wellington electricity

Wellington Electricity

10 Year Asset Management Plan
1 April 2014 - 31 March 2024

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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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Any person wishing to use any information contained in this AMP should seek and take expert advice in relation to their own circumstances and rely on their own judgement and advice.

Statement from the Chief Executive Officer

Wellington Electricity welcomes the opportunity to submit an updated Asset Management Plan (AMP) for the period 2014-2024. We confirm that this AMP has been prepared, for the second time, in accordance with the Commerce Commission's more detailed *Electricity Distribution Information Disclosure Determination 2012*.

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. This is despite being tested by the largest storms the network has experienced for four decades, and earthquakes which underline the need for our buildings to be checked and remediated for seismic reinforcement.

Some of our customer service levels were not met this year due to the number of natural events we have experienced. However, excluding these one-off events, the network performed to expectations. It is pleasing to see improvement in areas where we can exert some control and influence and these improvements can be achieved quite simply by engaging with third parties to explain safer methods to undertake their work.

We continue to invest in network assets where they require replacement to ensure we operate a safe and reliable electricity delivery infrastructure. This requires good planning based on well-defined asset strategies. The Asset Management Plan plays a central role 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 outlook for New Zealand's growth and GDP. However, business confidence continues to build and this is being supported with lower unemployment figures.

Wellington Electricity provides a lifeline utility service. We are well positioned to manage through uncertainty and continue to respond well to new challenges. We operate a risk management approach to analyse the business impacts and identify how often we need to rely on our controls so that identified risks can be well managed when they do arise. This underlines the thinking behind the evaluation of our Wellington buildings and their performance if there was a major earthquake. From our perspective, it is critical to have utility equipment protected and available to operate following a major earthquake event to support the community, business and economic recovery for the region.

Following the weather related events we reviewed a number of our systems and have implemented a series of improvements to address information flows and communication. We also discussed our learnings and response to these large events with the Councils. We are looking to adopt more customer facing systems so that we can keep people informed about how power restoration response is being prioritised. We have also taken on board a number of initiatives suggested in feedback from our customers who were unsure of the ownership boundaries between our network and their service lines.

From a regulatory perspective it has been a year of further development and understanding as Part 4 of the Commerce Act is bedded down. Uncertainty around the determination of the cost of capital figure continues, which raises the risk profile lending institutions apply to the industry.

Regulatory decisions have a large influence on our Asset Management position and we have been proactive in engaging with the Commission so that both parties gain the understanding of how regulation affects business outcomes

We have updated the output from our Asset Management Maturity Assessment Tool (AMMAT). This has been a useful “yardstick” for our internal review of the maturity of the asset management systems. The results of the gap analysis have also highlighted where we need to focus our attention so that the business can continue to improve its asset management systems, processes and capabilities.

As part of our ongoing efforts to improve our information datasets, this year we are extending our SAP system by implementing the Plant Maintenance module. This will deliver benefits to our asset management processes related to the planned, remedial and corrective maintenance of our assets. This will also enable our business rules to create a number of maintenance scenarios based on sensitivity of failure and repair rates. This system builds on our existing data gathering and assessment processes and provides superior asset condition information and works order management compared with our present system.

Overall Wellington Electricity are managing a mature set of assets which, when not affected by large natural events, are performing well for consumers.

We have completed the revisions required to update our Retailer Use of Network Agreements with a Model Use of System Agreement. This Agreement is currently being reviewed by Retailers ahead of final implementation. This process will provide a valuable update of current arrangements and the small number of changes are expected to deliver positive outcomes for our customers.

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

We are cognisant that to deliver all of the desired outcomes from our AMP involves people, either providing or receiving a service. So we need to ensure that we remain adequately resourced for the undertakings we have outlined in the plan and continue to grow a responsive, capable and high performing team. This team must be ready to adapt and remain flexible to meet the service needs of our customers as well as their increasing appetite for higher levels of information.

In conjunction with our service companies and in alignment with our business strategy, Wellington Electricity continues to focus on the development of asset management strategies, in parallel with the short to long-term planning of the network. This will help to ensure that appropriate levels of capital and operational expenditures are made 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

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1 Summary of the AMP

1.1 AMP Purpose

This Asset Management Plan (AMP) has been prepared for the following purposes:

- To inform stakeholders of how Wellington Electricity plans to manage its electricity distribution assets in order to ensure that connected electricity consumers continue to receive an electricity supply at a quality level which is reasonably priced and sustainable;
- To provide a working plan for use by Wellington Electricity for the management of the network; and
- To satisfy the Commerce Commission's Electricity Distribution Information Disclosure Determination 2012.

This AMP covers the 10-year period commencing 1 April 2014 and finishing on 31 March 2024. The plans described in this document for the year ending 31 March 2015 reflect Wellington Electricity's current business plan and are relatively firm for the next two to three years. Beyond three years the plans and strategies in this AMP are broader and will inevitably need to be adjusted to incorporate internal and external environmental changes as they arise.

Financial values presented in this AMP are in constant price New Zealand dollars, unless otherwise specified. 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 '2013' and '2012/13' respectively.

This AMP was approved by the Wellington Electricity Board of Directors on 28 March 2014.

1.2 Assets Covered

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 in Figure 1-2. As of 31 December 2013, there were over 165,100 connected consumers. The total system length (excluding streetlight circuits and DC cable) is 4,635 km, of which 62.3% was underground. Peak demand (system maximum demand) and energy injected (system energy injection) for the last six years are shown in Figure 1-1.

Year to	30 Sep 2008	30 Sep 2009	30 Sep 2010	30 Sep 2011	30 Sep 2012	30 Sep 2013
System Maximum Demand (MW)	537	565	583	585	552	542
System Energy Injection (GWh)	2,581	2,595	2,594	2,573	2,554	2,480

Figure 1-1 Peak Demand and Energy Injected

Figure 1-2 Wellington Electricity Network Area

1.3 AMP Assumptions

The AMP is based on the following assumptions:
(Note that further details of the assumptions are provided in Appendix B)

Demand and Consumption	Growth in peak demand and a decline in overall consumption present significant challenges to network planning due to the contrasting characteristics. • Demand growth will continue to be lower than the national average and will remain steady through the forecast period with an annual growth in peak electricity demand between 0.5% and 1.0% in some parts of the network, but showing signs of a slight decline or remaining steady across the network as a whole consistent with the experience in recent years. • Consumption of electricity (kWh volume) has historically decreased at around 1.0% per annum since 2009, and is forecast to continue decreasing at around 0.5% per annum.
Quality targets	The quality targets for the Wellington Electricity business in the period 2010 – 2015 will be maintained as per the Commerce Commission's decision paper on the default price path (November 2009). Internal targets for the period 2015-19 will remain the same as the present period, however due to the increasing number of extreme weather events the regulatory limits will increase. The underlying performance of the network, excluding these major events, is not expected to materially deteriorate.
Regulatory environment	The regulatory environment will encourage Wellington Electricity to continue to deploy CAPEX and OPEX to invest in the network to maintain quality targets.

Shareholders	The reset DPP will provide a WACC sufficient to incentivise shareholders to continue to invest in the network to ensure a sustainably profitable business.
Economy	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.
Business cycle	Wellington Electricity continually undertakes detailed assessments of network assets. It is assumed no new information is uncovered that changes our premise of network assets being in a reasonable condition. Increased levels of investment will be required in the later part of the planning period to address asset risk arising from age and condition (as assets approach end of life), as well as necessary resilience investment.
Technology	No dramatic change is forecast that would result in a rapid uptake of new technology leading to higher expenditure or stranding of existing assets. Technologies such as distributed generation and electric vehicles are not at present being purchased in large numbers, as they are relatively high in cost, and it is assumed this situation will not change significantly over the planning period.
Inflation and Price Escalation	Financial information is 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. Costs are forecast to increase due to annual inflation and price escalation of between 1.8% and 3.6% per year.

1.4 Network Reliability

The reliability of Wellington Electricity's distribution network is high by both New Zealand and international standards. Wellington Electricity plans to maintain supply reliability at current levels over the planning period, although the impact of major events in recent years is likely to result in a higher calculated reliability limit under the DPP for the period 2015-19. The average consumer connected to the network should only experience an outage lasting a little over an hour about once every two years, excluding the impact of severe storm events and high wind gusts which can frequently occur within the Wellington region. Wellington Electricity's asset management strategies and forecast levels of expenditure and investment are designed to achieve this by replacing assets that are at their end of life and maintaining in service assets through to end of life.

1.5 Network Development

The forecast annual growth of peak electricity demand in the Wellington Electricity network area is between 0.5% and 1.0% in some areas, such as the CBD, Churton Park and Whitby (along with their surrounding suburbs). While this drives the need for localised investment, across the entire network both peak demand and energy volumes have decreased since 2010. Hence, the growth in peak demand on the network is lower than the national average of around 2.0%. Wellington Electricity's load forecasts are based on long-term historic data and indicate overall growth through the planning period. However, this growth is not occurring on the network at the present time. Total consumption of electricity (kWh volume) has decreased in recent years and is forecast to continue decreasing at around 0.5% per annum.

During 2012, Wellington Electricity completed 11kV feeder upgrade projects in the CBD and Hataitai to address security and loading constraints within the localised 11kV system. However, as incremental load in the CBD increases, due to new building developments, reinforcement of the existing network is required and this AMP provides for the construction of a new zone substation on a site owned by Wellington Electricity in Bond Street to commence in 2015. This would be the first zone substation built in the CBD for 25 years. However, before a final decision to proceed is made, Wellington Electricity will evaluate alternative approaches, including increasing the transformer capacity at existing zone substations and upgrading or replacing 11kV switchgear.

Other areas with identified capacity constraints are Mana, Whitby and the Johnsonville-Churton Park areas. This AMP includes the following projects to address these issues:

- Installation of a special protection scheme at both the Mana and Plimmerton substations and a network reconfiguration in the Mana area in 2014. This will avoid a sustained loss of supply in the event of a loss of the incoming Pauatahanui-Mana 33kV circuit, by automatically transferring some of the load to other zone substations;
- Land was purchased in late 2012 at Grenada for the future development of a zone substation to supply the Grenada and Churton Park areas, thus reducing the loading on the Johnsonville zone substation. This new zone substation is expected to be required around 2017. In the meantime Wellington Electricity is securing the easements that will be required before construction can commence; and
- Investigation into suitable sites and configurations for a new zone substation in the Whitby area is now on hold as Wellington Electricity expects to be able to construct this substation on the site of the Pauatahanui GXP. Based on the current load forecast, the new zone substation is expected to be required before 2023.

The vulnerability of the distribution network to a high impact low probability (HILP) event causing an extended supply interruption at the Central Park GXP is of increasing concern as more than 30% of the electricity distributed by the network, including a significant proportion of CBD load, is supplied through this GXP. Wellington Electricity is currently working with Transpower to develop strategies to mitigate these risks. Potential strategies include increasing the transformer capacity, transferring load away from Central Park to another GXP (most likely Wilton), changing the physical design of the GXP to reduce the likely impact of a HILP event on the serviceability of the substation and putting contingency plans in place to reduce the time required to restore supply following such an event.

A number of smaller 11kV reinforcement projects have also been included in this AMP to address localised constraints identified as being present now, or occurring within the next few years. Projects for the current year include the completion of a 33kV reinforcement (cable replacement/upgrade) to Palm Grove zone substation as well as 11kV reinforcements in Tawa, Naenae, and the CBD around the stadium and waterfront developments.

1.6 Asset Replacement and Renewal

The CBD network is designed to provide high levels of availability and reliability and consists of many high voltage ‘rings’ to provide for uninterrupted supply in the event of the loss of any one component. The

Wellington Electricity network also comprises a high percentage of underground cabling with over 70% of subtransmission circuits being underground. Of this underground cabling, 60km is of pressured gas filled construction, mostly installed in the 1960s. While underground cables provide high reliability and resilience against weather and environmental deterioration, they are costly and time consuming to repair and vulnerable to earthquake activity where ground movement can occur.

Wellington Electricity now applies a "Stage of Life" condition based risk management process to prioritise asset replacements for the three major asset types (33kV subtransmission cables, zone substation power transformers and primary distribution circuit breakers). This analysis was updated in 2013. A number of projects have been identified from this work, including:

- Replacement of the Palm Grove 33kV cables, which is currently underway and will be completed in 2014;
- Replacement of the transformers at Evans Bay zone substation, planned for 2015;
- Replacement of the Karori zone substation switchboard, which is ongoing and will be completed in 2014; and
- Replacement of the switchboard at Gracefield zone substation, planned for 2014 and 2015.

The high level of reliability on Wellington Electricity's network reflects an asset intensive design with a high number of circuit breakers, the HV feeder rings and the predominance of underground cabling. Wellington Electricity has programmes in place to regularly monitor the condition of its older assets. This ongoing condition assessment indicates that existing assets are still serviceable and generally in reasonable condition for their age. However, as equipment condition factors change and the risk of failure increases, Wellington Electricity is forecasting a period where a high level of capital expenditure on asset replacement and renewal will be required to maintain the present levels of reliability.

As a result, around 50% of forecast capital expenditure over the planning period is expected to be for the proactive asset replacement and renewal of older assets. All replacements will be the result of an assessment of asset condition and the consequences of asset failure. Improvements in the collection of inspection and condition assessment data is helping to prioritise the replacement of these assets on a risk prioritised basis.

Before implementing any replacement, the asset location and functionality are reviewed to make sure asset replacement solutions are optimised.

1.7 Asset Management Systems

Since the last AMP, there has been further improvement in the Asset Management systems used and the data collected. Key Asset Management system objectives and projects for 2014 are:

- Develop a company load control strategy and preparation of a business case for the replacement of the existing Foxboro load control system;
- Complete the implementation of the SAP Plant Maintenance (SAP PM) asset management software. This is currently in progress and is expected to "go live" in June 2014;
- Produce a design and construction manual by the end of 2014;
- Revise the network development plan. This includes revisiting the load forecasting methodology and outputs, ensuring the network model is up to date and factoring in detailed studies of the CBD, Grenada and Whitby, where major network augmentation is required within the planning period;

- Develop detailed asset strategies for all the major asset classes;
- Consult with Wellington City Council on emergency overhead line routes and development of prioritised routes in the Hutt Valley and Porirua areas;
- Implement improvements to the systems and processes used in the Contact Centre to better handle communications with consumers during major events;
- Undertake a consumer survey to measure consumer satisfaction with the service levels provided by Wellington Electricity; and
- 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.

1.8 Risk Management

A major objective of the network development and lifecycle asset management plans is to mitigate the risks inherent in operating an electricity distribution business. Risk assessment therefore plays a major role in the prioritisation of network development and asset replacement projects.

The detailed design and operation of the network is not described in this AMP but it is summarised at a high level to demonstrate it is in accordance with industry standard practices and procedures. These practices and procedures have been developed and refined over time to manage the risks and hazards associated with high voltage electricity distribution.

Wellington Electricity has continued to develop risk assessment methodologies that provide input to the planning of network development, maintenance strategies and project evaluation. This risk based approach has resulted in a number of projects that have been completed over previous regulatory years (refer to section 8.6 for an example of one such project), and also identified a range of projects to be completed through the planning period In accordance with their risk profile.

Two major projects currently in progress have been driven by the events associated with the Canterbury earthquakes, namely development of a:

- major event resilience network plan, in particular 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. Discussion with Wellington City Council on the inclusion of these routes within the District Plan will continue in 2014 and a start will be also be made on the development of emergency overhead line routes in the Hutt Valley and Porirua areas; and
- substation building seismic policy. This policy has been approved and a programme for assessment of 320 network substation buildings started in 2012 and is expected to run through until early 2016. Following this work there will be a number of earthquake prone buildings identified that will require seismic reinforcement over the following 10 year period.

As part of its Business Continuity Management Policy, Wellington Electricity has Emergency Response Plans to cover emergency and high business impact situations. These plans are periodically reviewed and revised to best meet the business emergency management and response requirements. These plans were routinely tested during 2012 and feedback provided from the exercises incorporated into the plans. It is planned to test the Business Continuity Management Plan again in 2014.

1.9 Safety and Environmental Management

Wellington Electricity has continued to build on its strong foundations of past Health, Safety and Environmental (HSE) performance and has again noted some significant improvements during 2013. Notable performance improvements include:

- A positive change in safety culture through an increase in the reporting 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-conformance 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, timely 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 arrangements.

In early 2014, Wellington Electricity also achieved recertification of its Public Safety Management System, which is a positive endorsement that the processes and systems are providing a safe environment for consumers and the public.

During 2013, Wellington Electricity continued its safety awareness programmes with schools, contractors, and the general public and this will continue in 2014.

2 Background and Objectives

2.1 History and Ownership Overview

Wellington Electricity is an electrical distribution business (EDB) that supplies electricity to over 165,100 installation control points (ICPs) in its network, which covers the Wellington, Porirua and the Hutt Valley regions of New Zealand, an area with a population of around 400,000.

The ownership of Wellington Electricity has changed significantly since the early 1990s. At the start of the 1990s, the Wellington City Council Municipal Electricity Department (MED) and the Hutt Valley Electric Power Board (HVEPB) 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.

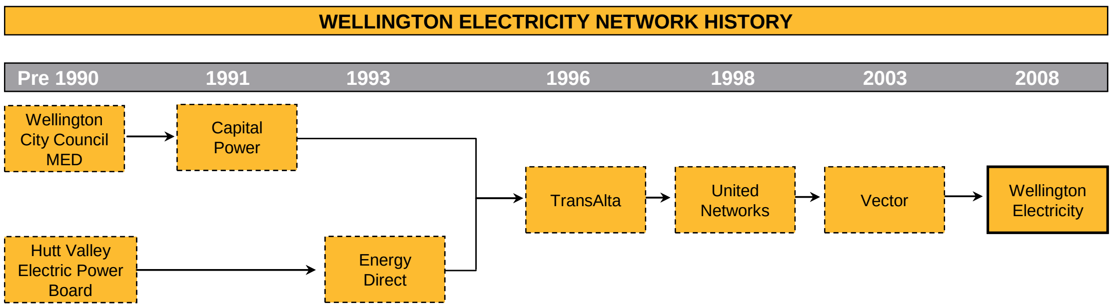


Figure 2-1 Wellington Electricity Ownership History

In July 2008 the network was purchased by Cheung Kong Infrastructure Holdings Limited (CKI) and Hong Kong Electric Holdings Limited to create Wellington Electricity Lines Limited (Wellington Electricity). Since then Wellington Electricity has continued to establish 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 better 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 regarding the Wellington Electricity ownership structure is available at the website www.welectricity.co.nz.

2.2 AMP Purpose and Objectives

The primary purpose of the AMP is to communicate with consumers and other stakeholders Wellington Electricity's strategies, polices and processes for the effective and responsible management of the network assets in order to ensure that connected electricity consumers continue to receive electricity supply at a quality level that is reasonably priced and sustainable. This AMP also provides a working plan for use by Wellington Electricity for the management of the network.

Other goals of the AMP are to:

- Ensure that all stakeholder interests are considered and integrated into business planning processes to achieve an optimum balance between levels of service and cost effective investment, while maintaining regulated service targets. The level of service is reflective of a price/quality trade off where pricing is set at a level that allows Wellington Electricity to upgrade, maintain, and renew the network assets to meet the demand for electricity in accordance with stakeholder expectations regarding quality of supply. The Commerce Commission, as the industry economic regulator, has a part to play not only in ensuring that the business is managed efficiently to avoid unnecessary consumer costs but also in ensuring that Wellington Electricity can achieve adequate levels of return on its investment in the regulated asset base so that it continues to invest in network assets to the extent necessary to meet the growth in the demand for electricity and maintain service quality to consumers;
- Provide a consolidated governance and management framework that encompasses the asset management and planning strategy in a 'live' document;
- Address 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 sustainable and equitable return to the shareholders; and
- Provide a platform for monitoring and demonstrating continuous improvement in alignment with best industry practice.

The AMP is a key internal planning document and has become a consolidated repository for asset management planning. It is a dynamic document requiring continuous review and adjustment to align with the changes in the business environment.

This is a collectively produced document that draws information from external stakeholders and from within the Wellington Electricity business. Contributions to this plan have been received from consumer surveys, field service providers and the following teams within the business: asset and planning, operations and maintenance, capital works projects, quality, safety and environmental, commercial and finance and the executive. The document is approved for disclosure by the Wellington Electricity Board of Directors.

The AMP is compiled in accordance with the Electricity Distribution Information Disclosure Determination 2012.

2.3 Legislative and Regulatory Environment

Wellington Electricity's principal activity is providing electrical infrastructure and systems that safely and effectively distribute electricity. It is an electricity operator pursuant to section 4 of the Electricity Act 1992. As an electricity operator Wellington Electricity provides electricity lines services to consumers in its distribution supply area using its electricity distribution system.

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 Commerce Commission's Electricity Distribution Information Disclosure Determination 2012; 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 of the supply of electricity to consumers. Reliability of supply is measured with reference to the duration of interruptions to supply (system average interruption duration index (SAIDI)) and the frequency of interruptions to supply (system average interruption frequency index (SAIFI)). Wellington Electricity is subject to the Commerce Commission's Electricity Distribution Services Default Price-Quality Path Determination 2012.

- Price oversight under the Electricity Industry Act 2010 administered by the Electricity Authority. While the Commerce 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 (Part 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.
- 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 the best practice asset management policies and procedures that underpin this AMP.

There are currently no regulated national supply security standards in force. However, Wellington Electricity has developed its own security standards, which specify the minimum levels of capacity (including levels of redundancy) for its network in accordance with industry best practice. Wellington Electricity's security standards are discussed in Section 5 of this AMP.

2.3.1 Economic Regulatory Environment

As noted above, Wellington Electricity is a regulated business and the revenue it can earn from the provision of regulated lines services is subject to regulation by the Commerce Commission under Part 4 of the Commerce Act 1986.

Wellington Electricity's maximum average price for providing regulated electricity lines services is set out in the Electricity Distribution Services Default Price-Quality Path Determination made by the Commission on 30 November 2012 and applies to the remainder of the regulatory control period from 1 April 2013 to 31 March 2015. This price is calculated in accordance with a regulatory framework that applies a weighted average price cap for each year of the regulatory control period and is recovered through charges for the use of the distribution system (otherwise known as Electricity Lines Services charges). These charges are payable by retailers and are included in the prices retailers charge consumers for the supply of electricity.

Substantial changes have been made to the regulatory framework since the commencement of the current regulatory control period in April 2010. These include:

- Publication of Electricity Distribution Information Disclosure Determination 2012 on 1 October 2012 by the Commerce Commission. This determination introduces new information disclosure requirements which apply to all aspects of disclosure including requirements for more detail on expenditure forecasts and the composition and condition of the asset base to be collected and disclosed in the AMP.
- Publication of the Re-determined Input Methodology Determination (Re-determined IMs) on 15 November 2012 by the Commerce Commission. The Re-determined IMs are important because they set out the rules, requirements and processes applying to the regulation of electricity distribution services. These include, amongst other things, IMs for: cost of capital, asset valuation, treatment of taxation and cash-flow timing assumptions applying to default price-quality paths (DPPs).
- Publication of the Electricity Distribution Services Default Price-Quality Path Determination 2012 on 30 November 2012 by the Commerce Commission. This determination reset the starting prices applying to Wellington Electricity's 2010-15 DPP. This has reset the prices Wellington Electricity may charge for the remainder of the current regulatory control period, from 1 April 2013 to 31 March 2015.
- Amendments to the Electricity Industry Participation Code 2010 by the Electricity Authority, including in relation to indemnity provisions and prudential security requirements under Part 12A as well as new provisions for the indemnity of retailers by EDBs under the Consumer Guarantees Act (CGA);
- Introduction of the Model Use of System Agreement (MUoSA) developed by the Electricity Authority. The MUoSA has a number of distinct differences from Wellington Electricity's current Use of Network Agreement. This has resulted in a requirement to develop Wellington Electricity's own Use of System Agreement which is currently being developed - retailers are reviewing the current draft.

2.3.2 Impact of Regulatory Environment on the Business

The regulatory environment has a number of financial, technical and reliability impacts on Wellington Electricity's business. Wellington Electricity regularly engages with the Electricity Authority and Commerce Commission through active participation in submissions on various matters and regular information disclosures. Ultimately these regulatory bodies will make decisions that determine the price-quality trade-off experienced by consumers. These impacts include:

<u>Price-Quality compliance</u>

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

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 Commerce Commission, taking effect in 2013. 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.

Starting Price Adjustments

In 2012 the Commerce Commission adjusted the starting prices applying to the 2010/11 to 2014/15 DPP. This resulted in an adjustment to Wellington Electricity's prices, in addition to the allowed Consumer Price Index movements, from 1 April 2013 to 31 March 2015. The Commerce Commission is in the process of determining a new DPP for Wellington Electricity for the five year regulatory control period starting 1 April 2015.

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 Electricity Authority published a 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 this 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. In order to mitigate this risk, provisions allowing Wellington Electricity to control load in response to system emergencies and to preserve distribution voltage quality for the consumer need to be included in protocols to be developed between market participants as part of the new requirements of the MUoSA. This would avoid possible unexpected and unnecessary interruptions and ultimately a need to increase investment in network capacity to ensure quality levels are not degraded and continuity of supply is maintained.

Government Policy - Major Infrastructure projects

Major infrastructure projects driven by Government policy have an impact upon the Wellington Electricity network. The ultra-fast broadband rollout is a positive initiative for New Zealand. However, 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 roll-out of ultrafast broadband.

Requirements driven by local authorities

Wellington Electricity must comply with new local authority requirements, which can add costs to the business. Examples of these 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 assessment 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, the costs of which need to be passed through to customers in a similar way to the insurance allowances, or by increased allowable revenue through the DPP based on revised forecasts. These investments were not included in previous AMP forecasts as the requirements were not as actively enforced by councils until recently, and the magnitude of costs to Wellington Electricity was unknown. Ad-hoc engineering assessments and minor strengthening work prior to 2013 (two sites strengthened over the period 2006-2012) were accommodated within existing budgets by deferring other asset replacement work. The magnitude of costs required to manage the risks are now significant and cannot be accommodated within existing forecasts.

This AMP includes forecasts of the CAPEX and OPEX which Wellington Electricity estimates to be necessary to provide an adequate level of seismic resilience, including the assessment of around 320 pre-1976 buildings, 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 Section 8.10.1 of this AMP.

At the time of writing, the Building (Earthquake-prone Buildings) Amendment Bill 2013 is being introduced to “improve the system for managing earthquake-prone buildings”. If passed into law, this will increase Wellington Electricity’s obligations to assess and strengthen substation buildings, with a corresponding increase in costs to the business. As the impact of this Bill is unknown at this time, it is not included in forecasts; however it is expected to require around 150 more buildings to be assessed, and potentially strengthened. It is also likely to bring forward the timeframes for Wellington Electricity to complete the strengthening of earthquake-prone buildings from 10 years to 5 years, doubling the requirement for capital investment in strengthening works in the period 2015-2020. As discussed further in Section 8.10.1, the expenditure forecast in this AMP assumes that this strengthening work will be undertaken over a ten year period from 2014 to 2024.

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.

Other local authority activities such as roading and drainage projects can lead to relocation work which cannot be fully recovered and contributes to increased costs for the business.

2.4 Interaction between AMP and Other 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 tactical action planning within the business and effectively drives asset management planning and delivery. To meet this mission, it is essential for the business to operate in the most commercially efficient manner possible within the current regulatory environment.

The AMP incorporates information from internal business and asset management related documents, which cascade down from the Business Plan and Strategy to the asset maintenance and lifecycle plans through to the annual Capital and Maintenance works delivery plans and programmes, as shown below.

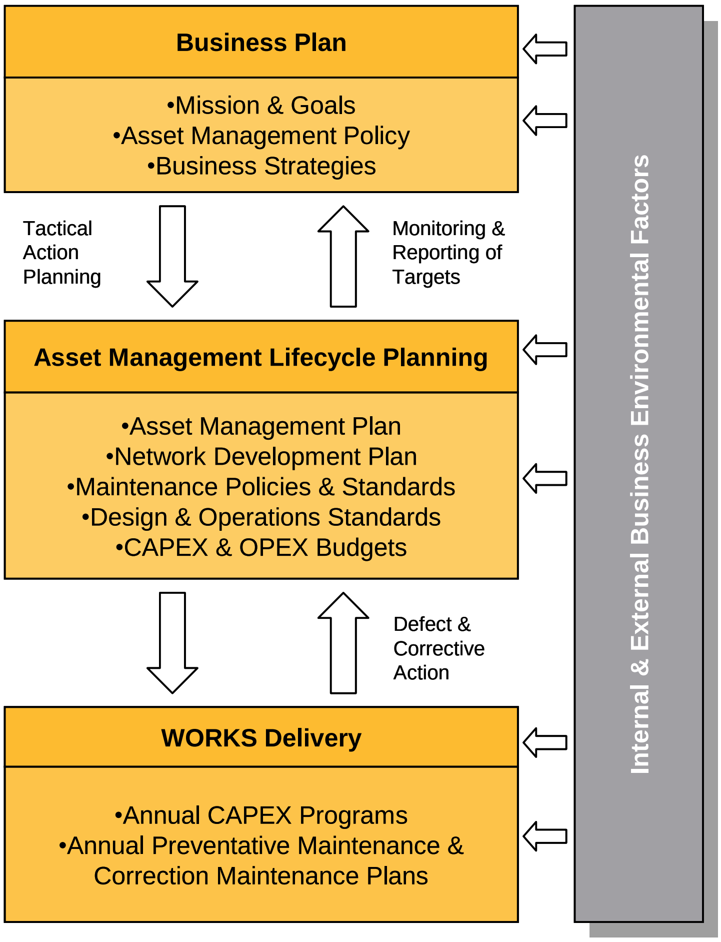


Figure 2-2 AMP Interaction with Business Planning

2.4.1 Business Plan and Strategy

Wellington Electricity's strategic business direction is supported by the Business Plan and aims to deliver a long-term sustainable business to all of its stakeholders.

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 our financial targets Manage our treasury responsibilities	165,100 reasons to provide effective and efficient service Understand our investment in their future for a quality service
People	**Regulatory**
Working safely Developing a great team & organisational culture Employees are aligned with business goals & direction Building strong relationships with our service providers Reputable employer	Health & Safety in Employment Act Commerce Act – Price/Quality Path reset & controls Electricity Act, Electricity Industry Act and associated Codes & Regulations **Economic** Business cycles post-recession 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 our stakeholders	Well managed media and stakeholder communication Local people managing the business well with high quality service **Political** Responsibility of 4th largest EDB serving nation's capital Government & business leaders interested in affordable & reliable supply Managing local & regional council expectations

Figure 2-3 Wellington Electricity Business Plan

Wellington Electricity's Business Strategy 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 strategies effectively 'shape' the AMP, taking into consideration the changing regulatory environment and the needs and interests of Wellington Electricity's stakeholders.

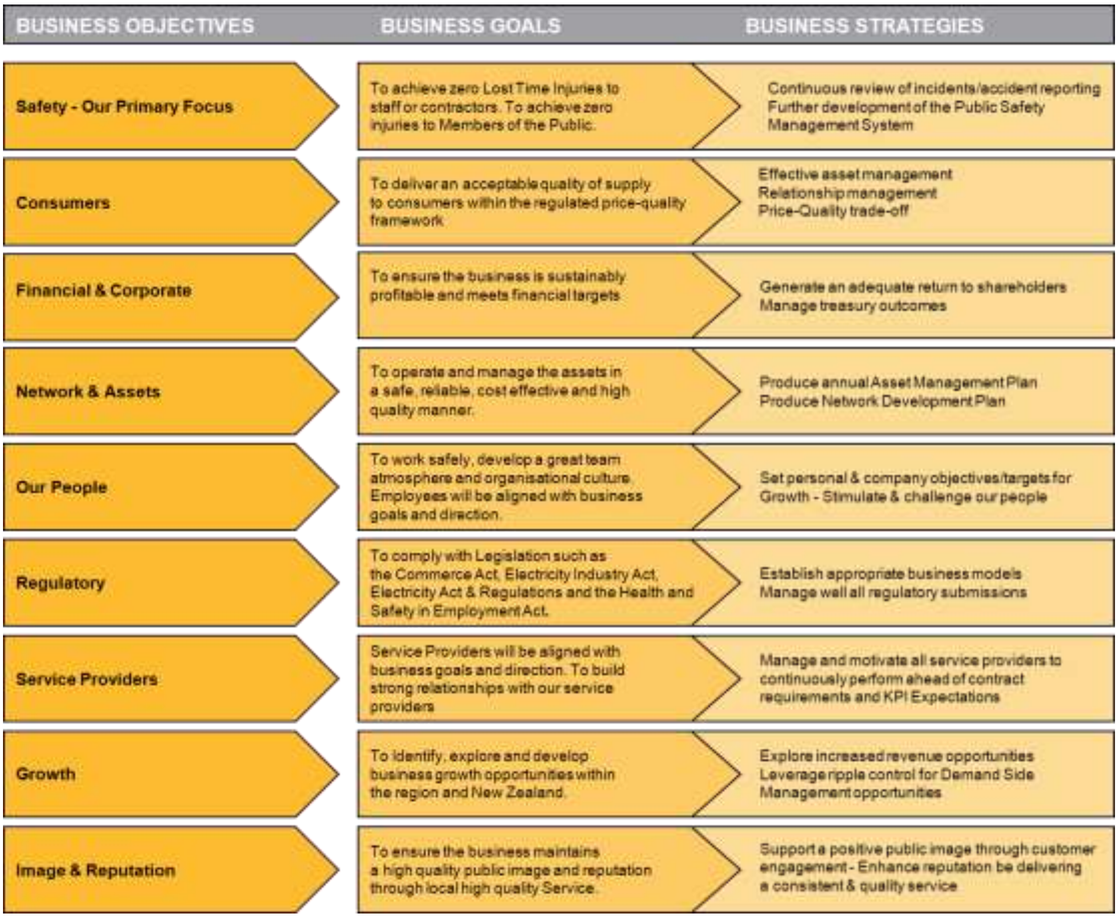


Figure 2-4 Wellington Electricity Business Strategies

2.5 Planning Period Covered by the AMP

This AMP covers the 10 year period from 1 April 2014 to 31 March 2024 and replaces the April 2013 AMP. Plans for the first year of the planning period are firm at the time of writing. Plans for subsequent years are likely to be affected by the on-going development of asset management strategies as well as changes to the internal and external environments in which Wellington Electricity operates. However, the AMP provides clear plans for the management of assets over the next five years, with plans for the subsequent five year period not presented in the same level of detail. This reflects the impact of uncertainty over the longer timeframes.

The 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; and
- Changes to business strategy driven by internal and external factors.

The AMP was approved by the Wellington Electricity Board of Directors on 28 March 2014.

2.6 Managing Stakeholders

2.6.1 Stakeholder Interests and Identification

Wellington Electricity has identified stakeholders, their interests and expectations, and how these interests and expectations are being managed by all of the business through a number of activities – described in the following table.

Shareholders

How are the interests identified?	What are their interests / expectations?	Accommodation of interests / expectations?
• Governance and Board mandates • Board Meetings and committees • Business Plan and Strategic Objectives	Shareholders expect a fair economic return for their investment. Shareholders expect the company to meet industry-leading operational and Health, Safety and Environment standards. 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	• Customer initiated projects produce appropriate revenue levels to meet the cost of capital • Meeting reliability and customer service levels

Consumers

How are the interests identified?	What are their interests / expectations?	Accommodation of interests / expectations?
• Customer satisfaction and engagement surveys • Feedback received via complaints and compliments • Media related enquiries and sponsorship • Price / Quality trade-off	The consumers connected to Wellington Electricity's network require a safe and reliable supply of electricity of acceptable quality at a reasonable price. While consumers 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 that can be considered acceptable	• Meeting reliability and customer service levels • Appropriate investment in the network • Public safety initiatives • Price / Quality trade-off

Retailers

How are the interests identified?	What are their interests / expectations?	Accommodation of interests / expectations?
• Electricity Industry Participation Code (EIPC) • Relationship meetings and direct business communications • Via Use of Network Agreement terms	As retailers rely on the network to deliver the energy they sell to consumers, they also require the network to be reliable and to meet agreed service level targets. Retailers are reliant on electricity distribution services to conduct their business and therefore want Wellington Electricity to assist them in providing innovative products and services for the benefit of their customers. Retailers have an expectation to access the proposed load control market under the new Electricity Authority Model Use of System Agreement	• Meeting reliability targets • Achieving customer service levels • Consultation • Development of standard Use of System Agreement taking into account the Electricity Authority Model

Regulators		
How are the interests identified?	What are their interests / expectations?	Accommodation of interests / expectations?
• 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 the consumer achieves a supply of electricity at a fair price commensurate with an acceptable level of quality	• Meeting reliability compliance targets and controls for price and quality • Compliance with legislation, engagement and submissions as required • Monitoring information disclosures • Engagement with Regulators and Regulatory Impact Statements

Staff & Service Providers		
How are the interests identified?	What are their interests / expectations?	Accommodation of interests / expectations?
• Team and individual direct discussion • Employee satisfaction surveys • Relationship meetings and direct business communications • Contractual agreements	Staff and contractors want job satisfaction, a safe and enjoyable working environment and to be fairly rewarded for the services they provide Contractors also want assurance around work delivery continuity and the mitigation of working hazards by appropriate asset management planning	• Health & Safety policies and initiatives • Forward planning of work through asset management practises • Performance reviews • Life balance

Transpower		
How are the interests identified?	What are their interests / expectations?	Accommodation of interests / expectations?
• EIPC • Relationship meetings and direct business communications • Annual planning documents • Grid notifications & warnings	Transpower obtain sustainable revenue earnings from the allocation of connected and inter-connected transmission assets. Wellington Electricity under the Electricity Industry Participation Code (EIPC) will operate and interface under instruction as and when required. Further assurance is required 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		
How are the interests identified?	What are their interests / expectations?	Accommodation of interests / expectations?
• Through legislation • Relationship meetings and direct business communications • Focus working groups	Local Councils require that appropriate levels of investment are made in the electricity network to allow for levels of local growth Regional Councils require that both current and new network assets do not affect the environment Central Government's interests are mainly managed through the respective Ministries e.g. MBIE, to ensure the general public receive a safe, reliable and fairly priced electricity supply All three require appropriate emergency response and contingency planning to manage a significant civil defence event Councils undertaking their obligations under legislation that impact upon electricity network buildings, e.g. seismic assessment and reinforcement of earthquake prone buildings	• Compliance with legislation, engagement and submissions as required • Emergency Response Plans • Environmental Management Plans • Identification of costs associated with the reinforcement of substation buildings

Figure 2-5 Stakeholder Identification

2.6.2 Managing Conflicting Interests

Safety will always be a 'non-negotiable' attribute when managing a stakeholder conflict. Wellington Electricity will not compromise the safety of the public, its staff or service providers.

Other stakeholder interests that conflict will be managed on a case-by-case basis. This will often involve consultation with the affected stakeholders and may involve the development of innovative "win-win" approaches that are acceptable to all affected parties.

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 provides 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.

2.7 Wellington Electricity Structure and Asset Management Accountability

2.7.1 Governance

The Wellington Electricity Board of Directors is responsible for the overall governance of the business. The Board has approved capital and operational expenditure budgets and business plans for the 2014 calendar year, consistent with the financial year planning required by its owners. Information is provided to the Board as part of a monthly consolidated business report that includes health and safety reports, capital and operational expenditure vs. budget, reliability statistics against targets and consumer satisfaction survey results.

All network capital projects greater than $400,000 require approval from the Capital Investment Committee (CIC). The CIC comprises, as a minimum, one company director and the CEO. The CIC meets on a regular basis to review and approve projects and to be appraised of progress on approved projects.

2.7.2 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.

International Infrastructure Services Company (IISC) is a separate infrastructure services company, which provides management services to Wellington Electricity.

Field work is undertaken by external service providers contracted to Wellington Electricity.

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

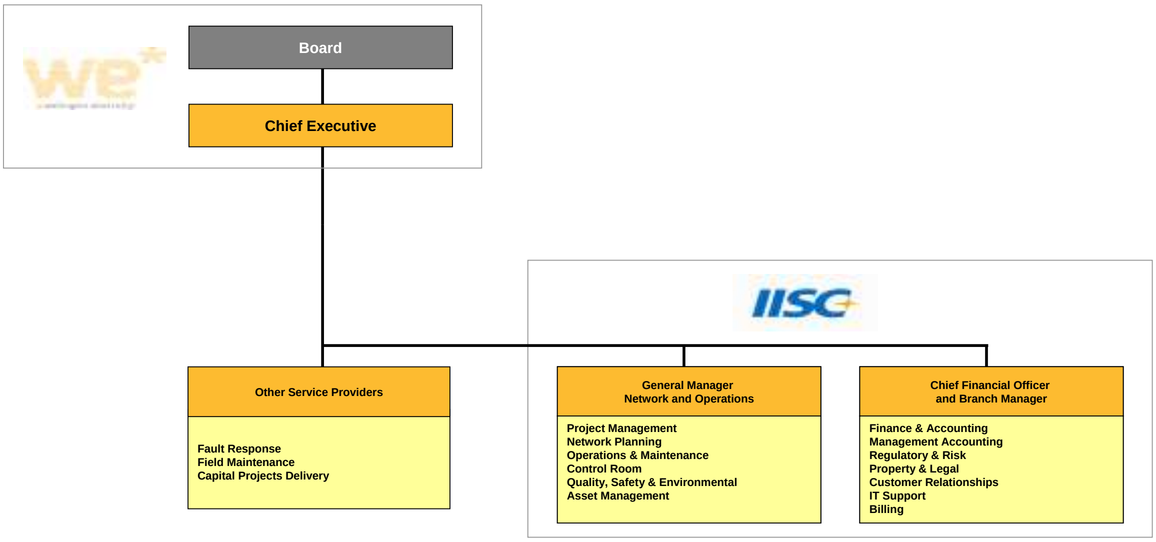


Figure 2-6 Wellington Electricity Organisation Structure

2.7.3 Network & Operations Team Structure and Asset Management Accountability

The IISC Networks and Operations team is responsible for the management of network assets, however the entire business has some direct or indirect interaction with the network assets on a daily basis.

The General Manager – Network and Operations is accountable for the delivery of asset management services to Wellington Electricity. These services include asset planning, project management, capital expenditure delivery, operations and maintenance and safety, quality and environmental performance.

A notable change to our organisation structure occurred during 2013 when management of the Network Control Room was reorganised to report directly to the General Manager, Network and Operations. This is part of the strategy for lifting system performance and increasing the level of service provided to consumers and to Wellington Electricity. Network control services were taken over by IISC and the network control room was relocated to Wellington Electricity's head office in Petone in 2012.

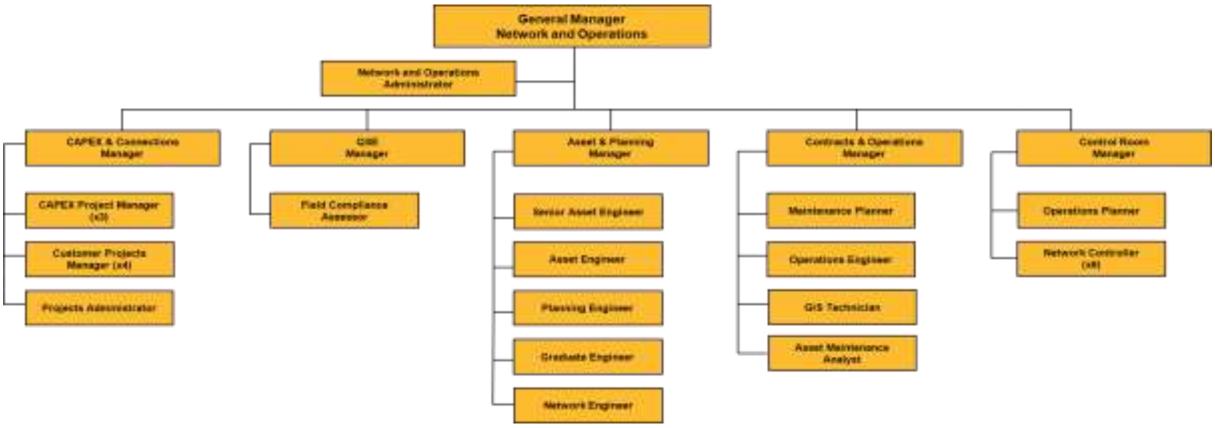


Figure 2-7 IISC Network and Operations Support Structure for Wellington Electricity

2.7.4 Finance and Commercial Team Structure and Asset Management Accountability

Financial and accounting support for the management of network assets is also provided within the IISC structure for service delivery to Wellington Electricity. The Finance and Commercial team provides indirect interaction with the network assets on a daily basis through managing support systems.

The Wellington based 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.

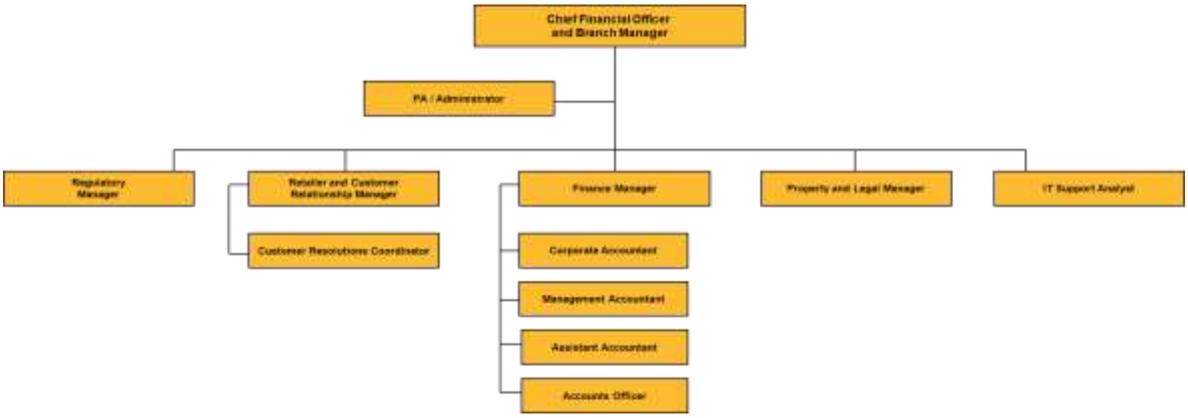


Figure 2-8 IISC Finance and Commercial Support Structure for Wellington Electricity

2.7.5 External Service Providers – Field and Network Operations

Wellington Electricity outsources field services on its network utilising a number of service providers for core field and network functions. Northpower Ltd was appointed as Wellington Electricity's Field Service Provider responsible for fault response and maintenance from 2011 for an initial four-year term, which has been extended for one year through to the end of 2015.

The Field Services Agreement with Northpower is designed to deliver a number of strategic objectives for Wellington Electricity. A particular focus is on alignment with Wellington Electricity asset management strategies, to obtain a greater understanding of the condition of network assets and to improve the integrity of the asset data held in Wellington Electricity's information systems.

In summary, the outsourced field operations and the approved Wellington Electricity service providers are:

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 to the asset owner;
- Corrective maintenance – remedial maintenance on defective assets;
- Value added services – safety disconnects and reconnects, on site cable mark-outs, sub-transmission 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.

This contract is managed under the terms of the Field Services Agreement, which 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 the commercially tendered unit rates that formed part of the original RFP evaluation. It is the responsibility of the Contract and Operations Manager to ensure the work completed is kept 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, and this is detailed further in Section 2.10.1.

Contestable Capital Works Projects (Northpower and Connetics)

- Customer initiated works – new connections, subdivisions and substations, undergrounding and relocations; and
- Network initiated works – asset replacement projects and cable/line reinforcements.

This work is covered by Independent Contractor Agreements (and also under the Field Services Agreement with Northpower) which outline the terms under which the work is completed, including any relevant KPIs, other performance requirements such as defects liability periods, performance bonds as well as insurance and liabilities provisions to limit the risk exposure of Wellington Electricity. Contracts are managed on an individual basis for each project and there is a structured reporting and project close-out process, as well as field auditing during the course of the works.

Contestable capital works projects are generally competitively tendered to three contractors; however in some cases there is the ability to sole-source low value works or where only one supplier can provide the required service. In the case of sole-source supply, pricing is benchmarked against comparable market data. Under the project management framework the scopes are well defined and there are stringent controls in place for variations to fixed price work. Unit rates have been agreed with all contractors for certain types of repetitive, low value work. It is the responsibility of the CAPEX and Connections Manager to ensure work undertaken is managed contractually to deliver value to the business.

During 2013, Transfield Services, one of three contestable capital works contractors on the Wellington Electricity network, withdrew from providing electrical contracting services to Wellington Electricity and a process was undertaken to select a replacement third contractor. Negotiations are currently underway with the preferred tenderer who will commence operating on the network during 2014.

Contractors working on an underground cable

<u>Vegetation Management (Treescape)</u>

- 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)

- Contact Centre – providing a dispatch function for High Voltage (HV) and Low Voltage (LV) outages, management of customer and retailer service requests, outage notification to retailers and handling general enquiries; and

This outsourced contract is planned for re-negotiation in 2014.

In summary, Wellington Electricity manages and audits all service providers and also collates reports on network operations and maintenance performance and expenditure, customer satisfaction, safety statistics and network reliability.

Wellington Electricity will continue to review these activities in order to achieve optimum asset management outcomes.

2.8 Asset Management Systems and Processes

Wellington Electricity has invested significantly in IT systems, which place it in a strong position to operate and establish best practice asset management services.

2.8.1 Systems for Managing Asset Data

This section of the AMP identifies 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.

2.8.1.1 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 was fully commissioned during 2011 following separation of the automatic load control system. The ENMAC system provides 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. Following the June 2013 storm, a number of improvements were identified to the Calltaker system and processes used by the Contact Centre when managing high volumes of calls. Several improvements are being made to this system in 2014 to better handle communications during major events.

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 late 2014.

Two other systems related to the SCADA system are being investigated for upgrade and business cases for their upgrades will be completed in 2014.

- 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, that 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.

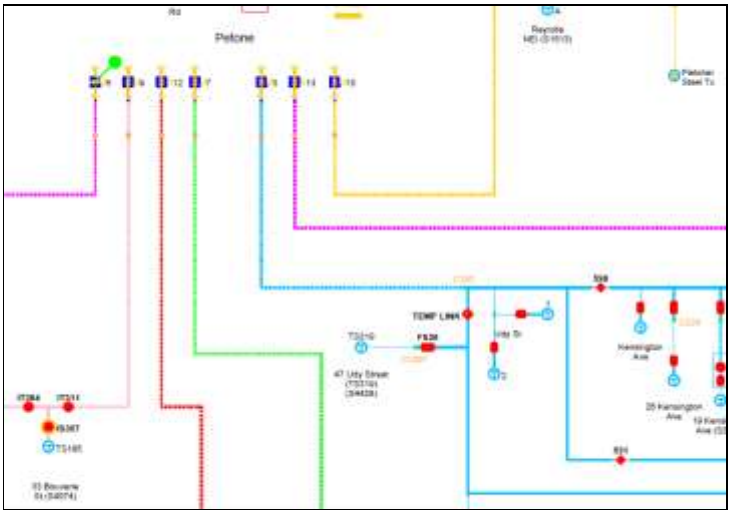


Figure 2-9 Screen shot of ENMAC SCADA/DMS system

2.8.1.2 Geographic Information System (GIS)

The Geographic Information System (GIS) is a representation of the system fixed assets overlaid on a map of the supply area. Wellington Electricity uses the GE Smallworld application for planning, designing and operating the distribution system and this is the primary repository of network asset information. Asset condition data in the Maintenance Database 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 Maintenance Database, on a nightly basis ensuring that all systems have the latest asset data. By linking the GIS system with the Maintenance Database, 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 2-10 Screen shot of Smallworld GIS system

2.8.1.3 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.

2.8.1.4 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, reliability and protection studies. The Power Factory database contains detailed connectivity and asset rating information. In 2011 Wellington Electricity completed a review of its Power Factory model which confirmed its accuracy and completeness. It views this tool as a key part of optimising the network and input into planning development projects.

To ensure ongoing accuracy, the model is progressively updated with new network information as assets are replaced or as the network is extended. This is completed by the Planning Engineer following receipt of information from the Projects team. Wellington Electricity has explored processes that can ensure it remains synchronised with the actual power system, through such means as an automated cross reference with GIS; however, the low volume of updates means a manual update process is appropriate for the time being. This will be reviewed if the volume of updates increases significantly in future years.

2.8.1.5 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.

2.8.1.6 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 interfaces directly to Power Factory to allow for protection discrimination studies to be carried out.

2.8.1.7 Hard Copies and Spreadsheets

Wellington Electricity has much of the historic asset condition information of the network in the form of hard copies and/or spreadsheets of inspection records and test results. These are stored in various locations, both electronically, or in hard copy. Examples of asset condition data and maintenance record data held include:

- Scanned and printed copies of inspection results;
- Spreadsheets of transformer oil analysis; and
- Scanned copies and hard copies of historical cable test results.

In 2010, Wellington Electricity worked through the challenge of entering this hardcopy and spreadsheet data as electronic records into the Maintenance Database in order to more effectively manage asset information for future decision making. These historic records can be accessed if required to verify information in the Database, but are no longer used as working records.

Initially a number of gaps existed in the maintenance history and test results for some assets. These assets have been prioritised for inspection or maintenance ahead of those with a known history (within an acceptable risk profile) to establish a baseline of knowledge on those assets. Given the progress on the maintenance programme in recent years, Wellington Electricity has built up a reasonably sound knowledge of the assets on the network. However, analysis is not always possible due to gaps in historic information dating prior to purchase of the assets in 2008. Over time, this will improve as more information is obtained and a wider range of information is recorded when new assets are installed and throughout the asset lifecycle.

Wellington Electricity is continuing the acquisition of data and test results for all asset categories and maintenance activities, which operate on multi-year cycles. It is anticipated that detailed condition information may not be complete for all asset categories for several years. This will impact the ability of Wellington Electricity to meet the requirements for an application for a customised price path, should this prove necessary.

2.8.1.8 Maintenance Database

Wellington Electricity has developed a Maintenance Database to store the maintenance history of network assets and electronically capture maintenance data. Over 15,000 historic maintenance records from the period 2007 to 2010 were in this database at the time of the field services contractor transition. Maintenance data is regularly provided electronically by the Field Service Provider on completion of maintenance works such as condition assessments, inspection and test results and to record defects against the asset. The Maintenance Database has reporting functionality to enable Wellington Electricity to verify the work completed, test the record accuracy, and allow sorting and searching to support the design of future maintenance and replacement programmes, based upon the historic inspection and condition assessment results. Wellington Electricity is focussing on obtaining additional resources to review the data to identify gaps with asset records, where priority actions are required on network assets, as well as to schedule future works.

