CB10	University CB10	Military Rd	125.20%
		UNI CB11	University CB11	Chaytor St	124.80%
NAI 8/12	NAI CB08 Out	NAI CB12	Nairn St CB12	Webb St	105.69%
	NAI CB12 Out	NAI CB08	Nairn St CB08	Arthur St	107.32%

Figure 9-17 - Meshed Ring Feeder Contingency Analysis

9.5.2 Southern Network Development Options

This section describes the development options available to mitigate the constraints described above. It is set out according to the network hierarchy, GXP, subtransmission, and distribution. Significantly, more detail on these options are included in the NDP and as such only a summary is provided for the purpose of this AMP.

9.5.2.1 GXP Level Development Strategy

There are several options available to mitigate the capacity and security of supply risks identified at the GXP level. These options are currently being investigated as part of the Southern NDP.

Central Park Security of Supply

Central Park GXP

Wellington Electricity have initiated a HLR with Transpower to determine the feasibility and costing of the following works to mitigate the risks to security of supply:

- Transformer blast walls to be constructed to segregate the three transformer banks at Central Park and prevent cascade failure in the event of catastrophic failure of a single unit;
- Replacement of one of the single phase 109MVA transformer banks with a modern equivalent. This unit would be rated to 148MVA post-contingency and minimise the risk of reduction of supply capacity to N-2 and some of the risks associated with the condition of the transformers;
- Feasibility and costing for installation of active fire suppression within the 33kV switchroom. These measures were previously identified as a priority in Transpower's HILP study and would drastically improve the security of supply from Central Park; and

- The operational constraints at Central Park GXP could be further reduced by installing an 110kV bus. This option will improve the security and supply options at Central Park without compromising the reliability of the network.

The installation of a 110kV bus will require that the single phase 109MVA bank at the southern end of the substation is removed to provide sufficient room. These works will reduce security of supply to 148MVA at N-1, reducing the peak demand load at risk at Central Park to 30MVA. The network development options discussed in Section 9.5.2.2 are designed to provide improve transfer capacity between Central Park and Wilton through subtransmission and distribution level improvements. The recommended development option, discussed in Section 9.5.3, provides approximately 36MVA of transfer capacity between Wilton and Central Park through improved distribution inter-connectivity and a new zone substation supplied from Wilton. The peak demand load at risk at Central Park on completion of the recommended development path will be minimal.

In addition to the issues Wellington Electricity has raised, Transpower has also identified a need to reconductor the three Wilton-Central Park 110kV circuits, which would require Central Park to be operated at reduced security for extended periods of time. In particular, it would need to be operated with only one incoming circuit, whilst the two circuits on double circuit towers were reconductored.

Other site risk issues, such as catastrophic damage from fire and natural disaster are being worked through by Transpower, include: development of contingency plans for transformer replacement, installation of a temporary 33kV switchroom, and other operational solutions which would be used to reduce the restoration time should the site experience such an outage.

Wilton GXP

All three 110kV circuits to Central Park are presently supplied from the same bus at Wilton GXP (which is configured as a single upper and lower bus arrangement). An outage on the 110kV bus at Wilton would cause a complete loss of supply to Central Park, as has occurred in the past during maintenance. Transpower has identified that the Wilton 110kV bus does not meet grid reliability standards and has an investment proposal underway to rebuild the bus as a new outdoor three-section bus (expected completion in 2016). This will address the supply diversity concerns at Wilton as the three Central Park circuits will each have their own bus section, each with an incoming 110kV supply circuit from the grid.

Wellington Electricity believes this option adequately addresses the Wilton GXP diversity issues.

Transpower has also undertaken, as part of its regional HILP study, a risk assessment of a loss of key assets at Wilton, such as the entire 220kV or 110kV bus structures, and has developed concept plans for bypass arrangements that would allow it to restore supply within short timeframes, should such an event occur.

Diversity of Supply to the CBD

As part of its investigation into this option, Wellington Electricity is considering the long-term economics of investing in its own network as an alternative to investing in further development of the Transpower grid. There are a number of options being investigated for diversifying load away from Central Park by utilising the distribution network and are detailed in the NDP. These options involve integration of the investment with that required to mitigate all of the identified existing and forecasted capacity constraints and risks to security of supply within the network. While further investigation is required to determine an optimal solution, four development options have been identified. These development strategies are discussed further in Section 9.5.2.2.

Prospective Submarine Cable Gracefield to Evans Bay

As detailed in previous AMPs, an option exists to install a submarine 110kV link between the Wellington City area (Evans Bay) and Gracefield. Wellington Electricity is currently exploring the feasibility of this option.

Local authorities have indicated that water supply to the Eastern Suburbs is a potential future problem and that an underwater pipeline may be installed across the harbour in the medium to long-term. If this were to eventuate, Wellington Electricity would assess the merits of installing a submarine cable at that time.

The subtransmission link concept is currently being investigated and is estimated to be in the order of $50 to $70 million. This is not included in current expenditure forecasts due to the uncertainty of the work.

9.5.2.2 Zone and Distribution Level Development Options

The NDP options for the Wellington CBD are comprised of a combination of the individual options required to meet each need. However, each option is not mutually exclusive and as such there are options which meet several needs for the same investment. Therefore there are combinations of options that result in different development paths and resulting investment requirements over the planning period. Four options have been identified as being the most practical within the planning period.

These are laid out in detail in Wellington Electricity's internal Network Development Plan document. A brief summary of the options is presented here, with a comparison table shown in Figure 9.22, and more detail provided on the components of the recommended option.

Section 9.5.1 identifies the current and forecasted constraints and the magnitude of peak demand load at risk. When compared with the total peak demand for the Wellington Region, the magnitude of peak demand load at risk is relatively small. Conversely, the prospective investment is estimated to be significant due to the quantity of works required to address the identified issues, physical constraints and the unique geography of the Wellington region.

Prior to any investment in any infrastructure being recommended, the first consideration is on non-network solutions to defer significant short term investment. These options include:

- Open point shifts using existing infrastructure to reduce loading on highly loaded feeders;
- Operational changes to better utilise existing network capacity over construction of redundant capacity; and
- Consideration of the cost effectiveness of demand side management to alleviate localised network constraints.

Common elements of all development paths are:

- Every effort is made to re-balance the loading across the isolated bus-sections at all zone substations. This is typically achieved by shifting open points or re-configuring which bus section individual feeders are terminated to;
- All distribution switchgear with a low condition or age score is to be replaced as per the ongoing asset renewal programme. All key switching points are to be replaced with switchgear complete with facility to remotely switch and monitor the outgoing feeders;

- In all development paths, there is the option to initiate a customer driven project with Transpower to replace the existing transformers at Central Park GXP with two new 148MVA units, effectively eliminating the Central Park N-2 risk.

- Minor breach of subtransmission constraints is accounted for by installing sufficient load transfer capacity and capability such that during contingency operation, large quantities of load can be readily shifted to reduce the risk of a potential overload.

Four development options identified are:

- Option 1: Installation of a new zone substation supplied from Wilton with distribution level interconnections to The Terrace, Frederick St and Palm Grove;

- Option 2: Augmentation of subtransmission and distribution infrastructure to alleviate constraints and improve transfer capacity;

- Option 3: Re-configuration of Nairn St to be supplied from Wilton, initiation of a customer driven project to improve security of supply at CPK and reinforcement of distribution links to adjacent zones;

- Option 4 (Recommended): Installation of a new zone substation supplied from Wilton with distribution level interconnections to Frederick St and Palm Grove and a separate distribution link between The Terrace and Moore St.

Further options are being investigated and will be detailed in the Southern NDP.

Option 1: Installation of a New Zone Substation

This option involves installation of a new zone substation supplied from Wilton.

The new zone substation would have distribution feeders inter-connecting with the highly loaded ring feeder configurations at The Terrace, Frederick St and Palm Grove. Load would be permanently transferred from these feeders such that identified subtransmission and distribution level issues are mitigated. A significant proportion of load within the Wellington CBD would be supplied from Wilton GXP via the new zone substation.

A number of smaller projects are enacted around these works to alleviate localised distribution level constraints, replace aging assets and improve security of supply.

Figure 9-18 provides a visual representation of the end product of this development path.

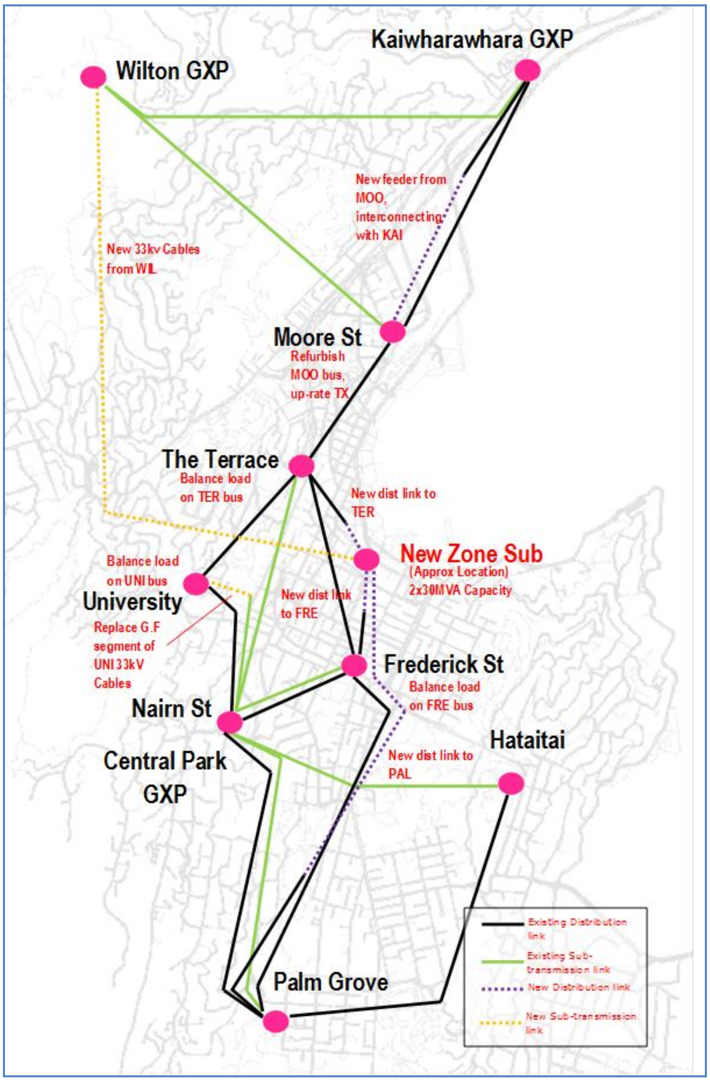


Figure 9-18 Proposed Configuration for Option 1

Option 2: Subtransmission & Distribution Level Augmentation

This option involves augmentation of the subtransmission and distribution networks to alleviate the identified issues. Increased transfer capacity is installed between Frederick St to Kaiwharawhara and The Terrace to Moore St utilising existing highly loaded ring feeder configurations. The loading on these ring feeders at Frederick St and The Terrace is reduced by permanently shifting via the new infrastructure to Moore St and Kaiwharawhara. These works effectively shifts load from Central Park to Wilton, alleviating the Central Park N-2 issue. Supply to load in the Wellington CBD is further diversified. The new infrastructure also serves to alleviate the subtransmission circuit loading to Frederick St and The Terrace and reduce loading on a number of highly loaded feeders and provides high capacity transfer for post-contingency offload during subtransmission faults at the four zones concerned.

The issues at Palm Grove are alleviated in isolation from the rest of the network. Further subtransmission capacity is provided by replacing the Palm Grove transformers with two new 30MVA units (36MVA cyclic). The distribution network is also reconfigured and reinforced to increase capacity. The existing inter-connections between Palm Grove and Nairn St are reinforced to provide post-contingency transfer capacity for a subtransmission fault at Palm Grove.

A number of smaller projects are enacted around these works to alleviate localised distribution level constraints, replace aging assets and improve security of supply.

Figure 9-19 below provides a visual representation of the end product of this development path.

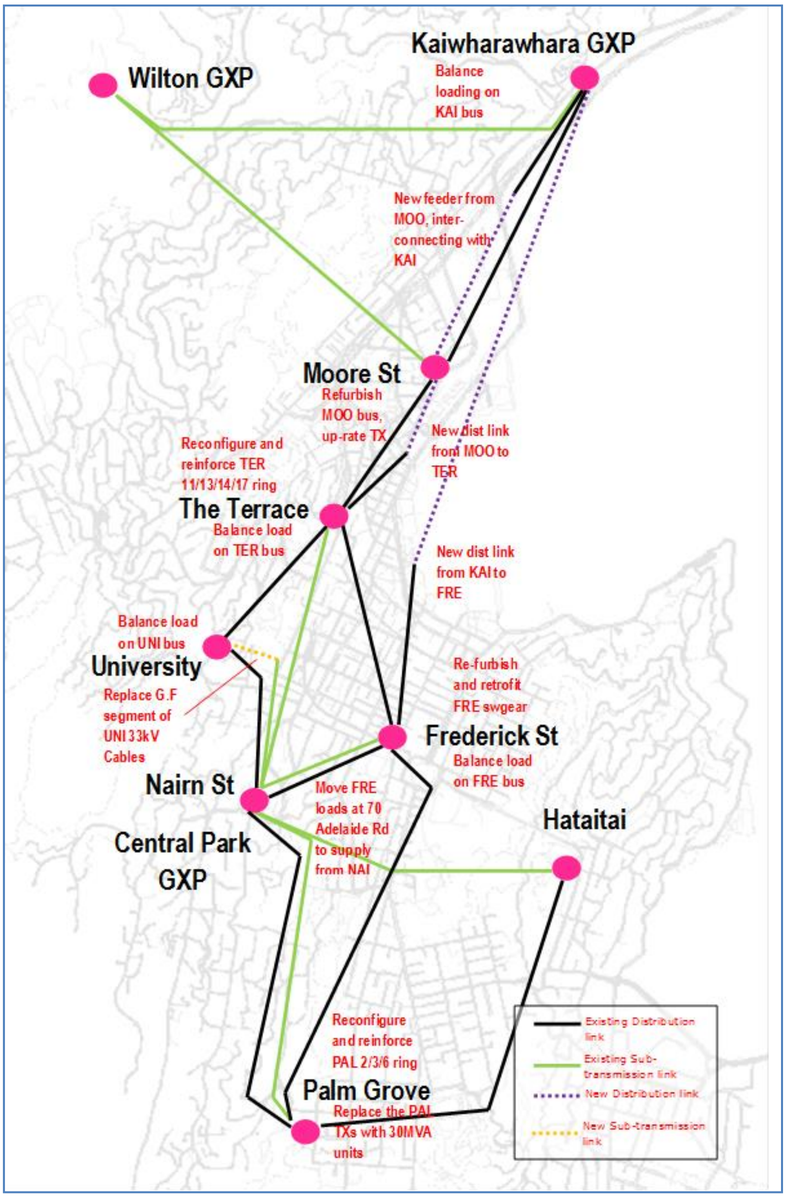


Figure 9-19 Proposed Configuration for Option 2

Option 3: Re-configuration of Nairn St for supply from Wilton GXP

This option involves reconfiguration of Nairn St as a zone substation supplied from Wilton. This can be achieved by reconfiguring Central Park GXP by replacing one of the single 109MVA transformer banks with Transpower's modern equivalent which is a 3 phase 148MVA unit. The third 109MVA transformer bank can be removed which modifies the available security of supply to 148MVA at N-1. A single Wilton to Central Park 110kV line can be operated at 33kV, terminated between the Wilton 33kV bus and directly onto the existing Nairn St transformers at Central Park such that all load supplied from Nairn St will be transferred to Wilton and reduce demand at Central Park to less than the newly modified N-1 capacity. A customer project will have to be initiated with Transpower to progress this development path.

The existing Nairn St transformers at Central Park are limited to 24MVA capacity which may be insufficient for this development path. A possibility will be to construct a new transformer bay adjacent to the Nairn St switchroom. This will involve significant civil works as the new structure will need to be constructed into the side of a bank with all the strengthening and earthworks entailed. Two new 30MVA units (36MVA cyclic capacity) can be installed such that additional load can be transferred to Nairn St, further diversifying supply of load in the Wellington CBD.

The distribution network at Nairn St is to be reconfigured and reinforced to provide further transfer capacity to presently backfeed load from Palm Grove and Frederick St. The issues at The Terrace are alleviated by introducing a new distribution link between The Terrace and Moore St and permanently shifting load.

A number of smaller projects are enacted around these works to alleviate localised distribution level constraints, replace aging assets and improve security of supply.

Figure 9-20 below provides a visual representation of the end product of this development path.

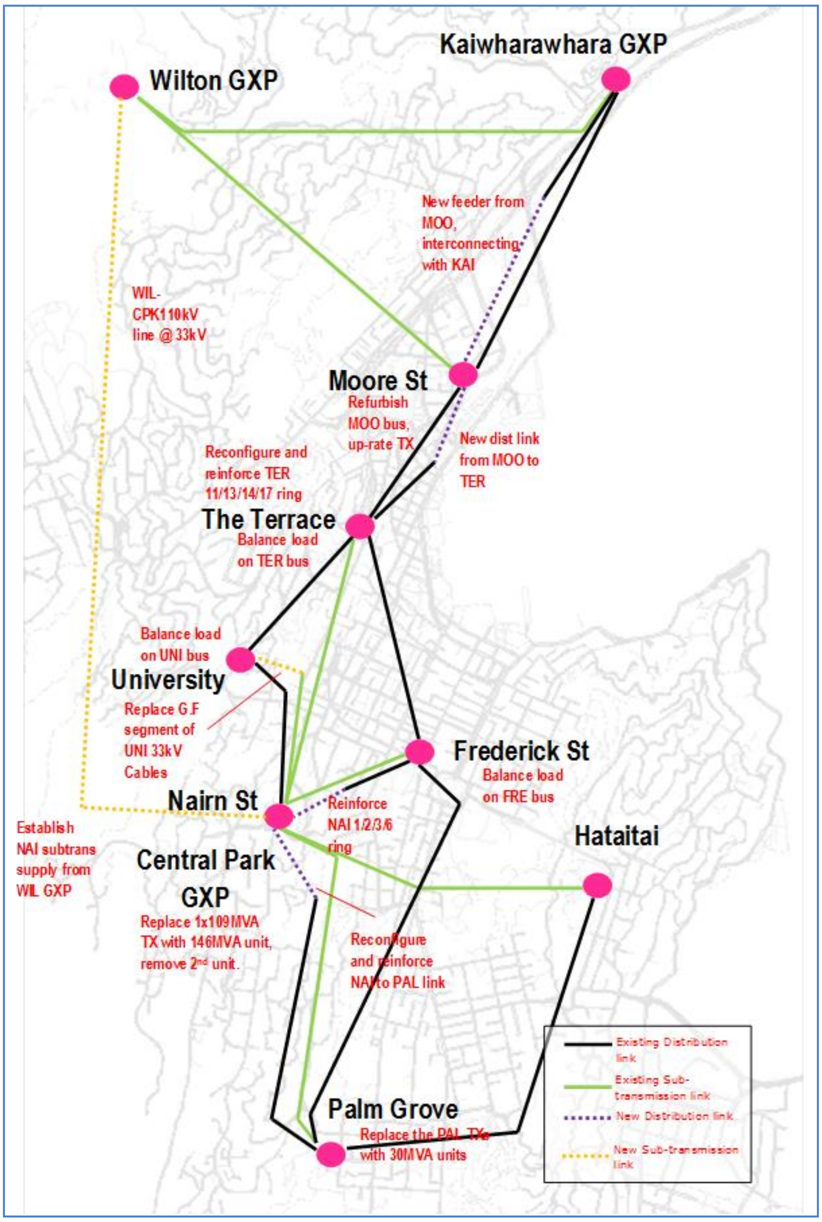


Figure 9-20 Proposed Configuration for Option 3

<u>Option 4 (Recommended): Installation of a new zone substation and improved transfer capacity at The Terrace</u>

This option is similar to Option 1 in that it involves installation of a new zone substation supplied from Wilton GXP.

The new zone substation would have distribution feeders inter-connecting with the highly loaded ring feeder configurations at Frederick St and Palm Grove. Load would be permanently transferred from these feeders such that identified subtransmission and distribution level issues are mitigated. A significant proportion of load within the Wellington CBD will now be supplied from Wilton GXP via the new zone substation.

The issues at The Terrace are alleviated by introducing a new distribution link between The Terrace and Moore St and permanently shifting load.

Figure 9-21 below provides a visual representation of the end product of this development path.

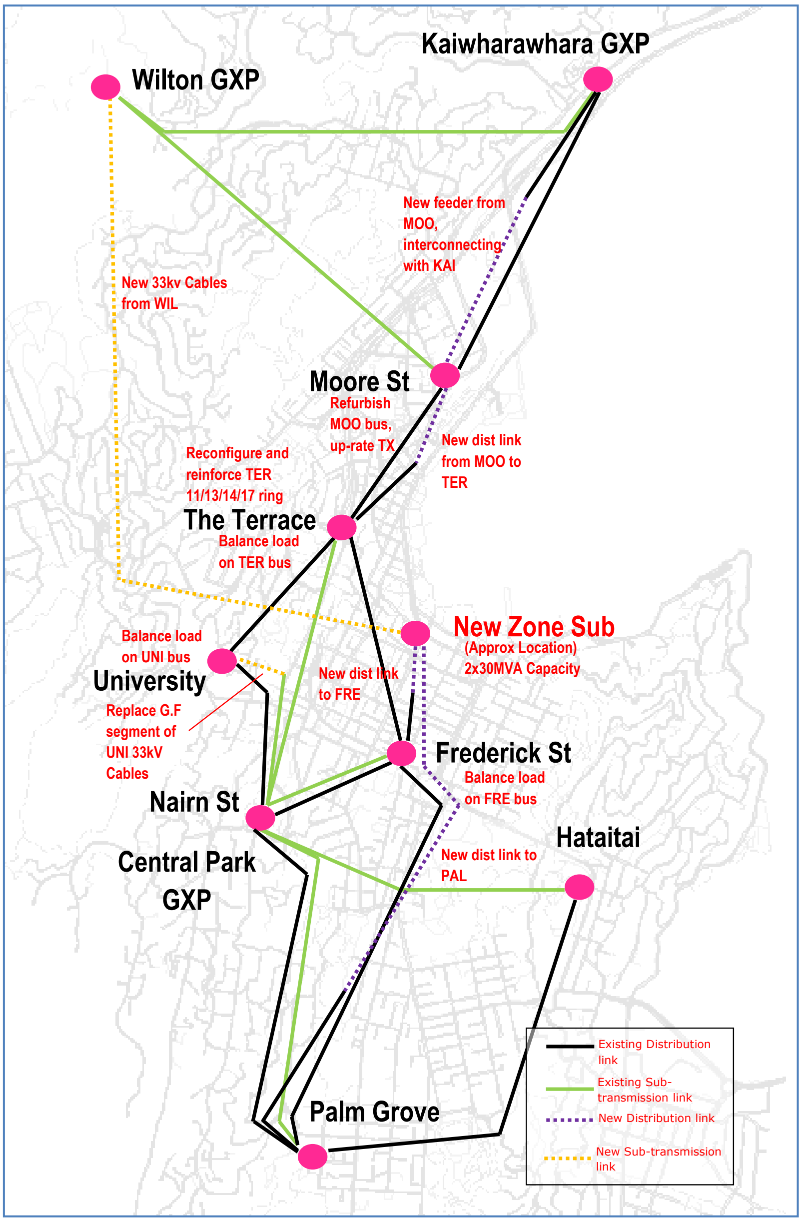


Figure 9-21 Proposed Configuration for Option 4

9.5.3 Comparison of Options

Figure 9-22 shows the comparison of the presented development paths for the Wellington CBD, including the pros and cons as well as the high level cost estimates of the four options.

	Option 1	Option 2	Option 3	Option 4
Description	Installation of a new zone substation supplied from Wilton with distribution level interconnections to The Terrace, Frederick St, Kaiwharawhara and Palm Grove	Augmentation of sub-transmission and distribution infrastructure to alleviate constraints and improve transfer capacity	Re-configuration of Nairn St to be supplied from Wilton, initiation of a customer driven project to improve security of supply at CPK and reinforcement of distribution links to adjacent zones	Installation of a new zone substation supplied from Wilton with distribution level interconnections to Frederick St, Kaiwharawhara and Palm Grove and a separate distribution link between The Terrace and Moore St
CAPEX Costs	**$38,410,000**	**$40,332,420**	**$36,627,680**	**$36,280,000**
NPV	**$26,639,101**	**$27,360,170**	**$25,553,226**	**$24,567,168**
Pros	• Reduces the magnitude of load at risk in the event of a Central Park N-2 issue; • Introduces a new point of supply into the network and diversifies supply to the Wellington CBD area at sub-transmission and distribution levels; • Mitigates all distribution level issues by introducing distribution links to highly loaded areas; and • Defers replacement of the Palm Grove transformers by shifting load to the new zone substation.	• Reduces the magnitude of load at risk in the event of a Central Park N-2 issue; • Mitigates all distribution level issues by introducing distribution links to highly loaded areas; and • Improves distribution inter-connectivity allowing large scale load shift during contingency situations.	• Utilises existing infrastructure where possible to introduce additional sub-transmission capacity into the Wellington CBD area as well as diversifying supply by shifting Nairn St to supply from Wilton GXP; • Mitigates all distribution level issues by introducing distribution links to highly loaded areas.; and • Reduces the magnitude of load at risk in the event of a Central Park N-2 issue.	• Reduces the magnitude of load at risk in the event of a Central Park N-2 issue; • Introduces a new point of supply into the network and diversifies supply to the Wellington CBD area at sub-transmission and distribution levels; • Improves distribution level inter-connectivity within critical zones within the Wellington CBD; • Mitigates all distribution level issues by introducing distribution links to highly loaded areas; • Reduces load transferred to the new zone substation, potentially allowing for lower rated sub-trans circuits; and • Defers replacement of the Palm Grove transformers by shifting load to the new zone substation.

	Option 1	Option 2	Option 3	Option 4
Cons	• Significant capital investment required to mitigate the issues; • Significant challenges in designating a suitable substation site (or utilising the existing property at Bond St) and complexity during construction; • Significant investment required to introduce distribution links from the new zone substation to The Terrace as well as Frederick St and Palm Grove; and • Zone substation and feeders will be highly utilised due to magnitude of offload from Frederick St, Palm Grove and The Terrace.	• Significant capital investment is required to individually augment the sub-transmission and distribution issues; • Significant capital investment required to replace the Palm Grove transformers which are highly utilised but in good condition; and • Overlay of the Frederick St sub-transmission cables will require significant investment and determination of a cable route will be challenging due to the location of Frederick St.	• Significant capital required to establish a new transformer bay adjacent to Nairn St zone substation; • Establishing a new transformer bay adjacent to the Nairn St switchroom may not be feasible due to the consents and civil/earthworks required; • Significant capital investment required to replace the Palm Grove transformers which are highly utilised but in good condition ; and • Significant capital investment required to replace the Palm Grove transformers which are highly utilised but in good condition.	• Significant capital investment required to mitigate the issues; and • Significant challenges in designating a suitable substation site (or utilising the existing property at Bond St) and complexity during construction.

Figure 9-22 Comparison of Options for Wellington CBD Development

9.5.4 Components of the Recommended Southern Area Development Option

The recommendation of a specific Development Path is determined by:

- The option that addresses all issues identified and coincides with asset renewal requirements;
- The option that is cost effective and involves efficiencies to reduce or defer cost through operational measures; and
- The option that most improves the efficiency of the network.

The most cost effective option which mitigates all identified issues while also ensuring a balanced network and increased transfer capacity is Option 4.

Option 4 has the benefit of introducing high capacity ties between critical zone substations as well as limiting the load transferred to the new zone substation. Options involving a new zone substation are costed for the scenario where new subtransmission cables are installed from Wilton. The cost of this will be offset by the reduction in cost to supply the new zone substation by repurposing one of the Wilton - Central Park 110kV lines as detailed in Section 9.5.2.1.

Option 4 involves the following discrete milestones and timing of works to mitigate the identified constraints in the most feasible and cost effective manner:

- **2015/16** - Open point shift to temporarily alleviate distribution level constraints and defer network investment till 2016/17;

- **2016/17** - Replacement of one of the Central Park 110/33kV single phase transformer banks with a 146MVA unit and recovery of the remaining single phase transformer bank at end of life. This will reduce the peak demand load at risk at Central Park during N-2 to 30MVA;

- **2016/17** - Installation of new distribution cabling between The Terrace and Moore St to provide additional transfer capacity and offload of The Terrace to allow eventual decommissioning at end of life (outside of the planning period);

- **2017/18** - Diversion, extension and simplexing of the duplexed Wilton-Central Park 110kV line to supply the new zone substation. These works allow for supply to the new zone substation from Wilton to improve diversity of supply into the Wellington CBD;

- **2018/19** - Installation of a new 30MVA (N-1 capacity) zone substation within the Wellington CBD at a suitable site. Redundant capacity and security of supply within the Wellington CBD will be significantly improved on completion of these works;

- **2018/19** - Installation of new distribution cabling from the new zone substation to Palm Grove, Frederick St and Kaiwharawhara for permanent offload of these sites. Transfer of loading from these sites will reduce the peak demand load at risk for an N-2 event at Central Park to minimal levels;

- **2019/20** - Installation of a new 110kV bus at Central Park to allow multiple transformer arrangements and improves security of supply during planned outages. A 110kV bus at Central Park also allows for potential future initiatives such as a undersea cable from Gracefield;

- **2020** - Reinforcement of The Terrace Zone 2 ring is planned for 2020 based on peak demand forecasts and identified feeder constraints;

- **2021/22** - Improve distribution inter-connectivity between Evans Bay, Ira St and adjacent zone substations. These works will be further detailed on completion of the Wellington Southern Area NDP;

- **2024** - Installation of a new 33kV bus at Evans Bay. Diversion of the 8 Ira St subtransmission cables to the new bus to provide supply to both 8 Ira St and Evans Bay stations and can potentially negate the requirement to replace the Evans Bay subtransmission cables. These works also allow for future initiatives such as an undersea cable from Gracefield. The feasibility of this option is to be studied further in 2015; and

- **2015-2024** - Refurbishment of network critical distribution switchgear to enable remote switching, automation and telemetry to provide fast contingency response.

The majority of identified feeder overloads will be eliminated by the end of the planning period. A number of feeder overloads at Moore St, Palm Grove and Nairn St are accepted on the basis of the ability to enact contingency load shifts to an adjacent zone following retrofit of remote switching and telemetry to a number of network critical distribution switching points throughout the network.

9.5.4.1 Central Park GXP Reconfiguration

<u>Central Park GXP Proposed Works</u>

In late 2014, a HLR was submitted to Transpower to identify possible options for mitigation of the risks identified at Central Park GXP.

To summarise, this HLR requested study of the feasibility and pricing implications for the following:

- Replacement of one of the single phase 109MVA transformer banks with a 148MVA three phase bank complete with blast walls to provide segregation of the three transformer compounds;
- Installation of active suppression complete with a Very Early Smoke Detection (VESDA) system to minimise the risk of critical failure due to fire; and
- Future installation of a 110kV bus. Due to the space restrictions at Central Park, a GIS system is the most likely option.

Wellington Electricity received a response to the HLR with the following costing for the initial mitigation works required at Central Park GXP as shown in Figure 9-23. This is not part of the expenditure forecasts included in the AMP as it is pass-through Connection Asset costs.

Project Description	Cost ($M)
Replacement of T3 with a new 120MVA transformer and installation of firewalls Installation of an active fire protection system Installation of a 110kV GIS bus	$13 – $18 M

Figure 9-23 Cost estimate for Central Park Mitigation Works

The HLR information resulted from a high-level study undertaken by Transpower. The next step to be decided by Wellington Electricity is whether to progress to a more detailed study of the options provided by Transpower.

The measures proposed on the HLR will mitigate the majority of the historical risks at Central Park, however further investigation is recommended to identify solutions to mitigate the following risks:

- The three bus sections comprising the 33kV switchgear are not segregated. Transpower standard designs for new 33kV installations is to segregate each separate bus section with concrete blast walls with inter-bus connections provided by flexible bus ties; and
- The cable trench behind the switchgear presents a substantial single point of failure. A fire or cable failure within this cable trench has the potential to damage adjacent cables.

Wilton to Central Park 110kV Line Diversion

Replacement of one of the single phase 109MVA transformer banks and installation of a 110kV bus presents an opportunity to divert one of the Wilton – Central Park 110kV lines to directly supply a site within the Wellington CBD and thus improve the diversity of supply within the area.

It will eventually be necessary to decommission the remaining single phase 109MVA transformer bank. A modern equivalent may be installed to replace this unit or alternatively, demand can be shifted to Wilton GXP.

To facilitate this, the Wilton – Central Park 110kV duplex circuit may be separated to provide two independent lines. These lines can be terminated at the 33kV bus at Wilton and run at 33kV.

Diversion of the line to a new zone substation will require installation of buried subtransmission cabling, however the distances involved are minimal compared to the installation of dedicated subtransmission circuits to Wilton.

The proposed configuration of subtransmission supply provided by the diverted Central Park – Wilton 110kV line is shown in Figure 9-24.

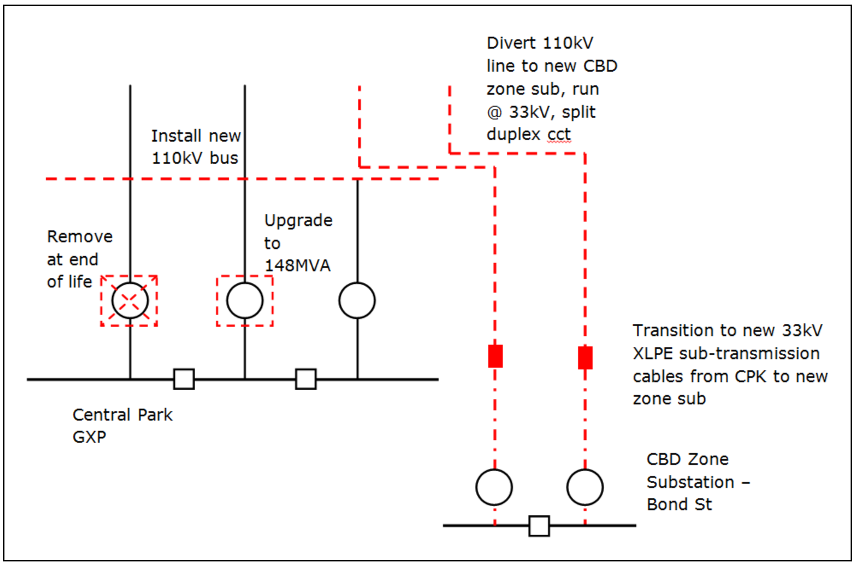


Figure 9-24 Wilton to Central Park Line Diversion

The cost and feasibility of these measures will be further explored through discussions with Transpower during 2015.

9.5.4.2 Install a New CBD Zone Substation

Site Designation

Designation of a zone substation site within the CBD poses a number of complications:

- The footprint of the 11kV switchgear and 33/11kV transformers is substantial. The space requirement may exceed the size of available lots within the required precinct in the Wellington CBD. A two story structure may be required to house the substation;

- The Wellington CBD district plan requires that all subtransmission and distribution cabling installed within the CBD limits is to be installed buried under the road reserve. Installation of new cabling requires determination of existing buried services and avoiding congested areas;

- This is particularly challenging when installing subtransmission cabling due to the requirement for minimum separation between circuits and the size, configuration and number of conduits within a trench; and

- Transport and installation of transformers, switchgear or buried cable will require significant traffic management. Additionally, space constraints at the zone substation site will complicate access and security for plant and equipment required for construction.

Wellington Electricity has ownership of a vacant lot in the CBD. This section was originally purchased for the sole purpose of re-developing as a zone substation site. The location of this site is in close proximity to

Frederick St zone substation and The Terrace feeders and inter-connection will involve minimal network augmentation. Wellington Electricity would utilise this property to construct a 33/11kV zone substation with an installed capacity of 2 x 30MV.

Distribution Network Interconnectivity

The 11kV distribution network arrangement designed for the new zone substation is to alleviate a number of distribution level issues within the Wellington CBD area:

- Provide sufficient inter-connectivity between Central Park and Wilton to alleviate the Central Park N-2 constraint issue;
- Provide offload of highly loaded meshed rings within the networks Frederick St feeder 3/4/5/8 ring, Frederick St feeder 13/14 ring and Palm Grove feeder 2/3/6 ring; and
- Utilise spare conduit where possible and optimise switchgear requirements.

Figure 9-25 shows the proposed distribution links from the new zone substation to Frederick St and Palm Grove.

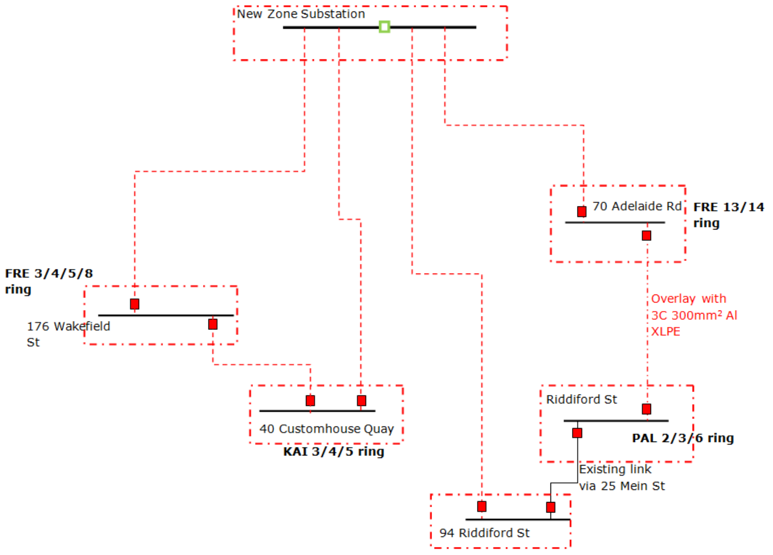


Figure 9-25 Proposed Distribution Inter-connectivity

Figure 9-26 provides a high level cost estimate and time periods for the option of a new zone substation.

Project Description	Cost ($K)	Years Investment Required
Zone Substation Site: Establishment of a 2 x 30MVA zone substation **Ref 17-001-18-001**	8,100	2017-2019
Distribution link to Frederick St and Kaiwharawhara **Ref 18-002**	5,300	2017-2019
Total	**13,400**	

Figure 9-26 Cost Estimate for Proposed New Zone Substation in the Wellington CBD

New subtransmission cabling will be required between Central Park GXP and the new zone substation as discussed in Section 9.5.1.1

Subtransmission Supply

Figure 9-27 shows potential routes for subtransmission cabling between Central Park GXP and the approximate locale of the new zone substation..

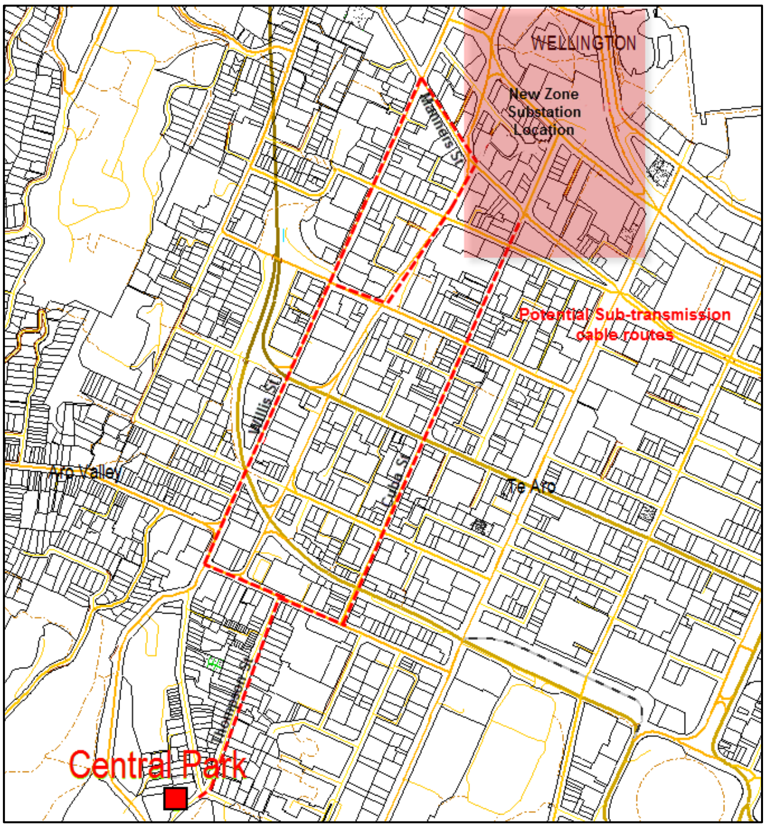


Figure 9-27 Proposed Route of Subtransmission Cabling from Central Park GXP

While this is a reasonably direct route, it is highly probable that existing buried services and traffic management requirements will require that the cable route deviate at a number of points. The cable route is estimated to be approximately 2500m in length.

Modelling shows two 33kV 3C Al 800mm2 XLPE cables will provide an N-1 normal rating of 32MVA with an assumed worst case de-rating factor of 0.8. Cyclic capacity of these cables will be approximately 37MVA. The capacity of the subtransmission circuit will be limited to the capacity of the transformers installed which is sufficient for the expected loading at the new zone substation.

Figure 9-28 provides a high level cost estimate for installation of subtransmission cables from the new zone substation to Central Park GXP where they will eventually be supplied by the newly diverted Wilton-Central Park line discussed in Section 9.5.4.1.

Project Description	Cost ($K)	Year Investment Required
Subtransmission Supply: Installation of 33kV cabling from Central Park **Ref 18-006**	5,000	2018

Figure 9-28 Cost Estimate for New Subtransmission Cabling from Central Park GXP

9.5.4.3 Palm Grove Feeder 2/3/6 Mesh Ring Reinforcement

Palm Grove Feeders 3 and 6 form a normally closed ring that feeds the Wellington Hospital connected at the 25 Mein Street substation.

Due to seasonal variations in the Wellington Hospital load, there is a risk that, in the event of a loss of either Palm Grove Feeder 3 or Feeder 6, loading on the remaining incomer circuit will exceed operating limits. This risk exists for approximately 20% of the year. As loading is unbalanced across Palm Grove Feeders 3 and 6, the likelihood of a fault on Feeder 3 breaching capacity on Feeder 6 is higher than the risk of a fault on Feeder 6.

A third incomer circuit to 25 Mein St is available via 381 Adelaide Rd, however the effective rating of the circuit only allows for operation in parallel with Palm Grove Feeder 3 or Feeder 6 and a lack of differential protection makes closed operation for any longer than switching time in this configuration infeasible, as a fault on the section without differential protection would not clear, and potentially result in half the Palm Grove zone substation bus tripping. This incomer utilises CB8 which currently also supplies 2 Owen Street via a double cable box.

There are a number of options being considered for mitigating these risks. Previous AMP planning has detailed a project to mitigate the supply concerns to 25 Mein St and the Wellington Hospital by balancing the load across the two existing incomers to below 66% and installing a new extensible switchboard within the 25 Mein Street substation. These works will provide a third reliable incomer to supply 25 Mein St and improve the security of supply to Wellington Hospital.

Switching is to be enacted, as an ancillary component of a customer connection project, to balance the loading on the Palm Grove feeder 2/3/6 mesh ring. However the physical work required at 25 Mein St has been put on hold in favour of a more complete solution being developed as part of the Wellington Southern Network Development Plan. Possible solutions include:

- Reinforcing the Palm Grove feeder 2/3/6 mesh ring and overlaying undersized sections of cable to improve the capacity of the ring; and
- Providing distribution infrastructure from a new zone substation to offload the Wellington Hospital and reinforce the Palm Grove 2/3/6 mesh ring by overlaying undersized sections of cable.

The recommended option, as per the recommended Wellington CBD development strategy, is to provide distribution infrastructure from a new zone substation in close proximity to Frederick St. The proposed cable route for the required distribution links are shown in Figure 9-29.

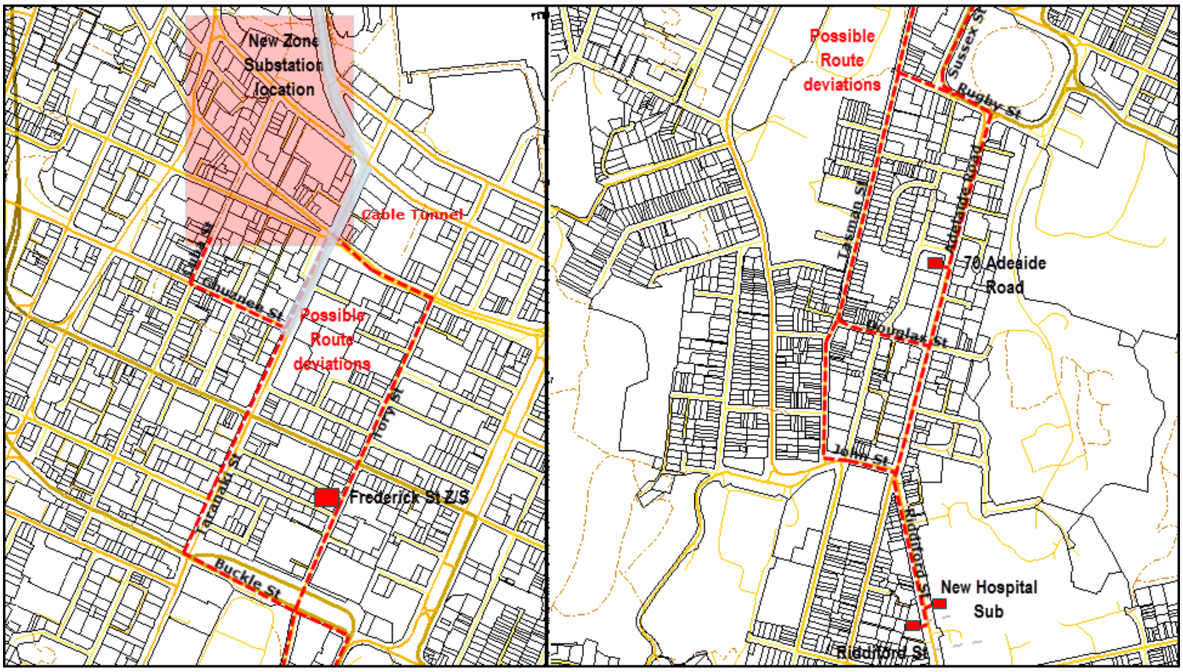


Figure 9-29 Distribution Links from a new zone substation to New Zone Substation to Palm Grove

Spare conduit capacity was installed as part of the NZTA Buckle St tunnel project completed in late 2014. These conduits can be utilised to eliminate the cost of trenching, reinstatement and traffic management along Buckle St.

The magnitude of load shifted from Palm Grove to the new zone substation reduces the loading on the Palm Grove transformers to within available N-1 capacity. Once these works are complete, the asset criticality rating for the Palm Grove transformers will be substantially improved, negating the requirement to replace as was proposed in the previous year's AMP.

Figure 9-30 provides the estimated cost for the recommended option.

Project Description	Cost ($K)	Year Investment Required
Palm Grove Distribution Inter-connectivity **Ref 19-001**	$6,500	2019

Figure 9-30 Cost Estimate for Proposed Palm Grove Distribution Reinforcement

9.5.4.4 Distribution Inter-connectivity between The Terrace Zone 1 Ring and Moore St

Reducing the loading on The Terrace Zone 1 ring, consisting of feeder 3/4/5/6 in a meshed configuration, and improving the transfer capacity between Wilton and Central Park GXPs can be achieved with distribution level network augmentation. A new distribution ring can be introduced to inter-connect The Terrace (supplied from Central Park) and Moore St (supplied from Wilton).

The most practical point of inter-connection is via distribution substations supplied from The Terrace Zone 2 ring. This allows the new distribution ring to serve multiple purposes - offload of The Terrace feeder 3/4/5/6 ring, diversify supply into the Wellington CBD and improve the total available transfer capacity between

Wilton and Central Park. The new ring is to be installed between Moore St, 8 Waring Taylor St and Farmers Lane as shown in Figure 9-31.

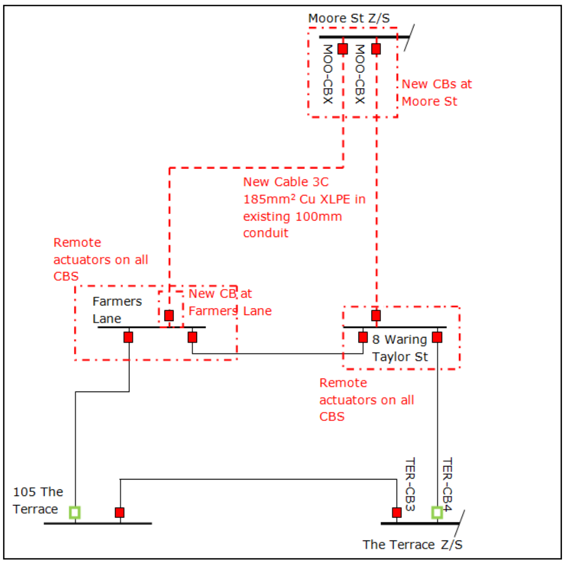


Figure 9-31 The Terrace to Moore St Distribution Inter-connectivity

Monitoring of peak demand growth over the short term will be required to ascertain when the recommended works should be applied.

Figure 9-32 provides the estimated cost for this distribution link.

Project Description	Cost($K)	Year Investment Required
The Terrace to Moore St distribution inter-connectivity **Ref 16-001**	$3,400	2016-17

Figure 9-32 Cost Estimate for New Distribution Inter-connection between The Terrace and Moore St

9.5.4.5 Reinforcement of The Terrace Zone 2 Ring

Load forecasts show that the load on The Terrace zone 2 ring, consisting of feeders 11/13/14/17 in a meshed configuration, will breach planning criteria by 2020. In order to alleviate loading on this ring, a new cable is to be installed between 24 Hunter St and 56 Victoria St. Open point shifts will also be enacted to shift approximately 1.5MVA of load to the Nairn St 1/2/3/6 ring.

Figure 9-33 shows the proposed modifications to the network to reinforce The Terrace Zone 2 ring.

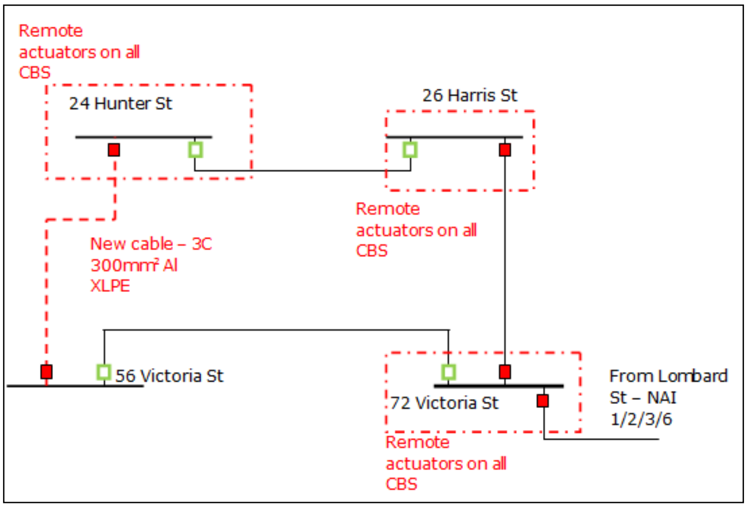


Figure 9-33 The Terrace Zone 2 Ring Reinforcement

The loading on The Terrace Zone 2 ring will be monitored during the planning period to confirm the project will be justified and the exact timing of implementation. Further options, including non-network solutions such as demand side management, shall be investigated to determine the most cost effective strategy to mitigate the issue.

Figure 9-34 provides the estimated cost for this distribution link.

Project Description	Cost ($K)	Year Investment Required
Reinforcement of The Terrace Zone 2 ring **Ref 20-001**	4,000	2020

Figure 9-34 Cost Estimate for Reinforcement of the Terrace 11/13/14/17 Ring

9.5.4.6 University Subtransmission Reinforcement

The University subtransmission circuits have a section of XLPE and a section of gas-filled cables with a transition gas to XLPE joint on both circuits. The gas filled cables are three-core 300mm² copper PIAS gas insulated cables with a length of 600m and were installed in 1987 (believed to be of old stock cable as gas-filled cable was not widely used by that time). The XLPE cables are single-core 400mm² aluminium and were installed in 2006 to replace an older section of 160mm² gas-filled cable with a length of 2.25km.

The capacity constraint is due to the XLPE cable section but the gas-filled cables are 26 years old and present a risk to reliability longer term. Replacing the gas-filled cable with high capacity XLPE will improve the resilience of the circuits, and lower the overall cost of ownership by reducing maintenance requirements.

Previous AMP planning indicated that the replacement of these projects will be dictated by the loading at University. The 2014 peak demand at University was 24MVA, which is at the same level as the available N-1 subtransmission capacity. The replacement of the gas-filled segments of the University subtransmission cables will be driven by asset age and condition. The project has been included in all development strategies as part of the Wellington Southern NDP for execution in 2024, when the gas-filled segments will be at end of life.

Further options, including non-network solutions such as demand side management, shall be investigated to determine the most cost effective strategy to mitigate the issue.

Figure 9-35 provides the estimated cost for this distribution link.

Project Description	Cost ($K)	Year Investment Required
University Subtransmission Reinforcement **Ref 24-002**	1,300	2024

Figure 9-35 Cost Estimate Replacement of Gas-filled Segments of University Subtransmission Circuits

A potential alternative to network investment may be to adopt demand side management with Victoria University, as they are a large, single site load which contributes to this constraint. This option shall be explored further to determine the viability and cost benefit of establishing a demand side management scheme as opposed to traditional network investment,

9.5.4.7 Moore St New Feeder

Moore St zone substation supplies part of the Wellington CBD area around Parliament, serving government offices and departments, large commercial buildings, Westpac Stadium, CentrePort and the central railway station. It has a summer peak and a typically commercial load profile.

A project was approved in 2013 to install a new feeder from Moore St zone substation. This will connect into the existing zone 2 ring for closed ring operation, and involves installation of a new circuit breaker on the T2 side of the 11kV bus at Moore St and connection into an existing substation on Waterloo Quay.

The CentrePort reconfiguration project completed during 2014 has alleviated the loading on Moore St feeder 12 and 14. As such, this project has been deferred, however the Wellington Southern NDP has identified load growth in the region will require this project be enacted by 2017.

Load growth is high around the CentrePort and Waterloo Quay area with recent customer requests for load connections over 500kVA. At present Moore St zone 2 ring feeders (CB12 and CB14) supply the load around these areas, resulting in breaches of the planning criteria. As the demand increases over time, this problem will be compounded. The overloading of the zone 2 ring could result in cascade failure should one feeder in the ring be out of service at peak times.

The approximate route of the new feeder will be along Thorndon Quay and Bunny Street to Customhouse Quay, terminating at 66 Waterloo Quay substation. This project will be coordinated with a planned customer driven project in the area to allow the costs of road opening, reinstatement and traffic management along the common route to be shared.

This new feeder will provide around 6MVA of capacity into Waterloo Quay and CentrePort area to allow connection of future load, and alleviate existing high loading.

Figure 9-36 provides the estimated cost for this new feeder option.

Project Description	Cost ($K)	Year Investment Required
1. Installation of a new feeder cable in Thorndon Quay, pedestrian overpass and substation	1,100	2017
2. New circuit breaker with protection relays at Moore St zone substation	80	2017
3. Switchgear extension at distribution substation (addition of new circuit breaker)	20	2017
Total	**1,200**	

Figure 9-36 Cost Estimate for New Feeder into Waterloo Quay

The cost of this project is integrated into the Wellington Southern development strategy for 2017.

9.5.4.8 Remote Distribution Switching

There is potential for efficiencies to be introduced to subtransmission and distribution level supply reliability through further deployment of remote switching.

In contrast to more traditional planning philosophies of installing redundant capacity, a more cost effective solution may be to utilise existing distribution level capacity and interconnectivity introduced through the development options considered in the previous sections. This can be achieved by identifying network critical distribution switching points and implementing a programme of refurbishment at these sites. Refurbishment will include the following works:

- Installation of communications infrastructure, including RTUs and communications links if necessary;
- Retrofit or replacement of distribution switchgear to provide facilities for remote actuation;
- Metering and telemetry of switch states, analogues etc. available via SCADA communications; and
- Installation of fault passage indication with remote indication.

Network critical switch points are defined as:

- RMUs with load break isolators supplying multiple feeder connections to adjacent feeders or zones; and
- Distribution switchboards with fault interrupting circuit breakers and protection relays to provide fault detection and clearing downstream from the zone substation.

For instance, at Frederick St, loss of a radial feeder during peak demand would require a number of open points be manually switched to restore load. If the open points were remote actuated, either through automation or by an operator in the Network Control Room, the SAIDI and SAIFI impact of the out of service bus would be minimal. Supply could be restored as rapidly as switch states could be altered.

Figure 9-37 shows a simplified overview of the proposed architecture.

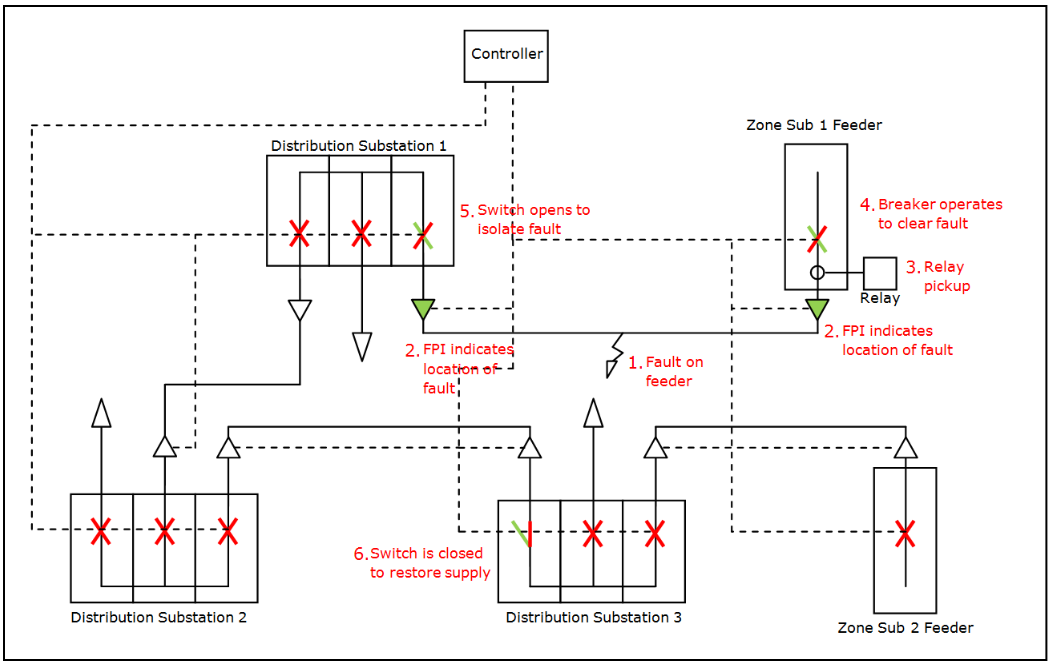


Figure 9-37 Distribution Level Remote Switching

Further investigation of key sites and interconnections between zones will be required, however a high level investigation shows that approximately 65 sites would benefit from refurbishment with automation capability. These works should coincide with asset renewal programmes.

9.5.5 Updates to Projects Discussed in the 2014-2024 AMP

9.5.5.1 Palm Grove Subtransmission Capacity

Works to replace both existing incoming sub-transmission circuits with new high capacity XLPE subtransmission cables between Central Park and Palm Grove were completed in late 2014. These new cables provide a higher capacity and a higher level of supply resilience to Palm Grove than the existing gas filled cables.

The installed N-1 transformer capacity (24MVA) is now the constraining factor on demand at Palm Grove and is the defining factor of the poor asset health scoring for these transformers. On completion of the new zone substation and distribution links to Palm Grove, a proportion of load will be transferred thus reducing the loading on the Palm Grove transformers to within installed N-1 transformer capacity.

9.5.5.2 Waikowhai Subtransmission Protection Upgrade

During 2014, Transpower replaced the existing Wilton GXP 33kV outdoor switchyard with an indoor switchboard. As part of these works, Wellington Electricity provided switching and technical resourcing for cut-over and testing of the subtransmission circuits to Karori, Moore St and Waikowhai zone substations. A portion of the cost of this work was recovered from Transpower.

Following this work, the subtransmission protection on the Wilton – Waikowhai subtransmission circuits, provided by aging electro-mechanical relays, was replaced with new numerical devices. These works were completed successfully.

9.5.5.3 Ira St Feeder 2 Reinforcement

Ira St Feeder 2 supplies the mainly residential area in the Seatoun area and provides backup to the feeder at Evans Bay supplying the Weta workshop and museum premises. Loading on this feeder exceeds 66%, which is in breach of planning criteria and does not allow for sufficient redundant capacity to allow for back-feed of the Weta premises.

Accordingly, reinforcement of the Ira St Feeder 2 is planned for early 2015. This project involves shifting a proportion of load from Ira Street Feeder 2 to a new feeder. CB11 at Ira St, currently feeding the local distribution transformer, is to be repurposed to feed an RMU. This RMU is to supply cabling out to tie-in points on Ira Street Feeder 2 between Broadway substation and Devonshire Road substation. This project was originally planned for execution during 2014 but was deferred in lieu of higher priority projects.

Figure 9-38 shows the proposed network reconfiguration at 8 Ira St.

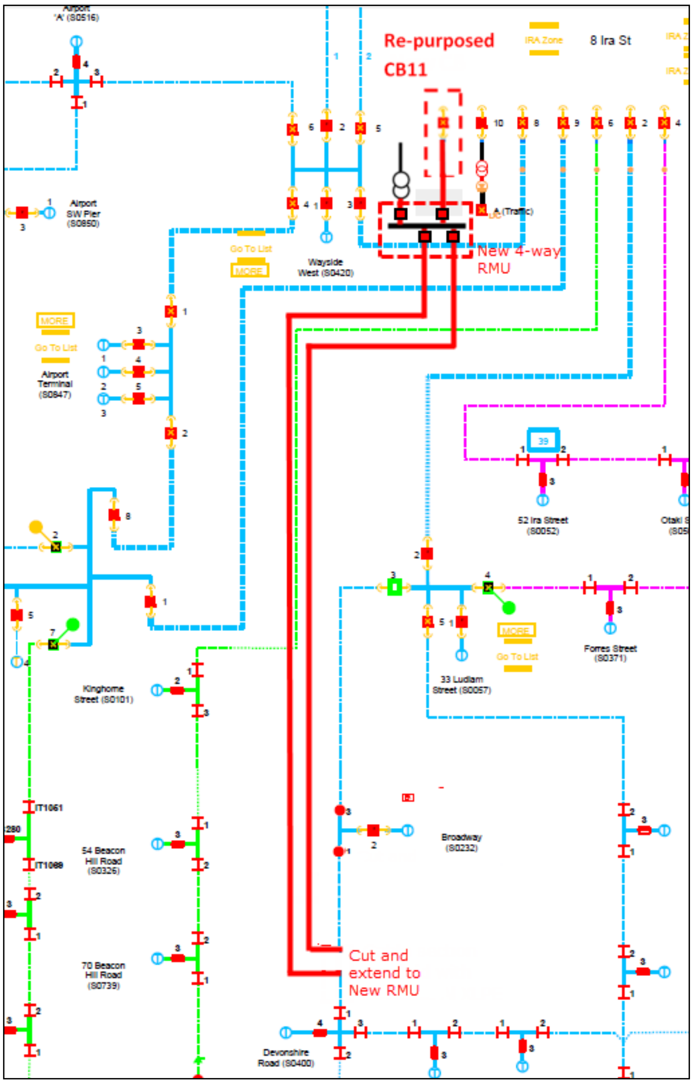


Figure 9-38 Ira St Feeder 2 Reinforcement Project

Figure 9-39 provides the approved budget for implementation of the 8 Ira St Reinforcement project.

Project Description	Cost ($K)	Year Investment Required
Ira St Feeder 2 Reinforcement **Ref 14-002**	345	2015

Figure 9-39 Cost Estimate for Proposed Solutions for Ira St Feeder 2

Switching will be required, on completion of physical works, to provide further off-load from Ira St feeder 2 to feeder 4 and to balance the loading across the zone 1 and 2 bus sections.

9.5.5.4 University Substation Feeder Reconfiguration

During 2014, a project was commissioned to balance loading on the University power transformers and relieve loading on University Feeder 8 and 11. These works involved moving University Feeder 13, supplying 84 Fairlie Terrace to the other side of the bus as per Figure 9-40 and enacting a number of open point shifts to shift load from University 8 and 11 to adjacent zones.

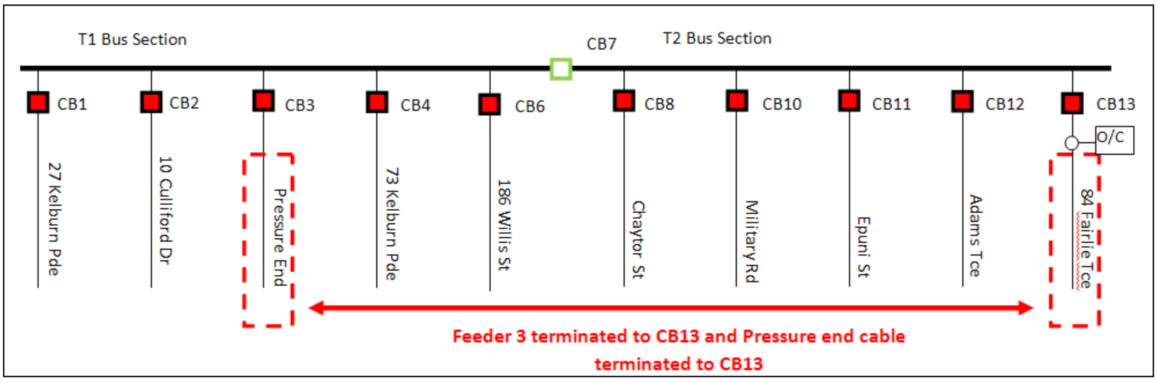


Figure 9-40 Re-configuration of the University Zone Substation

This project was successfully completed in late 2014 and has had the desired effect.

9.5.5.5 Fault Levels at CBD Zone Substations

All CBD[49] zone substations are operated with a split 11kV bus due to the high fault levels (as a result of low impedance supply transformers) and also due to protection limitations (to prevent a cascade tripping should a downstream 11kV meshed ring system fail to clear a fault correctly). The average fault level on an 11kV closed bus at CBD zone substations is around 15kA which is above the 11kV asset fault ratings both at zone substations and downstream.

There are a number of options available to mitigate the risk of high fault levels at CBD zone substations.

Increasing 11kV Switchgear Fault Ratings

[49] The CBD area is considered to be the commercial areas supplied by Frederick St, Nairn St, University, The Terrace, Moore St, Palm Grove zone substations and the Kaiwharawhara GXP.

This option involves increasing the fault ratings of the 11kV switchgear at zone substations and downstream sites, to allow closed 11kV bus operation. To achieve this, all distribution switchgear would need to be replaced and given the high cost of this option is not considered viable in the short term. It may become possible over time as older switchgear is progressively replaced for other reasons, and faster protection is installed.

High Impedance Zone Transformers

To reduce the fault level below 10kA, this option suggests installation of transformers with high winding impedance at CBD zone substations. CBD transformers are currently around 10-12% impedance, whereas much higher impedance would be required to control fault levels. However, the existing transformers at CBD zone substations are in good condition and are not due to be replaced within the planning period. The benefit of this option is no additional equipment would be required and hence no space constraints would arise. The disadvantages are the high cost and very high losses in the zone transformers, as well as the costs associated with the accelerated depreciation of assets.

Current Limiting Reactors or Resistors

Wellington Electricity's CBD high voltage network is over 95% underground and almost all faults are phase-to-earth faults. An option to control fault levels would be limiting the earth fault current below 10kA at CBD zone substations. This could be achieved by the use of current limiting reactors or resistors, installed at CBD zone transformer neutral points.

Another alternative would be to install bus tie reactors at CBD zone substations on the 11kV bus. The advantage of this approach is that if the load is essentially balanced on the both sides of the bus tie reactor under normal operating conditions, the reactor has negligible effect on voltage regulation or system losses.

Figure 9-41 shows the typical arrangement of a bus tie reactor in a distribution system.

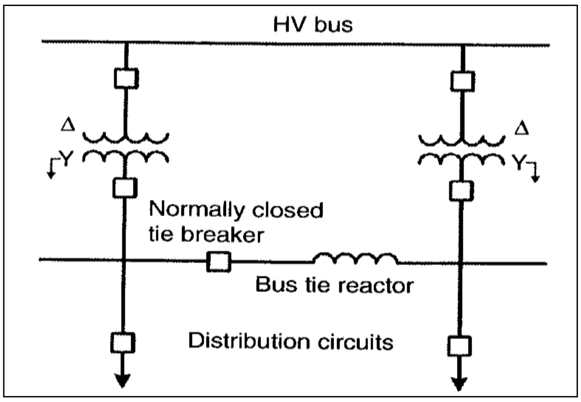


Figure 9-41 Typical Bus Tie Reactor Arrangement

There is a physical limitation to the use of bus tie reactors in CBD substations as the 11kV switchgear is of the metal clad type. Connecting the bus tie reactor to this type of switchgear would be an issue as the two sides of the bus and the circuit breaker are fully enclosed and inaccessible. Generally, these devices are better suited to outdoor switchyards so an engineering study would be required to confirm the practicality of such a solution.

Further investigation would be required within the planning period to determine appropriate device sizes for limiting earth fault current at the various CBD zone substations while allowing for fast acting protection clearing and adequate coordination with downstream devices. This may not address three-phase fault levels which could still remain high, and outside the rating of network equipment.

The key points to be considered and addressed before installation of current limiting reactors or resistors are:

- Space availability;
- Protection setting review as fault levels will be lowered;
- Protection discrimination and co-ordination review, and possible upgrade of relays;
- Sensitive earth fault protection might be required due to reduced earth fault current;
- Physical connection to metal clad switchgear at CBD zone substations (for bus-tie reactors); and
- CBD meshed 11kV system co-ordination.

The outcome of a detailed study into this issue may reveal that due to the age and condition of switchgear in the affected network areas, replacement with higher rated (and internally arc contained) switchgear may be a better overall investment.

Figure 9-42 provides a project cost estimate for bus fault level improvements (or mitigation through other means).

Project Description	Cost ($K)	Year Investment Required
CBD substation bus fault level improvements **Ref: 18-002, 19-002, 20-002, 21-002, 22-002**	850	Annually from 2018 onwards

Figure 9-42 Cost Estimate for Bus Fault Level Improvements

9.5.6 Summary of the Southern Area Investment

Figure 9-43 shows the investment plan for growth and reinforcement projects in the Wellington Southern area for the planning period from 2015-2025. This summary includes investment not included in the Southern Development NDP recommended Option 4 such as CBD zone substation fault level improvements and introducing increased inter-connectivity between Evans Bay, Ira St and adjacent zone substations. The Wellington Southern Development Plan assumes that the recommended option is to install a new zone substation in the CBD and replacement of the Evans Bay subtransmission assets.

Year	Reference	Project	Estimated Cost ($M)
2015	14-002	8 Ira St Feeder 2 Reinforcement	0.345
2016	16-001	The Terrace to Moore St Distribution inter-connectivity	3.4
2017	17-001	Establish new 2x30MVA zone substation	8.1

Year	Reference	Project	Estimated Cost ($M)
	17-002	Evans Bay Transformer Replacement	5.0
	17-004	Moore St New Feeder	1.2
2018	18-001	Distribution link from new zone substation to Frederick St and Kaiwharawhara	5.3
	18-002	CBD Zone Substation Fault Level Improvements	0.85
	18-006	CBD Zone Substation subtransmission supply	5.0
2019	19-001	Distribution link from new zone substation to Palm Grove	6.5
	19-002	CBD Zone Substation Fault Level Improvements	0.85
2020	20-001	Reinforcement of The Terrace Zone 2 Ring	4
	20-002	CBD Zone Substation Fault Level Improvements	0.85
2021	21-001	CBD Zone Substation Fault Level Improvements	0.85
2022	22-001	CBD Zone Substation Fault Level Improvements	0.85
	22-005	Evans Bay and Ira St Distribution Inter-connectivity	2.5
2023	22-001	CBD Zone Substation Fault Level Improvements	0.85
2024	24-001	University Subtransmission Reinforcement	3.5
	24-002	Evans Bay 33kV bus	4
Total Investment			**53.95**

Figure 9-43 Summary of Southern Area Investment Requirement

9.6 Northwestern Area NDP

Porirua City looking north (photography credit: Porirua City Council)

The Northwestern NDP has been developed from the planned and outstanding projects from previous AMP planning. This will be updated in 2015 as part of reviewing and developing a more comprehensive Northwestern NDP.

9.6.1 Development Needs

9.6.1.1 GXP Level Constraints

The Northwestern area is supplied from two GXPs. The transformer capacity and the maximum system demand are set out in Figure 9-44.

GXP	Installed Capacity (MVA)	Firm Capacity (MVA)	System Maximum Demand MVA	
			2015	2024
Pauatahanui 33kV	2x20	24	20	20
Takapu Rd 33kV	2x90	123	92	95

Figure 9-44 Northwestern Area GXP Capacities

The Pauatahanui GXP supplies the Mana and Plimmerton zone substations via a single 33kV overhead circuit connection to each substation. Mana and Plimmerton zone substations are linked at 11kV providing a degree of redundancy should one of the 33kV connections be out of service.

Pauatahanui

Pauatahanui GXP comprises a conventional arrangement of two parallel 110/33kV transformers rated at 20MVA each. The maximum peak demand on the Pauatahanui GXP in 2016 was 19.6MVA. This is within the transformer emergency ratings and also the winter cyclic rating of 24MVA.

Transpower has identified that the Pauatahanui supply transformers are approaching end-of-life and that replacement will be required within the next 10 years, which coincides with the site loading exceeding the N-1 rating. At the time of replacement a capacity upgrade will be required, with the future ratings still to be determined.

The planned zone substation for the Whitby/Pauatahanui area, supplied from Pauatahanui GXP, will allow for loading to be transferred from Takapu Road GXP. This will relieve prospective loading constraints at Waitangirua and Porirua while also providing additional transformer capacity such that feeders supplied by the Mana-Plimmerton zone substation can eventually be supplied by the new Whitby/Pauatahanui zone substation. Should Wellington Electricity take ownership of the Pauatahanui GXP assets, the new zone substation would be built at the Pauatahanui site with the installation of 110/11kV or 33/11kV transformers and an 11kV indoor switchboard.

Wellington Electricity will also consider an upgrade of the subtransmission differential protection from this site within the later part of the planning period.

Takapu Road

The Takapu Road GXP comprises a conventional arrangement of two parallel 110/33kV transformers each nominally rated at 90 MVA. Maximum demand on the Takapu Road GXP in 2014 was 91.5 MVA. Takapu Road supplies zone substations at Waitangirua, Porirua, Kenepuru, Tawa, Ngauranga and Johnsonville each via double circuit 33kV feeders. These circuits leave the GXP as overhead lines across rural land and become underground lines at the urban boundary.

The nominal firm 110/33kV transformer capacity at Takapu Road GXP is 90MVA with a potential N-1 cyclic capacity of 116MVA. This was previously constrained by a protection limitation; however this has been removed and the transformer N-1 cyclic rating has now been increased from 92MVA to 107MVA. This will provide sufficient firm transformer capacity until beyond the end of the planning period.

Transpower will be replacing the Takapu Road GXP 33kV outdoor switchyard with indoor switchgear in 2015. As part of these works, Wellington Electricity will provide switching and technical resourcing for cut-over and testing of the subtransmission circuits to supplied zone substations. The cost of these works, less internal project management, will be recovered from Transpower on completion.

The cost of these works and the recoverable portion are detailed in Figure 9-45.

Project Description	Cost	Year Investment Required
OD-ID Conversion (Stage 2) Provide switching assistance and labour to facilitate feeder cut-over and protection testing for OD-ID works **Ref 15-001**	$50,000	2015

Figure 9-45 Takapu Road OD-ID Conversion Works

Wellington Electricity have identified that the existing subtransmission protection on circuits supplied from Takapu Road is nearing end of life. A sequence of projects is to be executed to provide a staged replacement of the existing electro-mechanical subtransmission relays on these circuits with modern microprocessor based relays. These relays have a pilot cable supervision facility to guard against spurious tripping in the event of a failure of a pilot circuit and distance to fault measurement to allow accurate pinpointing of the location of a fault reducing restoration time.

Replacement of the Waitangirua subtransmission protection relays will occur following completion of the Takapu Road OD-ID conversion works in early 2015. It will be necessary to establish a fibre or copper pilot communications link between Ngauranga and Takapu Road, suitable for differential and SCADA communications. These works are currently being investigated with the assistance of a third party communications provider and are to be implemented during 2015.

The Ngauranga communications link will be necessary prior to replacement of the subtransmission protection relays on the Johnsonville, Tawa/Kenepuru and Ngauranga subtransmission circuits.

9.6.1.2 Subtransmission Level Constraints

This section describes the existing subtransmission network, identifies where the network topography and capacity does not meet Wellington Electricity's security criteria. The options for mitigation of the constraints are also discussed.

The Northwestern network consists of 14 subtransmission 33kV circuits supplying seven zone substations. Each zone substation supplies the respective zone 11kV distribution network with inter-connectivity via switched open points to adjacent zones. The characteristics of each zone substation are listed in Figure 9-46.

Zone Substation	Firm Capacity (MVA)	Single Incoming Circuit Capacity (MVA)		Peak Season	Forecast Demand (MVA)		ICP Counts as at 2014
		Winter	Summer		2015	2024	
Mana-Plimmerton	16	27	34	Winter	20	20	7,271
Johnsonville	23	21	14	Winter	17	15	7,142
Kenepuru	23	19	14	Winter	12	11	2,420
Ngauranga	12	20	14	Winter	13	14	5,483
Porirua[50]	20	22	14	Winter	20	20	5,977
Tawa	16	21	14	Winter	15	17	5,272
Waitangirua	16	22	16	Winter	16	18	6,095

Figure 9-46 Northwestern Area Zone Substation Capacities

[50] ICP counts for Porirua include Titahi Bay

Takapu Road Subtransmission Protection Replacement

The existing protection relays on the subtransmission circuits supplied from Takapu Road are at the end of their technical life. There is an increasing risk of mal-operation or spurious tripping as a result of the advanced age of the relays.

The programme of replacement of these relays shall be staged over the next two years following completion of the TPNZ Takapu Road OD-ID conversion project discussed in Section 6.1.1.2. The staging of this programme is as follows:

- 2014: Enabling Works (Stage 1): Modification of overhead lines and poles to allow construction of the new 33kV switchroom at Takapu Rd;
- 2015: Main OD-ID work for Transpower (Stage 2): Feeder cut-over works, testing and commissioning of protection and communications;
- 2015: Waitangirua Subtransmission Protection Replacement (Stage 3): Replacement of the protection relays on the Takapu Rd to Waitangirua subtransmission circuits;
- 2015/16: Establishment of a communications link between Ngauranga Z/S and Takapu Rd GXP (Stage 4) and replacement of subtransmission relays (Stage 5): Business case is being developed; and
- 2016: Replacement of the subtransmission relays on the Takapu Road to Tawa, Kenepuru, Johnsonville and Porirua subtransmission circuits: Staging is yet to be determined.

Waitangirua Subtransmission Protection Replacement (Stage 3)

Waitangirua zone substation is supplied from the Takapu Road GXP via two 33kV subtransmission feeders. Subtransmission protection for the Takapu Road-Waintangirua circuits is provided by Reyrolle Solkor R relays, which are nearing the end of their technical life.

New numerical relays are to be installed at Takapu Road GXP and Waitangirua zone substation to replace the existing subtransmission protection relays. These numerical relays have a pilot cable supervision facility to guard against spurious tripping in the event of a failure of a pilot circuit and distance to fault measurement to allow ease in location of a fault to reduce restoration times.

This project is approved and implementation is planned for early in 2015 following completion of Transpower's Takapu Road OD-ID conversion project.

Ngauranga Communications Link and Subtransmission Protection (Stages 4 & 5)

Differential communications for the Johnsonville subtransmission protection relays and inter-trip communications for the Ngauranga circuits are currently provided by copper pilots.

There are a number of sections of these pilot links which are in poor condition and prone to failure as evidenced during a number of recent events:

- During 2014 failure of a pilot wire caused a trip of the Johnsonville subtransmission circuit; and
- During 2014 failure of the pilots between Takapu Road and Ngauranga interrupted inter-trip communications for a single circuit.

Replacement of the subtransmission protection relays on the Ngauranga and Johnsonville circuits is dependent on the quality of the copper pilot bearers installed from Takapu Road to Ngauranga. Modern microprocessor based relays have a more stringent requirement for signal quality and losses than the Solkor electromechanical differential relays currently installed.

There is no direct pilot communications route between Johnsonville and Takapu Road. Solkor operation is possible however it is expected that the pilots will be unsuitable for a digital differential link. The existing pilots are also unsuitable for implementation of a TCP/IP network.

The recommended option to mitigate these issues is to install a dedicated fibre optic cable with sufficient for protection and SCADA communications routed in conduit leased from Transpower and spare conduit installed from a third party. Planning for this project is currently in progress and is planned for execution in late 2015 or early 2016.

Further stages involving replacement of the subtransmission relays on the Takapu Road to Tawa, Kenepuru, Johnsonville and Porirua subtransmission circuits are yet to be detailed.

The estimated cost of replacement of the Takapu Road subtransmission protection relays is shown in Figure 9-47.

Project Description	Cost ($M)	Year Investment required	Duration of Solution
Waitangirua Subtransmission Protection Replacement (Stage 3) **Ref 15-002**	0.366	2015	Beyond 2030
Ngauranga Communications Link and Subtransmission Protection Replacement (Stages 4 & 5) **Ref 15-003**	0.8	2015/16	Beyond 2030
Ngauranga, Tawa, Kenepuru, Johnsonville and Porirua subtransmission Protection Replacement (Stage 6 onwards) **Ref 16-002, 16-004, 16-005**	1.1	2016/17	Beyond 2030

Figure 9-47 Cost Estimate Takapu Road Subtransmission Protection Replacement

Prospective New Grenada Zone Substation

Johnsonville has historically experienced high load growth as a result of ongoing residential development. A project to install new 11kV feeder interconnections with Ngauranga was completed in in 2012. This shifted around 4 to 5MVA of peak load from Johnsonville to the Ngauranga zone substation, creating the equivalent spare capacity at the Johnsonville site. The 11kV feeder between Ngauranga and Johnsonville will provide a useful interconnection for its entire service life, as it will allow load to be easily shifted between the two zone substations.

While peak demand growth at Johnsonville has declined over the past three years, an increased number of subdivisions in this area is expected to drive a future increase in peak demand growth. The existing distribution feeder capacity to feeders supplying the Grenada area is nearing planning criteria and further load cannot be supported on these feeders.

Different options have been analysed and load flow simulation indicates it is not possible to run new 11kV capacity from the Tawa zone substation (north of Johnsonville) due to its geographic location and high utilisation factor. The preferred solution is the construction of a new zone substation to the north-east of Johnsonville to supply the existing high loads and to allow for new residential developments in this area. This is expected to be required by 2020-2021. Land was purchased in Grenada in 2012 for the new substation. The land has been designated as a substation site and easements are to be created for connecting to the existing networks in the area.

The subtransmission supply to the new zone substation is proposed to be from Transpower's existing Takapu Road-Ngauranga overhead 33kV circuits, which pass near this location. The substation will require a non-standard substation design that does not use transformer feeders, since the incoming circuits will be shared with the Ngauranga zone substation. A 33kV switchboard may be required to allow adequate protection and segregation of circuits continuing on to Ngauranga, the requirement for which will be determined through further investigation.

Figure 9-48 provides a high level cost estimate and time periods for the new zone substation.

Project Description	Cost ($M)	Year Investment Required	Duration of Solution
Construction of new 20MVA, 33/11kV Zone substation in Grenada **Ref 20-004, 21-004**	15.0	2020 (over two years)	Beyond 2030

Figure 9-48 Cost Estimate for Possible Substation for Grenada

<u>Mana-Plimmerton</u>

Plimmerton and Mana each have a single 33kV supply to a single power transformer. There is an interconnection between the two switchboards and the two substations operate as a single N-1 substation with a geographic separation of 1.5 km.

Zone Transformer Constraint

The combined load at the two zone substations can presently exceed the N-1 rating of the transformers at peak times. Back-feed connections from neighbouring substations allow for N-1 operation at present, but this capacity is being eroded over time. During an outage on either of the zone substation transformers or one of the subtransmission circuits, the load is transferred by the existing 11kV tie cable and excess load above the capacity of the 11kV interconnection is off-loaded to neighbouring substations by reconfiguring the 11kV distribution network. However, it has been known at peak times for the 11kV interconnecting cable to trip out of service on overload following a subtransmission fault, although this is rare (one event in every five years or more).