The Maintenance Database, although functional to meet Wellington Electricity's current maintenance management requirements, was an interim solution. Following a review process, Wellington Electricity has approved a project to implement SAP Plant Maintenance (SAP PM). This system is used by a group company, Citipower/Powercor in Australia, as well as several large utilities in New Zealand, and is well supported.

Wellington Electricity is currently undertaking a process to review and translate the existing business rules and strategies into the full implementation of the SAP PM system. This system is planned to go live in mid-2014.

The asset data within the existing Maintenance Database can be migrated to the SAP PM system once implemented.

Following the implementation of SAP PM in mid-2014, the SAP Project System will be evaluated to potentially bring together SAP financials, SAP PM and the project systems used by the CAPEX project team.

2.8.1.9 GenTrack

GenTrack is an application designed to manage Installation Control Point (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.

2.8.2 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.

2.8.3 Summary Table

The following table 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	✓	✓			
Spreadsheets / hardcopy	✓	✓	✓		
Maintenance Database	✓	✓	✓		✓
GenTrack				✓	✓
SAP (Financial)					✓

Figure 2-11 Asset Data Repositories

2.8.4 Process for 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 the GIS system is required to drive asset strategies, as the 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 the Maintenance Database 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.

Where gaps exist in the data that may be required for maintenance and renewal processes, changes are made to business processes in order to obtain this data. However data is generally gathered during the normal course of business, rather than through a special data collection project, and missing data is therefore acquired over time. In order to ensure that data is accurate and complete, controls need to be put in place and the systems through which data is gathered need constant monitoring.

2.8.5 Data quality

Wellington Electricity is routinely reviewing its asset data to check the quality of the records in the IT systems (GIS, Gentrack and the Maintenance Database), as inconsistencies have been found between some of the data in different locations. Initiatives 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 continuing 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.

The Field Services Agreement includes a number of business processes that over time are assisting Wellington Electricity fill data gaps and correct inaccuracies, with a particular focus on the GIS data.

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, Maintenance Database). 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 the table below.

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
GIS	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)
GIS	Some asset types not represented in GIS or incomplete	Asset types such as relays, batteries and chargers, ripple plant and some DC trolley bus equipment is not stored in GIS and these are being progressively added following installation or inspection activities
Maintenance Database	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
Maintenance Database	Condition Assessment (CA) scores incorrect for early inspections arising from misunderstandings of new Field Inspectors	Field Inspectors given briefing sessions to improve understanding of CA scores Annual re-inspection will provide correct information from second pass

System	Limitation	Control in Place
Power Factory	New network additions, capacity upgrades or replaced equipment may be delayed in updating the model	Network planning engineers update the model to reflect new and updated system components from GIS and at 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 gathered 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
ENMAC SCADA	Not all network branches have ratings assigned to them 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 Spreadsheet of branch ratings provided to Network Control as an interim measure

Figure 2-12 Overview of Asset Data Gaps and Improvements

2.9 Asset Management Strategy

The asset management strategy that Wellington Electricity has adopted aligns with the asset management policy, business strategies and goals listed in section 2.4. Wellington Electricity intends, during 2014, to complete the development of management strategies for each of the asset categories on the network. These 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 6 of this plan. 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.

2.10 Process Overview

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

- Inspection and maintenance;
- Planning; and
- Investment selection.

The interaction of these processes is illustrated in the diagram below. Each of these processes and the Asset Works Plan are described in detail in the following sections.

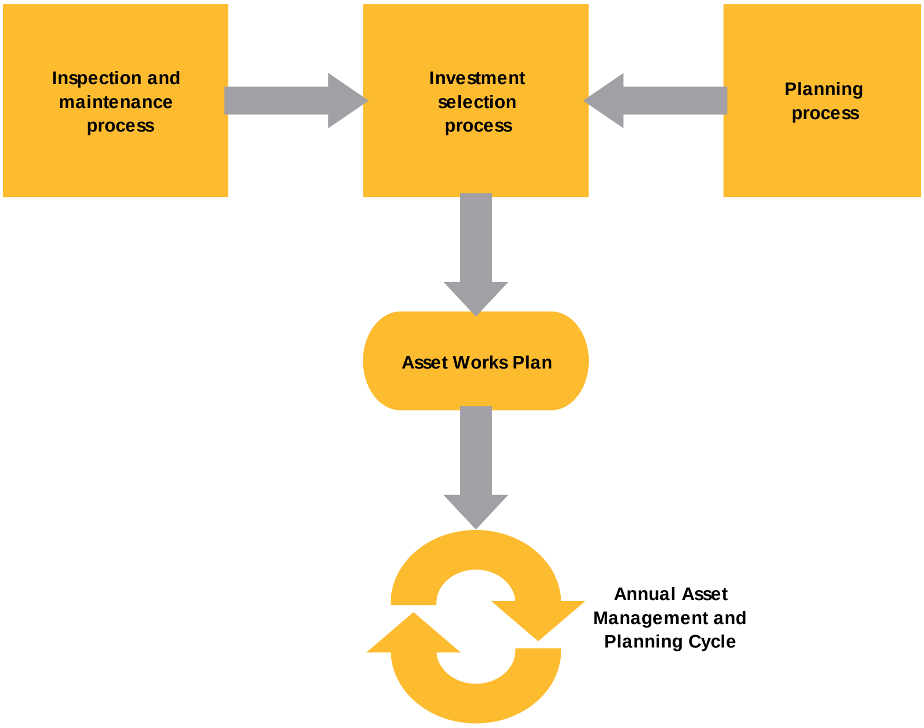


Figure 2-13 Asset Management Processes

A key output from these processes is the Asset Works Plan (AWP), which in turn feeds into the annual asset management and planning cycle. The AWP is discussed in more detail in Section 2.10.4. The development of the AWP is ongoing, and continually reviewed for input into the AMP process.

2.10.1 Inspection and Maintenance Process

[maybe this should have a sub heading of Current Inspection and Maintenance Process as there is a lot of text before the next subheading of a review of the process]

The asset inspection and maintenance process is centred on the Preventative Maintenance (PM) plan that is prepared annually by the Wellington Electricity engineering and maintenance groups. The PM plan lists all assets by group and details the inspection and routine maintenance activities that are required for them. Each type of asset 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 6 (Lifecycle Asset Management). The timing and scope of these activities are optimised 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 identification of individual assets requiring inspection and maintenance is derived from the Maintenance Database (to be replaced with SAP PM in 2014) and a list of these assets is available to the maintenance planners within Wellington Electricity and the Field Service Provider. The maintenance history, such as date of last activity and the condition assessment outcome, drives the next activity date.

The PM plan is then scheduled by the Field Services Provider into a PM programme. The Field Services Provider is responsible for implementation of the programme and held accountable for this through its service contract. The Field Services Provider will inspect the assets, undertake a condition assessment, identify any asset defects, carry out the routine maintenance and also carry out corrective maintenance (i.e. correction of issues uncovered during routine inspection) provided the total cost of this is under a threshold set by Wellington Electricity. The inspection and test results, condition assessments, defect assessments and work records are reported to Wellington Electricity on a regular basis with prescribed maintenance data recorded into the Maintenance Database. Wellington Electricity engineering staff analyse the maintenance data via the Maintenance Database and, in discussion with the Field Services Provider, may approve further corrective maintenance or initiate the investment selection process to address refurbishment and renewal requirements. Additionally, the cyclic review of asset performance (e.g. feeder performance) may initiate either corrective or project works. Wellington Electricity completed enhancements to the Maintenance Database during 2012, which allows for the monitoring and detailed reporting of outstanding and completed defects, as well as analysis of aging and overdue defects. This enables the business to undertake more detailed analysis of defects and manage the risk associated with the pool of current defects. Further enhancements to the reporting and analysis capabilities are expected during 2014 with the introduction of SAP PM.

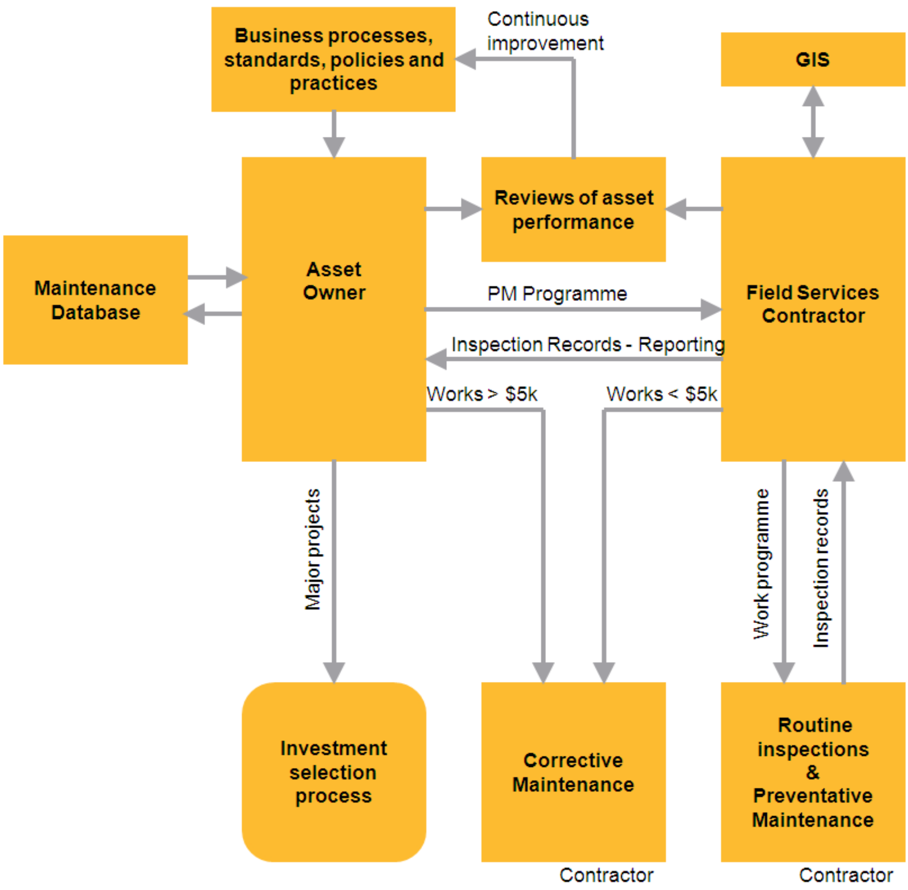


Figure 2-14 Inspection and Maintenance Process

2.10.1.1 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 needs. A number of initiatives have already been put in place to improve data capture and records management, such as identifying missing asset information in the GIS and other systems, updating equipment ratings and undertaking condition assessments of some assets. Increasing the understanding of each type of equipment enables targeted maintenance programmes or revisions to the standards to be made. Since 2011, significant improvements have been made to the asset information held in the GIS, as well as in understanding asset condition, defect types and asset specific issues. 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. It is envisaged that once an overall view of asset condition and asset risk is known, from two or more cycles of the maintenance programme, the intervals between inspections or invasive maintenance activities can be optimised.

2.10.2 Planning Process

Network constraints are identified by reviewing the capacity and the security of the network on a regular basis against network standards and policies. Should a constraint be identified, options for addressing it through reconfiguration of the network (e.g. by moving an open point) will be considered first, to optimise the use of existing network capacity. Should no reconfiguration options be available using the existing network infrastructure, then other options will be investigated as part of the investment selection process. The options may include both network (installation of new lines, cables and transformers to create new capacity or allow utilisation of nearby capacity) and non-network solutions (such as localised generation or demand side management initiatives). Key inputs to the capacity and reliability review are the planning criteria, which are kept constant, and load forecasts, which are updated on a yearly basis. These are described in detail under separate headings in Section 5 (Network Planning).

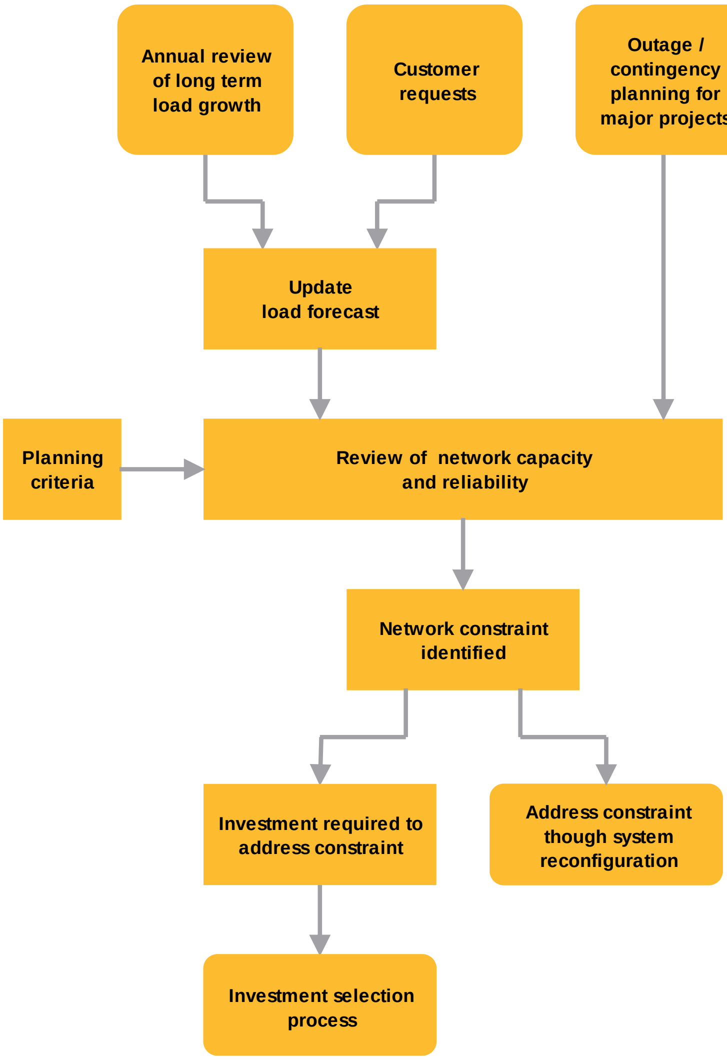


Figure 2-15 Planning Process

2.10.3 Investment Selection Process

This process describes the way in which network investments are taken from a high level need though to a preferred investment option that in turn results in a business case. It includes consideration of a long list of options, refinement of the long list to a short list of practicable options followed by detailed analysis and selection of a preferred option. The Asset Works Plan is the repository for all potential network investments including those at the early 'needs have been identified' stage and 'preferred option' stage.

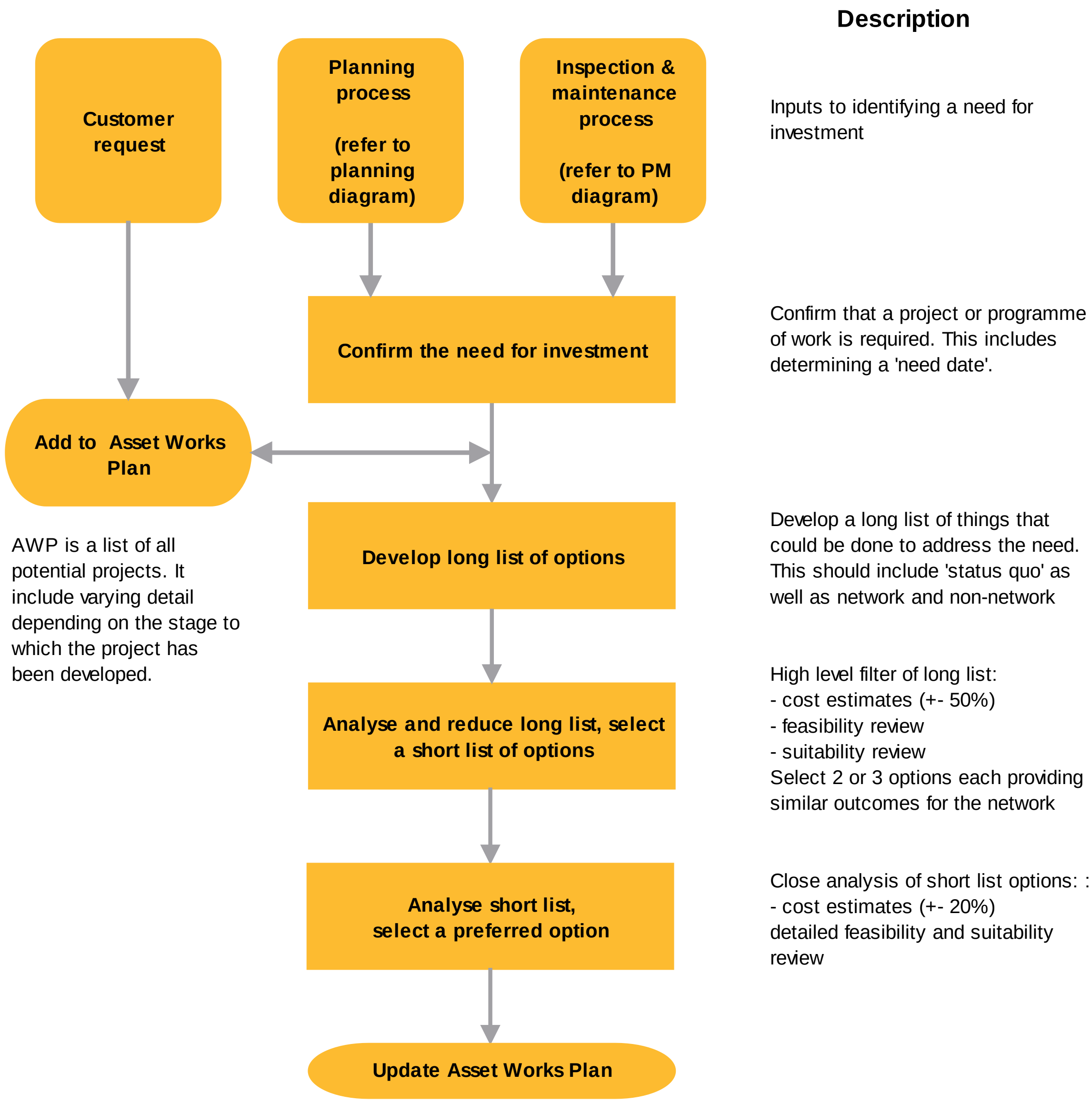


Figure 2-16 Investment Selection Process

2.10.4 Asset Works Plan

The Asset Works Plan (AWP) comprises a list of potential projects at the high level 'need has been identified' stage and at the 'preferred option' stage of the investment selection process. The AWP is a dynamic list that includes projects up to ten or more years in the future and is continually updated and amended as new 'needs' are identified, project details are refined and projects are executed. Every year the prioritised projects identified in the AWP for the next financial year are further investigated to the 'preferred option' stage of the Investment Selection Process. This list of projects is then scheduled for delivery. Following prioritisation, each project is matched against the available budget for capital works and a list of projects for the following year (i.e. the capital works spend plan) is prepared for both Board approval and CIC approval.

Wellington Electricity's internal work planning cycle is based on its financial year (which is the same as the calendar year and aligns with the requirements of its owners). Project timings given in Section 5 and 6 of this AMP are therefore expressed in financial years to be consistent with Wellington Electricity's internal planning. However, expenditure forecasts in this AMP are based on regulatory years, consistent with the Commission's information disclosure requirements, being 1 April top 31 March.

2.10.5 Processes for Measuring Network Performance for Disclosure Purposes

SCADA and ICP allocation information stored within the ENMAC database[1] is extracted using reporting tools to provide the business with fault (unplanned) and planned outage information. All relevant details of faults are entered into the ENMAC fault log database, which calculates the impact of each fault on SAIDI and SAIFI. Where supply is restored progressively through switching over a period of time, the switching sequence is recorded and used as the basis for recording 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 the reliability of the network is available on an ongoing basis throughout the measurement period and is regularly reported both within the business and to the Board through its monthly reports.

2.10.5.1 Unplanned Outages

The process for handling and recording the impact of unplanned outages is illustrated below.

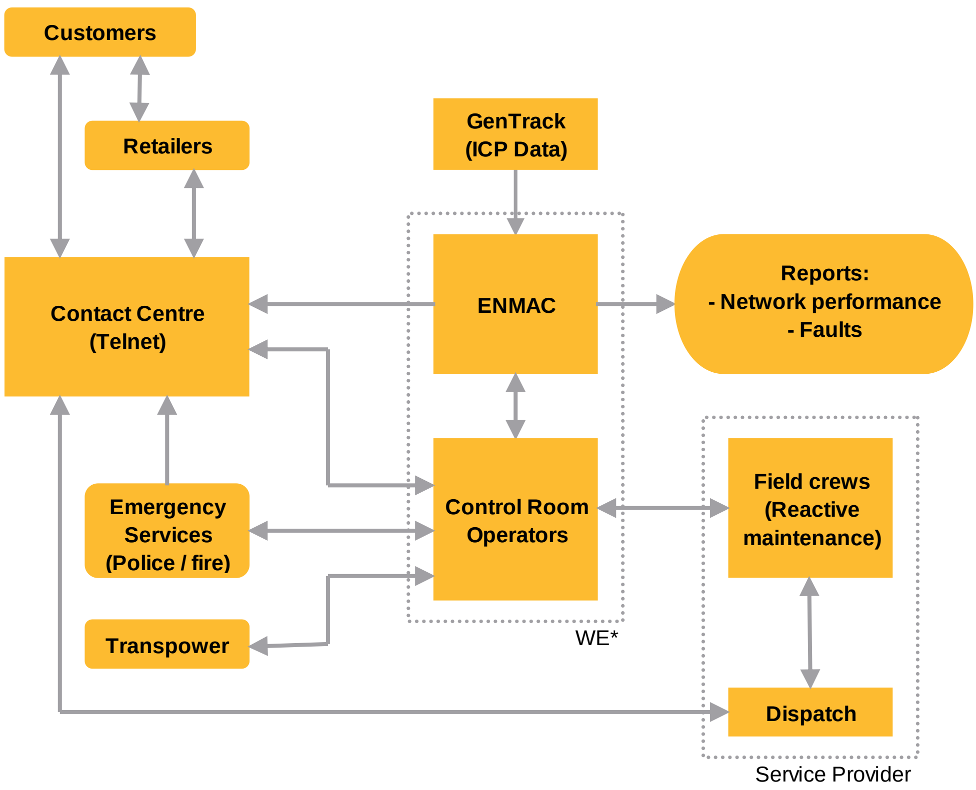


Figure 2-17 Unplanned Outage Process

[1] SCADA includes the status of circuit breakers and switches as well as system voltages and currents. ICP allocation information comprises connections made to each part of the network.

The main operating teams that comprise this system 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 a 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.

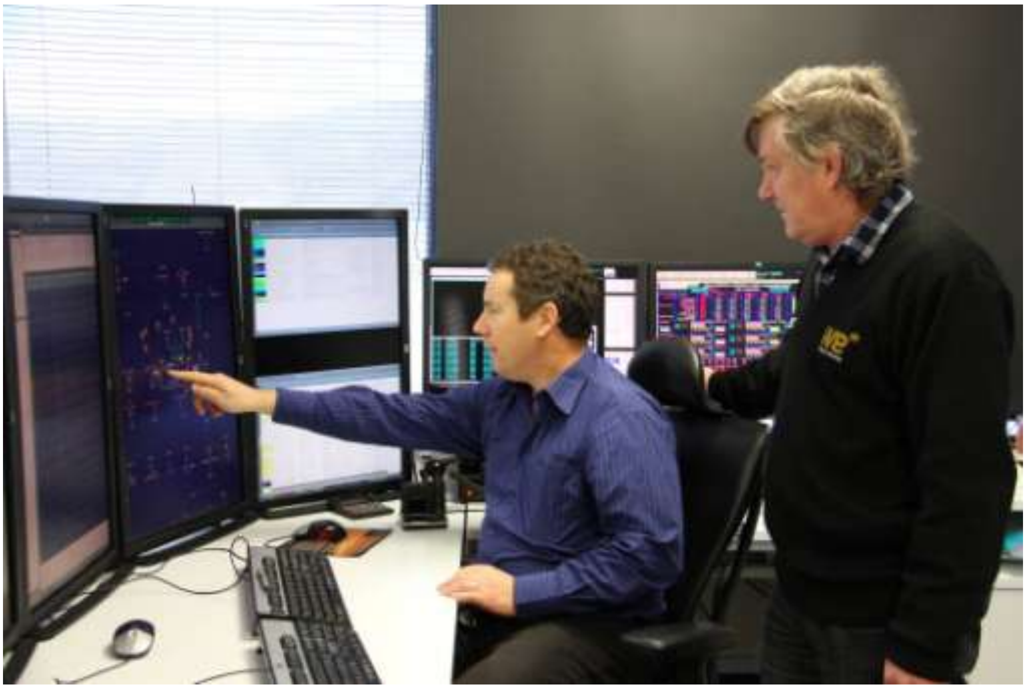
The Field Services Provider dispatches a faultman to the faulted customer(s). Updated information is fed back from the field to the Contact Centre via the outage management systems to enable the consumer (via its energy retailer) to be kept informed of progress of the fault and its restoration.

High Voltage Faults (11kV or above)

The control room via the SCADA system will be directly notified of most faults or trippings on the 11kV (or above) network 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 NCR operators (via the field crews) progressively update the fault log in ENMAC. Fault logs are available from ENMAC via a reporting tool. On a regular basis, these logs are interrogated and network performance statistics obtained.

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.



2.10.5.2 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 requirements, such as the minimum prior notification periods for the request to be made to the Network Control Room (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 (see Section 2.10.1) to produce a forward schedule of planned works for the NCR to assist in the optimisation of planned outages and to minimise the number and duration of planned outages on the network.

The Wellington Electricity 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 supplies is recorded in ENMAC. This log is interrogated to determine network performance.

The planned outage process is illustrated below.

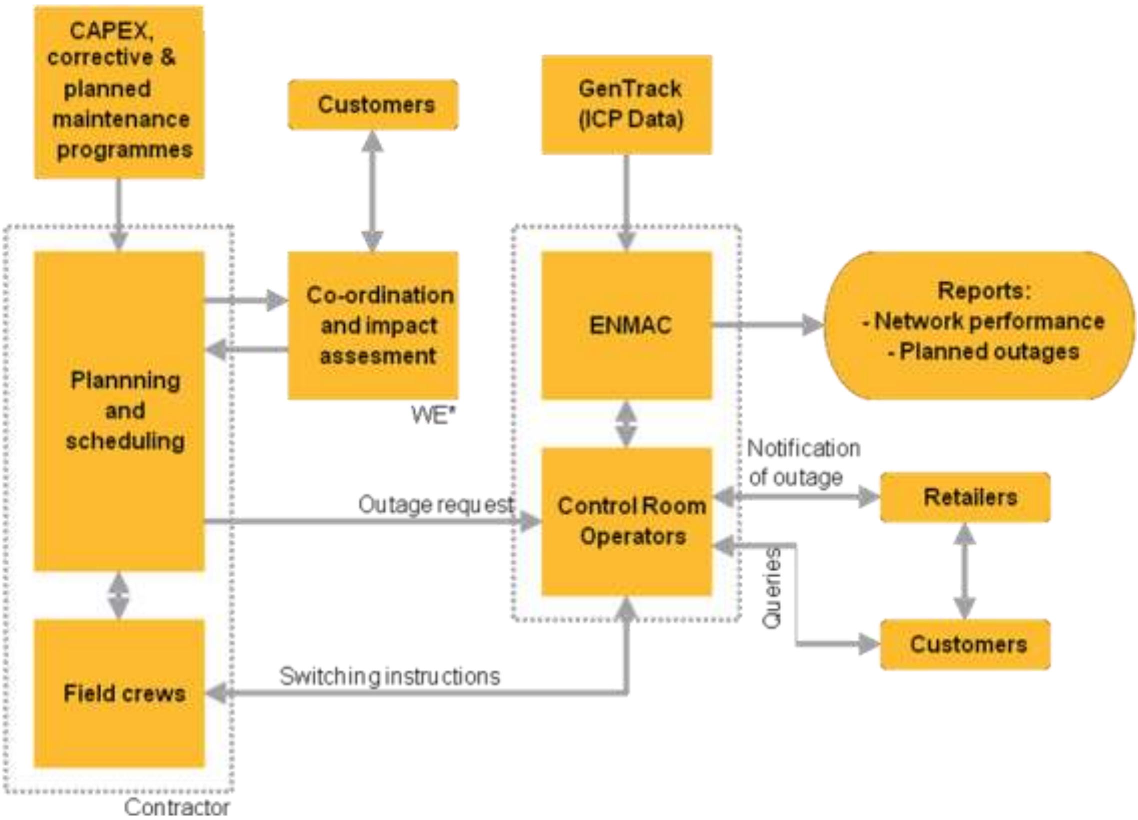


Figure 2-18 Planned Outage Process

2.11 Asset Management Documentation and Control

Wellington Electricity has a range of documents relating to the asset management system ranging from high level policy documents, through technical standards for procurement, construction, maintenance and operation of network assets. In addition, there are guidelines and network instructions to provide line of sight asset management and covering the entire asset lifecycle. The keystone document is the Wellington Electricity Asset Management Policy, which provides direction for the asset strategies, processes and supporting documents.

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.

In late 2012, Wellington Electricity commenced a gap analysis to determine where asset lifecycle documents are missing or incomplete. This has been used to drive the development of new documents as required. As part of this process, Wellington Electricity is undertaking a review and update of the standards inherited from previous owners of the network. In particular, the review covers technical standards for procurement, construction, maintenance and standard construction drawings. Whilst older, these documents still contain technical information which is relevant to the ongoing operation and management of Wellington Electricity's assets, and are therefore considered a valuable resource. A large number of standards relating to network materials, construction (including standard drawings) and operational standards were updated or developed in 2013 and approved through the Controlled Document Process. This work will continue in 2014 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 drive 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.

Agreements with Wellington Electricity's contractors also define the terms under which information has to be provided to Wellington Electricity relating to tasks completed on the network including faults, planned maintenance and corrective maintenance. The GIS system is required to be updated following alterations or renewal of system components, as well as updating data gaps where asset attribute or nameplate information has not been captured. The GIS system and Maintenance Database are owned and controlled by Wellington Electricity and it is the responsibility of the contractors to update information within these systems so that Wellington Electricity retains control of this information.

2.12 Communication of Asset Management Strategies and Policies

Wellington Electricity communicates its asset management strategy through the annual disclosure of the Asset Management Plan, as well as making a range of the asset management documents such as policies, standards and guidelines available to internal and external stakeholders.

Monthly management meetings are held with both the main Field Service Provider and other contractors working on the Wellington Electricity network. These monthly management meetings track progress to Key Performance Indicators covering safety, operations, maintenance, capital works and general technical requirements, including the rollout and embedding of new policies and standards which apply to the work being undertaken by the contractors. In addition to the monthly management meetings, asset management information is communicated to staff via group technical, project specific and operational meetings.

Wellington Electricity presents asset management information to internal and external stakeholders as relevant. Managers are aware of the relevant asset management plans and strategies and are expected to communicate these to their teams as required. Staff generally demonstrate an awareness of asset management strategies and, if unsure of specific elements of the strategy, are aware of where to find more information within the organisation.

2.13 Capability to Deliver

The Board and senior management team review this AMP against the business strategy and ensure alignment with business capability and priorities. Management consider this plan to be reflective of current business capability. 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 help the business achieve these new business requirements.

A key area for specific development during 2014 is in preparing a resource strategy for the delivery of long-term asset management needs. The intention is to map the technical, design, management and field delivery requirements of the OPEX and CAPEX expenditure programme contained within this plan to determine what resourcing levels are required and to identify where future gaps in resource capability pose significant risk to achievement of Wellington Electricity’s asset management goals.

3 Assets Covered

3.1 Distribution Area

Wellington Electricity's distribution network covers the cities of Wellington, Porirua, Lower Hutt and Upper Hutt. Wellington City is one of the major metropolitan centres in the country with high density commercial developments. It is also the seat of government and includes Parliament Buildings and the head offices of most government departments. A map of the network area is below.

Figure 3-1 Wellington Electricity Network Area

As of 31 December 2013, there were over 165,100 connected consumers. The total system length (excluding streetlight circuits and DC cable) was 4,635km, of which 62.3% was underground.

The Wellington CBD is the largest business and retail centre for the region, although there are also significant retail centres in Lower Hutt, Porirua and Upper Hutt. Apart from within the CBD there is widespread residential load throughout the network area. This is interspersed with pockets of commercial and light industrial load.

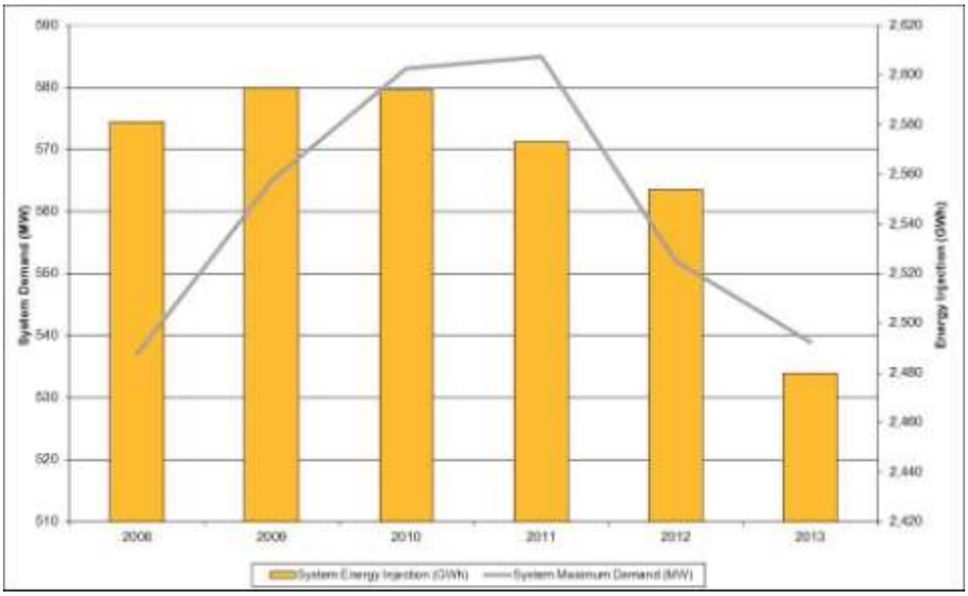
Major customers with significant loads include Parliament, Wellington Airport, Centreport, Wellington, Kenepuru and Hutt Hospitals, Victoria University, as well as council infrastructure such as water and wastewater treatment and pumping stations. Wellington Electricity also supplies the electrified suburban railway network and the trolley bus network. The network area is notable for the absence of large industrial loads.

The network area covers four local councils, namely Wellington City, Hutt City, Upper Hutt City and Porirua City. In addition to the local councils, the Wellington Regional Council covers the entire network area. The different council areas have varying requirements relating to permitted activities for an electrical utility, for example in relation to road corridor access and environmental compliance.

The trolley bus network is supplied through Wellington Electricity owned DC assets comprising 15 converter transformers, 15 mercury arc rectifiers, 4 solid state rectifiers and 52 DC circuit breakers. There are approximately 49km of underground DC cables linking various DC substations. These DC assets are managed in accordance with a network connection and services agreement with NZ Bus Limited (the sole customer supplied by these assets) and are therefore not covered by this AMP.

3.2 Load Characteristics

Peak demands and energy distributed for the last six years is shown below.



From observation of actual load data peak demand on the network is rising over the long-term at between 0.5% to 1.0% per annum, although with slight decreases in recent years due to mild temperatures. This long-term trend is forecast to continue. Consumption of electricity (kWh volume) is decreasing at a rate of around 0.5% per annum and is forecast to continue this trend for the future.

Year to	30 Sep 2008	30 Sep 2009	30 Sep 2010	30 Sep 2011	30 Sep 2012	30 Sep 2013
System Maximum Demand (MW)	537	565	583	585	552	542
System Energy Injection (GWh)	2,581	2,595	2,594	2,573	2,554	2,480

Figure 3-2 Peak Demand and Energy Injected

* August 2011 peak demand during an unusual snowstorm pushed the network peak demand to 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.

3.2.1 Typical Load Profiles

Typical load profiles for CBD and residential loads are shown below. These graphs illustrate that CBD loads are relatively even throughout the year with a slight trend towards a summer peak, and their daily profile is relatively flat though the day (Figure 3-3 and 3-5). Residential loads are winter peaking with a pronounced dip in demand during the middle of a typical working day (Figure 3-4 and 3-6).

At a system wide level, demand and volume has declined over the past two years, however in certain locations where development is occurring there is growth observed.

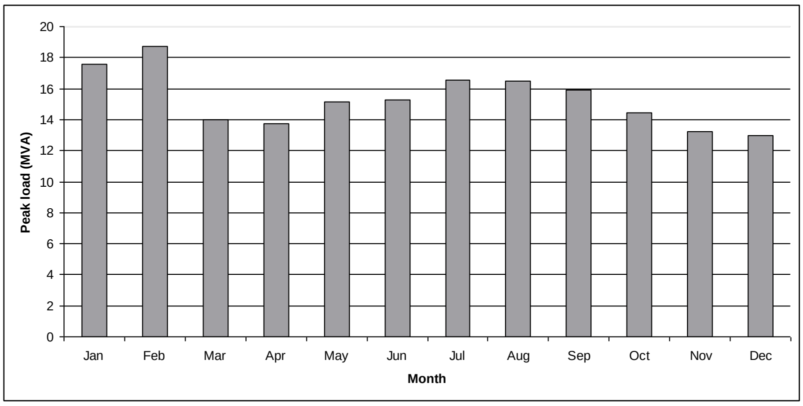


Figure 3-3 Typical CBD Monthly Peak Load Profile

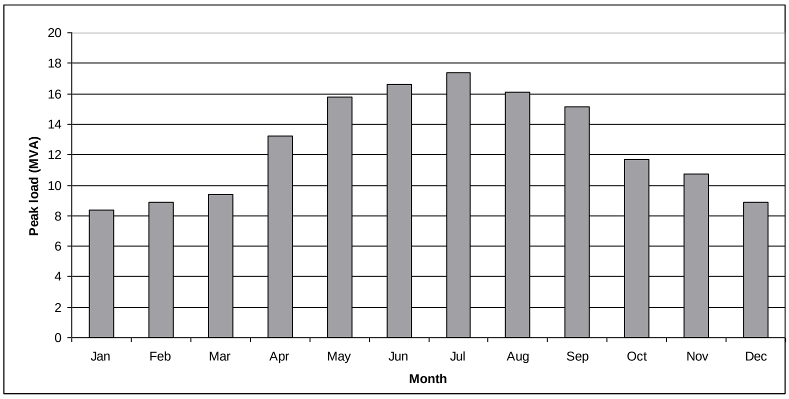


Figure 3-4 Typical Residential Monthly Peak Load Profile

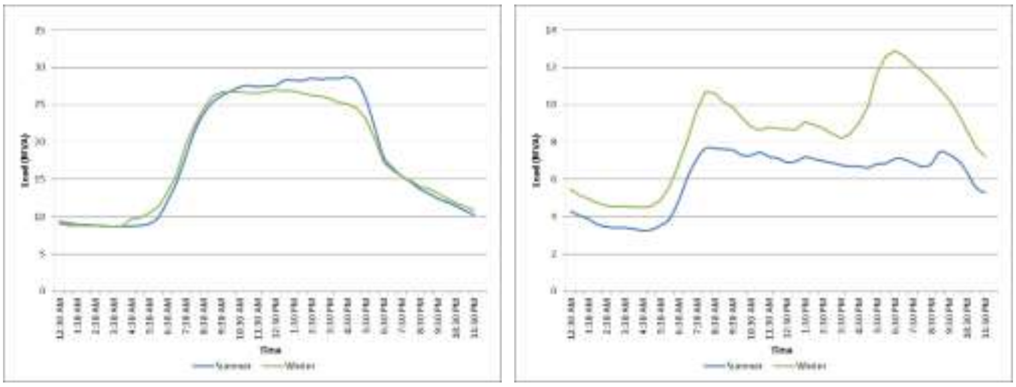


Figure 3-5 and 3-6 Typical CBD (L) and Residential (R) Zone Substation Daily Load Profile

3.3 Network Configuration and High Level Asset Description

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

3.3.1 Grid Exit Points

Wellington Electricity's network is supplied from Transpower's national transmission grid through nine grid exit points (GXPs), as shown in Figures 3-8 to 3-11. Central Park, Haywards and Melling 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 GXPs are described in more detail below.

3.3.1.1 Upper Hutt

Upper Hutt GXP comprises a conventional arrangement of two parallel 110/33kV transformers each nominally rated at 37MVA. Maximum demand on the Upper Hutt GXP in 2013 was 31.3MVA. Upper Hutt GXP supplies Maidstone and Brown Owl zone substations via double circuit 33kV underground cables. The existing 33kV outdoor switchyard owned by Transpower at Upper Hutt is to be replaced by an indoor switchboard as part of their ongoing outdoor to indoor conversion program. This is currently programmed to occur in 2020.

3.3.1.2 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. The maximum demand on the Haywards 11kV bus and 33kV bus in 2013 was 20.1MVA and 16.8MVA respectively. A 5MVA 33/11kV transformer supplies the Haywards local service switchboard and also links the 33kV and 11kV switchboards. Wellington Electricity is in discussion with Transpower regarding future options to resolve the security constraints at this site, as part of a Transpower policy-driven transformer replacement (see Section 5.12.3).

3.3.1.3 Pauatahanui

Pauatahanui GXP comprises a conventional arrangement of two parallel 110/33kV transformers each nominally rated at 20MVA. Maximum demand on the Pauatahanui GXP in 2013 was 19.2MVA. This is within each transformer's 22MVA cyclic rating; however load growth in this area is relatively strong. 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 should one of the 33kV circuits be out of service.

As discussed in Section 5.13.5, towards the end of the planning period Wellington Electricity is planning to construct a new zone substation to supply load in the Whitby area. This substation will off-load the Waitangirua zone substation supplied from Takapu Rd and will require the transformer capacity at Pauatahanui GXP to be increased.

3.3.1.4 Takapu Road

Takapu Road GXP comprises a conventional arrangement of two parallel 110/33kV transformers nominally rated at 90MVA each. Maximum demand on the Takapu Road GXP in 2013 was 91.3MVA. 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 at the urban boundary.

Wellington Electricity plan a review of the Takapu Road GXP. This will consider how to accommodate future load growth and whether existing arrangements will provide the appropriate security levels in the future. Transpower has advised that Takapu Road will be included in the second tranche of its outdoor-indoor 33kV conversions – work that Transpower is currently planning with construction anticipated to commence in 2015.

3.3.1.5 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, with a 32MVA cyclic rating following mitigation of a protection constraint. The maximum demand on the Melling GXP in 2013 was 34.5MVA for the 33kV supply and 27.7MVA supplied at 11kV. During 2013, the old 33kV double circuit connection from Melling GXP to Petone was decommissioned in favour of an 11kV feeder from Korokoro zone substation.

Melling GXP is located within a flood zone of the Hutt River and in recent times there have been two floods that have caused damage at this site. Transpower redeveloped the site and moved all sensitive equipment, including the 11kV switchboard into a raised building. A flood barrier was built to deflect floating debris away from Transpower's switchyard. Unfortunately, this barrier will deflect debris into Wellington Electricity owned equipment such as 33kV cable risers and the Melling ripple injection plant (which may also be submerged in high water). Wellington Electricity has raised this issue with Transpower and the risks at this site are being jointly reviewed. Both companies are also identifying and evaluating solutions to this problem including, if necessary, relocation of the Wellington Electricity owned ripple equipment and extension of the flood barrier. It is anticipated this risk review will be completed during 2014, and any remediation projects will be included in the 2015 AMP.

3.3.1.6 Gracefield

Gracefield GXP comprises a conventional arrangement of two parallel 110/33kV transformers nominally rated at 85MVA each. Maximum demand on the Gracefield GXP in 2013 was 58.8MVA. 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. There are currently no issues with the Transpower owned assets at Gracefield GXP.

3.3.1.7 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 via Transpower owned circuits from the Wilton GXP, and has two 38MVA 110/11kV transformers in service. These assets are owned by Transpower.

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.

Maximum demand at Kaiwharawhara in 2013 was 33.5MVA.

3.3.1.8 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 Transpower owned 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 only transformer connected to that circuit.

Maximum demand at Central Park GXP in 2013 was 181MVA, which is within the N-1 rating of the supply transformers. However, due to System Operator rules for managing the transmission network in situations where there is no 110kV bus, the loading would normally be constrained to 109MVA in the event of one 110kV supply circuit being out of service. This operating restriction is in place to protect the transformers in the event of an unplanned outage of one of the two remaining incoming circuits.

To overcome this operating restriction, Transpower has installed a special protection scheme. This avoids any load reduction when only two of the three incoming circuits are in service, but automatically sheds load in the event of an unplanned outage of one of these two remaining incoming circuits. The potential loss of supply in such an event is around 70MW, but it would affect substations with limited back feed options from other GXPs. Transpower has identified a need to replace the Central Park transformers in the short term and at this time a permanent solution will be considered. This is discussed further in Section 5.12.1.

Central Park GXP currently supplies over 30% of Wellington Electricity's total load, including much of the electricity used within the Wellington CBD. Hence, Wellington Electricity is vulnerable to a HILP event that could potentially disrupt all supply from this GXP for an extended period. This vulnerability could be mitigated by transferring load away from Central Park to another GXP (most likely Wilton), by changing the physical design of the GXP to reduce the likely impact of a HILP event on the serviceability of the substation or by putting contingency plans in place to reduce the time required to restore supply following such an event. As also discussed in Section 5.12.1, Wellington Electricity is currently working with Transpower to develop strategies to reduce this vulnerability.

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.

3.3.1.9 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. These transformers are each nominally rated at 100MVA, and the maximum demand in 2013 was 51.4MVA. Mill Creek wind farm, being commissioned during 2014, is connected to the Wilton 33kV bus. This is expected to contribute to a reduction in peak demand from the National Grid at this location – the extent of which is not fully known at this time due to the variable nature of wind generation.

By March 2014, Transpower will have completed the replacement of the outdoor 33kV switchyard with an indoor switchboard. It is also planning to replace the existing 110kV bus with three outdoor bus sections by 2015. No further issues with the Transpower owned assets at Wilton GXP are expected to arise during the planning period.

3.3.2 Embedded Generation

There is a range of embedded generation connected to the network, including over 140 installations of photovoltaic solar panels averaging 3.5kW per site. Some major customers such as hospitals, have standby diesel generators that can be synchronised to the power system. 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.

Generation Type	Installed Capacity
Standby Diesel	9.0MW
Landfill Gas	4.0MW
Hydroelectric	0.8MW
Photovoltaic	0.5MW
Wind	0.2MW
Total	**14.5MW**

Figure 3-7 Summary of Embedded Generation Connected to Wellington Electricity Network

Construction of the Meridian Energy Mill Creek wind farm is due for completion by early to mid-2014. This is located in the Ohariu Valley area and will have a capacity of 60MW. The Mill Creek wind farm will connect at 33kV via lines owned by Wellington Electricity.

A further wind farm, to be located on the south coast of Wellington, with an installed capacity of approximately 8MW, has been consented but development has halted for the time being. Wellington Electricity has previously worked with the wind farm developer on options for providing a connection to its 11kV network and this connection requirement may arise in the short to medium term.

3.3.3 Subtransmission

The 33kV subtransmission system is comprised of assets that take supply from the Transpower GXPs and feed a total of 28 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 205km, of which 147km is underground.

All zone substations have N-1 subtransmission supply at 33kV, with one supply from each side of a Transpower bus where this is available. Plimmerton and Mana 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. More detail on this is in Section 5.13.4.

A potential weakness in the Wellington Electricity subtransmission network, as highlighted by recent experiences in Christchurch, is earthquake damage to underground cables. While each zone substation has two 33kV incoming supplies, in most cases these two cables follow a single route. This leaves the network vulnerable to both incoming supplies to a substation being damaged by a single event, for example a major earthquake. Attempting to mitigate this risk by installing new cables on diverse routes and creating interconnectivity at 33kV level would be very expensive, and due to the unpredictable nature of earthquake strength, location and damaged caused, not guaranteed to be successful. Wellington Electricity is currently in consultation with Wellington City Council to secure routes for emergency 33kV overhead lines that could be rapidly constructed following a major earthquake to restore supply in an emergency.

As of October 2013, Petone zone substation is no longer supplied at 33kV from the Melling GXP, and its 11kV switchboard is now supplied by a dedicated 11kV feeder from Korokoro zone substation, which is in turn supplied at 33kV from Gracefield GXP. Load control on the Petone subtransmission circuits has been reconnected to the Naenae subtransmission circuits.

A schedule showing each zone substation’s firm capacity, incorporating both 33kV cables and transformers is in Section 5.13.