The existing transformers (ONAF cooling) at Mana and Plimmerton zone substations have cyclic ratings of 16 MVA each with 16.8MVA as the emergency two hour rating. The cyclic ratings of the existing transformers could be increased to around 20MVA by installing oil pumps and converting them to oil forced and air forced (OFAF) cooling transformers. The combined coincident peak of Mana-Plimmerton in 2014 was 19.6 MVA.

Another option would be to shift the second decommissioned Petone zone substation transformers (rated at 20MVA) to the Plimmerton zone substation. Due to space constraints at the Mana zone substation a second transformer cannot be accommodated; however a higher rated unit could replace the existing transformer. By either upgrading to oil forced cooling, or relocating a Petone transformer to Plimmerton, firm capacity of 20MVA would be provided at these zone substations.

Mana-Plimmerton 11kV Tie Cable

The 11kV tie cable between Mana and Plimmerton has a capacity of only 7.60MVA. The peak load of Mana zone substation is around 13 MVA. Should the 33kV circuit supplying Mana zone transformer be out of service, the Mana peak load cannot be supplied from Plimmerton through the existing 11kV tie cable alone. The situation is not as acute at Plimmerton, as the load is significantly lower.

Figure 9-49 shows the layout of Mana and Plimmerton zone substations.

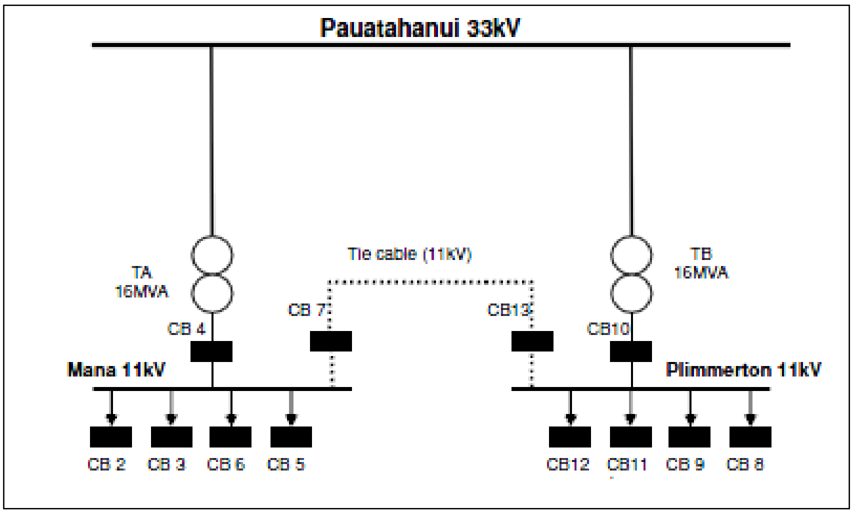


Figure 9-49 Mana-Plimmerton Connection Layout

During an outage under the present conditions, two things may occur – the loads are operationally managed through peaks or the load is transferred away by manual switching of the 11kV network. This results in not having true N-1 security. Remote switching may be introduced in the future to reduce the potential network reliability impact and improve the speed of supply restoration.

There are two options for mitigating this issue:

1. Install a higher capacity tie cable between Mana and Plimmerton zone substations requiring an investment in the order of $2.7 million.

2. Install a SPS to avoid overloading the tie cable and offload the substation following a supply interruption. This option is readily implemented at a low cost and is therefore preferred.

The SPS with intertrip and close functions would fully offload Mana Feeders 5 and 6 onto the Porirua zone substation following an outage on either the 33kV circuit or zone transformer at Mana to prevent the overloading of the 11kV tie cable. The residual loading would remain within the rating of the 11kV interconnecting cable until at least 2018 at current forecast growth rates.

Figure 9-50 provides the overview of the proposed special protection scheme at Mana and Plimmerton.

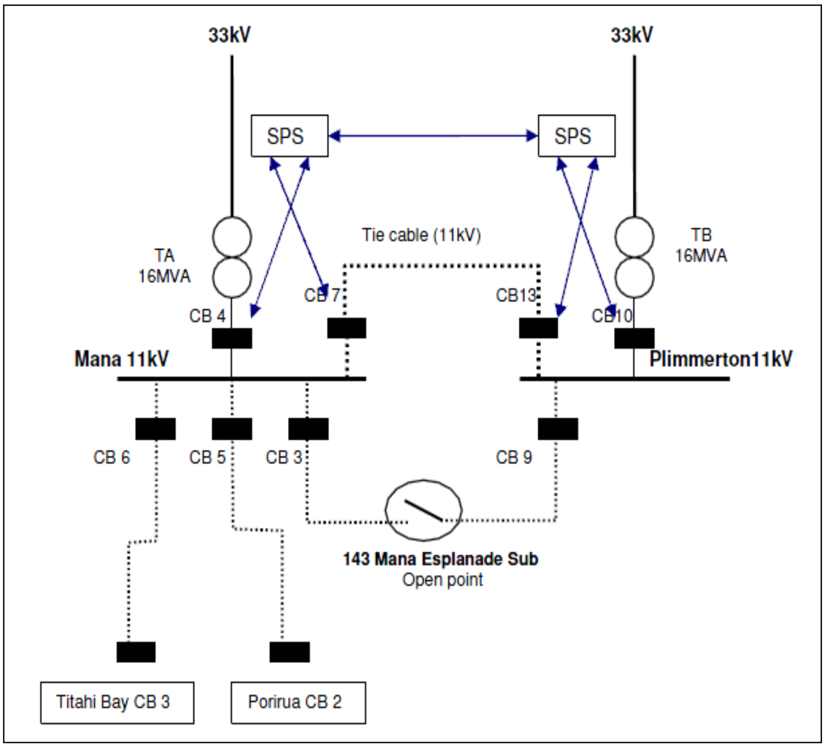


Figure 9-50 Special Protection Scheme Logic at Mana and Plimmerton

As part of the SPS implementation, it is also proposed to install a remote operated switch at the 143 Mana Esplanade distribution substation to allow load transfer at the 11kV feeder level between Mana and Plimmerton 11kV buses.

Figure 9-51 provides a high level cost estimate and time periods for the SPS implementation.

Project Description	Cost ($K)	Year Investment Required	Duration of Solution
SPS installed at Mana and Plimmerton zone substations and converting switchgear at 143 Mana Esplanade substation to be remote operated **Ref: 16-003**	250	2016	Beyond 2030

Figure 9-51 Cost Estimate for Option 2 SPS for Mana-Plimmerton

Prospective New Zone Substation in Whitby/Pauatahanui Area

Peak demand in the Whitby area has grown to approximately 35MVA, due to a large number of recent subdivisions, and is expected to increase by 1-2MVA per year over the short to mid- term driven by further subdivisions currently in the consenting process. This area is currently fed from Waitangirua and Mana zone substations with Waitangirua forecast to reach its N-1 capacity during 2015. This shortfall is projected to grow to approximately 5MVA by 2025. Mana and Plimmerton exceeded their combined N-1 capacity by 4MVA during 2015, so there is no ability to transfer the Whitby load to relieve the capacity constraint.

An additional zone substation will be required to meet the future load growth in Whitby. Ideally this would be located at Pauatahanui GXP, subject to an arrangement being made with Transpower that would either result in the acquisition of the substation by Wellington Electricity (see Section 5.12.4) or an agreement that would allow the new zone substation to be constructed on Transpower land. Alternatively, two additional 33kV feeders will be required from Pauatahanui to feed a zone substation site in Whitby itself.

Figure 9-52 shows the proposed site location for the new zone substation.

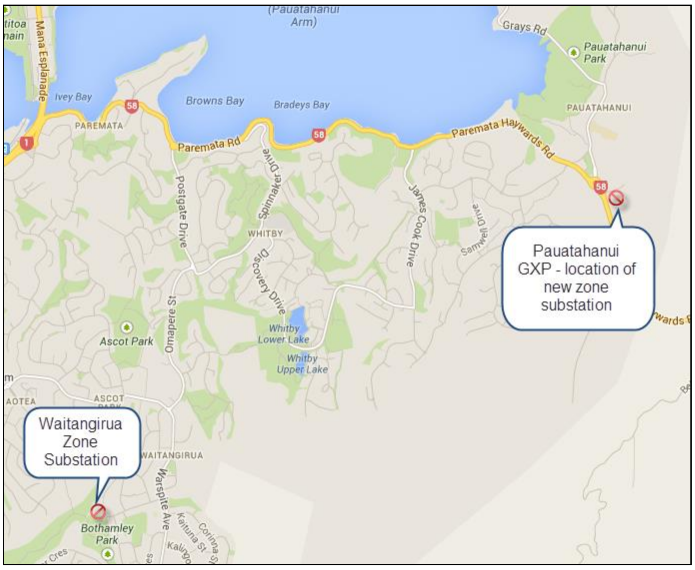


Figure 9-52 Preferred Site for Possible Substation in Whitby Area

Figure 9-53 provides a high level cost estimate and time periods for the new zone substation in the Whitby/Pauatahanui area.

Project Description	Cost ($M)	Year Investment Required	Duration of Solution
1. Purchase or shared use of Pauatahanui GXP or purchase of land in Whitby for new zone substation 2. Construction of new 20-30 MVA zone substation in Whitby or Pauatahanui area **Ref 17-003, 18-005**	15.0	2017 (over two years)	Beyond 2030

Figure 9-53 Cost Estimate for Possible Substation in Whitby/Pauatahanui Area

9.6.1.3 Distribution Level

The most critical distribution level issues are those associated with overload of meshed ring feeders supplying a high number of customers or links between zones which can be used for load transfer. Figure 9-54 shows where the applicable planning criteria for the various feeder configurations shown in Figure 9-2 breached within the distribution network and an estimation of when the constraints bind.

Feeder		Zone Substation	Current Loading	+5 years	+10 years	Feeder ICP Count
NGA 01	Salford St	Ngauranga	68%	71%	73%	1,821
NGA 04[1]	16 Malvern Rd	Ngauranga	71%	80%	81%	1,644
TAW 10	Duncan St	Tawa	72%	76%	80%	927
TAW 13	Oxford St	Tawa		67%	71%	1,058
POR 01	Titahi Bay A	Porirua	69%	73%	73%	2,921
POR 11	Titahi Bay B	Porirua	72%	76%	76%	
WTA 03[1]	Caduceuos Pl	Waitangirua		69%	74%	1,409
WTA 05[1]	Postgate Dr	Waitangirua	75%	83%	89%	1,440

Figure 9-54 Distribution Level Issues

Note to Figure 9-54

1: Due to potential step change in the area

The identified highly loaded feeders at Grenada supplied from Tawa and Ngauranga may be mitigated through construction of a new zone substation. Open point shifts are recommended for the identified overloaded feeders supplied from Porirua.

The new zone substation planned for the Whitby/Pauatahanui area will offload a portion of load from Waitangirua and allow for offload of the heavily loaded feeders supplied from Waitangirua.

9.6.2 Northwestern Network Development Strategy

As discussed previously, the identified constraints and planned projects for the Northwestern area consist of projects identified from previous AMP planning. The Northwestern NDP (currently in development) will provide a more detailed investigation of the area and provide a number of strategies to mitigate the identified issues. These strategies may involve or substitute the currently planned works for the Northwestern area.

For budgeting purposes, an allowance has been included for establishment of a zone substation in Whitby/Pauatahanui and Grenada as well as various distribution level works. The planned distribution reinforcement costs are estimated based on the average distribution level reinforcement costs for a year and provides for

- Overlay of approximately 400m of undersized 11kV cable including trenching, traffic management and reinstatement costs;
- Installation of approximately 600m of new distribution links between zones at 11kV; and

- Establishment of one new distribution switching station.

Due to the location of the proposed Grenada zone substation, significant further investment will be required to inter-connect to, reinforce, and expand, the existing distribution network. This is expected to occur in 2023 and 2024. Allowances have also been included for installation of a new 33kV switching station at Grenada, tee-ed off the existing Ngauranga sub-transmission circuits.

Ngauranga zone substation is expected to experience further growth outside the planning period on completion of the Grenada to Petone link road and development of the Grenada area. Distribution inter-connectivity between Ngauranga and adjacent zone substations will provide additional transfer capacity and defer replacement of the Ngaruanga transformers.

Further growth is expected in the Paremata region which will increase demand at Mana-Plimmerton. A potential option is to install a 33kV bus at Plimmerton to supply both Mana and Plimmerton zone substations. The Plimmerton bus would be extended and a matched pair of transformers, rated to 20MVA each, would be installed to offer security of supply. The existing Plimmerton transformer could be relocated to replace the transformer at Mana which is nearing end of life.

These options have been accounted for in the Northeastern area investment summary and will be studied further as part of the Northeastern and Northwestern area NDPs during 2015.

9.6.3 Changes to Projects Discussed in the 2014-2024 AMP

The Takapu Road subtransmission protection upgrade has been separated into discrete stages spread over the next two years due to the scope of the project. The initial stages are components of the Transpower Takapu Road OD-ID project.

The Northwestern area NDP, to be completed in 2015, will provide identification of all constraints against the most recent forecast, and evaluation of a development path to mitigate. The projects forming this development path will be detailed in the 2016 AMP.

9.6.4 Summary of the Northwestern Area Investment

Figure 9-60 shows the investment plan for growth and reinforcement projects in the Northwestern area for the planning period from 2015-2025. An allowance has been included for distribution level development of the Northwestern area and establishment of a new zone substation in Whitby/Pauatahanui and Grenada. These figures will be updated following completion of the Northwestern area NDP.

Year	Reference	Project	Estimated Cost ($M)
2015	15-001	Takapu Road OD-ID Works (Stage 2): OD-ID Conversion	0.025
	15-002	Waitangirua Subtransmission Protection Upgrade (Stage 3)	0.37
	15-003	Ngauranga communications and Subtransmission Protection Upgrade (Stage 3 and 4)	0.8

Year	Reference	Project	Estimated Cost ($M)
2016	16-002	Johnsonville Subtransmission Protection Upgrade	0.35
	16-003	Mana-Plimmerton SPS	0.25
	16-004	Tawa/Kenepuru Subtransmission Protection Upgrade	0.35
	16-005	Porirua Subtransmission Protection Upgrade	0.35
2017	17-003	New Whitby/Pauatahanui Zone Substation – Stage 1 2017	7.5
2018	18-003	Wellington Northwestern Development Strategy 2018 – Distribution Reinforcement Allowance	1.5
	18-005	New Whitby/Pauatahanui Zone Substation – Stage 2 2018	7.5
2019	19-003	Wellington Northwestern Development Strategy 2019 – Distribution Reinforcement Allowance	1.5
2020	20-003	Wellington Northwestern Development Strategy 2020 – Distribution Reinforcement Allowance	1.5
	20-004	New Zone Substation in Grenada – Stage 1 2020	7.5
2021	21-003	Wellington Northwestern Development Strategy 2021 – Distribution Reinforcement Allowance	1.5
	21-004	New Zone Substation in Grenada – Stage 2 2021	7.5
	21-005	Sub-transmission supply for Grenada via new 33kV bus	4
2022	22-003	Wellington Northwestern Development Strategy 2022 – Distribution Reinforcement Allowance	1.5
	22-004	Pauatahanui Subtransmission Protection Upgrade	0.7
	22-006	Grenada Distribution inter-connectivity	2.5
2023	23-002	Distribution Reinforcement Allowance	5
	23-004	Grenada Distribution inter-connectivity	2.5
	23-005	Ngauranga Distribution inter-connectivity	2.5

Year	Reference	Project	Estimated Cost ($M)
2024	24-003	Distribution Reinforcement Allowance	5
	24-004	New Plimmerton 33kV bus	4
2025	25-001	Plimmerton 11kV bus extension	2
	25-002	2x20MVA Transformers at Plimmerton	2
	25-003	Plimmerton Distribution inter-connectivity	2
Total Investment			**64.2**

Figure 9-55 Summary of Northwestern Area Investment Requirement

9.7 Northeastern Area NDP

The Hutt Valley (photography credit: Hutt City Council)

The Northeastern NDP is based on the projects from previous AMP planning. This will be updated in 2015 as part of the review and further development of the Northeastern NDP.

9.7.1 Development Needs

9.7.1.1 GXP Level Constraints

The Northeastern area is supplied from four GXPs. Melling and Haywards GXPs both consist of bulk supply at 33kV and 11kV to separate zone substations. The transformer capacity and the maximum system demand are set out in Figure 9-56.

GXP	Installed Capacity (MVA)	Firm Capacity (MVA)	System Maximum Demand MVA	
			2015	2024
Gracefield 33kV	2x100	89	62	56
Haywards 33kV	1x20	20	17	18
Melling 33kV	2x50	52	36	36
Upper Hutt 33kV	2x40	37	28	30
Haywards 11kV	1x20	20	17	17
Melling 11kV	2x25	27	26	25

Figure 9-56 Northeastern Area GXP Capacities

Gracefield

Currently there are two transformers at Gracefield, which provide 33kV supply to four Wellington Electricity zone substations (Wainuiomata, Gracefield, Seaview and Korokoro). There are no capacity and security issues at Gracefield as the peak demand at this GXP is below the supply transformer capacity.

The protection on the subtransmission circuits from Gracefield GXP was installed in the 1970s. These relays are now at the end of their technical life. However, there is no immediate need for them to be replaced. Wellington Electricity will upgrade all subtransmission differential protection from Gracefield GXP as part of the ongoing programme of works to replace all existing subtransmission electromechanical type differential relay schemes with modern numerical relay schemes by 2023. The subtransmission protection of the Gracefield GXP – Gracefield zone substation circuit will be replaced in 2016 as part of the Gracefield zone substation switchgear replacement works. The other subtransmission circuit protection will be replaced as separate works, currently forecast for 2019.

Haywards

Haywards supplies Trentham zone substation via a 33kV outdoor bus and an 11kV switchboard, which is fed by a 20MVA 110/11kV transformer in parallel with a 5MVA 33/11kV transformer. The loss of either of the 110/33kV or 110/11kV supply transformers has a significant impact on system security.

Transpower has identified the need to replace the existing transformers at Haywards due to their condition, with an indicative timing of 2017. The level of security offered at Haywards is less than that offered at comparable GXPs. Outages required for routine maintenance and similar activities require back-feed switching at the distribution level due to the atypical configuration of the supply to the Haywards 33kV and 11kV buses.

A formal HLR was requested from Transpower to identify potential options. Transpower have indicated that the preferred solution is to install two three winding transformers with sufficient capacity to provide N-1 security for both 11kV and 33kV supplies. The final configuration, as well as the ratings of the new transformers and the timing of the project, has still to be confirmed and will likely influence network development options for the Wellington Northeastern area.

Upper Hutt

The Upper Hutt GXP comprises a conventional arrangement of two parallel 110/33kV transformers nominally rated at 37 MVA each, supplying a 33kV bus that feeds zone substations at Brown Owl and Maidstone through underground 33kV fluid filled cables. The existing Solkor differential protection on the Wellington Electricity subtransmission circuits from Upper Hutt has been reliable but this protection lacks pilot wire supervision. This presents a risk that, if the pilot becomes damaged, the protection may not operate as intended. The standard replacement for subtransmission protection schemes is with numerical differential protection relays with pilot wire monitoring capability, which will guard against mal-operation due to pilot wire failure.

Transpower has indicated that the existing Upper Hutt GXP 33kV outdoor bus is to be replaced by an indoor switchboard in 2020. During this outdoor to indoor conversion, Wellington Electricity will look to upgrade all subtransmission differential protection on the Brown Owl and Maidstone circuits.

9.7.1.2 Subtransmission Level Constraints

This section describes the existing subtransmission network, identifies where the network topography and capacity does not meet Wellington Electricity's security criteria. The options for mitigation of the constraints are also discussed.

The Wellington Northeastern network consists of nine subtransmission 33kV circuits supplying nine zone substations. Each zone substation supplies the respective 11kV distribution network with inter-connectivity via switched open points to adjacent zones. The characteristics of each zone substation are listed in Figure 9-57.

Zone Substation	Firm Capacity (MVA)	Single Incoming Circuit Capacity (MVA)		Peak Season	Forecast Demand (MVA)		ICP Counts as at 2014
		Winter	Summer		2015	2024	
Gracefield	23	21	17	Winter	11	9	2,885
Korokoro	23	22.5	16.5	Winter	19	17	7,556[51]
Seaview	22	21	13	Winter	16	15	3,106
Wainuiomata[52]	20	23	20	Winter	17	16	6,901
Trentham	23	20	14	Winter	17	18	5,414
Naenae	23	19	14	Winter	18	17	6,246
Waterloo	23	21	13	Winter	19	20	6,016
Brown Owl	23	19	13	Winter	15	17	6,556
Maidstone	22	18	10	Winter	13	14	4,815

Figure 9-57 Northeastern Area Zone Substation Capacities

[51] ICP counts for Korokoro include Petone

[52] Wainuiomata firm capacity cyclic capacity is constrained to the rating of the relocated ex-Petone A 20MVA transformer.

Trentham Subtransmission Protection Upgrade

New protection relays

Trentham zone substation is supplied from the Haywards GXP via two 33kV subtransmission feeders. Subtransmission protection for the Haywards-Trentham circuits is provided by Reyrolle Solkor R relays, which are nearing the end of their technical life.

New numerical relays were installed at Haywards GXP and Trentham zone substation in early 2015 to replace the existing subtransmission protection relays. These numerical relays have a pilot cable supervision facility to guard against spurious tripping in the event of a failure of a pilot circuit and distance to fault measurement to allow ease in location of a fault to reduce restoration times.

The individual pilot cable routes for the two subtransmission circuits were diversified using existing infrastructure between Haywards GXP and Trentham zone substation. This negates the risk of concurrent failure of both pilot wires in the event of a fault or the common-mode failure evidenced during the September 2012 storm, which resulted in a trip of both subtransmission circuits.

This project was completed successfully in early 2015.

9.7.1.3 Distribution Level

The most critical distribution level issues are those associated with overload radial feeders supplying critical loads. Figure 9-58 shows where the applicable planning criteria for the various feeder configurations shown in Figure 9-2 breached within the distribution network and an estimation of when the constraints bind.

Feeder		Zone Substation	Current Loading	+5 years	+10 years	Feeder ICP Count
BRO 08	Montgomery Cres	Brown Owl			69%	1,434
MAI 06	Leisure Centre	Maidstone	66%	70%	74%	990
WAT 03	Hautana St	Waterloo	75%	70%	66%	473
KOR 09	Londons Rd	Korokoro	79%	69%		1,549
TRE 12[1]	Gower St	Trentham		67%	72%	1,389
TRE 08[1]	Messines Army Centre	Trentham			68%	312
HAY 2722	Silver stream	Haywards (GXP)	82%	72%		1,466

Figure 9-58 Distribution Level Issues

Note to Figure 9-58

1: Due to potential step change in the area

The identified highly loaded feeders supplied from Maidstone, Waterloo, Korokoro and Haywards are predicted to decline in load over the planning period and may not require mitigation. Operational solutions are recommended to mitigate the overloaded feeders supplied from Trentham.

Haywards Feeder 2722

Haywards feeder 2722 supplying the Silverstream area is highly loaded. It is supplied from Transpower's Haywards 11kV GXP. The most feasible option is to install a new feeder at Haywards and permanently shift the KiwiRail traction substation on to the proposed new feeder.

Figure 9-59 provides the estimated cost to reduce the loading on Haywards feeder 2722.

Project Description	Cost ($M)	Year Investment Required	Duration of Solution
New Feeder at Haywards 11kV GXP to offload feeder 2722 including new feeder cable **Ref 16-006**	0.5	2016	Beyond 2025

Figure 9-59 Cost Estimate for Offloading Haywards 2722

9.7.2 Northeastern Network Development Strategy

As discussed previously, the identified constraints and planned projects for the Northeastern area consists of projects brought forward from previous AMP planning. The Northeastern NDP will provide a more detailed investigation of the area and provide a number of strategies to mitigate the identified issues. These strategies may involve or substitute the currently planned works for the Northeastern area.

For budgeting purposes, an allowance has been included for various distribution level works. The allowance is estimated based on the average distribution level reinforcement costs for a year and provides for:

- Overlay of approximately 400m of undersized 11kV cable including trenching, traffic management and reinstatement costs;
- Installation of approximately 600m of new distribution links between zones at 11kV; and
- Establishment of one new distribution switching station.

9.7.3 Changes to Projects Discussed in the 2014-2024 AMP

A number of projects have been re-evaluated against the current load forecast and deferred or removed completely upon further investigation. These projects include:

- Wainuiomata Zone substation 11kV incomer cables upgrade: Site investigation indicated that the cable size of the incomers was sufficiently rated to provide for maximum supply transformer capacity, thus this project is no longer required;
- Gracefield Feeder 2 Reinforcement: The current load forecast indicates that the load on Gracefield feeder 2 is not projected to breach capacity, thus this project is not currently required; and
- 11kV feeder at Haywards 11kV GXP: The current load forecast indicates that the load on Haywards feeder 2722 is not projected to breach capacity by 2015 as detailed in the previous AMP. This project has been deferred to 2016 and will be re-evaluated against the 2016 load forecast.

The Northeastern area NDP, to be completed in 2015, will provide identification of all constraints against the most recent forecast, and evaluation of a development path to mitigate. The projects forming this development path will be detailed in the 2016 AMP.

9.7.4 Summary of the Northeastern Area Investment

Figure 9-60 shows the investment plan for growth and reinforcement projects in the Northeastern area for the planning period from 2015-2025. An allowance has been included for distribution level development of the Northeastern area. These figures will be updated following completion of the Northeastern area NDP.

Year	Reference	Project	Estimated Cost ($M)
2015	14-003	Trentham Subtransmission Protection Upgrade	0.416
2016	16-006	New 11kV feeder at Haywards 11kV GXP	0.5
2018	18-004	Wellington Northeastern Development Strategy 2018 – Distribution Reinforcement Allowance	1.5
2019	19-004	Wellington Northeastern Development Strategy 2019 – Distribution Reinforcement Allowance	1.5

	19-005	Gracefield Subtransmission Protection Upgrade	0.5
2020	20-005	Wellington Northeastern Development Strategy 2020 – Distribution Reinforcement Allowance	1.5
	20-006	Upper Hutt Subtransmission Protection Upgrade	0.5
2021	21-005	Wellington Northeastern Development Strategy 2021 – Distribution Reinforcement Allowance	1.5
2022	22-005	Wellington Northeastern Development Strategy 2022 – Distribution Reinforcement Allowance	1.5
	22-006	Hutt area zone substation 33kV bus	4
Total Investment			**13.4**

Figure 9-60 Summary of Northeastern Area Investment Requirement

9.8 Customer Initiated Projects and Relocations

These projects have been aggregated in the budget in accordance with the categories discussed below. Overall, the budgeted expenditure for 2015 of $7.9 million is higher than the 2014 actual cost of $6.2 million. This is attributed to a recent lift in consumer and developer confidence and a one off proposal requiring major network reinforcement from two zone substations.

9.8.1 New Connections

For the second consecutive year running the number of residential building consents issued in the Wellington region has risen, driven by the growth in apartments within the Wellington CBD and subdivision growth along the northern belt. Figure 9-61 below shows the number of building consents issued for new houses and apartments over the last five years. The 2015 budget for new connections is similar to expenditure in 2014.

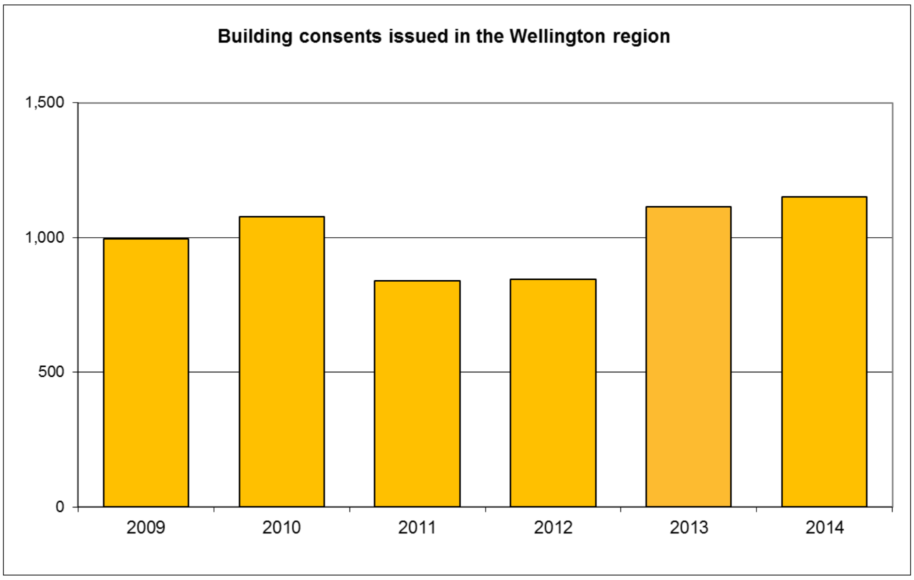


Figure 9-61 Number of Building Consents Issued in the Wellington Area

9.8.2 Substations

The noteworthy increase in customer substation expenditure to $4.3 million is due to a data centre expansion requiring network capacity above 3MVA. Excluding this single development, overall substation related spend, including transformer capacity changes, is slightly down on levels seen in the past 3 years.

9.8.3 Subdivisions

While small and infill subdivisions look to remain at similar levels to previous years, local developers are beginning to show more appetite for large scale residential (>100 lots) subdivisions. However this is offset by industrial property development which has all but ceased because of insufficient demand, and the existence of vacant sites that can be easily converted to meet tenancy needs. The budget allocation for subdivisions in 2015 is $2.0 million.

9.8.4 Capacity Changes

Expenditure associated with transformer upgrades or downgrades is included within the customer substation area of the customer connection forecasts.

9.8.5 Relocations

An allowance in 2015 of $1.1 million for relocation work, initiated from NZTA and TLAs, as well as other customer initiated relocations, has been made based on the respective TLAs strategy plans.

9.8.6 Non-material Works

An allowance in 2015 of $250,000 has been allocated for unplanned non-material projects. This can include HV underground and overhead works which are outside of the Capital Works Plan but required to maintain network reliability and service levels. Non-material works are categorised as works under $250,000, thus not requiring higher approval.

9.9 Summary of the Capital Expenditure Forecasts

From the details in the sections above, Wellington Electricity's network development and growth capital expenditure forecast is summarised in the table in Figure 9-62. It includes the large projects described as well as expenditure on other growth related capital works such as customer projects and relocations. In comparison to asset renewal expenditure, the expenditure on growth projects is relatively modest, reflecting the low growth rates forecast. Expenditure on other line items generally reflects historic expenditure levels. Note that the table does not include asset replacement capital expenditure, this is detailed in Section 6.

The information in this Network Planning section shows that network development and growth expenditure are cyclic over the planning period. Notable network reinforcement projects are seen around 2013-2017 and 2019-2021, reflective of the prospective need for zone substation development to address network constraints. Customer connection expenditure is forecast to rise slightly around the middle of the planning period. This reflects the increased development of residential areas as the economy continues to improve following the recession. As existing vacant land is fully developed there will be a corresponding second wave of expenditure in network growth projects.

Category	2015/16	2016/17	2017/18	2018/19	2019/20	2020/21	2021/22	2022/23	2023/24	2024/25
Consumer Connection	8,015	7,899	7,291	6872	6,494	6,956	7,543	8,375	8,898	9,249
System Growth	1,911	8,100	18,013	18,950	12,100	15,475	14,150	13,125	11,762	10,625
Asset Relocations	1,143	1,090	925	958	1,034	1,092	1,165	1,273	1,337	1,363
Total	**11,069**	**17,089**	**26,229**	**26,780**	**19,628**	**23,523**	**22,858**	**22,773**	**21,997**	**21,**237

Figure 9-62 Capital Expenditure Forecasts – 2015 to 2025 ($K in constant prices)

10 Lifecycle Asset Management

This section provides an overview of Wellington Electricity's asset maintenance, refurbishment and replacement strategies over the planning period. The objective of these strategies is to optimise operational, replacement and renewal capital expenditure on network assets, whilst ensuring that the network is capable of meeting the service level targets and mitigating risks inherent in running an electricity distribution network.

10.1 Asset Lifecycle Planning Criteria and Assumptions

Asset lifecycle management consists of the following:

- Routine asset inspections, condition assessments and servicing of in-service assets;
- Evaluation of the results for terms of meeting customer service levels, performance expectations and control of risks;
- Maintenance requirements and equipment specifications to address known issues; and
- Repair, refurbishment or replacement of assets when required.

The preventative maintenance programme is typically based on a time-based cycle, with each asset type or maintenance task across a group of assets having a set cycle based on a known reliability history or condition degradation trend. Some maintenance activities may involve an intervention outside the normal time based programme, either based on the number of operations undertaken by the asset (e.g. circuit breaker maintenance following fault trips) or based upon external testing results (e.g. transformer maintenance based on oil tests).

In time, as condition assessment data improves for each asset category, planned maintenance cycles for some assets may be extended as the risks associated with the assets may be reduced. Conversely, some assets may need a shorter maintenance cycle as a form of control to manage their higher risk. Some assets, with a low value, low replacement cost, and where the risks and consequences of failure are low, may simply be replaced when they fail, as this is more economic than implementing a full maintenance and refurbishment programme. There are also legislative requirements that require a regular inspection of publicly accessible assets to ensure they pose no unforeseen risk to the public.

Electricity distribution assets have a long but finite life expectancy and eventually require replacement. Premature asset replacement is costly as the service potential of the replaced asset is not fully utilised. Equally, replacing assets too late can result in safety incidences and service interruptions for customers. Asset replacement planning therefore requires the costs of premature replacement to be balanced against the risks of asset failure, public or contractor safety and the deterioration of supply reliability that will occur if critical assets are allowed to fail in service. Hence, there is a balance to be found between the cost of maintaining an asset in service and the cost to replace it.

Wellington Electricity uses the following criteria to determine whether an in-service asset should be replaced. An asset will be replaced if:

- The asset presents an unacceptable risk to the environment or to the safety of the public or operating and maintenance personnel;

- The asset condition has deteriorated to the extent that replacement is required, to control the risk of an in-service failure, where repair or refurbishment is not practical or economic;
- The asset technology is obsolete and spare parts are no longer available;
- The maintenance cost of the asset over its remaining life in order to sustain existing levels of asset reliability is expected to be higher than the asset replacement cost; or
- The asset failure would have a large impact on ongoing customer service or network reliability, or would adversely impact Wellington Electricity's reputation.

These criteria lead to a risk-based approach to asset management. The remainder of this section focuses on the different asset classes and provides an insight into the condition and maintenance of each class with an overview of maintenance programs and renewal and refurbishment programmes.

One of the key assumptions that Wellington Electricity has based its maintenance and renewal programmes on is that the assets are mature, but are generally in fair condition. This is due to sound maintenance programmes early in their service life which has been confirmed by further condition assessment activities undertaken in recent years. Improved condition assessment and reporting has enabled Wellington Electricity to gain a better understanding of the network assets and to target maintenance and renewal activities to the highest priority assets.

10.2 Stage of Life and Asset Health Analysis

Prior to 2015, Wellington Electricity used a "Stage of Life" analysis to prioritise major asset replacement. Stage of Life gave weightings to asset age and a number of factors influencing condition and utilisation to provide an overall score for each asset, which could then be ranked to give a priority.

In practice, Stage of Life was very sensitive to the weightings given to each attribute, and the method of normalisation meant that scores were not comparable across different asset classes. However, the analysis did provide a useful means of highlighting which assets within a class required closer attention.

During 2014, the Electricity Engineers Association released their draft guide to Asset Health Indicators[53]. This method specifies a number of health indices for each asset class, which are rated on a scale of H5 (new) to H1 (end of life). The overall health score of an asset is determined by its worst health index, further reduced by any indices scoring less than H4.

Asset Health Analysis offers a number of advantages over Stage of Life, particularly in that it does not rely on factors having subjective weightings. However, unlike Stage of Life, Asset Health Analysis does not take any account of asset criticality or consequence of failure. Wellington Electricity has developed an Asset Criticality Indicator using the same methodology as Asset Health Analysis, incorporating factors such as number of customers affected, load type and firm capacity.

The result of this analysis is a health-criticality matrix for each major asset class, with the asset location on the matrix giving an indication of risk. As an example, the health-criticality matrix for power transformers on the Wellington Electricity network is shown in Figure 10-1 and further discussed in Section 10.4.

[53] "EEA Asset Health Indicators Consultation Draft", May 2014

		Lowest Impact		Asset Criticality			Highest Impact	
		5.0	4.0	3.0	2.5	2.0	1.5	1.0
Worst Health	1.0				1			
	1.5				1			
Asset Health	2.0				1			
	2.5			3	9		2	
	3.0			5	14		2	1
	4.0			2	6		4	1
Best Health	5.0							

Figure 10-1 Example Health-Criticality Matrix

Each number in the matrix gives the number of assets, be they units or circuits, falling into that particular combination of health and criticality. The highest priority is to address assets in the red area of the matrix. These require work to move them to a lower priority colour. Orange assets are the next priority, and should have work undertaken to move them to a lower priority. Yellow assets are candidates for additional monitoring, maintenance or contingency planning, due to either their health being marginal or their criticality being high. Green assets can continue operating with normal routine maintenance as identified in Wellington Electricity's maintenance practices, as outlined in Section 10.3.

Projects are identified to either improve the health of an asset, or reduce its criticality. The impact of potential changes to health and/or criticality, whether the result of a project or deterioration in condition, can be clearly shown by the movement of the asset within the matrix.

Accordingly, Wellington Electricity is progressively moving the assessment of asset fleets to the risk based asset health, asset criticality framework to provide an objective and prioritised list of needs to be addressed within the planning period. To date the asset classes that have been addressed are:

- Subtransmission Cables;
- Zone Substation Power Transformers and Tap Changers; and
- Zone Substation Switchboards and Circuit Breakers.

It is expected that the development of asset health and criticality for the remaining asset classes will be completed during the remainder of 2015.

10.3 Maintenance Practices

10.3.1 Maintenance Contracts

Wellington Electricity currently contracts Northpower as its Field Services Provider to undertake the network maintenance programme under a Field Services Agreement. Northpower has completed four years of operation on the Wellington network. Within the agreement, the scheduling of inspection and maintenance activities is driven by Wellington Electricity. This arrangement enables Wellington Electricity to lead the overall management of its assets, while allowing the opportunity to receive proposals from the Field Services Provider for reliability centred investment.

Maintenance of all assets is undertaken according to standards that have been developed by Wellington Electricity. These documents have been peer reviewed by senior engineers within other CKI and Power Assets group companies, such as CitiPower and Powercor in Australia and New Zealand industry specialists, and benchmarked against current NZ industry best practice.

Condition-based risk management of assets is achieved through a well-defined condition assessment and defect identification process that is applied during planned inspection and maintenance activities. The condition information is then fed into the SAP PM maintenance management system by the Field Services Provider and analysed alongside other key network information. This enables Wellington Electricity to prioritise field data to make efficient and optimised asset replacement decisions and maintain visibility and tracking of maintenance tasks in the field. Further details of the asset management systems and processes are provided in Section 3.3 and 3.4.

Vegetation management is provided by Treescape and is carried out in accordance with Wellington Electricity policies and the Electricity (Hazards from Trees) Regulations 2003. Under the regulations, tree owners will now be responsible for maintaining their vegetation to a safe clearance distance. There is a risk that this maintenance does not occur and vegetation related outages may start to increase again if tree owners neglect their obligations under the Regulations. Dealing with tree owners who do not take responsibility for their trees becomes resource intensive.

10.3.2 Maintenance Categories

Maintenance is categorised into the following areas:

1. **Planned/Preventative Maintenance (PM) works.** The plan is jointly developed by Northpower and Wellington Electricity based on the requirements of the maintenance standards and the asset condition. The PM plan consists of routine inspections, routine maintenance, condition assessment and servicing work undertaken on the network. The results of planned inspections, and maintenance, drive corrective maintenance or renewal activities.

2. **Corrective Maintenance works.** This work is undertaken in response to defects raised from the planned inspection and maintenance activities, or from observations in the field. Generally the complete programme is not known at the beginning of the financial year and budgets are set based on rolling averages from previous years, adjusted (if required) for prioritisation of any defects. When common failure modes occur these may be progressed into an asset renewal programme to more efficiently manage the defect.

3. **Reactive Maintenance works.** This work is undertaken in response to faults or third party incidents and includes equipment repairs following failure or damage.

4. **Management Fee and Value Added.** This provides for the contractor management overhead and to provide customer services such as cable mark outs, stand over provisions for third party contractors, provision of asset plans for the 'B4U Dig' programme etc.

5. **Vegetation Management.** This covers planned and reactive vegetation work undertaken by Treescape.

The forecast maintenance expenditure for 2015-2025 is summarised at the end of this section.

10.3.3 Managing Network Defects

Within the preventative maintenance and inspection programme, Wellington Electricity operates a process for identifying, prioritising and rectifying defects on network assets. These defects are reported, categorised, prioritised and remedied according to the nature of the defect, the system level it affects, and the risk it poses to the public, employees and the proper operation of the system.

10.4 Maintenance and Renewal Programmes

This section describes Wellington Electricity's approach to preventative maintenance and inspections. It sets out the maintenance activities undertaken for each asset class and commentary is provided on renewal and refurbishment policies or criteria plus known systematic issues. The asset classes covered are:

- Subtransmission;
- Zone Substations;
- Distribution and LV Lines;
- Distribution and LV cables;
- Distribution substations and transformers;
- Distribution switchgear;
- Other system fixed assets; and
- Other assets.

The description for each asset class is structured in the following manner:

- Maintenance activities relevant to the asset class;
- The condition of the assets;
- The approach to renewals for the class including life extension activities and innovations; and
- The health indices.

10.4.1 Subtransmission

10.4.1.1 Maintenance Activities

The following routine planned inspection, testing and maintenance activities are undertaken on subtransmission cables:

Activity	Description	Frequency
Cable sheath tests	Testing of cable sheath and outer servings, continuity of sheath, cross bonding links and sheath voltage limiters	2 yearly
Subtransmission - cable gas / oil injection equipment inspection	Inspection and minor maintenance of equipment in substations, kiosks and underground chambers	6 monthly
Subtransmission - regular patrol	Patrol of cable route; replace missing or damaged cable markers	Weekly

Figure 10-2 Inspection and Routine Maintenance Schedule for Subtransmission Cables

In conjunction with the above routine maintenance schedule, all oil filled and pressurised gas cables have pressure continuously monitored via the centralised SCADA system, with managerial oversight through a monthly reporting process. This monitoring provides information that identifies cables where pressure is reducing and allows the situation to be promptly investigated. One of the key tests is the sheath test, which indicates whether there is damage to the outer sheath and gives an early indication of situations where corrosion or further damage (leading to leaks) may occur, as well as proving the integrity of the earth return path.

When fluid-filled cables develop a leak, they can usually be dug up and repaired without having to cut the cable. However when a more serious electrical fault occurs a new section of cable will be necessary. On some occasions transition joints are made to join the pressurised cables to sections of XLPE cable. These joints are relatively expensive at around $100,000 each, meaning that to replace even short sections of cable will cost a minimum of $250,000, making it uneconomic to have a large number of such joints in a single cable. The outcome of this is that where a cable is located in an environment where damage is likely to occur, it is more economical to install a long length of replacement XLPE cable than several short lengths.

Objective condition assessment on cables with oil or gas pressurisation is difficult and quite limited, as a number of assessment techniques, including partial discharge testing, are not applicable to these types of cables. The main mode of failure of these cables is stress on the joints and resulting failure, as well as sheath failures allowing gas leaks and areas of low pressurisation along the length of the cable. Accordingly, the leaks and the cable can be repaired before the electrical insulation properties are compromised.

The historic fault information for each cable, where known, is used to assess and prioritise the need for cable replacement, as well as determining the strategic spares to be held. Strategic spares for subtransmission cables are outlined in Figure 10-3.

Strategic Spares	
Medium lengths of cable	It is necessary to hold medium lengths of oil and gas cable in store to allow replacement of short sections following damage. By holding oil and gas cable lengths, the Field Service Provider is able to undertake repairs without requiring termination and transition to XLPE cable.
Standard joint fittings	Stock is held by the Field Service Provider to repair standard oil and gas joints. A minimum stock level is required and if stocks fall below this level, replacement parts need to be sourced and if necessary be manufactured locally.
Termination/transition joints	Two gas to XLPE cable transition joints are held in storage to allow the replacement of damaged sections of gas filled cables with non-pressurised XLPE cables.

Figure 10-3 Spares Held for Subtransmission Cables

10.4.1.2 Cable Condition and Failure Modes

Gas filled cables

Gas filled HV cables have been in use internationally since the 1940s and are still in service in many utilities in New Zealand and Australia. They have proven to perform well when they are installed in benign environments that are not prone to disturbance or damage. Wellington Electricity, however, has many of its gas-filled cables installed under busy roads in urban environments and through structures such as bridges. This requires close monitoring of their performance to manage any deterioration and consequent reduction in levels of service. Many cables also cross earthquake fault lines, with that risk being controlled through the emergency overhead line corridors discussed in Section 5.5.5. Some of these cables in particular have been repaired numerous times as a result of third party damage or after gas leaks have been found. Vibration from traffic has been identified as a contributing factor to some mechanical failures.

Oil-Filled Cables

Oil-filled cables were installed in the Wellington Electricity network from the mid-1960s until 1991, and comprise 38% of the subtransmission cable population. Some circuits, for example Johnsonville in 2012 and Korokoro in 2013, have experienced oil leaks but, in general, the condition of the cables remains good for their age.

Paper and Polymeric Cables

Approximately 32% of Wellington Electricity's subtransmission cable has solid insulation of either oil-impregnated paper or XLPE. These cables are relatively new when compared to the gas and oil filled installations.

A 33kV XLPE cable termination failed at Moore St zone substation in 2014, causing a short outage to key customers in the Wellington CBD. This termination was subsequently found to be of a particular model that has a reputation in the New Zealand industry for premature failure and is no longer sold. The failed termination was replaced, as were the other 33kV terminations at the substation and identical terminations at The Terrace zone substation. With the exception of this termination failure, the XLPE and paper insulated cables are performing well, and no renewal is expected to be required during the period covered by this AMP.

Cable Strikes

Wellington Electricity, like most lines businesses and other utilities, experiences a number of third party strikes on its underground assets each year. These pose a serious risk to health and safety, impact network performance, and incur a large cost to repair. Unfortunately not all of these third party incidents are identified and reported at the time of the incident, which may lead to future safety and network reliability problems.

To minimise the number of third party strikes, Wellington Electricity uses the B4U-DIG programme to facilitate the provision of obstruction plans to contractors working in the area, with Northpower providing cable mark outs and stand-overs where appropriate. Wellington Electricity has a focused education campaign for contractors working for large utility companies and local authorities with presentations educating them on the importance of cable location and excavation practices. Wellington Electricity is working with the Ministry of Business, Innovation and Employment on this matter.

In addition, cable maintenance staff patrol the routes of all subtransmission circuits on a weekly basis and note any activities that may impact upon underground services. Where necessary, third party contractors are reminded of the risks associated with working around underground cables.

10.4.1.3 Renewal and Refurbishment

There are few options for refurbishment or extension of life of subtransmission cables once major leaks, discharge or electrical insulation breakdown has occurred, and in most cases the most cost-effective solution is replacement of sections, or the entire length, of cable. Due to the cost of transition joints, it is likely to be more economical to replace sections end to end in their entirety.

10.4.1.4 Subtransmission Health and Criticality Analysis

The asset health analysis considers the attributes of each subtransmission cable circuit. For subtransmission cables the health attributes for each category are shown in Figure 10-4.

Category	Attribute
Health	Sheath Integrity
Health	Leakage History (gas- and oil-filled cables only)
Health	Known Type Issues
Health	Thermal Degradation and Loading History
Health	Partial Discharge (solid insulation only)
Health	Water Trees (XLPE insulation only)
Health	Availability of Parts
Health	Orphan Asset

Category	Attribute
Health	Repeat Failures
Health	Workforce Skills
Criticality	Primary Load Type (CBD, Industrial, Residential)
Criticality	Number of Customers Served
Criticality	Bus Configuration at Zone Substation
Criticality	Availability of 11kV backfeeds

Figure 10-4 Categories and Indices for Subtransmission Circuits

Considering the above attributes for each circuit gives the health-criticality matrix shown in Figure 10-5, with individual circuit scores and ratings being presented in Figure 10-6. Where a circuit comprises multiple cable types, for example a predominantly gas-filled cable that includes a section of XLPE cable, the health indices are calculated independently for each cable type, with the lowest health index governing the AHI of the circuit as a whole.

		Lowest Impact		**Asset Criticality**			Highest Impact	
Asset Health		5.0	4.0	3.0	2.5	2.0	1.5	1.0
Worst Health	1.0				2			
	1.5							
	2.0							
	2.5			8	18		2	2
	3.0				2			
	4.0			2	10		4	
Best Health	5.0						2	

Figure 10-5 Subtransmission Circuit Health-Criticality Matrix

Subtransmission Circuit	Primary Type	AHI	ACI	Rating
Evans Bay 1 & 2	Gas	1.1	2.8	
Frederick Street 1	Gas	2.7	1.4	
Frederick Street 2	Gas	2.8	1.4	
University 1	Gas	2.8	1.7	
University 2	Gas	2.7	1.7	
Moore Street 1 & 2	XLPE	4.0	1.8	
Terrace 1 & 2	XLPE	4.0	1.8	
Palm Grove 1 & 2	XLPE	5.0	1.8	
Johnsonville A & B	Oil	2.6	2.9	
Maidstone A	Gas	2.6	2.9	
Tawa A	Oil	2.7	2.9	
Hataitai 1 & 2	Gas	2.8	2.8	
Ira Street 1 & 2	Gas	2.8	2.9	
Karori 1 & 2	Gas	2.8	2.9	
Kenepuru A & B	Oil	2.8	2.9	
Korokoro A & B	Oil	2.8	2.9	
Porirua A & B	Oil	2.8	2.9	
Tawa B	Oil	2.8	2.9	
Waterloo A & B	Oil	2.8	2.9	
Maidstone B	Gas	2.8	2.9	
Brown Owl A & B	Oil	2.8	3.0	
Naenae A & B	Oil	2.8	3.0	
Trentham A & B	Oil	2.8	3.0	
Waitangirua A & B	Oil	2.8	3.0	

Subtransmission Circuit	Primary Type	AHI	ACI	Rating
Mana	XLPE	4.0	2.8	
Ngauranga A & B	XLPE	4.0	2.8	
Gracefield A & B	PILC	4.0	2.9	
Waikowhai A & B	PILC	4.0	2.9	
Wainuiomata A & B	PILC	4.0	3.0	

Figure 10-6 Health Criticality Scores for Subtransmission Circuits

Outcome of the Asset Health Analysis

The asset health analysis shows that gas and oil-filled cables rate lower than modern cables on a number of categories, primarily driven by the cost and availability of parts and workforce skills. The highest possible health index for a gas or oil-filled cable under the AHI method is 2.8, even if it is in perfect physical condition. Accordingly, gas and oil-filled cables have the highest health based priority for replacement.

The highest priority subtransmission cable circuits are discussed below.

Evans Bay

The Evans Bay subtransmission circuits are old and in poor condition but are sufficiently lightly loaded that the Evans Bay load can be temporarily back-fed from neighbouring zone substations through the 11kV network with relative ease. Evans Bay zone substation does not appear likely to increase in criticality. There is also uncertainty around the future development of the Mt Victoria road tunnel where the cables presently run.

The Evans Bay cables will eventually need to be removed from service, however direct replacement with new subtransmission cables may not be the most cost-effective solution as a range of potential alternative solutions exists. An options study will be undertaken during 2015 to assess these solutions and determine project details and timing.

Frederick Street

The gas-filled Frederick Street cables are in good condition, however their location in the Wellington CBD and capacity constraints as identified in Section 9.5.1.2 gives them a high criticality score. Their health will continued to be monitored through routine testing to watch for any deterioration in condition. However there are no health-related drives for replacement at this time.

University

The gas-filled University cables were largely replaced during 2008, however approximately 500 metres of gas cable remains in each circuit. These cables have high criticality due to University Zone Substation supplying a portion of the Wellington CBD, and a small shortfall in N-1 capacity that can be met with 11kV backfeeds. At this time there are no health-related drivers for replacement, however the cable condition will continue to be closely monitored until their eventual replacement due to the capacity constraint.

Figure 10-7 provides the projects and expected expenditure list resulting from the asset health analysis.

Zone Substation	Project Description	Investment Year	Driver	Proposed Expenditure
Evans Bay	Replacement Options Study	2015	Age and condition	<$0.1M

Figure 10-7 Project List for Subtransmission Cables

10.4.2 Zone Substations

10.4.2.1 Zone Substation Transformers and Tap Changers

Maintenance Activities

The following routine planned inspection, testing and maintenance activities are undertaken on zone substation power transformers:

Activity	Description	Frequency
Transformer oil test	Dissolved gas analysis (DGA) testing of transformer main tank oil	Annually
Transformer Maintenance, Protection and AVR Test	De-energised transformer maintenance, inspection and testing of transformer, replacement of silica crystals, diagnostic tests as required. Gas injection for testing of Buchholz. Testing of temperature gauge and probe. Confirmation of correct alarms. Test AVR and ensure correct operation and indications	4 yearly
OLTC Maintenance	Programmed maintenance of OLTC	4 yearly

Figure 10-8 Inspection and Routine Maintenance Schedule for Zone Substations Transformers and Tap Changers

Strategic Spares

Wellington Electricity holds critical spares for the power transformers and tap changers as detailed in Figure 10-9.

Strategic Spares	
Tap changer fittings	Wellington Electricity holds a number of critical and maintenance spares for the tap changers on zone substation transformers, typically contacts and related components. These components have high wear and are eroded by arcing during operation. Where excessive wear is noted during maintenance, spares are ordered and held in stock for that model of tap changer. Spares are still available for most models on the network, and if necessary spares can be re-manufactured by third party suppliers.

Strategic Spares	
Transformer misc. fittings	Various other transformer fittings have been identified and held for sites where having a transformer out of service for a prolonged period is unacceptable. Fittings include Buchholz relays, high voltage bushings etc. If major repairs are needed, a unit will be swapped out.
Spare transformers	Two spare power transformers are available. One unit came from Petone substation when this was decommissioned in 2013 and is held at the Bouverie Street yard. Another is the newly refurbished Wainuiomata A, which is held at the Wainuiomata zone substation. Should additional spare transformers be required, one could be taken from any of a number of substations that are lightly loaded with sufficient distribution network back-feed options. These include Trentham, Gracefield, Tawa and Kenepuru. In extreme situations, these sites could be evaluated for transformer removal.

Figure 10-9   Spares Held for Zone Substation Transformers

Transformer Condition

Zone substation power transformer

The condition of most transformers on the network indicates normal performance. Where evidence of heating is present, corrective maintenance such as tightening or renewing internal connections outside of the core or tap changer maintenance is undertaken, if economic. By far, the most common issue is not electrical performance but mechanical deterioration. Examples include tap changer mechanism wear, contact wear, and similar problems associated with moving machinery. External condition issues include leaking gaskets, fan and cooling system problems and, for outdoor installations, corrosion and weathering of the transformer tanks, especially the tops where water can sometimes pool.

Oil tests provide an estimated Degree of Polymerisation (DP) value for the paper insulation, which provides an initial overview of the transformer condition. Furan analysis undertaken with the DGA oil tests in 2009 show the DP of the majority of transformers to be above 450. It is proposed that once a transformer DP reaches 300, a paper sample will be taken to confirm the accuracy of the furan analysis and determine what further steps are required.

During 2013, routine oil testing of Wainuiomata A indicated abnormal internal heating. The unit was replaced with a spare, and sent to a workshop for further evaluation. The fault was found to be a stray earth contact inside the tank. A sample of the insulating paper gave a DP result of 958, indicating that the insulation has a remaining life of 45 years despite already being 42 years old. On this basis the fault was repaired and the transformer refurbished to be held as a spare.

Figure 10-10 shows the estimated remaining life of Wellington Electricity's power transformer fleet as given by DP results, plotted against the nominal 60-year life of the assets. This clearly shows that, as long as corrosion and other mechanical issues can be managed, all of the transformers except one are expected to last beyond their nominal 60-year life. The exception is University 1, which is discussed further later in this section.

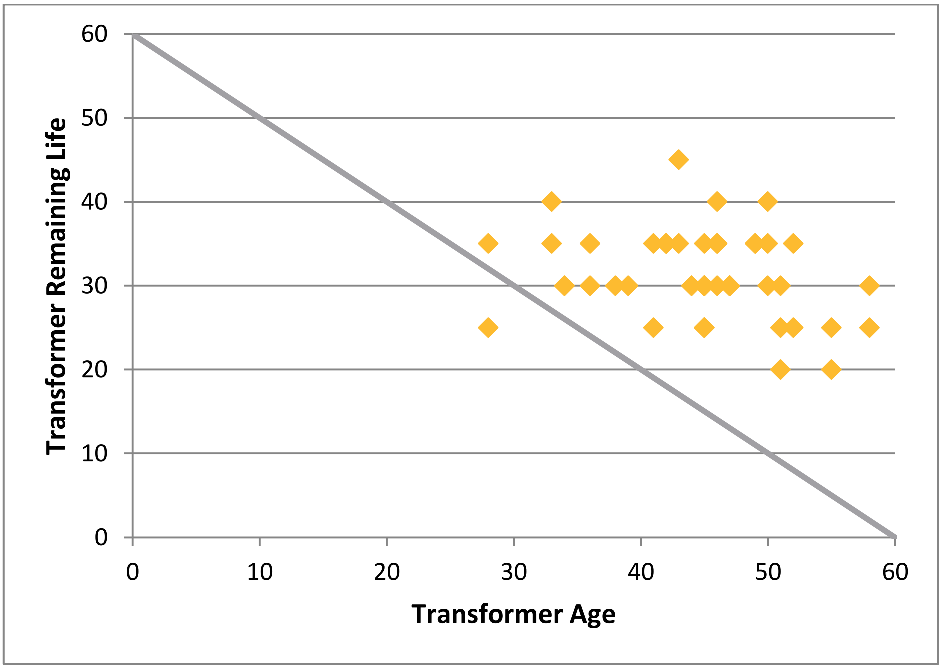


Figure 10-10 Profile of Age vs Remaining Life for Power Transformers

Renewal and Refurbishment

Where a transformer is identified for relocation, refurbishment is generally performed if it is economic to do so based on the condition and residual life of the transformer. A non-invasive test to determine the moisture content of the winding insulation is used to inform the assessment of whether a major transformer refurbishment would be economic.

The following projects have been provided for in the asset maintenance and replacement forecasts for the planning period:

- Ongoing preventative maintenance including testing and inspections;
- Transformer replacements at two zone substations; and
- Ongoing transformer refurbishment costs.

Based on asset health and criticality, at least two zone substation transformers can be expected to require replacement during the period 2015 to 2025. The units to be replaced may not be the oldest nor in the worst condition, but will be transformers where capacity and security constraints indicate a high risk associated with failure. All factors considered in the replacement decision-making process are covered in the Asset Health analysis described below.

In some instances, where a power transformer is approaching, or at, its service half-life, subject to condition assessment results, a refurbishment including mechanical repairs, drying and tightening of the core and associated electrical repairs can be justified. For the power transformers in the Wellington Electricity network, the testing and inspection programme will aid in getting the best life from the transformer and optimal timing of replacement of the unit.

<u>Transformer Asset Health Analysis</u>

The Asset Health Analysis considers the attributes of each power transformer as defined by the properties shown in Figure 10-11.

Category	Index
Health	Degree of Polymerisation
Health	Bushing Condition
Health	Mechanical Integrity (i.e. SFRA testing)[54]
Health	Insulation System Condition
Health	Known Type or Design Issues
Health	Safety Features
Health	Availability of Parts for OLTC Maintenance
Health	Noise
Health	Workforce Skills
Criticality	Primary Load Type (CBD, Industrial, Residential)
Criticality	Number of Customers Served
Criticality	Bus Configuration at Zone Substation
Criticality	Availability of 11kV Backfeeds

Figure 10-11 Categories and Indices for Power Transformers

Applying the above factors to each transformer gives the health-criticality matrix shown in Figure 10-12, with individual transformer scores and ratings being presented in Figure 10-13.

[54] Transformer SFRA testing is not currently undertaken by Wellington Electricity.

		Lowest Impact		Asset Criticality			Highest Impact	
		5.0	4.0	3.0	2.5	2.0	1.5	1.0
Worst Health	1.0				1			
	1.5				1			
	2.0				1			
	2.5			3	9		2	
Asset Health	3.0			5	14		2	1
	4.0			2	6		4	1
Best Health	5.0							

Figure 10-12 Power Transformer Health-Criticality Matrix

Transformer	Substation	AHI	ACI	Rating
Evans Bay T1	Evans Bay	1.3	2.8	
Evans Bay T2	Evans Bay	1.7	2.8	
Palm Grove T1	Palm Grove	2.9	1.8	
Palm Grove T2	Palm Grove	2.9	1.8	
Frederick Street T1	Frederick Street	3.0	1.4	
Frederick Street T2	Frederick Street	4.0	1.4	
Mana	Mana-Plimmerton	2.0	2.8	
Moore Street T1	Moore Street	4.0	1.8	
Moore Street T2	Moore Street	3.0	1.8	
Terrace T1	Terrace	4.0	1.8	
Terrace T2	Terrace	4.0	1.8	
University T1	University	3.0	1.7	
University T2	University	4.0	1.7	

Transformer	Substation	AHI	ACI	Rating
Brown Owl A	Brown Owl	3.0	3.0	
Brown Owl B	Brown Owl	2.9	3.0	
Gracefield A	Gracefield	3.0	2.9	
Gracefield B	Gracefield	3.0	2.9	
Hataitai T1	Hataitai	3.0	2.8	
Hataitai T2	Hataitai	3.0	2.8	
Ira Street T1	Ira Street	4.0	2.9	
Ira Street T2	Ira Street	4.0	2.9	
Johnsonville A	Johnsonville	2.9	2.9	
Johnsonville B	Johnsonville	2.9	2.9	
Karori T1	Karori	2.9	2.9	
Karori T2	Karori	3.0	2.9	
Kenepuru A	Kenepuru	4.0	2.9	
Kenepuru B	Kenepuru	3.0	2.9	
Korokoro A	Korokoro	3.0	2.9	
Korokoro B	Korokoro	3.0	2.9	
Maidstone A	Maidstone	4.0	2.9	
Maidstone B	Maidstone	3.0	2.9	
Naenae T1	Naenae	3.0	3.0	
Naenae T2	Naenae	3.0	3.0	
Ngauranga A	Ngauranga	2.9	2.8	
Ngauranga B	Ngauranga	3.0	2.8	
ex-Petone A[55]	Spare	3.0	N/A	

[55] Spare 20MVA unit held at Petone Zone Substation

Transformer	Substation	AHI	ACI	Rating
Plimmerton	Mana-Plimmerton	2.9	2.8	
Porirua A	Porirua	3.0	2.9	
Porirua B	Porirua	3.0	2.9	
Seaview A	Seaview	3.0	2.9	
Seaview B	Seaview	3.0	2.9	
Tawa A	Tawa	1.8	2.9	
Tawa B	Tawa	1.7	2.9	
Trentham A	Trentham	2.8	3.0	
Trentham B	Trentham	2.8	3.0	
Waikowhai T1	Waikowhai	2.8	2.9	
Waikowhai T2	Waikowhai	2.9	2.9	
ex-Wainuiomata A[56]	Spare	4.0	N/A	
Wainuiomata B	Wainuiomata	4.0	3.0	
Wainuiomata C[57]	Wainuiomata	3.0	3.0	
Waitangirua A	Waitangirua	4.0	3.0	
Waitangirua B	Waitangirua	3.0	3.0	
Waterloo A	Waterloo	4.0	2.9	
Waterloo B	Waterloo	4.0	2.9	

Figure 10-13 Health-Criticality Scores for Power Transformers

<u>Outcome of Asset Health Analysis</u>

Evans Bay

The transformers installed at Evans Bay are two of the oldest on the network, having been installed in 1959, and have the lowest health indices in the network. These transformers have experienced an increasing number of problems in recent years, mostly relating to the mechanical performance of the tap changer and

[56] Spare 23MVA unit held at Wainuiomata Zone Substation

[57] 20MVA unit ex-Petone B

excessive leaks due to deterioration of valves, flanges, gaskets and radiators. Fortunately to date corrective works have been possible and the transformers returned to service.

The high level of redundancy at this site makes a long duration transformer outage possible with minimal risk to supply. However the poor mechanical condition of these transformers indicates they are near the end of their life and major repairs to address the issues are not economic. It is anticipated that these transformers will be replaced, or have transformers of better condition swapped into this location, within the planning period.

Palm Grove

The Palm Grove transformers are in good condition, but have high criticality due to the peak loading and number of customers supplied by the substation. Their asset health is marked down slightly due to the noise created by their forced cooling and the proximity of residential neighbours. The proposed development path outlined in Section 9 ensures adequate firm capacity at the site for expected future loadings, so there is no immediate requirement to replace these transformers with higher-rated units. However the installation of new low-noise transformers remains an option if required in future.

Other Comments

In addition to the health-criticality issues noted above, the following issues are known to Wellington Electricity:

Ngauranga

Ngauranga has the two oldest power transformers installed in Wellington Electricity's network. These transformers are generally reliable but have experienced problems with the tap changer diverter switches in the past. These issues will be monitored and corrective repairs undertaken as required. It is expected that replacement will be required at the end of the planning period. This site has full N-1 security at the transformer level and can supply the load should one unit be temporarily unavailable.

Frederick Street

Frederick Street has a high criticality index due to its location in Wellington CBD and the number of customers it supplies. The transformers are in good condition, however in early 2014 the DGA results on T1 and T2 indicated elevated levels of ethylene and moisture, respectively. In both cases, the absence of other key gases suggested there were no major problems with either unit so the oil was filtered and routine monitoring will continue.

Waikowhai Street

The transformers at Waikowhai Street substation are in good condition. They are fitted with vertical Reinhausen tap changers which are the only two of this kind on the network. These are more difficult to maintain and are refurbished on a 6-8 yearly cycle. The tap changers were last refurbished in 2011 by a Reinhausen technician and it is expected that further refurbishment will not be required until 2019.

University 1

The University transformers are only 28 years old, however University 1 is showing a much lower degree of polymerisation than University 2. This is attributed to an historic loading imbalance, which has since been resolved, that has caused the paper insulation on University 1 to age faster than that of its twin. While the

DP result is low it is still indicating an estimated remaining life of 25 years, so replacement is not expected to be required within the planning period. The condition of both units will continue to be monitored through the routine maintenance programme.

The project list reflecting the asset health-criticality analysis is shown in Figure 10-14.

Zone Substation	Project Description	Investment year	Driver	Proposed Budget
Evans Bay	Power transformer replacement	2017	Condition	$2.0M
Ngauranga	Power transformer replacement	2025	Condition	$2.0M

Figure 10-14 Project List for Power Transformers

10.4.2.2 Switchboards and Circuit Breakers

Replacement in progress of Reyrolle Type C with RPS LMVP switchgear at a zone substation

Maintenance Activities

The following routine planned inspection, testing and maintenance activities are undertaken on metal clad switchboards and circuit breakers:

Activity	Description	Frequency
General Inspection of 33kV Circuit Breaker	Visual inspection of equipment and condition assessment based upon visible defects. Thermal image of accessible connections. Handheld PD and Ultrasonic scan	Annually
General Inspection of 11kV Circuit Breaker	Visual inspection of equipment and condition assessment based upon visible defects. Thermal image of accessible connections. Handheld PD and Ultrasonic scan	Annually
33kV Circuit Breaker Maintenance (Oil)	Maintenance of OCB, drain oil, ensure correct mechanical operation, dress or replace contacts as required, undertake minor repairs, refill with clean oil, return to service. Trip timing test before and after service	4 yearly
11kV Circuit Breaker Maintenance (Oil)	Withdraw and drain OCB, ensure correct mechanical operation, dress or replace contacts as required, undertake minor repairs, refill with clean oil, return to service. Trip timing test before and after service	4 yearly (Zone) 5 yearly (Distribution)
11kV Circuit Breaker Maintenance (Vacuum or Gas)	Withdraw CB and maintain carriage and mechanisms as required, record condition of interrupter bottles where possible, clean and return to service. Trip timing test before and after service	4 yearly (Zone) 5 yearly (Distribution)
11kV Switchboard Major Maintenance (zone)	Full or bus section shutdown, removal of all busbar and chamber access panels, clean and inspect all switchboard fixed portion components, undertake condition and diagnostic tests as required. Maintain VTs and CTs. Return to service	8 yearly (Zone) 10 yearly (Distribution)
11kV Circuit Breaker - Annual Operational Check	Back-feed supply; arrange remote and local operation in conjunction with NCR to ensure correct operation and indication	Annually (Zone only)
PD Location by External Specialist	External specialist to undertake partial discharge location service, presently HV Diagnostics	Annually (Zone only)

Figure 10-15 Inspection and Routine Maintenance Schedule for Zone Substation Circuit Breakers

In addition to the routine maintenance programme, oil circuit breakers are maintained as required following a number of fault clearance operations.

Strategic Spares

Given the high number of circuit breakers in service on the Wellington Electricity network, it is important to keep adequate quantities of spares to enable fast repair of minor defects. Some types of circuit breakers, such as early Statter and AEI, have limited numbers of spares available; however, there are fewer of these types still installed on the system. The largest quantity of circuit breakers on the network is the Reyrolle type LMT, which is used predominantly at zone substations, and Wellington Electricity holds large numbers of spares for these circuit breakers. Furthermore, the RPS (formerly Reyrolle Pacific) switchgear factory is located in Petone which means that spares are available within short timeframes if required for LMT type switchgear. An overview of strategic spares held for circuit breakers is shown in Figure 10-16.

Strategic Spares	
Circuit breaker trucks	At least one circuit breaker truck of each rating (or the maximum rating where it is universal fitment) is held for each type of withdrawable circuit breaker on the network.
Trip/Close coils	Spare coils held for each type of circuit breaker and all operating voltages.
Spring charge motors	Spare spring charge motors held for each voltage for the major types of switchgear in service.
Current transformers and primary bars	Where available, spare current transformers and primary bars are held to replace defective units. In particular, 400A current transformers for Reyrolle LMT are held, as this type of equipment has a known issue with partial discharge.

Figure 10-16 Spare Parts Held for Circuit Breakers

Switchgear Condition

The switchgear installed on the Wellington Electricity network is generally in very good condition, although there is some deterioration on older units. The equipment is installed indoors, has not been exposed to extreme operating conditions and has been well maintained. In some locations, the type of load served or the known risks with the type of switchgear mean that an enhanced maintenance programme is required whilst a replacement programme is in place for some older switchgear types, for example Reyrolle Type C and Yorkshire SO-HI.

Examples of poor condition include partial discharge (particularly around cast resin components), corrosion and compound leaks that are visible externally, slow or worn mechanisms and unacceptable contact wear. The majority of these defects can be easily remedied under corrective maintenance programmes.

The condition of zone substation switchboards is discussed in detail in the circuit breaker health-criticality analysis below. Due to their lower criticality, distribution substation switchboards are not currently included in the analysis.

Renewal and Refurbishment

Based on the condition assessment carried out as part of the preventative maintenance routine, assets are identified for replacement, or targeted inspection and maintenance programmes are put in place to manage risks until replacement is possible. A large number of older circuit breakers are still in service and are in excellent condition due to regular maintenance over their service life. However other older units are showing their age with pitch leaks and failing mechanisms.

Condition, performance, ratings and operational history across the industry are considered when determining when a circuit breaker is replaced. Other drivers that influence the replacement decision include safety, criticality, operability and co-ordination with modern equipment.

The following replacement programmes are in place for the planning period:

Reyrolle Type C

Reyrolle Type C circuit breakers were installed between 1938 and the late 1960s and the majority of units have reached the end of their effective service life. There are 29 units remaining in service at three substations and these are being replaced over the next two years. The replacement programme is shown in Figure 10-17:

Substation	No. of Circuit Breakers	Year installed	Replacement year	Estimated Cost
Karori Zone	11	1962	2015	$2,200,000
Flag Staff Hill	5	1953	2015	$900,000
Gracefield Zone	13	1958	2016	$1,850,000

Figure 10-17 Proposed C-type Circuit Breaker Replacement Programme

Yorkshire SO-HI

Yorkshire SO-HI switchgear was installed during the 1970s and 1980s in indoor kiosk type substations. SO-HI switchgear has a history of failing in service and a number of EDBs have either removed the equipment entirely, or imposed operational restrictions. Wellington Electricity has imposed an operational restriction on these units and they are not operated manually under fault conditions.

In 2011 Wellington Electricity initiated a replacement programme for SO-HI units, commencing with sites identified as having a high consequence of failure. The majority of SO-HI installations have now been replaced with conventional ring main units or secondary class circuit breakers, leaving one site to be replaced during 2015 as detailed in Figure 10-18. This will complete the SO-HI replacement programme.

Sub No.	Location	Feeder	No. of Switches	Replacement year	Estimated Cost
S3183	Todd Motors	KEN 02	14	2015	$400,000

Figure 10-18 Proposed SO-HI Replacement Programme

Statter

As at October 2014, there are 78 sites with Statter switchgear, with 222 units in service including circuit breakers, oil switches and fuse switches, installed between 1955 and 1991.

In recent years, there have been instances where Statter switchgear has failed to operate requiring operating restrictions to be in place until the unit is repaired or replaced. Statter switchgear is at the end of its useful service life and is becoming difficult to keep in service due to a lack of spares.

The majority of Statter installations do not have protective elements enabled or remote control on the circuit breakers. The units can be replaced with conventional ring main units without causing a decrease in network reliability. In a few cases, the units have full protection and control, and are located on feeders with high cumulative SAIDI. These will be replaced with modular secondary class circuit breakers to maintain reliability levels.

With this replacement strategy, the estimated cost of replacing the Statter switchgear is approximately $10.6 million over nine years, with replacements prioritised on condition and criticality.

Replacement Year	Number of Sites	Proposed Budget
2015	9 sites	$1,200,000
2016	10 sites	$1,150,000
2017	8 sites	$1,200,000
2018	9 sites	$1,150,000
2019	8 sites	$1,300,000
2020	8 sites	$1,150,000
2021	8 sites	$1,150,000
2022	8 sites	$1,100,000
2023	10 sites	$1,200,000

Figure 10-19 Proposed Statter Replacement Spend Plan

Reyrolle LMT - Partial Discharge

Reyrolle LMT circuit breakers were installed on the network from late 1960s onwards. There are over 600 units in service on the Wellington Electricity network.

In the latter part of 2012, a Reyrolle LMT circuit breaker at Waitangirua zone substation was found to have high levels of partial discharge emanating from the CT chamber. This prompted a replacement of the CTs, bushings, and pitch-filled cable termination using a specially developed retrofit kit, which lowered the PD to normal levels. Circuit breakers are refurbished using this kit when they are identified as having unacceptable partial discharge levels.

All circuit breakers are surveyed with a handheld TEV meter as part of their routine annual general inspection, with zone substation circuit breakers receiving a full partial discharge survey annually from an external specialist. Corrective maintenance is undertaken when high levels of PD are detected however at this stage there do not appear to be any other type issues similar to that which was experienced with LMT.

Reyrolle LMT – Rotary Auxiliary Switch Failure

During 2011 a number of instances of circuit breaker “failure to operate” alarms occurred under fault and switching operations. This was identified as being a result of contamination of the rotary auxiliary switch, leading to false indications and also preventing operation due to the interlocking status being incorrect.

A sample of the contaminant was analysed and a high level of a styrene residue was found, as well as other oil and grime. Although the cause is uncertain, it is suspected that previous maintenance practices have introduced solvents that have released the glues and plastics inside the switch body. These have migrated onto the contacts and act as an insulator, leading to the “failure to operate” issues.

The Field Services Provider has been trained in the correct maintenance practices, including the appropriate corrective actions when a faulty unit is found. Dust covers are fitted to cleaned contacts to prevent dust and grime ingress. The switchgear manufacturer is now providing factory made dust covers on new circuit breakers of this type supplied to Wellington Electricity.

After the introduction of dust covers and the corrective maintenance regime to clean the contacts, reports of "failure to operate" alarms on LMT type circuit breakers has been reduced. This outcome is expected to improve further when all the LMT circuit breakers are maintained and installed with dust covers on the auxiliary switches.

Circuit Breaker Health Analysis

The Asset Health-Criticality analysis considers the attributes of each zone substation switchboard as defined by the properties shown in Figure 10-20.

Category	Attribute
Health	External Condition
Health	Interrupter Life and Operation Count
Health	Insulation Properties
Health	Partial Discharge
Health	Gas/Oil Leaks
Health	Type or Design Issues
Health	Operating History
Health	Availability of Parts and Tools
Health	Orphan Asset
Health	Uncertified Modifications
Health	Workforce Skills
Health	Failure Containment and Operator Safety
Criticality	Primary Load Type (CBD, Industrial, Residential)
Criticality	Number of Customers Served
Criticality	Bus Configuration at Zone Substation
Criticality	Availability of 11kV Backfeeds

Figure 10-20 Categories and Indices for Zone Substation Switchboards

Considering the above attributes for each switchboard gives the health-criticality matrix shown in Figure 10-21, with individual switchboard scores and ratings being presented in Figure 10-21.

		Lowest Impact		Asset Criticality			Highest Impact	
		5.0	4.0	3.0	2.5	2.0	1.5	1.0
Worst Health	1.0				2			
	1.5			1	2		1	
	2.0						1	1
	2.5			5	12		2	
Asset Health	3.0							
	4.0				1			
Best Health	5.0				1		2	

Figure 10-21 Zone Substation Switchboard Health-Criticality Matrix

11kV Switchboard	Model	AHI	ACI	Rating
University	LMT	1.9	1.7	
Frederick Street	LM23T	2.0	1.4	
Kaiwharawhara	LMVP	2.0	1.8	
Gracefield	C	1.2	2.9	
Karori	C	1.2	2.9	
Mana	LM23T	1.8	2.8	
Johnsonville	LM23T	1.8	2.9	
Brown Owl	LM23T	1.8	3.0	
Moore Street	LM23T	2.9	1.8	
Nairn Street	LMT	2.9	1.8	
Palm Grove	LMVP	5.0	1.8	
Terrace	NX-PLUS	5.0	1.8	
Evans Bay	LMVP	5.0	2.8	
Hataitai	LM23T	2.9	2.8	

11kV Switchboard	Model	AHI	ACI	Rating
Ira Street	LM23T	2.9	2.9	
Kenepuru	LM23T	2.8	2.9	
Korokoro	LM23T	2.8	2.9	
Maidstone	LM23T	2.9	2.9	
Naenae	LM23T	2.9	3.0	
Ngauranga	LMT	2.9	2.8	
Petone	LM23T	2.9	2.9	
Plimmerton	LM23T	2.8	2.8	
Porirua	LM23T	2.9	2.9	
Seaview	LM23T	2.9	2.9	
Tawa	LM23T	2.9	2.9	
Titahi Bay	LMT	2.9	3.0	
Trentham	LM23T	2.9	3.0	
Waikowhai	LMT	4.0	2.9	
Wainuiomata	LMT	2.9	3.0	
Waitangirua	LM23T	2.8	3.0	
Waterloo	LMT	2.9	2.9	

Figure 10-22 Health-Criticality Scores for Zone Substation Switchboards

Outcome of the Health Analysis

University and Frederick Street

The Reyrolle LMT switchboards at University and Frederick Street have a number of circuit breakers requiring partial discharge mitigation, which will take place during 2015. Apart from the partial discharge issue, the switchboards are in good health, but have high criticality due to their location in the Wellington CBD.

Kaiwharawhara

One circuit breaker on the Reyrolle LMVP switchboard at Kaiwharawhara has given some unusual readings during partial discharge testing, but the cause has not been identified. A period of further testing will be undertaken during 2015 to provide more information about what may be happening on the switchboard.

Karori and Gracefield

The Karori and Gracefield switchboards are Reyrolle Type C, which has multiple design issues and is being phased out of the network, as discussed earlier. The replacement of the Karori switchboard is in progress for completion during 2015, with Gracefield to be completed in 2016.

Partial Discharge Mitigation

Three other Reyrolle LMT switchboards have circuit breakers that require partial discharge mitigation during 2015, being:

- Brown Owl;
- Johnsonville; and
- Mana.

Other Comments

Wellington Electricity's fleet of zone substation circuit breakers is generally in good condition. Apart from the replacement of the remaining Reyrolle Type C switchboards, and assuming that the partial discharge mitigation refurbishments continue to be successful, no zone substation circuit breakers are expected to require replacement for health reasons during the next five years. During the period 2021-2025, three zone substation switchboards will exceed 60 years of age. There is no indication that replacement of these switchboards needs to be driven purely by age, however their condition will continue to be monitored through routine maintenance.

Further improvements in circuit breaker health could be achieved through installing arc fault containment measures, particularly at Wellington CBD zone substations where system fault levels are high relative to switchgear ratings, and general refurbishment including replacement of oil circuit breaker trucks with vacuum technology.

The project list reflecting the asset health-criticality analysis is shown in Figure 10-23.

Zone Substation	Project Description	Investment Year	Driver	Proposed Budget
Karori	Replacement of Reyrolle Type C	2015	End of Life	$2.2M
Gracefield	Replacement of Reyrolle Type C	2016	End of Life	$1.85M
Frederick Street	Refurbishment and rerating	2017	Criticality	$0.8M
Nairn Street	Refurbishment and rerating	2018	Criticality	$0.7M
University	Refurbishment and rerating	2019	Criticality	$0.6M
Moore Street	Refurbishment and rerating	2020	Criticality	$0.7M

Figure 10-23 Project List for Zone Substation Switchboards

10.4.2.3 Substation Buildings and Equipment

Maintenance Activities

The following routine planned inspection, testing and maintenance activities are undertaken on substation buildings and related equipment:

Activity	Description	Frequency
Zone Substation - Routine Inspection	Routine visual inspection of zone substation to ensure asset integrity, safety and security. Record and report defects, undertake minor repairs as required. Thermal inspection of all equipment, handheld PD and Ultrasonic scan. Inspect and maintain oil containment systems, inspect and test transformer pumps and fans	3 monthly
Grounds maintenance - Lump sum	General programme of grounds and building maintenance for zone substations	Ongoing
Fire Suppression System Inspection and Maintenance	Inspect, test and maintain fire suppression system (Inergen / gas flood)	3 monthly
Fire Alarm Test	Inspect and test passive fire alarm system	3 monthly
Fire Extinguisher Check	Inspect and change fire extinguishers as required	Annually
Test Zone Substation Earthing system	Test zone substation earthing systems	5 yearly

Figure 10-24 Inspection and Routine Maintenance Schedule for Zone Substations and Equipment

Routine zone substation inspections are undertaken quarterly and include the building and other assets such as lighting, fire systems, security systems, fans, heaters and safety equipment. The grounds and ripple injection spaces are also maintained to ensure access, security, condition and safety. Where appropriate, annual building warrant of fitness inspections are carried out and any defects rectified. Building maintenance varies depending upon the site and minor defects are corrected as they are identified.

Renewal and Refurbishment

The substation building refurbishment programme includes tasks such as roof replacement, exterior and interior painting, security and fencing improvements to maintain the assets in good condition on an as-needed basis.

Given the average age of substation buildings, Wellington Electricity is approaching a period of increased spend to replace doors, roofs and other building components. Deterioration from the natural elements has resulted in maintenance being uneconomic to address weathertightness issues and these components are replaced in their entirety. This work is critical to ensure ongoing reliability of electrical plant. Wellington Electricity also considers environmental effects such as heating, cooling and ventilation to ensure network assets are operated within acceptable temperature and humidity levels. Where necessary improvements at substations are undertaken to control the environment in which the plant operates.

Seismic Compliance and Upgrades

TLAs, under their Earthquake Prone Buildings Policies, undertake evaluations of buildings built prior to 1976, which include Wellington Electricity substation buildings. The outcome of the TLAs' evaluations, and of Wellington Electricity's own independent assessments, may require seismic improvement works on some of these buildings. The seismic reinforcing of substation buildings and how this risk is managed is discussed in detail in Section 5 (Risk Management).

Wellington Electricity completes seismic investigations prior to undertaking any major substation work and this may lead to additional seismic strengthening works.

While these seismic projects are essential for the security and safety of the network, they can be costly. During 2012, Wellington Electricity completed and approved its policy on the categorisation, assessment and management of substation building seismic strength, and requirements for reinforcing. The revised policy clarified the business guidance on the risk and importance of each Wellington Electricity owned substation building. The policy is used to prioritise the reinforcement programme of works including capital expenditure forecast over the planning period.

10.4.2.4 Substation DC Systems

Substation DC panels

Maintenance Activities

The following routine planned inspection, testing and maintenance activities are undertaken on substation DC supply systems (battery banks):

Activity	Description	Frequency
Inspection and monitoring of battery & charger condition.	Routine visual inspection of batteries, chargers and associated equipment. Voltage check on batteries and charger	Annually
Comprehensive battery discharge test.	Comprehensive battery discharge test for all batteries, measurement and reporting of results	2 yearly (Zone only)

Figure 10-25 Inspection and Routine Maintenance Schedule for Zone Substation Battery Banks

Valve regulated lead acid batteries are now the only type of battery used. Maintenance is based on the recommendations of IEEE–1188 (IEEE Recommended Practice for Maintenance, Testing and Replacement of Valve Regulated Lead Acid Batteries for Stationary Applications).