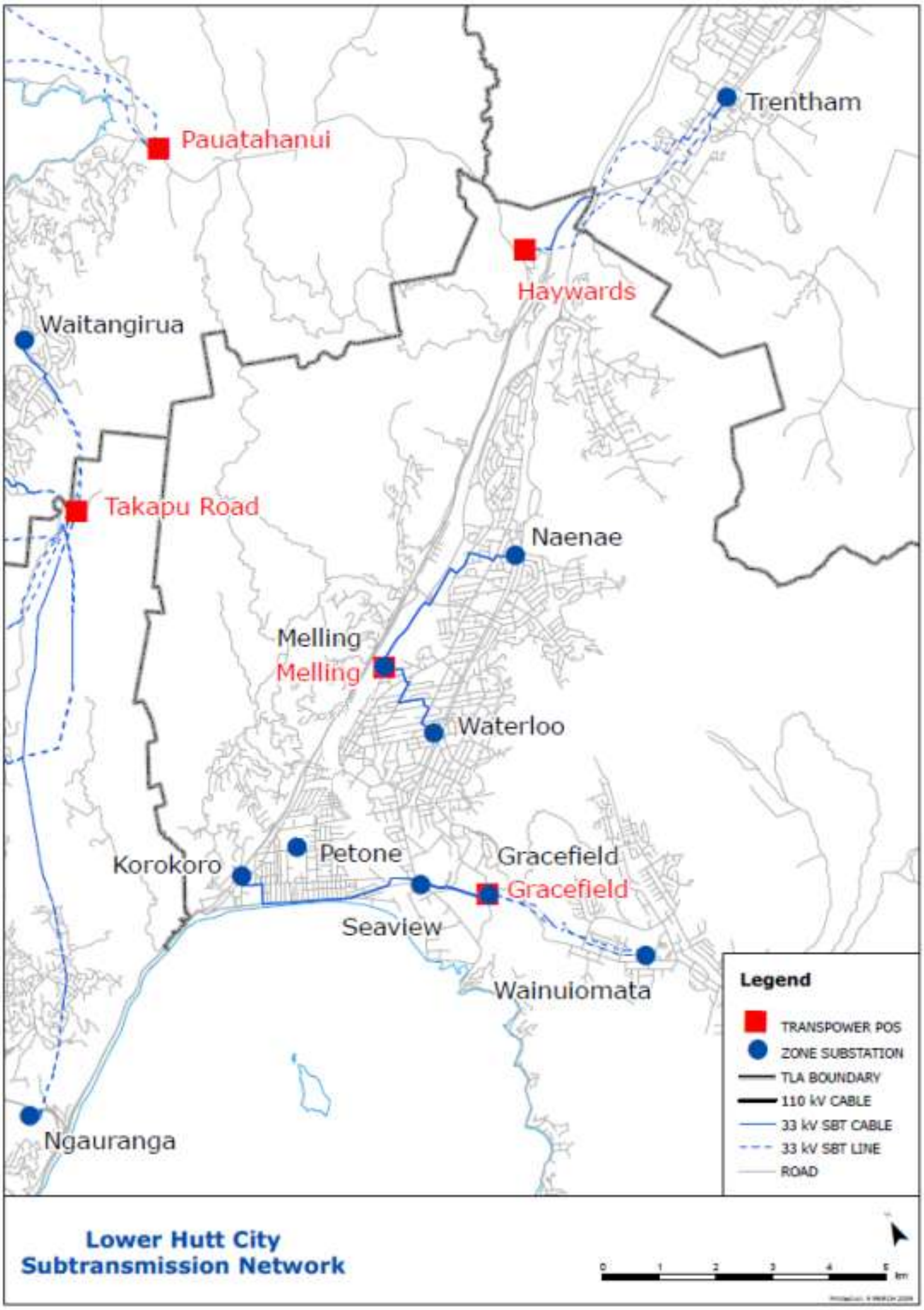


Figure 3-8 Lower Hutt Subtransmission Network

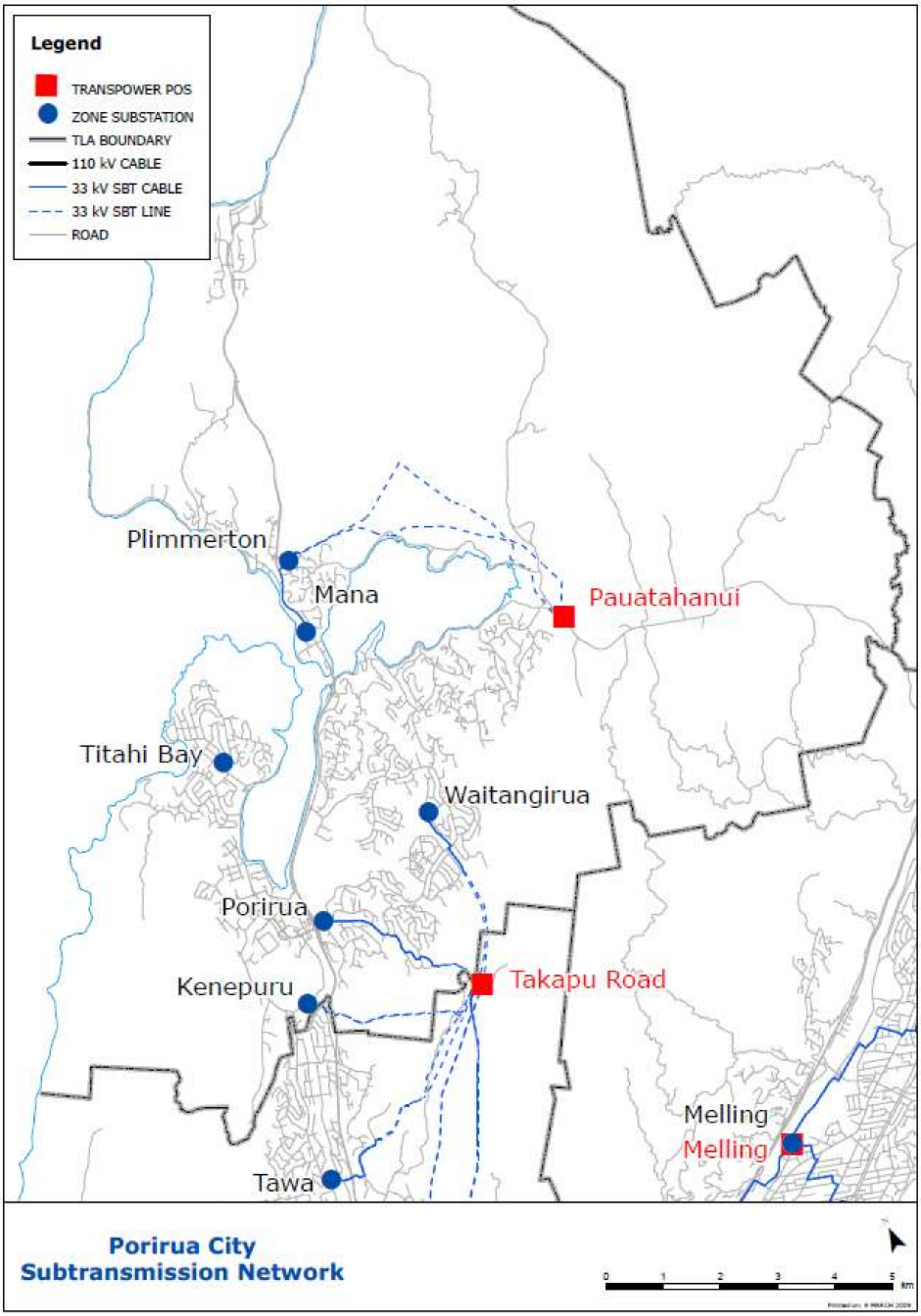


Figure 3-9 Porirua City Subtransmission Network

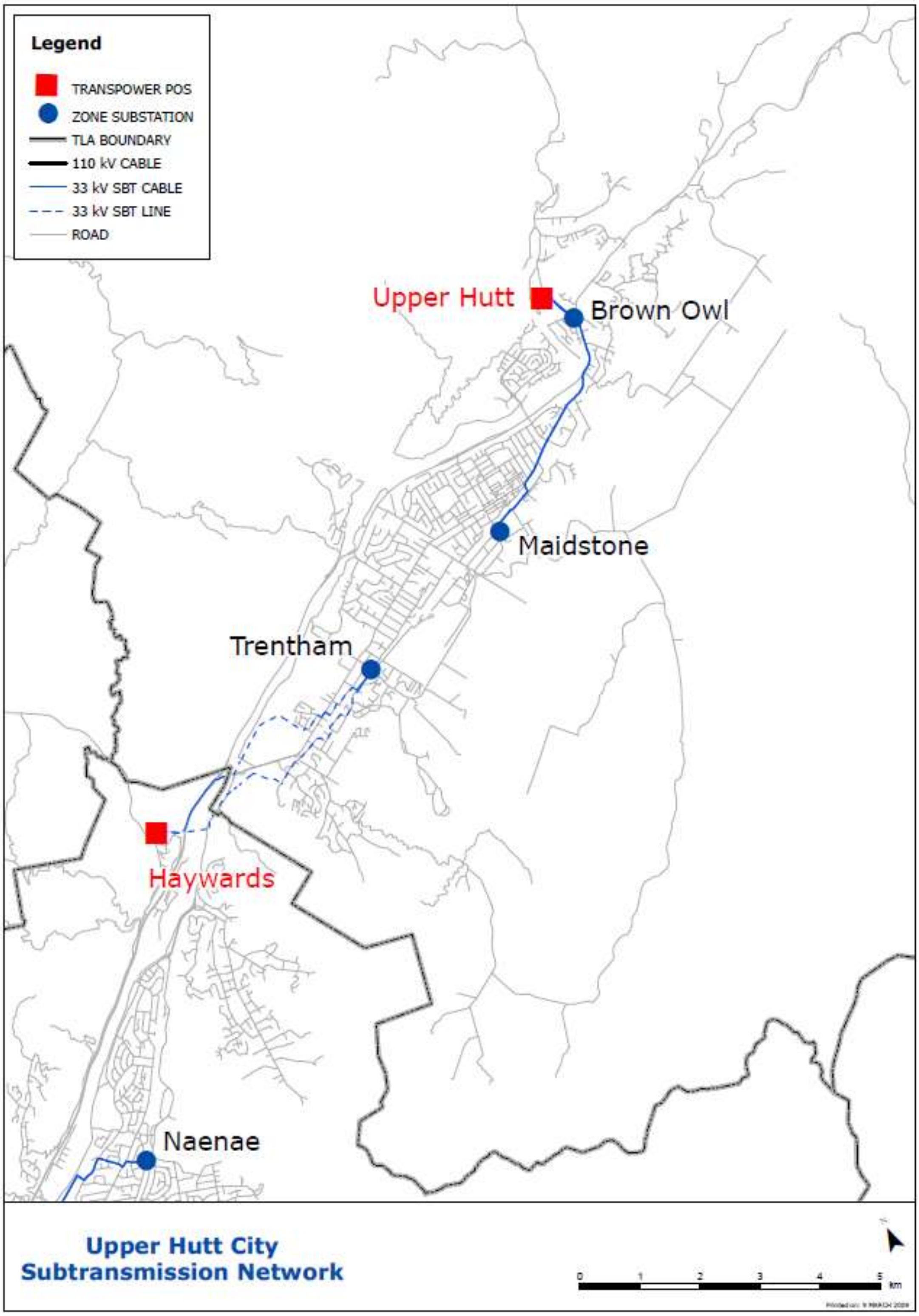


Figure 3-10 Upper Hutt City Subtransmission Network

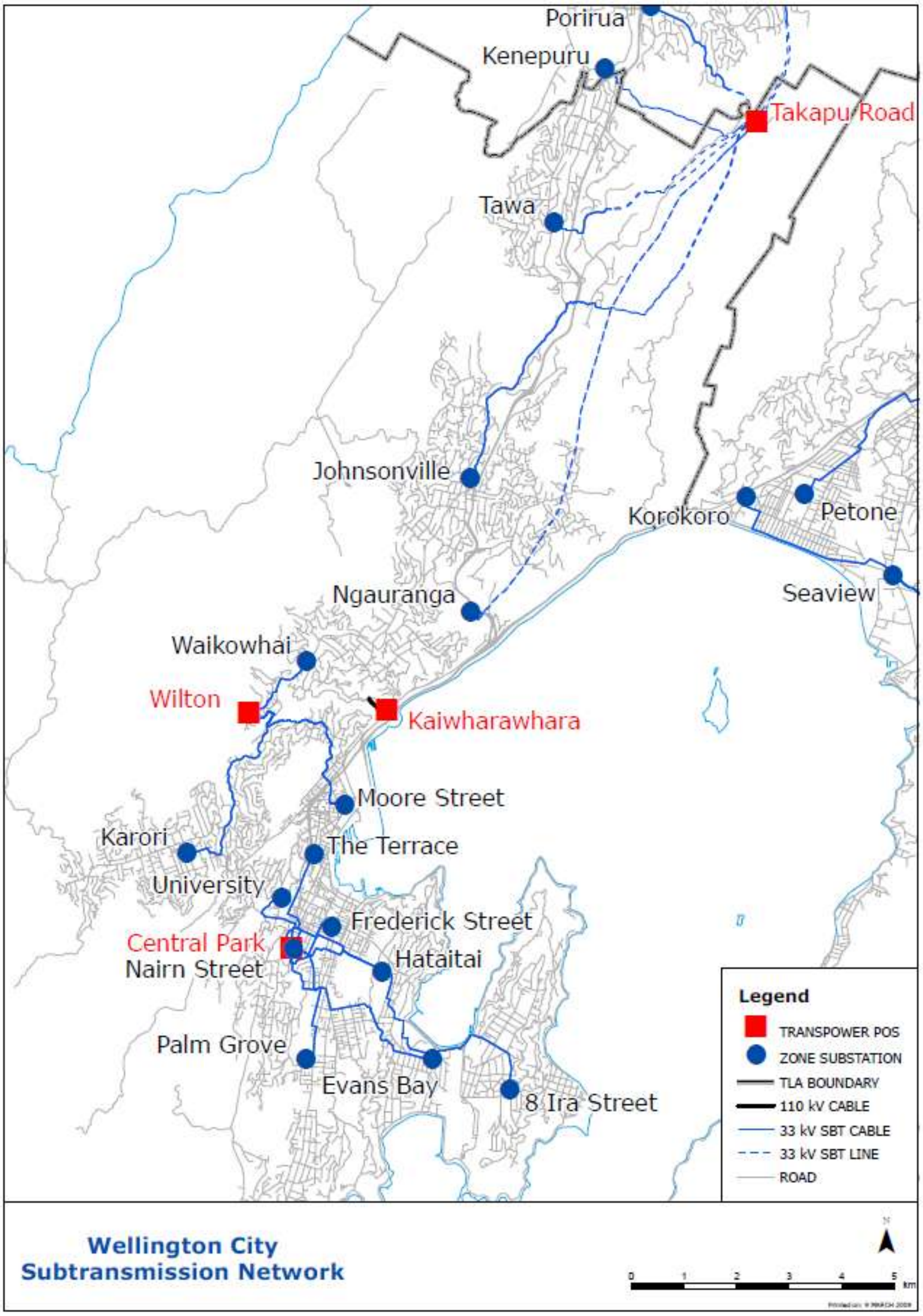
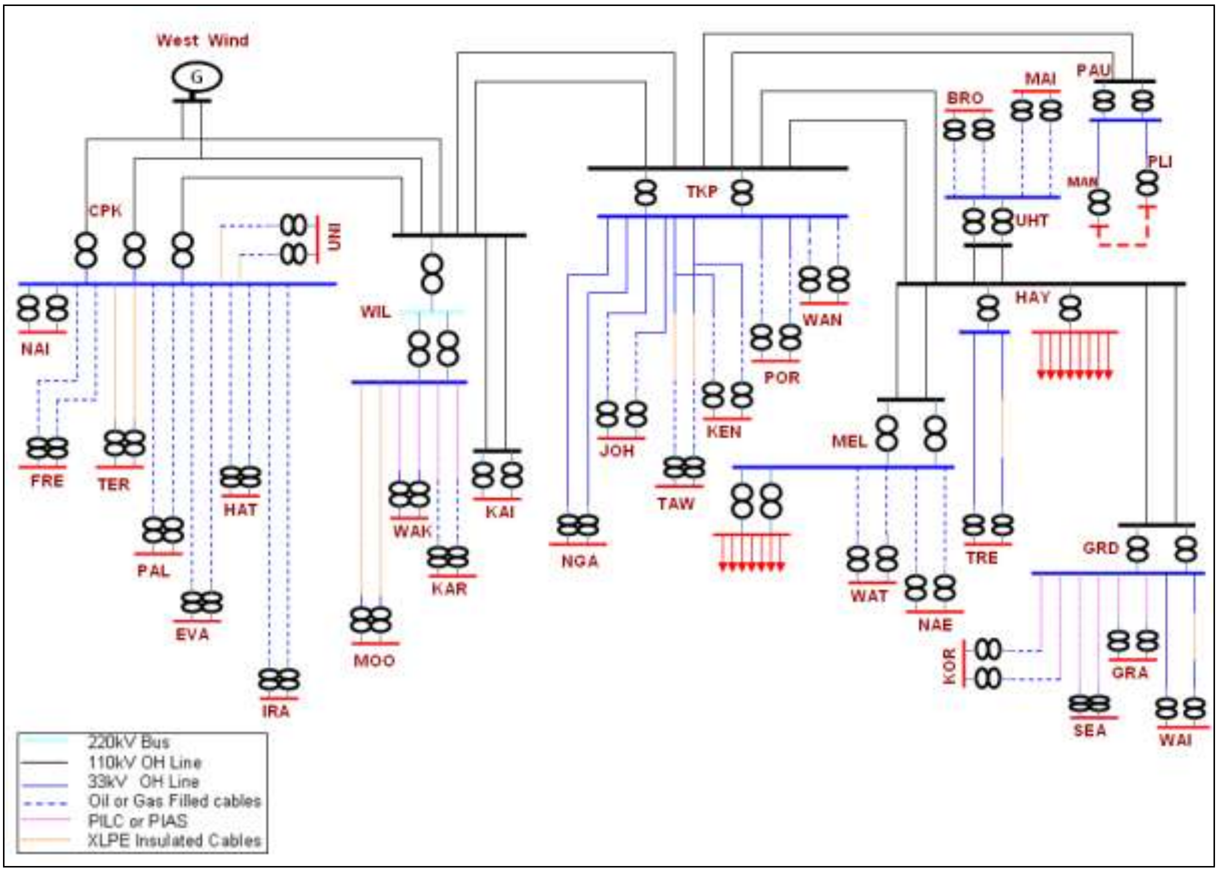


Figure 3-11 Wellington City Subtransmission Network



Note: The 110kV lines and transformers shown in Figure 3.12 are all owned by Transpower and are not covered by this AMP.

Figure 3-12 Overview of Wellington Electricity Network Connectivity

3.3.4 Distribution System

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 approximately 4,240 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 1,740km, of which 66% is underground. In Wellington City the 11kV network is largely underground, whereas in the Hutt Valley and Porirua 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[2] 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 11kV network outside the Wellington CBD, both in the Wellington City and Hutt Valley 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

[2] 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 approximately 1,750 11kV circuit breakers operating within the distribution system. Around 370 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, mostly situated within or close to the Wellington CBD or in the Wellington City area, and allow the primary feeders in their respective areas to be operated in a closed loop arrangement. 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. This is subject to cables having sufficient rating to carry extra load to support these contingent events.

The number of circuit breaker used in the distribution network is high in relation to other networks in New Zealand as illustrated in Figure 3-13.

Network	ICP count (approx.)	CB count (approx.)	ICP/ CB ratio (approx.)
Vector Networks	520,000	1,550	330
Orion NZ	190,000	800	240
Wellington Electricity	**165,000**	**1,750**	**95**
Unison	107,000	270	400
WEL Networks	84,000	380	220
Aurora Energy	81,000	400	200
Northpower	53,000	200	260

Figure 3-13 Comparison of Number of Circuit Breakers in Various Networks

The high number of circuit breakers in the network is a result of historic design practices, particularly within the Wellington City area where a former owner constructed a very reliable network. 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. Wellington Electricity aims to maintain the current service level for an area when equipment renewal or network reinforcement is required and therefore may replace circuit breakers with like for like in those parts of the distribution network where the existing architecture makes use of mid-feeder circuit breakers. 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.

3.3.5 Distribution Substations

Throughout the distribution network there are approximately 4,240 distribution substation sites (3,540 owned by Wellington Electricity as standalone sites and 700 housed within consumer premises) with around 4,310 distribution transformers in service, as some sites have multiple transformers installed. Smaller substations (typically 200kVA or less) in areas supplied by overhead lines are generally pole-mounted and are either simple 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 or frame) up to larger three-transformer substations with multiple circuit breaker (CB) switchboards and extensive LV distribution framing. More compact ground mounted substation designs are also used; these are generally a pad mounted integral style, with an LV distribution frame, 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.

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 3-14.

Enclosure type	Quantity
Outdoor	275
Indoor	973
Pad mounted Integral	1,170
Pole	1,821

Figure 3-14 Overview of Distribution Substation Types

3.3.6 Low Voltage Lines and Cables

Low voltage 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 2,700 circuit-km, of which approximately 61% is underground.

Consumers are supplied via a low voltage fuse, which is the installation control 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. 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 service pillars there are approximately 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 in situations where their condition is poor and where they provide operational flexibility, or where the type of load served is sensitive to outages on the low voltage network, and back feeding will ensure higher service levels. In some cases, the LV network configuration has changed and where there is no longer a requirement for link pillars, they are removed once they have become unserviceable.

3.3.7 Secondary Systems

3.3.7.1 Protection Assets

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 more than 1,200 protection relays in operation. Around 85% are older 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

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

3.3.7.2 Supervisory Control and Data Acquisition (SCADA)

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 located at the Haywards substation through dedicated communication links. Control signals travel in the opposite direction over the same communications links.

Network control rooms are located at Petone and Haywards. The Petone NCR functions as the main control room and is connected to the Haywards central master station via the Transmission Control Protocol/Internet Protocol (TCP/IP) network.

The Haywards NCR serves as a backup should the Petone NCR not be operational or be unsafe to operate. The Haywards NCR is directly connected to the central master station.

3.3.7.3 Load Control

Wellington Electricity uses a ripple injection load control system to control selected loads such as water heating and storage heaters within consumers' premises, to control street lighting and to provide tariff signalling as required by retailers using the network.

Wellington Electricity owns ripple injection equipment at a number of its zone substations, connected at 33kV in Wellington, and at 11kV in the Hutt Valley. The ripple injection equipment sends coded signals over the power lines, which are detected by control relays at the point of control. These relays, which are not owned by Wellington Electricity, then turn the controlled load on or off according to the signals they receive.

Since April 2012, Wellington Electricity has offered a controlled rate tariff intended primarily for electric vehicle (EV) charging. This load is controlled using conventional ripple signals through the addition of an EV channel.

The system is automatically operated by the ripple control master station located at Haywards, and can be remotely operated from a user terminal at the Petone NCR. Load control is fundamental to the operation of an optimised distribution network since it allows higher utilisation of available system capacity and can avoid the need to dispatch peak generating plant with high operating cost.

3.3.7.4 Communications System

Operation of secondary systems requires the use of high security communication links between the master station and the different remote control and monitoring points. Like most distribution businesses, Wellington Electricity owns and operates its own communications system, which also incorporates a small number of dedicated communications links leased from service providers such as Telecom, Vector Communications and Transpower. Wellington Electricity's own network comprises mainly copper pilot cable with a small amount of fibre-optic and UHF radio infrastructure. Communication links leased from other service providers are either fibre-optic or radio links.

3.4 Categories of Assets and Age Profiles

3.4.1 Subtransmission Cables and Lines

3.4.1.1 Subtransmission Cables

Wellington Electricity owns approximately 137km of subtransmission cables operating at 33kV. These cables comprise some 52 circuits connecting Transpower GXPs to Wellington Electricity's zone substations. Around 25km of subtransmission cable is of XLPE construction and requires little maintenance. 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 fluid filled PIAS (paper insulated aluminium sheath) cables rated for 110kV but operating at 33kV. The lengths, age profile and spare holdings of this asset class are shown in Figures 3-15 to 3-17 below.

Construction	Design voltage	Percentage	Quantity
Paper Insulated, Oil Pressurised	33kV	31%	42km
Paper Insulated, Gas Pressurised	33kV	35%	48km
Paper Insulated	33kV	9%	13km
XLPE Insulated	33kV	18%	25km
Paper Insulated, Oil Pressurised	110kV	7%	9km

Figure 3-15 Summary of Subtransmission Cables

33kV rated cables that are run at 11kV are not included in the subtransmission circuit length. These include oil-filled cables supplying the Titahi Bay 11kV switching station from Porirua zone substation, which could in future be energised at 33kV if Titahi Bay was developed into a full zone substation.

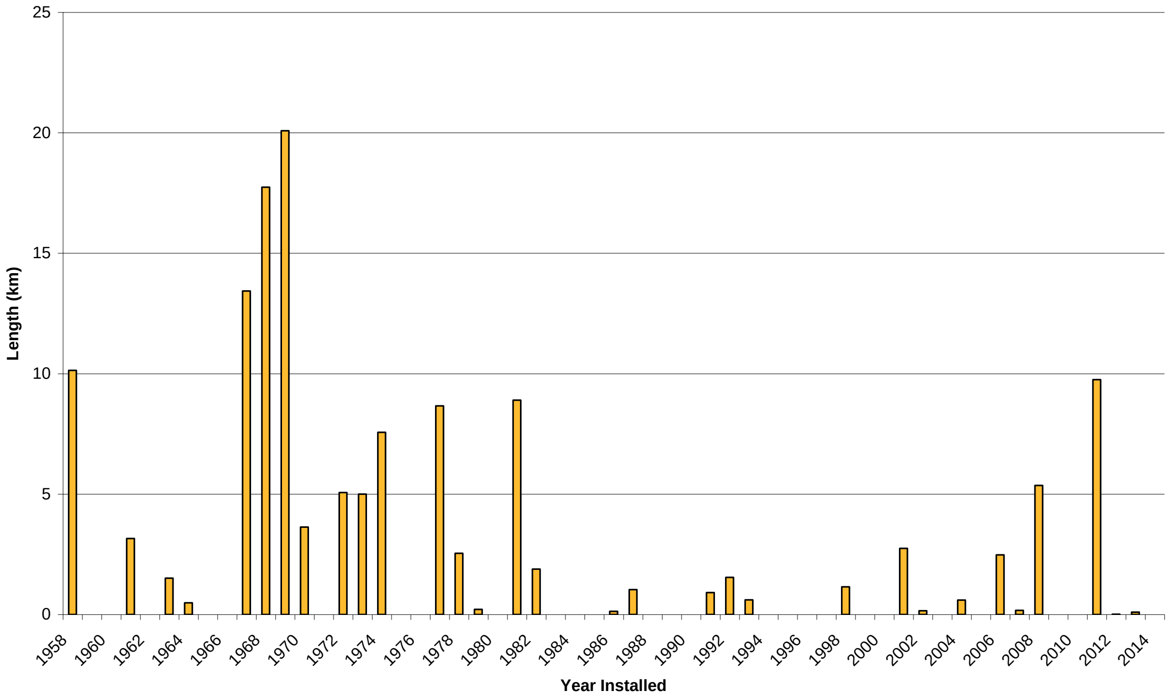


Figure 3-16 Age Profile of Subtransmission Cables

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 have been purchased and are held in storage to allow the replacement of damaged sections of gas filled cables with non-pressurised XLPE cables

Figure 3-17 Spares Held for Subtransmission Cables

Full details of maintenance, refurbishment and renewal practices are in Section 6 (Lifecycle Asset Management).

3.4.1.2 Subtransmission Lines

Wellington Electricity owns approximately 58km of subtransmission overhead lines operating at 33kV, which connect Transpower GXPs to Wellington Electricity's zone substations. These are on both wood and concrete pole lines with AAC conductor being the predominant type. Overhead line was typically used for subtransmission in the former Hutt Valley network, 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.

Category	Quantity
33kV Overhead Line	58km

Figure 3-18 Summary of Subtransmission Lines

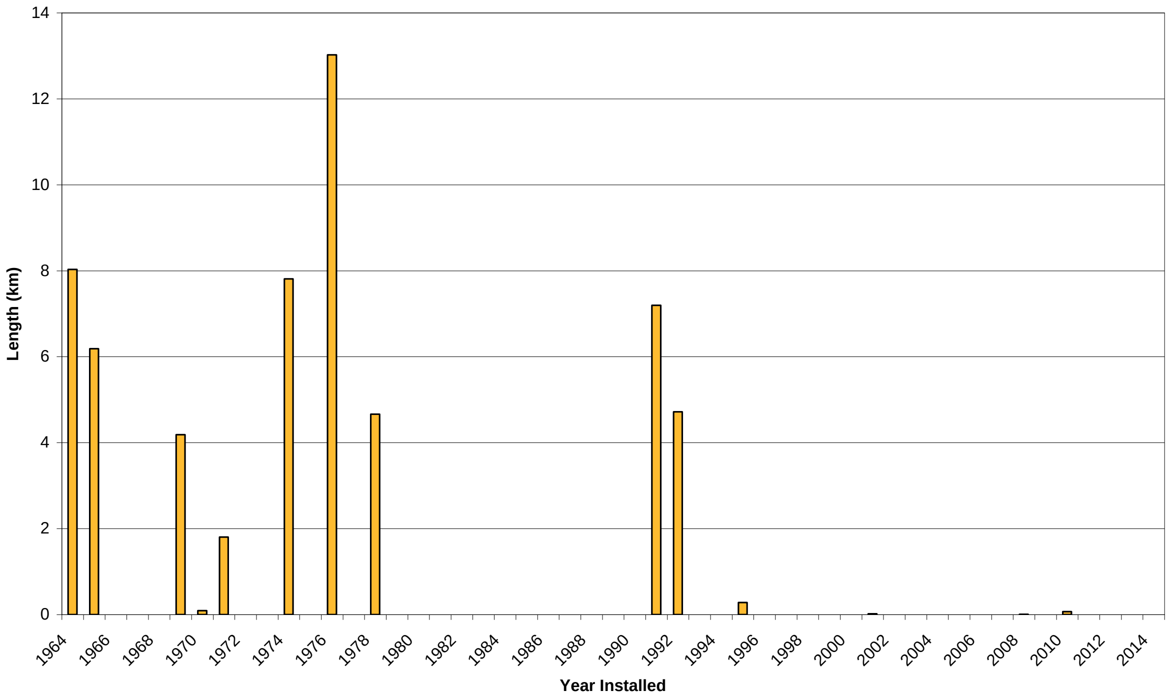


Figure 3-19 Age Profile of Subtransmission Lines

3.4.2 Zone Substation Buildings

Wellington Electricity has nearly 500 substation buildings on the network. There are 30 major substation buildings, 27 of which are located at zone substation sites 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 below.

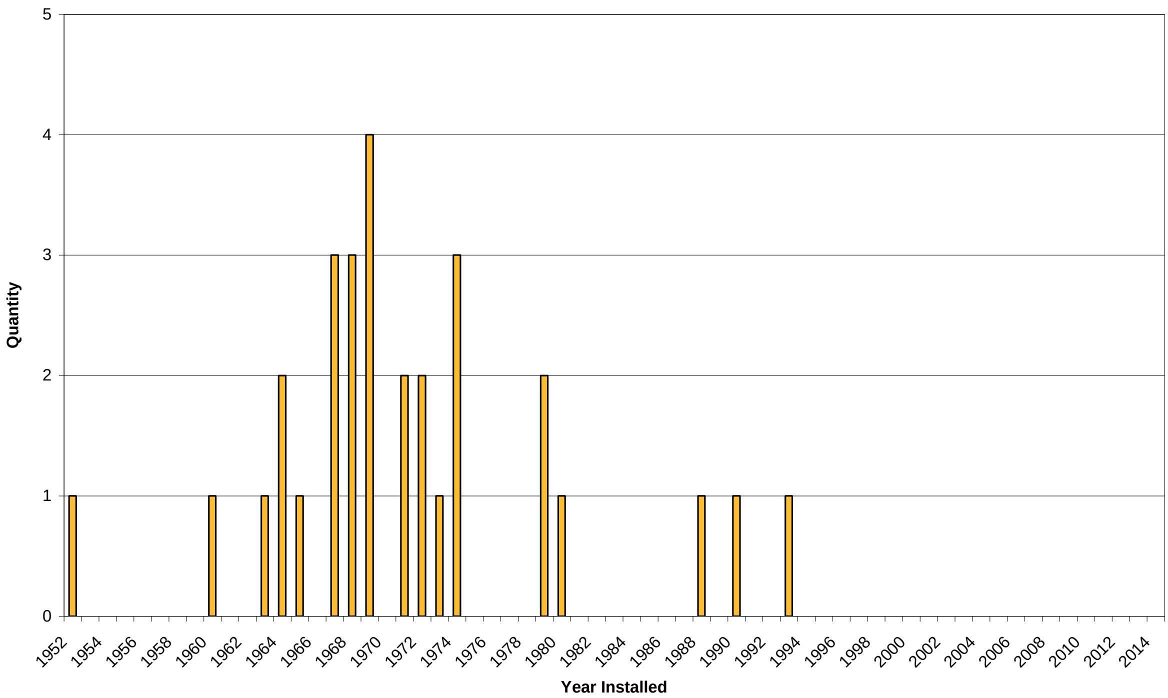


Figure 3-20 Age Profile of Zone Substation Buildings

The average age of the buildings is 42 years and they are in good condition. However, from time to time maintenance or replacement of some components such as doors, roofs and spouting is required. Wellington Electricity is required to undertake seismic strengthening activities on buildings as required by the local councils on some of the older buildings constructed prior to 1976. A seismic review and assessment has been undertaken on the majority of zone substation buildings. Remedial work, including securing plant inside substations, has been undertaken as a result of this review.

In some cases, Wellington Electricity does not own the land under the zone substation and has a long-term lease with the landowner.

Full details of maintenance and refurbishment practices are in Section 6 (Lifecycle Asset Management).

3.4.3 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. Overall, the transformer fleet is in a generally sound condition even though a number of transformers are reaching their end of design life of 55 years. Based on their operating conditions and maintenance, most transformers are expected to continue to operate beyond their design life. Nevertheless, older transformers require more intensive monitoring to assess and evaluate their condition. Estimated DP tests[3] on these transformers completed in 2009, using the Furan analysis method, indicate a high level of remaining life given their age. Whilst not as conclusive as taking internal paper samples, this assessment method provides a good indicator of internal condition. Mechanical deterioration

[3] Degree of Polymerisation, an indicator of dielectric strength of paper insulation.

is an issue that needs to be monitored on older units, both for the condition of external fittings, as well as internal components such as tap changer contacts and mechanisms.

The age profile for zone substation transformers is shown below.

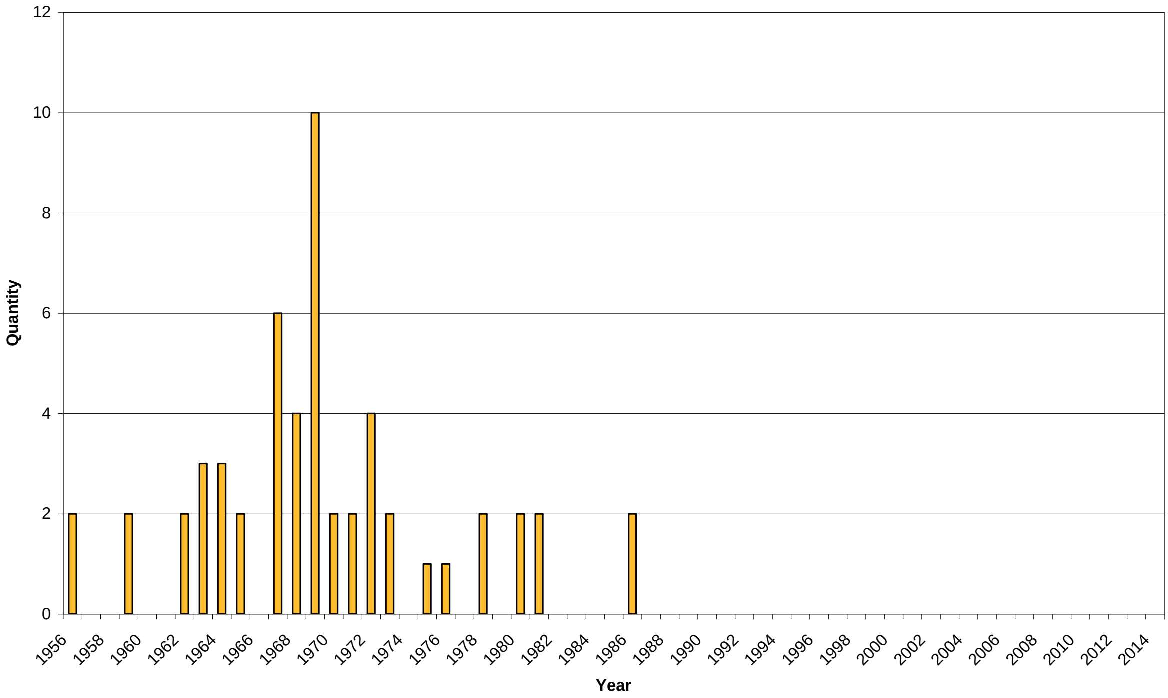


Figure 3-21 Age Profile of Zone Substation Transformers

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 two transformers have exceeded an age of 55 years.

Wellington Electricity holds critical spares for the power transformers and tap changers in the system as detailed in the table below.

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
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

Strategic Spares	
Spare transformers	Two spare power transformers became available when the Petone substation was decommissioned in 2013. One of these has been installed at Wainuiomata to allow refurbishment of Wainuiomata A following a fault with the unit, and the other is held at the Bouverie Street yard 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 3-22 Spares Held for Zone Substation Transformers

3.4.4 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.

A range of spares is held - mostly chargers of different voltages that have been removed from sites over recent times. Batteries are available locally at short notice so are not held.

3.4.5 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 largest single type is Reyrolle Pacific type LMT circuit breakers, but other types are also in service in large numbers. There are approximately 1,750 circuit breakers forming 427 11kV switchboards on the Wellington Electricity network.

An age profile of the circuit breakers and switchboards is shown below.

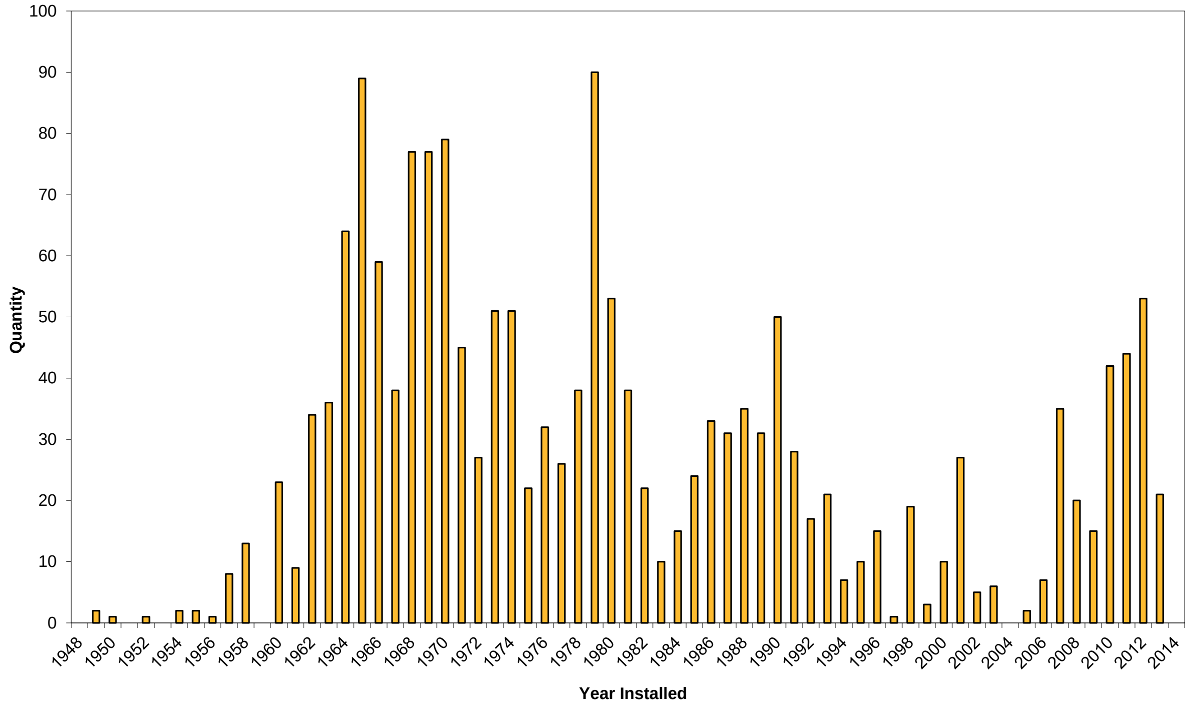


Figure 3-23 Age Profile for Circuit Breakers

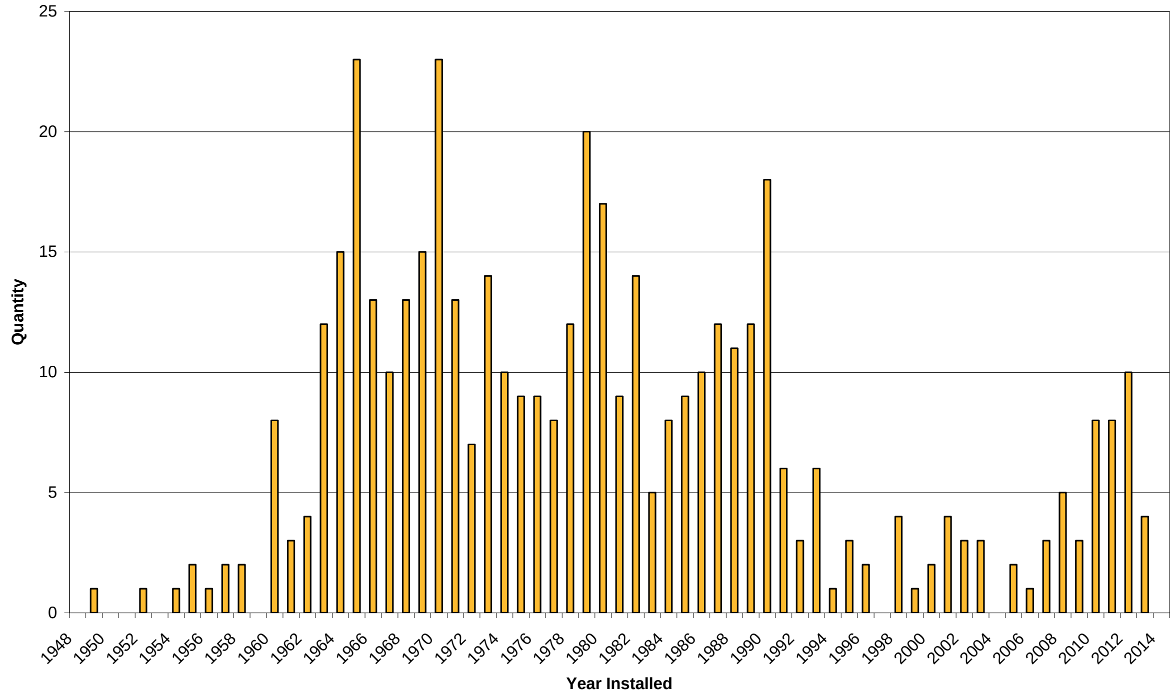


Figure 3-24 Age Profile for Switchboards

The age profile indicates that the average age of circuit breakers in the Wellington Network is around 32 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. Nevertheless, 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 oil circuit breakers at Ngauranga, which have been in service at this site for approximately 21 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. However, certain circuit breaker types are of concern due to inadequate fault level rating, equipment failures, lack of spare parts, and increased maintenance costs. Renewal programmes to address these issues are in place, as discussed in Section 6.4.6.

Category	Quantity
33kV Circuit Breakers	2
11kV Circuit Breakers	1,743

Figure 3-25 Summary of Circuit Breakers

Manufacturer	Breaker Type	Quantity
ABB	Vacuum	11
AEI	Oil	88
BTH	Oil	50
Crompton Parkinson	Oil	2
GEC/Alstom	Oil	100
Merlin Gerin / Schneider	SF_6	159
Reyrolle	Oil	1057
	Vacuum	81
Siemens	SF_6	16
South Wales	SF_6	36
Statter	Oil	49
Yorkshire	Oil	66
Not recorded	Not Recorded	30
Total		**1,745**

Figure 3-26 Summary of Circuit Breaker by Manufacturer

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.

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 (Reyrolle C gear, LMT, etc).
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 3-27 Spare Parts Held for Circuit Breakers

Full details of maintenance, refurbishment and renewal are in Section 6 (Lifecycle Asset Management).

Typical installation of Reyrolle LMT switchgear at a zone substation

3.4.6 Protection and Control Systems

Due to the closed-ring architecture of the central Wellington distribution network, there are a large number of protection relays, the majority (close to 85%) of which are electromechanical type. Numerical type relays are the latest addition to the network but constitute only 10% of the population. Other non-numerical solid state or static type relays ranging in age from around 15 to 25 years represent around 5% of the total number of relays.

The average age of the protection relays on the Wellington Electricity network is around 33 years and it is estimated that around 400 or 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. As noted in Section 6.4.7, 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 2014. PBO relays are replaced when their switchboards are replaced.

Full details of maintenance, refurbishment and renewal are in Section 6 (Lifecycle Asset Management).

3.4.7 SCADA

Wellington Electricity's SCADA master station is located at the Transpower-owned Haywards substation. It is a GE ENMAC system, which was installed in 2009 and became fully functional in 2011. The GE ENMAC system replaced a Foxboro (formerly Leeds & Northrup (L&N)) 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. Wellington Electricity has investigated the replacement of the automatic load control system and found that an independent system may provide other benefits such as supporting demand side management initiatives. Further investigation of this is planned in 2014 prior to preparation of a business case that will determine the future implementation of the load control functions currently undertaken by the Foxboro system.

Data is communicated to the master station through remote terminal units (RTUs) that are located at the various remote control and monitoring sites. The age and technology of the RTUs vary and many are now obsolete. Wellington Electricity has 251 RTUs installed in sites from GXP level down to small distribution substations and the protocols in use are Conitel, DNP3.0 and IEC61850.

An age profile of SCADA RTUs is shown below.

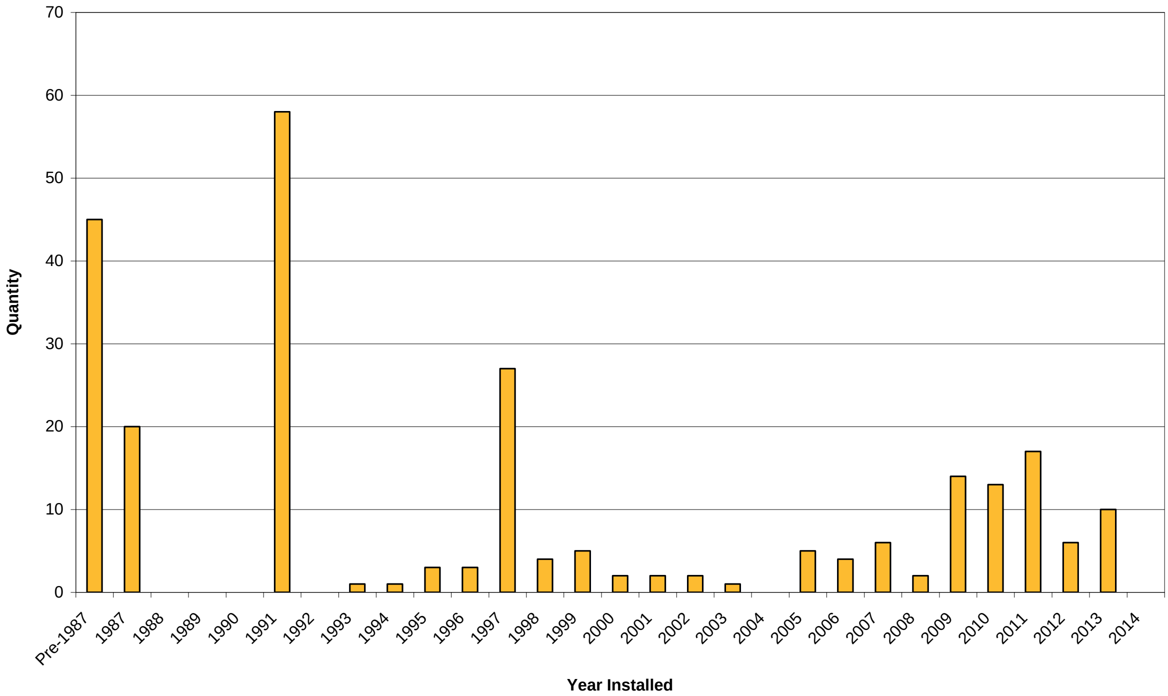


Figure 3-28 Age Profile of SCADA RTUs

Full details of maintenance, refurbishment and renewal are in Section 6 (Lifecycle Asset Management).

3.4.7.1 Substation Level TCP/IP Communications

Presently a number of substation level TCP/IP network communications circuits are leased from external service providers. The contract with the main service provider for the TCP/IP network expired in June 2013, at which point Wellington Electricity took ownership of around 300 routers and other terminal equipment. A draft communications strategy has been developed which outlines the future for all communications, of which substation communications is a major part. Finalisation of this strategy is expected during 2014 and details will be included in the 2015 AMP. The renewal of the communications contracts in 2014 will be an outcome of the final strategy.

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 51 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. Eventually, it is proposed to install separate IP based RTUs at the three sites which utilise the Siemens PAS, which will eliminate the reporting of multiple sites through to the PAS. The details of this transfer have still to be finalised and it is not currently provided for in this AMP.

Full details of maintenance, refurbishment and renewal are in Section 6 (Lifecycle Asset Management).

3.4.8 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 Wellington city 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 Hutt and Porirua areas have a 1050Hz signal injected at 11kV at each zone substation. All ripple injection is controlled automatically by the Foxboro master station at the Haywards Substation but can also be controlled remotely from the Petone NCR. An age profile of ripple plant is shown below.

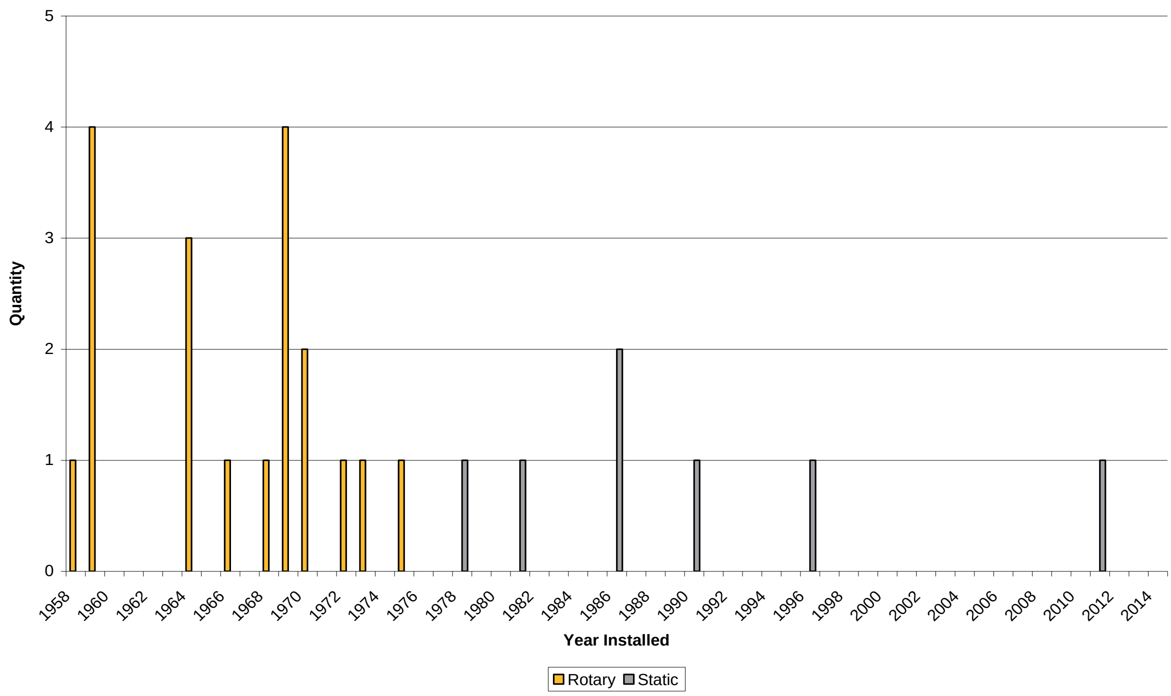


Figure 3-29 Age Profile of Ripple Plant

There is significant benefit in having a fully functional load control system that can control loads at peak times and defer energy consumption by shifting interruptible load at peak times to times of lower demand on the system. This allows for better asset utilisation as the distribution network does not need to be oversized to allow for short duration peaks. However, Wellington Electricity does not own the ripple receivers installed at consumer premises, and is experiencing decreasing levels of control as these devices fail and are not replaced by retailers and metering providers.

Wellington Electricity is encouraging retailers and metering providers to ensure investments and upgrades preserve the ripple control system, due to its importance to managing loading on the network and transmission system. Wellington Electricity believes ripple control is the most cost effective technology for load control due to the existing installed base, and will continue to operate this system. Wellington Electricity also uses the ripple control system to participate in the Instantaneous Reserves market and to support Transpower’s Automatic Under Frequency Load Shedding (AUFLS) system.

For more than 50 years the distribution network has been developed and sized on the basis of having a fully functioning load control system to limit network peak demand. Changes to the Electricity Authority's Model Use of Service Agreement and the development of a market arrangement for load control could potentially lead to Wellington Electricity losing its ability to effectively control the load on its network. The loss of this ability to move load, and the potential decentralised control of it, could lead to negative outcomes such as overloading of system components, increased peak demand on assets and voltage and power quality complaints under some conditions due to high loadings.

If the market concept continues, then protocols need to be established and enforced to make sure that controllable load "owners" do not create system issues through their actions or inactions. In the event that Wellington Electricity is unable to maintain its ability to control load, it will need to increase its load forecasts to account for the reduced level of controllable load at peak times. This could result in a capital investment requirement significantly higher than provided for in the CAPEX forecasts in this AMP in order to provide increased capacity on heavily loaded parts of the network.

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 recently 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 3-30 Spares Held for Load Control Plant

Full details of maintenance, refurbishment and renewal are in Section 6 (Lifecycle Asset Management).

3.4.9 Poles

The total number of poles owned by Wellington Electricity, including subtransmission distribution lines and low voltage lines, is 36,480. Of this number, 28% are wooden poles and 72% are concrete poles. Another 16,361 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).

Pole Owner	Wood	Concrete	Total
Wellington Electricity	10,142	26,338	36,480
Customer / Chorus	11,952	2,398	14,350
Trolley Bus	1,323	688	2,011
Total	**23,417**	**29,424**	**52,841**

Figure 3-31 Summary of Poles

The average age of concrete poles is 25 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 37 years and nearly 38% 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. Crossarms have a shorter life than poles, especially concrete poles, and may require replacement halfway through the life of the pole. An age profile of poles owned by Wellington Electricity is shown below.

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 hazards are identified on consumer owned poles or service lines.

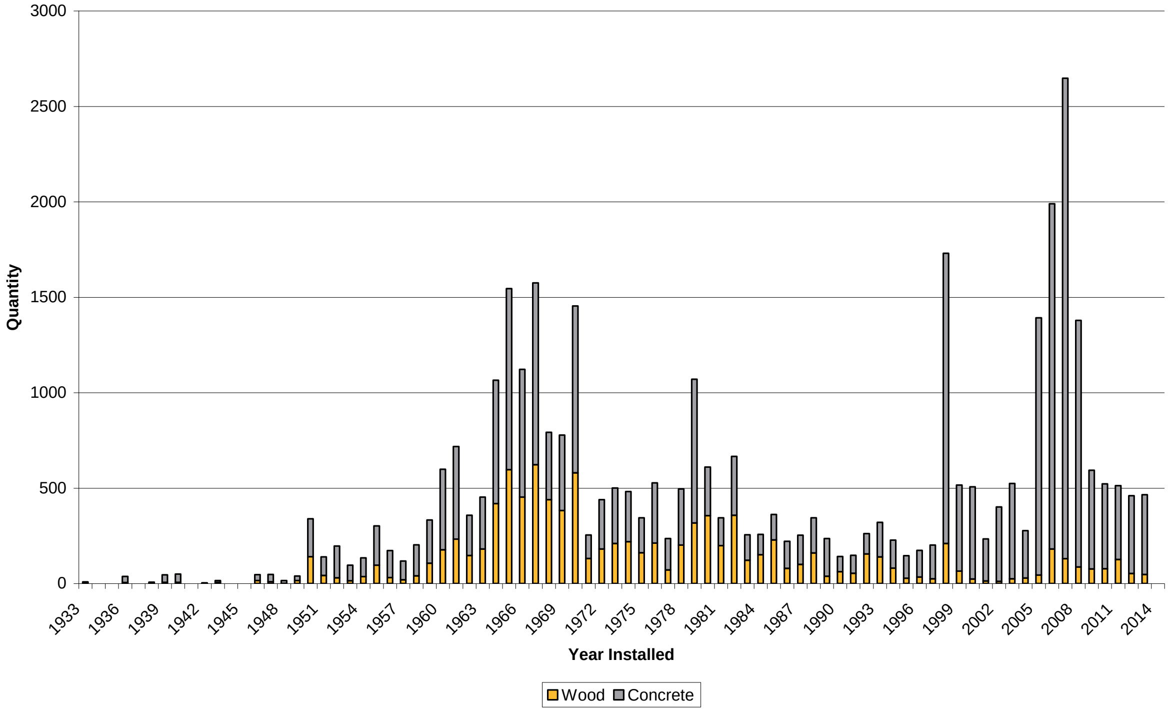


Figure 3-32 Age Profile of Poles

Along with Chorus (formerly Telecom) accessing the poles for its copper telephone services, a previous network owner entered into an agreement with Saturn (now Vodafone) to support cable TV circuits from the majority of the network poles across the region. This is causing problems for maintenance and operations due to congestion on the poles. Due to this congestion, Wellington Electricity must consider the impact and full life cycle costs of future access for wide scale attachment to poles. Each case will be evaluated on its own merits. Wellington Electricity and Chorus have entered an agreement for the use of Wellington Electricity poles to support aerial service lines for the ultrafast broadband roll-out that Chorus is undertaking. Due to the existing congestion on poles, and negative impacts of multiple third party attachments to poles, the agreement allows for only underground to overhead risers or road crossings to poles outside individual properties that have existing overhead telephone services. While not as problematic as circuits running along the lines, these will impede access to Wellington Electricity poles for maintenance and replacement activities.

3.4.10 Distribution and Low Voltage Overhead Lines

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 area. New line reconstruction utilises all aluminium alloy conductor (AAAC). Where possible, low voltage aerial bundled conductor (LV ABC) and, to a lesser extent, covered conductor thick (CCT) for 11kV lines are used in areas susceptible to tree damage. The following graph is the age profile of overhead line conductors.