Battery and Charger Condition

In 2009, it was discovered that a large number of batteries had been allowed to pass their end of service life replacement date. Some batteries had already failed in-service when called upon to operate substation devices during fault or switching conditions. As a result, a comprehensive survey of battery installation dates was undertaken, identifying that 60% of battery banks required replacement. This work was completed during 2010 and, as a result, there are now no batteries outside the manufacturer's design life. In some installations, where heat is excessive and uncontrollable, the batteries are replaced earlier than usual due to thermal deterioration. The overall condition of the battery population is now very good.

Battery chargers are also generally in good condition. Many have SCADA supervision so the NCR is notified if the charger has failed. Given the low value and high repair cost of battery chargers they are repaired only where it is clearly economic. Generally, the chargers are at the end of their design life at the time of failure so replacement is readily justified.

Battery Replacement

Wellington Electricity has a total of 516 battery banks across 275 sites. Batteries are a critical system for substation operation, and Wellington Electricity's policy is that all batteries are now replaced at 80% of their design life. For a number of sites with higher ampere-hour (Ah) demand, 10-year life batteries are available. For smaller sites, or communications batteries where the Ah demand is lower, batteries are only available with 5-year lives. As part of primary plant replacements, Wellington Electricity is intending to standardise the voltages used for switchgear operation as well as communications equipment.

The number and cost of annual battery bank replacements will fluctuate depending on the number of small and large banks requiring replacement each year, as shown in Figure 10-26.

Replacement Year	Number of Battery Banks	Proposed Budget
2015	140	$205,000
2016	70	$65,000
2017	50	$65,000
2018	160	$195,000
2019	150	$150,000

Figure 10-26 Annual Battery Bank Replacements

10.4.2.5 Substation Protection Relays

Maintenance Activities

The following routine planned testing and maintenance activities are undertaken on protection relays:

Activity	Description	Frequency
Protection Testing for Electromechanical Relays	Visual inspection and testing of relay using secondary injection. Confirm as tested settings against expected settings. Update of test record and results into Protection Database.	2 yearly (Zone) 5 yearly (Distribution)
Protection Testing for Numerical Relays	Visual inspection, clearing of local indications, and testing of relay using secondary injection. Confirm as tested settings against expected settings. Confirm correct operation of logic and inter-trip functions. Update of test record and results into Protection Database.	2 yearly (Zone) 5 yearly (Distribution)
Numerical Relay Battery Replacement	Replacement of backup battery in numeric relay.	4 yearly (Zone) 5 yearly (Distribution)

Figure 10-27 Inspection and Routine Maintenance Schedule for Zone Substation Protection Relays

Regular testing of protection relays is undertaken to determine correct operating functionality. Protection relay testing will continue on a regular basis and budgetary provision for this is in the maintenance expenditure projections.

The key focus of protection relay maintenance is to identify any equipment that is not operating correctly or has failed. In order to maintain network reliability it is necessary to identify these issues before a failed or mal-operating protection relay is required to operate. This is especially relevant for the large number of older electromechanical relays on the network.

Testing of the large number of differential relays (Reyrolle SOLKOR, or similar) also serves to test the copper pilot cables between substations. Upon a failed test, the protection circuit is either moved to healthy pairs on the pilot cable or the cable is physically repaired. Due to deteriorating outer sheaths on pilot cables, some early pilot cables are now suffering from moisture ingress and subsequent degradation of insulation quality. A grease-filled pilot joint is now being used to block moisture from spreading though entire sections of cable.

Numerical relays, although equipped with self-diagnostic functions, are tested as shown in the table above. With more complex protection schemes coming into service, these need to be tested to ensure the correct functions and logic schemes are still operating as expected.

Renewal and Replacement

The majority of electromechanical relays are approaching the end of their technical life. However the economic impact of replacement with modern numerical protection relay equivalents is being carefully considered. Therefore the replacement programmes that are in place generally focus on relay condition and coordination with other replacement programmes or projects especially for assets such as switchgear and transformers. Rarely does a relay fail in-service and deterioration of relays is identified during routine maintenance testing which may lead to individual replacement.

At the time of primary equipment replacement the opportunity is taken to upgrade associated protection schemes to meet the current standards because the relays are usually mounted within switchgear panels as an integral system. To date, electromechanical relays have provided reliable service and are expected to remain in service for the life of the switchgear they control – generally greater than 40 years. For newer numeric relays, it is not expected that the relay will provide the same length of service and a service life of less than the ODV standard switchgear life is expected.

The following programmes and projects are included in the asset replacement and maintenance budgets:

- Ongoing replacement of PBO relays in conjunction with switchgear;
- Nilstat overcurrent relays in service need to be replaced. These are in the Reyrolle Type C switchboard at Gracefield zone substation and, as this switchboard is scheduled for replacement in 2016, a separate relay replacement project is not justified;
- Ongoing zone substation and network protection and control upgrades for assets supplied from GXPs, which are coordinated with GXP upgrades planned by Transpower; and
- Ongoing protection and control upgrades across the network as identified by asset condition monitoring.

Identified relay replacement projects that do not form part of a larger primary plant replacement project are shown in Figure 10-28.

Location	Protection Type	Replacement Year	Estimated Cost
Waitangirua Zone Sub	Subtransmission	2015	$360,000
Ngauranga Zone Sub	Subtransmission	2015	$360,000
Johnsonville Zone Sub	Subtransmission	2016	$360,000
Tawa Zone Sub	Subtransmission	2016	$240,000
Kenepuru Zone Sub	Subtransmission	2016	$240,000
Porirua Zone Sub	Subtransmission	2017	$420,000
Gracefield Zone Sub	Subtransmission	2019	$360,000
Wainuiomata Zone Sub	Subtransmission	2019	$360,000
Seaview Zone Sub	Subtransmission	2019	$360,000
Korokoro Zone Sub	Subtransmission	2019	$360,000
Brown Owl Zone Sub	Subtransmission	2020	$360,000
Maidstone Zone Sub	Subtransmission	2020	$360,000

Figure 10-28 Protection Relay Replacement Projects

10.4.3 Distribution and LV Lines

10.4.3.1 Poles and Overhead Lines

Maintenance Activities

The following routine planned inspection, testing and maintenance activities are undertaken on poles and overhead lines:

Activity	Description	Frequency
Inspection and condition assessment overhead lines by zone/feeder	Visual inspection of all overhead equipment including poles, stay wires, crossarms, insulators, jumpers and connectors, switchgear and transformers. Recording and reporting, and minor repairs as required.	Annually
Concrete and steel pole inspections and testing	Visual inspection of pole, tagging and reporting of results.	5 yearly
Wooden pole inspections and testing (Deuar)	Visual inspection of pole, testing and analysis of pole using Deuar MPT40 test, tagging and reporting of results.	5 yearly
LFI inspections	Visual inspection of line fault passage indicator, testing in accordance with manufacturer recommendation.	Annually
LFI battery replacement	Removal of unit, assessment of condition and replacement of on-board battery, replacement onto live line using hot stick.	8 yearly

Figure 10-29 Inspection and Routine Maintenance Schedule for Poles and Overhead Lines

All overhead lines are programmed for an annual, visual inspection to determine any immediately obvious issues with the lines, condition of components such as crossarms and insulators, and to note any prospective vegetation or safety issues. In addition, all connectors in the current carrying path get a thermal scan to identify any high resistance joints, which could potentially fail due to heating. These inspections drive a large part of the overhead corrective maintenance works and also contribute to asset replacement programmes for insulators and crossarms.

Wellington Electricity has been using the Deuar MPT40 to test its wooden pole population since 2011. The testing programme ensures the detection of structural issues deeper at the base of the pole, and also provides useful remaining life indicators.

Deuar Tests being performed

Approximately 5,000 poles have been tested since the start of the Deuar testing programme. From this programme, a substantial number of old poles have been given a serviceability extension, whereas others have been identified for replacement early in their life due to serviceability issues resulting from the pole loading.

Pole Condition

The majority of poles on the Wellington Electricity network are in good condition as the result of a large scale testing and replacement programme, which occurred between 2004 and 2006. Over two thirds of the poles installed in the Wellington area are concrete, which are durable and in good condition. The remainder are timber poles, which are tested and replaced in accordance with their Deuar serviceability index results or where there are visible structural defects.

Common condition issues with timber poles are deterioration of pole strength, due to internal or external decay. Poles are also leaning, have head splits or incur third party damage, which may necessitate pole remediation or replacement.

Common condition issues with concrete poles include cracks, spalling (loss of concrete mass due to corrosion of the reinforcing steel), leaning poles and third party damage.

A significant contributor to leaning poles on the Wellington network is third party attachments. There are existing agreements to support telecommunications cables from Vodafone and Chorus on network poles, and in some areas the additional loading exceeds the designed foundation strength, leading to leaning of poles across the network. Many of these can be remedied with corrective maintenance to straighten the pole and improve the foundation design through blocking or compacting course metal around the pole base.

Wellington Electricity has a standard that governs third party attachments to network poles. This standard will ensure future connections to poles for telecommunications infrastructure (for example) meet Wellington Electricity's requirements and do not have an injurious effect on the network, including safety for contractors and members of the public. Third party network operators will be required to contribute to the upgrade of network poles where there will be an adverse impact on pole service life or safe working load as the result of additional infrastructure connections.

Overhead Line Condition

Pin type insulators are no longer used for new 33kV or 11kV line construction as they develop reliability issues later in life such as split insulators due to pin corrosion, or leaning on crossarms due to the bending moment on the pin causing the cross arm hole to wear. There is no programme to proactively replace existing pin type insulators but replacement occurs when defects are identified or when crossarms require replacement. All new insulators are of the solid core post type as these do not suffer the same modes of failure as pin insulators, and they provide a higher level of reliability in polluted environments and lightning prone areas.

High wind loadings can sometimes result in fatigue failures around line hardware such as binders, compression sleeves, line guards and armour rods on the older All Aluminium Conductor (AAC) lines that have historically been used on the Wellington network. Recent incidents have also shown fatigue problems with fittings supporting strain points. Where a conductor issue is identified, All Aluminium Alloy Conductor (AAAC) is used as the replacement conductor.

Steel reinforced conductors have not been widely used in the Wellington Region as high salt pollution shortens service life due to corrosion of the steel core.

A number of Fargo sleeve type automatic line splices are failing in service. These sleeves were only suitable for a temporary repair, but in some cases have been in service for over 10 years. The failure mode for Fargo sleeves is likely to be vibration related and can cause lines to fall and result in feeder faults. Fargo sleeves are no longer used on the network and are replaced when found with full tension compression sleeves. Alternatively, the span will be reconductored if the joints are not suitably located for replacement.

Renewal and Refurbishment – Lines

Overhead line refurbishment

Since 2009, Wellington Electricity has invested in renewal of overhead lines in areas that have particularly high SAIDI and SAIFI, or to address public safety concerns. Areas of Newlands, Johnsonville and Korokoro have been progressively reconductored, and have had all the line hardware, crossarms and poor condition poles replaced. These feeders have had a significant improvement in performance since this work was completed.

Similar reconductoring, or area rebuild projects, will occur in areas as identified in Section 7.7.2 (Worst Performing Feeders). This work usually involves sections of line of only a few hundred metres up to several kilometres. The following overhead renewal projects are planned for 2015:

Porirua 2 Reliability Upgrade – 2015	
Driver: Asset Integrity **Estimated cost:** $250,000	The Porirua 2 feeder supplying Aotea has performed poorly during bad weather, due to the condition of an overhead section of line at the front end of the feeder. This line is to be rebuilt along a new, shorter route, which will also remove a number of tagged poles.

Melling 4 Reliability Upgrade – 2015	
Driver: Asset Integrity **Estimated cost:** $300,000	The overhead section of the Melling 4 feeder serves the Normandale area of Lower Hutt. These lines were stressed during the 2013 storms, and have experienced a subsequent decline in reliability performance. The reliability upgrade project will package together all identified defects on the feeder, including replacing a defective OYT recloser, eight sets of Fargo line splices, and three yellow tagged poles.

Johnsonville 10 Line Refurbishment – 2015	
Driver: Asset Integrity **Estimated cost:** $300,000	Since 2011, Johnsonville 10 has experienced increasing SAIDI, largely as a result of overhead equipment failure. Approximately 2km of the feeder is to be refurbished in 2015, including reconductoring, insulator replacement, and replacement of poles and transformers in poor condition.

Karori 2 Overhead Line Rebuild – Stage 3 – 2015	
Driver: Asset Integrity **Estimated cost:** $150,000	The Karori 2 feeder towards Makara has historically performed poorly, especially during adverse weather. The terrain is harsh and exposed in places, as well as being covered with dense vegetation, making access difficult. The third stage of nine will occur during 2015, and involves reconductoring 31 spans of 11kV to address reliability concerns arising from hardware condition. Six further stages of this project are planned for the period from 2016 to 2021, with an average annual budget of $150,000.

South Makara Overhead Line Refurbishment– 2015	
Driver: Asset Integrity **Estimated cost:** $137,000	South Maraka is supplied from the Karori 2 feeder, but was outside of the initial scope of the rebuild, that has been planned to target declining reliability performance. Since the Karori 2 project has commence, South Makara has begun to experience a similar decline in performance. The scope of this refurbishment is the replacement of pin insulators with line posts, the replacement of existing strain insulators, and the replacement of poles, crossarms and transformers that are in poor condition.

Wainuiomata Coast Road Line Rebuild – Stage 3 – 2015	
Driver: Asset Integrity **Estimated cost:** $200,000	The Wainuiomata Coast Road area runs south from Wainuiomata towards Baring Head. This has traditionally been a poorly performing feeder on the Wellington Electricity network due to the severe weather it experiences, and has been targeted for progressive upgrade to improve its reliability. The scope of this work is the replacement of pin insulators with line posts, and the replacement of poles and crossarms that are in poor condition. Seven further stages of this project are planned for the period from 2016 to 2022, with an average annual budget of $200,000.

Renewal and Refurbishment - Poles

Poles that are inspected and fail the serviceability test are categorised as red tagged, or yellow tagged. Red tagged poles have a serviceability index of less than 0.5 (to allow for a design safety factor of two) or have a major structural defect, and are programmed for replacement within 3 months. Yellow tagged poles have a serviceability index of 0.5 to 1.0, or have moderate structural defects, and are programmed for replacement within 12 months. Blue tags are used to identify poles that have a reduced ability to support design loads but a serviceability index greater than 1.0, with these poles to have further engineering investigation within three months. For all tag colours, the climbing of tagged poles by contractors is prohibited. Crossarms are identified for replacement from the detailed line inspections.

With the introduction of the Deuar pole testing methodology, it is expected that a higher accuracy of assessment of pole strength and remaining life will occur. As a result, it is anticipated that pole replacements will decrease over time and poles that are replaced will be limited to those that are the most "at-risk" on the network. Initial testing with the Deuar programme has produced similar replacement rates as previous methods; however the initial testing programme prioritised poles with known low strength but that were still considered serviceable at the time of the last test. On the other hand, a large number of poles that had reached the end of their expected lifespan based on their age were shown by the Deuar testing as having more than 10 years of further serviceability.

Poles on walkways and hard to reach areas are normally replaced with light softwood poles because they can be carried in by hand. However these are considered to be a poor choice of pole, as they are often of varying strength and have poor service life (typically no longer than 25 years). Steel and composite poles are being investigated for use on Wellington Electricity's network as a possible alternative to softwood poles. Cranes are used where practicable but have limited reach in some areas of Wellington. Wellington

Electricity does not consider the use of helicopters in erecting concrete poles in such areas viable, due to the cost and the need to evacuate residents around the pole location.

Concrete poles are replaced following an unsatisfactory visual inspection. The main replacement criteria are poles with large cracks, structural defects, spalling or loss of concrete mass. All replacement poles are concrete, except where the location requires the use of timber for weight, access constraints or loading design.

Figure 10-30 provides a yearly overview of proposed pole inspection rates, expected replacement rates and expenditure.

Year	Inspections			Replacements		
	Wood	Concrete	Expenditure	Wood	Concrete	Expenditure
2015	3,400	5,500	$0.32M	340	140	$5.0M
2016	2,500	5,500	$0.28M	330	150	$5.0M
2017	2,500	5,500	$0.28M	320	160	$5.0M
2018	2,500	5,500	$0.28M	310	170	$5.0M
2019	2,500	5,500	$0.28M	300	180	$5.0M

Figure 10-30 Yearly Pole Inspection and Replacement

10.4.4 Distribution and LV Cables

Maintenance of the underground distribution cable network is limited to visual inspection and thermal imaging of cable terminations. Cables are operated to failure and then either repaired or sections replaced. A proactive maintenance regime is not cost effective, given the network is generally designed so that supply can be maintained while cable repairs are undertaken. Cables are replaced when their condition has deteriorated to the point where repair is not considered economic.

The decision to replace rather than repair a cable is based on a combination of fault history and frequency, together with the results of tests undertaken after earlier cable fault repairs. An annual budget allowance is made for cable replacement, targeted at cables exhibiting high fault rates, or showing poor test results following a repair. Recent issues highlight the effect of fault stresses on older joints and the need to overlay sections of cables due to repeat joint failures. The small numbers of natural polyurethane insulated cables show high failure rates and this type of cable is therefore more likely to be replaced following a cable fault. An allowance is made each year in the CAPEX programme for cable replacement based upon historic trends and known defects. The need for a capacity upgrade is also considered.

In 2014, there were 28 cable, cable joint and termination failures at 11kV and above. Underground cables usually have a long life and high reliability as they are not subjected to environmental hazards, however as these cables age and reach their end of life, performance is seen to decrease. External influences such as third party strikes, inadvertent overloading, or even unusual high loading within normal conditions can reduce the service life of a cable. Some instances of failure are due to workmanship on newer joints (which can be addressed through training and education), whilst others are due to age or environment, which is less controllable.

10.4.4.1 Cable Terminations

Cable termination replacement is driven by visual inspection when signs of discharge or significant compound leaks are found as well as analysis of fault rates. The exception to this is 11kV cast metal pothead terminations where analysis of fault rates, together with a risk assessment, has resulted in a decision to replace them with heat shrink terminations.

10.4.5 Distribution Substations and transformers

10.4.5.1 HV Distribution Substations and Equipment

Maintenance Activities

The following routine planned inspection and maintenance activities are undertaken on distribution substations and associated equipment:

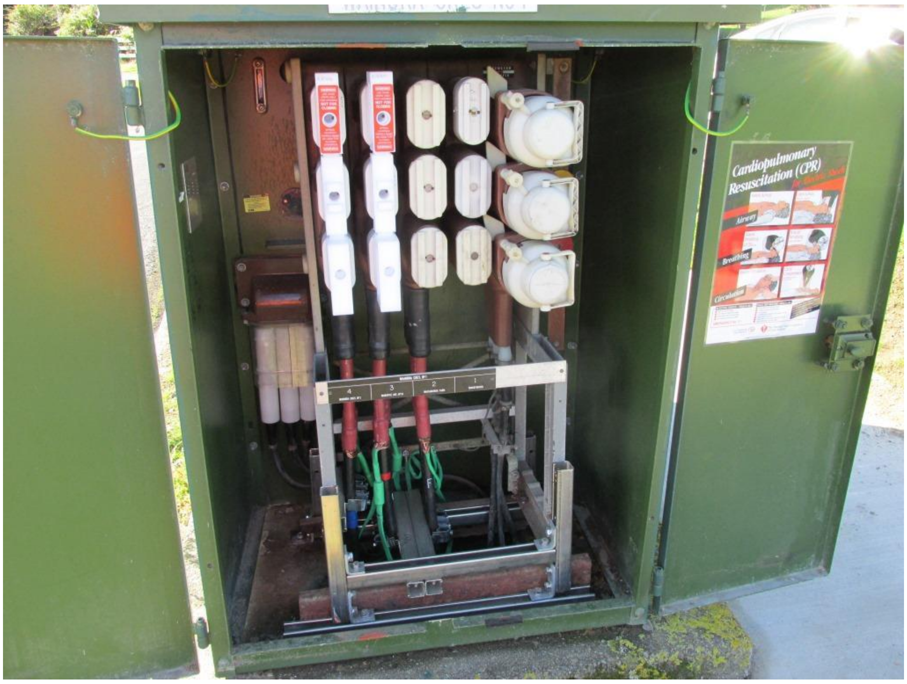
Activity	Description	Frequency
Inspection of Distribution Substations	Routine inspection of distribution substations to ensure asset integrity, security and safety. Record and report defects, undertake minor repairs as required. Record MDIs where fitted.	Annually
Grounds maintenance - Lump sum	General programme of ground and building maintenance for distribution substations.	Ongoing
Fire Alarm Test	Inspect and test passive fire alarm systems.	3 monthly
Visual Inspection and Thermal Image (Ground Mount Transformer)	Visual inspection of equipment, and condition assessment based upon visible defects. Thermal image of accessible connections. Handheld PD and Ultrasonic scan.	Annual
Visual Inspection and Thermal Image (Pole Transformer)	Visual inspection of equipment, and condition assessment based upon visible defects. Thermal image of accessible connections.	Annual
Inspection and Testing of Earthing	Visual inspection of earthing system installation and mechanical protection, testing of individual and combined earth bank resistance.	5 yearly

Figure 10-31 Inspection and Routine Maintenance Schedule for HV Distribution Substations and Transformers

Activity	Description	Frequency
Visual Inspection of Switchgear	Visual inspection of equipment, and condition assessment based upon visible defects. Thermal image of accessible connections. Handheld PD and Ultrasonic scan.	Annually
Switchgear Maintenance (Magnefix)	Clean and maintain Magnefix unit, inspect and replace link caps as required, test fuses, check terminations where possible.	5 yearly
Switchgear Maintenance (Oil Switch)	Clean and maintain oil switch unit, drain oil and check internally, check terminations and cable compartments. Ensure correct operation of unit. Refill with clean oil.	5 yearly
Switchgear Maintenance (Vacuum or Gas Switch)	Clean and maintain switch unit, check terminations and cable compartments. Ensure correct operation of unit. Check gas / vacuum levels.	5 yearly

Figure 10-32 Inspection and Routine Maintenance Schedule for HV Switch Units

Distribution Switchgear Condition



Ring Main Unit

The switchgear installed on the Wellington Electricity network is generally in good condition and comprises of both oil and gas insulated ring main units, as well as solid resin insulated equipment. Routine maintenance addresses the majority of minor defects but, on occasion, a unit requires replacement when the condition is unacceptable. Common condition issues experienced include mechanical wear both of the enclosure/body as well as operating mechanisms, electrical discharge issues or poor oil condition and insulation levels.

Some specific condition issues are noted below:

Solid Insulation Units - Magnefix/Krone

Magnefix switchgear is cleaned five-yearly, with targeted cleaning for a number of sites undertaken more frequently as a corrective maintenance activity. Magnefix switchgear is generally reliable however there are specific cleaning requirements to avoid tracking problems associated with the resin body casing due to the accumulation of dust and other deposits (such as blown salt and diesel fumes).

There have been past experiences of Magnefix failures on the network due to a suspected termination failure. It is believed that the “figure 8” connectors on some older units (typically installed between 1968 and 1975) fail under heavy loads due to heating and thermo-mechanical cycling problems. The failures all occurred on residential feeders with recent load growth and during the winter evening peak. A survey of older units has shown a number with low or leaking termination grease levels, which may be a physical sign of heating in the connector. These units are prioritised for termination replacement using new connectors and heat shrink terminations, if evaluation indicates the unit does not need replacement due to age, overall condition, or operational factors. During 2014, Wellington Electricity replaced the terminations on 15 units, prioritised by the lowest levels of grease in the termination. This work will continue during 2015 with another 45 units scheduled for re-termination. Aside from the connector issue, these units are not at end of life and replacement of the terminations is considered an effective and efficient maintenance strategy.

Substation Switching Access

In 2012 it was identified that some sites had limited access to conduct safe switching due to vegetation, fences or landscaping, or poor site design. Some of the sites have had the obstructions removed or, where this is impractical, a different type of ring main unit that requires a smaller switching space was installed. This issue is being monitored through the routine inspection programme.

Statter and Long and Crawford

There are a number of Statter and Long and Crawford/GEC type ring main switches installed on the Hutt Valley network. These are installed in outdoor cage substations subject to harsh environments. Where possible these are being replaced in conjunction with other distribution network upgrades. Other networks have experienced catastrophic failures of early Statter switches in outdoor environments and, in a recent incident in Western Australia, involving a Long and Crawford fuse switch. A replacement programme started in 2013 to replace the end of life Statter switchgear typically with standard ring main units. Wellington Electricity has imposed operational restrictions on Statter, Long and Crawford and GEC fuse switches, to prevent the fuse compartments being opened while the switchgear is alive.

Renewal and Refurbishment

HV Distribution Switchgear (Ground Mounted)

Note – This section excludes circuit breakers, which are discussed in Section 10.4.2.2.

Any minor defects or maintenance issues are addressed on-site during inspections. This may include such maintenance as topping up oil reservoirs, replacing bolts, rust treatment and paint repairs. Major issues that cannot be addressed on site usually result in replacement of the device. Wellington Electricity has an ongoing refurbishment and replacement programme for all ground mounted distribution switchgear with an annual budget of $1.5 million, in addition to previously identified programmes for replacing specific switchgear, for example Statter as outlined in Section 10.4.2.2.

- The assessed condition of the equipment;
- The availability of spare parts;
- The switchgear insulating medium; and
- The location on the network and consequence of failure.

Oil insulated switchgear is no longer installed with vacuum or gas (SF6) insulated types are now used. When any switchgear device fails, the reason for the failure is studied and cost benefit analysis undertaken to determine whether to repair, refurbish, replace, or decommission the device. The maintenance policies for other devices of the same type are also reviewed. As noted above, there are several types of ring main switch with identified issues around age, condition and known operational issues. These may be replaced based on the risk assessment for that type.

Low Voltage Distribution Switchgear (Substation)

Low voltage distribution switchgear and fusing is maintained as part of routine substation maintenance and any issues arising are dealt with at the time. The Wellington City area has a large number of open LV distribution boards in substations and a safety programme to cover these with clear Perspex covers has been completed. A small annual provision is made to capture any sites missed in the original programme. Smaller substations have a higher level of shielding on many of the installations.

The overall performance of LV distribution switchgear and fusing is good and there are no programmes underway to replace this equipment.

Distribution Transformers

If a distribution transformer is found to be in an unsatisfactory condition during its regular inspection, it is programmed for corrective maintenance or replacement. An in-service transformer failure is rare and, if it occurs, it is investigated to determine the cause. This assessment determines if the unit is repaired, refurbished, or scraped depending on cost and residual life of the unit. Typical condition issues include rust, heavy oil leaks, integrity and security of the unit. Some minor issues such as paint, spot rust and small leaks are repaired and the unit will be returned to service on the network. The refurbishment and replacement of transformers is an ongoing programme, which is provided for in the asset maintenance and replacement forecast, however it is undertaken on an as-needed basis (condition, loading, etc) arising from inspection rather than by age.

In addition to the transformer unit itself, the substation structures and associated fittings are inspected and replaced as needed. Examples include distribution earthing, substation canopies and kiosk building components (such as weather tightness improvements). Some renewals may be costly and time consuming as a large number of berm substations in the Hutt Valley area are an integral substation unit manufactured during the 1970s and 80s by the likes of Tolley Industries. Replacement of these units requires complete foundation replacement and extensive cable works. Consideration was given to developing a compatible replacement, and a prototype unit installed, however it was found that the reduced civil cost was offset by the additional cost for purchasing a specialised transformer rather than a standard design.

Wellington Electricity uses canopy type substations with independent components (LV switchgear, HV switchgear and transformer under a removable metal canopy) for new installations where practicable; however, cost and space constraints often mean integral substations are still used. The benefit of a canopy type substation is that it allows for component replacement or upgrade, or canopy replacement without affecting the entire installation. This will reduce the overall life cycle cost.

Wellington Electricity has reviewed the construction standards for overhead transformers. Previously, transformers up to 300kVA were mounted on overhead structures. A number of EDBs have moved away from pole mounting transformers above 150kVA due to seismic and safety concerns. Modern transformers of 200kVA are now lighter than older 150kVA units, and Wellington Electricity's current policy is that the largest pole mounted transformer permitted for replacement installations is 200kVA.

10.4.5.2 Low Voltage Pits and Pillars

Maintenance Activities

The following routine planned inspection and maintenance activities are undertaken on low voltage pits and pillars, for either consumer service connection and fusing or network LV linking:

Activity	Description	Frequency
Inspection of Service Pillars	Visual inspection and condition assessment of service pillar, minor repairs to lid as required.	5 yearly
Inspection of Service Pits	Visual inspection and condition assessment of service pit, minor repairs as required.	5 yearly
Inspection of Link Pillars	Visual inspection and condition assessment of link pillar, thermal imaging and minor repairs as required.	5 yearly
U/G link box inspection including Thermal Image	Visual inspection and condition assessment of link box, thermal imaging and minor repairs as required.	5 yearly

Figure 10-33 Inspection and Routine Maintenance Schedule for LV Pits and Pillars

Wellington Electricity includes a loop impedance test to check the condition of the connections from the fuses to the source in its underground pillars inspection regime. Where practical damaged pillars are repaired but otherwise a new pillar or a pit is installed.

Renewal and Refurbishment

Pillars are generally replaced following faults or reports of damage. Pillars with a high likelihood of future repeat damage by vehicles are replaced with pits. When large groups of older pillars, such as concrete or 'mushroom' type, are located and their overall condition is poor they are replaced as repair is impractical or uneconomic.

There are a number of different variants of service connection pillars on the network that are being replaced in small batches, particularly under-veranda service connection boxes in older commercial areas.

There has been ongoing replacement of underground link boxes around Wellington City driven by the poor condition of some of these assets which were over 50 years old. Many link boxes had deteriorated and might not have provided reliable service. The link boxes were either jointed through, where the functionality was no longer required, or replaced entirely to provide the same functionality. The renewal programme is based on condition assessment data collected in a complete survey conducted in 2009. The majority of unserviceable link boxes have now been replaced, so it is expected that fewer than 10 will now require replacement every year. For the remainder of the planning period, link boxes will only be replaced following an unsatisfactory inspection outcome.

A provision is made each year in the CAPEX forecast to replace service pillars that have become badly damaged, or for replacement with pits in areas subject to vehicle damage, with an annual budget of $150,000. This budget reflects historic trends, but replacements rarely exceed 60 units per year.

10.4.6 Distribution Switchgear

10.4.6.1 Overhead Switches, Links and Fuses

Maintenance Activities

The following routine planned inspection, testing and maintenance activities that are undertaken on overhead switches, links and fuses are shown in Figure 10-34:

Activity	Description	Frequency
Visual Inspection and Thermal Image	Visual inspection of equipment and condition assessment based upon visible defects. Thermal image of accessible connections	Annually
ABS Service	Maintain air break switch, clean and adjust contacts, check correct operation	3 yearly
HV Knife Link Service	Maintain knife links, clean and adjust contacts, check correct operation	3 yearly
Gas Switch Service	Maintain gas switch, check and adjust mechanism as required	9 yearly
Remote Controlled Switch - Annual Operational Check	Bypass unit or back feed, arrange remote and local operation in conjunction with NCR to ensure correct operation and indication	Annually
Inspection and Testing of Earthing	Visual inspection of earthing system installation and mechanical protection, testing of individual and combined earth bank resistance	5 yearly

Figure 10-34 Inspection and Routine Maintenance Schedule for Overhead Switch Equipment

All overhead switches and links are treated in the same manner, and are maintained under the preventative maintenance programme detailed above. Overhead HV fuses are visually inspected during both the annual overhead line survey and at the time of transformer maintenance (for fuses supplying overhead transformers). The large quantity and low risk associated with fuses does not justify an independent inspection and maintenance programme. Remote controlled overhead switches are operationally checked annually to ensure correct operation and indication, from both local and remote (SCADA) control points. This is achieved by closing a bypass link, or back-feeding from either side.

Condition of Overhead Switches, Links and Fuses

Generally, the condition of overhead equipment on the network is good. The environment subjects equipment to wind, salt spray, pollution and debris, which causes a small number of units to fail annually. Common modes of deterioration are corrosion of steel frame components and operating handles, mechanical damage to insulators, as well as corrosion and electrical welding of contacts. In harsh environments, fully enclosed gas insulated switches with stainless steel components are now being used.

A problem has previously been identified with some types of expulsion drop out (EDO) fuses that are overheating, which is a result of the use of different metals causing the pivot point on the fuse holder to seize, and this is preventing the fuse holder from operating as designed. The situation is being monitored and, if warranted, a replacement programme will be put in place. Over the past three years this has not been a major issue and therefore replacement currently only occurs as required.

The coastal environment around Wellington causes accelerated corrosion on galvanised overhead equipment components and, where possible, stainless steel fittings are used as they have proven to provide a longer component service life. These high quality components come at an increased cost.

Renewal and Refurbishment

There is no structured programme to replace overhead switchgear or devices. Any renewal activity on these assets is driven from standard inspection rounds and resultant maintenance activities arise from the identification of corrective work. With the extensive pole and cross arm replacements undertaken over recent years, a large number of overhead switches have now been replaced. Replacement generally occurs following a poor condition assessment result from the routine inspections, or at the time of pole or cross arm replacement if the condition of the switch justifies this at that time.

An annual $1.5 million allowance in the CAPEX programme for HV switchgear replacement funds the required replacements that do not occur in conjunction with other projects.

10.4.6.2 Auto Reclosers and Sectionalisers

Maintenance Activities

The following routine planned inspection, testing and maintenance activities are undertaken on auto reclosers and sectionalisers:

Activity	Description	Frequency
Visual Inspection and Thermal Image	Visual inspection of equipment and condition assessment based upon visible defects. Thermal image of accessible connections.	Annually
Recloser and Sectionaliser - Annual Operational Check	Bypass unit or back feed, arrange remote and local operation in conjunction with NCR to ensure correct operation and indication.	Annually
Recloser & Sectionaliser Service	Maintenance of recloser, inspect and maintain contacts, change oil as required, prove correct operation.	3 yearly
Inspection and Testing of Earthing	Visual inspection of earthing system installation and mechanical protection, testing of individual and combined earth bank resistance.	5 yearly

Figure 10-35 Inspection and Routine Maintenance Schedule for Auto Reclosers and Sectionalisers

Condition of Auto Reclosers and Sectionalisers

The majority of the units in service are in good condition and performing as expected, however a number of older units have failed to operate as intended in recent years.

Reyrolle OYT reclosers are now beyond their service life and some have malfunctioned, leading to the zone substation feeder tripping. Upon re-energisation of the feeder the recloser continues its cycle and trips again. These units are replaced if this fault is found to be due to their age.

McGraw-Edison KFE reclosers are approaching the end of their life. A number of failures have occurred in recent years and, while the units have been repaired and returned to service, their future service life is largely unknown.

Renewal and Refurbishment

In recent years there have been reliability and automation projects undertaken resulting in having the appropriately placed reclosers and sectionalisers in service. A replacement programme commenced in 2013, with the intention of removing all hydraulic reclosers from service by 2020. Units are prioritised for replacement on the basis of performance history, other defects, and the potential SAIDI impact of future failures.

Replacement Year	Number of Reclosers	Proposed Budget
2015	2 units	$260,000
2016	2 units	$260,000
2017	3 units	$390,000
2018	2 units	$260,000
2019	2 units	$260,000

Figure 10-36 Proposed Auto-Recloser Replacement Spend Plan

10.4.7 Other System Fixed Assets

10.4.7.1 SCADA and Communications Assets

The SCADA system is generally self-monitoring and there is little preventative maintenance carried out on it apart from planned server and software upgrades and replacement. Master station maintenance is broken into two categories:

(a) Hardware support for the Haywards disaster recovery site is provided as required by Wellington based maintenance contractors; and

(b) Software maintenance and support is provided by external service providers.

Existing remote terminal units (RTUs) are managed on a run to failure strategy. First line maintenance on the system is carried out as required by the Field Service Provider within the scope of its substation maintenance contracts. The substation level IP network is monitored and supported from within New Zealand by the respective service providers of the IP network infrastructure.

The SCADA front end processors at Haywards and Central Park have Uninterruptible Power Supply (UPS) systems to provide backup supply and there is a UPS system installed at Petone to provide supply to the operator terminals in the Network Control Room. This is subject to a maintenance programme provided by the equipment supplier. In addition, these units have their self-diagnostics remotely monitored and dual redundancy of converters and batteries to provide a high level of supply security in the unlikely event of failure.

Condition Assessment of SCADA System Components

C225 RTU

There are 17 C225 RTUs in service on the network. Power supply failure is the most common failure mode with around one failure a year. Spares are at a central location and repairs are carried out where possible. These RTUs are being replaced in conjunction with substation switchgear replacements and the redundant units are then held as spares.

C5 RTU

There are six C5 RTU's in service at very small distribution substations. They are no longer manufactured and are difficult to repair, so as they fail they are interchanged with current technology alternatives.

Load Control PLC

There are 23 of this type of PLC in service on the network. Installed in 1996, these Toshiba PLC's drive the load control equipment. This type of PLC is an obsolete item however one spare is held in case of failure. The future of these RTUs will be addressed as part of any load control upgrade and they are unlikely to be replaced outside of any other replacement programme.

Dataterm RTU

There are four of these still in service on the network, including three at zone substations. These RTU's have an inherent design flaw in the analogue card, which, over time, causes the analogues to "jump." This is repairable with the replacement of reed relays on the analogue card at an approximate cost of $500 per card. There are normally four cards per RTU and the cards fail at a rate of about five per year. These units are being replaced with Foxboro SCD5200 RTUs as zone substations are upgraded and moved onto the IP network.

Miniterm RTU

There are 53 of these in service on the network. These units fail at the rate of approximately two a year due to board level IC failure, with replacement ICs gradually becoming harder to source. These RTU's cannot be directly replaced by current technology however spare units are becoming available as a result of the switchgear replacement works. There is no active programme for replacing these but replacement occurs in conjunction with substation switchgear replacements, or where a risk is identified in having this type of RTU installed.

Common Alarms

There are 46 of these in service on the network. These are a custom-built device, placed in minor "ringed" distribution substations to give an indication back to the NCR of a tripping event. They are prone to failure and there are no spares. On failure, the units are replaced by current technology such as a low cost RC02 RTU which is widely used on the network.

Cisco 2811 Routers

There are 20 Cisco 2811 routers in service, located in distribution substations connected to the TCP/IP network. These devices are no longer supported by the manufacturer and replacement parts cannot be purchased. There are no concerns about the performance of the equipment but where expansion is required, for example the addition of VOIP interface cards, the 2811 router is replaced with its modern equivalent and returned to stock as a spare.

Renewal and Refurbishment

The asset replacement budget also provides for the ongoing replacement of obsolete RTUs throughout the network. Obsolete RTUs that may have a significant impact on network reliability are targeted first with priority being given to the zone and major switching substations.

If an RTU at a zone substation or major switching point in the network is adjacent to the existing TCP/IP network, consideration is given to upgrading the equipment to allow TCP/IP connection in order to continuously improve communication system reliability. Furthermore the TCP/IP infrastructure will also allow other substation based equipment (such as security alarms etc.) to efficiently communicate with distant receive devices.

Master Station

As detailed in Section 3, Wellington Electricity has planned and budgeted for an upgrade of its GE ENMAC system during 2015 to the latest version, known as PowerOn Fusion. Some further expenditure is expected during the planning period for ongoing hardware and software upgrades as well as for commissioning tests on field devices and communications links. Elements of the existing Foxboro master station are being retained in the short term to run the automatic load control packages with the future of this system to be determined as part of the broader load control strategy.

Siemens Power Automation System (PAS)

The PAS unit acts as a protocol converter between the IEC61850 field devices at three sites and the SCADA master station. It was installed by a previous network owner in 2007. The PAS has reached the end of its life, is based on an operating system that is no longer supported, and is experiencing increased unreliability. The PAS will be decommissioned and replaced with standard station RTUs during 2015.

Remote Terminal Units (RTUs)

During 2011, All Foxboro C25 and C225 RTUs at GXPs were replaced for two reasons:

1. The GE ENMAC SCADA master station has no automatic load management facility and in order to retain this facility, the old Foxboro L&N2068 master station will be used in the short term. This was achieved with the use of SCD5200 RTUs at the GXPs to provide information to both master stations; and

2. The upgrade coincided with Transpower’s move to a TCP/IP network and the resulting loss of the serial link that Wellington Electricity used to transfer data from the GXPs back to Haywards.

The initial priorities of the substation RTU replacement programme will align with GXP protection upgrade and zone substation switchgear replacement projects, along with RTU replacement at three sites in the Wellington city area that have Plessey Dataterm RTUs installed. One of these sites, Karori, has a Reyrolle Type C gear switchboard that is being replaced during 2015. At this site the RTU upgrade will occur as part of the switchboard upgrade project. The RTUs at the two remaining sites (Hataitai and Ira Street) are targeted for replacement at the same time. However, as spares are made available from Karori, the two sites may be able to be kept in service longer if input and output capacity and functionality constraints are not present.

There is currently no programme to replace RTUs at distribution substations as these sites generally have a lower risk profile than GXPs and zone substations and replacement can occur upon failure of the RTU. However an RTU upgrade will be scheduled when a specific risk is identified. In addition, sites where switchgear is upgraded may also have an RTU upgrade. These are incorporated as part of the switchgear replacement project and the need for an RTU replacement is evaluated on a case-by-case basis.

Wellington Electricity will continue the replacement of the remaining C225 RTUs installed at 16 zone substations with an aim to complete all replacements by 2020 (by which time the units will be at end of their service life).

The medium term replacement plan for substation RTU replacement is shown below:

Site	Site Type	Present RTU	Proposed RTU	Driver	Replacement Year
Waitangirua	Zone Substation	C225	SCD5200	GXP Protection Upgrade	2015
Ngauranga	Zone Substation	C225	SCD5200	GXP Protection Upgrade	2015
8 Ira Street	Zone Substation	Dataterm	SCD5200	Obsolescence	2015
Karori	Zone Substation	Dataterm	SCD5200	Switchgear Replacement	2015
Johnsonville	Zone Substation	C225	SCD5200	GXP Protection Upgrade	2016
Gracefield	Zone Substation	C225	SCD5200	Switchgear Replacement	2016
Hataitai	Zone Substation	Dataterm	SCD5200	Obsolescence	2016
Tawa	Zone Substation	C225	SCD5200	GXP Protection Upgrade	2016
Kenepuru	Zone Substation	C225	SCD5200	GXP Protection Upgrade	2016
Porirua	Zone Substation	C225	SCD5200	GXP Protection Upgrade	2017
Titahi Bay	Zone Substation	C225	SCD5200	Obsolescence	2017
Korokoro	Zone Substation	C225	SCD5200	Obsolescence	2018

Site	Site Type	Present RTU	Proposed RTU	Driver	Replacement Year
Waterloo	Zone Substation	C225	SCD5200	Obsolescence	2018
Naenae	Zone Substation	C225	SCD5200	Obsolescence	2018
Petone	Zone Substation	C225	SCD5200	Obsolescence	2019
Seaview	Zone Substation	C225	SCD5200	Obsolescence	2019
Wainuiomata	Zone Substation	C225	SCD5200	Obsolescence	2019
Maidstone	Zone Substation	C225	SCD5200	GXP Protection Upgrade	2020
Brown Owl	Zone Substation	C225	SCD5200	GXP Protection Upgrade	2020

Figure 10-37 Proposed RTU Replacement Programme

Analogue SCADA Radio Replacement

The Network Communications Strategy has identified a risk associated with the age and configuration of the analogue radio network which is used as the communications link for a number of field devices (such as reclosers and remote switches). To address this an upgrade of the repeaters located at Mt Climie and Mt Kaukau, as well as a secondary repeater at Stokes Valley, may be undertaken in the medium term. With this system upgrade communications components at the field devices, such as radio modems, may also require upgrading. The private radio network provides a number of strategic benefits including lower costs of operation than using cellular networks and a high level of resilience following a major event when cellular networks may be overloaded or unavailable.

A review of the existing network, future requirements and potential replacement systems was commenced during 2014, with a decision to be made during 2015 about the most appropriate development path. The cost of replacing the existing network has been estimated at approximately $500,000.

10.4.8 Other Assets

10.4.8.1 Metering

Check meters are not proactively maintained, however their output is continuously monitored by SCADA and compared to the Transpower revenue meters. Alarms are triggered where the discrepancy between the Transpower revenue meters and Wellington Electricity's check meters exceeds an acceptable tolerance.

10.4.8.2 Load Control Equipment

Maintenance Activities

The following routine planned inspection, testing and maintenance activities are undertaken on load control equipment. Wellington Electricity owns the injection plants located at substations and the blocking cells at GXPs, but does not own the consumer receivers. As such, the full end-to-end testing of the ripple system is not possible.

Activity	Description	Frequency
General Inspection	Check output signal, visual inspection, thermal image and partial discharge scan, motor generator test run.	6 monthly
Maintain Ripple Injection Plant	Clean and inspect all equipment, maintain motor generator sets, coupling cell test and inspection.	Annually
Blocking Cell Testing and Maintenance	Visual inspection, cleaning and maintenance of ripple blocking cells at GXPs as required.	5 yearly

Figure 10-38 Inspection and Routine Maintenance Schedule for Ripple Plant

Renewal and Refurbishment

The existing load control plant is generally reliable, with repairs and maintenance undertaken as required. Wellington Electricity has no immediate plans to replace any ripple injection plant due to age or condition but is currently reviewing its load control asset strategy which may recommend investment during the planning period.

The rotary injection plants in the Hutt Valley area, while old, are easily maintained and repaired. Interconnectivity at 11kV allows the ripple signal to be provided from adjacent substations in the event of failure.

The static injection plants in Wellington City are approaching end of life. A stock of spare parts is held locally, but many components such as integrated circuits are no longer manufactured. In the Wellington City area, there is dual plant connected at 33kV and located to cover each of the GXPs, with two 11kV plants at the Kaiwharawhara 11kV point of supply. In addition, a spare ripple injection unit was purchased in 2011 that could be installed at any of the four Wellington City ripple injection locations in the event of a failure of the existing plant. The primary risk is the failure of one of the two injection units at Frederick Street as the remaining unit is not large enough to provide adequate signal for all network configurations. This has been investigated and it is related to the increased load on the Central Park 33kV bus following the reconfiguration of supply to The Terrace substation from Central Park (previously from Wilton GXP), and moving the Central Park 11kV point of supply (Nairn St substation) transformers to the 33kV bus.

There is an ongoing programme of removing bias equipment from distribution substations following the decommissioning of the DC bias load control system in 2013. Wellington Electricity is working with metering equipment owners to ensure that load control can be preserved at those sites.

Strategic Spares

The spares held for load control plant is shown in Figure 10-39.

Strategic Spares	
Injection plant	A spare rotary motor-generator set is held for the 11kV ripple system in the Hutt Valley area, rated at 24kVA. A spare solid state controller has been purchased to cover a failure at any of the four Wellington city locations. An assortment of capacitors and coupling cell equipment is held in store.
Controllers	A spare Load Control RTU Controller is kept as a strategic spare as the same type is used across the network.

Figure 10-39 Spares Held for Load Control Plant

10.5 Asset Renewal and Refurbishment Programme

10.5.1 Asset Replacement Programmes for 2015-2020

In addition to the specific projects identified in the fleet summaries in Section 10.4, Wellington Electricity also makes provision for replacements that arise from condition assessment programmes during the year. The total projected capital budget for 2015 to 2020 is presented in Figure 10-40. For the period beyond 2015, these projections are less certain in nature. Whether they proceed will depend on the risks to the network and the risks relative to other asset replacement projects. Should the consequence of failure increase, or the asset deteriorates faster than expected, then renewal may need to be brought forward. Conversely, should the risk level decrease then the project may be able to be deferred until later in the planning period or an alternative found.

Asset Category	2015/16	2016/17	2017/18	2018/19	2019/20
Subtransmission Lines and Cables	0	0	0	0	0
Zone Substations	1,335	1,775	775	1,175	2,125
Distribution Poles and Lines	6,100	5,950	5,500	5,500	5,500
Distribution Cables	1,536	1,750	1,750	1,750	1,750
Distribution Substations	3,263	3,763	38,00	3,783	3,748
Distribution Switchgear	4,578	5,455	5,545	5,448	5,458
Other Network Assets	1,509	1,855	1,165	850	1,405
Total	**$18,820**	**$21,048**	**$19,035**	**$19,005**	**$20,485**

Figure 10-40 Prospective System Asset Renewal Forecast ($K in constant prices)

This investment profile is to maintain existing service levels. Over time as condition information improves, and full asset strategies are developed and refined, the category split may change.

10.5.2 Prospective Asset Replacement Projects for 2021 – 2025

Asset replacement and renewal projects that are listed in this section are less specific than the previous sections and are more uncertain in nature. There are few specific projects identified at this time and the prospective investments are broken down only by asset category. As risks and needs change on the network, individual projects will change. However, to ensure safety, and to maintain security and reliability levels that the consumers are presently prepared to accept in their price/quality trade-off decision, the following investment levels are expected to be required over this period:

Investment Driver	Asset Category	Investment
Asset Renewal	Pole Replacement	25,000
Asset Renewal	Load Control Plant Replacement	6,000
Asset Renewal	Power Transformer Replacement	2,000
Asset Renewal	Distribution Switchgear Replacement	19,600
Asset Renewal	SCADA and RTU Replacement	500
Asset Renewal	Distribution Transformer Replacement	14,000
Asset Renewal	Distribution Cable and Conductor Replacement	3,750
Asset Renewal	Zone Substation Switchboard Replacement	4,300
Safety	Earthing Compliance Upgrades	1,500
Reliability	Reliability Improvement Projects	2,500

Figure 10-41 Prospective Asset Replacement Programme 2021-2025 ($K in constant prices)

This investment profile is to maintain existing service levels over time as condition information improves and then the category split may change to reflect the changing risks.

10.5.3 Asset Renewal and Replacement Expenditure

For clarity, the forecast provided below does not include non-maintenance related operational expenditure. Asset replacement and renewal costs for regulatory periods are shown for the line item on which Wellington Electricity proposes to invest the most capital expenditure - reflecting the increasing age of the asset base.

Category	2015/16	2016/17	2017/18	2018/19	2019/20	2020/21	2021/22	2022/23	2023/24	2024/25
Asset Replacement & Renewal	18,820	21,048	19,035	19,005	20,485	20,565	20,388	19,475	22,275	22,900
Reliability, Safety & Environment (other)	798	988	931	869	838	800	800	800	800	800
Quality of Supply	2,174	1,758	1,458	1,570	1,328	600	600	600	600	600
Subtotal - Capital Expenditure on Asset Replacement Safety and Quality	**21,791**	**23,793**	**21,424**	**21,444**	**22,650**	**21,965**	**21,788**	**20,875**	**23,675**	**24,300**
Service interruptions & emergencies maintenance	4,133	4,136	4,127	4,113	4,100	4,088	4,076	4,065	4,054	4,052
Vegetation management maintenance	1,263	1,273	1,280	1,286	1,291	1,297	1,302	1,308	1,314	1,314
Routine & corrective maintenance and inspection maintenance	8,562	8,590	8,445	8,176	8,199	8,224	8,252	8,279	8,307	8,303
Asset replacement & renewal maintenance	701	707	710	714	716	719	722	727	730	729
Subtotal - Operational Expenditure on Asset Management	**14,658**	**14,705**	**14,562**	**14,288**	**14,306**	**14,328**	**14,353**	**14,379**	**14,405**	**14,397**

Figure 10-42 Optimal Lifecycle Asset Management Expenditure Forecast – 2014/15 to 2023/24 ($K in constant prices)

A breakdown of forecast preventative and corrective maintenance expenditure by asset category is shown in Figure 10-43.

These forecasts are based on long-term averages and year on year variances across the different asset categories will occur depending on the nature of the corrective maintenance that is required in any given year. The preventative maintenance component (routine inspections and maintenance) is agreed with the Field Service Provider as part of the Field Services Agreement and remains relatively constant year-on-year.

Service interruptions and emergency maintenance (faults) can only be forecast and reported at a system level as the Field Service Agreement defines the rates for fault response services at a total level and not further broken into asset category detail levels.

Asset replacement and renewal maintenance is similar to corrective maintenance and is not forecast at asset category level at present due to the varying nature of the work required. As Wellington Electricity develops more history on this expenditure category, forecasts and asset category splits will be enhanced. This is an area for future improvement.

Routine & Corrective Maintenance & Inspection Maintenance	2015/16	2016/17	2017/18	2018/19	2019/20	2020/21	2021/22	2022/23	2023/24	2024/25
Battery / Secondary Systems	166	165	163	158	159	158	159	160	160	160
Cables (All Voltages)	788	791	779	753	754	758	760	762	765	765
Circuit Breaker	951	954	937	908	910	912	915	919	922	922
Distribution Substation	1,195	1,199	1,178	1,140	1,144	1,147	1,151	1,155	1,158	1,157
Distribution Transformer	2,069	2,077	2,041	1,976	1,981	1,989	1,998	2,001	2,008	2007
Overhead Switch / Recloser	391	393	386	375	375	376	377	379	380	379
Pillar / Pit	201	203	200	194	195	195	196	196	197	197
Pole / Overhead Line	1,661	1,666	1,638	1,587	1,591	1,595	1,601	1,607	1,612	1,611
Power Transformer	231	232	229	221	222	222	222	223	224	224
Ring Main Unit / Ground Mount Switchgear	575	576	567	548	550	552	553	556	558	558
Zone Substation / GXP	333	334	327	317	317	319	319	321	322	322
Total	**8,562**	**8,590**	**8,445**	**8,176**	**8,199**	**8,224**	**8,252**	**8,279**	**8,307**	**8,303**

Figure 10-43 Optimal Preventative & Corrective Maintenance by Asset Category – 2014/15 to 2023/24 ($K in constant prices)

10.5.4 Non-Network Asset Lifecycle Management - Renewal and Replacement

Wellington Electricity does not have a wide range of non-network assets and therefore has limited requirement to renew and replace these assets.

10.5.4.1 Information Technology Assets

IT assets are replaced in accordance with the information technology replacement policies and IT equipment is replaced on a cycle of between three and five years. Items such as telecommunications equipment may be replaced when service provider contracts are renewed.

Upgrades to business support software tools will made on a regular basis as new versions are required.

Investment will be required for additional computer hardware and software to provide for business continuity purposes. New equipment is procured as required for business needs.

Item	Regulatory Year	Estimated Cost
ENMAC Upgrade	2015/16	$815,000
Load Control Master Station Upgrade	2015/16	$310,000
IT Hardware Upgrades	2015/16	$600,000

Figure 10-44 Overview of Planned IT Asset Investment

10.5.4.2 Plant and Machinery

Leased vehicles are replaced on a time basis in accordance with Wellington Electricity's Motor Vehicle Policy. It is expected that the fleet will be renewed over the short term (typically every three years) and on an on-going basis thereafter.

There is provision in the 2015 non-network CAPEX programme to extend the Deuar license. Other test equipment and tools are replaced as required, for example power quality and partial discharge test sets.

Item	Regulatory Year	Estimated Cost
Specialist Test Equipment and Licenses	2015/16	$200,000

Figure 10-45 Overview of planned Plant and Machinery Investment

There are no other material investments planned for non-network plant and machinery.

10.5.4.3 Land and Buildings

Wellington Electricity expects minimal investment or costs associated with the non-network land and buildings it owns. Costs include grounds maintenance and council rates on undeveloped site.

10.5.4.4 Non-network Asset Expenditure Profile

Category	2015/16	2016/17	2017/18	2018/19	2019/20	2020/21	2021/22	2022/23	2023/24	2024/25
Non-network Assets	2,100	1,720	1,829	1,944	1,587	1,858	1,900	1,943	1,986	2,031

Figure 10-46 Non-Network Capital Expenditure Forecast – 2015/16 to 2024/25 ($K in constant prices)

Appendix A Assumptions

Note that these assumptions apply to the situation prior to the Commission's DPP Determination in late November 2014. As indicated earlier, this date was too late for the AMP to factor in the impacts of the DPP decision. The four categories of assumptions marked with an asterisk (*) are those most affected by the decision, as explained in the section at the front of the AMP titled "Impact of the 2014 DPP Decision on this Plan". While all the expenditure information in the body of the AMP is done on a Pre-2014 DPP decision, the forecast expenditure in Schedule 11 does factor in the DPP decision. Network Quality targets and the Regulatory assumptions are based on the DPP Determination.

Area	Possible impact and variation to plan	Assumption	Reason for assumption
Demand and Consumption	Growth at higher levels may bring forward network reinforcement investment, or conversely a decrease in demand growth may lead to deferral of reinforcement investment	Peak demand growth and overall consumption decline present significant challenges to network planning due to contrasting characteristics. • Growth in peak demand will continue to be lower than the national average and will remain steady through the forecast period. An annual growth in peak electricity demand of 0.5% to 1.0% is forecast in some parts of the network, with steady to a slight decline in peak demand across the network as a whole • Overall consumption of electricity (kWh volume) has decreased at around 1.0% per annum since 2009 and is forecast to continue decreasing at around 0.5% per annum	Measured system loadings and load analysis indicate minor load growth in some areas but volumes declining across the network as a whole. No identified major developments. Low to moderate levels of growth in the housing sector. Assumptions supported by NZIER reports
Capital Expenditure - Customer Driven	Investment levels may increase or decrease in response to changes in demand for new connections from customers	The capital expenditure proposed for customer initiated projects will remain within forecast levels	Overall customer market in residential sector is slow and steady. Minor levels of commercial development. Ability to recover upstream costs for larger investments or uneconomic supplies

Area	Possible impact and variation to plan	Assumption	Reason for assumption
Capital Expenditure - Network Driven*	Investment levels may increase or decrease in response to changes in known asset condition and possible increased requirements for asset replacement that cannot be accommodated in present plans, or catastrophic plant failure requiring a high one-off cost	The capital expenditure proposed for asset integrity and performance will continue at forecast levels, which assume a steady operating state	The overall condition and rate of aging of network assets is steady and no "step change" in expenditure is expected
Operational Expenditure - Routine Inspection and Maintenance*	Any material change to the annual maintenance programme may lead to an increase, or decrease in the OPEX costs associated with inspection and maintenance	The inspection and maintenance expenditure proposed will remain within forecast levels for the next 2 years. Although managing aging network assets, the routine of inspection and servicing is not likely to change	Field Services Agreement outlines maintenance programme for duration of the contract
Operational Expenditure - Reactive Maintenance*	A change in the rate of failure of network equipment could lead to an increase in reactive maintenance requirements and costs. A change to the field service provider could lead to a higher cost of maintenance	The reactive maintenance expenditure proposed will remain within forecast levels for the next 2 years. Aging assets may lead to higher levels of reactive maintenance required longer term	Field Services Agreement is expected to continue. No apparent change in rate of failure of equipment
Inflation	Capital and Operational Expenditure forecasts have been inflated for future years to take into account changes in CPI, the cost of labour and materials. Should inflation vary from the assumed value forecast amounts may increase or decrease	The 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 is based on increases in costs due to annual forecast inflation and price escalation as follows: 2016 (1.74%); 2017 (2.11%); 2018 (2.17%); 2019 (2.11%); 2020 (2.06%); 2021 to 2025 (2.04%).	The rates from 2016 to 2020 were provided by the Commerce Commission. The rates for the five years thereafter are an average of the previous five.

Area	Possible impact and variation to plan	Assumption	Reason for assumption
Quality targets	Any increase in quality targets, or alteration in the assessment method, may lead to increased level of investment to improve network performance	Network reliability performance targets have been set by the Commission's 2014 DPP Determination for SAIDI, SAIFI and faults per 100km. These are shown in Fig 7.2 of the AMP, as they reflect the current reliability levels of the network. However, it is important to note that the data set utilised to establish these performance targets is now ten years (2004-2014). The targets for SAIDI and SAIFI reflect Wellington Electricity's intention to maintain network reliability at current levels. However, this assumes that capital and operational expenditure is not unreasonably restricted by the regulatory environment, as this would have the potential to make these targets hard to meet.	The SAIDI, SAIFI and faults per 100km targets were provided by the Commission in its 2014 DPP determination.
Regulatory environment*	A change to the regulatory environment may lead to increased or decreased ability to recover on investments. Investment levels will be adjusted to maintain regulatory compliance and to achieve a sustainable return on investments	Spending to meet regulated quality levels is factored into forecast expenditures. The DPP Determination issued by the Commission in November 2014 has a potentially significant impact on this AMP. This is explained in the section at the front of the AMP titled "Impact of the 2014 DPP Decision on this Plan"	No change will be made to the 2014 DPP Determination.
Transmission Network	A change to the configuration or capability of the transmission system could lead to a requirement for increased levels of investment on the network to provide capacity or security in the absence of grid capability	The transmission grid, and grid exit point connections, will remain unchanged apart from agreed projects	Asset Plans from Transpower indicate no significant changes to the grid within the planning period. Ownership boundaries may change in time with reviews of customer connection assets by Transpower, and desire by lines companies to purchase and operate these assets

Area	Possible impact and variation to plan	Assumption	Reason for assumption
Transmission Pricing	Changes to the methods of transmission pass-through pricing may lead to increased expenditure as grid alternative options become more attractive in a non pass-through environment	The transmission pricing methodologies will remain largely unchanged and the transmission pass-through pricing will remain in place	Transmission pricing is regulated as a pass-through cost and our expectation that this will remain as a pass-through cost with the net effect to the business remaining the same
Shareholders	Changes to the regulatory environment and the allowable regulated return on investment will impact on shareholders, and may lead to either increased or reduced expenditure	The DPP Determination and price reset will have a significant impact on revenue, and thus on the shareholders.	The impact of the DPP price reset has been quantified, and the forecasted gap shown in the section at the front of the AMP titled “Impact of the 2014 DPP Decision on this Plan”
Economy	An increase in the cost of raw materials and imported equipment could cause an increase in investment costs, or lead to deferral of projects to remain within budgets	The commodity markets will remain stable during the forecast period limiting equipment price rises. GDP growth in the area supplied by Wellington Electricity will continue to be lower than the national average, and is likely to be modest at best for the foreseeable future. Industrial and large commercial activity continues to decline	Present economy is depressed, but global prices appear stable based on recent trends. Strong NZ dollar allows for steady materials costs Apparent growth on the network and observation of local business activities supports this assumption
Business cycle	The evolution of a business and its operating environment can impact on strategic decision making and overall approach	Whilst more mature assets require a higher level of maintenance there is no evidence to suggest that asset conditions will cause a material change to the AMP. This remains subject to further consultation with stakeholders and the Commerce Commission around large events which impact on business continuity and further strategic assessments of network resilience plans	Until discussions with stakeholders and the Commerce Commission clarify impacts and expectations around resilience and business continuity plans, it is appropriate to continue to plan for a steady state business cycle

Area	Possible impact and variation to plan	Assumption	Reason for assumption
Technology	Increased levels of network reinforcement may be required to accommodate sudden load increases at consumer premises resulting from demand side technologies, or significantly reduced loads may be seen that could defer investment if load reduction technologies are introduced to consumers	There will be no dramatic changes that would result in a rapid uptake of new technology by consumers leading to higher expenditure or stranding of existing network assets	At demand side, displacement or disruptive technologies such as electric vehicles, vehicle-to-grid and distributed generation are still costly and unlikely to have high uptake. The areas of "smart" technology are not commercially viable over the period unless a return on their investment is built into the present DPP by the regulator
Public Safety	Assets in the public domain may require higher than average rates of replacement, or increased level of isolation from the public leading to higher costs, or reallocation of work programmes	That compliance with requirements for public safety management will not adversely impact upon the existing network assets located in the public domain	Implementation of a public safety management system in the business, including compliance with NZS 7901 and promoting a culture of incident reporting and safety awareness

Appendix B Update from 2014 Plan

During the past year, Wellington Electricity has continued the review of its asset management strategy and practices. Progress against the gaps identified in the last AMP is shown in the table below. Despite generally good progress, not all areas were addressed and are carried forward for action in 2015.

Section	Item	Description
Items incomplete from the 2014 AMP brought forward		
2.3.1	Use of System Agreement	Finalise the drafting of a revised Use of System Agreement in line with the model agreement prepared by the Electricity Authority and commence negotiations with retailers using the network
		In Progress: Work to continue during 2015.
2.7.5	Contestable capital works contractor	Complete negotiations to permit a third contestable capital works contractor to commence operating on the network during 2014
		Complete: Tenix was selected as the third capital works contractor, and commenced operating on the network in 2014.
2.7.5	Contact Centre	Renegotiate the contract for the outsourced Wellington Electricity contact centre
		In Progress: Contract extended for 12 months, to be re-evaluated in 2015.
2.7.5 & 2.8.1.1	Contact Centre	Implement improvements to the Calltaker system and processes used by the Contact Centre to better handle communications during major events
		Complete: Improvements have been implemented and tested with a simulated major event. Ongoing refinements will be made as they are identified.
2.8.1.1	SCADA	Upgrade the SCADA master station software to PowerOn Fusion
		In Progress: A business case was approved in 2014 for the SCADA master station upgrade, to take place during 2015.
2.8.1.1	SCADA	Prepare a business case for introduction of new software to replace the TrendSCADA data historian tool
		In Progress: A business case is to be prepared during 2015.

Section	Item	Description
2.8.1	Automatic Load Control System	Undertake further investigation and planning into the replacement for the Foxboro automatic load control system. Preliminary work has been completed but further development of a final solution is still required. Changes to the proposed Electricity Authority MUoSA may impact upon the timing and solution
		Ongoing: Pricing has been obtained for possible replacements of the load control system. Development of a company load control strategy commenced in 2014.
2.8.1	Maintenance Management System	Ongoing development of the Maintenance Management Database is required, and a trial of SAP is planned for 2013. It is anticipated that a full implementation of SAP PM will be scoped during 2013 for commissioning in 2014
		Complete: The Maintenance Database was replaced with SAP PM in August 2014.
2.8.5	Data validity and improvement	Ongoing connection point (ICP) data validation and connectivity improvements is to be made in the GIS as part of an ongoing programme, as well as continuous updating of records captured during field inspections, such as nameplate data of equipment
		In Progress: This work is ongoing, good progress made during 2013 with ICP data for 1,116 substation sites updated
2.13	Capability to Deliver	To resource map key projects and work items identified in this plan against available internal and external resources
		In Progress: The work programmes identified within this plan will be resource mapped during 2015, and an appropriate optimised sourcing strategy determined in consultation with contracting service providers
3.3.1.5	Melling GXP risk review	Complete the evaluation of strategies to mitigate the flood risk at Melling substation so that remediation projects to be funded by Wellington Electricity can be included in the AMP
		In Progress: Remediation options to be considered during 2015.
3.4	Spares Management	Further work to be undertaken around the recording of spares, and spares movements. Some further rationalisation of the spares held may be possible
		Ongoing: To be revisited in 2015.

Section	Item	Description
4.3.1	Consumer engagement	Undertake consumer engagement to measure consumer satisfaction with the service levels provided by Wellington Electricity
		Ongoing: To be revisited in 2015.
5.1	Design and Construction Standards	Further updates to the design and construction standard drawings will continue during 2013 and into 2014
		Complete: A design and construction manual of standards and drawings was completed during 2014. In practice, this will be a "living document", with new standards and drawings being added as they are required.
5.7.6	Step Load Changes	Presently only step load increases are covered in this section, and Wellington Electricity does not identify or record major step decreases in load as no formal notification process exists between consumers, retailers and Wellington Electricity
		On Hold: This will be reviewed as part of the revised Network Development Plan
5.9	Investment in DG schemes	Wellington Electricity will investigate further whether there is benefit in investing in Distributed Generation schemes on the network to offset investment to address security and capacity risks
		On Hold: This will be reviewed as part of the revised Network Development Plan
5.11	Network Development Plan	Further enhancements to the draft Network Development Plan are required to update it with more recent development projects and new risks identified
		In Progress: Volume 1 of the draft Network Development Plan, covering the Wellington city area, was completely revised in 2014. This included revisiting the load forecasting methodology and outputs, ensuring the network model is up to date and developing four potential development paths.
5.11	Emerging Technology	New technologies such as local storage schemes need to be investigated for possible benefits to the network
		On Hold: This will be reviewed following compilation of the revised Network Development Plan

Section	Item	Description
5.12	Transmission Connection Assets	Wellington Electricity is exploring opportunities to transfer ownership of Connection Assets from Transpower. There is potential opportunity to take ownership of sites such as Melling, Gracefield and Pauatahanui, as these sites supply only Wellington Electricity and may be better placed under EDB ownership
		In Progress: Wellington Electricity has been in discussion with Transpower over possible asset transfers. One transfer (the ex-Khandallah line) was not an economic proposition and did not proceed. Further work on larger assets will continue during 2015.
5.12.1	Resilience of Central Park to HILP events	In conjunction with Transpower, finalise the Central Park HILP study in order to provide the information needed to develop plans to increase the resilience of this GXP to HILP events and mitigate Wellington Electricity's vulnerability to such events
		In Progress: The Central Park HILP study has been received, with further work required to develop mitigate vulnerabilities.
6.1	Asset Lifecycle Planning	Continued development of asset lifecycle plans for all asset categories
		In Progress: Development of detailed asset strategies for commenced in 2014, for completion in 2015.
6.2	"Stage of Life" Analysis	Develop the "Stage of Life" analysis into a full network lifecycle model to assist in optimising expenditure against risk of failure and reliability over the asset lifecycle for the network assets as a whole
		In Progress: The Stage of Life analysis has been replaced with the EEA Asset Health Index analysis for the three major asset classes. This will be further extended to other asset classes during 2015, and incorporated in the detailed asset strategies.
6.4.2	Subtransmission Cable Replacement Strategy	Further work is required to optimise the replacement of fluid filled subtransmission cables and to show year on year length changes between solid and fluid filled cable insulation types (discussed in Section 3 and 6)
		In Progress: As part of the development of detailed asset strategies, a forward plan of all fluid filled cable replacements is to be developed

Section	Item	Description
6.4.4	Zone transformer relocation plan	A plan will be investigated to show where zone substation power transformers can be relocated to address capacity and condition concerns. Relocation may be a viable alternative to replacement where the risk profile remains at an acceptable level
		In Progress: Resulting from the relocation of the Petone transformer to Wainuiomata, and the development of detailed asset strategies, a plan for the relocation of transformers will be finalised.
6.4.4.1	Transformer oil analysis	Undertake a full oil analysis to get full particle, dissolved gas and furan results of all zone transformers
		In Progress: Full oil analysis of zone transformers is to be undertaken during 2015.
6.4.6.3	Load Control Replacement Strategy	Prepare a longer term switchgear renewal programme targeting both equipment make and model (type replacement)
		In Progress: The switchgear renewal programme is to be developed as part of the asset strategy during 2015.
6.4.8	Poles and Overhead Lines	Wellington Electricity needs to evaluate a strategy for replacing load control assets, including the DC Bias system as some system components are showing end of life failure modes. Changes proposed by the Electricity Authority MUoSA may impact upon the decision Wellington Electricity will make regarding this equipment
		In Progress: The DC Bias system has been decommissioned to address network risks identified, and a strategy is being developed for the future of the overall load control system on the network. To be completed in 2015.
6.4.9	Operating Expense by Asset Category	Further work to be completed on below ground life extension techniques for poles to optimise the repair vs. replacement decision for unserviceable poles
		In Progress: Preliminary testing in 2013 indicated pole nailing (reinforcement) is effective in addressing serviceability issues where ground rot exists. Application and suitability for the Wellington network is to be finalised.

Section	Item	Description
6.5		Wellington Electricity is working to improve OPEX breakdowns for each asset category, particularly in reactive (faults) and corrective maintenance categories. As a history develops, asset category splits of OPEX for future years will be able to be forecast with greater certainty
		In Progress: Further work has been undertaken to split future OPEX forecasts into major categories (preventative, corrective, reactive, etc) but not to specific asset categories
8.10.1	Seismic Reinforcing of Equipment and Buildings	Ongoing assessment of nominated substation buildings in accordance with the seismic assessment programme Commencement of Reinforcement Projects on those buildings found to be "Earthquake Prone"
		In Progress: Karori Zone Substation was strengthened during 2014. The remaining pre-1976 buildings will be assessed during 2015, and work will be tendered for reinforcement at Gracefield and Chaytor Street substations
8.10.2	33kV Overhead Emergency Corridors	Completion of designs for the remaining overhead subtransmission routes, and consultation with WCC to gain approval for these routes
		In Progress: All except one Wellington City route have been developed. Surface foundations have been prototyped for proof testing in 2015. Presentation and consultation with WCC will be held at completion of the remaining routes. A prioritised list of routes for the Hutt Valley and Porirua areas will be developed during 2015.
8.12	Emergency Response Plans	Continue to build capability with internal and external staff and field service contractors via simulation testing of plans. Develop lifelines interdependencies and mutual aid agreements
		Complete: A Joint Field Response Plan was developed in 2014 and successfully tested in September 2014.
8.12.3	Business Recovery Management Plan	Test the Business Recovery Management Plan
		Complete: Business Recovery Management Plan was successfully tested in January 2015.
9	Health, Safety and Environmental Improvements	Further review of corporate QSE policies Completion of development of Work Type Competency training programmes and material

Section	Item	Description
		In Progress: Course material for a number of work type competencies have been developed and reviewed during the year. Wellington Electricity will continue to review and improve WTC material during 2015.

Appendix C Evaluation of AMMAT Results

From the completed Asset Management Maturity Assessment Tool (AMMAT) provided as a schedule to this plan, the assessed result was effective, with a final score of 2.7. Minor inconsistencies or gaps identified were in the areas of Asset Data, Quality and Process Level Control. The following graph extracted from the AMMAT gives a summary of the results.

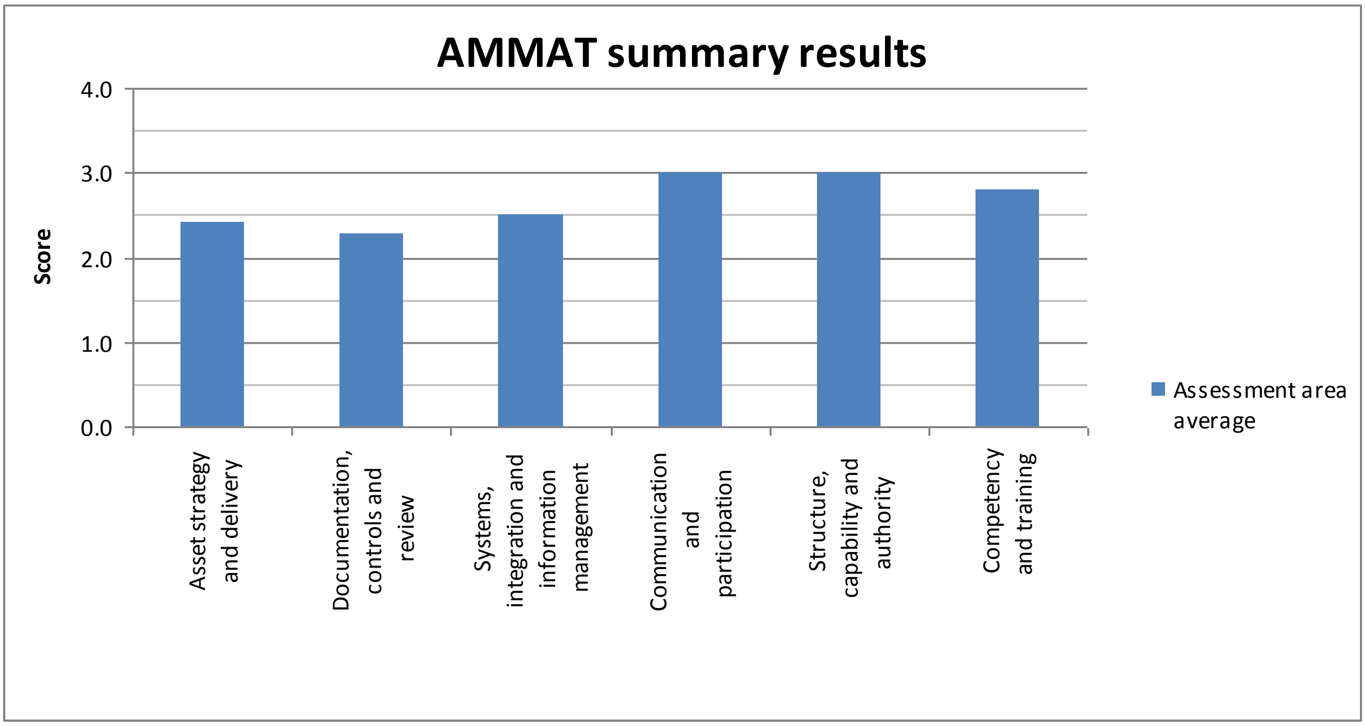


Figure 10-11 Summary of the AMMAT Assessment 2015

The following areas were identified in the AMMAT through self-assessment, to be lower than Maturity level 3 (taken to be the target level of the business), and a brief description of the development strategy to get from the present maturity level to level 3 is provided in the table. Development beyond Maturity level 3 for individual aspects of the AMMAT will be considered by Wellington Electricity where the need is clear, cost effective and justifiable.

No	Function	Question	Maturity Level Comment	Evidence - Summary	Score	Development Strategy
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?	Some of the linkages between the long-term asset management strategy and other organisational policies, strategies and stakeholder requirements are defined. The work is fairly well advanced but still incomplete	The WE AMP considers asset strategy. The work is advanced, however there are currently gaps with regard to all asset categories and long-term strategy for all assets	2	Development of long-term strategies for all asset categories will occur during 2015
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?	The long-term asset management strategy takes account of the lifecycle of some, but not all, of its assets, asset types and asset systems	Lifecycle strategy has been introduced for the major asset classes such as switchgear, subtransmission cables, poles and transformers, but remains incomplete for all asset classes	2	As per question 10 above, development of lifecycle asset management strategies will occur during 2015
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?	The organisation is in the process of putting in place comprehensive, documented asset management plan(s) that cover all life cycle activities, clearly aligned to asset management objectives and the asset management strategy	The organisation is in the process of putting in place comprehensive, documented asset management plans that cover all life cycle activities, clearly aligned to asset management objectives and the asset management strategy	2	As per question 10 above, development of lifecycle asset management strategies will occur during 2015
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?	Controls systematically considered but currently only provide for the compliant delivery of some, but not all, aspects of the organisational strategic plan and/or its asset management policy and strategy. Gaps exist	Whilst significant controls are in place to manage the delivery of asset management activities within the outsourced contractors, there are gaps in asset management strategy communication and contractor process control. In particular these are with maintenance and reactive fault quality assurance management	2	SAP PM allows greater control of the delivery of the organisational strategic plan, asset management policy and strategy. The tools for ensuring compliance are in development, for deployment in 2015.

No	Function	Question	Maturity Level Comment	Evidence - Summary	Score	Development Strategy
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?	The organisation in the process of documenting its asset management system and has documentation in place that describes some, but not all, of the main elements of its asset management system and their interaction	The AMP describes the key attributes of an asset management system however there are gaps in the overall completeness of that system. An effective architectural overview document would provide this visibility and connectivity	2	An overview document of the asset management system needs to be developed and included in the next AMP
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?	The organisation is in the process of documenting the identification and assessment of asset related risk across the asset lifecycle but it is incomplete or there are inconsistencies between approaches and a lack of integration	Asset related risks have been implemented as part of the risk management framework. There are, however, gaps surrounding the risks associated with each stage of the lifecycle of assets	2	Through the development of the lifecycle asset strategies for all categories that will be developed during 2015, a summary of all asset related risks can be compiled and provided in future plans where appropriate
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?	The organisation is in the process of putting in place process(es) and procedure(s) to manage and control the implementation of asset management plan(s) during activities related to asset creation including design, modification, procurement, construction and commissioning. Gaps and inconsistencies are being addressed.	There are asset management policies, procedures and processes in place which deal with the management of assets during the design to commissioning phases. There are procedures to determine how these are derived and prioritised within the asset management plan. There are gaps covering projects accelerated and not included within the AMP, together with works management quality monitoring. These gaps are being addressed.	2	There are gaps in some areas of the lifecycle of the assets, such as standards relating to procurement, construction, testing and operation and maintenance. Development of identified undeveloped standards together with works management quality monitoring forms part of the asset strategies currently in development.

No	Function	Question	Maturity Level Comment	Evidence - Summary	Score	Development Strategy
105	Audit	What has the organisation done to establish procedure(s) for the audit of its asset management system (process(es))?	The organisation is establishing its audit procedure(s) but they do not yet cover all the appropriate asset-related activities	Whilst the audit program is mature and targeted to areas of risk and quality delivery, there are some areas of the asset management system and process which are not covered within the current audit regime	2	Extend audit regime to cover identified areas of the asset management process which are not presently covered.
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?	Continuous improvement process(es) are set out and include consideration of cost, risk, performance and condition for assets managed across the whole life cycle but it is not yet being systematically applied	Continual improvement and optimisation of asset health, costs and risks across the whole asset lifecycle are in place although need to be finalised and fully implemented and embedded. Continuous improvement processes are set out and include consideration of cost, risk, performance and condition for assets managed across the whole life cycle but it is not yet being systematically applied	2	Review of the effectiveness of the newly developed asset strategies identified above. Provision of feedback into the strategy documents to ensure effectiveness.