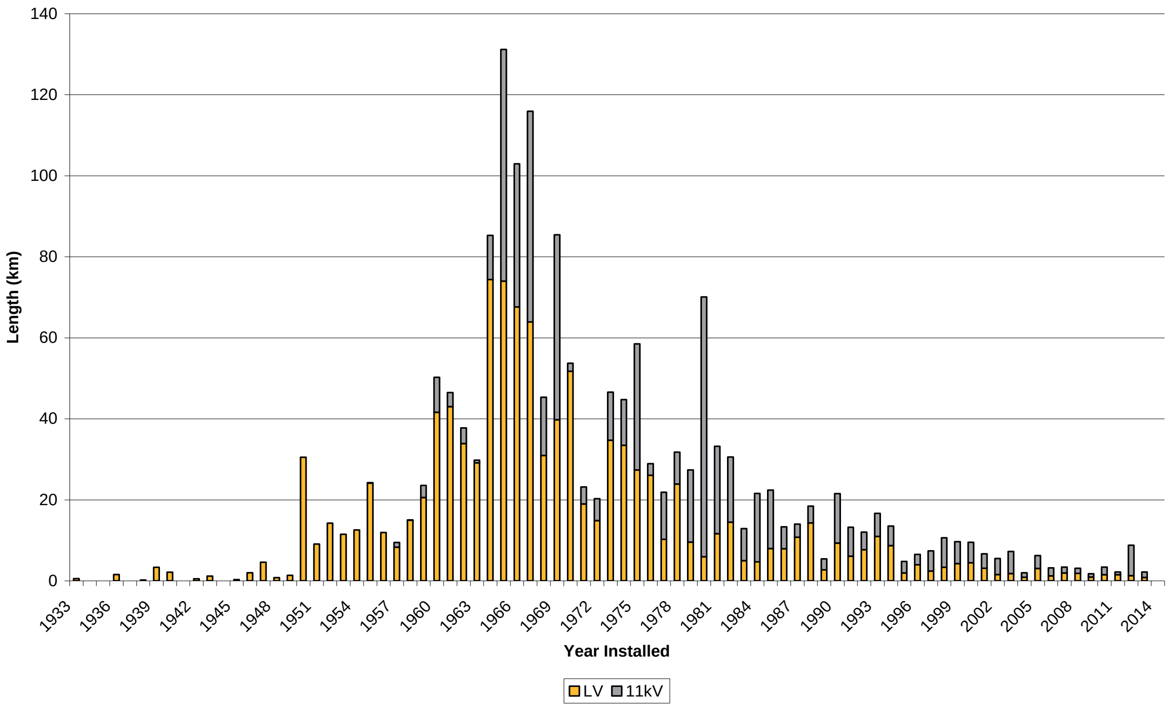


Figure 3-33 Age Profile of Distribution Overhead Line Conductors

Category	Quantity
11kV Line	596km
Low Voltage Line	1,095km

Figure 3-34 Summary of Distribution Overhead Lines

Full details of maintenance, refurbishment and renewal are in Section 6 (Lifecycle Asset Management).

3.4.11 Overhead Switchgear and Devices

There are 295 air break switches (ABS), 21 auto-reclosers, 179 knife links, 59 gas insulated overhead switches and a mix of expulsion type dropout fuses for breaking the overhead network into sections.

Many of the ABSs are more than 29 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 majority of the 21 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 table below.

ACR Manufacturer	Insulation	ACR Model	Quantity
G&W	Solid/Vacuum	ViperS	5
Reyrolle	Oil	OYT	8
Metropolitan Vickers	Oil	UPC	2
McGraw-Edison	Oil	KFE	6
Total			**21**

Figure 3-35 Summary of Auto-Recloser Types

Fault passage indicators, with either remote or local indication, have been installed at a number of major tee offs on the overhead lines. This practice aids fault detection and allows faster restoration of areas affected by interruptions.

Manufacturer	Model	Quantity
Bardin	Flite 110	22
CHK	Not recorded	7
Not recorded	N/A	4
Total		**33**

Figure 3-36 Summary of Overhead Fault Passage Indicators

Age profiles of these overhead line devices are shown below.

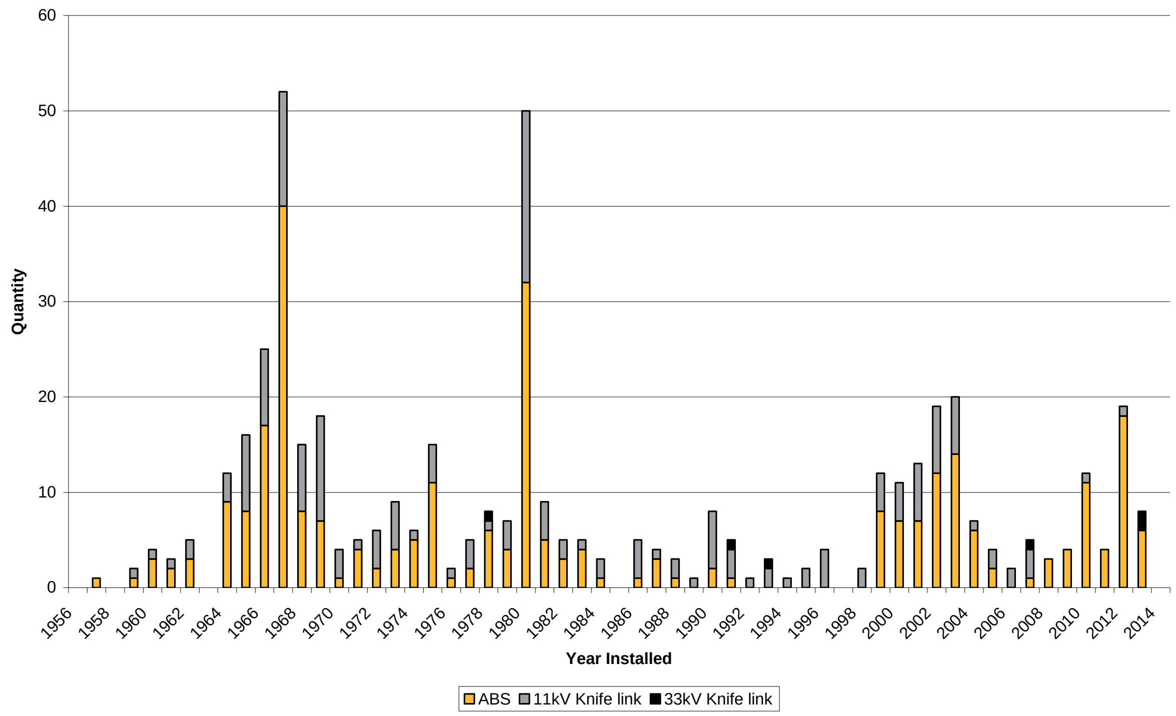


Figure 3-37 Age Profile of Overhead Switchgear and Devices

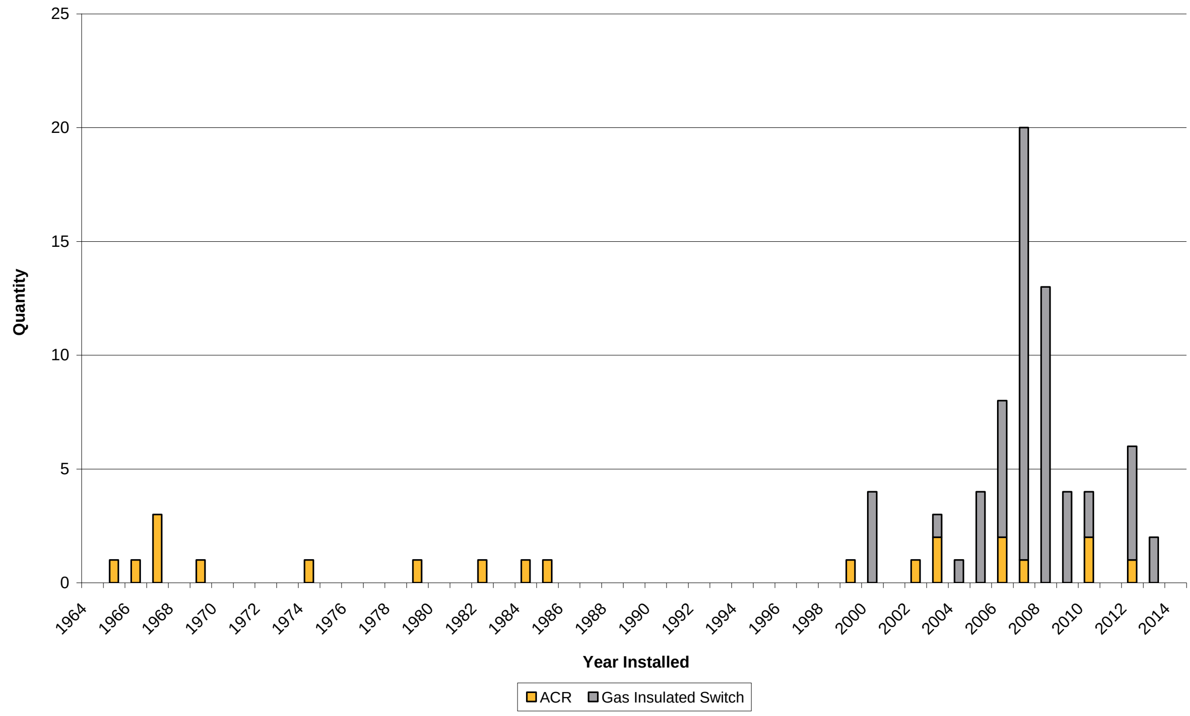


Figure 3-38 Age Profile of Overhead Auto-reclosers and Gas Switches

3.4.12 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 a major defect. 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 are shown below.

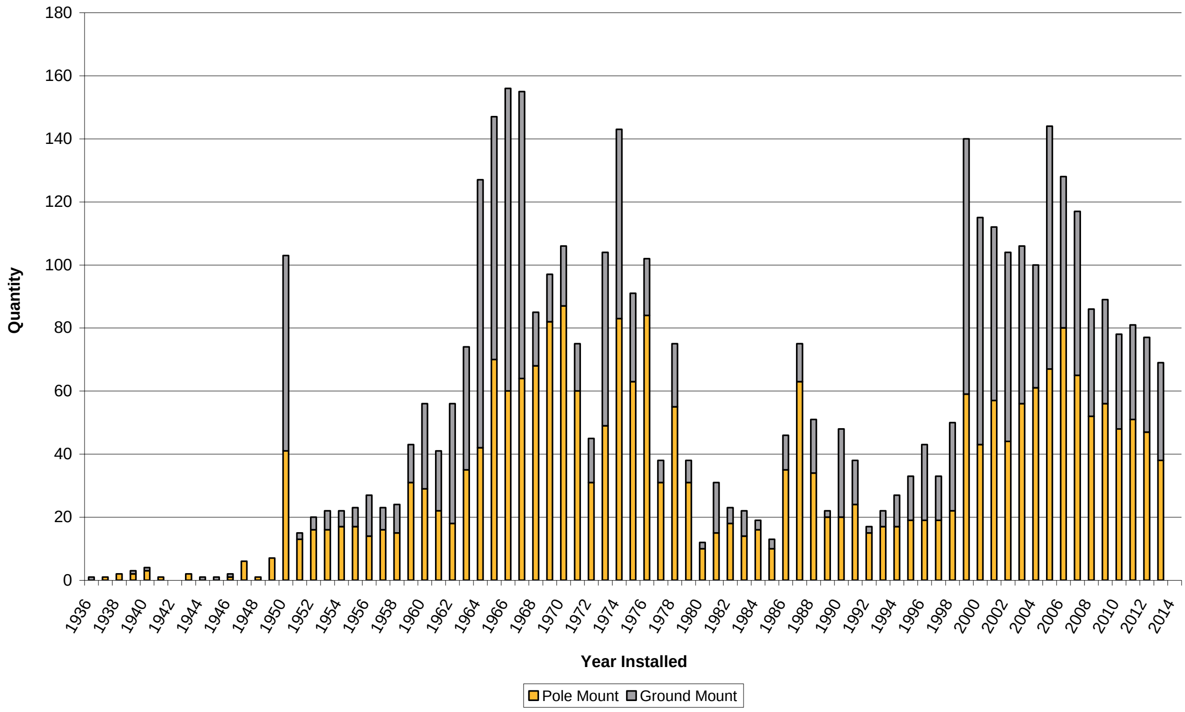


Figure 3-39 Age Profile of Distribution Transformers

In addition to pole and integral padmount berm substations, Wellington Electricity owns 497 indoor substation kiosks and occupies a further 696 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.

Category	Quantity
Distribution transformers	4,310

Category	Quantity
Wellington Electricity owned substations	3,543
Customer owned substations	696
Distribution substations - Total	4,239

Figure 3-40 Summary of Distribution Transformers and Substations

Full details of maintenance, refurbishment and renewal are in Section 6 (Lifecycle Asset Management).

A canopy type distribution substation

3.4.13 Ground Mounted Distribution Switchgear

This section covers ring main units and similar switching equipment that are often mounted outdoors. It does not cover 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 1,931 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 1,380 circuit breakers located within the distribution network), is shown in the graph below.

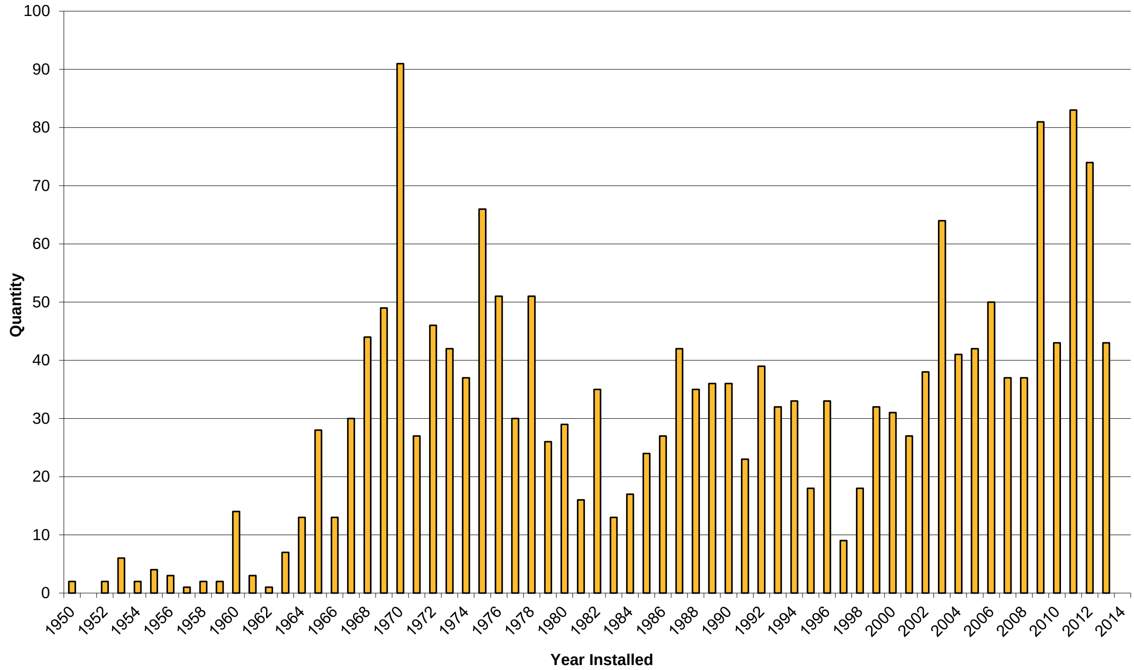


Figure 3-41 Age Profile of Ground Mounted Distribution Switchgear

The average age of the ground mounted distribution switchgear is 24 years.

Category	Quantity
Oil Filled RMUs	269
Gas Insulated RMUs	581
Solid Insulated RMUs	1,081
Total Ring Main Units	**1,931**

Figure 3-42 Summary of Ground Mounted Distribution Switchgear

Full details of maintenance, refurbishment and renewal are in Section 6 (Lifecycle Asset Management).

3.4.14 11kV and Low Voltage Underground Distribution System

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)	1,147km
Low Voltage cable (incl. risers)	1,602km

Figure 3-43 Summary of Distribution Cables

3.4.14.1 11kV and LV 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 relatively old 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.

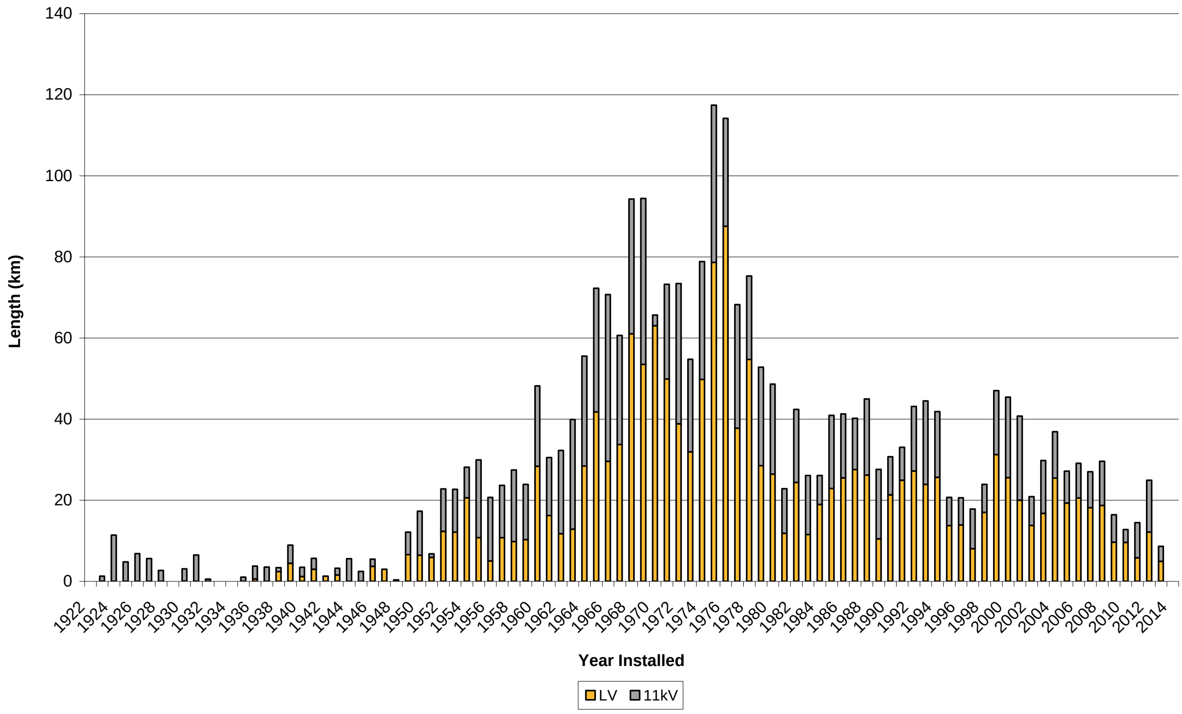


Figure 3-44 Age Profile of Distribution Cables

3.4.14.2 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 the Wellington 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 below.

Type	Quantity
Customer service pillar	13,707
Customer service pit	1,425
Link pillars and pits	397
Total	**15,529**

Figure 3-45 Summary of LV Pillars and Pits

3.4.15 Metering

Wellington Electricity does not own any revenue metering assets as these are owned by retailers and metering companies.

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.

3.4.16 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 at Haywards substation. Wellington Electricity also has shared use of a generator at its corporate office in Petone; however, this generator is owned and maintained by others.

All generation required for network operations and outage mitigation is provided by the works contractor.

Wellington Electricity owns a canopy type substation with 11kV switchgear installed and this is used in instances where switchgear replacement or other major works is occurring at a substation and the 11kV supply cannot be out of service for extended periods. This equipment is stored at the Bouverie Street yard and deployed for planned work to assist with supply continuity and security. It can also be used for fault restoration or where catastrophic damage has occurred to an 11kV switchboard; however, it has not been used for this purpose to date. This equipment is inspected and maintained when it is used, and at other times, by the Field Service Provider under the requirements for management of critical and emergency spares.

In the future Wellington Electricity proposes to evaluate the location of private backup generation, in particular large generators within the CBD, and the potential for this to be synchronised and utilised for maintaining customer supply or assisting during network outages or grid emergencies. This will require the engagement of both retailers and the generator owners, as well as a detailed understanding of generator capabilities. Generator owners will have to be willing to participate in such an arrangement and synchronisation and protection equipment will need to be planned and installed. Developments are already being made in this area by load aggregators and other third parties, and their cooperation will also be required to realise the benefits that may be obtained by Wellington Electricity and consumers in this space.

3.4.17 Embedded Distribution Networks

Within the Wellington Electricity network area there are a number of embedded networks owned by others. These range from apartment or commercial buildings, through to full reticulated subdivisions with 11kV networks. These arise due to the preferences of the developers and favourable commercial arrangements with embedded network operators.

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 plan.

Wellington Electricity will assess, where practicable, the purchase of embedded networks from their owners where there is a clear commercial driver to do so.

3.4.18 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.

3.4.18.1 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.

3.4.18.2 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.

3.4.18.3 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.

3.4.18.4 SCADA, RTUs and Communications equipment

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

3.4.18.5 DC power supplies and battery banks

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

3.4.18.6 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.

3.4.19 Non Network Assets

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

3.4.19.1 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.

Software and user licenses for a range of packages including Smallworld GIS, SCADA, Power Factory, ProjectWise, Microstation CAD and SAP are also owned by Wellington Electricity.

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.

3.4.19.2 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.

3.4.19.3 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.

3.4.19.4 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.

3.5 Asset Justification

The distribution system is designed to provide a safe electricity supply of sufficient capacity and reliability to meet the price/quality trade-off consumers are prepared to make. The network capacity takes into account the ability to shift controllable load from peak congestion periods into periods of lower usage but makes some provision for forecast load increases. This strategy (which is widely adopted by electricity distribution businesses) is an efficient approach to network development due to the high cost and long life cycles of electricity distribution infrastructure assets.

3.5.1 Urban Network

The urban network, both in residential and business/CBD areas, is designed to support present and near-term forecast loads, and to be operated within the disclosed service levels for the period of this AMP. Where capacity shortfalls are identified, network reinforcement projects or demand side initiatives (or a mixture of both) may be undertaken. There are different network architectures between the former Wellington MED (Wellington City Council) and Hutt Valley/Porirua areas. There is a higher level of security in the Wellington CBD, and surrounding suburbs, which incorporates a greater density of circuit breakers and protection devices, a predominantly underground network, and a higher level of redundancy. This legacy system architecture is appropriate to meet the security criteria for the CBD and also reflects the importance of the Wellington CBD being the centre of government, government departments and commerce and their reliance upon secure electricity supply. Following recent seismic events in Canterbury, resilience of supply is also being considered in network planning.

There has been reasonably low load growth in the Wellington network over recent years and the decline of manufacturing within the supply area from the 1980s onwards has created capacity headroom in some areas of the network, especially the Hutt Valley and Porirua areas. Despite this, changing load demands (apartment conversions, new buildings and building conversions, increased use of air conditioning etc) in the CBD has created some constraints that will require further network reinforcement.

3.5.2 Rural Network

The rural network is generally overhead and supplied at 11kV from urban zone substations. Often a rural feeder supplies urban load before entering a rural area. There are fewer back-feed options for rural feeders, and this is reflected in lower service levels. Less than 30% of the Wellington network (by length) is rural and the load served is very low density. There is no major agricultural sector in the Wellington area so loading, voltage and power quality is less of an issue than for other rural networks that experience high load growth due to irrigation and increasingly intensive agricultural activities. However, the exposure of the Wellington network to weather and vegetation interference necessitates a large number of line reclosers, remote switches and sectionalisers to meet service level targets.

3.5.3 Voltage Levels

11kV has been the predominant distribution voltage in Wellington since the first grid connected substation was built at Khandallah in 1924, and the subsequent development and connection of Melling and Central Park substations in the 1930s and 1940s.

33kV was introduced in the late 1950s for subtransmission, when load growth exceeded the capacity of the 11kV system.

Wellington Electricity has no current plans to use other voltages for distribution or subtransmission.

110kV cabling was installed by the Wellington MED in the early 1980s to future proof supply capacity to the Eastern Suburbs area (incorporating Evan's Bay and Miramar). This is currently operated at 33kV.

4 Service Levels

4.1 Consumer Orientated Performance Targets

4.1.1 Network Reliability

Network reliability is measured using two internationally recognised performance indicators, SAIDI and SAIFI, which taken together are indicators of the availability of electricity supply to the average consumer connected to the network.

- SAIDI[4] is a measure of the total time in a measurement year that an electricity supply is not available to the average consumer connected to the network. It is measured in minutes; and
- SAIFI[5] 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[6].

These indicators include both planned and unplanned outages. On average, planned outages account for approximately 10% of the total number of outages every year but only contribute to 3% of the annual SAIDI minutes. Consistent with the approach taken by the Commerce Commission, the following supply interruptions are not included in the measured performance indicators.

- Interruptions caused by the unavailability of supply at a GXP, or as a result of automatic or manual load shedding directed by the transmission grid operator[7], or as a result of some other event external to the Wellington Electricity network;
- 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
- Interruptions resulting from an outage of the low voltage network or a single phase outage of the 11kV distribution network. The Commerce Commission does not require these interruptions to be recorded for information disclosure or for the operation of the price-quality control regime. 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.

For asset management purposes, Wellington Electricity uses the reliability targets determined using the methodology set down by the Commerce Commission[8]. These are 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 Commerce Commission methodology, is set as the target network reliability with the objective of ensuring that over time there is no deterioration in the overall reliability of the electricity supply provided by the network.

[4] System Average Interruption Duration Index

[5] System Average Interruption Frequency Index

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

[7] 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.

[8] Commerce Commission, Electricity Distribution Services Default Price-Quality Path Determination 2012, Schedule 2.

As an investor owned EDB, Wellington Electricity is subject to price-quality regulation under the Commerce Commission's Default Price Path (DPP) regime. In addition to targets, this regime also sets reliability limits, which are one standard deviation above the mean and measure the lowest level of reliability that a regulated EDB is permitted to deliver in any regulatory year[9]. Under the DPP regime, targets and limits are set for both SAIDI and SAIFI. The target and limit values for Wellington Electricity calculated using this method are presented below.

Justification for the targets Wellington Electricity has set is set out in section 4.3.

Regulatory Year	2010/11	2011/12	2012/13	2013/14	2014/15	2015/16 to 2019/20	2020/21 to 2024/25
SAIDI target [1] (mean)	**33.90**	**33.90**	**33.90**	**33.90**	**33.90**	**33.90[2]** **50.36[3]**	**33.90[2]** **TBC[4]**
SAIDI limit (target + 1SD)	40.74	40.74	40.74	40.74	40.74	40.74 63.10[3]	40.74 TBC[4]
SAIDI actual	34.74	45.88	43.29	77.00 (YTD)			
SAIFI target[1] (mean)	**0.52**	**0.52**	**0.52**	**0.52**	**0.52**	**0.52[2]** **0.72[3]**	**0.52[2]** **TBC[4]**
SAIFI limit (target + 1SD)	0.60	0.60	0.60	0.60	0.60	0.60 0.90[3]	0.60 TBC[4]
SAIFI actual	0.537	0.715	0.573	1.14 (YTD)			

1: SAIDI is measured in minutes and SAIFI in average number of interruptions.

2: Internal Targets for the period 2015/16 to 2024/25 with the exception of major events remain at levels that reflect no material deterioration of the network.

3: Prospective Regulatory Targets for the period 2015/16 to 2019/20 are estimated based on the present DPP methodology and data for the period 2010/11 to 2014/15.

4: The DPP targets and limits may change following the 2015/16 and 2019/20 DPP resets, in which case Wellington Electricity may need to review the internal targets it uses for asset management purposes.

Figure 4-1 Reliability Targets and Limits (as defined by the Regulator)

The targets and limits for the current period (2010-2015) have been calculated in accordance with the Commerce Commission's current requirements for the reporting of reliability and restrict the impact of 'major event days' by adjusting for the number of outages when these outages exceed the ability of Wellington Electricity's Field Service Provider to respond in a timely manner. This limits the extent to which

[9] A reliability limit is not simply an alternative target because the DPP regime includes a financial penalty if a reliability target to be exceeded more than twice in any three-year period.

measurements of network reliability can be distorted by extreme weather events and is intended to ensure that the measured reliability better reflects the quality of Wellington Electricity's asset management.

Major event days are usually caused by extreme environmental events, such as severe storms, that are outside Wellington Electricity's direct control. Wellington Electricity has experienced five major event days in the last eight regulatory years, two in 2003/04, one in 2004/05, and two in 2013/14. The major storm that hit the Wellington network on 20 June 2013 was similar to the "Wahine storm" of 1968 and resulted in widespread network outages that received extensive national media coverage. Major event days generally have a much bigger impact on SAIDI than on SAIFI because during severe weather events consumers may only experience one interruption but can be without power for hours or, in extreme situations, days.

The measured historic reliability of Wellington Electricity's network is illustrated in the graphs below. In broad terms the graphs show that, under normal circumstances, the average consumer can expect one sustained interruption every two years and that this interruption will last a little over an hour – Figure 4-3 and 4-4. Figure 4-2 also shows that, notwithstanding Wellington's reputation as an extremely windy city, on average consumers connected to Wellington Electricity's distribution network receive one of the most reliable electricity supplies in the country.

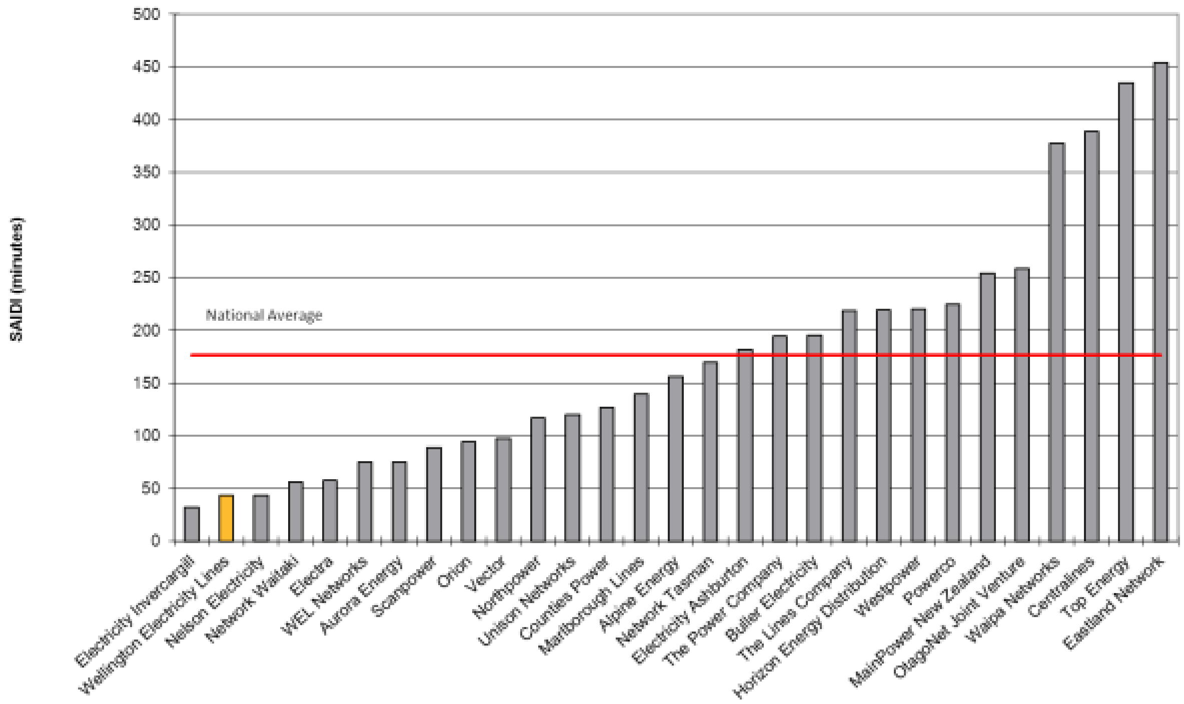


Figure 4-2 NZ Electricity Distribution Network performance 2012/13

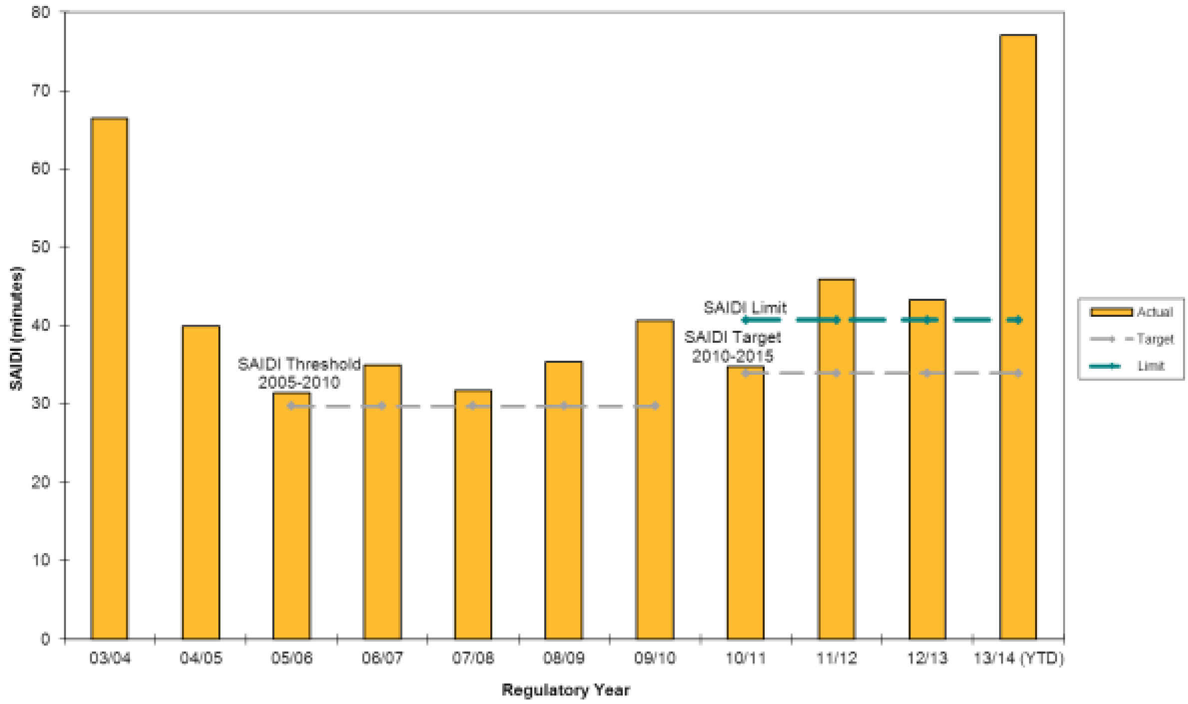
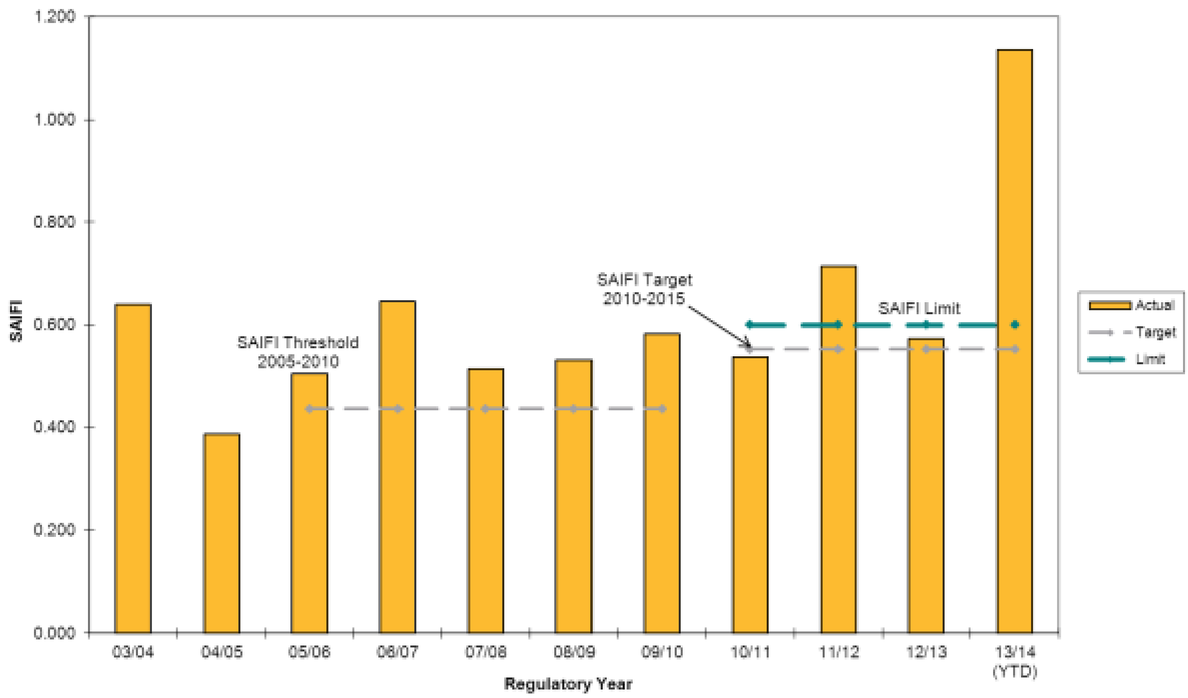


Figure 4-3 Historic SAIDI of the Wellington Electricity Network



Note: 2013/14 (YTD) covers the 9 months to 31 December 2013.

Figure 4-4 Historic SAIFI of the Wellington Electricity Network

4.1.2 Contact Centre Service Levels

Wellington Electricity has developed a set of key performance indicators and financial incentives that serve as service level benchmarks for its contact centre provider (Telnet) and these are set out below. Measurement is by way of the Telnet monthly online Executive Summary Report.

4.1.2.1 General Contact Centre Service Levels

SL	Service Element	Measure	KPI	2012 Actual	2013 Actual	2014 Target	2015-2024 Target
A1	Overall service Level	Average service level across all categories	80%	95.9%	83.4%	80%	85.0%
A2	Call response	Average wait time across all categories	20 seconds	17 seconds	34 seconds	20 seconds	18 seconds
A3	Missed calls	Total missed/abandoned calls across all categories	4%	2.3%	3.6%	4%	3%

Figure 4-5 General Contact Centre Service Level Benchmarks

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.

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. The actual call response time in CY2013 exceeded the KPI target due to high volumes of calls during the extreme storm conditions during June and October 2013. Excluding the response time during the June and October storm events, actual Call Response performance was approximately 15 seconds.

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.

While the current call centre service level targets have been set in line with international standards for utility call centres, Wellington Electricity is looking to deliver an enhanced call centre response and is planning more stringent targets from 2015 as part of the call centre contract review process. This may also include increased resource levels available during major events when call volumes are higher.

4.1.2.2 Customer Experience

All customer contact should contribute to customer satisfaction in dealings with the service provider when representing Wellington Electricity. Measurement is by way of a random sample survey of callers with the sample selected by Wellington Electricity.

SL	Service Element	Measure	KPI	2012 Actual	2013 Actual	2014 Target	2015-2024 Target
C1	Specific Contact Centre experience	Wellington Electricity is properly represented during specific calls	Qualitative assessment 80%	88.6%	84.49%	80%	82.5%

Figure 4-6 Customer Experience

Note C1: Contact Centre contribution to customer experience will be monitored as part of Wellington Electricity's monthly survey of Contact Centre calls. The relevant results of this survey are to be discussed with Telnet with a view to constant performance improvement.

Specific Contact Centre experience (C1) - This is measured monthly and reported as a "sample of 10 calls from on-line reporting" of the quality of interaction with callers. The target is to reach a minimum of 80% and was developed to focus 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 general public.

Consistent with Telnet's past performance and Wellington Electricity's objective of further enhancing the customer experience, it is proposed to set a more stringent customer experience target from 2015.

4.1.2.3 Energy Retailer Satisfaction

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.

SL	Service Element	Measure	KPI	2012 Actual	2013 Actual	2014 Target	2015-2024 Target
D1	Overall retailer satisfaction with Contact Centre performance	Wellington Electricity is properly represented with retailer interaction	80% satisfied	94%	94%	80%	82.5%

Figure 4-7 Energy Retailer Satisfaction

In line with Wellington Electricity's objective of further enhancing the experience of stakeholders when dealing with the company, it is planned to set a more stringent target from 2015. This new target should be readily achievable as it is still well below the more recent survey results.

4.1.3 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 (SAP–CARE database). 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 prompting for seven days followed by internal escalation. Wellington Electricity is a member of the Electricity and Gas Complaints Commission (EGCC) and follows its process for dispute resolution. Recent changes proposed under the Electricity Authority MoUSA will lead to Wellington Electricity (and all EDBs) having to indemnify retailers under the Consumer Guarantees Act 1993 for goods and services performance related to distribution network outages. This is expected to increase the number of enquiries and complaints received by EDBs.

4.2 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. Most of the indicators are also required for reporting to the Commerce Commission under its information disclosure regime.

4.2.1 Standard Service Levels for Restoration of Power

Wellington Electricity's published 'Electricity Network Pricing Schedule' provides standard service levels for the restoration of power to three different categories of customers, as shown in the map below. These service levels are agreed between Wellington Electricity and all retailers and provide Wellington Electricity with financial incentives to not exceed the maximum restoration times detailed below. These standard service levels apply for the entire AMP period (2014 to 2024).

	Urban	Rural
Maximum time to restore power	3 hours	6 hours

Figure 4-8 Standard Service Levels for Residential Customers

	Urban	Rural
Maximum time to restore power	3 hours	6 hours

Figure 4-9 Standard Service Levels for Business Customers

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

Figure 4-10 Standard Service Levels for Industrial Customers

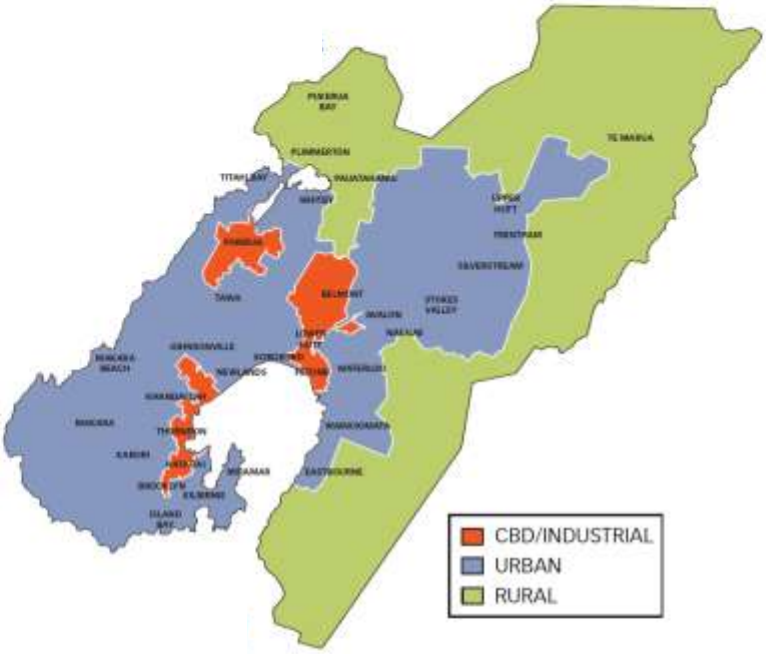


Figure 4-11 Standard Service Level Areas

Time taken to restore power is recorded in ENMAC. Refer to Section 2.10.5 for details on how unplanned outages are recorded.

4.2.2 Faults per 100 Circuit-km

For the purpose of this performance indicator 'faults per 100 Circuit-km', 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.

Wellington Electricity designs its network to withstand the average environmental conditions to which it is exposed, particularly the typical Wellington winds (up to 100km/h) and the high level of atmospheric salt contamination. As discussed in Section 6, Wellington Electricity has a preventive maintenance system in place where assets are regularly inspected to identify and remedy defects that could potentially cause an asset failure. In addition, Wellington Electricity has a vegetation management system in place to reduce the number of faults resulting from trees coming into contact with overhead power lines. Faults are also subject to a root cause analysis aimed at identifying systemic issues that may be causing unplanned outages followed by projects that will address the issue. This performance indicator is a measure of the effectiveness of these asset management strategies.

The table below sets out the faults per 100 Circuit-km targets for the planning period. The current target has been set based on the current performance of the network and considering performance over the previous five regulatory years since Wellington Electricity's purchase of the network. The future targets reflect a continuation of the current trend of asset performance. 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.

Regulatory Year	2008/09	2009/10	2010/11	2011/12	2012/13	2013/14	2014/15	2015/16	2016/17	2017/18	2018/19	2019/20	2020/21	2021/22	2022/23	2023/24
Target	11.6	11.7	11.9	12.0	12.2	12.3	12.5	12.6	12.8	12.9	13.1	13.2	13.3	13.5	13.6	13.8
Actual	7.1	12.6	11.9	13.3	12.3											

Figure 4-12 Performance Targets for Faults per 100 Circuit-km

4.2.3 Asset Efficiency and Utilisation

Load factor reflects consumer demand profiles and Wellington Electricity's predominantly urban network results in a higher than average utilisation and load density. Wellington Electricity aims to maintain utilisation and loss ratios at current levels in line with similar networks. Where assets are being replaced, consideration is given to reducing losses through selection of more efficient equipment, in particular transformers. The following table 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 2012/13	61.4	31	5.74	39.8	193	13	16,258
Wellington Electricity 2010/11	51.7	42.6	4.8	124.0	533	36	14,946
Wellington Electricity 2011/12	48.0	45.7	4.8	133.0	531	36	14,935
Wellington Electricity 2012/13	52.0	41.0	4.1	120.0	520	36	14,609

Figure 4-13 Asset Efficiency and Utilisation

4.3 Justification for Targets

Wellington Electricity operates its distribution system in accordance with all relevant legal requirements, including the Electricity Act 1992, the Health and Safety in Employment Act 1992, the Resource Management Act 1991, the Electricity Industry Act 2010, the Commerce Act 1986 and all Regulations associated with these Acts. For the most part the legal requirements are non-discretionary and therefore act as a constraint on the way in which the system must be managed. Costs are also incurred in meeting these different legal requirements.

Within these legal constraints, Wellington Electricity must still meet the requirements of its stakeholders. It must ensure that safety is not compromised and that the quality and reliability of supply meet the expectations of retailers and consumers for a price that they consider reasonable and that also provides its owner a commercial return on its investment.

4.3.1 Consumer Survey

Wellington Electricity regularly conducts a major phone survey of its consumers evaluate how well Wellington Electricity is meeting the expectations of consumers.

The most recent comprehensive customer survey was completed in December 2011 and involved surveying:

- The top 25 consumers;
- A random sample of 25 of the top 26 to 130 consumers (industrial and business consumers); and
- A random sample of 3,500 residential consumers.

Wellington Electricity has scheduled a further consumer survey for later in 2014.

Of the 3,500 residential consumers called, a total of 412 completed the 2011 survey - a response rate of 13%. The survey questions included:

- What is most important (service issue) to consumers (e.g. keeping power on, low prices etc)?
- How well is Wellington Electricity performing? and
- What price / quality trade-offs are consumers prepared to make (e.g. pay less for lower quality etc)?

Graphs of the responses to these questions are provided below.

In addition to this major survey, interim surveys are conducted following service calls to the Contact Centre to establish consumer views on how well Wellington Electricity and its service providers meet service levels for the specific service call that was raised.

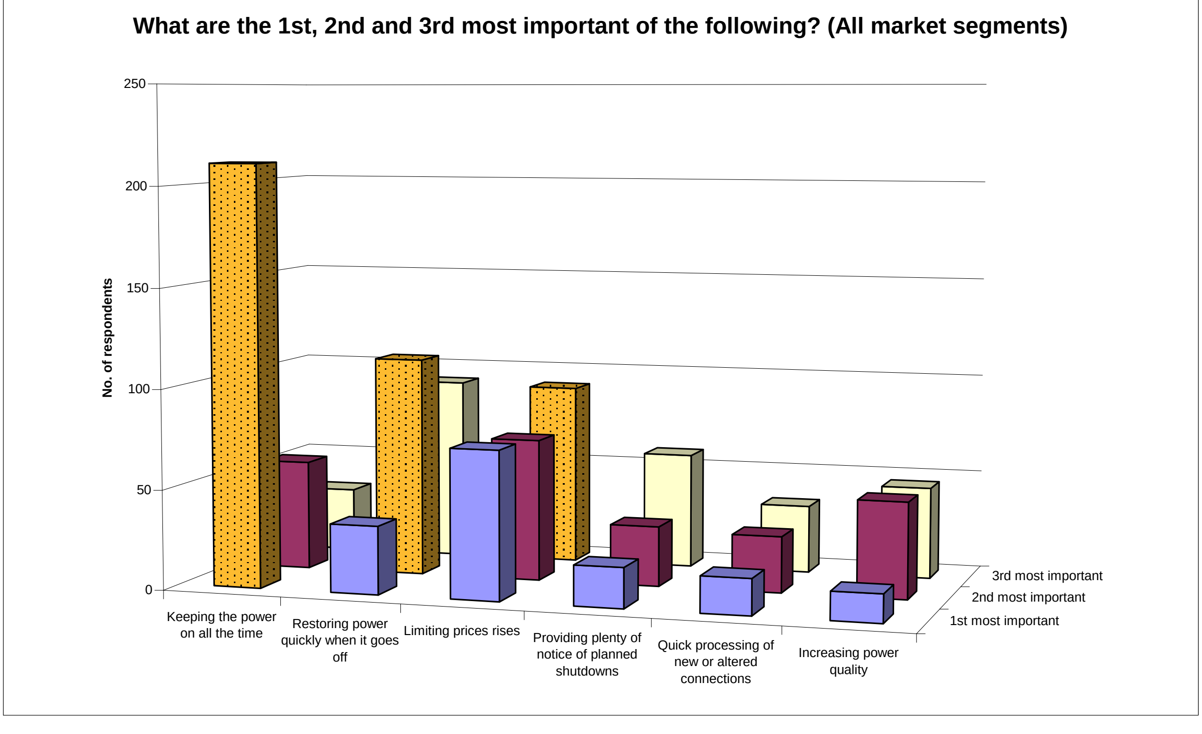


Figure 4-14 What is most important to consumers?

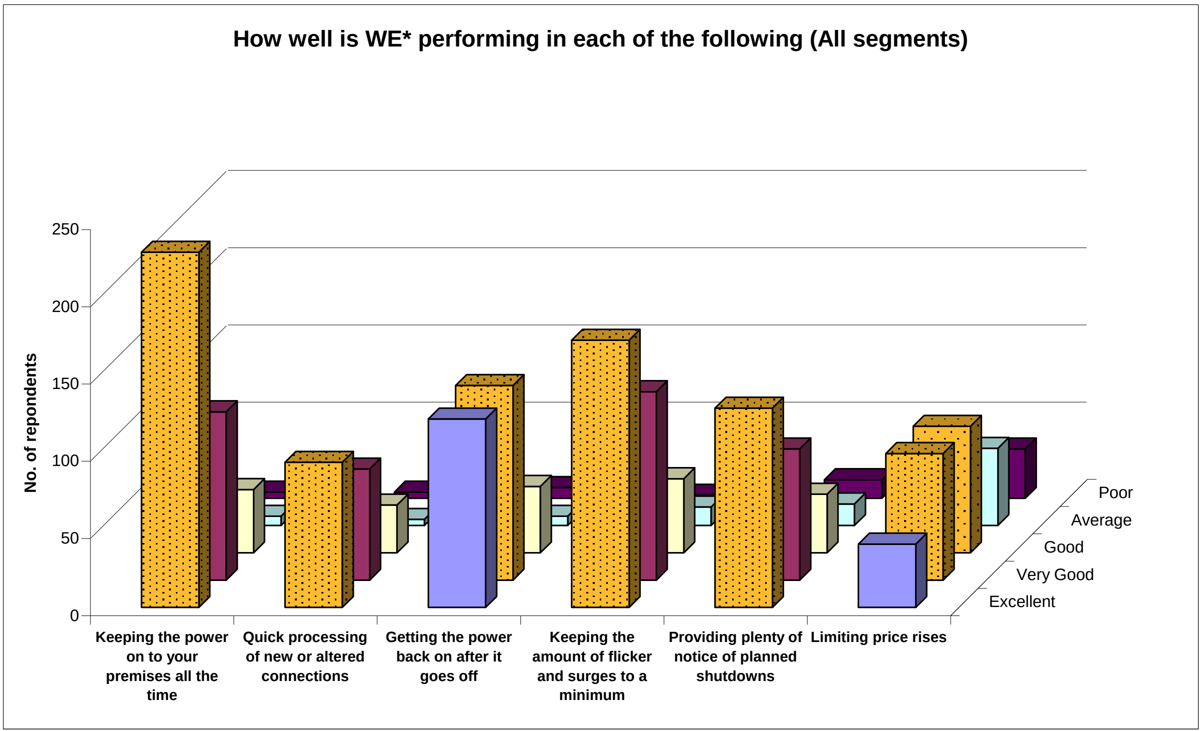


Figure 4-15 How well is Wellington Electricity performing?

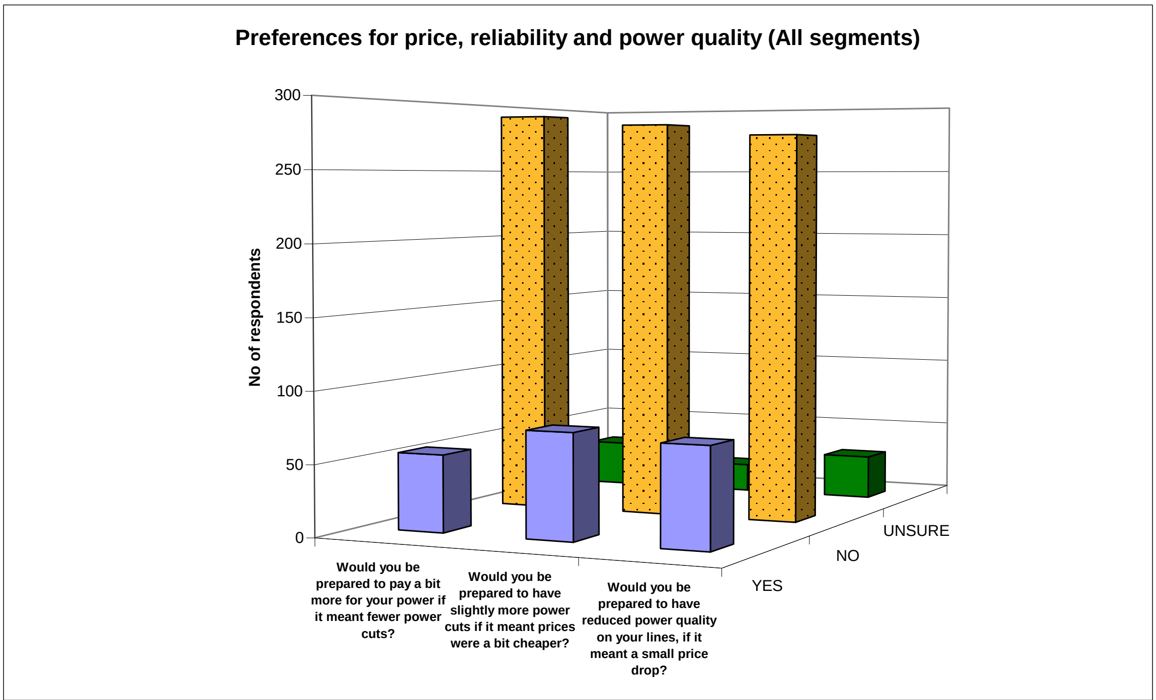


Figure 4-16 What price / quality trade-offs are consumers prepared to make?

Key results from the 2011 survey are:

- Consumers in all segments regard continuity (‘keeping the power on’) and restoration (‘getting the power back on’) as the first and second most important components of electricity line services;
- Consumers across all segments regard Wellington Electricity’s performance in regard to the above two components as either excellent or very good;

- Limiting price increases is the third most important service component;
- The majority of consumers across all segments do not want to pay either a bit less if it means more power cuts, or a bit more if it means less power cuts. This indicates a high level of satisfaction with the current balance between price and quality; and
- The majority of consumers across all segments were against paying a bit less for electricity if it meant having more flicker or surge. This indicates a strong preference for having either the same or less flicker.

The survey shows that consumers are advising Wellington Electricity that:

- Efforts and resources should be focused on continuity and restoration;
- Price increases matter less than maintaining the status quo on quality; and
- Present levels of quality are about right.

These results are reflected in Wellington Electricity's asset management approach of investing to maintain reliability at present levels. As a result, the following objectives have been set:

- To maintain service continuity and restoration of electricity supply as priorities;
- To improve the response time of service providers to consumer calls;
- To maintain the quality of electricity supply being delivered; and
- To provide sufficient notice for any planned shutdowns.

5 Network Planning

5.1 Planning Criteria and Assumptions

Network development planning is concerned with delivering the required network capacity and security of supply:

- In an economic, sustainable and profitable manner;
- At a price level which is acceptable for the quality expected by consumers; while at the same time
- Maintaining risk at a level which is acceptable to the Wellington Electricity Board.

The principles that underpin network planning are encapsulated in a number of standards, with the key document being the Wellington Electricity security standard. The main planning principles 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'[10] reasonable electricity capacity requirements will be met;
- Network augmentations will be designed to include a prudent capacity margin to cater for foreseeable near-term load growth;
- Equipment will be purchased and installed in accordance with network standards;
- Varying security standards will apply to different network areas (CBD/industrial, urban, rural) and consumer segments, broadly reflecting the price/quality trade-offs that consumers are willing to make;
- The network will be resilient to foreseeable HILP events, including extreme weather and earthquakes, to a level consistent with good industry practice in New Zealand; and
- Network investment will provide an appropriate commercial return for the business.

These principles create competing priorities, which must be balanced to find the best outcomes for Wellington Electricity and its stakeholders.

Wellington Electricity has a number of key policies and standards underpinning its network planning approach. These policies and standards cover the following areas:

- Network security – specifies the minimum levels of network capacity (including levels of redundancy) to ensure the required level of supply reliability is maintained notwithstanding the risk of equipment failure;
- Service level – established as part of the Use of Network Agreement with retailers and customers. The service levels reflect expected restoration timeframes and fault frequencies;
- Technical standards – ensures optimum asset life and performance is achieved (i.e. capital cost, asset ratings, maintenance costs and expected life are optimised to minimise lifetime cost). Standardisation also reduces design costs and minimises spare equipment holding costs, leading to lower overall project and maintenance costs; and

[10] This includes consumers with non-standard requirements where special contractual arrangements apply.

- Network operating parameters – including acceptable fault levels, voltage levels, power factor, etc., providing an appropriate operating framework for the network.

To identify the network constraints within the planning period, the forecast peak load (based on a moderately probable forecast) for future years at different parts of the network 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) conditions. Solutions 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 violated.

Wellington Electricity plans to eliminate any constraint arising because a part of the network is forecast to become overloaded during system normal operating conditions through the planning and implementation of an optimal solution to relieve the constraint. However, in some cases, where an overload only arises during a contingency operating situation, implementation of a solution to relieve the constraint may be delayed. This decision requires a risk assessment that will consider response times, repair times and the consequences of the overload.

Repair time assumptions for major faults on critical power system components are:

- Substation transformer - 5 days;
- 33kV underground cable - 9 days;
- 33kV circuit breaker - 3 days; and
- 33kV overhead line - 10 hours.

When the forecast load exceeds the firm network capacity, after applying the security criteria, a constraint is identified and a suitable solution is sought. Projects required to avoid breaching the load thresholds established within the planning criteria are submitted for each year's capital budget and the Asset Works Plan where:

- The overload cannot be eliminated by load transfers for distribution substations and distribution feeders;
- Forecast sustained peak loading is greater than a substation's installed capacity (for substations with an installed capacity exceeding 1MVA a tolerance of 0.2 MVA is considered to allow for metering errors);
- Load during a contingency event is greater than a zone substation's firm delivery capacity;
- During a contingency event, the load at risk on a distribution feeder is greater than 100A (approximately 2MVA at 11kV); or
- Normal load is greater than a subtransmission line's normal rating or the contingency load is greater than a subtransmission line's emergency rating.

5.2 Prioritisation of Capital Works Projects

The processes described in this AMP invariably identify more potential work than can be accommodated by budgets or resources available to Wellington Electricity; hence the need for a project prioritisation process.

Every year, as part of the capital works budgeting process, the list of potential projects is reviewed for necessity and prioritised accordingly. The detail of how projects are prioritised has been developed into an assessment tool that was used to prepare the 2014 capital works programme and will be used again in future years. The drivers for prioritisation of projects are:

- Health and safety;
- Legal and statutory obligations;
- Company policies and standards;
- Risk to the network;
- Environmental;
- Financial value;
- Quality of supply;
- Strategic benefit; and
- Stakeholder satisfaction.

The subset of potential projects that are non-discretionary and outside of the prioritisation process as they will not be deferred include:

- Works necessary to ensure public and employee safety; and
- Works necessary to meet legal requirements.

5.2.1 Cost and Risk Factors

Where changes to legal requirements impose significant additional costs, it may be necessary to undertake the required works over an extended period of time. This is usually agreed with the authority responsible for monitoring compliance with the changed requirement. Under a Default Price Path there are limitations to what can be achieved and the step change to gain a Customised Price Path presents a significant investment in time and cost with no guarantee of success.

All other projects are prioritised on the basis of benefit-cost ratios and risk analysis using an assessment of the project 'drivers' as outlined above. Projects that mitigate extreme or high risks to the business and projects with high benefit-cost ratios are generally given the highest priority.

An example of how the prioritisation criteria are applied in the prioritisation of a project on the basis of risk analysis is shown in the discussion on the Johnsonville zone substation reinforcement project in Section 8.6.

5.2.2 Prioritisation Process

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 in finally selecting projects for inclusion in the works programme. Wellington Electricity's general prioritisation sequence for including projects in its capital expenditure programme is as follows:

- Essential safety or legal compliance;
- Customer initiated projects;
- Network integrity projects for meeting capacity requirements;
- Reliability and security of supply projects; and then
- Other economically attractive investments.

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. However, all projects must provide an appropriate return to shareholders, either financially in the case of asset replacement, network growth and reinforcement projects, or through non-financial benefits such as safety, or legal compliance.

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.

5.3 Voltage Levels

Subtransmission voltage is nominally 33kV in line with the source voltage at the supplying GXP. The voltage used at the medium voltage 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 customers, 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 customers.

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.

5.4 Security Criteria and Assumptions

The security criteria on which the design of the system is based is shown in Figures 5-1 and 5-2 and have been inherited from previous network owners and were the basis on which the network was designed and operated.

There are no regulated national security standards currently in force; however, the Electricity Engineers' Association (EEA) has produced a network security guideline[11] that has similar principles. These security standards are consistent with industry best practice 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.

Wellington Electricity's security standards accept a small risk that customer supplies may be interrupted when a network fault occurs during peak demand times[12]. The length of time (based on percentage measures) when the subtransmission network could not meet N-1 security, and the distribution network did not have full backstop, is defined with different durations for different categories of customers. However, even in the event that an interruption should occur, limits are set on the maximum load that would be lost.

Type of Load	Security Criteria
CBD	N-1 switching[1] 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[2] for 98% of the time in a year For the remaining time, supply will be restored within 3 hours following an interruption
Predominantly residential substations	N-1 switching[2] for 95% of the time in a year For the remaining time, supply will be restored within 3 hours following an interruption

1: A brief supply interruption of up to 1 minute may occur following an equipment failure while the network is automatically reconfigured.

2: A brief supply interruption of up to 5 minutes may occur following an equipment failure while the network is reconfigured.

Figure 5-1 Security Criteria for the Subtransmission Network

[11] *Guide for Security of Supply*, Electricity Engineers' Association, August 2013.

[12] A true deterministic standard, such as N-1, implies that supply will not be lost after a single fault at any time. The Wellington Electricity 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.

Type of Load	Security Criteria
CBD or high density industrial feeders	N-1 switching[1] 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[2] 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[2] 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

1: A brief supply interruption of up to 1 minute may occur following an equipment failure while the network is automatically reconfigured.

2: 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.

Figure 5-2 Security Criteria for the Distribution Network

While the reliability of the Wellington Electricity distribution system is high, notwithstanding the difficult physical environment in which the system must operate[13], 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 during the course of a year. 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 how much load will be supplied by spur lines and determine at which point additional supplies or back feed points are considered for a supply area.

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 5-1 and Figure 5-2.

[13] 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.

The 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 usually designed for 'n' security. In such situations an interruption will last for the time taken to make a repair.

The criteria also do 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.

In some situations, Wellington Electricity is able to provide a more secure supply than shown in Figure 5-1 or 5-2. This is discussed in Section 5.5.4 below.

5.5 Capacity of New Plant

When planning an augmentation to the network to increase its existing capacity, it is necessary to determine the capacity of the new equipment to be installed. This often involves a trade-off between the size of the increased capacity and the growth expected over the asset's service life because:

- If the capacity is too large, either Wellington Electricity or its consumers have to pay the cost of any capacity that will not have been economically utilised before the equipment reaches the end of its economic life; but
- If the capacity is too small, then premature asset replacement will be required and this generally increases costs.

Determining the optimum capacity is made more difficult by the fact that the economic life of most primary distribution assets is between 40 and 60 years and the difficulty of forecasting electricity demand over this period into the future.

Wellington Electricity uses a 10-year planning period as the starting point for making equipment capacity decisions and then generally:

- On the basis of the current load forecast, determines the maximum potential load on the equipment at the end of the planning period under the most severe operating condition that the network is planned to withstand; and
- Selects the next highest standard equipment size as identified in Figures 5-3 to 5-5.

5.5.1 11kV Switchgear

Application	Standard Ratings	Fault Rating
Zone incomer circuit breaker	1200A, 2000A	25kA
Zone feeder circuit breaker	630A	25kA
Dist feeder circuit breaker	630A	20kA
Dist transformer circuit breaker	200A	20kA
Ring main unit	400A minimum	20kA

Note 1: These are manufacturer's standard ratings.

Note 2: Existing equipment may have ratings different from those listed in the table.

Figure 5-3 Standard Ratings for 11kV Switchgear

5.5.2 11kV Cable

Application	Standard Ratings
Feeders – backbone	300A minimum
Feeders – branch	200A minimum
Dist transformer	Match transformer

Note 1: Larger cable ratings may be employed on a case-by-case basis.

Figure 5-4 Standard Ratings for 11kV Cable

5.5.3 Distribution Transformers

Standard Ratings (kVA)
15, 30 50, 100, 200, 300, 500, 750, 1000
1500kVA upon request for special customer projects

Note 1: All distribution transformers: 11kV/400V delta-wye.

Note 2: These are manufacturer's standard ratings.

Figure 5-5 Standard Ratings for Distribution Transformers

It is important to note that this is only a starting point for making capacity decisions. An engineering and economic judgement is then made as to whether the size determined using this approach is appropriate, taking other factors into account, including:

- Compliance with the network security criteria;
- Margin between the required capacity and the next highest standard size;
- Incremental cost of different equipment sizes;

- Forecast rate of demand growth; and
- Back-up capacity to adjacent areas.

An example of where a different approach would be used would be the sizing of new or replacement subtransmission cables. In this situation, Wellington Electricity considers it prudent to use a longer planning period because these have a long life and a high installation cost relative to the cost of the cable. In addition, installation costs do not vary greatly with cable size and the incremental cost of installing a larger cable is therefore relatively low. However, a shorter planning period might be appropriate for the associated transformer, as the installation cost is low relative to the cost of the asset and, should it be necessary to install a larger transformer, the replaced transformer could be relocated or sold.

5.5.4 11kV Feeders

Most of the 11kV feeders in the Wellington CBD and in some locations around Wellington's eastern suburbs and 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 below.

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 5-6 11kV Feeder Utilisation during Normal and Contingency Operation

A customer 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 customer can then choose to pay for a higher level of security to meet their needs for the load they are being supplied.

Given the relatively modest demand growth in its supply area, and the potential for further change to the Commerce 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. Where specific customers request higher capacity levels than Wellington Electricity would typically provide, these can accommodated subject to agreement of a satisfactory commercial arrangement.

5.6 Asset Standardisation and Design Efficiencies

5.6.1 Asset Category Standardisation

Distribution network equipment such as transformers, ring main units, and low voltage distribution assets is selected from manufacturers' standard product ranges to ensure that procurement costs are minimised (compared to custom designs). Materials and equipment are specified in the Approved Network Fittings standard, as well as individual technical specifications. In some cases Wellington Electricity will commission the design of custom equipment to reduce overall costs (such as a special transformer design to fit on an existing concrete pad which, although slightly more expensive to purchase, is significantly cheaper to install). Wellington Electricity is also reviewing all construction standard designs to ensure there is consistent construction across the entire network regardless of the build contractor.

Zone substation equipment is generally more specific in nature and therefore less standardised. However, for recent large asset replacement projects, items such as protection relays, circuit breakers, batteries, chargers and communications equipment have been of the same type.

Asset standardisation also leads to a rationalised spares inventory and allows field and engineering staff to become familiar with a common range of equipment, which provides efficiencies in installation, maintenance, repair and operation.

5.6.2 Approach to identify standard designs

Wellington Electricity has standard designs for the elements of the distribution system that are of low complexity and exist in large numbers. In addition, it has standardised equipment ratings, as detailed in Section 5.5 above, and has standardised equipment and designs for a range of substation components, including:

- SCADA/Communication panels;
- DC supply panels, battery banks and stands;
- Protection element designs (SEL-751A, Siemens 7SD610, Solkor); and
- Use of a limited standard range of switchgear for commonality across substations.

Wellington Electricity also has a range of standard construction designs for earthing and low voltage distribution, and is working towards developing standardised pole selection charts for routine pole replacement (pole assembly standard designs already exist).

5.6.3 Energy Efficiency

Wellington Electricity aims to improve energy efficiency in the operation of its network and to reduce losses on the system. Wellington Electricity looks forward to working with the Commerce Commission on incentives for investment in this area, which could be introduced under section 54Q of the Commerce Act.

The following energy efficiency objectives apply:

- 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).

5.7 Demand Forecasts

5.7.1 Methodology

Loads on individual feeders and zone substations are captured by the SCADA system while the load at each GXP is metered through the time-of-use revenue metering. This information allows Wellington Electricity to analyse actual demand at the GXP, zone substation and feeder level and to project trends in demand into the future using an extrapolation analysis model.

Demand forecasting is carried out using a 'bottom up' approach, starting at the zone substation level. The first stage of this process involves extracting historical load data from SCADA. The load data is then graphically analysed and any uneven spikes or peaks replaced with an average value derived from five days before and after the period of abnormal demand.

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. This approach recognises that primary electrical equipment can generally operate above its rating for short periods of time without being damaged.

After determining the sustained peak demand from actual load data, future year loads are forecast by extrapolating the historical data out over the 10 year planning horizon. Known step changes are then applied to the forecasts. These steps may be the result of:

- Planned system reconfigurations that move load between substations;
- Major developments that introduce large new loads onto the network;
- Changes to the Wellington Electricity load control system;
- New electricity generation that is expected to affect peak demand; or
- Load reductions caused by the movement or closure of businesses.

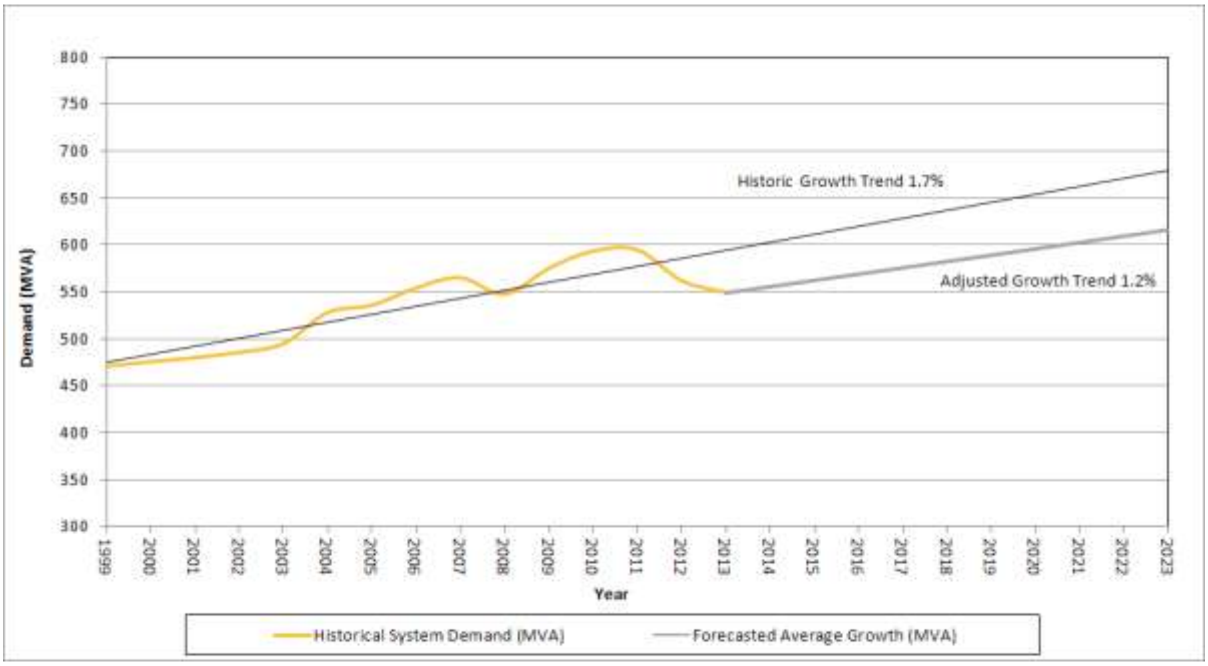
A high level review of the load forecasts for each zone substation is then undertaken. This comprises a check of the forecasts against local knowledge of trends that might impact network demand. Forecasts are reviewed by project managers and customer service staff who have a good awareness of customer connection trends and who have regular communication and consultation with key customers, developers and councils. Property developers and businesses may also be canvassed for information on plans that may result in introducing new loads to the network. Forecasts are modified if necessary to reflect this knowledge. The zone substation load forecasts are then 'rolled-up' to the GXP level, taking diversification factors into consideration as the peak zone substation demands may not always occur at the same time as each other.

The Wellington Electricity 'bottom up' GXP forecasts are then compared to Transpower's 'top down' GXP forecasts. Transpower's forecasts are derived from the national load and energy forecasts, which take into account economic and population growth indicators. While this forecast is usually accurate at the national level, it can be difficult to break the national growth down to the GXP level, which in turn can lead to differences from 'bottom up' forecasts. Any significant differences between the two forecasts are investigated and reconciled.

Detailed forecasts for the planning period are provided in the next sections. They indicate that the forecast demand growth in Wellington Electricity's supply area is relatively low compared to demand growth in many parts of the country, and this is consistent with figures provided by the NZ Institute of Economic Research (NZIER). In Wellington Electricity's experience, the top-down forecasting methodologies used by Transpower overstate the demand and growth at GXP level in Wellington. In many cases the difference between the two forecasts are substantial and Wellington Electricity considers that a number of the capacity enhancement projects for this region identified in Transpower's 2013 Annual Planning Report can be deferred. These projects include mitigation of supply capacity constraints at Melling and Upper Hutt GXPs.

Table 5-7 provides Wellington Electricity's after diversity peak demand forecast at the network level.

Wellington Electricity bases its load forecasts on the assumption that load control will be used to manage network peaks. If the ownership of rights to control load change, and Wellington Electricity can no longer manage peak demand periods using its ripple based load control system, these forecasts will need to increase.



Network	System Maximum Demand MVA[2] (including DG)										
	2013 Actual	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023
Wellington Electricity	551	556	562	568	573	579	585	591	596	602	608

Figure 5-7 Network Historic Demand and Forecast

5.7.2 GXP Demand Forecast

The 2013 actual and Wellington Electricity's forecast demand at each GXP supplying its distribution network is shown below.

GXP	Actual and Forecast System Demand MVA[2] (including DG)										
	2013 Actual	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023
Central Park 33kV[3]	161.4	164.5	167.6	175.8	179.1	182.5	186.0	189.5	193.1	196.8	200.5
Central Park 11kV	19.2	20.3	20.4	20.6	20.7	20.8	20.9	21.1	21.2	21.3	21.4
Gracefield 33kV	58.8	59.7	59.2	58.7	58.2	57.8	57.3	56.9	56.4	56.0	55.5
Haywards 33kV	16.8	17.1	17.3	17.5	17.8	18.1	18.3	18.6	18.9	19.1	19.4
Melling 33kV	34.5	34.8	35.1	35.4	35.7	36.0	36.3	36.6	37.0	37.3	37.6
Pauatahanui 33kV[4]	19.2	19.3	19.4	19.5	19.6	19.6	19.7	19.8	19.9	20.0	35.1
Takapu Rd 33kV	91.3	92.1	92.3	92.6	92.8	93.0	93.3	93.5	93.8	94.0	79.3
Upper Hutt 33kV	31.3	31.7	31.8	32.0	32.1	32.2	32.3	32.4	32.5	32.6	32.7
Wilton 33 kV[5, 6]	51.4	52.7	52.7	47.6	47.6	47.5	47.5	47.4	47.4	47.3	47.3
Kaiwharawhara 11kV[1]	33.5	33.4	33.4	33.4	33.4	33.3	33.3	33.3	33.2	33.2	33.2
Haywards 11kV	20.1	20.0	19.8	19.6	19.4	19.3	19.1	18.9	18.8	18.6	18.4
Melling 11kV	27.7	27.7	27.8	27.8	27.8	27.9	27.9	27.9	28.0	28.0	28.0

1: Kaiwharawhara GXP has a summer peak. All other GXPs have a winter peak.

2: Base MD value for the projection is for the year ending 31 December 2013.

3: Central Park 33kV peak demand is the sum of all 33kV feeders (excluding the 33/11kV supply transformer feeders Nairn Street zone substation – Central Park 11kV POS) from Central Park GXP. Load forecast assumes that the proposed Bond Street zone substation will supply approximately 20MVA of load within the CBD. The most likely option for supply of Bond Street zone substation is from Central Park.

4: Approximately 15MVA of load is to be transferred from Takapu Road GXP to Pauatahanui GXP on completion of the new Whitby/Pauatahanui zone substation in 2022.

5: Bond Street zone substation is planned to have interconnectivity with Moore Street zone substation. Approximately 5MVA of load is to be transferred from Wilton GXP to Central Park GXP.

6: Mill Creek will contribute to the reduction in the GXP peak at Wilton, however the extent is not known and not included in these forecasts

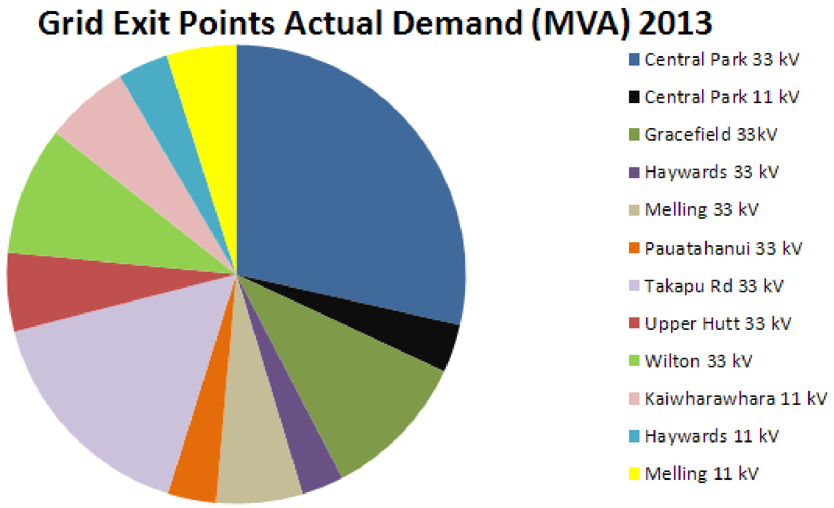


Figure 5-8 Network Demand by GXP – 2013

5.7.3 Zone Substation Demand Forecasts

Zone Substation	Actual and Forecast Demand (MVA)										
	2013 Actual	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023
8 Ira St	17.4	17.6	17.8	18.0	18.2	18.5	18.7	18.9	19.2	19.4	19.6
Brown Owl	15.6	15.8	15.7	15.7	15.6	15.5	15.4	15.4	15.3	15.2	15.2
Evans Bay	16.5	16.5	16.5	16.5	16.5	16.5	16.4	16.4	16.4	16.4	16.4
Frederick St	28.1	28.1	28.1	24.1	24.1	24.1	24.1	24.2	24.2	24.2	24.2
Gracefield	12.3	12.4	12.2	12.0	11.8	11.6	11.4	11.3	11.1	10.9	10.8
Hataitai	17.6	17.5	17.4	17.3	17.2	17.1	17.0	17.0	16.9	16.8	16.7
Johnsonville	16.4	16.3	16.2	16.1	16.0	15.9	12.8	12.8	12.7	12.6	12.6
Karori	17.5	17.4	17.3	17.1	17.0	16.9	16.8	16.7	16.6	16.5	16.4
Kenepuru	11.5	11.4	11.3	11.2	11.1	11.0	10.9	10.8	10.7	10.6	7.6
Korokoro	18.8	19.2	19.0	18.9	18.7	18.5	18.4	18.2	18.1	17.9	17.7
Maidstone	15.4	15.6	15.8	16.0	16.2	16.3	16.5	16.7	16.9	17.1	17.3
Mana-Plimmerton	19.2	19.3	19.4	19.5	19.6	19.6	19.7	19.8	19.9	20.0	10.1
Moore St	27.5	29.2	29.2	24.1	24.1	24.1	24.0	24.0	23.9	23.9	23.9
Naenae	14.7	15.0	14.9	14.9	14.9	14.9	14.8	14.8	14.8	14.8	14.7

Zone Substation	Actual and Forecast Demand (MVA)										
	2013 Actual	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023
Nairn St	19.2	20.1	20.0	16.9	16.9	16.8	16.7	16.6	16.6	16.5	16.4
Ngauranga	13.3	13.5	13.6	13.8	13.9	14.0	11.2	11.3	11.4	11.5	11.6
Palm Grove	28.0	28.1	28.2	28.2	28.3	28.4	28.4	28.5	28.6	28.7	28.7
Porirua	17.9	17.9	18.0	18.0	18.1	18.1	13.2	13.2	13.2	13.3	8.3
Seaview	15.2	15.4	15.4	15.3	15.3	15.3	15.3	15.3	15.3	15.2	15.2
Tawa	15.4	16.0	16.2	16.5	16.7	17.0	14.2	14.5	14.7	14.9	15.1
The Terrace	29.8	31.2	31.8	27.4	27.9	28.5	29.0	29.6	30.2	30.7	31.3
Trentham	16.8	17.1	17.3	17.5	17.8	18.1	18.3	18.6	18.9	19.1	19.4
University	26.1	24.3	24.3	21.3	21.3	21.3	21.3	21.3	21.3	21.3	21.3
Waikowhai	16.8	16.9	17.1	17.2	17.4	17.5	17.7	17.9	18.0	18.2	18.3
Wainuiomata	17.7	17.8	17.8	17.8	17.8	17.8	17.8	17.9	17.9	17.9	17.9
Waitangirua	15.5	16.0	16.3	16.6	16.8	17.1	17.4	17.6	17.9	18.2	10.5
Waterloo	19.8	19.7	19.7	19.7	19.7	19.6	19.6	19.6	19.5	19.5	19.5
Bond Street[1]				20.0	20.1	20.2	20.3	20.4	20.5	20.6	20.7
Grenada[1]							14.0	14.1	14.2	14.2	14.3
Whitby[1]											26.0

Note: Short term peaks due to operational switching and load shifts can lead to misrepresentation of peak loading. To this end, the forecast values are based on normalised data which represents the sustained peak demands, refer Section 5.7.1.

1: Forecast demand for the new zone substations at Bond Street, Grenada and Whitby are based on planned installed capacity and constraints present at adjacent substations.

Figure 5-9 Zone Substation Demand Forecast

5.7.4 High Load Growth Areas

Outside the Wellington CBD, there are few areas of high load growth as a result of the closure of major industry and low levels of residential development. There is nevertheless relatively high growth in pockets of the system, such as the suburbs of Whitby and Churton Park, where there has been significant housing development over the past 10 years. These areas of the network are at capacity and require investment within the planning period. Residential subdivision is continuing in these areas as detailed later in this section. Moderate load growth is also forecast in the Porirua area, as a result of the Aotea subdivision and proposed subdivision plans north of Plimmerton. There are a small number of growth industries in the Wellington region, particularly businesses supporting the international film industry. In most parts of the network however, growth is below NZIER forecasts and, at a system-wide level, growth and energy volumes have declined in the past two years. The level of load growth considered to be moderate to high on the Wellington network is nevertheless low by national standards.

5.7.4.1 Wellington CBD

Load growth has reduced (compared to previous years) in parts of the Wellington CBD to an annual growth rate of approximately 2.5%. The main high load growth areas are within the Wellington CBD, Thorndon, Newtown and Te Aro. This growth is largely due to moderately sized step change loads resulting from the construction of new buildings with high load densities, with many of these having dedicated transformer capacity of 500kVA or more. The demand in the CBD area is supplied by Frederick Street, The Terrace, Moore Street and Palm Grove zone substations. The Terrace, Palm Grove and Frederick Street zone substations are now very highly loaded, compared to other substations in the network, as a result of gradual load increases over time. With no new zone substation capacity installed in over 25 years, this presents a constraint on the network.

Most of the load demand in the CBD area is supplied by a meshed (or closed ring) 11kV system with multiple feeds from a zone substation. As load within the CBD rises, the ability of the meshed system to respond to a single fault or event deceases as the transfer of load to the remaining feeders may cause overloads, potentially leading to cascaded feeder tripping. These overloading issues will need to be addressed within the short to medium term. This is discussed later in this section.

5.7.4.2 Porirua

The Aotea subdivision is an area of high growth, which is planned to be supplied from the Porirua zone substation. The Porirua zone substation has spare capacity at present and by reinforcing Porirua feeder 2 (presently a spare feeder) it would be able to supply the anticipated load increase without requiring substation level reinforcement during the planning period. The Porirua feeder 2 reinforcement work would require replacing the overhead section of this feeder with underground cables and will be driven by the developer because the overhead section of this feeder runs across the proposed subdivision land. Some of this demand growth at subdivision level is configured as an embedded network owned by others and the tariffs recovered do not always fully reflect the level of investment required to supply such loads.

5.7.4.3 Upper Hutt

It is expected that there will be moderate load growth in the industrial area of Upper Hutt currently supplied by the Trentham zone substation. Of particular note is the 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, with the further possibility of two additional 1MVA stages in 2016-17. The initial stages, required in 2014, can be supplied by existing infrastructure, which has been underutilised since the closure of vehicle assembly and tyre manufacturing plants in the area. Further stages will require a dedicated supply from the Trentham zone substation.

5.7.5 Low Load Growth Areas

With the exception of the areas identified above, load growth is low in most parts of Lower Hutt, Upper Hutt and Porirua. The load growth rate is below the national average, with some suburbs experiencing around 0.5% to 1.0% growth, and declining load in others. The overall effect has been a system decrease in both demand and energy volumes over the past two years. The distribution network is less constrained in these areas with adequate capacity and security to meet demand during normal operation and contingency events. The load growth in these areas is expected to follow historical trends with few constraints arising during the planning period.

Zone substations within the Lower Hutt region, especially Korokoro and Seaview, have low asset utilisation. Due to low load growth at Petone, the subtransmission supply to Petone zone substation has now been decommissioned in favour of a distribution level feed from Korokoro zone substation. A portion of the load formerly served by the Petone zone substation has been permanently transferred to adjacent zone substations.

5.7.6 Step Load Changes

Wellington Electricity has identified the following new major loads that may occur over the next regulatory year. The loads which are certain have been incorporated into the demand forecasts for the network as described in the sections above.

Anticipated Start Date	Likely Peak Demand (MW)	Expected Load Factor[1]	Type of Demand	GXP	Likelihood
2014/2015	0.4	35%	Commercial	Gracefield	Certain
2014/2015	0.4	30%	Residential	Upper Hutt	Most Likely
2014/2015	1.0	20%	Residential	Takapu Road	Most Likely
2014/2015	0.1	25%	Residential	Wilton	Most Likely
2014/2015	0.7	25%	Residential	Melling	Most Likely
2014/2015	0.6	20%	Residential	Gracefield	Certain
2014/2015	1.5	35%	Commercial	Wilton	Most Likely
2014/2015	1.0	35%	Commercial	Takapu Road	Most Likely
2014/2015	0.2	20%	Residential	Haywards	Most Likely
2014/2015	1.0	35%	Commercial	Haywards	Certain
2014/2015	2.0	35%	Commercial	Upper Hutt	Likely
2014/2015	0.5	35%	Commercial	Central Park	Most Likely

1: The expected load factor is an estimate of the average demand based on the likely maximum demand and type of load supplied.

Figure 5-10 New Step Change Loads Identified for 2014/15

Wellington Electricity has also identified the following loads which may come on stream in future years, where the timing and certainty are less well known.

Likely Demand Beyond 2014/15 (MW)	Expected Load Factor	Type of Demand	GXP
3.0	35%	Commercial	Haywards
4.0	20%	Residential	Takapu Road
0.75	20%	Residential	Pauatahanui
0.35	20%	Residential	Upper Hutt
2.0	35%	Commercial	Central Park

Figure 5-11 New Step Change Loads Identified Beyond 2014/15

5.7.7 Embedded Generation and Demand Control

The load forecast figures provided in this section take into account the impact of any embedded generation and load control operating at the time of the calculated peak. Further detail on embedded generation and load control is presented under separate headings in this section.

5.8 Network Development – Options Available

The process that Wellington Electricity follows when analysing major network investment opportunities includes the development of a long listing of options in accordance with the planning criteria outlined earlier in this section. The long list represents a range of possible solutions to address a clearly defined investment need and the options to meet this need are:

- Do nothing (status quo);
- Network solutions such as:
  - Redistributing demand (e.g. network reconfiguration);
  - Reinforcing the network (this may include many sub-options);
- Non-network solutions such as:
  - Reducing network demand (e.g. energy efficiency, load control, demand side initiatives);
  - Installing generation (e.g. distributed generation).

Non-network solutions are discussed in more detail in the following sections.

Each long listed option has a high level cost estimate associated with it, a benefit in terms of how it addresses the need for reinforcement and an assessment of its feasibility. The long list is ranked using the these criteria (i.e. cost, benefit and feasibility) to allow a short list of options to be developed. The short list is typically limited to two or three options that have roughly similar cost, benefits and feasibilities. The short-listed of options for each project are evaluated against the following factors:

- The impact on network security and reliability;
- Potential capital and on-going investment required to mitigate the issue;
- Compliance with standards and regulations; and
- Potential risks and complexities during construction and operation.

The implementation of this part of the network investment process is currently under review. Once the process is further developed and embedded, information about major investment projects will include the formal long list of alternatives that have been considered.

5.9 Distributed Generation Policy

There is already a small but significant 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 the proponent:

- 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 despatch 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.

Information about connecting distributed generation is available on the Wellington Electricity website – www.welectricity.co.nz or by calling 0800 248 148.

5.10 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. 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 is so effective. Demand response will however be included as a long list option in any major network investment options analysis where it may be potentially useful. Wellington Electricity will pursue demand response if investigation reveals it is an effective way to defer the need for network augmentation. Notwithstanding this, a non-network solution policy that includes demand response will be developed over time as Wellington Electricity progresses with establishing such systems and processes.

5.11 Emerging Technologies and Practices

There continues to be much industry excitement around so-called “smart grids” and smart technologies that will find their way into transmission and distribution networks, the metering and retail space, as well as at consumer level within homes and businesses.

As what constitutes a “smart grid” is largely undefined and there are many different technologies emerging, Wellington Electricity is not actively pursuing smart grid projects or trials. By design, the Wellington Electricity network has a number of features that may be considered to be part of a “smart network”. These include closed ring feeders with differential protection zones that trip out leaving healthy sections in service, on demand load control via the existing ripple control system, and extensive use of SCADA, with over 230 sites offering remote control and indication.

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 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 incorporate 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.

5.12 Grid Exit Points - Constraints and Development Plans

The table below provides GXP capacities and forecast demands for the beginning and end of the forecast period. Figure 5-12 provides an indication of loadings on the GXPs.

GXP	Installed Capacity (MVA)	Transformer Cyclic N-1 Capacity (MVA)	System Maximum Demand MVA	
			2014	2023
Central Park 33kV	2x100 + 1x120	228	164.5	200.5
Central Park 11kV	2x25	30	20.3	21.4
Gracefield 33kV	2x100	89	59.7	55.5
Haywards 33kV	1x20	0	17.1	19.4
Haywards 11kV	1x20	0	20.0	18.4
Melling 33kV	2x50	52	34.8	37.6
Melling 11kV	2x25	27	27.7	28.0
Pauatahanui 33kV	2x201	24	19.3	35.1
Takapu Rd 33kV	2x90	123	92.1	79.3
Upper Hutt 33kV	2x40	37	31.7	32.7
Wilton 33kV	2x100	106	52.7	47.3
Kaiwharawhara 11kV	2x40	41	33.4	33.2

Note: Pauatahanui GXP transformer capacity is to increase if the planned Whitby/Pauatahanui Zone substation is completed.

Figure 5-12 GXP Capacities

The stacked line graph below provides the coincident peak demand forecasts for all GXPs.

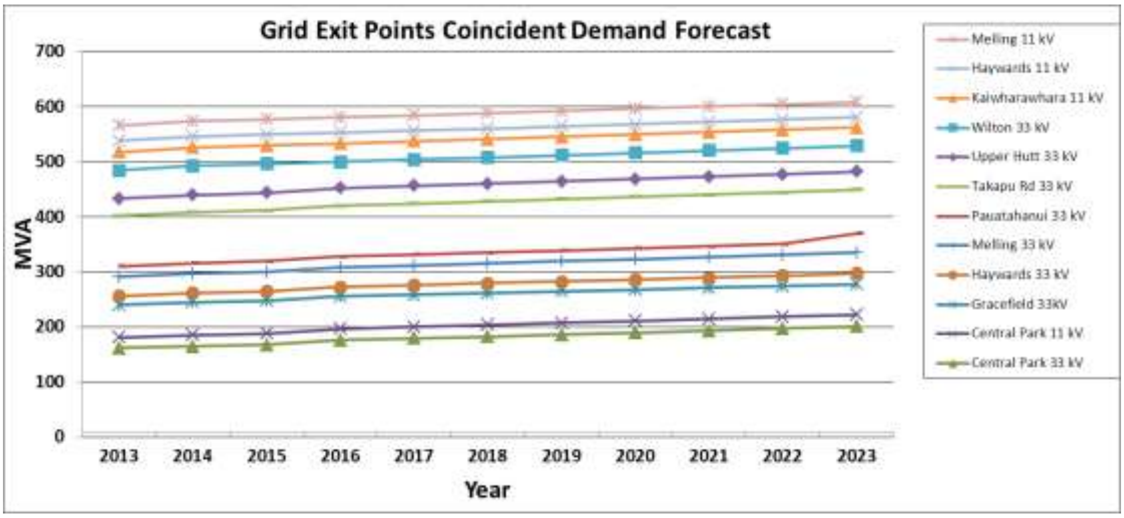


Figure 5-13 GXP Coincident demand forecast

5.12.1 Central Park and Wilton Constraints

As indicated in Figure 5.12, Central Park GXP has the highest peak demand in the Wellington Electricity network and accounts for almost 30% of the total after diversity network demand.

There are three incoming 110kV circuits from Wilton which supply three transformers (110/33 kV) at Central Park as shown in Figure 5-14. All three circuits into Central Park are supplied from the 110kV bus at Wilton and which is supplied by a single 220/110kV transformer (T8) and two 110kV circuits from Takapu Road GXP as shown in Figure 5-15. The West Wind wind farm connects into the double 110kV circuit to Central

Park but is not considered a permanent source of supply, due to its intermittent output, and is not factored into demand or security analysis. In addition, the tee configuration of this connection adopted by Transpower can impact on the reliability of the 110kV circuits.

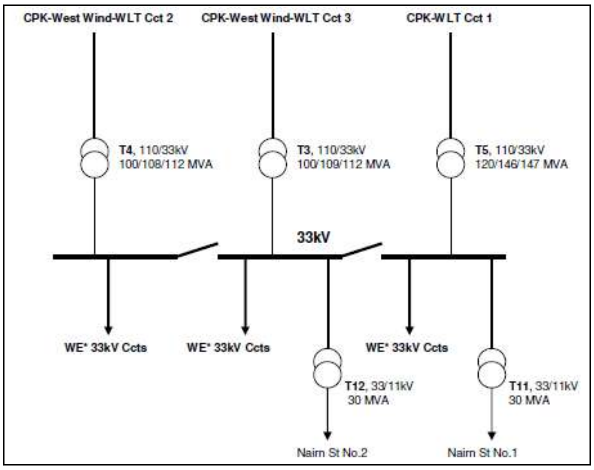


Figure 5-14 Central Park GXP Layout

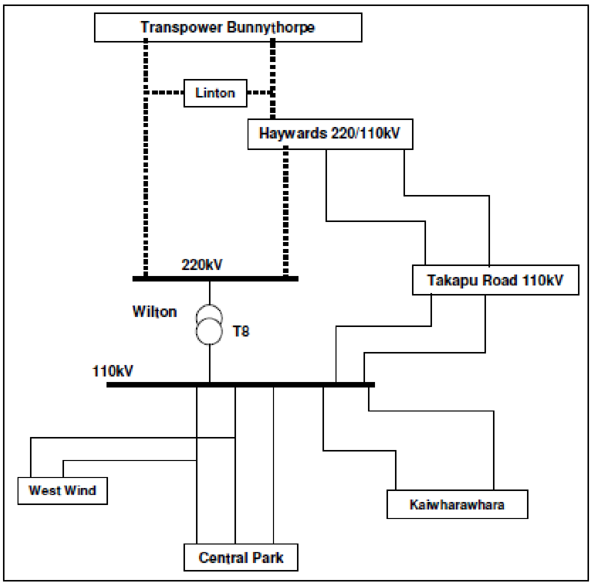


Figure 5-15 Transpower 220 & 110kV Network supplying Wellington Network layout

As there is no 110kV bus at Central Park, all three 110kV circuits are transformer feeders with Wilton circuit 1 supplying T5 (120MVA), Wilton circuit 2 supplying T4 (100MVA) and Wilton circuit 3 supplying T3 (100MVA). Should there be a double 110kV circuit outage, it is not possible to supply the entire Central Park load by the single remaining 110kV circuit from Wilton.

There are operational constraints at Central Park that restrict the firm capacity of the substation to 109 MVA. This reflects the System Operator's requirement to limit the post-contingency loading to the rating of a single 110kV branch, which arises because there is no 110kV bus at Central Park. If one circuit is out of service, load management is required to prevent transformer overloading in the event of a second circuit tripping. In late 2010 a special protection scheme (SPS) was installed at the Central Park GXP to provide automatic load management should one 110kV circuit or transformer be out of service and the remaining load be shared by two transformers. This allows the substation to be operated at higher loads when one circuit is out of service, and reduces the amount of load at risk in the event of a second circuit outage.

Installation of an 110kV bus has been assessed and would be difficult to install due to site space constraints, and the configuration of the 110kV supply network. It would be costly and still not address all the upstream 110kV supply issues.

The three key issues Wellington Electricity faces with the Central Park GXP are:

1. Post contingency rating limit – as described above there is a requirement to have an SPS and controlled load shedding in the event that two of three transformers are out of service at this site. The SPS is required to be armed in the event that one transformer is unavailable. The SPS allows full load to be supplied with one incoming circuit out of service and thus provides for N-1 security at the site. Although the site has three circuits, the N-2 rating cannot meet current demand on the site.

2. Diversity of supply from this site – as the largest GXP in the Wellington Region, supplying over 180MW of load, there is a significant risk should the incoming circuits and transformers be unavailable for service, or in the event of a major 110kV bus fault at Wilton or a complete loss of the Central Park GXP site due to fire, asset failure, or natural disaster. The three existing 110kV overhead circuits into Central Park share a common tower on their entry to Central Park. A catastrophic failure of this tower would result in the loss of all three circuits into Central Park. Additionally, the 110kV circuits from Wilton to Central Park are on two separate routes with a double circuit line on one tower route and single circuit on a different tower route. Due to the high demand at Central Park two 110kV circuits are required to be in service at all times in order to supply the required peak demand (based on the previously described branch rating limits).

3. Capacity for load growth in the CBD – there is an immediate requirement to build a new zone substation in the Wellington CBD area and, given geographic constraints, supply from Central Park is likely to be the most sensible option as the cost, route and length may make installing 33kV circuits back to the Wilton GXP to supply the new substation impractical. Another alternative to reduce reliance on Central Park is interconnection between the new zone substation and Wilton GXP via the Moore St 33kV, to allow for a proportion of load to be transferred between GXPs without having to install new 33kV circuits back to Wilton.

The assets described above at Central Park and Wilton are owned by Transpower. Any reinforcement to mitigate these constraints would normally be undertaken by Transpower with the capital cost charged as a new connection investment to Wellington Electricity, which in turn would pass this cost through to consumers over a fixed period (typically up to 20 years). Wellington Electricity needs to work with Transpower to address the security of supply risks described above.

Wellington Electricity has raised a high level request (HLR) for an investigation into options for addressing the Central Park capacity and security issue. In response Transpower has completed a draft HILP event risk study on the transmission supply into the Wellington CBD and has been able to quantify the risk and develop potential mitigation solutions with associated high level costs. Discussions on the outcome of the HILP study and possible mitigation approaches are underway between Transpower and Wellington Electricity. Wellington Electricity has contributed to this study, which is expected to be finalised in 2014.

5.12.1.1 Prospective Solutions to Eliminate Constraints at Central Park and Wilton

There are several options available to mitigate the security of supply risks identified in the three key issues above. Wellington Electricity has detailed in previous AMPs a range of options to address capacity, supply security and site diversity. A preferred option has now emerged from the HILP study and in discussions between Wellington Electricity and Transpower, and these is described below.

Wilton GXP

All three 110kV circuits are presently supplied from the same bus at Wilton GXP (which is configured as a two bus, 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 (tentatively commencing 2015 following approval). 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.

Central Park GXP

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.

The preferred solution being considered by the parties is as follows and addresses the majority of Wellington Electricity's concerns about this site:

- Replacement of the two 109MVA transformers with two 200MVA transformers;
- Removal of the single 150MVA transformer;
- Conversion of the third, lower rated 110kV circuit to a 33kV bus tie circuit between the Central Park and Wilton GXPs – with a possible transfer capacity of around 50MVA; and
- Diversification of the circuits on the last three towers, with possible undergrounding of the 110kV circuits.

This solution provides firm capacity of 200MVA at the site, with a possible short duration overload capacity of around 230-240MVA, and transfer capacity of around 50MVA at 33kV. It also addresses the 110kV line diversity concerns.

The operational constraints at Central Park GXP could be further reduced by installing an 110kV bus. This option will provide more operational flexibility at Central Park without compromising the reliability of the network. The installation of an 110kV bus will be considered as part of the solution described above, as with a site redevelopment, and reduction to two incoming circuits and transformers, an 110kV bus may be more easily achieved than at present where space constraints make installation very difficult and costly.

Other site risk issues, such as catastrophic damage from fire and natural disaster are being worked through by Transpower, including 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.

5.12.1.2 Prospective submarine cable Gracefield to Evans Bay

As detailed in previous plans, an option exists to install a submarine 110kV link between the Wellington City area (Evans Bay) and Gracefield. Although not the preferred solution to address security constraints at Central Park, and a relatively high cost to install such a circuit, Wellington Electricity is keeping this option open for future consideration.

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.

5.12.2 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 2013 peak demand at Gracefield was 55.6MVA.

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 and need 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 2015 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.

5.12.3 Haywards

Haywards supplies Trentham zone substation via a 33kV outdoor bus, which is supplied by a single 20MVA 110/33kV transformer. Wellington Electricity is also supplied from an 11kV switchboard, which is fed by a 20MVA 110/11kV transformer in parallel with a 5MVA 33/11kV transformer supplied from the Haywards 33kV bus. The loss of either of the 110/33kV or 110/11kV supply transformers would have 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 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 number of options have been developed by Transpower to mitigate this issue:

- Replace the existing configuration (1 x 110/33kV and 1 x 110/11kV supply transformers) to minimise maintenance requirements and improve reliability of supply; or
- Replace the existing configuration with a more typical configuration consisting of two supply transformers per voltage level (2 x 110/33kV and 2 x 110/11kV supply transformers); or

- Replace the existing configuration with two supply transformers (1 x 110/33kV and 1 x 110/11kV supply transformers) and supply a new interconnecting transformer (1 x 33/11kV); or
- Replace with two three-winding transformers with a 110kV primary, 33kV secondary and 11kV tertiary winding.

Transpower's preferred solution is to install two three winding transformers with sufficient capacity to provide N-1 security for both 11kV and 33kV supplies. However, Wellington Electricity is also considering the option of taking 33kV supply only from Transpower and developing its own 33/11kV substation (possibly co-located at Haywards) as an alternative to Transpower making this investment. The final configuration, as well as the ratings of the new transformers and the timing of the project, has still to be confirmed.

5.12.4 Pauatahanui

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 GXP comprises a conventional arrangement of two parallel 110/33kV transformers rated at 20MVA each. The maximum peak demand on the Pauatahanui GXP in 2013 was 19.2MVA. This is within the transformer emergency ratings and also the winter cyclic rating of 24MVA.

Discussions have been held with Transpower regarding prospective load increases at Pauatahanui. However, Transpower has identified a potential voltage and capacity constraint for an N-1 contingency on the Takapu Rd-Pauatahanui-Paraparaumu 110kV circuits, which would be exacerbated if the peak demand at Pauatahanui was to increase. Paraparaumu, which provides a supply to Electra, would be the GXP most affected by this constraint.

Transpower has commenced a project to transfer the Paraparaumu GXP onto its 220kV network, which will be completed by 2015. This will address the above constraint on the 110kV lines from Takapu Road. The reconfiguration will mean the Pauatahanui GXP will be supplied by a dedicated 110kV line from Takapu Rd, which will become a connection asset rather than part of the shared transmission grid. Wellington Electricity may look to take ownership of the line and substation at this time.

Until the Paraparaumu GXP is transferred to the 220kV system, the constraints on the 110kV network can be managed operationally, and Wellington Electricity will continue to work with Transpower and Electra to manage this issue.

Transpower has also 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.

5.12.5 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 2013 was 91.3 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 has notified Wellington Electricity that it will be replacing the Takapu Road GXP 33kV outdoor switchyard with indoor switchgear in 2015. During this outdoor to indoor conversion, a full review and upgrade of the substation protection will occur. The protection limits on Takapu Road GXP transformers will be further raised to provide full transformer N-1 cyclic ratings of 116MVA.

At the time of this upgrade, Wellington Electricity will upgrade all its subtransmission circuit protection, including all differential protection schemes, on circuits supplied from the Takapu Rd GXP.

5.12.6 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. Maximum demand on the Upper Hutt GXP in 2013 was 31.3 MVA. 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.

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.

5.12.7 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. These transformers are each nominally rated at 100 MVA and the maximum demand in 2013 was 53.5 MVA.

By March 2014, Transpower will have completed the replacement of the Wilton 33kV outdoor switchyard with an indoor switchboard. As part of these works, two new feeders are being constructed for termination of the circuits from Meridian Energy's Mill Creek wind farm. The new indoor switchboard will have a Transpower standard feeder protection scheme (owned by Transpower) and subtransmission differential protection owned by Wellington Electricity. Dedicated earth fault relays will be installed due to the installation of neutral earthing resistors on the 220/33kV transformers. Following completion of works at Wilton, Wellington Electricity will replace the existing electromechanical subtransmission differential protection relays on the Waikowhai Street and Karori circuits with modern numerical relays.

5.12.8 Wellington 220kV-110kV interconnection capacity

Presently, the 110kV and 220kV networks in Wellington are interconnected at Haywards and Wilton, and Transpower has identified that another interconnecting bank will be required in the region. The need for this is deferred now that Transpower has decided to move the Paraparaumu GXP onto the 220kV network, but it will be eventually be required.

The need for a fourth interconnector would be further deferred if a new a 33kV subtransmission link is installed from Wilton into the CBD to enable the transfer of load from the 110kV system (ex-Central Park) to the 220kV system (ex-Wilton). Transpower and Wellington Electricity are currently working through this option to determine its costs and feasibility. A benefit to Wellington Electricity would be the ability to move load away from Central Park 110kV supply at times when the incoming supply is constrained (N-1 events) and the SPS is armed, thus reducing the load at risk should a second contingent event occur. This outcome would be achieved if the lower rated Wilton-Central Park 110kV line was operated at 33kV, as discussed in Section 5.12.1.1, and is one of the benefits of this approach.

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.

With the construction of the Bond Street zone substation, an opportunity exists for interlinking Bond Street (likely to be supplied from Central Park) and Moore Street zone substations (or the Wilton GXP) at 33kV level, although the space constraints for installing a 33kV switchboard at Moore Street will need to be addressed. This idea will be further developed in 2014 when considering the CBD capacity issues, new zone substation development and Central Park redevelopment options and will updated in the next AMP.