Appendix D Information Schedules

Company Name	Wellington Electricity Lines Limited
AMP Planning Period	1 April 2015 – 31 March 2025

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												
7		*Current Year CY*	*CY+1*	*CY+2*	*CY+3*	*CY+4*	*CY+5*	*CY+6*	*CY+7*	*CY+8*	*CY+9*	*CY+10*
8	for year ended	**31 Mar 15**	**31 Mar 16**	**31 Mar 17**	**31 Mar 18**	**31 Mar 19**	**31 Mar 20**	**31 Mar 21**	**31 Mar 22**	**31 Mar 23**	**31 Mar 24**	**31 Mar 25**
9	**11a(i): Expenditure on Assets Forecast**	**$000 (in nominal dollars)**										
10	Consumer connection	5,771	8,015	7,899	7,291	6,872	6,494	6,956	7,543	8,375	8,898	9,249
11	System growth	6,283	825	2,881	9,211	7,882	5,328	15,561	28,978	27,026	28,146	17,448
12	Asset replacement and renewal	18,481	17,978	17,911	18,104	16,161	19,169	21,035	27,599	26,137	29,822	34,171
13	Asset relocations	1,214	1,143	1,090	925	958	1,034	1,092	1,165	1,273	1,337	1,363
14	Reliability, safety and environment:											
15	Quality of supply	521	2,084	1,442	1,421	1,163	1,193	1,241	1,267	1,146	719	734
16	Legislative and regulatory	-	-	-	-	-	-	-	-	-	-	-
17	Other reliability, safety and environment	231	811	1,030	993	944	927	903	921	940	959	979
18	**Total reliability, safety and environment**	752	2,896	2,471	2,414	2,108	2,120	2,144	2,188	2,086	1,679	1,713
19	**Expenditure on network assets**	32,501	30,857	32,252	37,945	33,980	34,145	46,790	67,472	64,897	69,883	63,944
20	Non-network assets	896	2,100	1,720	1,829	1,944	1,587	1,858	1,900	1,943	1,986	2,031
21	**Expenditure on assets**	33,397	32,957	33,972	39,775	35,924	35,732	48,648	69,372	66,840	71,869	65,975
22												
23	*plus* Cost of financing	628	620	639	748	675	672	914	1,304	1,256	1,351	1,240
24	*less* Value of capital contributions	4,879	6,319	6,202	5,669	5,403	5,194	5,554	6,008	6,657	7,062	7,322
25	*plus* Value of vested assets	-	-	-	-	-	-	-	-	-	-	-
26												
27	**Capital expenditure forecast**	29,145	27,257	28,408	34,853	31,197	31,209	44,009	64,668	61,439	66,157	59,893
28												
29	Value of commissioned assets	33,644	27,257	28,408	34,853	31,197	31,209	44,009	64,668	61,439	66,157	59,893
30		*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 15**	**31 Mar 16**	**31 Mar 17**	**31 Mar 18**	**31 Mar 19**	**31 Mar 20**	**31 Mar 21**	**31 Mar 22**	**31 Mar 23**	**31 Mar 24**	**31 Mar 25**
32		**$000 (in constant prices)**										
33	Consumer connection	5,771	7,878	7,576	6,837	6,321	5,866	6,164	6,550	7,128	7,421	7,560
34	System growth	6,283	811	2,763	8,638	7,250	4,813	13,788	25,163	23,000	23,475	14,262
35	Asset replacement and renewal	18,481	17,671	17,177	16,976	14,866	17,315	18,638	23,965	22,244	24,873	27,931
36	Asset relocations	1,214	1,124	1,045	868	881	934	968	1,011	1,083	1,116	1,114
37	Reliability, safety and environment:											
38	Quality of supply	521	2,049	1,383	1,333	1,070	1,078	1,100	1,100	975	600	600
39	Legislative and regulatory	-	-	-	-	-	-	-	-	-	-	-
40	Other reliability, safety and environment	231	798	988	931	869	838	800	800	800	800	800
41	**Total reliability, safety and environment**	752	2,846	2,370	2,264	1,939	1,915	1,900	1,900	1,775	1,400	1,400
42	**Expenditure on network assets**	32,501	30,330	30,930	35,582	31,256	30,842	41,458	58,590	55,229	58,285	52,267
43	Non-network assets	896	2,064	1,650	1,715	1,788	1,433	1,647	1,650	1,653	1,656	1,660
44	**Expenditure on assets**	33,397	32,394	32,580	37,297	33,044	32,275	43,104	60,239	56,882	59,941	53,927
45												
46	**Subcomponents of expenditure on assets (where known)**											
47	Energy efficiency and demand side management, reduction of energy losses	-	-	-	-	-	-	-	-	-	-	-
48	Overhead to underground conversion	-	-	-	-	-	-	-	-	-	-	-
49	Research and development	-	-	-	-	-	-	-	-	-	-	-

			Current Year CY	CY+1	CY+2	CY+3	CY+4	CY+5	CY+6	CY+7	CY+8	CY+9	CY+10
57			Current Year CY	CY+1	CY+2	CY+3	CY+4	CY+5	CY+6	CY+7	CY+8	CY+9	CY+10
58		for year ended	**31 Mar 15**	**31 Mar 16**	**31 Mar 17**	**31 Mar 18**	**31 Mar 19**	**31 Mar 20**	**31 Mar 21**	**31 Mar 22**	**31 Mar 23**	**31 Mar 24**	**31 Mar 25**
59	**Difference between nominal and constant price forecasts**		**$000**										
60	Consumer connection		-	137	324	454	551	628	793	993	1,248	1,477	1,689
61	System growth		-	14	118	574	632	515	1,773	3,815	4,026	4,671	3,186
62	Asset replacement and renewal		-	307	734	1,128	1,295	1,854	2,397	3,633	3,894	4,950	6,240
63	Asset relocations		-	20	45	58	77	100	124	153	190	222	249
64	Reliability, safety and environment:												
65	Quality of supply		-	36	59	89	93	115	141	167	171	119	134
66	Legislative and regulatory		-	-	-	-	-	-	-	-	-	-	-
67	Other reliability, safety and environment		-	14	42	62	76	90	103	121	140	159	179
68	**Total reliability, safety and environment**		-	49	101	150	169	205	244	288	311	279	313
69	**Expenditure on network assets**		-	527	1,321	2,364	2,724	3,303	5,332	8,882	9,668	11,598	11,677
70	Non-network assets		-	36	70	114	156	154	212	250	289	330	371
71	**Expenditure on assets**		-	563	1,392	2,478	2,880	3,457	5,544	9,132	9,958	11,928	12,048
72													

			Current Year CY	CY+1	CY+2	CY+3	CY+4	CY+5
73		for year ended	**31 Mar 15**	**31 Mar 16**	**31 Mar 17**	**31 Mar 18**	**31 Mar 19**	**31 Mar 20**
74	**11a(ii): Consumer Connection**							
75	*Consumer types defined by EDB**		**$000 (in constant prices)**					
76	Substation		2,050	3,634	2,711	2,561	2,536	2,592
77	Subdivision		2,076	2,003	2,261	2,131	2,094	2,133
78	High Voltage Connection		241	138	-	-	-	-
79	Residential customers		1,331	2,043	2,604	2,145	1,691	1,141
80	Public Lighting		73	60	-	-	-	-
81	**include additional rows if needed*							
82	**Consumer connection expenditure**		5,771	7,878	7,576	6,837	6,321	5,866
83	*less* Capital contributions funding consumer connection		3,982	5,195	5,157	4,802	4,522	4,260
84	**Consumer connection less capital contributions**		1,789	2,683	2,418	2,035	1,799	1,605
85	**11a(iii): System Growth**							
86	Subtransmission		5,877	-	1,250	3,750	-	-
87	Zone substations		54	-	-	2,025	6,075	213
88	Distribution and LV lines		-	-	-	125	875	2,375
89	Distribution and LV cables		352	-	850	2,550	300	2,225
90	Distribution substations and transformers		-	-	-	-	-	-
91	Distribution switchgear		-	-	-	-	-	-
92	Other network assets		-	811	663	188	-	-
93	**System growth expenditure**		6,283	811	2,763	8,638	7,250	4,813
94	*less* Capital contributions funding system growth		-	-	-	-	-	-
95	**System growth less capital contributions**		6,283	811	2,763	8,638	7,250	4,813

	Current Year CY	CY+1	CY+2	CY+3	CY+4	CY+5
for year ended	31 Mar 15	31 Mar 16	31 Mar 17	31 Mar 18	31 Mar 19	31 Mar 20
11a(iv): Asset Replacement and Renewal	**$000 (in constant prices)**					
Subtransmission	37	500	500	500	500	500
Zone substations	2,216	1,335	1,775	775	1,175	2,125
Distribution and LV lines	11,099	5,791	5,337	6,453	4,561	5,672
Distribution and LV cables	81	1,486	1,550	1,550	1,550	1,550
Distribution substations and transformers	1,512	2,900	2,325	2,400	2,383	2,510
Distribution switchgear	2,999	4,240	4,105	4,133	3,848	4,108
Other network assets	537	1,419	1,585	1,165	850	850
Asset replacement and renewal expenditure	18,481	17,671	17,177	16,976	14,866	17,315
less Capital contributions funding asset replacement and renewal	-	-	-	-	-	-
Asset replacement and renewal less capital contributions	18,481	17,671	17,177	16,976	14,866	17,315
11a(v):Asset Relocations						
*Project or programme**						
Asset relocations	1,214	1,124	1,045	868	881	934
[Description of material project or programme]	-	-	-	-	-	-
[Description of material project or programme]	-	-	-	-	-	-
[Description of material project or programme]	-	-	-	-	-	-
[Description of material project or programme]	-	-	-	-	-	-
**include additional rows if needed*						
All other asset relocations projects or programmes	-	-	-	-	-	-
Asset relocations expenditure	1,214	1,124	1,045	868	881	934
less Capital contributions funding asset relocations	897	1,124	1,045	868	881	934
Asset relocations less capital contributions	317	-	-	-	-	-
11a(vi):Quality of Supply						
*Project or programme**						
Reliability Projects	-	1,100	625	875	500	625
Ngauranga - Reconductoring	179	-	-	-	-	-
Karori - Reliability improvement	137	-	-	-	-	-
Johnsonville - Reliability improvement	45	-	-	-	-	-
SCADA	-	949	758	458	570	453
**include additional rows if needed*						
All other quality of supply projects or programmes	161	-	-	-	-	-
Quality of supply expenditure	521	2,049	1,383	1,333	1,070	1,078
less Capital contributions funding quality of supply	-	-	-	-	-	-
Quality of supply less capital contributions	521	2,049	1,383	1,333	1,070	1,078
11a(vii): Legislative and Regulatory						
*Project or programme**						
[Description of material project or programme]	-	-	-	-	-	-
[Description of material project or programme]	-	-	-	-	-	-
[Description of material project or programme]	-	-	-	-	-	-
[Description of material project or programme]	-	-	-	-	-	-
[Description of material project or programme]	-	-	-	-	-	-
**include additional rows if needed*						
All other legislative and regulatory projects or programmes	-	-	-	-	-	-
Legislative and regulatory expenditure	-	-	-	-	-	-
less Capital contributions funding legislative and regulatory	-	-	-	-	-	-
Legislative and regulatory less capital contributions	-	-	-	-	-	-

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

for year ended	Current Year CY 31 Mar 15	CY+1 31 Mar 16	CY+2 31 Mar 17	CY+3 31 Mar 18	CY+4 31 Mar 19	CY+5 31 Mar 20
*Project or programme**	$000 (in constant prices)					
Seismic Strengthening	231	498	688	631	569	538
Earthing Upgrades	-	300	300	300	300	300
[Description of material project or programme]	-	-	-	-	-	-
[Description of material project or programme]	-	-	-	-	-	-
[Description of material project or programme]	-	-	-	-	-	-
**include additional rows if needed*						
All other reliability, safety and environment projects or programmes	-	-	-	-	-	-
Other reliability, safety and environment expenditure	231	798	988	931	869	838
less Capital contributions funding other reliability, safety and environment	-	-	-	-	-	-
Other reliability, safety and environment less capital contributions	231	798	988	931	869	838

11a(ix): Non-Network Assets

	Current Year CY 31 Mar 15	CY+1 31 Mar 16	CY+2 31 Mar 17	CY+3 31 Mar 18	CY+4 31 Mar 19	CY+5 31 Mar 20
Routine expenditure						
*Project or programme**						
Control room	59	-	-	-	-	-
Software	383	1,800	1,456	1,510	1,474	1,182
IT Infrastructure	454	264	194	205	313	251
[Description of material project or programme]	-	-	-	-	-	-
[Description of material project or programme]	-	-	-	-	-	-
**include additional rows if needed*						
All other routine expenditure projects or programmes	-	-	-	-	-	-
Routine expenditure	896	2,064	1,650	1,715	1,788	1,433
Atypical expenditure						
*Project or programme**						
[Description of material project or programme]	-	-	-	-	-	-
[Description of material project or programme]	-	-	-	-	-	-
[Description of material project or programme]	-	-	-	-	-	-
[Description of material project or programme]	-	-	-	-	-	-
[Description of material project or programme]	-	-	-	-	-	-
**include additional rows if needed*						
All other atypical projects or programmes	-	-	-	-	-	-
Atypical expenditure	-	-	-	-	-	-
Non-network assets expenditure	896	2,064	1,650	1,715	1,788	1,433

Company Name	Wellington Electricity Lines Limited
AMP Planning Period	1 April 2015 – 31 March 2025

SCHEDULE 11b: REPORT ON FORECAST OPERATIONAL EXPENDITURE

This schedule requires a breakdown of forecast operational expenditure for the disclosure year and a 10 year planning period. The forecasts should be consistent with the supporting information set out in the AMP. The forecast is to be expressed in both constant price and nominal dollar terms.
EDBs must provide explanatory comment on the difference between constant price and nominal dollar operational expenditure forecasts in Schedule 14a (Mandatory Explanatory Notes).
This information is not part of audited disclosure information.

sch ref		*Current Year CY*	*CY+1*	*CY+2*	*CY+3*	*CY+4*	*CY+5*	*CY+6*	*CY+7*	*CY+8*	*CY+9*	*CY+10*
8	for year ended	**31 Mar 15**	**31 Mar 16**	**31 Mar 17**	**31 Mar 18**	**31 Mar 19**	**31 Mar 20**	**31 Mar 21**	**31 Mar 22**	**31 Mar 23**	**31 Mar 24**	**31 Mar 25**
9	**Operational Expenditure Forecast**	**$000 (in nominal dollars)**										
10	Service interruptions and emergencies	2,513	3,655	3,782	3,891	4,015	4,115	5,829	6,401	6,128	5,848	5,915
11	Vegetation management	1,133	1,648	1,705	1,754	1,810	1,855	2,628	2,886	2,763	2,636	2,667
12	Routine and corrective maintenance and inspection	6,269	9,118	9,433	9,705	10,014	10,263	14,540	15,967	15,286	14,586	14,754
13	Asset replacement and renewal	621	903	934	961	992	1,017	1,440	1,582	1,514	1,445	1,461
14	**Network Opex**	10,537	15,324	15,853	16,311	16,830	17,250	24,437	26,835	25,691	24,514	24,797
15	System operations and network support	4,258	4,354	4,484	4,609	4,723	4,833	4,952	5,078	5,207	5,340	5,476
16	Business support	10,926	11,221	11,612	11,993	12,351	12,706	13,088	13,498	13,924	14,366	14,825
17	**Non-network opex**	15,184	15,575	16,096	16,603	17,073	17,539	18,040	18,576	19,131	19,706	20,301
18	**Operational expenditure**	25,720	30,899	31,950	32,914	33,903	34,789	42,477	45,411	44,822	44,220	45,098

19		*Current Year CY*	*CY+1*	*CY+2*	*CY+3*	*CY+4*	*CY+5*	*CY+6*	*CY+7*	*CY+8*	*CY+9*	*CY+10*
20	for year ended	**31 Mar 15**	**31 Mar 16**	**31 Mar 17**	**31 Mar 18**	**31 Mar 19**	**31 Mar 20**	**31 Mar 21**	**31 Mar 22**	**31 Mar 23**	**31 Mar 24**	**31 Mar 25**
21		**$000 (in constant prices)**										
22	Service interruptions and emergencies	2,513	3,593	3,627	3,649	3,693	3,717	5,165	5,559	5,215	4,877	4,835
23	Vegetation management	1,133	1,620	1,635	1,645	1,665	1,675	2,328	2,506	2,351	2,199	2,180
24	Routine and corrective maintenance and inspection	6,269	8,962	9,046	9,100	9,211	9,270	12,883	13,865	13,008	12,165	12,060
25	Asset replacement and renewal	621	888	896	901	912	918	1,276	1,373	1,289	1,205	1,195
26	**Network Opex**	10,537	15,062	15,204	15,295	15,480	15,581	21,653	23,303	21,862	20,446	20,269
27	System operations and network support	4,258	4,279	4,301	4,322	4,344	4,366	4,387	4,409	4,431	4,454	4,476
28	Business support	10,926	11,030	11,137	11,247	11,360	11,477	11,597	11,721	11,849	11,981	12,118
29	**Non-network opex**	15,184	15,309	15,437	15,569	15,704	15,842	15,985	16,131	16,281	16,435	16,594
30	**Operational expenditure**	25,720	30,371	30,642	30,864	31,184	31,423	37,637	39,433	38,143	36,881	36,863
31	**Subcomponents of operational expenditure (where known)**											
32–33	Energy efficiency and demand side management, reduction of energy losses	-	-	-	-	-	-	-	-	-	-	-
34	Direct billing*	-	-	-	-	-	-	-	-	-	-	-
35	Research and Development	-	-	-	-	-	-	-	-	-	-	-
36	Insurance	1,097	1,151	1,209	1,269	1,333	1,400	1,470	1,543	1,620	1,701	1,786

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

39		*Current Year CY*	*CY+1*	*CY+2*	*CY+3*	*CY+4*	*CY+5*	*CY+6*	*CY+7*	*CY+8*	*CY+9*	*CY+10*
40	for year ended	**31 Mar 15**	**31 Mar 16**	**31 Mar 17**	**31 Mar 18**	**31 Mar 19**	**31 Mar 20**	**31 Mar 21**	**31 Mar 22**	**31 Mar 23**	**31 Mar 24**	**31 Mar 25**
41	**Difference between nominal and real forecasts**	**$000**										
42	Service interruptions and emergencies	-	63	155	242	322	398	664	843	913	971	1,080
43	Vegetation management	-	28	70	109	145	179	299	380	412	438	487
44	Routine and corrective maintenance and inspection	-	156	386	604	803	993	1,657	2,102	2,278	2,421	2,694
45	Asset replacement and renewal	-	15	38	60	80	98	164	208	226	240	267
46	**Network Opex**	-	262	649	1,016	1,350	1,669	2,785	3,533	3,828	4,069	4,528
47	System operations and network support	-	74	184	287	379	468	564	668	776	886	1,000
48	Business support	-	192	476	747	991	1,229	1,491	1,777	2,075	2,384	2,707
49	**Non-network opex**	-	266	659	1,034	1,369	1,697	2,056	2,445	2,851	3,271	3,707
50	**Operational expenditure**	-	528	1,308	2,049	2,719	3,365	4,840	5,978	6,679	7,339	8,235

Company Name **Wellington Electricity**

AMP Planning Period **1 April 2015 – 31 March 2025**

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											
7					**Asset condition at start of planning period (percentage of units by grade)**						
8	**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**
9											
10	All	Overhead Line	Concrete poles / steel structure	No.	0.09%	1.12%	34.42%	57.33%	7.04%	3	1.00%
11	All	Overhead Line	Wood poles	No.	0.57%	12.17%	65.50%	16.96%	4.79%	3	16.00%
12	All	Overhead Line	Other pole types	No.						N/A	
13	HV	Subtransmission Line	Subtransmission OH up to 66kV conductor	km		5.17%	85.25%	9.58%		3	1.00%
14	HV	Subtransmission Line	Subtransmission OH 110kV+ conductor	km						N/A	
15	HV	Subtransmission Cable	Subtransmission UG up to 66kV (XLPE)	km			4.84%	95.16%		3	-
16	HV	Subtransmission Cable	Subtransmission UG up to 66kV (Oil pressurised)	km		23.24%	76.76%			3	-
17	HV	Subtransmission Cable	Subtransmission UG up to 66kV (Gas pressurised)	km	2.25%	3.39%	94.36%			3	-
18	HV	Subtransmission Cable	Subtransmission UG up to 66kV (PILC)	km		29.00%	71.00%			3	-
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.			100.00%			4	-
25	HV	Zone substation Buildings	Zone substations 110kV+	No.						N/A	
26	HV	Zone substation switchgear	22/33kV CB (Indoor)	No.		100.00%				4	100.00%
27	HV	Zone substation switchgear	22/33kV CB (Outdoor)	No.						N/A	
28	HV	Zone substation switchgear	33kV Switch (Ground Mounted)	No.						N/A	
29	HV	Zone substation switchgear	33kV Switch (Pole Mounted)	No.			50.00%	50.00%		3	-
30	HV	Zone substation switchgear	33kV RMU	No.						N/A	
31	HV	Zone substation switchgear	50/66/110kV CB (Indoor)	No.						N/A	
32	HV	Zone substation switchgear	50/66/110kV CB (Outdoor)	No.						N/A	
33	HV	Zone substation switchgear	3.3/6.6/11/22kV CB (ground mounted)	No.	6.27%	6.54%	70.30%	16.89%		3	7.00%
34	HV	Zone substation switchgear	3.3/6.6/11/22kV CB (pole mounted)	No.						N/A	

42					Asset condition at start of planning period (percentage of units by grade)						
43	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
44											
45	HV	Zone Substation Transformer	Zone Substation Transformers	No.	3.70%	19.37%	67.31%	9.62%		4	4.00%
46	HV	Distribution Line	Distribution OH Open Wire Conductor	km	0.50%	16.55%	71.20%	11.75%		3	1.00%
47	HV	Distribution Line	Distribution OH Aerial Cable Conductor	km	1.19%	9.62%	84.55%	4.64%		3	1.00%
48	HV	Distribution Line	SWER conductor	km						N/A	
49	HV	Distribution Cable	Distribution UG XLPE or PVC	km	0.02%	0.70%	36.52%	62.76%		3	-
50	HV	Distribution Cable	Distribution UG PILC	km	0.08%	5.88%	83.50%	10.54%		3	-
51	HV	Distribution Cable	Distribution Submarine Cable	km						N/A	
52	HV	Distribution switchgear	3.3/6.6/11/22kV CB (pole mounted) - reclosers and sectionalisers	No.	8.51%	5.32%	39.36%	46.81%		3	10.00%
53	HV	Distribution switchgear	3.3/6.6/11/22kV CB (Indoor)	No.	5.25%	15.38%	50.63%	28.74%		3	10.00%
54	HV	Distribution switchgear	3.3/6.6/11/22kV Switches and fuses (pole mounted)	No.	4.13%	33.99%	38.08%	23.80%		3	10.00%
55	HV	Distribution switchgear	3.3/6.6/11/22kV Switch (ground mounted) - except RMU	No.	4.63%	8.93%	61.12%	25.32%		3	10.00%
56	HV	Distribution switchgear	3.3/6.6/11/22kV RMU	No.	1.50%	8.57%	48.04%	41.89%		3	15.00%
57	HV	Distribution Transformer	Pole Mounted Transformer	No.	0.28%	7.52%	51.89%	40.31%		3	2.00%
58	HV	Distribution Transformer	Ground Mounted Transformer	No.	2.03%	24.98%	39.82%	33.17%		3	3.00%
59	HV	Distribution Transformer	Voltage regulators	No.						N/A	
60	HV	Distribution Substations	Ground Mounted Substation Housing	No.	0.16%	10.07%	56.02%	33.75%		3	3.00%
61	LV	LV Line	LV OH Conductor	km	0.21%	13.97%	79.55%	6.27%		2	1.00%
62	LV	LV Cable	LV UG Cable	km	1.14%	2.96%	69.04%	26.86%		2	2.00%
63	LV	LV Streetlighting	LV OH/UG Streetlight circuit	km	1.17%	7.17%	73.08%	18.58%		2	2.00%
64	LV	Connections	OH/UG consumer service connections	No.	0.19%	0.82%	98.09%	0.90%		2	1.00%
65	All	Protection	Protection relays (electromechanical, solid state and numeric)	No.	2.00%	31.84%	41.85%	24.31%		3	10.00%
66	All	SCADA and communications	SCADA and communications equipment operating as a single system	Lot	17.72%	30.71%	22.44%	29.13%		3	10.00%
67	All	Capacitor Banks	Capacitors including controls	No.						N/A	
68	All	Load Control	Centralised plant	Lot	7.69%	15.38%	69.24%	7.69%		3	-
69	All	Load Control	Relays	No.						N/A	
70	All	Civils	Cable Tunnels	km			100.00%			3	-

Company Name	**Wellington Electricity**
AMP Planning Period	**1 April 2015 – 31 March 2025**

SCHEDULE 12b: REPORT ON FORECAST CAPACITY

This schedule requires a breakdown of current and forecast capacity and utilisation for each zone substation and current distribution transformer capacity. The data provided should be consistent with the information provided in the AMP. Information provided in this table should relate to the operation of the network in its normal steady state configuration.

sch ref

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

sch ref	*Existing Zone Substations*	Current Peak Load (MVA)	Installed Firm Capacity (MVA)	Security of Supply Classification (type)	Transfer Capacity (MVA)	Utilisation of Installed Firm Capacity %	Installed Firm Capacity +5 years (MVA)	Utilisation of Installed Firm Capacity + 5yrs %	Installed Firm Capacity Constraint +5 years (cause)	Explanation
9	8 Ira St	18	24	N-1	9	75%	24	67%	No constraint within +5 years	
10	Brown Owl	15	23	N-1	7	65%	23	70%	No constraint within +5 years	
11	Evans Bay	15	24	N-1	11	63%	24	67%	No constraint within +5 years	
12	Frederick St	28	36	N-1	13	78%	36	75%	Subtransmission circuit	High Demand, Capacity shortfall to be rectified by new substation
13	Gracefield	12	23	N-1	12	52%	23	43%	No constraint within +5 years	
14	Hataitai	19	23	N-1	11	83%	23	87%	No constraint within +5 years	
15	Johnsonville	17	23	N-1	9	74%	23	74%	No constraint within +5 years	
16	Karori	17	24	N-1	7	71%	24	71%	No constraint within +5 years	
17	Kenepuru	12	23	N-1	9	52%	23	48%	No constraint within +5 years	
18	Korokoro	19	23	N-1	17	83%	23	78%	No constraint within +5 years	Petone station now supplied from Korokoro
19	Maidstone	14	22	N-1	12	64%	22	64%	No constraint within +5 years	
20	Mana-Plimmerton	20	16	N-1	12	125%	16	125%	Transformer	Capacity Shortfall
21	Moore St	24	36	N-1	14	67%	36	72%	No constraint within +5 years	
22	Naenae	18	23	N-1	11	78%	23	74%	No constraint within +5 years	
23	Nairn St	23	30	N-1	16	77%	30	83%	No constraint within +5 years	
24	Ngauranga	13	12	N-1	10	108%	12	117%	Transformer	High Demand growth north east of Ngauranga and in Johnsonville - Development of new Sub-division
25	Palm Grove	25	24	N-1	13	104%	24	69%	Transformer	Capacity shortfall to be rectified by new susbtation.
27	Porirua	19	20	N-1	14	95%	20	105%	Transformer	Capacity Shortfall
28	Seaview	16	22	N-1	12	73%	22	73%	No constraint within +5 years	
29	Tawa	14	16	N-1	13	88%	16	106%	Transformer	Capacity Shortfall - High load growth in Tawa/Grenada area
30	The Terrace	27	36	N-1	21	75%	36	78%	No constraint within +5 years	
31	Trentham	17	23	N-1	10	74%	23	74%	No constraint within +5 years	
32	University	26	24	N-1	21	108%	24	100%	Transformer	Capacity Shortfall
33	Waikowhai	16	19	N-1	10	84%	19	89%	No constraint within +5 years	
34	Wainuiomata	17	20	N-1	3	85%	23	70%	No constraint within +5 years	
35	Waitangirua	15	16	N-1	11	94%	16	106%	Transformer	Capacity Shortfall - High load growth in Waitangirua area
36	Waterloo	19	23	N-1	14	83%	23	83%	No constraint within +5 years	
37	Bond St					-	36	60%	No constraint within +5 years	New Zone Substation

38 [1] *Extend forecast capacity table as necessary to disclose all capacity by each zone substation*

39 ### 12b(ii): Transformer Capacity

sch ref		(MVA)
41	Distribution transformer capacity (EDB owned)	1,374
42	Distribution transformer capacity (Non-EDB owned)	18
43	**Total distribution transformer capacity**	1,392
44		
45	**Zone substation transformer capacity**	1,199

Company Name	Wellington Electricity Lines Limited
AMP Planning Period	1 April 2015 – 31 March 2025

SCHEDULE 12C: REPORT ON FORECAST NETWORK DEMAND

This schedule requires a forecast of new connections (by consumer type), peak demand and energy volumes for the disclosure year and a 5 year planning period. The forecasts should be consistent with the supporting information set out in the AMP as well as the assumptions used in developing the expenditure forecasts in Schedule 11a and Schedule 11b and the capacity and utilisation forecasts in Schedule 12b.

sch ref

7 12c(i): Consumer Connections

sch ref				Number of connections					
8	*Number of ICPs connected in year by consumer type*								
9				*Current Year CY*	*CY+1*	*CY+2*	*CY+3*	*CY+4*	*CY+5*
10			for year ended	**31 Mar 15**	**31 Mar 16**	**31 Mar 17**	**31 Mar 18**	**31 Mar 19**	**31 Mar 20**
11	*Consumer types defined by EDB**								
12	Domestic			1,613	809	809	809	809	809
13	Large Commercial			11	8	8	8	8	8
14	Large Industrial			2	2	2	2	2	2
	Medium Commercial			19	16	16	16	16	16
	Small Commercial			500	305	305	305	305	305
15	Small Industrial			11	2	2	2	2	2
16	Unmetered			140	39	39	39	39	39
17	**Connections total**			2,296	1,179	1,179	1,179	1,179	1,179
18	**include additional rows if needed*								
19	**Distributed generation**								
20	Number of connections			149	180	200	200	200	200
21	Installed connection capacity of distributed generation (MVA)			0.5	1.0	1.0	1.0	1.0	1.0

22 12c(ii) System Demand

sch ref									
23				*Current Year CY*	*CY+1*	*CY+2*	*CY+3*	*CY+4*	*CY+5*
24		**Maximum coincident system demand (MW)**	for year ended	**31 Mar 15**	**31 Mar 16**	**31 Mar 17**	**31 Mar 18**	**31 Mar 19**	**31 Mar 20**
25		GXP demand		461	463	465	467	465	464
26	*plus*	Distributed generation output at HV and above		75	75	75	75	75	75
27		**Maximum coincident system demand**		536	538	540	542	540	539
28	*less*	Net transfers to (from) other EDBs at HV and above		-	-	-	-	-	-
29		**Demand on system for supply to consumers' connection points**		536	538	540	542	540	539

sch ref								
30		**Electricity volumes carried (GWh)**						
31		Electricity supplied from GXPs	2,284	2,243	2,202	2,162	2,122	2,083
32	*less*	Electricity exports to GXPs	-	-	-	-	-	-
33	*plus*	Electricity supplied from distributed generation	157	157	157	157	157	157
34	*less*	Net electricity supplied to (from) other EDBs	-	-	-	-	-	-
35		**Electricity entering system for supply to ICPs**	2,442	2,400	2,359	2,319	2,280	2,241
36	*less*	Total energy delivered to ICPs	2,325	2,285	2,246	2,208	2,170	2,133
37		**Losses**	116	115	113	111	109	108
38								
39		**Load factor**	52%	51%	50%	49%	48%	47%
40		**Loss ratio**	4.8%	4.8%	4.8%	4.8%	4.8%	4.8%

Company Name	**Wellington Electricity**
AMP Planning Period	**1 April 2015 – 31 March 2025**
Network / Sub-network Name	

SCHEDULE 12d: REPORT FORECAST INTERRUPTIONS AND DURATION

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

sch ref		*Current Year CY*	*CY+1*	*CY+2*	*CY+3*	*CY+4*	*CY+5*
9	for year ended	**31 Mar 15**	**31 Mar 16**	**31 Mar 17**	**31 Mar 18**	**31 Mar 19**	**31 Mar 20**
10	**SAIDI**						
11	Class B (planned interruptions on the network)	2.9	1.8	1.8	1.8	1.8	1.8
12	Class C (unplanned interruptions on the network)	36.8	33.7	33.7	33.7	33.7	33.7
13	**SAIFI**						
14	Class B (planned interruptions on the network)	0.02	0.01	0.01	0.01	0.01	0.01
15	Class C (unplanned interruptions on the network)	0.56	0.53	0.53	0.53	0.53	0.53

Company Name	**Wellington Electricity**
AMP Planning Period	**1 April 2015 – 31 March 2025**
Asset Management Standard Applied	**PAS 55**

SCHEDULE 13: REPORT ON ASSET MANAGEMENT MATURITY

This schedule requires information on the EDB'S self-assessment of the maturity of its asset management practices .

Question No.	Function	Question	Score	Evidence—Summary	User Guidance	Why	Who	Record/documented Information
3	Asset management policy	To what extent has an asset management policy been documented, authorised and communicated?	3	WE has an asset management policy which is derived from the organisational vision and linked to organisational strategies, objectives,and targets. WE also has a number of focused policies for the management of discrete assets which are consistent with the corporate AM policy.		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	The WE AMP conisders asset stategy. The work is advanced, however there are currently gaps with regard to all asset categories and long term strategy for all assets.		In setting an organisation's asset management strategy, it is important that it is consistent with any other policies and strategies that the organisation has and has taken into account the requirements of relevant stakeholders. This question examines to what extent the asset management strategy is consistent with other organisational policies and strategies (eg, as required by PAS 55 para 4.3.1 b) and has taken account of stakeholder requirements as required by PAS 55 para 4.3.1 c). Generally, this will take into account the same polices, strategies and stakeholder requirements as covered in drafting the asset management policy but at a greater level of detail.	Top management. The organisation's strategic planning team. The management team that has overall responsibility for asset management.	The organisation's asset management strategy document and other related organisational policies and strategies. Other than the organisation's strategic plan, these could include those relating to health and safety, environmental, etc. Results of stakeholder consultation.
11	Asset management strategy	In what way does the organisation's asset management strategy take account of the lifecycle of the assets, asset types and asset systems over which the organisation has stewardship?	2	Lifecycle strategy has been introduced for the major asset classes such as switchgear, subtransmission cables, poles and transformers, but remains incomplete for all asset classes.		Good asset stewardship is the hallmark of an organisation compliant with widely used AM standards. A key component of this is the need to take account of the lifecycle of the assets, asset types and asset systems. (For example, this requirement is recognised in 4.3.1 d) of PAS 55). This question explores what an organisation has done to take lifecycle into account in its asset management strategy.	Top management. People in the organisation with expert knowledge of the assets, asset types, asset systems and their associated life-cycles. The management team that has overall responsibility for asset management. Those responsible for developing and adopting methods and processes used in asset management	The organisation's documented asset management strategy and supporting working documents.
26	Asset management plan(s)	How does the organisation establish and document its asset management plan(s) across the life cycle activities of its assets and asset systems?	2	The organisation is in the process of putting in place comprehensive, documented asset management plans that cover all life cycle activities, clearly aligned to asset management objectives and the asset management strategy.		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	**Wellington Electricity**
AMP Planning Period	**1 April 2015 – 31 March 2025**
Asset Management Standard Applied	**PAS 55**

SCHEDULE 13: REPORT ON ASSET MANAGEMENT MATURITY (cont)

Question No.	Function	Question	Maturity Level 0	Maturity Level 1	Maturity Level 2	Maturity Level 3	Maturity Level 4
3	Asset management policy	To what extent has an asset management policy been documented, authorised and communicated?	The organisation does not have a documented asset management policy.	The organisation has an asset management policy, but it has not been authorised by top management, or it is not influencing the management of the assets.	The organisation has an asset management policy, which has been authorised by top management, but it has had limited circulation. It may be in use to influence development of strategy and planning but its effect is limited.	The asset management policy is authorised by top management, is widely and effectively communicated to all relevant employees and stakeholders, and used to make these persons aware of their asset related obligations.	The organisation's process(es) surpass the standard required to comply with requirements set out in a recognised standard. The assessor is advised to note in the Evidence section why this is the case and the evidence seen.
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?	The organisation has not considered the need to ensure that its asset management strategy is appropriately aligned with the organisation's other organisational policies and strategies or with stakeholder requirements. OR The organisation does not have an asset management strategy.	The need to align the asset management strategy with other organisational policies and strategies as well as stakeholder requirements is understood and work has started to identify the linkages or to incorporate them in the drafting of asset management strategy.	Some of the linkages between the long-term asset management strategy and other organisational policies, strategies and stakeholder requirements are defined but the work is fairly well advanced but still incomplete.	All linkages are in place and evidence is available to demonstrate that, where appropriate, the organisation's asset management strategy is consistent with its other organisational policies and strategies. The organisation has also identified and considered the requirements of relevant stakeholders.	The organisation's process(es) surpass the standard required to comply with requirements set out in a recognised standard. The assessor is advised to note in the Evidence section why this is the case and the evidence seen.
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?	The organisation has not considered the need to ensure that its asset management strategy is produced with due regard to the lifecycle of the assets, asset types or asset systems that it manages. OR The organisation does not have an asset management strategy.	The need is understood, and the organisation is drafting its asset management strategy to address the lifecycle of its assets, asset types and asset systems.	The long-term asset management strategy takes account of the lifecycle of some, but not all, of its assets, asset types and asset systems.	The asset management strategy takes account of the lifecycle of all of its assets, asset types and asset systems.	The organisation's process(es) surpass the standard required to comply with requirements set out in a recognised standard. The assessor is advised to note in the Evidence section why this is the case and the evidence seen.
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?	The organisation does not have an identifiable asset management plan(s) covering asset systems and critical assets.	The organisation has asset management plan(s) but they are not aligned with the asset management strategy and objectives and do not take into consideration the full asset life cycle (including asset creation, acquisition, enhancement, utilisation, maintenance decommissioning and disposal).	The organisation is in the process of putting in place comprehensive, documented asset management plan(s) that cover all life cycle activities, clearly aligned to asset management objectives and the asset management strategy.	Asset management plan(s) are established, documented, implemented and maintained for asset systems and critical assets to achieve the asset management strategy and asset management objectives across all life cycle phases.	The organisation's process(es) surpass the standard required to comply with requirements set out in a recognised standard. The assessor is advised to note in the Evidence section why this is the case and the evidence seen.

Company Name	**Wellington Electricity**
AMP Planning Period	**1 April 2015 – 31 March 2025**
Asset Management Standard Applied	**PAS 55**

SCHEDULE 13: REPORT ON ASSET MANAGEMENT MATURITY (cont)

Question No.	Function	Question	Score	Evidence—Summary	User Guidance	Why	Who	Record/documented Information
27	Asset management plan(s)	How has the organisation communicated its plan(s) to all relevant parties to a level of detail appropriate to the receiver's role in their delivery?	3	The plan is communicated to all relevant employees, stakeholders and contracted service providers to a level of detail appropriate to their participation or business interests in the delivery of the plan, and there is confirmation that they are being used effectively. It demonstrably supports business process.		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 asset management plan consistently documents responsibilities for the delivery actions, and there is adequate detail to enable delivery of actions. Designated responsibility and authority for achievement ofasset plan actions is appropriate.		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)	3	WE's arrangements fully cover all the requirements for the efficient and cost-effective implementation of the asset management plan, and realistically address the resources and timescales required, and any changes needed to functional policies, standards, processes and the asset management information system. A long term strategic resource map relative to asset managment organisational delivery requirements is still to be developed.		It is essential that the plan(s) are realistic and can be implemented, which requires appropriate resources to be available and enabling mechanisms in place. This question explores how well this is achieved. The plan(s) not only need to consider the resources directly required and timescales, but also the enabling activities, including for example, training requirements, supply chain capability and procurement timescales.	The management team with overall responsibility for the asset management system. Operations, maintenance and engineering managers. If appropriate, the performance management team. If appropriate, the performance management team. Where appropriate the procurement team and service providers working on the organisation's asset-related activities.	The organisation's asset management plan(s). Documented processes and procedures for the delivery of the asset management plan.
33	Contingency planning	What plan(s) and procedure(s) does the organisation have for identifying and responding to incidents and emergency situations and ensuring continuity of critical asset management activities?	3	Emergency management for credible events has been planned and practiced. Further stategies for specific crisis events have been developed.		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	**Wellington Electricity**
AMP Planning Period	**1 April 2015 – 31 March 2025**
Asset Management Standard Applied	**PAS 55**

SCHEDULE 13: REPORT ON ASSET MANAGEMENT MATURITY (cont)

Question No.	Function	Question	Maturity Level 0	Maturity Level 1	Maturity Level 2	Maturity Level 3	Maturity Level 4
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?	The organisation does not have plan(s) or their distribution is limited to the authors.	The plan(s) are communicated to some of those responsible for delivery of the plan(s). OR Communicated to those responsible for delivery is either irregular or ad-hoc.	The plan(s) are communicated to most of those responsible for delivery but there are weaknesses in identifying relevant parties resulting in incomplete or inappropriate communication. The organisation recognises improvement is needed as is working towards resolution.	The plan(s) are communicated to all relevant employees, stakeholders and contracted service providers to a level of detail appropriate to their participation or business interests in the delivery of the plan(s) and there is confirmation that they are being used effectively.	The organisation's process(es) surpass the standard required to comply with requirements set out in a recognised standard. The assessor is advised to note in the Evidence section why this is the case and the evidence seen.
29	Asset management plan(s)	How are designated responsibilities for delivery of asset plan actions documented?	The organisation has not documented responsibilities for delivery of asset plan actions.	Asset management plan(s) inconsistently document responsibilities for delivery of plan actions and activities and/or responsibilities and authorities for implementation inadequate and/or delegation level inadequate to ensure effective delivery and/or contain misalignments with organisational accountability.	Asset management plan(s) consistently document responsibilities for the delivery of actions but responsibility/authority levels are inappropriate/ inadequate, and/or there are misalignments within the organisation.	Asset management plan(s) consistently document responsibilities for the delivery actions and there is adequate detail to enable delivery of actions. Designated responsibility and authority for achievement of asset plan actions is appropriate.	The organisation's process(es) surpass the standard required to comply with requirements set out in a recognised standard. The assessor is advised to note in the Evidence section why this is the case and the evidence seen.
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)	The organisation has not considered the arrangements needed for the effective implementation of plan(s).	The organisation recognises the need to ensure appropriate arrangements are in place for implementation of asset management plan(s) and is in the process of determining an appropriate approach for achieving this.	The organisation has arrangements in place for the implementation of asset management plan(s) but the arrangements are not yet adequately efficient and/or effective. The organisation is working to resolve existing weaknesses.	The organisation's arrangements fully cover all the requirements for the efficient and cost effective implementation of asset management plan(s) and realistically address the resources and timescales required, and any changes needed to functional policies, standards, processes and the asset management information system.	The organisation's process(es) surpass the standard required to comply with requirements set out in a recognised standard. The assessor is advised to note in the Evidence section why this is the case and the evidence seen.
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?	The organisation has not considered the need to establish plan(s) and procedure(s) to identify and respond to incidents and emergency situations.	The organisation has some ad-hoc arrangements to deal with incidents and emergency situations, but these have been developed on a reactive basis in response to specific events that have occurred in the past.	Most credible incidents and emergency situations are identified. Either appropriate plan(s) and procedure(s) are incomplete for critical activities or they are inadequate. Training/ external alignment may be incomplete.	Appropriate emergency plan(s) and procedure(s) are in place to respond to credible incidents and manage continuity of critical asset management activities consistent with policies and asset management objectives. Training and external agency alignment is in place.	The organisation's process(es) surpass the standard required to comply with requirements set out in a recognised standard. The assessor is advised to note in the Evidence section why this is the case and the evidence seen.