The subtransmission link concept is estimated to be in the order of $8 to $12 million. This is not included in current expenditure forecasts due to the uncertainty of the work.

5.13 Zone Substations – Constraints and Development Plans

Figure 5-16 provides installed subtransmission capacities and forecast demands for the beginning and end of the forecast period. This table provides an indication of loadings on the subtransmission system.

Zone Substation	Transformer N-1 Cyclic Capacity (MVA)	Single Incoming Circuit Capacity (MVA)		Peak Season	Forecast Demand (MVA)	
		Winter	Summer		2014	2023
8 Ira St	24	21	15	Winter	17.6	19.6
Brown Owl	23	19	13	Winter	15.8	15.2
Evans Bay	24	19	15	Winter	16.5	16.4
Frederick St	36	30	22	Winter	28.1	24.2[3]

Zone Substation	Transformer N-1 Cyclic Capacity (MVA)	Single Incoming Circuit Capacity (MVA)		Peak Season	Forecast Demand (MVA)	
		Winter	Summer		2014	2023
Gracefield	23	21	17	Winter	12.4	10.8
Hataitai	23	22	13	Winter	17.5	16.7
Johnsonville	23	21	14	Winter	16.3	12.6
Karori	24	21	11	Winter	17.4	16.4
Kenepuru	23	19	14	Winter	11.4	7.6
Korokoro	23	22.5	16.5	Winter	19.2	17.7
Maidstone	22	18	10	Winter	15.6	17.3
Mana-Plimmerton	16	27	23	Winter	19.3	10.1
Moore St	36	36	31	Summer	29.2	23.9[3]
Naenae	23	19	14	Winter	15.0	14.7
Nairn St	30.1	25	25	Winter	20.1	16.4[3]
Ngauranga	12	20	14	Winter	13.5	11.6
Palm Grove[2]	24	34	32	Winter	28.1	28.7[3]
Porirua	20	22	14	Winter	17.9	8.3
Seaview	22	21	13	Winter	15.4	15.2
Tawa	16	21	14	Winter	16.0	15.1
The Terrace	36	35	30	Summer	31.2	31.3
Trentham	23	20	14	Winter	17.1	19.4
University	24	24	18	Winter	24.3	21.3
Waikowhai	19	22	15	Winter	16.9	18.3
Wainuiomata[1]	20	16	12.5	Winter	17.8	17.9
Waitangirua	16	22	16	Winter	16.0	10.5
Waterloo	23	21	13	Winter	19.7	19.5

1: Wainuiomata single incoming circuit capacity constraint is the rating of the 11kV incomers. See Section 5.13.10. Wainuiomata transformer N-1 cyclic capacity is the rating of the relocated ex-Petone A 20MVA transformer.

2: The incoming circuit capacity to Palm Grove zone substation will be 34MVA on completion of the Palm Grove subtransmission upgrade project.

3: The loading at Frederick St, Nairn St and other CBD zone substations will be reduced on completion of the new Bond Street zone substation.

Figure 5-16 Zone Substation Capacities and Loadings

The majority of zone substation assets have sufficient capacity available throughout the planning period. However, the following ten zone substations have potential capacity constraints arising within the planning period:

- Frederick Street;
- Johnsonville;
- The Terrace;
- University;
- Wainuiomata;
- Waterloo;
- University;
- Mana – Plimmerton;
- Palm Grove; and
- Trentham.

The capacity constraints are addressed in the following sections with a range of options presented.

5.13.1 Additional 11kV Capacity in CBD

System demand is presently very high in the central Wellington area at both subtransmission and distribution level as a result of new developments and load growth over the past decade. This has largely been accommodated by existing capacity from Frederick Street, The Terrace, Moore Street and Kaiwharawhara substations. The 11kV distribution system is also experiencing high loadings and there are limited options for increasing the 11kV capacity from the existing substations, both physically in terms of site constraints, but also due to upstream subtransmission constraints. From the load forecasts it can be seen that there is a requirement to have significant additional 11kV capacity in the CBD by around 2015.

To resolve these issues, Wellington Electricity plans to construct a new zone substation in the CBD, with construction commencing in 2015 and has purchased a site in Bond Street. Wellington Electricity would utilise this property to construct a 33/11kV zone substation with an installed capacity of 2 x 30MVA. Figure 5-17 shows the planned location for this new zone substation.

The subtransmission supply to the proposed Bond Street substation will most likely be provided from Central Park GXP through high capacity underground 33kV circuits as the route is through the CBD. While this is the least cost approach, it would over time exacerbate the current situation whereby a high proportion of Wellington Electricity's delivered energy, including much of the supply to the CBD, is routed through a single GXP making the network vulnerable to a HILP event that caused extensive damage to the Central Park substation. As noted in Section 5.12.1.1, Transpower's HILP study is quantifying these risks and developing mitigation plans, including plans to facilitate the restoration of supply to consumers should such a catastrophic event occur. A final decision on how the Bond Street substation is to be supplied will not be made until Transpower's HILP study is complete and the residual risk to the business of a catastrophic event disrupting supply from the Central Park GXP is fully understood.

An alternative approach would be to supply the Bond Street substation from the Wilton GXP. However, the geographical location of Wilton would require the subtransmission cables to be three times the length required from Central Park.

Variations on these two approaches are also being considered. One possibility would be to terminate the proposed 33kV bus-tie circuit from Wilton (see Section 5.12.1.1) at Bond Street, bypassing Central Park completely. Another would be to interconnect the new Bond Street substation with Moore Street (which is already supplied from Wilton) by installing double 33kV underground circuits between the two substations. This would go some way to mitigating the risk issue by providing increased security of supply not only to Bond Street and Moore Street substations but also to interconnecting substations supplied from Central Park should there be an outage at the Central Park GXP.

Further investigation is required to quantify the risks, costs and benefits associated with taking supply from each GXP before a final decision is made as to how the new Bond Street substation is to be supplied. This investigation will be completed in 2014. However, the forecasts in this AMP assume the supply will come from Central Park., which is the option with the lowest cost to Wellington Electricity.

Wellington Electricity is also looking at potential projects that could defer the construction of the Bond Street zone substation. These include the installation of new 11kV feeders from existing zone substations, which would mean increasing the transformer capacity at existing zone substations (either by replacing existing transformers with larger units or installation of a third unit at some sites). Development of such alternatives would require consideration of the "Stage of Life" and utilisation of the other network assets within the CBD. A new zone substation would lower the utilisation score under the "Stage of Life" analysis (refer Section 6) and would reduce the risks associated with subtransmission cables, power transformers and switchboards in the CBD, thus deferring replacement expenditure in those areas.

A detailed CBD area study will be completed during 2014, considering not only the immediate 11kV capacity issues, but long-term asset renewal requirements (including subtransmission and substation requirements for the other five CBD zone substations) with a long-term plan and recommended projects then being presented to the Board for approval. Detailed planning will commence in late 2014 for the preferred options with construction commencing in 2015.

Figure 5-17 Land Owned by Wellington Electricity for Possible Substation in Bond Street

Figure 5-18 provides a high level cost estimate and time periods for the construction of a new substation at Bond Street supplied from Central Park. Given the planning undertaken to date, this is currently seen as the most cost effective alternative.

Option Description	Cost	Year investment is required	Duration of Solution
1. New 2X30MVA, 33/11kV zone substation in Bond Street (eight 11kV feeders) 2. Two 33kV Circuits from Central Park to Bond Street substation **Ref 15-001**	$15 million $5 million	2015 and 2016	Beyond 2030
3. Existing 11kV distribution network re-configuration around new Bond Street substation **Ref 16-002**	$2 - $3 million	2016	Beyond 2030
Total estimated cost	**$22-23 million**		

Figure 5-18 Cost Estimate for Possible Substation in Bond Street

5.13.2 Frederick Street Load Transfer

Frederick Street zone substation is presently one of the most highly loaded substations on the Wellington network. Maximum demand is approximately 99% of N-1 subtransmission capacity and there is limited capacity in the 11kV interconnections with adjacent substations to allow offloading at peak times. The available transfer capacity is further limited due to high demand on neighbouring feeders. The 2013 peak demand at Frederick Street was 28.1MVA.

On completion of the proposed new Bond Street zone substation in 2016, a proportion of the load at Frederick Street can be permanently transferred to Bond Street. This will reduce the demand at Frederick Street to well within the single incoming circuit capacity. The CBD supply investigation discussed in Section 5.13.1 will identify the quantity of load transfer achievable with a minimum of network augmentation.

It is expected that at current growth rates, the demand at Frederick Street zone substation will not exceed the single incoming circuit capacity during the period of the AMP after the planned load transfer. In the event of higher growth rates, the existing 33kV PIAS gas filled cables from Central Park GXP will need to be replaced by higher rated 33kV XLPE cables to increase the single incoming circuit capacity to match the transformer N-1 cyclic capacity. A decision on when to upgrade the subtransmission cables supplying Frederick Street zone substation can be deferred until after completion of the Bond Street substation.

5.13.3 Johnsonville

Johnsonville has experienced high load growth over the past decade as a result of ongoing residential development and has a current winter peak load demand of 16.4 MVA. Johnsonville zone substation is supplied by two 33kV circuits from the Takapu Road GXP, which start as an overhead line through rural land and then change to underground cables for the last 5 kilometres into Johnsonville. A project to install new 11kV feeder interconnections with Ngauranga has been completed, as discussed in Section 8.6, which has 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.

The north-east side of Johnsonville is now experiencing relatively high load growth, with an increased number of subdivisions in Grenada Village underway or in the consenting process. This load growth, along with the previous high levels of growth in Churton Park (to the north of Johnsonville), is leading to a capacity constraint in this area which will become more of an issue as new developments are completed. There are limited options for increasing 11kV capacity and security into these areas from Johnsonville.

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, currently under development, is the construction of a new zone substation to the north-east of Johnsonville to supply the existing high loads and to allow for high load growth in this area. This is expected to be required by 2017-18. 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 new substation will not only supply load growth in and around the Grenada area, but also offload Johnsonville Feeders 2 and 3 and Tawa Feeders 3 and 11.

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.

Figure 5-19 provides a high level cost estimate and time periods for the new zone substation.

Project Description	Cost	Year investment is required	Duration of Solution
Construction of new 20MVA, 33/11kV Zone substation in Grenada **Ref 17-005**	$15 million	2017	Beyond 2030

Figure 5-19 Cost Estimate for Possible Substation for Grenada

5.13.4 Mana-Plimmerton

As discussed in Section 3.3.3 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.

5.13.4.1 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 2013 was 19.2 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.

5.13.4.2 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 13.5MVA. 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 5-20 shows the layout of Mana and Plimmerton zone substations.

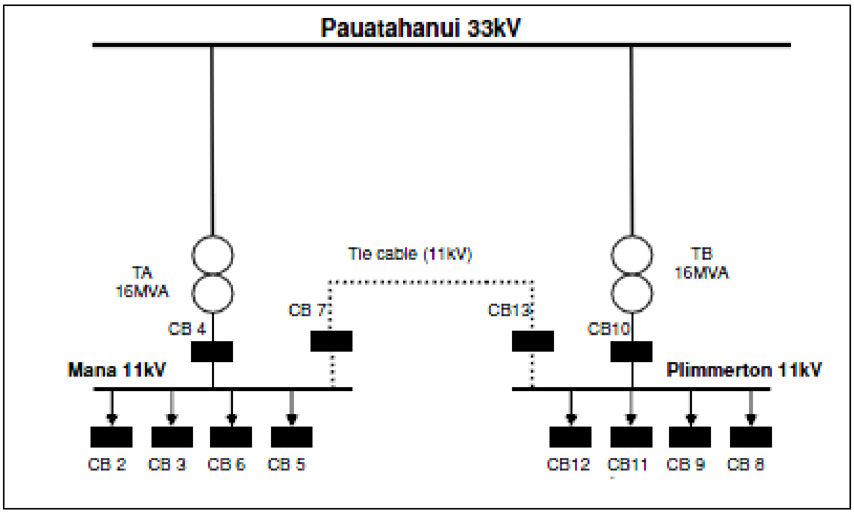


Figure 5-20 Mana-Plimmerton Connection Layout

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.

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 special protection scheme (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 5-21 provides the overview of the proposed special protection scheme at Mana and Plimmerton.

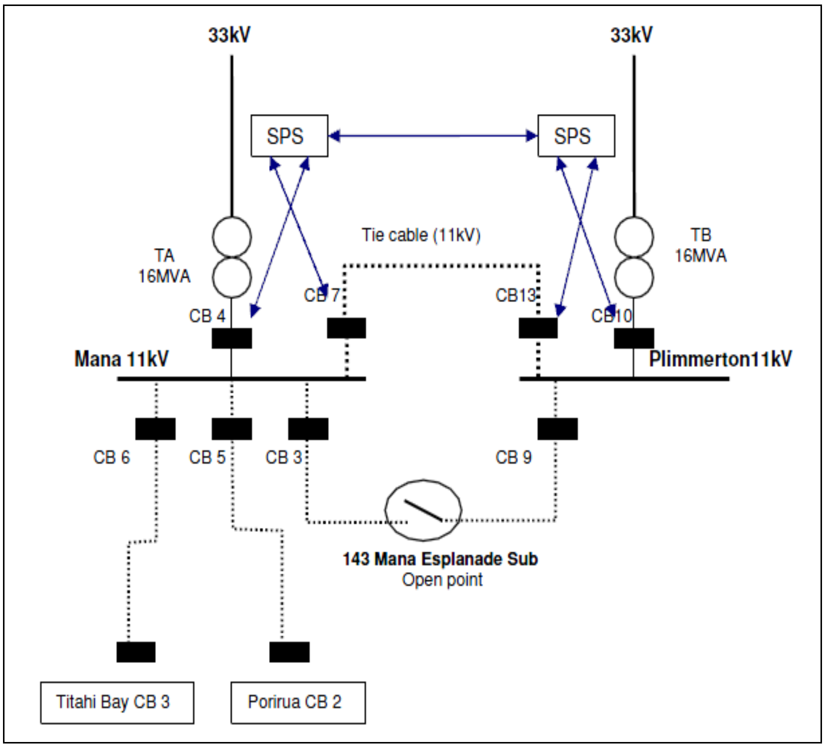


Figure 5-21 Special protection scheme logic at Mana and Plimmerton

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 5-22 provides a high level cost estimate and time periods for the SPS implementation.

Project Description	Cost	Year investment is 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: 14-006**	$250,000	2014	2017-18

Figure 5-22 Cost Estimate for Option 2 SPS for Mana-Plimmerton

5.13.5 New Zone Substation in Whitby/Pauatahanui Area

There is both high system demand and high load growth in the Whitby area due to a large number of recent subdivisions, as well as the prospective load from subdivisions currently in the consenting process. This area is currently fed from Waitangirua and Mana zone substations. Waitangirua is forecast to reach its N-1 capacity during 2014. This shortfall is projected to grow to approximately 5MVA by 2023. Mana and Plimmerton exceeded their combined N-1 capacity by 4MVA during 2013, 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.

Substation construction is currently planned for 2020-2021 but may need to be brought forward following detailed investigation of load growth and interim reconfiguration scenarios for off-loading Waitangirua.

Figure 5-23 shows the proposed site location for the new zone substation.

Figure 5-23 Preferred Site for Possible Substation in Whitby Area

Project Description	Cost	Year investment is 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 20-002**	$15 million	2020-22	Beyond 2030

Figure 5-24 Cost Estimate for Possible Substation in Whitby/Pauatahanui Area

5.13.6 Palm Grove

Works are currently underway to replace both existing incoming circuits with new high capacity XLPE subtransmission cables between Central Park and Palm Grove. This will provide a higher capacity and a higher level of supply resilience to Palm Grove than the existing gas filled cables. Works are due to be completed by mid-2014.

On completion of the new incoming subtransmission cables, the installed N-1 transformer capacity (24MVA) will be the constraining factor on demand at Palm Grove. Transformer capacity at Palm Grove zone substation will need to be upgraded within the planning period. The current preference will be to install two new 30MVA units and redeploy the existing Palm Grove transformers, either to eliminate a capacity network constraint elsewhere in the network, or to replace transformers that have reached end-of-life. The transformers installed at Evans Bay currently have the poorest condition score, and could be replaced by the Palm Grove units, which are currently in good condition. This will be investigated further in 2014.

Project Description	Cost	Year investment is required	Duration of Solution
1. Supply and installation of two new 30MVA transformers 2. Removal of Evans Bay transformers, relocation and installation of existing Palm Grove transformers at Evans Bay **Ref 15-007**	$2 million	2015	Beyond 2030

Figure 5-25 Cost Estimate for Upgrade of Transformer Capacity at Palm Grove

Another identified constraint at Palm Grove is that the 11kV distribution network does not have any open points to allow paralleling between the zone 1 and zone 2 ring networks (i.e. each side of the 11kV bus). Palm Grove zone substation is normally operated with a split 11kV bus configuration and there is no option available for shifting load between T1 and T2 buses at the distribution network level. This presents a risk during an outage on either bus section at Palm Grove. Currently there is adequate capacity to offload one side of each bus onto adjacent zone substations at 11kV.

A network load flow study will be undertaken to identify possible locations to install open points between the two parts of the Palm Grove zone substation distribution networks to offer better operational flexibility at the distribution level. Figure 5-26 provides the estimated cost and time frames for creating the interconnectivity between the Palm Grove zone 1 and zone 2 distribution networks.

Project Description	Cost	Year investment is required	Duration of Solution
Install interconnectivity between two Palm Grove distribution network zones **Ref 16-001**	$500,000	2016	Beyond 2030

Figure 5-26 Cost Estimate for interconnectivity between Palm Grove Z1 and Z2

5.13.7 Trentham Subtransmission Protection Upgrade

Trentham zone substation is supplied from the Haywards GXP via two 33kV sub-transmission 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 are to be installed at Haywards GXP and Trentham 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.

The individual pilot cable routes for the two subtransmission circuits are to be diversified using existing infrastructure between Haywards GXP and Trentham zone substation. This will negate the risk of con-current 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 is approved and implementation is planned for early in 2014.

Figure 5-27 provides the approved budget and timing for replacing the Solkor protection with new differential relays and diversifying the pilot circuits.

Project Description	Cost	Year investment is required	Duration of Solution
Replace subtransmission protection on Haywards – Trentham circuits and diversify pilot routes. **Ref 14-003**	$416,000	2014	Beyond 2030

Figure 5-27 Cost Estimate for Trentham Subtransmission protection upgrade

5.13.8 Trentham – Maidstone Interconnection

The peak demand at Trentham zone substation will exceed the single incoming circuit capacity during the planning period.

A customer has requested network connection of an extension to a large data centre facility in the Trentham area with a forecast peak load of approximately 5MVA. The peak demand of the existing facility is 1MVA and currently supplied from Trentham via an open ring configuration. This ring has insufficient capacity for this additional load that will be connected by 2015.

Two options exist for supplying sufficient capacity to the customer's facility without compromising the Trentham area network.

1. Install a new normally closed ring feed from Trentham to connect the existing data centre facility and provide provision for the future extension. The customer has indicated that this option is not preferred, and it will not be pursued further.

2. Install a new interconnecting 11kV cable between the Trentham and Maidstone zone substations to connect the existing data centre facility and provide provision for the future extension.

A new 300mm2 Al XLPE circuit would be installed between Trentham and Maidstone zone substations along the route shown in Figure 5-28.

Figure 5-28 Proposed inter-connection between Trentham and Maidstone

This cable would provide adequate capacity to the customer while also providing back-feed capability between Trentham and Maidstone zone substations. Maidstone zone substation is lightly loaded and has sufficient firm subtransmission capacity to accommodate a significant proportion of loading at Trentham zone substation in the event of a loss of a single subtransmission circuit. The new interconnecting cable would be normally open at the customer facility to avoid creating a parallel between the Upper Hutt and Haywards GXPs.

Normal supply to the customer connection would be from Trentham zone substation but supply could be readily switched to Maidstone zone substation in the event of a loss of supply, thus providing N-1 security. Figure 5-29 shows the proposed interconnection between Trentham and Maidstone zone substations and supply to the customer facility.

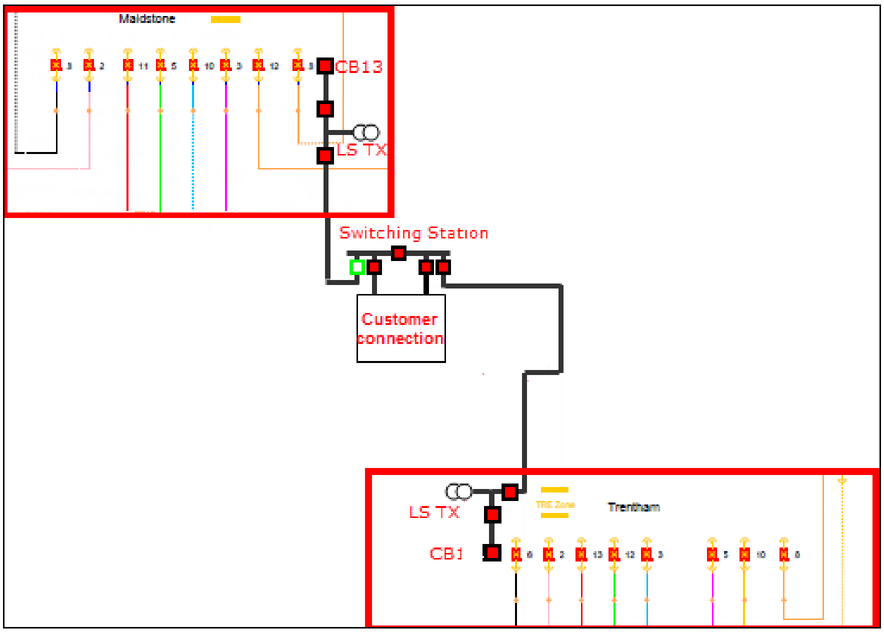


Figure 5-29 Proposed ring feed to Customer data centre facility

The customer has indicated that this is the preferred option. This is also Wellington Electricity's preferred option because it would allow load to be transferred away from Trentham zone substation in the event of a subtransmission contingency, thus avoiding the need to increase the capacity of the existing subtransmission infrastructure.

Figure 5-30 provides a high level cost estimate and timing for installation of the proposed 11kV interconnection. Completion of this project is dependent on reaching a satisfactory commercial agreement with the customer, which will include a capital contribution towards the cost of the work.

Project Description	Cost	Year investment is required	Duration of Solution
11kV inter-connection of Trentham and Maidstone zone substations via customer connection. **Ref 15-004**	$2.5 million	2015	Beyond 2030

Figure 5-30 Cost estimate for Trentham – Maidstone interconnection

5.13.9 University Subtransmission Reinforcement

The peak demand at University zone substation is 26.1MVA, which is currently above its firm incoming subtransmission capacity of 24MVA. Permanent load transfer as part of the University zone reinforcement project (Section 5.14.2.7) will reduce the loading to 24.5MVA in 2014; however, projected growth rates will result in the load exceeding the single incoming circuit capacity by 2MVA in 2023.

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.

As the present issues relate to utilisation, a transfer of load from University to a new CBD zone substation would manage the capacity constraint within the planning period. This would result in the timing of potential investment being driven by the age and condition of the cables rather than the loading at University zone substation. The extent to which the capacity constraint will be reduced by the new CBD zone substation is not known at this time (subject to a study in 2014) therefore this project will remain in the plan.

The project costs and timing are based on the information available at the present time.

Figure 5-31 provides a high level cost estimate and time periods for replacing the University subtransmission cables.

Project Description	Cost	Year investment is required	Duration of Solution
Replace the University subtransmission circuits **Ref 17-002**	$3.5 million	2017	Beyond 2030

Figure 5-31 Cost Estimate for University Subtransmission reinforcement

5.13.10 Wainuiomata

The peak demand at Wainuiomata zone substation in 2013 was 17.7 MVA. Wainuiomata has a typical residential load profile and is supplied from the Gracefield GXP by two 33kV overhead lines with underground cable sections at the GXP end. There is only one limited back-feed option at 11kV, due to Wainuiomata's geographic isolation. Hence, in the event that supply to Wainuiomata is compromised through a loss of 33kV supply from Gracefield, or an 11kV bus fault at Wainuiomata, full restoration of supply would be difficult. As the likelihood of it occurring is small, such an event would normally be considered a HILP event and fall outside Wellington Electricity's normal network planning criteria.

However, the area supplied from Wainuiomata zone substation is less resilient to HILP events than other parts of the network due to the lack of 11kV back-feed. The majority of zone substations on the network have a higher level of back-feed available through the 11kV network, typical of an interconnected urban network.

Two network options exist to improve the security of supply to the Wainuiomata 11kV network.

1. Construction of 11kV overhead lines, or under-built 11kV on the 33kV lines, to improve the 11kV connectivity; or

2. Installing cable within the water services tunnel between Wainuiomata and Gracefield to provide interconnectivity at the 11kV level (and add resilience to the 33kV supply).

A network planning study will be undertaken to quantify the risk and economics of such an investment. This will need to consider the cost of the work against the risk of a total loss of supply. Consultation will be required to determine whether consumers are willing to pay more for a higher level of security. This is a price-quality trade-off which Wellington Electricity cannot make on their behalf. In the meantime a contingency plan is being developed to deploy mobile generation and manage rolling outages to reduce the impact of this risk.

Other issues identified with the Wainuiomata zone substation relate to a mismatch of asset ratings:

1. The main constraining factor is with the 11kV incomer cables, which have a rating of 12.5 MVA but can be run up to 16 MVA as an emergency rating (two hours). The maximum demand in 2013 was 17.7 MVA which is in excess of this rating, and an upgrade is required. The incomer capacity would be doubled by replacing the existing incomer cables by two per phase XLPE cables (6x1C 630mm^2 Al XLPE).

2. Relocation of the ex-Petone A zone transformer to Wainuiomata reduced the N-1 transformer capacity to 20MVA. While this transformer has a lower rating than the unit it replaced, this does not present an immediate issue as the forecast load in the area is not expected to exceed this before the end of the planning period;

Figure 5-32 shows the Wainuiomata zone substation layout and highlights these constraints.

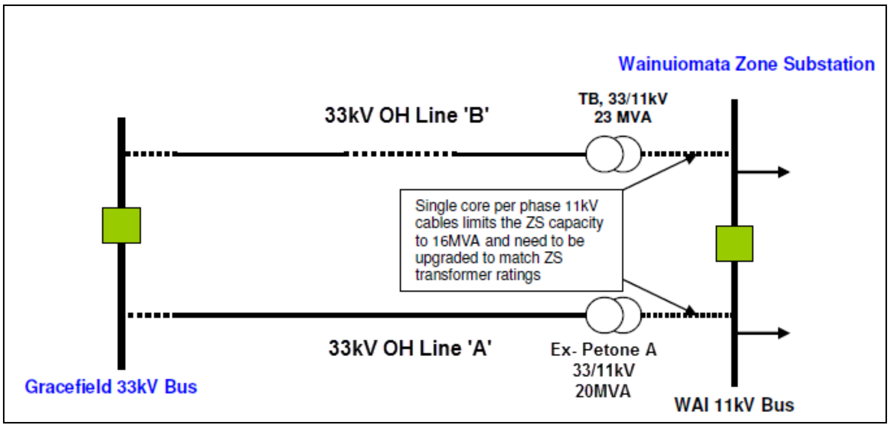


Figure 5-32 Wainuiomata Zone Substation Layout

Given the current low level of load growth in the Wainuiomata area, the recommendation is to upgrade only the 11kV incomer cables such that the transformer N-1 rating is the constraining factor. Long-term load growth will determine when further upgrades are required. These may include upgrade of the zone transformers and mitigation of the capacity constraints imposed by undersized sections of the subtransmission cables.

Figure 5-33 provides a high level cost estimate of the proposed solutions for Wainuiomata zone substation.

Project Description	Cost	Year investment is required	Duration of Solution
Replacement of existing 11kV incomer cables with 1C, 630mm^2, Al, XLPE, 11kV cables (two per phase) **Ref 15-005**	$100,000	2015	Beyond 2030

Figure 5-33 Cost Estimate for Proposed Solutions for Wainuiomata

5.13.11 Waikowhai Subtransmission Protection Upgrade

Transpower is replacing the existing Wilton GXP 33kV outdoor switchyard with an indoor switchboard in early 2014. As part of these works, Wellington Electricity will be required to provide 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 will be recoverable from Transpower.

Following this work, the subtransmission protection on the Wilton – Waikowhai subtransmission circuits will be replaced. Waikowhai Street zone substation supplies the mostly residential loading in Ngaio and Khandallah, and is supplied via 33kV subtransmission cables from the Wilton GXP. Subtransmission protection is currently provided by Solkor R relays, which are nearing the end of their technical life.

New numerical relays will be installed at both Wilton GXP and Waikowhai zone substation. These relays have a pilot cable supervision facility to guard against spurious tripping in the event of a failure of a pilot circuit.

This project was originally approved for $225,000; however, non-recoverable costs arising from the additional scope for the Wilton outdoor-indoor conversion project have increased the cost to $241,000.

Figure 5-34 provides the approved budget and timing for provision of resourcing to assist Transpower to complete the Wilton outdoor-indoor conversion project and works to replace the existing Wilton – Waikowhai subtransmission circuit protection with new numerical relays.

Project Description	Cost	Year investment is required	Duration of Solution
Replace sub-transmission protection relays on Wilton – Waikowhai circuits. **Ref 14-004**	$241,000	2014	Beyond 2030

Figure 5-34 Cost Estimate for Waikowhai Subtransmission Protection upgrade

5.13.12 Fault Levels at CBD Zone Substations

All CBD[14] 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.

As an example, the fault level on the Frederick Street 11kV bus (when closed) is 16kA. Typically switchgear at zone substations of that era are rated at 13.1kA (250MVA). Distribution equipment downstream is of similar rating. All new equipment being installed is rated at up to 25kA at zone substations, and up to 21kA at distribution substations, in anticipation of being able to raise the fault levels in future.

Due to the split bus system, there is a short break in the event of a subtransmission circuit outage and there is not true “no-break” N-1 security of supply to CBD loads. Wellington Electricity’s NCR has to

[14] 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.

remotely close the bus section on the switchboard, or, in some cases, a fault person is required to manually close the switch on site. This impacts on system SAIDI.

There are a number of options available to mitigate the risk of high fault levels at CBD zone substations.

<u>Increasing 11kV Switchgear Fault Ratings</u>

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.

<u>High Impedance Zone Transformers</u>

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 a 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 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 premature replacement of assets.

<u>Current Limiting Reactors or Resistors</u>

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 5-35 shows the typical arrangement of a bus tie reactor in a distribution system.

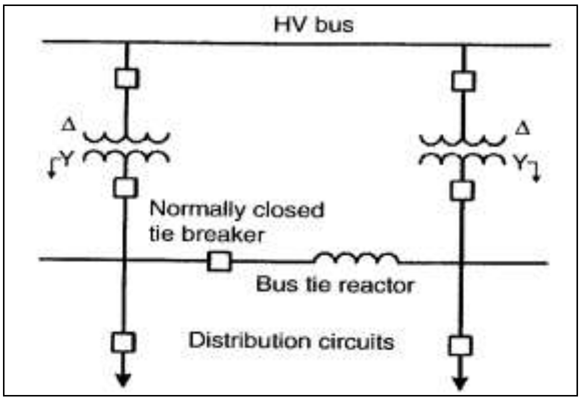


Figure 5-35 Typical Bus Tie Reactor Arrangement

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 5-36 provides a project cost estimate for bus fault level improvements (or mitigation through other means).

Project Description	Cost	Year investment is required	Duration of Solution
CBD substation bus fault level improvements **Ref: 17-001, 18-001, 19-001, 20-001, 21-001, 22-001, 23-001, 24-001**	$850,000	Annually from 2017 onwards	Beyond 2030

Figure 5-36 Cost Estimate for Bus Fault Level Improvements

5.14 11kV Distribution System – Constraints and Development Plans

Figure 5-37 lists the 11kV feeders that in 2019 are forecast to be operating above 70% loading and the duration of the peaks does not exceed the relevant security criteria for the feeder type.

Feeder		Zone Substation	Loading at peak time (2019)
FRE CB2	2 College St	Frederick Street	72%
KAI CB09	209 Hutt Rd	Kaiwharawhara	79%
MOO CB12	47 Thorndon Quay	Moore Street	78%
MOO CB14	50 Thorndon Quay	Moore Street	78%
MAI CB06	Leisure Centre	Maidstone	75%
TAW CB11	Jamaica Dr C	Tawa	71%
TRE CB08	Messines Army Centre	Trentham	75%
TRE CB12	Gower St	Trentham	76%
WAN CB03	Caduceous Pl	Waitangirua	75%
WAT CB05	Brook St	Waterloo	78%

Figure 5-37 11kV Feeder Loading Forecast – Short Duration Peak Loading

Monitoring of these feeders will continue. If the duration or magnitude of the loading is found to exceed the security criteria for the feeder type, solutions will be identified for reducing the loading or reinforcing the network to ensure compliance with the security criteria.

Figure 5-38 lists the 11kV feeders that in 2019 are forecast to be operating above 70% loading for sustained periods at peak time during normal operation and are likely to be in breach of the security criteria for that feeder. These feeders have been, or are in the process of being, assessed for network reconfiguration and augmentation solutions to the high loading. Figure 5-39 lists the feeders which are identified to have constraints in the period 2019-2024.

Feeder		Zone Substation	Loading at peak time (2019)	Loading to exceed N-1 Criteria
MOO CB2	National Library	Moore Street	83%	2013
NGA CB01	C1035	Ngauranga	90%	2013
PAL CB11	Parade	Palm Grove	84%	2013
PAL CB06	Mansfield St	Palm Grove	81%	2013
POR CB01	Titahi Bay A	Porirua	95%	2013
POR CB05	Lyttleton Ave	Porirua	80%	2013
POR CB11	Titahi Bay B	Porirua	98%	2013
WAN CB05	Postgate Dr	Waitangirua	96%	2013
WAT CB03	Hautana St	Waterloo	82%	2013

Figure 5-38 11kV Feeder Loading Forecast – Sustained High Loading at 2019 (5 years)

Feeder		Zone Substation	Feeder loading at peak time (2024)
IRA CB2	33 Ludlam St	8 Ira Street	73%
IRA CB08 (ring)	Wayside West	8 Ira Street	52%
BRO CB08	Clearwater Cres	Brown Owl	67%
EVA CB02 (ring)	69 Miramar Ave	Evans Bay	69%
EVA CB04 (ring)	Batten St	Evans Bay	68%
FRE CB13	21 Tasman St	Frederick Street	60%
FRE CB14	19 College St	Frederick Street	69%
KAR CB02 (ring)	Dasent St	Karori	60%
KAR CB04 (ring)	Burrows Ave	Karori	56%
KOR CB09	Londons Rd	Korokoro	58%
MAI CB11	42 Lane St	Maidstone	70%
MAN CB02	Ivey Bay	Mana	67%
MEL CB04	Melling Railway Stn	Melling 11kV	60%
MOO CB05	2 The Terrace	Moore Street	69%
NGA CB07	Jarden Mile	Ngauranga	72%
NGA CB09	WRC Pumps	Ngauranga	78%
TAW CB13	Oxford St	Tawa	72%
WAI CB13 (ring)	Fitzherbert Rd	Wainuiomata	56%

Figure 5-39 11kV Feeder Loading Forecast – Sustained High Loading at 2024 (10 years)

Moore Street, The Terrace, Evans Bay, Frederick Street and 8 Ira Street zone substations have loading constraints which are linked with wider CBD supply capacity constraints. The building of a new zone substation in the CBD will allow these to be reconfigured. Presently there is a short term solution available to off-load some these feeders onto interconnecting neighbouring feeders by shifting open points.

Loading constraints on Waitangirua Feeder 5 are linked to a large subdivision development which will continue to grow over the coming years. As part of this work, significant reconfiguration of the 11kV network is required to supply the subdivision and to relocate existing overhead lines. This project commenced in 2013 as a customer initiated project and is on-going.

5.14.1 Operational Solutions to Identified High Load Feeders

Volumes on a number of the high load feeders can be off-loaded by shifting open points to utilise available capacity in adjacent feeders, without the need for further investment in the network. Figure 5-40 lists the constrained feeders which can be off-loaded onto adjacent feeders.

Feeder	Load Moved to	Forecast loading at peak time (2019)	
		Existing	Proposed
MOO CB02	KAI CB12	83%	60%
MOO CB14 (ring)	TER CB03 & KAI CB04	78%	65%
KAI CB09	KAI CB06	79%	66%
MAI CB11	MAI CB02	70%	52%
WATCB03	SEA CB12	82%	67%
POR CB01 (ring)	MAN CB6 & TIT CB11	71%	53%
POR CB11 (ring)	MAN CB6 & TIT CB11	71%	53%
MAN CB02	MAN CB5	67%	51%
WAN CB05	WAN CB11	96%	55%

Figure 5-40 Proposed Open Point Configurations to Reduce Loadings on Feeders

This proposed open point configuration would reduce feeder loadings below or close to 66% at peak load time. The high load feeders that cannot be addressed in this manner require a solution such as reinforcement work to increase capacity, or to reduce the feeder loadings via other methods such as demand side management, temporary generation or other means.

5.14.2 Feeders Requiring Investment in Non-operational Solutions

The feeders which have constraints that cannot be easily resolved in the short to medium term by operational means will require network investment and reinforcement. A description of the major 11kV feeder reinforcement projects is discussed below.

5.14.2.1 Ira Street Feeder 2 Reinforcement

Ira Street feeder 2 supplies a mixture of residential and commercial load in the Seatoun area and has a peak demand of 5.60MVA, which is 82% of the feeder rating.

The following options were considered to reduce loading on this feeder to within the planning criteria of 66%:

1. Install a new feeder bay at Ira Street and connect to the feeder from 33 Ludlam Street CB3. This option is not preferred due to the cost space constraints within the Ira Street zone substation.

2. Install a new RMU supplied from CB11 and connect to the feeder from 33 Ludlam Street CB3. This is the preferred option.

Works are planned to shift a portion of load from Ira Street Feeder 2 to CB11. A new RMU will be installed outside the Ira Street substation and supplied from CB10. The cable currently terminated to 33 Ludlam Street CB3 will be routed to this new RMU. The RMU will also provide a parallel connection to the local service transformer previously connected to CB11.

Ancillary works will also be required to mitigate a constraint resulting from an undersized section of cable between Broadway substation and Devonshire Road substation. This section of Ira Street feeder 2 provides back up supply to Evans Bay zone 1 ring load and also supplies key commercial loads. Back-feed capacity is restricted to 200A due to this constraint. Works are planned to overlay this undersized section of cable.

Figure 5-41 shows the proposed network reconfiguration at 8 Ira Street.

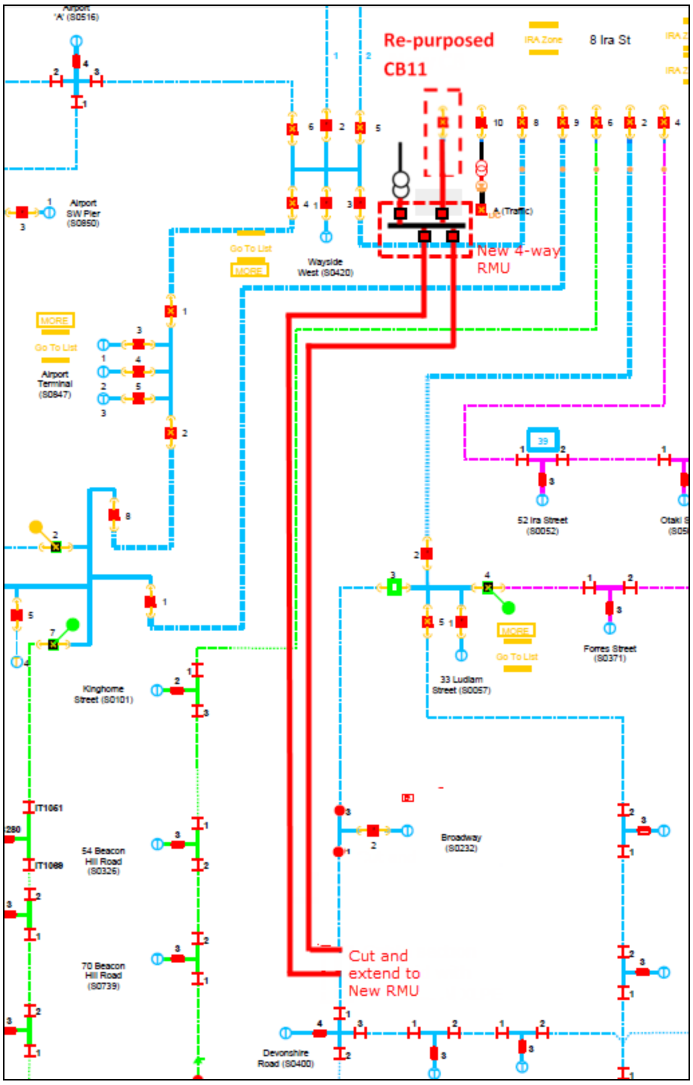


Figure 5-41 Ira Street Feeder 2 Reinforcement Project

Figure 5-42 provides the approved budget for implementation of the 8 Ira Street Reinforcement project.

Project description	Cost	Year investment is required	Project description
New feeder via RMU supplied from CB10 at Ira Street substation to off-load Ira Street feeder 2 and Evans Bay zone 1 ring feeders and overlay of 188m of undersized cable section **Ref 14-002**	$345,000	2014	Beyond 2025

Figure 5-42 Cost Estimate for Proposed Solutions for Ira Street Feeder 2

Switching will be required, on completion of physical works, to provide further off-load from Ira Street feeder 2 to feeder 4 and to balance the loading across the zone 1 and 2 bus sections.

5.14.2.2 Palm Grove Feeder 6 – 25 Mein Street 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. Figure 5-43 shows the forecast load duration curve for Palm Grove Feeders 3 and 6 during the 2014 summer peak period.

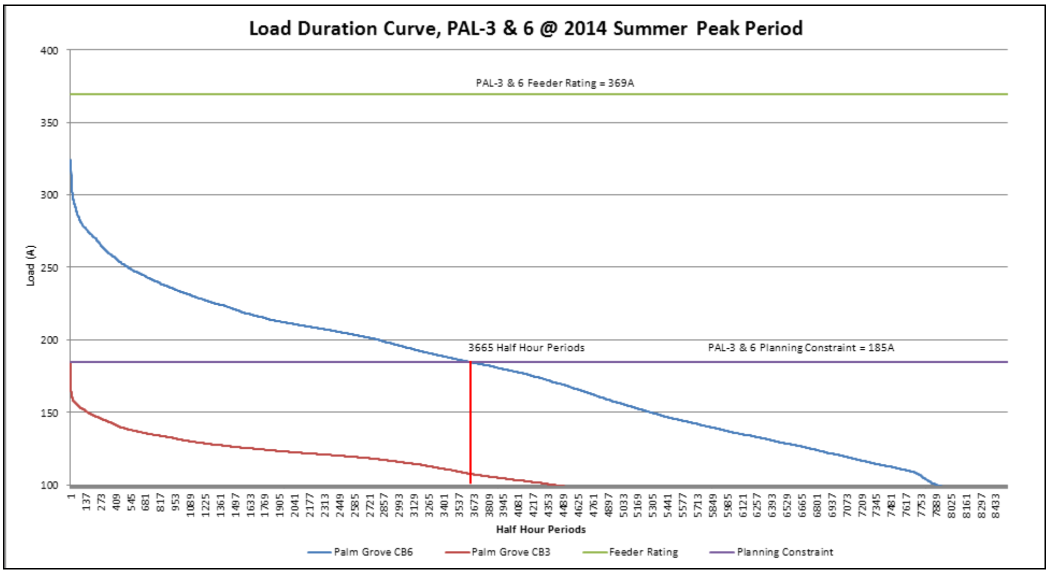


Figure 5-43 Load Duration Curve for Palm Grove Feeder 3 and 6

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.

A number of options are considered for mitigating these issues. Space constraints within the 25 Mein Street substation limit extension of the switchgear to provide an additional feeder bay for a dedicated circuit breaker for the incomer circuit from 381 Adelaide Street. Figure 5-44 shows the current network configuration at 25 Mein St.

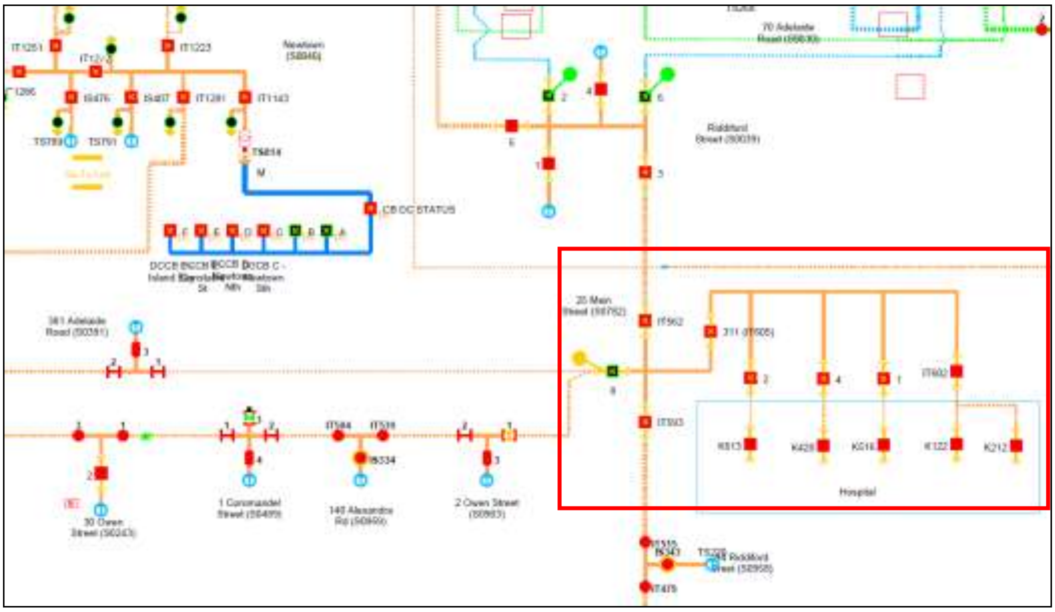


Figure 5-44 25 Mein Street network configuration

The proposed option to mitigate the supply concerns to 25 Mein St and the Wellington Hospital is to balance the load across the two existing incomers to below 66% and install a new extensible switchboard within the 25 Mein Street substation. Figure 5-45 shows the proposed option for introducing a third normally closed incomer from 381 Adelaide Road complete with protection.

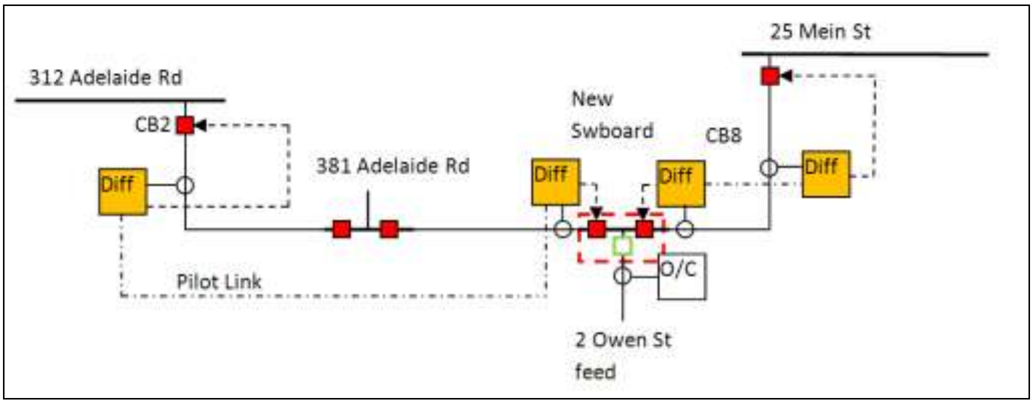


Figure 5-45 Proposed re-configuration of 25 Mein St substation

The third incomer circuit from 381 Adelaide Rd will be connected to the new switchboard and protected via differential protection allowing operation in a normally closed meshed ring feed with Palm Grove Feeder 3 and 6. A loss of any one of these three incoming circuits will not compromise the rating of the remaining two. N-1 supply to the Hospital will be available via the three incomers at all times.

Figure 5-46 provides the budget estimate for mitigation of the security of supply risk to 25 Mein St and reduction of loading on Palm Grove feeder 6. This project is subject to review and negotiation with the Capital Coast District Health Board.

Project description	Cost	Year investment is required	Duration of Solution
Balance loading across Palm Grove Feeder 3 and 6, introduce third feeder to 25 Mein St **Ref 14-007**	$380,000	2014	Beyond 2025

Figure 5-46 Cost Estimate for Proposed Solutions for Ira Street Feeder 2

5.14.2.3 Gracefield Feeder 2

Gracefield Feeder 2 supplies the Eastbourne area which is mostly residential with a winter peak demand of 3.28MVA. The maximum capacity of Gracefield Feeder 2 is 5.37MVA with a peak loading of 62% in 2013. Planning based on the 2012 demand forecast suggested that the loading on Gracefield Feeder 2 will grow to 77% by 2017. The 2013 forecast suggests the load at Gracefield has decreased. As such, these works are proposed for 2015 subject to review after the actual rate of growth in 2014 is known.

There are two network options that would address the loading concerns at Gracefield. One option is to increase the capacity of the existing feeder and the second option involves shifting the load onto interconnecting feeders.

Increasing the feeder capacity involves replacing the existing 11kV feeder cable by installing a new three core 300mm^2 aluminium cable, which would require replacing more than 2km of existing cable. This option is not an efficient solution due to the cost of installing such a length of cable.

The second option involves shifting a portion of the load from Gracefield Feeder 2 to Gracefield Feeder 8. Gracefield Feeder 8 follows the same route as Gracefield Feeder 2 but has lower loading. However, the capacity of Gracefield Feeder 8 is limited due to around 500m of undersized three core 95mm^2 aluminium cable installed between Seaview Wharf substation and Days Bay switching station.

This proposed plan is to shift the last six distribution substations at the end of Gracefield Feeder 2 onto Gracefield Feeder 8 by closing the normally open point CB03 at Days Bay switching station. This will reduce the loading on Gracefield Feeder 2 cable to below 66% at peak load time. Implementing the proposed plan requires replacement of the existing undersized cable on Gracefield Feeder 8 with three-core 185mm^2 aluminium cable before the proposed switching could be carried out.

Figure 5-47 provides the estimated cost to replace the undersized cable between Seaview Wharf and Days Bay switching station.

Project description	Cost	Year investment is required	Duration of Solution
Replace existing 95mm^2 Aluminium cable with 185mm^2 Aluminium on Gracefield Feeder 8. Reconfigure existing open points **Ref 15-002**	\$420,000	2015-16	Beyond 2025

Figure 5-47 Cost Estimate for Proposed Solutions for Gracefield Feeder 2

5.14.2.4 Haywards Feeder 2722

Haywards feeder 2722 supplies the Silverstream area and has a residential load profile. The 2013 peak demand on Haywards 2722 was 4.39MVA. This feeder also supplies the Silverstream KiwiRail substation, which contributes to the high loading on this feeder.

Haywards feeder 2722 is supplied from Transpower's Haywards 11kV GXP. It shares an open point with Trentham feeder 5 and around 500kVA of load will be moved onto Trentham 5 in 2013 as part of a customer load connection project and subsequent reconfiguration of that part of the network. This will reduce the loading on Haywards feeder 2722 but peak demand on this feeder will still be above the feeder planning criteria limit. 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 5-48 provides the estimated cost to reduce the loading on Haywards feeder 2722.

Project description	Cost	Year investment is required	Duration of Solution
New Feeder at Haywards 11kV GXP to offload feeder 2722 including new feeder cable **Ref 15-006**	\$500,000	2015	Beyond 2025

Figure 5-48 Cost Estimate for offloading Haywards 2722

5.14.2.5 Moore Street New Feeder

Moore Street 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.

Load growth is high around the Centreport and Waterloo Quay area with recent customer requests for load connections over 500kVA. At present Moore Street 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.

A project was approved in 2013 to install a new feeder from Moore Street 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 Street and connection into an existing substation on Waterloo Quay. Construction did not commence in 2013 and this project will now be undertaken in 2014.

The feeder route is shown in figure 5-49.

Figure 5-49 New feeder layout from Moore Street to Waterloo Quay

Installing the new feeder from Moore Street into Waterloo Quay as shown in the above diagram is the approved solution. This will provide around 6MVA of capacity into Waterloo Quay and Centreport area to allow connection of future load, and alleviate existing high loading.

Figure 5-50 provides the estimated cost for this new feeder option.

Project Description	Cost	Year investment is required	Duration of Solution
1. Installation of a new feeder cable in Thorndon Quay, Pedestrian overpass and substation	$640,000	2014	Beyond 2030
2. New circuit breaker with protection relays at Moore Street zone substation	$80,000	2014	Beyond 2030
3. Switchgear extension at distribution substation (addition of new circuit breaker)	$25,000	2014	Beyond 2030
Total	**$745,000**		

Figure 5-50 Cost Estimate for New Feeder into Waterloo Quay

5.14.2.6 Palm Grove Feeder 12

The peak demand on Palm Grove feeder 12 is 5.6MVA or 85% of its capacity. Palm Grove feeder 12 is part of the Palm Grove zone 1 ring and loading is not evenly balanced across the three feeders supplying this ring.

A planning study is to be undertaken to determine the optimum solution to address the constraints. A possible solution would be to install a new feeder to share the load at Palm Grove feeder 12. Figure 5-51 below provides the estimated cost for this solution along with timeframe for this work.

Project Description	Cost	Year investment is required	Duration of Solution
Reinforcement of Palm Grove zone 2 ring to reduce loading at Palm Grove feeder 12 **Ref 16-001**	$500,000	2016	Beyond 2030

Figure 5-51 Cost Estimate for Palm Grove feeder 12 reinforcement

5.14.2.7 University Substation Feeder Reconfiguration

During the winter-summer shoulder and summer periods, the loading on transformers T1 and T2 supplying University Zone Substation is uneven. T1 supplies mostly commercial loading while T2 supplies mostly residential. As such, the expected peak loading periods during the day are non-coincident leading to variations in the winding temperature of the two transformers.

T1 experiences a 10-15 degree temperature rise at peak periods during the day while the temperature at T2 remains approximately constant. It is expected that T1 will have a shorter operating life than T2 due to these higher temperature variations. Figure 5-52 shows the expected temperature fluctuations in T1 and T2 during the worst case loading.