Company Name	**Wellington Electricity**
AMP Planning Period	**1 April 2015 – 31 March 2025**
Asset Management Standard Applied	**PAS 55**

SCHEDULE 13: REPORT ON ASSET MANAGEMENT MATURITY (cont)

Question No.	Function	Question	Score	Evidence—Summary	User Guidance	Why	Who	Record/documented Information
37	Structure, authority and responsibilities	What has the organisation done to appoint member(s) of its management team to be responsible for ensuring that the organisation's assets deliver the requirements of the asset management strategy, objectives and plan(s)?	3	Accountability for asset management responsibility from CEO, through Network GM and through Network Team functional Line Managers.		In order to ensure that the organisation's assets and asset systems deliver the requirements of the asset management policy, strategy and objectives responsibilities need to be allocated to appropriate people who have the necessary authority to fulfil their responsibilities. (This question, relates to the organisation's assets eg, para b), s 4.4.1 of PAS 55, making it therefore distinct from the requirement contained in para a), s 4.4.1 of PAS 55).	Top management. People with management responsibility for the delivery of asset management policy, strategy, objectives and plan(s). People working on asset-related activities.	Evidence that managers with responsibility for the delivery of asset management policy, strategy, objectives and plan(s) have been appointed and have assumed their responsibilities. Evidence may include the organisation's documents relating to its asset management system, organisational charts, job descriptions of post-holders, annual targets/objectives and personal development plan(s) of post-holders as appropriate.
40	Structure, authority and responsibilities	What evidence can the organisation's top management provide to demonstrate that sufficient resources are available for asset management?	3	An effective process exists for determining the resources needed for asset management and that sufficient resources are available. It can be demonstrated that resources are matched to asset management requirements. A long term strategic resource map relative to asset management organisational delivery requirements is to be developed.		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	Communication is guided through the annual AMP disclosures and through weekly and monthly performance meetings with management teams and contractors.		Widely used AM practice standards require an organisation to communicate the importance of meeting its asset management requirements such that personnel fully understand, take ownership of, and are fully engaged in the delivery of the asset management requirements (eg, PAS 55 s 4.4.1 g).	Top management. The management team that has overall responsibility for asset management. People involved in the delivery of the asset management requirements.	Evidence of such activities as road shows, written bulletins, workshops, team talks and management walk-abouts would assist an organisation to demonstrate it is meeting this requirement of PAS 55.
45	Outsourcing of asset management activities	Where the organisation has outsourced some of its asset management activities, how has it ensured that appropriate controls are in place to ensure the compliant delivery of its organisational strategic plan, and its asset management policy and strategy?	2	Whilst significant controls are in place to manage the delivery of AM activities within the outsourced contractors, there are gaps in AM strategy communication and contractor process control. In particular these are with maintenance and reactive fault quality assurance management.		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	Maturity Level 0	Maturity Level 1	Maturity Level 2	Maturity Level 3	Maturity Level 4
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)?	Top management has not considered the need to appoint a person or persons to ensure that the organisation's assets deliver the requirements of the asset management strategy, objectives and plan(s).	Top management understands the need to appoint a person or persons to ensure that the organisation's assets deliver the requirements of the asset management strategy, objectives and plan(s).	Top management has appointed an appropriate people to ensure the assets deliver the requirements of the asset management strategy, objectives and plan(s) but their areas of responsibility are not fully defined and/or they have insufficient delegated authority to fully execute their responsibilities.	The appointed person or persons have full responsibility for ensuring that the organisation's assets deliver the requirements of the asset management strategy, objectives and plan(s). They have been given the necessary authority to achieve this.	The organisation's process(es) surpass the standard required to comply with requirements set out in a recognised standard. The assessor is advised to note in the Evidence section why this is the case and the evidence seen.
40	Structure, authority and responsibilities	What evidence can the organisation's top management provide to demonstrate that sufficient resources are available for asset management?	The organisation's top management has not considered the resources required to deliver asset management.	The organisations top management understands the need for sufficient resources but there are no effective mechanisms in place to ensure this is the case.	A process exists for determining what resources are required for its asset management activities and in most cases these are available but in some instances resources remain insufficient.	An effective process exists for determining the resources needed for asset management and sufficient resources are available. It can be demonstrated that resources are matched to asset management requirements.	The organisation's process(es) surpass the standard required to comply with requirements set out in a recognised standard. The assessor is advised to note in the Evidence section why this is the case and the evidence seen.
42	Structure, authority and responsibilities	To what degree does the organisation's top management communicate the importance of meeting its asset management requirements?	The organisation's top management has not considered the need to communicate the importance of meeting asset management requirements.	The organisations top management understands the need to communicate the importance of meeting its asset management requirements but does not do so.	Top management communicates the importance of meeting its asset management requirements but only to parts of the organisation.	Top management communicates the importance of meeting its asset management requirements to all relevant parts of the organisation.	The organisation's process(es) surpass the standard required to comply with requirements set out in a recognised standard. The assessor is advised to note in the Evidence section why this is the case and the evidence seen.
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?	The organisation has not considered the need to put controls in place.	The organisation controls its outsourced activities on an ad-hoc basis, with little regard for ensuring for the compliant delivery of the organisational strategic plan and/or its asset management policy and strategy.	Controls systematically considered but currently only provide for the compliant delivery of some, but not all, aspects of the organisational strategic plan and/or its asset management policy and strategy. Gaps exist.	Evidence exists to demonstrate that outsourced activities are appropriately controlled to provide for the compliant delivery of the organisational strategic plan, asset management policy and strategy, and that these controls are integrated into the asset management system	The organisation's process(es) surpass the standard required to comply with requirements set out in a recognised standard. The assessor is advised to note in the Evidence section why this is the case and the evidence seen.

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SCHEDULE 13: REPORT ON ASSET MANAGEMENT MATURITY (cont)

Question No.	Function	Question	Score	Evidence—Summary	User Guidance	Why	Who	Record/documented Information
48	Training, awareness and competence	How does the organisation develop plan(s) for the human resources required to undertake asset management activities - including the development and delivery of asset management strategy, process(es), objectives and plan(s)?	3	WE can demonstrate that plans are in place and effective in matching competencies and capabilities to the asset management system including the plan for both internal and contracted activities. Plans are reviewed integral to asset management system processes. The organisation's arrangements fully cover all the requirements for the efficient and cost-effective implementation of asset management plans and realistically address the resources and timescales required, and any changes neeeded to functional policies, standards, processes and the asset management information system. A long term strategic resource map relative to asset management organisational delivery requirements is to be developed.		There is a need for an organisation to demonstrate that it has considered what resources are required to develop and implement its asset management system. There is also a need for the organisation to demonstrate that it has assessed what development plan(s) are required to provide its human resources with the skills and competencies to develop and implement its asset management systems. The timescales over which the plan(s) are relevant should be commensurate with the planning horizons within the asset management strategy considers e.g. if the asset management strategy considers 5, 10 and 15 year time scales then the human resources development plan(s) should align with these. Resources include both 'in house' and external resources who undertake asset management activities.	Senior management responsible for agreement of plan(s). Managers responsible for developing asset management strategy and plan(s). Managers with responsibility for development and recruitment of staff (including HR functions). Staff responsible for training. Procurement officers. Contracted service providers.	Evidence of analysis of future work load plan(s) in terms of human resources. Document(s) containing analysis of the organisation's own direct resources and contractors resource capability over suitable timescales. Evidence, such as minutes of meetings, that suitable management forums are monitoring human resource development plan(s). Training plan(s), personal development plan(s), contract and service level agreements.
49	Training, awareness and competence	How does the organisation identify competency requirements and then plan, provide and record the training necessary to achieve the competencies?	3	There is the requirement for defined levels of management, technical and AM competencies through job descriptions and standard key competency requirements. These are reviewed six monthly through performance reviews. Thse are also being reviewed with the intention of developing and AM competencies framework wtihin the company.		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	There is the requirement for defined levels of management, technical and AM competencies through job descriptions and standard key competency requirements. These are reviewed six monthly through performance reviews. Thse are also being reviewed with the intention of developing and AM competencies framework wtihin the company.		A critical success factor for the effective development and implementation of an asset management system is the competence of persons undertaking these activities. organisations should have effective means in place for ensuring the competence of employees to carry out their designated asset management function(s). Where an organisation has contracted service providers undertaking elements of its asset management system then the organisation shall assure itself that the outsourced service provider also has suitable arrangements in place to manage the competencies of its employees. The organisation should ensure that the individual and corporate competencies it requires are in place and actively monitor, develop and maintain an appropriate balance of these competencies.	Managers, supervisors, persons responsible for developing training programmes. Staff responsible for procurement and service agreements. HR staff and those responsible for recruitment.	Evidence of a competency assessment framework that aligns with established frameworks such as the asset management Competencies Requirements Framework (Version 2.0); National Occupational Standards for Management and Leadership; UK Standard for Professional Engineering Competence, Engineering Council, 2005.

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SCHEDULE 13: REPORT ON ASSET MANAGEMENT MATURITY (cont)

Question No.	Function	Question	Maturity Level 0	Maturity Level 1	Maturity Level 2	Maturity Level 3	Maturity Level 4
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)?	The organisation has not recognised the need for assessing human resources requirements to develop and implement its asset management system.	The organisation has recognised the need to assess its human resources requirements and to develop a plan(s). There is limited recognition of the need to align these with the development and implementation of its asset management system.	The organisation has developed a strategic approach to aligning competencies and human resources to the asset management system including the asset management plan but the work is incomplete or has not been consistently implemented.	The organisation can demonstrate that plan(s) are in place and effective in matching competencies and capabilities to the asset management system including the plan for both internal and contracted activities. Plans are reviewed integral to asset management system process(es).	The organisation's process(es) surpass the standard required to comply with requirements set out in a recognised standard. The assessor is advised to note in the Evidence section why this is the case and the evidence seen.
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?	The organisation does not have any means in place to identify competency requirements.	The organisation has recognised the need to identify competency requirements and then plan, provide and record the training necessary to achieve the competencies.	The organisation is the process of identifying competency requirements aligned to the asset management plan(s) and then plan, provide and record appropriate training. It is incomplete or inconsistently applied.	Competency requirements are in place and aligned with asset management plan(s). Plans are in place and effective in providing the training necessary to achieve the competencies. A structured means of recording the competencies achieved is in place.	The organisation's process(es) surpass the standard required to comply with requirements set out in a recognised standard. The assessor is advised to note in the Evidence section why this is the case and the evidence seen.
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?	The organization has not recognised the need to assess the competence of person(s) undertaking asset management related activities.	Competency of staff undertaking asset management related activities is not managed or assessed in a structured way, other than formal requirements for legal compliance and safety management.	The organization is in the process of putting in place a means for assessing the competence of person(s) involved in asset management activities including contractors. There are gaps and inconsistencies.	Competency requirements are identified and assessed for all persons carrying out asset management related activities - internal and contracted. Requirements are reviewed and staff reassessed at appropriate intervals aligned to asset management requirements.	The organisation's process(es) surpass the standard required to comply with requirements set out in a recognised standard. The assessor is advised to note in the Evidence section why this is the case and the evidence seen.

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SCHEDULE 13: REPORT ON ASSET MANAGEMENT MATURITY (cont)

Question No.	Function	Question	Score	Evidence—Summary	User Guidance	Why	Who	Record/documented Information
53	Communication, participation and consultation	How does the organisation ensure that pertinent asset management information is effectively communicated to and from employees and other stakeholders, including contracted service providers?	3	In addition to the annual AMP disclosure, regular contract meetings are held between Safety, Operations, Maintenance, Planning and Capital delivery managers and the respective contractors. In addition, specific asset management information is communicated directly to employees and contractors via safety alerts, technical alerts, and network instructions.		Widely used AM practice standards require that pertinent asset management information is effectively communicated to and from employees and other stakeholders including contracted service providers. Pertinent information refers to information required in order to effectively and efficiently comply with and deliver asset management strategy, plan(s) and objectives. This will include for example the communication of the asset management policy, asset performance information, and planning information as appropriate to contractors.	Top management and senior management representative(s), employee's representative(s), employee's trade union representative(s); contracted service provider management and employee representative(s); representative(s) from the organisation's Health, Safety and Environmental team. Key stakeholder representative(s).	Asset management policy statement prominently displayed on notice boards, intranet and internet; use of organisation's website for displaying asset performance data; evidence of formal briefings to employees, stakeholders and contracted service providers; evidence of inclusion of asset management issues in team meetings and contracted service provider contract meetings; newsletters, etc.
59	Asset Management System documentation	What documentation has the organisation established to describe the main elements of its asset management system and interactions between them?	2	The AMP describes the key attributes of an asset management system, however there are gaps in the overall completeness of that system An effective architectural overview document would provide this visibility and connectivity.		Widely used AM practice standards require an organisation maintain up to date documentation that ensures that its asset management systems (ie, the systems the organisation has in place to meet the standards) can be understood, communicated and operated. (eg, s 4.5 of PAS 55 requires the maintenance of up to date documentation of the asset management system requirements specified throughout s 4 of PAS 55).	The management team that has overall responsibility for asset management. Managers engaged in asset management activities.	The documented information describing the main elements of the asset management system (process(es)) and their interaction.
62	Information management	What has the organisation done to determine what its asset management information system(s) should contain in order to support its asset management system?	3	Various systems are in place for the management of asset management information and data. The primary record of asset information is GIS, with maintenance records being held in SAP-PM.		Effective asset management requires appropriate information to be available. Widely used AM standards therefore require the organisation to identify the asset management information it requires in order to support its asset management system. Some of the information required may be held by suppliers. The maintenance and development of asset management information systems is a poorly understood specialist activity that is akin to IT management but different from IT management. This group of questions provides some indications as to whether the capability is available and applied. Note: To be effective, an asset information management system requires the mobilisation of technology, people and process(es) that create, secure, make available and destroy the information required to support the asset management system.	The organisation's strategic planning team. The management team that has overall responsibility for asset management. Information management team. Operations, maintenance and engineering managers	Details of the process the organisation has employed to determine what its asset information system should contain in order to support its asset management system. Evidence that this has been effectively implemented.
63	Information management	How does the organisation maintain its asset management information system(s) and ensure that the data held within it (them) is of the requisite quality and accuracy and is consistent?	3	Controls are in place to manage the quality of the data entered into the asset management system. Development and training is being carried out to manage the consistency of the data collected.		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	Maturity Level 0	Maturity Level 1	Maturity Level 2	Maturity Level 3	Maturity Level 4
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?	The organisation has not recognised the need to formally communicate any asset management information.	There is evidence that the pertinent asset management information to be shared along with those to share it with is being determined.	The organisation has determined pertinent information and relevant parties. Some effective two way communication is in place but as yet not all relevant parties are clear on their roles and responsibilities with respect to asset management information.	Two way communication is in place between all relevant parties, ensuring that information is effectively communicated to match the requirements of asset management strategy, plan(s) and process(es). Pertinent asset information requirements are regularly reviewed.	The organisation's process(es) surpass the standard required to comply with requirements set out in a recognised standard. The assessor is advised to note in the Evidence section why this is the case and the evidence seen.
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?	The organisation has not established documentation that describes the main elements of the asset management system.	The organisation is aware of the need to put documentation in place and is in the process of determining how to document the main elements of its asset management system.	The organisation in the process of documenting its asset management system and has documentation in place that describes some, but not all, of the main elements of its asset management system and their interaction.	The organisation has established documentation that comprehensively describes all the main elements of its asset management system and the interactions between them. The documentation is kept up to date.	The organisation's process(es) surpass the standard required to comply with requirements set out in a recognised standard. The assessor is advised to note in the Evidence section why this is the case and the evidence seen.
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?	The organisation has not considered what asset management information is required.	The organisation is aware of the need to determine in a structured manner what its asset information system should contain in order to support its asset management system and is in the process of deciding how to do this.	The organisation has developed a structured process to determine what its asset information system should contain in order to support its asset management system and has commenced implementation of the process.	The organisation has determined what its asset information system should contain in order to support its asset management system. The requirements relate to the whole life cycle and cover information originating from both internal and external sources.	The organisation's process(es) surpass the standard required to comply with requirements set out in a recognised standard. The assessor is advised to note in the Evidence section why this is the case and the evidence seen.
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?	There are no formal controls in place or controls are extremely limited in scope and/or effectiveness.	The organisation is aware of the need for effective controls and is in the process of developing an appropriate control process(es).	The organisation has developed a controls that will ensure the data held is of the requisite quality and accuracy and is consistent and is in the process of implementing them.	The organisation has effective controls in place that ensure the data held is of the requisite quality and accuracy and is consistent. The controls are regularly reviewed and improved where necessary.	The organisation's process(es) surpass the standard required to comply with requirements set out in a recognised standard. The assessor is advised to note in the Evidence section why this is the case and the evidence seen.

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SCHEDULE 13: REPORT ON ASSET MANAGEMENT MATURITY (cont)

Question No.	Function	Question	Score	Evidence—Summary	User Guidance	Why	Who	Record/documented Information
64	Information management	How has the organisation's ensured its asset management information system is relevant to its needs?	3	Asset management processes were fully reviewed during development of the business case to implement SAP PM, ensuring that they meet Wellington Electricity's requirements.		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	Asset related risk controls have been implemented as part of the risk management framework. There are however gaps surrounding the risks associated with each stage of the lifecycle of assets.		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?	3	Outputs from risk assessments are fed back into standards, procedures and training through the actions resulting from weekly risk review meetings.		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	There is a formal mechanism for ensuring we are meeting our reporting obligations. The Regulatory Analyst formally checks with the responsible person whether they are on track for meeting the requirements that are due.		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	Maturity Level 0	Maturity Level 1	Maturity Level 2	Maturity Level 3	Maturity Level 4
64	Information management	How has the organisation's ensured its asset management information system is relevant to its needs?	The organisation has not considered the need to determine the relevance of its management information system. At present there are major gaps between what the information system provides and the organisations needs.	The organisation understands the need to ensure its asset management information system is relevant to its needs and is determining an appropriate means by which it will achieve this. At present there are significant gaps between what the information system provides and the organisations needs.	The organisation has developed and is implementing a process to ensure its asset management information system is relevant to its needs. Gaps between what the information system provides and the organisations needs have been identified and action is being taken to close them.	The organisation's asset management information system aligns with its asset management requirements. Users can confirm that it is relevant to their needs.	The organisation's process(es) surpass the standard required to comply with requirements set out in a recognised standard. The assessor is advised to note in the Evidence section why this is the case and the evidence seen.
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?	The organisation has not considered the need to document process(es) and/or procedure(s) for the identification and assessment of asset and asset management related risks throughout the asset life cycle.	The organisation is aware of the need to document the management of asset related risk across the asset lifecycle. The organisation has plan(s) to formally document all relevant process(es) and procedure(s) or has already commenced this activity.	The organisation is in the process of documenting the identification and assessment of asset related risk across the asset lifecycle but it is incomplete or there are inconsistencies between approaches and a lack of integration.	Identification and assessment of asset related risk across the asset lifecycle is fully documented. The organisation can demonstrate that appropriate documented mechanisms are integrated across life cycle phases and are being consistently applied.	The organisation's process(es) surpass the standard required to comply with requirements set out in a recognised standard. The assessor is advised to note in the Evidence section why this is the case and the evidence seen.
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?	The organisation has not considered the need to conduct risk assessments.	The organisation is aware of the need to consider the results of risk assessments and effects of risk control measures to provide input into reviews of resources, training and competency needs. Current input is typically ad-hoc and reactive.	The organisation is in the process ensuring that outputs of risk assessment are included in developing requirements for resources and training. The implementation is incomplete and there are gaps and inconsistencies.	Outputs from risk assessments are consistently and systematically used as inputs to develop resources, training and competency requirements. Examples and evidence is available.	The organisation's process(es) surpass the standard required to comply with requirements set out in a recognised standard. The assessor is advised to note in the Evidence section why this is the case and the evidence seen.
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?	The organisation has not considered the need to identify its legal, regulatory, statutory and other asset management requirements.	The organisation identifies some its legal, regulatory, statutory and other asset management requirements, but this is done in an ad-hoc manner in the absence of a procedure.	The organisation has procedure(s) to identify its legal, regulatory, statutory and other asset management requirements, but the information is not kept up to date, inadequate or inconsistently managed.	Evidence exists to demonstrate that the organisation's legal, regulatory, statutory and other asset management requirements are identified and kept up to date. Systematic mechanisms for identifying relevant legal and statutory requirements.	The organisation's process(es) surpass the standard required to comply with requirements set out in a recognised standard. The assessor is advised to note in the Evidence section why this is the case and the evidence seen.

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SCHEDULE 13: REPORT ON ASSET MANAGEMENT MATURITY (cont)

Question No.	Function	Question	Score	Evidence—Summary	User Guidance	Why	Who	Record/documented Information
88	Life Cycle Activities	How does the organisation establish implement and maintain process(es) for the implementation of its asset management plan(s) and control of activities across the creation, acquisition or enhancement of assets. This includes design, modification, procurement, construction and commissioning activities?	2	There are asset management policies, procedures and processes in place which deal with the management of assets during the design to commissioning phases. There are procedures to determine how these are derived and prioritised within the asset management plan. There are gaps covering projects accelerated and not included within the AMP, together with works management quality monitoring. These gaps are being addressed.		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?	3	There is a general inspection plan in place with remedial actions derived around prioritisation of critical defects. Further work is being carried out in standardising the level of consistency across the inspection and condition assessment process, and how the results are then optimised within the maintenance planning function. These plans are reviewed and optimised on an annual basis.		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?	3	A detailed inspection plan is in place with identified and remediated defects reported to the Senior Management Team on a monthly basis. Although the majority of measures are reactive in application, leading asset condition and performance measure indicators have been introduced and are driving changes in pefromance management. Gaps in data and data quality exist, however this is being addressed through a proactive audit process.		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?	3	Wellington Electricity has procedures that clearly outline the roles and responsibilities for managing incident and emergency situations. The asset failure investigation standard describes the process and responsibilities for investigating asset-related failures.		Widely used AM standards require that the organisation establishes implements and maintains process(es) for the handling and investigation of failures incidents and non-conformities for assets and sets down a number of expectations. Specifically this question examines the requirement to define clearly responsibilities and authorities for these activities, and communicate these unambiguously to relevant people including external stakeholders if appropriate.	The organisation's safety and environment management team. The team with overall responsibility for the management of the assets. People who have appointed roles within the asset-related investigation procedure, from those who carry out the investigations to senior management who review the recommendations. Operational controllers responsible for managing the asset base under fault conditions and maintaining services to consumers. Contractors and other third parties as appropriate.	Process(es) and procedure(s) for the handling, investigation and mitigation of asset-related failures, incidents and emergency situations and non conformances. Documentation of assigned responsibilities and authority to employees. Job Descriptions, Audit reports. Common communication systems i.e. all Job Descriptions on Internet etc.

Company Name	**Wellington Electricity**
AMP Planning Period	**1 April 2015 – 31 March 2025**
Asset Management Standard Applied	**PAS 55**

SCHEDULE 13: REPORT ON ASSET MANAGEMENT MATURITY (cont)

Question No.	Function	Question	Maturity Level 0	Maturity Level 1	Maturity Level 2	Maturity Level 3	Maturity Level 4
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?	The organisation does not have process(es) in place to manage and control the implementation of asset management plan(s) during activities related to asset creation including design, modification, procurement, construction and commissioning.	The organisation is aware of the need to have process(es) and procedure(s) in place to manage and control the implementation of asset management plan(s) during activities related to asset creation including design, modification, procurement, construction and commissioning but currently do not have these in place (note: procedure(s) may exist but they are inconsistent/incomplete).	The organisation is in the process of putting in place process(es) and procedure(s) to manage and control the implementation of asset management plan(s) during activities related to asset creation including design, modification, procurement, construction and commissioning. Gaps and inconsistencies are being addressed.	Effective process(es) and procedure(s) are in place to manage and control the implementation of asset management plan(s) during activities related to asset creation including design, modification, procurement, construction and commissioning.	The organisation's process(es) surpass the standard required to comply with requirements set out in a recognised standard. The assessor is advised to note in the Evidence section why this is the case and the evidence seen.
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?	The organisation does not have process(es)/procedure(s) in place to control or manage the implementation of asset management plan(s) during this life cycle phase.	The organisation is aware of the need to have process(es) and procedure(s) in place to manage and control the implementation of asset management plan(s) during this life cycle phase but currently do not have these in place and/or there is no mechanism for confirming they are effective and where needed modifying them.	The organisation is in the process of putting in place process(es) and procedure(s) to manage and control the implementation of asset management plan(s) during this life cycle phase. They include a process for confirming the process(es)/procedure(s) are effective and if necessary carrying out modifications.	The organisation has in place process(es) and procedure(s) to manage and control the implementation of asset management plan(s) during this life cycle phase. They include a process, which is itself regularly reviewed to ensure it is effective, for confirming the process(es)/ procedure(s) are effective and if necessary carrying out modifications.	The organisation's process(es) surpass the standard required to comply with requirements set out in a recognised standard. The assessor is advised to note in the Evidence section why this is the case and the evidence seen.
95	Performance and condition monitoring	How does the organisation measure the performance and condition of its assets?	The organisation has not considered how to monitor the performance and condition of its assets.	The organisation recognises the need for monitoring asset performance but has not developed a coherent approach. Measures are incomplete, predominantly reactive and lagging. There is no linkage to asset management objectives.	The organisation is developing coherent asset performance monitoring linked to asset management objectives. Reactive and proactive measures are in place. Use is being made of leading indicators and analysis. Gaps and inconsistencies remain.	Consistent asset performance monitoring linked to asset management objectives is in place and universally used including reactive and proactive measures. Data quality management and review process are appropriate. Evidence of leading indicators and analysis.	The organisation's process(es) surpass the standard required to comply with requirements set out in a recognised standard. The assessor is advised to note in the Evidence section why this is the case and the evidence seen.
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?	The organisation has not considered the need to define the appropriate responsibilities and the authorities.	The organisation understands the requirements and is in the process of determining how to define them.	The organisation are in the process of defining the responsibilities and authorities with evidence. Alternatively there are some gaps or inconsistencies in the identified responsibilities/authorities.	The organisation have defined the appropriate responsibilities and authorities and evidence is available to show that these are applied across the business and kept up to date.	The organisation's process(es) surpass the standard required to comply with requirements set out in a recognised standard. The assessor is advised to note in the Evidence section why this is the case and the evidence seen.

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AMP Planning Period	**1 April 2015 – 31 March 2025**
Asset Management Standard Applied	**PAS 55**

SCHEDULE 13: REPORT ON ASSET MANAGEMENT MATURITY (cont)

Question No.	Function	Question	Score	Evidence—Summary	User Guidance	Why	Who	Record/documented Information
105	Audit	What has the organisation done to establish procedure(s) for the audit of its asset management system (process(es))?	2	Whilst the audit programme is mature and targeted to areas of risk and quality delivery, there are some areas of the asset management system and process that are not covered within the current audit regime.		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?	3	Incidents and root cause analysis investigations and corrective actions are logged, reviewed and discussed at a weekly Network Management Team meeting.		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	Continual improvement and optimisation of asset health, costs and risks across the whole asset lifecycle are in place although need to be finalised and fully implemented and embedded. Continuous improvement processes are set out and include consideration of cost, risk, performance and condition for assets managed across the whole lifecycle but it is not yet being systematically applied.		Widely used AM standards have requirements to establish, implement and maintain process(es)/procedure(s) for identifying, assessing, prioritising and implementing actions to achieve continual improvement. Specifically there is a requirement to demonstrate continual improvement in optimisation of cost risk and performance/condition of assets across the life cycle. This question explores an organisation's capabilities in this area—looking for systematic improvement mechanisms rather that reviews and audit (which are separately examined).	The top management of the organisation. The manager/team responsible for managing the organisation's asset management system, including its continual improvement. Managers responsible for policy development and implementation.	Records showing systematic exploration of improvement. Evidence of new techniques being explored and implemented. Changes in procedure(s) and process(es) reflecting improved use of optimisation tools/techniques and available information. Evidence of working parties and research.
115	Continual Improvement	How does the organisation seek and acquire knowledge about new asset management related technology and practices, and evaluate their potential benefit to the organisation?	3	Being part of a wider international group, WE does place a high level of importance on learnings that can be made from sister companies within the group and from within the industry in New Zealand.		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.

Company Name	**Wellington Electricity**
AMP Planning Period	**1 April 2015 – 31 March 2025**
Asset Management Standard Applied	**PAS 55**

SCHEDULE 13: REPORT ON ASSET MANAGEMENT MATURITY (cont)

Question No.	Function	Question	Maturity Level 0	Maturity Level 1	Maturity Level 2	Maturity Level 3	Maturity Level 4
105	Audit	What has the organisation done to establish procedure(s) for the audit of its asset management system (process(es))?	The organisation has not recognised the need to establish procedure(s) for the audit of its asset management system.	The organisation understands the need for audit procedure(s) and is determining the appropriate scope, frequency and methodology(s).	The organisation is establishing its audit procedure(s) but they do not yet cover all the appropriate asset-related activities.	The organisation can demonstrate that its audit procedure(s) cover all the appropriate asset-related activities and the associated reporting of audit results. Audits are to an appropriate level of detail and consistently managed.	The organisation's process(es) surpass the standard required to comply with requirements set out in a recognised standard. The assessor is advised to note in the Evidence section why this is the case and the evidence seen.
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?	The organisation does not recognise the need to have systematic approaches to instigating corrective or preventive actions.	The organisation recognises the need to have systematic approaches to instigating corrective or preventive actions. There is ad-hoc implementation for corrective actions to address failures of assets but not the asset management system.	The need is recognized for systematic instigation of preventive and corrective actions to address root causes of non compliance or incidents identified by investigations, compliance evaluation or audit. It is only partially or inconsistently in place.	Mechanisms are consistently in place and effective for the systematic instigation of preventive and corrective actions to address root causes of non compliance or incidents identified by investigations, compliance evaluation or audit.	The organisation's process(es) surpass the standard required to comply with requirements set out in a recognised standard. The assessor is advised to note in the Evidence section why this is the case and the evidence seen.
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?	The organisation does not consider continual improvement of these factors to be a requirement, or has not considered the issue.	A Continual Improvement ethos is recognised as beneficial, however it has just been started, and or covers partially the asset drivers.	Continuous improvement process(es) are set out and include consideration of cost risk, performance and condition for assets managed across the whole life cycle but it is not yet being systematically applied.	There is evidence to show that continuous improvement process(es) which include consideration of cost risk, performance and condition for assets managed across the whole life cycle are being systematically applied.	The organisation's process(es) surpass the standard required to comply with requirements set out in a recognised standard. The assessor is advised to note in the Evidence section why this is the case and the evidence seen.
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?	The organisation makes no attempt to seek knowledge about new asset management related technology or practices.	The organisation is inward looking, however it recognises that asset management is not sector specific and other sectors have developed good practice and new ideas that could apply. Ad-hoc approach.	The organisation has initiated asset management communication within sector to share and, or identify 'new' to sector asset management practices and seeks to evaluate them.	The organisation actively engages internally and externally with other asset management practitioners, professional bodies and relevant conferences. Actively investigates and evaluates new practices and evolves its asset management activities using appropriate developments.	The organisation's process(es) surpass the standard required to comply with requirements set out in a recognised standard. The assessor is advised to note in the Evidence section why this is the case and the evidence seen.

Mandatory Explanatory Notes on Forecast Information

(In this Schedule, clause references are to the Electricity Distribution Information Disclosure Determination 2012)

This Schedule provides for EDBs to provide explanatory notes to reports prepared in accordance with clause 2.6.5.

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)

In the box below, comment on the difference between nominal and constant price capital expenditure for the disclosure year, as disclosed in Schedule 11a.

Box 1: Commentary on difference between nominal and constant price capital expenditure forecasts

Network and Non-network capital expenditure:

The difference represents inflation and is as follows:
2016 (1.74%); 2017 (2.11%); 2018 (2.17%); 2019 (2.11%); 2020 (2.06%); 2021 to 2025 (2.04%).

The rates from 2016 to 2020 were provided by the Commerce Commission. The rates for the five years thereafter are an average of the previous five.

Commentary on difference between nominal and constant price operational expenditure forecasts (Schedule 11b)

In the box below, comment on the difference between nominal and constant price operational expenditure for the disclosure year, as disclosed in Schedule 11b.

Box 2: Commentary on difference between nominal and constant price operational expenditure forecasts

The difference represents inflation and is as follows:

2016 (1.74%); 2017 (2.11%); 2018 (2.17%); 2019 (2.11%); 2020 (2.06%); 2021 to 2025 (2.04%).

The rates from 2016 to 2020 were provided by the Commerce Commission. The rates for the five years thereafter are an average of the previous five.

Appendix E Summary of AMP Coverage of Information Disclosure Requirements

Information Disclosure Requirements 2012 clause	AMP section
3.1 A summary that provides a brief overview of the contents and highlights information that the **EDB** considers significant	1
3.2 Details of the background and objectives of the **EDB**'s asset management and planning processes	3.3
3.3 A purpose statement which- 3.3.1 makes clear the purpose and status of the **AMP** in the **EDB**'s asset management practices. The purpose statement must also include a statement of the objectives of the asset management and planning processes 3.3.2 states the corporate mission or vision as it relates to asset management 3.3.3 identifies the documented plans produced as outputs of the annual business planning process adopted by the **EDB** 3.3.4 states how the different documented plans relate to one another, with particular reference to any plans specifically dealing with asset management 3.3.5 includes a description of the interaction between the objectives of the **AMP** and other corporate goals, business planning processes, and plans	2.1 2.6, 3.1 2.6 2.6 2.6, 3.1
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	2.2
3.5 The date that it was approved by the **directors**	2.1.1
3.6 A description of stakeholder interests (owners, consumers etc.) which identifies important stakeholders and indicates- 3.6.1 how the interests of stakeholders are identified 3.6.2 what these interests are 3.6.3 how these interests are accommodated in asset management practices 3.6.4 how conflicting interests are managed	2.5 2.5 2.5 2.5 2.5.2

Information Disclosure Requirements 2012 clause	AMP section
3.7 A description of the accountabilities and responsibilities for asset management on at least 3 levels, including-	
3.7.1 governance—a description of the extent of **director** approval required for key asset management decisions and the extent to which asset management outcomes are regularly reported to **directors**	2.7.2
3.7.2 executive—an indication of how the in-house asset management and planning organisation is structured	2.7.4
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	2.7.6, 10
3.8 All significant assumptions:	
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	Appendix A
3.8.5 the price inflator assumptions used to prepare the financial information disclosed in **nominal New Zealand dollars** in the Report on Forecast Capital Expenditure set out in Schedule 11a and the Report on Forecast Operational Expenditure set out in Schedule 11b.	Appendix D
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	Pgs 5 - 10
3.10 An overview of asset management strategy and delivery	3.2
3.11 An overview of systems and information management data	3.4
3.12 A statement covering any limitations in the availability or completeness of asset management data and disclose any initiatives intended to improve the quality of this data	3.4.5
3.13 A description of the processes used within the **EDB** for-	
3.13.1 managing routine asset inspections and **network** maintenance	3.3.1
3.13.2 planning and implementing **network** development projects	3.3.2, 9
3.13.3 measuring **network** performance.	7

Information Disclosure Requirements 2012 clause	AMP section
3.14 An overview of asset management documentation, controls and review processes	3.5
3.15 An overview of communication and participation processes	2.5
3.16 The **AMP** must present all financial values in **constant price New Zealand dollars** except where specified otherwise;	6, 9, 10
3.17 The **AMP** must be structured and presented in a way that the **EDB** considers will support the purposes of **AMP** disclosure set out in clause 2.6.2 of the determination.	2.1
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.	2.4 2.4 8 8
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.	6.1.5 6.1.2 6.2.3, 6.2.4 6.2.5 6.2.3, 6.2.4 6.2.7, 6.2.8
4.3 If **sub-networks** exist, the **network** configuration information referred to in subclause 4.2 above must be disclosed for each **sub-network**.	6

Information Disclosure Requirements 2012 clause	AMP section
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; 4.4.2 description and quantity of assets; 4.4.3 age profiles; and 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.	6.0 6.2 6.2 10
4.5 The asset categories discussed in subclause 4.4 above should include at least the following- 4.5.1 Sub transmission 4.5.2 Zone substations 4.5.3 Distribution and LV lines 4.5.4 Distribution and LV cables 4.5.5 Distribution substations and transformers 4.5.6 Distribution switchgear 4.5.7 Other system fixed assets 4.5.8 Other assets; 4.5.9 assets owned by the **EDB** but installed at bulk electricity supply points owned by others; 4.5.10 **EDB** owned mobile substations and generators whose function is to increase supply reliability or reduce peak demand; and 4.5.11 other generation plant owned by the **EDB**.	6.1.2 6.2.2 6.2.3 6.2.4 6.2.5 6.2.6 6.2.7 6.2.9 6.2.8
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**.	7
6. Performance indicators for which targets have been defined in clause 5 above must include **SAIDI** and **SAIFI** values for the next 5 **disclosure years**.	7.2

Information Disclosure Requirements 2012 clause	AMP section
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; 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.	2.5, 7 7.4.2
8. The **AMP** must describe the basis on which the target level for each performance indicator was determined. Justification for target levels of service includes **consumer** expectations or demands, legislative, regulatory, and other stakeholders' requirements or considerations. The **AMP** should demonstrate how stakeholder needs were ascertained and translated into service level targets.	7
9. Targets should be compared to historic values where available to provide context and scale to the reader.	7.5
10. Where forecast expenditure is expected to materially affect performance against a target defined in clause 5 above, the target should be consistent with the expected change in the level of performance.	Pgs 5 - 10
Network Development Planning 11. **AMP**s must provide a detailed description of **network** development plans, including— 11.1 A description of the planning criteria and assumptions for **network** development;	9.2
11.2 Planning criteria for network developments should be described logically and succinctly. Where probabilistic or scenario-based planning techniques are used, this should be indicated and the methodology briefly described;	9.2
11.3 A description of strategies or processes (if any) used by the **EDB** that promote cost efficiency including through the use of standardised assets and designs;	9.2.8
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; 11.4.2 the approach used to identify standard designs.	9.2.8 9.2.8
11.5 A description of strategies or processes (if any) used by the **EDB** that promote the energy efficient operation of the **network**.	9.2.3
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**.	9.2.1

Information Disclosure Requirements 2012 clause	AMP section
11.7 A description of the process and criteria used to prioritise **network** development projects and how these processes and criteria align with the overall corporate goals and vision.	9.3
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; 11.8.1 explain the load forecasting methodology and indicate all the factors used in preparing the load estimates; 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; 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 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.	8 8.1 8.5.1 9 8
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- 11.9.1 the reasons for choosing a selected option for projects where decisions have been made; 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; 11.9.3 consideration of planned innovations that improve efficiencies within the **network**, such as improved utilisation, extended asset lives, and deferred investment.	9.3 9.5.3 9.5.2
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- 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; 11.10.2 a summary description of the programmes and projects planned for the following four years (where known); and 11.10.3 an overview of the material projects being considered for the remainder of the **AMP planning period**.	9.5.6, 9.6.4, 9.7.4, 10.5 9.5.6, 9.6.4, 9.7.4, 10.5 9.5.6, 9.6.4, 9.7.4, 10.5
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.	9.2.2

Information Disclosure Requirements 2012 clause	AMP section
11.12 A description of the **EDB**'s policies on non-network solutions, including- 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 11.12.2 the potential for non-network solutions to address **network** problems or constraints.	9.2.5 9.2.5
<u>Lifecycle Asset Management Planning (Maintenance and Renewal)</u> 12. The **AMP** must provide a detailed description of the lifecycle asset management processes, including— 12.1 The key drivers for maintenance planning and assumptions; 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- 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; 12.2.2 any systemic problems identified with any particular asset types and the proposed actions to address these problems; and 12.2.3 budgets for maintenance activities broken down by asset category for the **AMP planning period**.	10.4.1 to 10.4.6
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- 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; 12.3.2 a description of innovations made that have deferred asset replacement; 12.3.3 a description of the projects currently underway or planned for the next 12 months; 12.3.4 a summary of the projects planned for the following four years (where known); and 12.3.5 an overview of other work being considered for the remainder of the **AMP planning period**. 12.4 The asset categories discussed in subclauses 12.2 and 12.3 above should include at least the categories in subclause 4.5 above.	10.4.1 to 10.4.6

Information Disclosure Requirements 2012 clause	AMP section
Non-Network Development, Maintenance and Renewal	
13. **AMP**s must provide a summary description of material non-network development, maintenance and renewal plans, including—	
13.1 a description of non-network assets;	10.5.4
13.2 development, maintenance and renewal policies that cover them;	10.5.4
13.3 a description of material capital expenditure projects (where known) planned for the next five years;	10.5.4
13.4 a description of material maintenance and renewal projects (where known) planned for the next five years.	10.5.4
14. **AMP**s must provide details of risk policies, assessment, and mitigation, including—	
14.1 Methods, details and conclusions of risk analysis;	5.2 – 5.4
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;	5.5.3
14.3 A description of the policies to mitigate or manage the risks of events identified in sub clause 14.2;	5.5.2
14.4 Details of emergency response and contingency plans.	5.6
15. AMPs must provide details of performance measurement, evaluation, and improvement, including—	
15.1 A review of progress against plan, both physical and financial;	Appendix B
15.2 An evaluation and comparison of actual service level performance against targeted performance;	7.5, 7.6
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.	Appendix C
15.4 An analysis of gaps identified in subclauses 15.2 and 15.3 above. Where significant gaps exist (not caused by one-off factors), the **AMP** must describe any planned initiatives to address the situation.	Appendix C
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;	2.8
16.2 The organisation structure and the processes for authorisation and business capabilities will support the implementation of the AMP plans.	2.8

Appendix F Glossary of Terms

AAC	All Aluminium Conductor
AAAC	All Aluminium Alloy Conductor
ABS	Air Break Switch
ACSR	Aluminium Conductor Steel Reinforced
AHI	Asset Health Indicator
AMP	Asset Management Plan
Capex	Capital Expenditure
CB	Circuit Breaker
CBD	Central Business District
CCT	Covered Conductor Thick
CEO	Chief Executive Officer
CIC	Capital Investment Committee
CKI	Cheung Kong Infrastructure Holdings Limited
CPI	Consumer Price Index
CPP	Customised Price Path
CPRG	Constant Price Revenue Growth
Cu	Copper
DC	Direct Current
DG	Distributed Generation
DGA	Dissolved Gas Analysis
DPP	Default Price-quality Path
DSA	Detailed Seismic Assessment
DTS	Distributed Temperature Sensing
EDB	Electricity Distribution Business
EDO	Expulsion Drop-out
EEA	Electricity Engineers Association
ENMAC	Electricity Network Management and Control
ERP	Emergency Response Plan
FPI	Fault Passage Indicators
GWh	Gigawatt Hour

GIS	Geographical Information System
GXP	Grid Exit Point
HILP	High Impact Low Probability
HLR	High Level Request/Response
HSE	Health, Safety and Environmental
HV	High Voltage
ICP	Installation Control Point
IEEE	Institute of Electrical and Electronic Engineers
IISC	International Infrastructure Services Company (NZ Branch)
IEP	Initial Evaluation Procedure
ISO	International Standards Organisation
km	Kilometre
KPI	Key Performance Indicator
kV	Kilovolt
kVA	Kilovolt Ampere
kW	Kilowatt
kWh	Kilowatt hour
LTI	Lost time injury
LV	Low Voltage
LVABC	Low Voltage Aerial Bundled Conductor
MAR	Maximum Allowable Revenue
MUoSA	Model Use of System Agreement
MW	Megawatt
MVA	Mega Volt Ampere
NBS	New Building Standard
NCR	Network Control Room
NDP	Network Development Plan
NICAD	Nickel Cadmium Battery
NIWA	National Institute of Water and Atmospheric Research
NPV	Net Present Value
NZTA	New Zealand Transport Agency

OD-ID	Outdoor to Indoor (conversion)
ODV	Optimised Deprival Value/Valuation
O&M	Operating and Maintenance
OLTC	On Load Tap Changer
Opex	Operational Expenditure
PAHL	Power Asset Holdings Limited
PDC	Polarisation Depolarisation Current
PIAS	Paper Insulated Aluminium Sheath Cable
PILC	Paper Insulated Lead Cable
PLC	Programmable Logic Controller
PM	Preventative Maintenance
PVC	Polyvinyl Chloride
RMU	Ring Main Unit
RTU	Remote Terminal Unit
RY	Regulatory Year (1 April – 31 March)
SAIDI	System Average Interruption Duration Index
SAIFI	System Average Interruption Frequency Index
SAP	Systems Applications and Processes
SCADA	Supervisory Control and Data Acquisition System
SF_6	Sulphur Hexafluoride
TASA	Tap Changer Activity Signature Analysis
TCA	Transformer Condition Assessment
UFB	Ultrafast Broadband
VRLA	Valve Regulated Lead Acid Battery
WCC	Wellington City Council
WELL	Wellington Electricity Lines Limited
W/S	Winter / Summer
XLPE	Cross Linked Polyethylene Cable