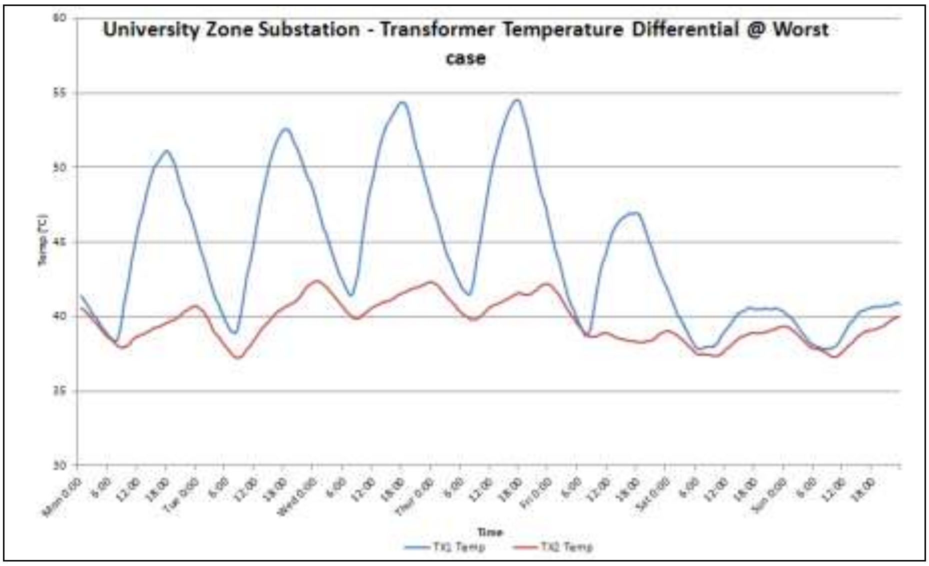


Figure 5-52 University zone substation T1 and T2 temperature differential

An additional issue is that University Feeder 8 and Feeder 11 were at approximately 70% loading during the winter peak period. This compromises the capacity for N-1 switching to back-feed loading at connected adjacent zones.

To mitigate these issues, University Feeder 3 is to be connected to the spare feeder bay at CB13 to balance the loading on T1 and T2. Figure 5-53 shows the proposed re-configuration of University zone substation.

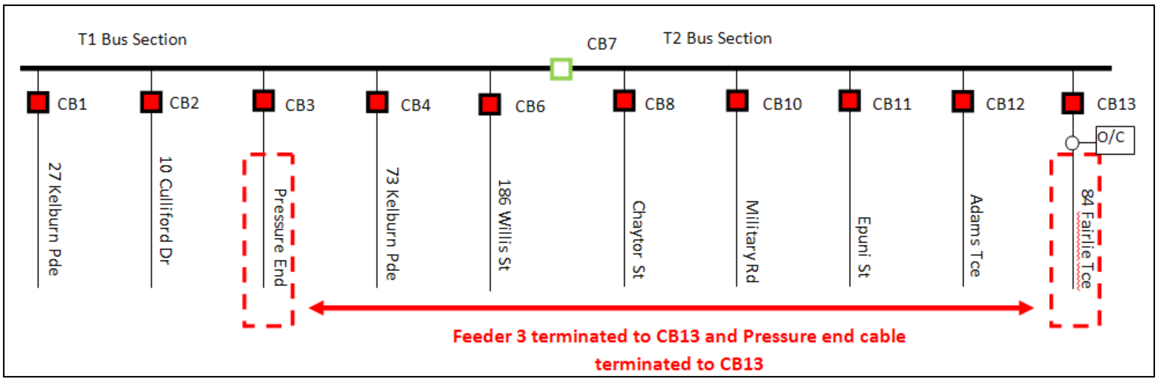


Figure 5-53 Re-configuration of the University zone substation

Permanent open point shifts will also be enacted to shift loading from University feeder 8 and 11 to Terrace feeder 15 and Nairn Street feeder 14. Peak loading on University feeder 8 and 11 is forecast to then be reduced to 66%.

Figure 5-54 provides the approved budget for balancing the loading at University zone transformers and shift of loading from University feeder 8 and 11.

Project Description	Cost	Year investment is required	Duration of Solution
Balancing the loading on University zone transformers – Shifting CB6 onto T2 side of bus. Enact open point shifts to reduce loading on University feeder 8 and 11 **Ref 14-001**	$72,500	2014	Beyond 2030

Figure 5-54 Cost Estimate for University zone reinforcement

5.15 Proposed Wellington Electricity Network in 2024

The figure below provides the proposed 2024 overview of the Wellington Electricity network. This is how it is expected to look given current growth trends and considering the required capacity and security levels. As described in this section, over the next 10 years three new zone substations are planned to be constructed to supply areas around the Wellington CBD, Grenada and Whitby/Pauatahanui. The proposed reinforcement of the subtransmission network, which would involve replacement of aged and highly utilised gas and oil filled cables with new XLPE cables, is also shown as dotted orange colour lines in the figure below. On completion of this work in 2024, the Wellington Electricity network will provide a high level of resilience within the subtransmission network, and have sufficient capacity within required security levels.

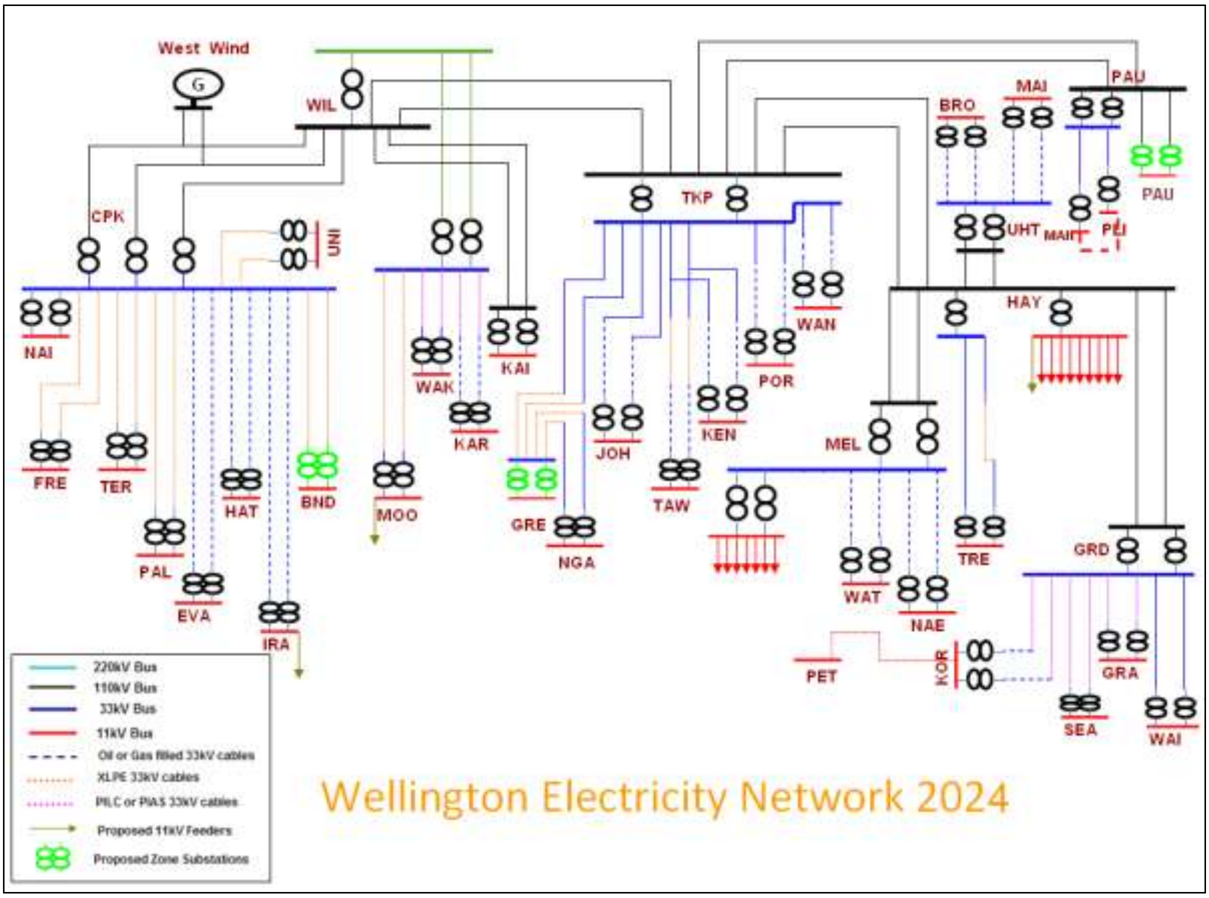


Figure 5-55 Proposed Wellington Electricity Network Overview – 2024

5.16 Investment Programme - Growth, Customer Connections and Asset Relocations

Major network investment covered in this section includes developments necessary to maintain security levels driven by system growth, and to enable customer connection and asset relocation work to occur. Asset replacement and renewal projects to address asset age or condition are covered in Section 6 (Lifecycle Asset Management).

5.16.1 Major Network Investments for 2014

The following major projects and programmes of work are budgeted for and expected to take place or commence during 2014. As discussed in Section 2.10.4, Wellington Electricity's internal asset management and planning cycle, as well as project timings described in this AMP, are based on the company's financial year (1 January to 31 December).

5.16.1.1 2014 Growth, Security and Reinforcement Projects

University Feeder 3 Reinforcement – 2014	
Driver: Growth, Security Estimated cost: $72,500 Ref: 14-001	Due to high loading on T1 side of University 11kV bus, the T1 transformer has high loading compared to the T2 transformer. To balance the loading on both transformers at University, feeder 3 will be shifted onto to the T2 side of bus. This will evenly balance the loading on both zone transformers at University. Open point shifts will be enacted to reduce loading on feeder 8 and 11 to 66% capacity For more details see Section 5.14.2.7

8 Ira Street Feeder 2 Reinforcement – 2014	
Driver: Growth, Security Estimated cost: $345,000 Ref: 14-002	Feeder 2 at 8 Ira Street zone substation is highly loaded, and in breach of Company policy for N-1 switching and loading on radial feeders. To relieve loading on this feeder, the cable supplying 33 Ludlam Street is to be re-terminated to CB11 via an RMU which will also provide a connection to the station-services transformer An undersized section of cable limiting back-feed capacity for off-load of critical commercial loading from Evans Bay zone substation is to be overlaid For more details see Section 5.14.2.1

Trentham Sub-transmission Protection Replacement – 2014	
Driver: Security Estimated cost: $416,000 Ref: 14-003	The existing sub-transmission protection relays on the Haywards-Trentham circuits are at the end of their technical life and will be replaced by modern numerical relays. In addition, the current pilot cable route has a number of locations where failure of pilot cables is possible due to common mode failure. The individual pilot cable routes are to be diversified using existing infrastructure between Haywards and Trentham For more details see Section 5.13.7

Wilton Subtransmission protection upgrade – 2014	
Driver: Security, Condition Estimated cost: $241,000 Ref: 14-004	Replace the existing cable differential protection scheme on Waikowhai and Karori 33kV feeders with new relays. These works are dependent on ancillary works required during the Transpower Wilton outdoor-indoor conversion project The outdoor 33kV bus at Wilton GXP is to be converted to an indoor GIS system as part of Transpower's ongoing programme of outdoor-indoor conversion works. As part of these works, Wellington Electricity is required to provide resourcing to accomplish switching, protection testing, SCADA modification and planning. All costs directly associated with this project are to be recovered from Transpower on completion For more details see Section 5.13.11

Mana-Plimmerton Zone Substation Reinforcement – Special Protection Scheme	
Driver: Growth Estimated cost: $250,000 Ref: 14-006	The 11kV tie line between Mana and Plimmerton has a capacity shortfall should the 33kV circuit supplying Mana zone transformer be out of service. A special protection scheme with intertrip and close is going to be implemented to manage the load during contingency situations For more details see Section 5.13.4.2

25 Mein Street Reinforcement - 2014	
Driver: Security Estimated cost: $380,000 Ref: 14-007	Summer peak loading at Wellington Hospital results in a N-1 supply security breach for approximately 20% of the year. A loss of either of the incoming circuits from Palm Grove during summer peak loading will compromise the capacity of the remaining circuit A third normally in-service incomer, complete with Solkor differential protection, is to be implemented by installing a new extensible switchboard such that the loss of any one of the incomer circuits will not compromise the total capacity of the remaining two For more details see Section 5.14.2.2

5.16.1.2 Overhead Reinforcement - General

There is an aggregated budget allowance of $250,000 for minor overhead reinforcement projects that are not able to be directly attributed to individual customers. Examples of this reinforcement would be re-conducting of overhead lines to relieve a capacity constraint.

5.16.1.3 Underground Reinforcement - General

There is an aggregated budget allowance of $400,000 for minor underground network reinforcement projects that are not able to be directly attributed to individual customers. Examples of such projects include installing overlaying of under-sized cable sections.

5.16.1.4 Customer Growth and Relocations

These projects have been aggregated in the budget in accordance with the categories discussed below. Overall, the budgeted expenditure for 2014 of $5.7 million is slightly higher than the 2013 actual cost of $5.5 million. This is attributed to a recent lift in consumer and developer confidence. It should be noted between 2005 and 2009, customer driven expenditure was, on average, $7.5 million per year.

New Connections

For the first time in three years the number of residential building consents issued in the Wellington region has risen, driven by the growth in residential apartments within the Wellington CBD.

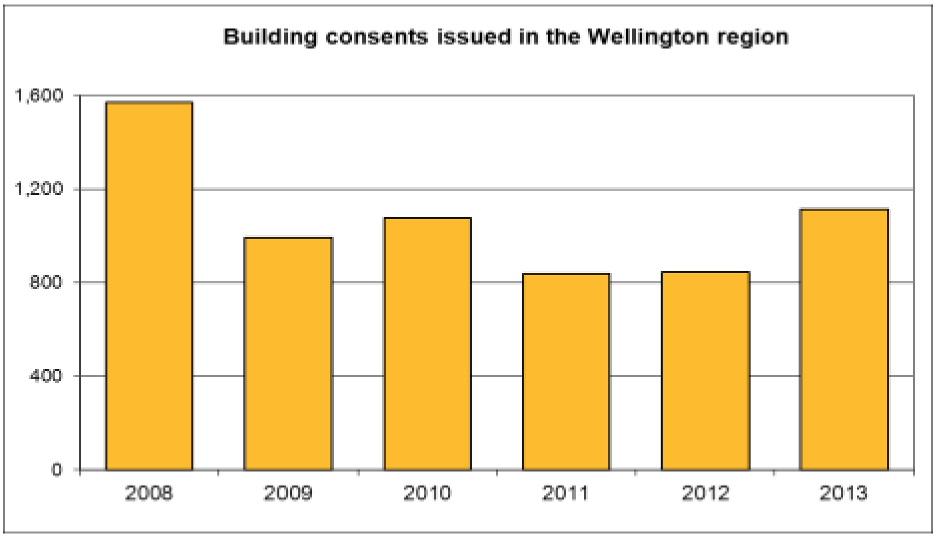


Figure 5-56 Number of Building Consents Issued in Wellington Region

While this 2014 budget for new connections is higher than expenditure in 2013, it is based on the last four year rolling average.

5.16.1.4.1 Substations

The minor decrease in customer substation expenditure is due to less large scale developments requiring network capacity above 1MVA. Overall substation related spend, including transformer capacity changes, is slightly down on levels seen in the past 4 years at $2.0 million.

5.16.1.4.2 Subdivisions

While small and infill subdivisions look to remain at similar levels to previous years, local developers continue to show little appetite for large scale residential (>100 lots) or business park subdivisions. New industrial property development 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 2014 is $1.4 million.

5.16.1.4.3 Capacity Changes

Expenditure associated with transformer upgrades or downgrades is included within the customer substation area of the customer connection forecasts.

5.16.1.4.4 Relocations

An allowance in 2014 of $1 million for relocation work, initiated from NZTA and Councils, as well as other customer initiated relocations, has been made based on the respective Authorities' strategy plans.

5.16.2 Prospective Investments for 2015 – 2019

Projects included in this section are less certain in nature. Whether or not they proceed, and their timing, will depend largely on whether forecast load growth materialises. It is possible that over the period before construction of any project must be committed, Wellington Electricity may identify more cost effective, including non-network, approaches that will supply the required load in accordance with the planning criteria.

New Wellington CBD Zone Substation – 2015-2016	
Driver: Growth, Security Estimated cost: $20 million (over two years) Ref: 15-001	Construction of a new 33/11kV zone substation in the Wellington CBD to address loading issues and improve security of supply to the CBD. The project includes the reconfiguration of 11kV feeders Investment in a single new zone substation may defer expenditure required to increase subtransmission and transformer capacity at multiple Wellington City zone substations around the CBD For more details see Section 5.13.1

Gracefield Feeder 2 Reinforcement – 2015	
Driver: Growth Estimated cost: $420,000 Ref: 15-002	Upgrade of around 500m of the existing 95mm^2 cable on Gracefield feeder 8 and transfer load from Feeder 2 onto Feeder 8 to address loading on Feeder 2 For more details see Section 5.14.2.3

Takapu Road Subtransmission protection upgrade – 2015	
Driver: Condition Estimated cost: $1.2 million Ref: 15-003	Replace the existing circuit differential protection schemes on the Takapu Rd 33kV feeders (Waitangirua, Porirua, Kenepuru, Tawa, Johnsonville and Ngauranga) with new relays during conversion of the Takapu Rd 33kV outdoor to indoor conversion which Transpower has indicated will occur in 2015. Wellington Electricity is also required to provide resourcing to accomplish switching, protection testing, SCADA modification and planning to assist in the indoor conversion. All costs directly associated with this project are to be recovered from Transpower on completion For more details see Section 5.12.6

Maidstone – Trentham Interconnect – Data Centre supply – 2015	
Driver: Growth, Security Estimated cost: $2.5 million, Wellington Electricity will recover a portion of costs from Customer Ref: 15-004	Install a new 11kV cable between Maidstone and Trentham zone substations for supply to the planned data centre facility. Cable will provide back-feed capability and satisfy the customer's redundancy requirements. Costs will be apportioned For more details see Section 5.13.8

Wainuiomata Zone Substation 11kV Incomer cables upgrade – 2015-16	
Driver: Growth Estimated cost: $100,000 Ref: 15-005	Upgrade the existing 11kV incomer cables at Wainuiomata to match transformer and switchgear ratings. These cables are forecast to cause a capacity constraint under N-1 conditions For more details see Section 5.13.10

New 11kV Feeder at Haywards 11kV GXP – 2015-16	
Driver: Growth, Security Estimated cost: $500,000 Ref: 15-006	Due to the high loading on Haywards feeder 2722, investment will be required to install a new feeder at the Haywards 11kV GXP to offload Haywards feeder 2722. This will provide spare capacity into the Silverstream area to meet high future growth and to manage existing high loading including that of the KiwiRail traction substation For more details see Section 5.14.2.4

Replace Palm Grove Transformers – 2015	
Driver: Growth Estimated cost: $2 million Ref: 15-007	Re-locate the existing Palm Grove transformers to replace units at Evans Bay which currently have the lowest condition score Supply and install two new 30MVA transformers at Palm Grove to remove the current fixed capacity constraint due to the existing transformers For more details see Section 5.13.6

Palm Grove 11kV Reinforcement – 2016	
Driver: Growth, Security Estimated cost: $500,000 Ref: 16-001	Installation of a new 11kV feeder into the Palm Grove zone 1 ring to address loading concerns and potential security of supply issues arising from the high loading in this area For more details see Section 5.14.2.6

Zone Reinforcement – University / Frederick St / Moore St / The Terrace – 2016	
Driver: Growth Estimated cost: $1-3 million per site Ref: 16-002	Following development of a new CBD zone substation, these substations are expected to require intra-zone reinforcement to provide acceptable security levels within their meshed 11kV ring systems. It may be determined that converting the meshed systems to radial feeders will provide adequate security and reduce the constraints in a more economical way. For more details see Section 5.13.1

CBD Zone Substation Fault Level Improvements – 2017	
Driver: Security Estimated cost: $850,000 Ref: 17-001	To reduce the fault levels at CBD zone substations in order to operate them as closed 11kV bus system For more details see Section 5.13.12

University Subtransmission Reinforcement – 2017	
Driver: Growth, Security Estimated cost: $3.5 Million Ref: 17-002	Replace and upgrade the existing subtransmission cables into University zone substation to address capacity and utilisation risks. Replacement of gas filled cables in is line with Wellington Electricity strategy and increases resilience in this area For more details see Section 5.13.9

New Grenada Zone Substation – 2017-2018	
Driver: Growth Estimated cost: $15 million (over two years) Ref:17-005	Construction of new 20-30MVA zone substation in Grenada Village north east of Johnsonville. The high load growth north of Johnsonville and in the Churton Park area will require a new zone substation to meet future demand. This will offload Johnsonville, Ngauranga and Tawa zone substations, which are expected to be overloaded by 2016 For more details see Section 5.13.3

CBD Zone Substation Fault Level Improvements – 2018	
Driver: Security Estimated cost: $850,000 Ref: 18-001	To reduce the fault levels at CBD zone substation in order to operate them as closed 11kV bus system For more details see Section 5.13.12

5.16.2.1 Prospective Investments for 2019 – 2023

The projects listed below may occur in the last five years of the planning period covered by this AMP. These have been budgeted unless otherwise stated; however, the timing of the investment may vary depending upon factors such as load growth, technological advances, and whether investments with higher priority are required in this period.

CBD Zone Substation Fault Level Improvements – 2019	
Driver: Security Estimated cost: $850,000 Ref: 19-001	To reduce the fault levels at CBD zone substation in order to operate them as closed 11kV bus system For more details see Section 5.13.12

Gracefield Subtransmission protection upgrade – 2019	
Driver: Security, Condition Estimated cost: $500,000 Ref: 19-003	Replace existing protection scheme on eight outgoing 33kV feeders from this GXP with new differential relays to improve security of supply, functionality and performance For more details see Section 5.12.2

CBD Zone Substation Fault Level Improvements - 2020	
Driver: Security Estimated cost: $850,000 Ref: 20-001	To reduce the fault levels at CBD zone substation in order to operate them as closed 11kV bus system For more details see Section 5.13.12

New Zone Substation in Whitby/Pauatahanui area – 2020	
Driver: Security Estimated cost: $15 million (over two years) Ref: 20-002	Construct a new 20-30MVA zone substation in the Whitby/Pauatahanui area to relieve loading at Waitangirua and Mana-Plimmerton zone substations For more details see Section 5.13.5

Upper Hutt Subtransmission protection upgrade – 2020	
Driver: Condition Estimated cost: $500,000 Ref: 20-003	Replace the existing cable differential protection scheme on Maidstone and Brown Owl 33kV feeders with new relays during conversion of the Upper Hutt 33kV outdoor to indoor conversion which Transpower has indicated will occur in 2020-21 Wellington Electricity is also required to provide resourcing to accomplish switching, protection testing, SCADA modification and planning to assist in the indoor conversion. All costs directly associated with this project are to be recovered from Transpower on completion. For more details see Section 5.12.6

CBD Zone Substation Fault Level Improvements - 2021	
Driver: Security Estimated cost: $850,000 Ref: 21-001	To reduce the fault levels at CBD zone substation in order to operate them as close 11kV bus system For more details see Section 5.13.12

CBD Zone Substation Fault Level Improvements - 2022	
Driver: Security Estimated cost: $850,000 Ref: 22-001	To reduce the fault levels at CBD zone substation in order to operate them as closed 11kV bus system For more details see Section 5.13.12

Pauatahanui Subtransmission protection upgrade - 2022	
Driver: Security, Condition Estimated cost: $700,000 Ref: 22-002	Replace existing protection relays on the 33kV circuits from this GXP with new differential relays at the time during commissioning of the new subtransmission supply to a new zone substation in Whitby. This work will be undertaken to improve security of supply and improve performance and will occur regardless of whether the proposed substation will be constructed at this time For more details refer to section 5.12.4

5.16.2.2 Capital Expenditure Forecasts

From the details in the section above, Wellington Electricity's network development and growth capital expenditure forecast is summarised in the table below. 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.

	2013/14	2014/15	2015/16	2016/17	2017/18	2018/19	2019/20	2020/21	2021/22	2022/23	2023/24
Consumer connection	5,608	6,437	6,908	7,343	6,713	6,363	6,615	6,663	6,751	7,299	7,220
System Growth	4,564	7,881	7,389	7,784	5,851	5,590	6,697	6,472	6,146	5,779	5,717
Asset Relocations	687	997	1,091	1,119	1,034	1,010	1,058	1,046	1,044	1,105	1,093
Total	**10,859**	**15,315**	**15,388**	**16,246**	**13,598**	**12,963**	**14,370**	**14,181**	**13,941**	**14,183**	**14,030**

Note: This table does not include asset replacement capital expenditure - detailed in Section 6.

Figure 5-57 Capital Expenditure Forecasts – 2013 to 2024 ($000 in constant prices)

From the above information shows that network development and growth expenditure is 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.

6 Lifecycle Asset Management

6.1 Asset Lifecycle Planning Criteria and Assumptions

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 as well as to mitigate the risks inherent in running an electricity distribution network.

Asset lifecycle management consists of the following:

- Routine asset inspections, condition assessments and servicing of in-service assets;
- Evaluation of the results in terms of meeting customer service levels, performance expectations and risks;
- Adjusting 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. tap changer maintenance based on oil tests). Inspections are undertaken on a time-based cycle, which may vary for certain assets within a particular category, based upon known issues and risks. 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 due to their higher risk. Some assets, with a low value, low replacement cost, and where the risks of failure are low, may simply be run to failure and then replaced, as this is more economical and performance efficient 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 do not have an infinite life and must eventually be replaced. Ideally, assets should be replaced before they fail. However, premature asset replacement is costly since it means that the service potential of the replaced asset is not fully utilised. 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 there is a high risk that it will fail if left in service and 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 and would result in a regulatory quality breach or would adversely impact Wellington Electricity's reputation.

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 the specific asset class, 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 and this is 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 on those assets that are in the worst condition and pose the highest risk to the network.

6.2 Stage of Life Analysis

During 2010, Wellington Electricity first undertook a "Stage of Life" analysis on three major asset categories: subtransmission cables, zone substation power transformers, and zone substation 11kV switchboards. Each year, the "Stage of Life" analysis is updated to incorporate new information gained from inspection and test data, knowledge gained from operating the network for another year, and to reflect the completion of work to address age, condition, performance or utilisation of the assets. Details of the outcome of this work are under the respective headings in this section.

The main feature of this analysis is that it combines the disciplines of asset lifecycle management and network planning to ensure optimal investment in the network. When considered holistically, factors such as age, condition and utilisation provide the basis for determining where asset replacement and renewal investment is required. However, if these factors are analysed independently, investment may occur in areas where the risk is not significant. As an example, an old transformer that is supported by 100% back-feed capacity could be a lower network risk than a transformer in better condition, but where back-feeds are not possible or constrained and where a failure may result in un-served load.

In the "Stage of Life" analysis, age, condition and utilisation are each given weightings. The highest weighting is given to utilisation, as the consequence of failure is a major concern and can be assessed more accurately than the likelihood of failure due to age or condition. Ultimately, loading and back-feed constraints have a longer term consequence if load cannot be supplied. More details of how the "Stage of Life" analysis is applied for each of the three asset categories are given in the relevant section below.

These three asset categories (power transformers, subtransmission cables and zone substation switchboards) were selected as they present the highest risk to the system. In addition, each discrete asset can be considered individually (unlike asset categories that may include thousands of individual assets) and they represent the areas where investment will be the largest, often millions of dollars for a single asset. Other categories generally have a lower risk profile and have renewal programmes driven by type issues, defect and condition information with a view to "whole of life" cost optimisation. However, there are network policies created for those asset categories that include elements of the "Stage of Life" analysis process.

The "Stage of Life" analysis is dynamic and may change over time as more experience is gained in using the analysis. For example, the factors considered to determine condition or utilisation could change or the relative weightings could be adjusted.

The result of the "Stage of Life" analysis for each of the three categories is provided in the relevant section below. The analysis does not aim to provide solutions, but rather to identify areas where further investigation is required.

The "Stage of Life" analysis is a constantly changing assessment and needs to be updated on a regular basis, as occurred in 2013. As the network changes and more or less capacity is available in certain areas, or as asset condition deteriorates or improves, or as spare parts are used up or made available from replacement work, the scores found in the "Stage of Life" analysis will change. As a result, any prospective investment arising from this analysis may change over the planning period.

A further area for improvement in the "Stage of Life" analysis is determining the optimal timing of investment. For some individual assets, the analysis will indicate an immediate need for renewal due to the lack of back-feed or exceptionally poor condition. For assets where there is not an immediate need, the use of more complex network investment decision making tools is required in order to determine the optimal timing for replacing the asset. During 2014, it is planned to develop the "Stage of Life" analysis into a full network lifecycle model, which will assist in optimising expenditure against risk of failure and reliability over the asset lifecycle for the network assets as a whole. The results of this will be included in future AMPs.

6.3 Maintenance Practices

6.3.1 Maintenance Contracts

As noted earlier, Wellington Electricity contracts Northpower as its Field Services Provider to undertake and manage the network maintenance programme under a Field Services Agreement. At the time of writing this AMP, Northpower has almost completed three years of operation on the Wellington network.

The Northpower Field Services Agreement brought a number of improvements to the way maintenance activities are undertaken, and how corrective repairs and defects are managed and reported.

The scheduling of inspection and maintenance activities is driven by Wellington Electricity, based upon the reporting tools available within the maintenance management systems, rather than by the Field Services Provider as it was previously. This arrangement still enables Wellington Electricity to receive proposals from the Field Services Provider for reliability centred investment above the maintenance expenditure guideline.

The most significant change arising from the new Field Service Agreement in 2011 was a move towards condition based risk management of assets. This is achieved through a well-defined condition assessment and defect identification process that is applied during planned inspection and maintenance activities. When this information is fed back into the maintenance management system by the Field Services Provider and analysed alongside other key network information, such as asset nameplate information from GIS and network performance statistics, Wellington Electricity is able to make more efficient and optimised asset replacement decisions.

This improved data reported back to Wellington Electricity allows better determination and scheduling of maintenance or replacement activities. Combined with the database query tools within Wellington Electricity's asset management systems, there is significantly improved visibility and tracking of maintenance tasks and test results received from the field. Further details of the asset management systems and processes are provided in Section 2.8 (Asset Management Systems and Processes).

Vegetation management is provided by Treescape in accordance with Wellington Electricity policies and the Electricity (Hazards from Trees) Regulations 2003. Wellington Electricity has completed the first cut and trim programme for trees encroaching the growth limit zone. 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 competes with other maintenance programmes for Wellington Electricity resources.

6.3.2 Maintenance Budget

The maintenance budget is categorised into the following areas:

1. Planned/Preventative Maintenance (PM) works – this PM programme is jointly developed by Northpower and Wellington Electricity based on the requirements of the maintenance standards and the asset quantities in service. The PM plan consists of routine inspections, as well as 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 random 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 any known defects beyond what would normally be expected. When common fault 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 replacement and 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' service etc.

5. Vegetation Management – covering planned and corrective vegetation work undertaken by Treescape.

The maintenance budget for 2014 is summarised at the end of this section.

6.3.3 Maintenance Standards

The maintenance standards shown in Figure 6-1 are referred to in this section. These standards have been developed by Wellington Electricity from previous network documents and have been rewritten to include new methodologies and requirements. These documents have been reviewed internally and also peer reviewed and benchmarked by senior engineers within other CKI group companies, such as CitiPower and Powercor in Australia. All standards are reviewed by New Zealand industry specialists and benchmarked against current NZ industry best practice.

Standard	Name
EMS-300	Maintenance of Substation Fire Systems
EMS-301	Maintenance of Mineral Insulating Oil
EMS-302	Maintenance of Grid Exit Points
EMS-303	Maintenance of Subtransmission Cables
EMS-304	Maintenance of Zone Substations
EMS-305	Maintenance of Substation Buildings and Enclosures
EMS-306	Maintenance of Zone Substation Transformers
EMS-307	Maintenance of 33kV Bulk Oil Circuit Breakers
EMS-308	Maintenance of 11kV Metalclad Switchboards and Circuit Breakers
EMS-309	Maintenance of Protection Systems
EMS-310	Maintenance of Distribution Substations
EMS-311	Maintenance of Ripple Injection Equipment
EMS-312	Maintenance of Traction DC Systems
EMS-313	Maintenance of Zone Substation Earthing Systems
EMS-314	Maintenance of Batteries and Chargers
EMS-315	Maintenance of Overhead Lines and Components
EMS-316	Maintenance of Fault Passage Indicators
EMS-317	Maintenance of Overhead Switches
EMS-318	Maintenance of Reclosers and Sectionalisers
EMS-319	Maintenance of Distribution Transformers
EMS-320	Maintenance of Distribution Earthing
EMS-321	Inspection and Maintenance of Poles
EMS-322	Maintenance of 11kV Ground Mounted Switchgear
EMS-323	Maintenance of Low Voltage Distribution Equipment
EMS-324	Maintenance of Communications Sites
EMS-325	Planned Maintenance Intervals

Figure 6-1 Maintenance Standards

6.4 Maintenance and Renewal Programmes

This section includes excerpts taken directly from the preventative maintenance and inspection programme, illustrating the maintenance activities undertaken for particular asset classes and their frequency. Commentary is provided on renewal and refurbishment policies or criteria plus known systematic issues associated with each asset class.

6.4.1 Network Defects Overview

Within the preventative maintenance and inspection programme, and through routine operations, a range of defects are found on network assets. These defects are reported, categorised 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.

Across the majority of asset categories, the number of reported defects is decreasing each year. This indicates that preventative and corrective maintenance activities are effective and the number of legacy defects is reducing. When compared with network performance detailed in Section 7, the reducing numbers of defects aligns with reductions in equipment related failures in some areas.

Asset Category	Priority Defects			Non Priority Defects			Total
	2011	2012	2013	2011	2012	2013	
Battery	0	1	4	0	0	0	5
Circuit Breaker	186	101	73	30	172	118	680
Distribution Substation	1,915	1,251	871	1,756	520	633	6,946
Distribution Transformer	291	627	397	771	510	368	2,964
Grid Exit Point	2	17	10	0	2	2	33
Overhead Conductor	2	0	0	0	0	0	2
Overhead Switch	10	28	45	44	28	8	163
Pillar / Pit	232	93	90	393	281	118	1,207
Pole	2,196	1,281	1,422	822	1,630	1,708	9,059
Power Transformer	2	27	13	36	3	2	83
Recloser	0	1	0	1	0	0	2
Ring Main Unit	2	74	145	21	359	269	870
Subtransmission Cable	0	0	0	0	0	3	3
Zone Substation	254	635	220	42	104	77	1,332

Asset Category	Priority Defects			Non Priority Defects			Total
	2011	2012	2013	2011	2012	2013	
Total	**5,092**	**4,136**	**3,290**	**3,916**	**3,609**	**3,306**	**23,349**

Figure 6-2 Summary of Yearly Network Defects

6.4.2 Subtransmission Cables

6.4.2.1 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 - general maintenance, regular patrol	General maintenance and management of subtransmission network	Ongoing

Figure 6-3 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. This monitoring provides information that identifies cables where pressure is reducing and allows the situation to be promptly investigated. Leaks will occur either at joints, which can be rebuilt, or along the cable where location and repair is significantly more difficult.

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. Most of the subtransmission cables installed on Wellington Electricity's network are three core aluminium or lead sheathed, with very few circuits consisting of single core cables with wire screens.

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. By their very nature, the pressurisation of the cables fills any voids in the insulation and prevents partial discharge. 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. Leaks are detected through routine operations 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.

6.4.2.2 Cable Condition

6.4.2.2.1 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, through structures such as bridges and crossing earthquake fault lines. This requires close monitoring of their performance to manage any deterioration and consequent reduction in levels of service. For example, most of the Evans Bay gas filled cables run under State Highway 1. 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.

When cables develop a gas 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 gas cables to sections of XLPE cable. These joints are relatively expensive at around $100,000 each and it is not economic 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.

A brief summary of the gas filled cable circuits is listed below:

Circuit	Length (km)[15]	Year installed
Central Park - Evan's Bay	10.1	1958
Central Park - Frederick Street	3.1	1978
Central Park - Hataitai	4.7	1968
Central Park - Palm Grove	5.8	1967
Central Park - University	1.0	1986
Evan's Bay - Ira Street	5.0	1961
Upper Hutt - Maidstone	10.7	1968
Wilton - Karori	7.6	1967
Wilton - Waikowhai Street	3.6	1962

Figure 6-4 Summary of Gas Filled Cable Circuits

[15] Circuit length is the total of all parallel circuits, divide length by number of circuits for route length.

The Evan's Bay cables are the oldest on the network and, over time, have suffered from a number of leaks which have been repaired. There are, however, well supported by back-feed options and the load they support is predominantly residential.

6.4.2.2.2 Gas Cable Joints

A known mode of failure of gas-filled cable joints is joint expansion and contraction under heavy fault current, which can pull the conductor from the joint ferrule. This fault was experienced in 2010 on one of the old Moore Street gas cable circuits, where the joint expansion was exacerbated by the steep terrain on the cable route, and a second fault occurred at Maidstone in 2013.

X-raying of joints was undertaken during United Networks' ownership, and little remedial work occurred as the problem was not found to be significantat that time. Historically this mode of failure has occurred on average every 10 years, but further testing may be required if a trend of more frequent joint failures develops.

6.4.2.2.3 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.

6.4.2.2.4 Paper and Polymeric Cables

Approximately 27% 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. They are performing well and no renewal is expected to be required during the period covered by this AMP.

6.4.2.2.5 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 impact network performance, pose a serious risk to health and safety, 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 a service provider, B4U-DIG, 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 targeted contractors working for large utility companies and Territorial Local Authorities (TLAs) 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. This is discussed further in Section 9.1.1 (Public Safety Management System).

In addition, cable maintenance staff patrol the routes of key subtransmission circuits on a regular 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.

6.4.2.3 Renewal and Refurbishment

The need for cable replacement is determined and prioritised using a combination of: the consequence of a cable failure, condition and performance assessments, analysis of failure and defect rates, a comparison of the estimated cost of maintaining the cable in service with the cost of replacement and the system capacity for supporting load whilst the subtransmission circuit is under repair. These factors are considered in the “Stage of Life” analysis of subtransmission circuits.

Unfortunately, there are few cost-effective options for refurbishment or extension of life once major leaks, discharge or electrical insulation breakdown has occurred. The solution in most cases is replacement of sections, or the entire length, of cable. Gas and oil filled cables require special transition and stop joints that range in cost from $100,000 upwards each. To relocate, replace sections or extend a cable would cost a minimum of $250,000 using this technology and it is often more economical to replace shorter sections end to end in their entirety.

6.4.2.4 Subtransmission Circuit “Stage of Life” Analysis

During 2013, the “Stage of Life” analysis was updated on all subtransmission circuits, and a summary of the analysis is provided below.

Parameters Considered

The “Stage of Life” analysis method considers the attributes of each subtransmission cable circuit as defined over three categories, each containing a number of measurable properties. A rating between 1 and 10 is given to each property - 1 being the most favourable (good) and 10 being the least favourable (poor).

Category	Property	Rating (normalised)
Age	Age	1 (good) to 10 (poor)
Condition	Total number of joints	1 (good) to 10 (poor)
Condition	Number of non-original joints	1 (good) to 10 (poor)
Condition	Joint density (Joints / km)	1 (good) to 10 (poor)
Condition	Environment that the cable is installed in	1 (good) to 10 (poor)
Condition	Assessment of cable condition (from field staff)	1 (good) to 10 (poor)
Condition	Assessment of sheath condition (from field staff)	1 (good) to 10 (poor)
Condition	Leakage history (for pressurised cables)	1 (good) to 10 (poor)
Utilisation	N-1 capacity shortfall	1 (good) to 10 (poor)
Utilisation	Residual capacity following transfer of load	1 (good) to 10 (poor)
Utilisation	Type of connected load	1 (good) to 10 (poor)

Figure 6-5 Categories, Properties and Ratings for Subtransmission Circuits

The ratings are normalised over all of the subtransmission circuits to enable a direct comparison between circuits. Ratings are then weighted as some properties have a greater impact on the stage of life than others.

Category Weightings

The weightings allocated to each of the three main categories of age, condition and utilisation are as follows:

Category	Weighting
Age	10%
Condition	40%
Utilisation	50%

Figure 6-6 Category Weightings

The rationale behind these weightings is that age and condition are categorised as asset related properties and given equal weighting (i.e. 50%). Utilisation (also 50%) is categorised as a planning related property. Age is less relevant to the overall stage of life of the circuit than the condition parameters; hence it is given a rating of 10%, compared to 40% for condition.

Applying the above weightings to the normalised ratings of each category gives the following ranking of circuits requiring attention, ordered with the highest priority circuit (i.e. highest score) at the top of the list.

Zone Substation	Age score	Condition score	Utilisation score	Weighted Total score
Evans Bay	10.0	9.9	2.3	6.1
Palm Grove	8.2	3.3	7.8	6.0
University	4.1	4.2	6.7	5.5
Korokoro	4.4	3.7	6.8	5.3
Johnsonville	5.2	4.8	4.9	4.9
Frederick St	6.1	2.9	6.2	4.9
Hataitai	8.0	4.5	4.5	4.8
Waterloo	4.6	3.8	5.3	4.7
Maidstone	8.0	5.8	3.0	4.6
Seaview	4.0	2.3	5.5	4.1
Moore St	0.0	2.0	6.6	4.1
Karori	9.0	4.2	2.9	4.0
Ira St	9.4	4.3	2.2	3.7

Zone Substation	Age score	Condition score	Utilisation score	Weighted Total score
Terrace	0.0	2.1	5.7	3.7
Waikowhai	7.8	3.7	2.6	3.6
Tawa	2.0	3.7	3.7	3.5
Wainuiomata	4.0	0.9	5.2	3.4
Plimmerton	3.6	2.0	3.7	3.1
Waitangirua	5.2	3.3	2.3	3.0
Brown Owl	5.3	2.3	3.0	3.0
Naenae	5.2	1.8	3.4	2.9
Trentham	5.9	2.1	2.8	2.8
Ngauranga	3.4	2.0	3.3	2.8
Porirua	4.7	1.5	3.5	2.8
Gracefield	4.0	0.7	4.2	2.7
Kenepuru	3.9	3.0	1.8	2.5
Mana	3.6	3.1	0.5	1.9

Figure 6-7 Stage of Life Category Scores for Subtransmission Circuits

Top Ranked Circuits

The five circuits identified as being most in need of attention are:

Subtransmission link	Ranking (1 = highest priority)
Evans Bay	1
Palm Grove	2
University	3
Korokoro	4
Johnsonville	5

Figure 6-8 Stage of Life Ranking of Subtransmission Circuits

Earlier "Stage of Life" Analysis outcomes

As a result of earlier "Stage of Life" analysis, the major projects initiated to address the highest risks on subtransmission network at that time were:

1. Palm Grove – replacement of the cables with higher rated XLPE cables. This project is currently underway and is due for completion during 2014.

2. University – Investigation was completed during 2013 of possible upgrading due to high joint density, loading and back-feed capacity shortfall. The outcome of this is detailed in Section 5.13.9 of this AMP.

3. Frederick Street – A new 11kV feeder project has been installed to reduce the loading on Frederick Street cables. The planned construction of a new zone substation in the CBD will further alleviate the loading on these cables.

<u>Outcome of the 2013 "Stage of Life" Analysis</u>

Evans Bay

The Evans Bay subtransmission circuits are old and in poor condition, but are sufficiently lightly loaded that they are still able to provide back-feed capacity to adjacent zone substations, and the Evans Bay load can be back-fed through the distribution system with relative ease. There is also uncertainty around the future development of the Mt Victoria road tunnel where the cables presently run. No plans to replace the cables will be made until the future development of the tunnel, and the potential for cost sharing with the New Zealand Transport Agency if relocation is required, are known.

Korokoro

The utilisation of the Korokoro subtransmission cables has increased markedly as a result of the decommissioning of Petone Substation. However, no remedial action is currently required as the cables are relatively new and in good condition, minimal load growth is forecast for the area, and sufficient options exist for offloading onto neighbouring substations.

Johnsonville

Johnsonville is in the top five priority list due to age, high loading and, to a lesser extent, condition issues related to recent leaks. The loading on these cables will be reduced as a result of the Grenada zone substation construction in 2017 and the residual age and condition factors will be reviewed at that time to determine whether replacement is still justified.

Figure 6.9 provides the project list resulting from the "Stage of Life" analysis. The replacement of the Palm Grove cables is in progress and the University cable replacement is detailed in Section 5.13.9. These projects are driven predominantly by security and capacity issues rather than overall condition.

Zone substation	Project Description	Investment year	Driver	Proposed Budget
Palm Grove	Installation of double XLPE 33kV circuit between Central Park and Palm Grove	2013-2014	Capacity, Security	$9.0M
University	Replace the gas filled section of University subtransmission circuits with double circuit XLPE 33kV cables	2017	Capacity, Security	$3.5M

Figure 6-9 Project List for Subtransmission Cables

6.4.3 Substation Buildings and Equipment

6.4.3.1 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 6-10 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.

6.4.3.2 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 weather tightness 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

Territorial Local Authorities (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 TLAs currently allow a period of up to 10 years to reach compliance levels. The scale of the reinforcing works required can differ depending on the independent engineering advice received.

Wellington Electricity also 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.

Seismic reinforcing of substation buildings and how this risk is managed is further discussed in Section 8 (Risk Management).

6.4.4 Zone Substation Transformers and Tap Changers

6.4.4.1 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
On Load Tap Changer (OLTC) Maintenance	Programmed maintenance of OLTC	4 yearly

Figure 6-11 Inspection and Routine Maintenance Schedule for Zone Substations Transformers and Tap Changers

Presently Wellington Electricity uses Transfield Services for oil analysis. The transformer oil test results and information in the reports are used to determine whether major maintenance or repairs need to be undertaken on a transformer. In the past three annual tests, only a basic oil dissolved gas analysis was undertaken; however, full oil analysis will be undertaken again in 2014 to get full particle, dissolved gas and furan results.

6.4.4.2 Transformer Condition

The condition of most transformers on the network indicates normal performance, with the exception of those described below. Where evidence of heating or arcing 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 can also give an estimated Degree of Polymerisation (DP) value that provides an initial overview of the transformer condition, and can signal the need for further maintenance, refurbishment or replacement. Estimated DP tests completed with the DGA oil tests in 2009 (furan analysis) 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. A profile of estimated DP (as measured in 2009) vs. age, is shown below. Estimated DP at all sites will be measured again as part of DGA oil testing in 2014.

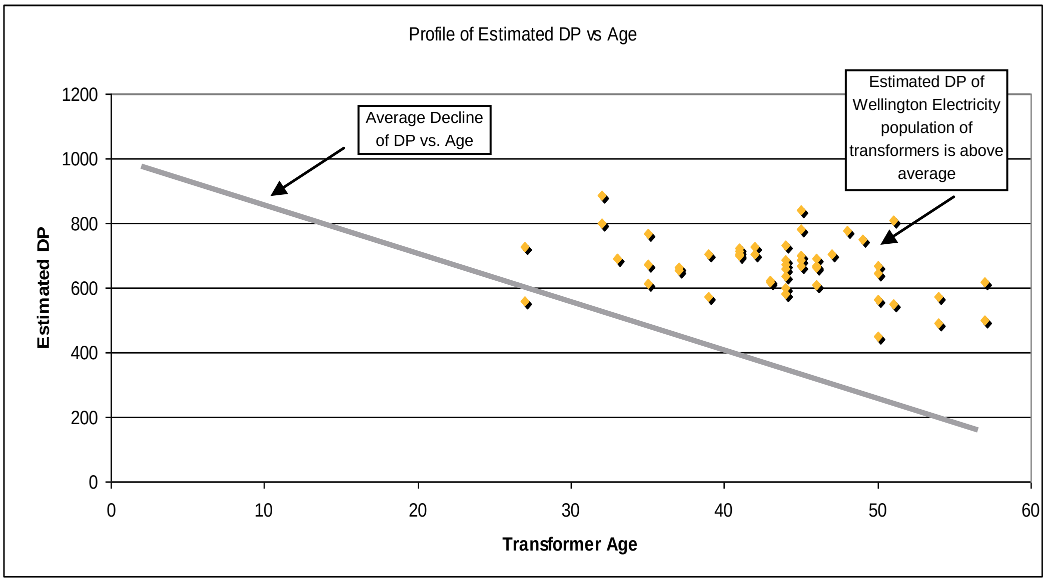


Figure 6-12 Profile of Estimated DP vs. Age (Based on 2009 Testing)

From observation of maintenance and testing results, the following site-specific issues are known to Wellington Electricity:

Evans Bay

The transformers installed at Evans Bay are two of the oldest on the network, having been installed in 1959. These transformers have experienced an increasing number of problems in recent years, mostly relating to the mechanical performance of the tap changer, and excessive leaks due to deterioration of valves, flanges, gaskets and radiators. Fortunately, 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.

Ngauranga

Ngauranga has the two oldest power transformers installed in the Wellington Electricity 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. This site has full N-1 capacity at the transformer level and can supply the load should one unit be unavailable.

Waikowhai Street

The transformers at Waikowhai Street substation are in good condition. They are, however, 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 another 8 years of service can be obtained before refurbishment is again required.

Wainuiomata

During 2012, the Wainuiomata A transformer was identified as having abnormal heating in its windings. A transformer made available by the decommissioning of Petone zone substation in 2013 was relocated to Wainuiomata, and the old unit removed for further assessment and possible midlife refurbishment.

The Terrace

The Terrace substation is located in the basement of the James Cook Hotel in central Wellington. The hotel was built around the zone substation and future replacement or removal of a transformer could be challenging. The transformers at this location are carefully monitored to ensure no major issues arise that may lead to removal being required.

Worn Contacts on Tap Changers

An increasingly common problem is worn contacts in tap changers, as previous maintenance practice has been to simply move worn middle contacts to the lesser used top and bottom taps. Now all contacts are found to be worn and it is costly to replace the entire set of contacts in all tap positions. Nevertheless, each year a number of transformers will have full tap changer contact replacement, where their condition is found to be unsatisfactory.

6.4.4.3 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:

- Transformer replacements at two zone substations (including Evans Bay in 2015 to 2016);

- Ongoing transformer refurbishment costs; and
- Ongoing preventative maintenance including testing and inspections.

Based on age information, and condition test results, at least two transformers (most likely Evans Bay) can be expected to require replacement during the period 2014 to 2016. 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 is covered in the "Stage of Life" 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. There are 12 transformers that are at a stage where refurbishment is still economic, and some that are showing slight signs of arcing, which may require minor refurbishment to check and tighten electrical components. For the majority of 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. This may however not necessarily lead to full refurbishment.

6.4.4.4 Power Transformer "Stage of Life" Analysis

During 2013, the "Stage of Life" analysis was updated for all zone substation transformers and a summary of the analysis is provided below.

Parameters Considered

The "Stage of Life" analysis method considers the attributes of each power transformer as defined over three categories, each containing a number of measurable properties. A rating between one and ten is given to each property, with 1 being the most favourable (good) and 10 being the least favourable (poor).

Category	Property	Rating (normalised)
Age	Age	1 (good) to 10 (poor)
Condition	Estimated Remaining Life	1 (good) to 10 (poor)
Condition	Environmental Protection	1 (good) to 10 (poor)
Condition	Electrical Condition	1 (good) to 10 (poor)
Condition	Assessment of known issues (from field staff)	1 (good) to 10 (poor)
Utilisation	Load vs. Load Rating	1 (good) to 10 (poor)
Utilisation	Type of connected load	1 (good) to 10 (poor)
Utilisation	Number of ICPs served	1 (good) to 10 (poor)
Utilisation	Residual capacity following transfer off-load	1 (good) to 10 (poor)

Figure 6-13 Categories, Properties and Ratings for Power Transformers

The ratings are normalised over all transformers to enable a direct comparison between transformers. Ratings are then weighted, as some properties have a greater impact on stage of life than others. The properties, along with the ratings and weightings applied to them, are described in detail below.

Category Weightings

The weightings allocated to each of the three main categories of age, condition and utilisation are as follows:

Category	Weighting
Age	20%
Condition	50%
Utilisation	30%

Figure 6-14 Category Weightings

The rationale behind these weightings is that age and condition are categorised as asset related properties and together are given a higher weighting (i.e. 70%). Utilisation (30%) is categorised as a planning related property. Age is considered to be less relevant to overall stage of life of the transformer than the condition parameters; hence it is given a rating of 20%, compared to 50% for condition. Condition has been given the highest weighting due to the complex nature of transformers, difficult and costly repairs, and the long lead time for replacement.

Applying the above weightings to the normalised ratings of each category gives the following ranking of transformers requiring attention, ordered with the highest priority transformer (i.e. highest score) at the top of the list.

Transformer	Substation	Age score	Condition score	Utilisation score	Weighted Total score
Evans Bay 1	Evans Bay	9.5	6.2	4.8	6.5
Palm Grove 1	Palm Grove	8.1	4.6	8.2	6.4
Palm Grove 2	Palm Grove	8.1	4.6	8.2	6.4
Evans Bay 2	Evans Bay	9.5	5.9	4.8	6.3
Frederick St 1	Frederick St	6.2	5.2	8.2	6.3
Frederick St 2	Frederick St	6.2	5.1	8.2	6.3
Plimmerton A	Plimmerton	8.8	5.9	5.1	6.3
Ngauranga A	Ngauranga	10.0	5.1	5.6	6.2
Tawa B	Tawa	8.8	5.5	5.6	6.2
Tawa A	Tawa	8.8	5.4	5.6	6.2
Johnsonville B	Johnsonville	7.8	5.6	6.0	6.1
University 1	University	4.8	5.4	8.1	6.1
Mana A	Mana	8.8	5.2	5.6	6.0
Johnsonville A	Johnsonville	7.8	5.3	6.0	6.0
Porirua B	Porirua	8.1	5.4	5.2	5.9
Porirua A	Porirua	8.1	5.4	5.2	5.9

Transformer	Substation	Age score	Condition score	Utilisation score	Weighted Total score
Terrace 2	Terrace	8.3	3.6	8.1	5.9
Wainuiomata A[1]	Wainuiomata	8.1	5.4	4.9	5.8
Hataitai 1	Hataitai	7.9	4.9	5.9	5.8
Terrace 1	Terrace	8.4	3.3	8.1	5.8
Waitangirua A	Waitangirua	8.6	5.1	4.8	5.7
Waikowhai 1	Waikowhai	9.0	4.8	5.0	5.7
Hataitai 2	Hataitai	7.9	4.5	5.9	5.6
Maidstone A	Maidstone	7.9	5.3	4.3	5.5
Wainuiomata B	Wainuiomata	7.4	5.3	4.6	5.5
Moore St 1	Moore St	6.9	4.8	5.7	5.5
Karori 1	Karori	7.6	4.5	5.6	5.5
Korokoro A	Korokoro	6.6	4.9	5.5	5.4
University 2	University	4.8	4.1	8.1	5.4
Karori 2	Karori	7.6	4.5	5.6	5.4
Ngauranga B	Ngauranga	10.0	3.5	5.6	5.4
Gracefield B	Gracefield	7.2	5.9	3.2	5.4
Maidstone B	Maidstone	7.9	4.8	4.3	5.3
Seaview A	Seaview	7.8	4.7	4.6	5.3
Trentham B	Trentham	5.9	5.9	3.6	5.2
Seaview B	Seaview	7.8	4.6	4.6	5.2
Waterloo A	Waterloo	7.2	4.2	5.6	5.2
Brown Owl A	Brown Owl	7.8	5.0	3.9	5.2
Waterloo B	Waterloo	7.2	4.2	5.6	5.2
Waikowhai 2	Waikowhai	9.0	3.8	5.0	5.2
Korokoro B	Korokoro	6.6	4.4	5.5	5.2
Brown Owl B	Brown Owl	6.2	5.4	3.9	5.1
Waitangirua B	Waitangirua	8.6	3.7	4.8	5.0
Moore St 2	Moore St	6.9	3.8	5.7	5.0
Naenae A	Naenae	7.8	4.6	3.9	5.0
Trentham A	Trentham	5.9	5.3	3.6	4.9
Kenepuru B	Kenepuru	7.8	4.3	3.7	4.8
Gracefield A	Gracefield	7.2	4.6	3.2	4.7
Kenepuru A	Kenepuru	7.8	4.1	3.7	4.7

Transformer	Substation	Age score	Condition score	Utilisation score	Weighted Total score
Naenae B	Naenae	7.9	3.1	3.9	4.3
8 Ira St 2	8 Ira St	5.7	3.8	4.2	4.3
8 Ira St 1	8 Ira St	5.7	3.5	4.2	4.1
Evans Bay 1	Evans Bay	9.5	6.2	4.8	6.5

1: Newly installed transformer, ex Petone.

Figure 6-15 Stage of Life Category Scores for Transformers

Top Ranked Transformers

The five transformers that identified as being most in need of attention are:

Transformer	Ranking (1 = highest priority)
Evans Bay 1	1
Palm Grove 1	2
Palm Grove 2	3
Evans Bay 2	4
Frederick St 1	5

Figure 6-16 Stage of Life Ranking of Transformers

Outcome of “Stage of Life” Analysis

Evans Bay

The Evans Bay transformers are old and issues related to their condition drive the rating of being most in need of attention. Replacement is proposed in the short term, potentially in 2015, due to their deteriorating condition.

The transformers are leaking oil from cooling fins, glands and flanges and several other places, and require regular inspection and maintenance. The most recent oil tests indicate some heating and cellulose degradation may be occurring. These units have a poor electrical rating as well as a poor mechanical condition rating.

Palm Grove

The Palm Grove transformers are old but in good condition. The high utilisation rating is a result of winter loading, which leads to their inclusion in the top five. At this time, no investigation or analysis has been carried out for Palm Grove to determine solutions involving increasing capacity or reducing loading. One possibility is relocating the Palm Grove transformers to Evans Bay, and installing two new transformers with greater capacity at Palm Grove.

Frederick Street

Frederick Street has a high utilisation score, and the most recent oil test results indicate that heating of the transformer is occurring. The loading at Frederick Street will be reduced by the proposed new zone substation in Wellington CBD. Both Frederick Street transformers are due for routine testing and maintenance in 2014 and at the same time their condition will be reassessed.

University

University 1 was originally in the top five in 2013 due to a poor DGA result. The oil was filtered and DGA samples were taken at six monthly intervals during 2013. These test results were normal, which improved the transformer's condition score and dropped it out of the top five as now shown in Figure 6-15. The high utilisation score will be reduced when a new zone substation in Wellington CBD is constructed. Normal monitoring of this transformer will continue, and no additional action is required at this time.

Wainuiomata

During 2013, Petone zone substation was decommissioned, and Petone A was relocated to replace Wainuiomata A and this has lowered its "Stage of Life" ranking, as now shown in Figure 6-15. While the replacement transformer is smaller than the unit it replaced, load at Wainuiomata is projected to fall, and it is not expected that any additional asset replacement will be required during the period of this plan.

Below is the project list reflecting the "Stage of Life" analysis.

Zone substation	Project Description	Investment year	Driver	Proposed Budget
Evans Bay	Power transformer replacement	2015	Age and Condition	$2.0M

Figure 6-17 Project List for Transformer Replacement

6.4.5 Substation DC Systems

6.4.5.1 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 6-18 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).

6.4.5.2 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 and, following replacement where required, 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 knows if the output has failed and can initiate a repair. 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.

6.4.5.3 Battery Replacement

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 battery age profile shows major replacement programmes will be required again in 2014 and 2015, returning to a steady state rate of replacement beyond that.

Replacement Year	Number of Battery Banks	Proposed Budget
2014	160	$150,000
2015	140	$150,000
2016	120	$120,000
2017	120	$120,000

Figure 6-19 Annual Battery Bank Replacements

6.4.6 Switchboards and Circuit Breakers

6.4.6.1 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 6-20 Inspection and Routine Maintenance Schedule for Zone Substation Circuit Breakers

In addition to the routine maintenance programme above, oil circuit breakers are maintained as required following a number of fault clearance operations.

6.4.6.2 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 assessment outcomes include partial discharge (particularly around cast resin components), corrosion and compound leaks visible externally, and slow or worn mechanisms or unacceptable contact wear. The majority of these defects either do not present a significant risk to the network, or can be easily remedied under corrective maintenance programmes.

The condition of zone substation switchboards is discussed in detail in the circuit breaker "Stage of Life" analysis below.

6.4.6.3 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 the majority of their service life. However, some of the 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, operability and co-ordination with modern equipment.

The new planned maintenance programme implemented in 2011, and the improved condition assessment information that has been obtained, has provided sufficient data to enable longer term renewal programmes targeting both equipment make and model (type replacement) and individual units, to be developed. This is still a work in progress to be completed in 2014.

The following replacement programmes are in place for the planning period:

6.4.6.3.1 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 34 units remaining in service and these are being replaced over the next two years, prioritised by condition and location. The replacement programme is shown below:

Substation	No. of Circuit Breakers	Year installed	Replacement year	Estimated cost
Karori Zone	11	1962	2014	$1,740,000
Cornwell Street	5	1945	2014	$275,000
Gracefield Zone	13	1958	2014-2015	$1,850,000
Flag Staff Hill	5	1953	2015	$600,000

Figure 6-21 Proposed C-type Circuit Breaker Replacement Programme

After discussion with CentrePort management, it is planned that the Type C switchgear in Cornwell Street will be decommissioned rather than replaced. The existing load will be transferred to an adjacent substation and the network reconfigured to maintain the same reliability.

Replacement in progress of Reyrolle Type C with RPS LMVP switchgear at a zone substation

6.4.6.3.2 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. In the past four years on the Wellington network two sites have experienced bus flashovers, and one site has had a circuit breaker flashover during a racking operation. 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 two sites to be replaced during 2014 as detailed in Figure 6-22. This will complete the SO-HI replacement programme.

Sub No.	Location	Feeder	No. of switches	Customer building	Customers beyond	Replacement year
S1032	Moera Reserve	SEA 03	4	NO	611	2014
S3183	Todd Motors	KEN 02	14	YES	10	2014

Figure 6-22 Proposed SO-HI Replacement Priority Sites

Replacement year	Sites	Proposed Budget
2014	Moera Reserve and Todd Motors	$500,000

Figure 6-23 Proposed SO-HI Replacement Spend Plan

6.4.6.3.3 Statter

There are 34 sites with Statter type switchgear on the Wellington network (predominantly in the Hutt Valley area) with 121 units of both circuit breaker and oil switch type in service. In recent years, there have been instances where the switchgear has failed to operate requiring operating restrictions to be in place until the unit is repaired or replaced. The 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 around $3.0 million, over five years with replacements prioritised on condition and criticality.

Replacement year	No of Sites	Proposed Budget
2014	3 RMU	$200,000
2015	3 CB / 5 RMU	$700,000
2016	3 CB / 5 RMU	$700,000
2017	3 CB / 5 RMU	$700,000
2018	3 CB / 4 RMU	$700,000

Figure 6-24 Proposed Statter Replacement Spend Plan

6.4.6.3.4 Reyrolle LMT - Partial Discharge

Reyrolle LMT circuit breakers were installed on the network from late 1960s onwards. There are over 600 units in service.

Partial discharge (PD) testing has indicated potential issues around the current transformers (CTs) or the CT chamber on units with cast resin CTs. In addition, the bushing insulator between the CT chamber and the cable box and cable box phase clearances have been identified as causing high levels of PD.

It has also been found that extensions to more recent switchboards have been made using older panels with SRPB type bushings, which has led to unusually high PD for the age of the switchboard. This practice will now require the replacement of bushings before reusing components.

Full partial discharge testing (or handheld TEV testing) and corrective maintenance is undertaken on these circuit breakers when high levels of PD are detected.

In the latter part of 2012 a circuit breaker at Waitangirua was found to have a high PD coming 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. A refurbishment plan for this type of equipment was developed using this new design, and this was implemented on the remainder of the Waitangirua circuit breakers and at two other zone substations during 2013. Partial discharge testing after completion of the remedial work indicated that the upgrades were successful, and the project will be extended to other sites in future years.

Replacement year	Number of Sites/CBs	Proposed Budget
2014	4 Sites	$100,000

Figure 6-25 Proposed PD Mitigation Spend Plan

6.4.6.3.5 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 CBs has been reduced. This outcome is expected to improve further when all the LMT CBs are maintained and installed with dust covers on the auxiliary switches.

6.4.6.4 Circuit Breaker “Stage of Life” Analysis

During 2013, the “Stage of Life” analysis was updated on all zone substation 11kV switchboards, and a summary of the analysis is provided below.

Parameters Considered

The “Stage of Life” analysis method considers the attributes of each switchboard as defined over three categories, each containing a number of measurable properties. A rating between 1 and 10 is given to each property, with 1 being the most favourable (good) and 10 being the least favourable (poor).

Category	Property	Rating (normalised)
Construction	Age	1 (good) to 10 (poor)
Construction	Number of Circuit Breakers	1 (good) to 10 (poor)

Category	Property	Rating (normalised)
Condition	Partial Discharge Testing Results	1 (good) to 10 (poor)
Condition	Internal Condition assessment	1 (good) to 10 (poor)
Condition	Spares availability	1 (good) to 10 (poor)
Utilisation	Loading vs. load rating	1 (good) to 10 (poor)
Utilisation	Fault level vs. fault rating	1 (good) to 10 (poor)
Utilisation	Type of load served	1 (good) to 10 (poor)
Utilisation	Number of ICPs served	1 (good) to 10 (poor)
Utilisation	11kV back feed capacity	1 (good) to 10 (poor)

Figure 6-26 Categories, Properties and Ratings for Switchboards

The ratings are normalised over all of the switchboards enabling a direct comparison. Ratings are also weighted as shown below as some factors have a greater impact on stage of life than others.

Category Weightings

The weightings allocated to each of the three main categories of construction, condition and utilisation is as follows:

Category	Weighting
Construction	20%
Condition	20%
Utilisation	60%

Figure 6-27 Category Weightings

The categories have been given these weightings on the basis that utilisation is one of the main drivers for remedial action to be taken on a switchboard. Wellington Electricity cannot operate equipment outside its ratings, or have underrated equipment that will affect the proper working of the system.

Construction and condition have equal weightings of 20% each, as neither by itself would be a major driver for remedial attention. Wellington Electricity has a number of medium sized switchboards in service in distribution substations that are over 60 years old. Minor defects or deteriorating condition can generally be addressed by partial replacement or increased levels of corrective maintenance. However, when combined with a high utilisation rating, construction and condition become more important in determining the risks associated with each switchboard.

Applying these weightings to the normalised scores from each category allows an overall “Stage of Life” score to be derived for each switchboard, in turn giving a priority ranking.

Substation	Switchboard type	Construction score	Condition score	Utilisation score	Total score
Frederick St	LM23T	8.0	4.8	9.1	8.1
Moore St	LM23T	9.2	4.8	7.5	7.3
University	LMT	6.2	4.8	8.5	7.3
Hataitai	LM23T	9.0	3.8	7.6	7.1
Nairn St	LMT	7.7	4.8	7.4	6.9
Karori	C	9.1	7.6	5.7	6.8
Waterloo	LMT	8.6	2.8	7.1	6.5
Gracefield	C	9.4	5.6	5.9	6.5
Ira St	LM23T	8.6	3.8	6.4	6.4
Korokoro	LM23T	8.8	3.8	6.3	6.3
Kaiwharawhara	LMVP	5.5	3.8	7.3	6.3
Seaview	LM23T	9.4	2.8	6.1	6.1
Porirua	LM23T	9.3	2.8	6.0	6.0
Brown Owl	LM23T	9.2	4.8	5.4	6.0
Waikowhai	LMT	8.9	1.8	6.5	6.0
Johnsonville	LM23T	9.1	3.8	5.7	6.0
Tawa	LM23T	9.3	3.8	5.6	5.9
Naenae	LM23T	9.4	2.8	5.4	5.7
Wainuiomata	LMT	8.7	2.8	5.4	5.6
Maidstone	LM23T	9.4	3.8	4.7	5.5
Waitangirua	LM23T	9.3	2.8	5.1	5.5
Petone	LM23T	9.1	2.8	4.8	5.3
Kenepuru	LM23T	8.9	2.8	4.7	5.2
Titahi Bay	LMT	8.6	4.8	4.0	5.1
Trentham	LM23T	9.4	3.8	4.0	5.0
Mana	LM23T	6.9	4.8	4.4	5.0
Terrace	NX-PLUS	3.5	2.0	6.3	4.9
Plimmerton	LM23T	8.0	3.8	3.9	4.7
Palm Grove	LMVP	2.1	0.3	6.9	4.6
Ngauranga	LMT	4.8	4.8	4.3	4.5
Evans Bay	LMVP	2.3	0.3	5.4	3.7

Figure 6-28 Stage of Life Category Scores for Switchboards

Top ranked switchboards

The top five ranked switchboards identified as being most in need of attention are:

Switchboard	Ranking (1 = highest priority)
Frederick St	1
Moore St	2
University	3
Hataitai	4
Nairn St	5

Figure 6-29 Stage of Life Ranking of Zone Substation Switchboards

Previous "Stage of Life" Analysis outcomes

From the previous "Stage of Life" analysis on zone substation switchboards, plans are in place to address two of the highest risk switchboards on the network:

1. Karori Zone Substation – replacement of this Reyrolle Type C switchboard has commenced, and will be completed during 2014, as shown in Figure 6-21.

2. Gracefield Zone Substation – Gracefield is the last zone substation site with Reyrolle type C switchgear and it is scheduled for replacement in 2014-2015, as also shown in Figure 6-21.

As discussed above, these replacements are prioritised components of the plan to replace all Reyrolle Type C switchgear on the network.

Outcome of 2013 "Stage of Life" Analysis

Frederick Street

Frederick Street ranks top in this analysis due to its utilisation score. It has a loading of over 30MVA and supplies over 10,000 consumers in the CBD area. Being a CBD substation, the bus is operated split, reducing the prospective fault level. However, under some switching conditions it is likely to exceed its fault rating. It is generally in sound condition, apart from some identified partial discharge activity around the CTs, which will be resolved under the PD correction programme in 2014. The high ranking is due to the consequence of failure related to the size and type of load served.

This switchboard may be a suitable candidate for a retrofit upgrade using new components from RPS Switchgear to improve load and fault ratings. Early LM23T boards such as this have been re-rated by the manufacturer to 25kA based on the fixed portion design (the busbars, CTs and other components, not including the circuit breaker units, which are withdrawable). The replacement of oil circuit breaker trucks is required to achieve this rating, and new blast protection panels provide improved safety. At Frederick Street specifically, the installation of vacuum circuit breakers, improved protection with arc-flash detection, and replacement of the double 1200A incomer arrangement with single 2000A incomers would see the rating issue reduced.

The Frederick Street 11kV reinforcement project has moved some load away from this site. While improving its utilisation score, as the loading is reduced, the residual utilisation is still high. Further analysis of the loading issue is found in Section 5.13.2.

University

The switchgear at University zone substation was installed in 1988 and is relatively new compared to the majority of Wellington Electricity zone substations. The utilisation factor on this substation is the main reason it is included in the top five. The substation supplies some CBD load and has a fault level under closed bus situations that exceeds the fault rating of the switchgear. The loading level is moderate.

This substation does not currently need switchgear replacement as the age and condition is good; however, restrictions regarding closed bus operation need to be observed. This is achieved through operating procedures that minimise the time the two supply transformers are paralleled. Following the evaluation of retrofit upgrades and re-rating at Frederick Street, this solution may be able to be applied to University to improve fault ratings.

Moore Street

Moore Street scores highly due to both its construction (age, and number of circuit breakers), as well as its utilisation, as it supplies CBD load, is heavily loaded and has inadequate fault rating under closed bus operation. The issues are currently managed through operational procedures. The condition score is low, indicating few issues with the switchgear condition, given its age.

A number of options exist for Moore Street. Solutions being investigated at other substations, particularly around re-rating the fault level, may be an alternative to replacement.

Hataitai

The Hataitai 11kV switchboard is one of the oldest on the network and uses Reyrolle Type LM23T switchgear. Its “Stage of Life” rating is high for both construction and utilisation, as it is at the end of its technical life and has inadequate fault rating for closed bus operation. However, there are adequate spares available and no major or reoccurring issues have been identified with this switchboard.

Given the age of the equipment and the high “Stage of Life” ratings, the need for replacement of this switchboard will be further investigated in 2014. This switchboard is older than similar boards at University, Frederick Street and Moore Street.

Nairn Street

Nairn Street houses a bank of Reyrolle LMT switchgear, installed in 1980, which is in good condition, but the site fault level with a closed bus exceeds the switchgear rating, and partial discharge was recorded when the site was tested. The switchgear may not need to be replaced, as retrofit solutions to both the partial discharge and fault level issues may be sufficient. Further investigation to be undertaken in 2014.

6.4.7 Substation Protection Relays

6.4.7.1 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 6-30 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.

6.4.7.2 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 it controls – 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 replacements and also where known risks exist.
- 10 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 2015, a separate relay replacement project is not justified.
- Ongoing zone substation and network protection and control replacement/upgrades for assets supplied from GXPs, particularly Takapu Rd, Haywards, Gracefield, Upper Hutt and Wilton, which will be coordinated with GXP upgrades planned by Transpower.
- Ongoing protection and control replacements/upgrades across the network as identified by asset condition monitoring.

6.4.8 Load Control Equipment

6.4.8.1 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 6-31 Inspection and Routine Maintenance Schedule for Ripple Plant

6.4.8.2 Renewal and Refurbishment

Wellington Electricity has no short term plans to replace any ripple injection plant due to age or condition. Repairs and maintenance are undertaken as required, and the plant is generally reliable. Basic spares are held locally, and other items can be sourced from abroad as required, but with longer lead times.

In the Hutt Valley area, interconnectivity at 11kV allows the ripple signal to be provided from adjacent substations in the event of failure. 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.

As risk mitigation for the Wellington City area, a spare ripple injection unit was purchased in 2011 to be able to connect to any of the four 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 is discussed further below.

In the medium term, Wellington Electricity will look to replace older rotary plant installed on the 11kV system in the Hutt Valley and Porirua areas as these assets are approaching the end of their service life. It is likely that replacement will involve rationalisation of plant by installing larger plant at GXP level, using modern low frequency ripple signals, rather than high frequency injection at zone substation level. Whilst technically straightforward it may become a complex issue involving retailers and meter/relay asset owners as it would involve a change in injection frequency.

The ripple control injection plant for the Central Park GXP area is a Brown-Boveri plant located at the Frederick Street zone substation and comprises two units operated in parallel. With one unit out of service, ripple signal strength is marginal in some parts of the network. 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. The installation of a larger plant connected to the Central Park 33kV bus is not necessarily the best option. A move to a modern low frequency plant (resulting in better signal propagation) would involve changing adjacent GXPs to the same frequency to ensure ripple control is available under any supply configuration. The overall solution for this area is still being developed, although it is expected that investment will be required within the planning period. This could involve installing ripple plant at the new CBD zone substation.

There are some small areas of network that have previously received DC bias load control signals. This system was removed from service during 2013, and affected consumers moved to ripple load control.

In 2012, the Takapu Road capacitors were found to be in need of replacement, and a similar set at Melling was also found to be in poor condition and requiring refurbishment. Maintenance requirements for these units are being worked through with the Field Services Provider. The blocking cells at Gracefield were refurbished in 2012 and early 2013 after a failure due to corrosion issues. Following refurbishment, these units have a reasonable remaining service life.

Investment in ripple injection plant is largely on hold at present due to the uncertainty around the future of load control as detailed in Section 2.3.2. An investment strategy will be developed during 2014 once the company's position has been clarified.

6.4.9 Poles and Overhead Lines

6.4.9.1 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 onboard battery, replacement onto live line using hot stick	8 yearly

Figure 6-32 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, third party encroachments 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.

Soon after taking ownership of the network, Wellington Electricity undertook a review of available pole testing methods which concluded that the Deuar MPT40 test best satisfies the need for objectivity, repeatability and accuracy. This conclusion is supported by independent analysis and referees.

The Deuar testing programme commenced in the third quarter of 2011 and has been effective, with the number of condemned poles being at expected levels. The programme addresses concerns that the previous method was not picking up structural issues deeper at the base of the pole, and also provides useful remaining life indicators. The efficiency of the programme is improving as operators become more familiar with the testing techniques.

Around 5,000 poles have been tested since the start of the Deuar testing program. From this programme, a substantial number of very 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.

6.4.9.2 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 region 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. A number of older hardwood poles have been reclassified as Wellington Electricity owned following a pole survey in 2009, and are now subject to the

Deuar test regime. These poles are presenting a high failure rate, which is likely a result of not having been part of a programmed test regime over the past decade.

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 Telecom 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 which 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. 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.

6.4.9.3 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 crossarm 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.

6.4.9.4 Renewal and Refurbishment - Lines

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 (Ngauranga 4 Feeder) and Korokoro have been reconductored, and have had all the line hardware, crossarms and poor condition poles replaced. These two feeders have had a significant improvement in performance since this work was completed. Another section of the Ngauranga 4 feeder was rebuilt and reconductored in 2012, which has further improved performance of this feeder.

Two of the worst performing feeders in 2012 were Wainuiomata 7 and Karori 2, and these are being refurbished over a 10 year period (to 2022). Both feeders will have Stage 3 of their renewal programme undertaken in 2014. A second section of Ngauranga 9 will also be refurbished in 2014 to address concerns around Newlands and Paparangi.

It is likely that similar reconductoring, or area rebuild projects, will occur as further issues arise or where there are increased instances of conductor or component failure. This work usually involves sections of line of only a few hundred metres up to several kilometres. Details of prospective overhead network renewal and refurbishment projects are in Section 6.5.

Overhead line refurbishment at Makara

6.4.9.5 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 immediate 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. 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 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.

Steel and composite poles are being investigated for use on the Wellington Electricity network as a possible replacement for softwood poles. 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). 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. Cranes are used where practicable but have limited reach in some areas of Wellington.

Concrete poles are replaced following an unsatisfactory visual inspection, with large cracks, structural defects, spalling or loss of concrete mass being the main criteria. All replacement poles are concrete, except where the location requires the use of timber for weight, access constraints or loading design.

Figure 6-33 provides a yearly overview of actual pole inspection and replacement rates.

Year	Inspected		Replaced	
	Wood	Concrete	Wood	Concrete
2010	1,094	35	316	33
2011	775	6,656	325	18
2012	2,816	4,995	306	51
2013	2,150	3,670	298	28

Figure 6-33 Yearly Pole Inspection and Replacement

6.4.10 Overhead Switches, Links and Fuses

6.4.10.1 Maintenance Activities

The following routine planned inspection, testing and maintenance activities are undertaken on overhead switches, links and fuses:

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 6-34 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.

6.4.10.2 Condition of overhead switches, links and fuses

Generally, the condition of overhead equipment on the Wellington 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 two 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 preferred as they have proven to provide a longer component service life. These high quality components come at an increased cost.

6.4.10.3 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 crossarm 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 crossarm replacement, if the condition of the switch justifies this at that time.

An allowance in the CAPEX programme for HV switchgear replacement funds the required replacements that do not occur in conjunction with other projects.

6.4.11 Auto Reclosers and Sectionalisers

6.4.11.1 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 6-35 Inspection and Routine Maintenance Schedule for Auto Reclosers and Sectionalisers

6.4.11.2 Condition of auto reclosers and sectionalisers

The majority of the units in service are in good condition. However, the base of a number of units have surface corrosion that can be addressed under the corrective maintenance programme. Testing of some recloser units in-situ is limited, and it has been found that several McGraw-Edison KFE reclosers have not been working as intended.

The operational performance of auto reclosers is evaluated from fault information, which indicates whether the unit performed as expected.

6.4.11.3 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 programme of replacement of older, poor performing reclosers commenced in 2013.

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 simply 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 were repaired and returned to service, their future service life is largely unknown. KFE units will be progressively replaced with modern SCADA connected reclosers.

A replacement program will be undertaken over the next four years to replace reclosers that have been in service for more than 40 years, that are located on feeders with high SAIDI, or that are found to have poor reliability. This will be incorporated into the switchgear replacement programme budget.

Replacement year	No of Reclosers	Proposed Budget
2014	2 units	$130,000
2015	2 units	$130,000
2016	2 units	$130,000
2017	2 units	$130,000

Figure 6-36 Proposed Auto-Recloser Replacement Spend Plan

6.4.12 HV Distribution Substations and Equipment

6.4.12.1 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	On going
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

Activity	Description	Frequency
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 6-37 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 6-38 Inspection and Routine Maintenance Schedule for HV Switch Units

6.4.12.2 Distribution Switchgear Condition

The switchgear installed on the Wellington Electricity network is generally in good condition and comprises 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:

6.4.12.2.1 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 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. Wellington Electricity has targeted around 40 units a year for replacement of connections, and these are prioritised from information obtained during routine inspections. Aside from the connector issue, these units are not at end of life and replacement of the connections is considered an effective and efficient maintenance strategy.

6.4.12.2.2 Andelect/ABB SD Series 1 and 2

All Andelect SD Series 1 switchgear has been replaced to address the known modes of failure and inherent safety concerns.

A number of ABB Series 2 SD switchgear units have a problem with oil contamination and the majority of units have been prioritised for maintenance (complete shutdown and oil change) to address this issue. This type of switchgear, once maintained, is generally in good condition and reliable and does not present a significant risk to the network. This risk is controlled by preventing live switching on the units unless the maintenance history is known, or the unit has been fully maintained.

6.4.12.2.3 Substation Switching Access

In 2012, following a serious incident, it was identified that some sites have limited access to conduct safe switching as a result of vegetation, encroaching 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 is used. This issue is being monitored through the routine inspection programme.

6.4.12.2.4 Statter, and Long and Crawford

There are a number of Statter, and Long and Crawford 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. A replacement programme started in 2013 to replace the end of life Statter switchgear typically with standard ring main units. As part of the routine inspection programme, Long and Crawford units in poor condition are identified and scheduled for corrective repairs or replacement.

6.4.12.3 Renewal and Refurbishment

6.4.12.3.1 HV Distribution Switchgear (Ground Mounted)

Note – This section excludes circuit breakers, which are discussed in Section 6.4.6.

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. Funding for this programme is included in the asset replacement forecast. The drivers for replacement of ground mounted switchgear include:

- 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 and vacuum or gas (SF_6) 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.

6.4.12.3.2 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 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.

6.4.12.3.3 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 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 need be. Examples include distribution earthing, substation canopies and kiosk building components (such as weathertightness 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. Given the high number of these in service, a compatible replacement unit is being developed with a transformer manufacturer to allow like for like replacement at much lower cost.

Wellington Electricity now prefers to use a canopy type substation 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 electricity lines businesses 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 the largest pole mounted transformer permitted for replacement installations is currently 200kVA.

Installation of a replacement distribution substation

6.4.12.3.4 Distribution 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. Cable replacements are 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 2013, there were 14 cable fault and cable joint and termination failures. 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 the 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.

6.4.12.3.5 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.

In recent years,, there has been a continued increase in the number of older outdoor heat shrink terminations that have failed in-service. This has become a concern and examination of failed terminations reveals workmanship is often the cause, with sealing mastic at the lug end of each phase not appropriately applied, or the heat shrink not adequately shrunk down or cut back too far. Over time moisture ingress occurs and eventually the termination blows out at the crutch. The faulty terminations were all in excess of 15 years old, and the heat shrink material had not failed. Reminders and training refreshers are given to the Field Service Provider following such findings.

6.4.13 Low Voltage Pits and Pillars

6.4.13.1 Maintenance Activities

The following routine planned inspection and maintenance activities are undertaken on low voltage pits and pillars, either for 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 6-39 Inspection and Routine Maintenance Schedule for LV Pits and Pillars

Since 2011, Wellington Electricity has included 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.

6.4.13.2 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 to a point where they were not safe to operate under some conditions or they 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. This budget reflects historic trends, but replacements rarely exceed 60 units per year.

6.4.14 SCADA

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 both Haywards and Central Park (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 RTUs do not have full back up capability and 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 master station at Haywards has a UPS system to provide backup supply and there is a UPS system installed at Petone to provide supply to the operator terminals in the NCR. This is subject to a maintenance programme provided by the equipment supplier. In addition, this unit has dual redundancy of converters and batteries to provide a high level of supply security in the unlikely event of failure.

6.4.14.1 Condition Assessment of SCADA System Components

C225 RTU

There are 18 of these 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 55 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 47 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.

6.4.14.2 Asset 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, the SCADA master station has been replaced with a GE ENMAC system. This will last at least five years. Some expenditure is expected during this planning period for 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.

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. A project is under investigation to separate the three sites from the PAS and install substation base equipment such as SCD5200 RTUs that can convert the substation 61850 protocol directly to DNP3. No budget provision is included in this AMP.

Remote Terminal Units (RTUs)

During 2011, All Foxboro C25 and C225 remote terminal units (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 substation RTU replacement programme will start with the 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 targeted for replacement in 2014. 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 17 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	Age	2014
Trentham	Zone Substation	C225	SCD5200	Age	2014
8 Ira Street	Zone Substation	Dataterm	SCD5200	Age	2014
Karori	Zone Substation	Dataterm	SCD5200	Switchgear Replacement	2014
Petone	Zone Substation	C225	SCD5200	Protection Upgrade	2015
Gracefield	Zone Substation	C225	SCD5200	Switchgear Replacement	2015
Hataitai	Zone Substation	Dataterm	SCD5200	Age	2015
Tawa	Zone Substation	C225	SCD5200	Age	2016
Porirua	Zone Substation	C225	SCD5200	Age	2016
Titahi Bay	Zone Substation	C225	SCD5200	Age	2017
Kenepuru	Zone Substation	C225	SCD5200	Age	2017
Korokoro	Zone Substation	C225	SCD5200	Age	2017
Waterloo	Zone Substation	C225	SCD5200	Age	2017
Naenae	Zone Substation	C225	SCD5200	Age	2018
Seaview	Zone Substation	C225	SCD5200	Age	2018
Wainuiomata	Zone Substation	C225	SCD5200	Age	2018
Johnsonville	Zone Substation	C225	SCD5200	Age	2018
Nguaranga	Zone Substation	C225	SCD5200	Age	2018
Maidstone	Zone Substation	C225	SCD5200	GXP Protection Upgrade	2020
Brown Owl	Zone Substation	C225	SCD5200	GXP Protection Upgrade	2020

Figure 6-40 Proposed RTU Replacement Programme

Analogue 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. This replacement programme is to be developed further and is not presently budgeted for a specific year. The cost of this work is estimated at approximately $250,000 to $300,000.

6.5 Asset Renewal and Refurbishment Programme

6.5.1 Asset Replacement Projects for the Current Year

The major asset replacement projects (greater than $100,000) that Wellington Electricity is planning to complete in the 2014, as detailed in this Section 6 (Lifecycle Asset Management), are summarised below:

Pole Replacement Programme – 2014	
Driver: Asset Integrity and Safety Estimated cost: $3.8 million	A new wood pole testing programme (the Deuar method) is already in place. Replacement of red and yellow tagged poles will continue in 2014, managed as packages of work following inspection. This work includes replacement of associated pole hardware. This budget is derived from historic levels of pole replacement and realistic replacement levels given current resourcing

Karori 11kV Switchboard Replacement – 2014	
Driver: Asset Integrity and Safety Estimated cost: $940.000	Following the "Stage of Life" analysis of zone substation switchboards, the Karori substation switchboard has the highest consequence of failure due to high loading, its age and condition. Full replacement of this switchboard and associated protection, control and secondary systems has commenced and the new switchboard will be commissioned in 2014

Gracefield 11kV Switchboard Replacement – 2014-2015	
Driver: Asset Integrity and Safety Estimated cost: $800,000	The Gracefield substation switchboard will be one of the oldest on the network after replacement of Karori. It will also be the last zone substation with Type C switchgear. Full replacement of this switchboard and associated protection, control and secondary systems is planned to commence with procurement in 2014 and installation in 2015

Cornwell St substation decommissioning and network reconfiguration - 2014	
Driver: Asset Integrity Estimated cost: $275,000	This project involves decommissioning the Cornwell St substation and reconfiguring the 11kV network as an alternative to the replacement of the aging Reyrolle Type C switchgear, which is underutilised and supplies only a small load at the Port of Wellington

Yorkshire SO-HI Replacement – 2014	
Driver: Asset Integrity Estimated cost: $500,000	This project is the second stage of a programme to replace Yorkshire SO-HI 11kV switchgear located in distribution substations. It is expected that the remaining two sites will be addressed in 2014

Zone RTU Upgrade (Waitangirua, Trentham, Ira St) - 2014	
Driver: Asset Integrity Estimated cost: $300,000	This project is to replace the zone substation RTUs with SCD5200 RTUs and upgrade to TCP/IP communications as the existing RTUs are at the end of their service lives

Transpower GXP redevelopment works (WIL/TKR) - 2014	
Driver: Asset Integrity Estimated cost: $500,000	Transpower is proposing to replace the outdoor 33kV switchyards at Wilton in 2014 and Takapu Rd in 2015. This project provides for the design and associated work for installing new protection and GXP equipment at these sites

Zone Substation Switchgear PD Mitigation and Upgrade - 2014	
Driver: Asset Integrity Estimated cost: $250,000	Replacement of components that are identified to be the source of high PD on several Reyrolle LMT switchboards

Ngauranga 9 Line Refurbishment – 2014	
Driver: Asset Integrity Estimated cost: $220,000 - Stage 2	Ngauranga 9 has recently been one of the worst performing feeders due to a section of overhead network that has reached end of life. This project is to replace this section of the feeder and rebuild the overhead network around the Newlands and Johnsonville area

Karori 2 Overhead Line Rebuild – Stage 3 - 2014	
Driver: Asset Integrity Estimated cost: $150,000 - Stage 3	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. This is the third stage of nine and involves reconductoring 31 spans of 11kV to address reliability concerns arising from hardware condition

In addition to the specific projects above, Wellington Electricity also makes provision for replacements that arise from condition assessment programmes during the year; programmes with a forecast cost greater than $50,000 are listed below:

Driver	Programme	Forecast cost
Asset Integrity	Transformer and Canopy Replacement	$1,750,000
Asset Integrity	Cable and Conductor Replacement	$500,000
Asset Integrity	Distribution Switchgear Replacement	$1,250,000
Asset Integrity	Protection and Secondary Systems	$500,000
Asset Integrity	Crossarm Replacement	$300,000

Driver	Programme	Forecast cost
Safety	Lock Replacement	$50,000
Safety	Earthing Upgrades and Compliance	$300,000
Safety	LV Pillar and Pit Replacement	$50,000
Safety	Asbestos Removal	$50,000
Safety	Fault Passage Indicator and Recloser Replacement	$130,000
Safety	Common Alarm Replacement	$120,000
Safety	WCCL Changeovers	$600,000

Figure 6-41 Asset Replacement Programme

6.5.2 Prospective Asset Replacement Projects for 2015 – 2019

The projects included in this section are less certain in nature. Whether or not they proceed, and their timing, will largely depend on the risks to the network that need to be mitigated, and the risk relative to other asset replacement projects. The timing of asset renewal projects is directly related to the risks associated with the assets, and changes to these alter the timing of the projects. It is assumed that the rate of deterioration, aging, and the increases of load remain constant. Should the loading or type of load served significantly change, and hence increase the consequence of failure, or if 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. These projects aim at ensuring existing service levels are maintained in a sustainable manner, and in line with the surveyed feedback from consumers:

33kV Cable Replacement	
Driver: Asset Integrity Estimated cost: $21 million	A number of subtransmission circuits with utilisation constraints will be addressed under network augmentation projects. However, several in the top 10 have age and condition constraints. Palm Grove, University and Frederick Street will require complete or partial replacement during this medium term period, and a medium section of at least one other set will require replacement due to condition. This is detailed further in Section 5 and included in the network reinforcement budgets, but noted here as it resolves condition and age issues

Zone Substation Transformer Replacement	
Driver: Asset Integrity Estimated cost: $4.0 million	Up to four zone substation transformers (33/11kV) are expected to need replacement based upon age and condition, with Evans Bay and Palm Grove the most likely

Pole Replacement Programme	
Driver: Asset Integrity and Safety Estimated cost: $4.0 million per annum	Replacement of red and yellow tagged poles will continue. This work includes replacement of associated pole hardware. Use of the Deuar pole test method and the decrease in the numbers of wooden poles is expected to produce a decline in the rate of replacement in the medium term

Various 11kV Switchboard Refurbishments	
Driver: Asset Integrity and Safety Estimated cost: $3.0 million (2014-2016) ($0.5 million per site)	A number of zone substation switchboards have a high consequence of failure due to high loading, but not particularly old age or poor condition. Full replacement of these switchboards is not justified, and retrofit components with higher ratings can be used to reduce the risks and provide a mid-life refurbishment extending the overall life. Upgrades of associated protection, control and secondary systems are planned. The sites are Frederick Street, University, Moore Street, Hataitai, Kaiwharawhara and Johnsonville

Load Control Plant Replacement	
Driver: Asset Integrity Estimated cost: $3.0 million	Concerns have been raised around reliability and performance of early solid state ripple injection plant in the Wellington City area. During the medium term it is anticipated that plant at three locations will require upgrade to a modern low frequency. The plan for this is under development; however, this investment has been allowed for in the budget forecasts

In addition to the specific projects indicated above, the following table gives indicative asset category investment that is not yet defined, but is estimated based on asset age and the known condition of assets in each category:

Investment driver	Asset category	Investment
Asset Renewal	Distribution Switchgear Replacement	$7.5M
Asset Renewal	SCADA and RTU Replacement	$2.0M
Asset Renewal	Distribution Transformer Replacement	$7.5M
Asset Renewal	Distribution Cable and Conductor Replacement	$2.0M
Asset Renewal	Zone Substation Switchboard Replacement	$1.5M
Asset Renewal	Crossarm Replacement	$0.5M
Asset Renewal	Protection and Secondary Systems	$1.0M
Safety	LV Pillar and Pit Replacement	$0.5M
Safety	Cast Metal Pothead Replacement	$0.3M
Safety	Earthing Compliance Upgrades	$1.2M
Safety	Asbestos Removal	$0.3M

Investment driver	Asset category	Investment
Reliability	Reliability Improvement Projects	$0.5M

Figure 6-42 Prospective Asset Replacement Programme 2015-2019

This investment profile is to maintain existing service levels. Over time as condition information improves, the category split may change.

6.5.3 Prospective Asset Replacement Projects for 2020 – 2024

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 maintain safety, 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	$5.0M
Asset Renewal	Subtransmission Cable Replacement	$25.0M
Asset Renewal	Load Control Plant Replacement	$6.0M
Asset Renewal	Power Transformer Replacement	$8.0M
Asset Renewal	Distribution Switchgear Replacement	$9.0M
Asset Renewal	SCADA and RTU Replacement	$0.5M
Asset Renewal	Distribution Transformer Replacement	$9.0M
Asset Renewal	Distribution Cable and Conductor Replacement	$7.0M
Asset Renewal	Zone Substation Switchboard Replacement	$3.0M
Safety	Earthing Compliance Upgrades	$2.0M
Reliability	Reliability Improvement Projects	$0.5M

Figure 6-43 Prospective Asset Replacement Programme 2020-2024

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

6.6 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	2014/15	2015/16	2016/17	2017/18	2018/19	2019/20	2020/21	2021/22	2022/23	2023/24
Asset Replacement & Renewal	18,029	17,568	17,517	22,088	22,858	21,187	20,428	20,350	21,355	21,018
Reliability, Safety & Environment (other)	2,439	3,626	3,650	3,637	3,434	3,416	3,413	3,410	3,404	2,698
Quality of Supply	311	23	24	27	26	25	25	25	25	-
Subtotal - Capital Expenditure on Asset Replacement Safety, and Quality	**20,779**	**21,217**	**21,191**	**25,752**	**26,318**	**24,628**	**23,866**	**23,785**	**24,784**	**23,716**
Service interruptions & emergencies maintenance	3,975	4,062	4,050	4,039	4,028	4,017	4,006	3,995	3,984	3,973
Vegetation management maintenance	1,206	1,241	1,247	1,253	1,259	1,265	1,271	1,276	1,282	1,288
Routine & corrective maintenance and inspection maintenance	8,281	8,416	8,412	8,266	8,007	8,034	8,060	8,087	8,114	8,141
Asset replacement & renewal maintenance	669	689	692	695	699	702	705	708	712	715
Subtotal - Operational Expenditure on Asset Management	**14,131**	**14,408**	**14,401**	**14,253**	**13,993**	**14,018**	**14,042**	**14,066**	**14,092**	**14,117**

Figure 6-44 Lifecycle Asset Management Expenditure Forecast – 2014/15 to 2023/24 ($000 in constant prices)

A breakdown of forecast preventative and corrective maintenance expenditure by asset category is shown in Figure 6-45. 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	2014/15	2015/16	2016/17	2017/18	2018/19	2019/20	2020/21	2021/22	2022/23	2023/24
Battery / Secondary Systems	160	163	162	160	155	156	155	156	157	157
Cables (All Voltages)	764	775	775	762	738	739	743	745	747	750
Circuit Breaker	919	935	934	917	889	892	894	897	901	904
Distribution Substation	1,155	1,175	1,174	1,153	1,117	1,121	1,124	1,128	1,132	1,135
Distribution Transformer	2,003	2,034	2,034	1,998	1,935	1,941	1,949	1,958	1,961	1,968
Overhead Switch / Recloser	378	384	385	378	367	367	368	370	371	372
Pillar / Pit	196	198	199	196	190	191	191	192	192	193
Pole / Overhead Line	1,606	1,633	1,632	1,603	1,554	1,559	1,563	1,569	1,575	1,580
Power Transformer	223	227	227	224	216	218	218	218	219	220
Ring Main Unit / Ground Mount Switchgear	556	565	564	555	537	539	541	542	545	547
Zone Substation / GXP	321	327	327	320	310	311	313	313	315	316
Total	**8,281**	**8,416**	**8,413**	**8,266**	**8,008**	**8,034**	**8,059**	**8,088**	**8,115**	**8,142**

Figure 6-45 Preventative and Corrective Maintenance by Asset Category – 2014/15 to 2023/24 ($000 in constant prices)

6.7 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.

6.7.1 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	2014/15	$815,000
Load Control Master Station Upgrade	2014/15	$310,000
IT Hardware Upgrades	2014/15	$600,000

Figure 6-46 Overview of planned IT Asset Investment

6.7.2 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 2014 non-network CAPEX programme to extend the Deuar license. Other test equipment and tools are replaced as required, these include power quality and partial discharge test sets.

Item	Regulatory Year	Estimated Cost
Specialist Test Equipment and Licenses	2014/15	$200,000

Figure 6-47 Overview of planned Plant and Machinery Investment

There are no other material investments planned for non-network plant and machinery.

6.7.3 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 sites.

6.7.4 Non-network Asset Expenditure Profile

Category	2014/15	2015/16	2016/17	2017/18	2018/19	2019/20	2020/21	2021/22	2022/23	2023/24
Non-network assets	1,717	1,202	1,325	4,640	456	448	440	432	424	417

Figure 6-48 Non-Network Capital Expenditure Forecast – 2014/15 to 2023/24 ($000 in constant prices)

Increased spend in 2018/19 is due to the renewal of the IT services contract and renewal of major hardware.

7 Network Performance

In addition to the management of assets at the component level, Wellington Electricity monitors the performance of asset groups at the feeder level. This includes root cause analysis of faults and analysis of asset performance as part of the on-going effort to improve systems, standards and procurement. Fault analysis provides a useful input to the asset maintenance process as it identifies feeders that are experiencing the most unplanned outages and may require remedial action in order to maintain overall network reliability.

Fault performance is also compared with the security of supply standard to ensure that expected maximum outage times are being met. In some cases, the terrain, exposure to elements or vegetation may conspire to result in multiple faults. Post-fault reviews include consideration of network configuration to reduce the impact of any future faults.

7.1 Network Performance Analysis (2012/13)

In 2012/13, Wellington Electricity exceeded its reliability limit for SAIDI but was under its SAIFI limit as shown in the table below:

Reliability metric	Limit 2012/13	Actual for 2012/13	Variance
SAIDI	40.74	43.29	+5.95%
SAIFI	0.60	0.57	-6.66%

Figure 7-1 Wellington Electricity Reliability 2012/13

A severe weather event (extreme winds for 17 hours) on 8 September 2012 affected the network and triggered the declaration of a major event response. Multiple outages were caused by trees and wind borne debris being blown into the overhead network, damaging assets and interrupting supply.

The largest single outage during this weather event was the loss of supply to Trentham zone substation. Shorting between a 33kV line and its under-hung protection communications cable damaged isolation equipment at each end of the pilot cable, which caused both 33kV lines supplying the substation to trip out. As a result of this outage, supply to 4,870 customers was interrupted for several hours before the subtransmission supply was restored. Two days after this event, a landowner felled trees into the second Trentham 33kV circuit causing a second complete substation outage, as the original faulted circuit was still out of service and the substation supplied by a single incoming line. The protection arrangement was upgraded following the fault, and further reconfigured in 2013 to reduce the likelihood of a similar incident occurring again. This fault is discussed further in Section 7.1.1 below.

In total, approximately 7,300 customers were affected by this storm. The majority of faults were in rural areas and, in many cases, restoration was delayed by safety concerns for the responding crews. While the SAIDI impact of this event was over 7 minutes, and constituted more than 16% of the total network SAIDI for the year, it does not qualify as a “major event day” when the SAIDI would be normalised for recording purposes by replacing the actual SAIDI with a boundary value.

The impact of this storm on the network SAIDI and SAIFI for 2012/13 is shown in the graphs below.

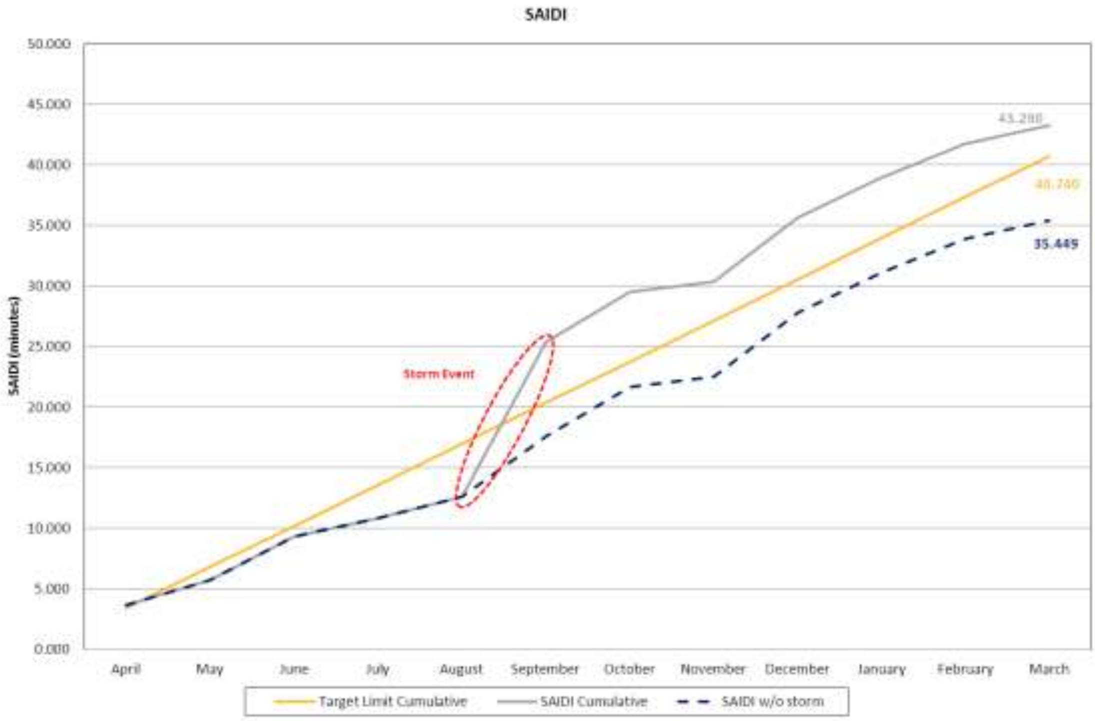


Figure 7-2 Wellington Electricity SAIDI Performance 2012/13

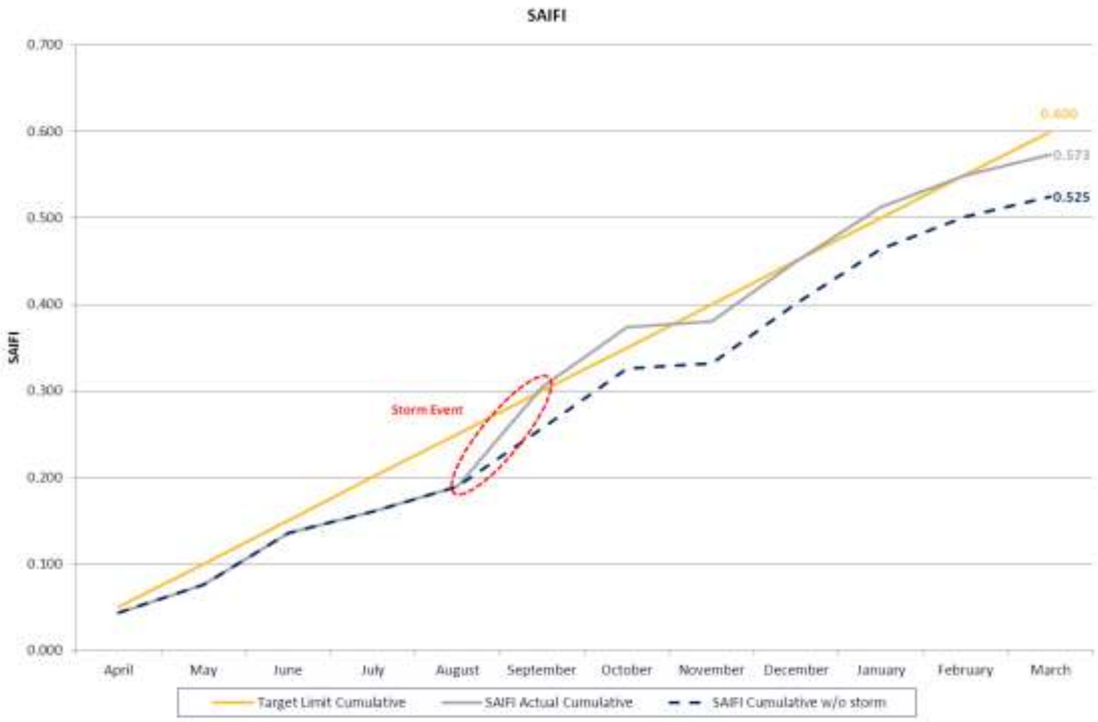


Figure 7-3 Wellington Electricity SAIFI Performance 2012/13

7.1.1 Extreme Weather Event

On 8 September 2012, during a severe storm, both 33kV circuits at Trentham zone substation tripped causing an interruption to supply to 4,870 customers. It is believed that a foreign object came into contact with both the Trentham "A" overhead 33kV line and its under-hung catenary communications cable at the same time as a result of the storm. This resulted in the total loss of supply to the Trentham zone substation as high voltage flashed over onto the communications pilot cable damaging both the cable and the terminal isolation units (barrier transformers) at each end. Wellington Electricity's network controller received no flagging information from the relevant protection relay. This lack of information contributed significantly to the length of time to restore the zone substation because there was no indication as to what had happened and a simultaneous outage of two single circuits supplying the same substation over diverse routes is very unusual. Power was restored using the contingency restoration plan for Trentham substation, but full restoration took about four hours as there were limited resources available due to the widespread faults that occurred elsewhere on the network during the storm. This single outage caused a system SAIDI of 5.16 minutes. Later it was revealed that the fault affected the 33kV line "A", but that the damage to the protection circuit created instability on the differential protection scheme, which tripped the second circuit.

On 10 September 2012, two days after the initial fault, another fault occurred, this time on the Trentham 33kV "B" line due to a third party incident where a tree was felled onto the line. This occurred before the "A" line had been returned to service following the first fault and the whole substation was supplied by only the "B" line. This had a quicker restoration time of only an hour, because the flag indication at Transpower's end of the line was immediately notified to Wellington Electricity's network controller. The affected section of the faulted 33kV circuit was patrolled and confirmed clear and power was restored to the Trentham substation. The SAIDI impact for this fault was 1.62 minutes.

7.2 Reliability Performance by Fault Type

The network SAIDI performance by fault type for 2012/13 is shown in the chart below (Figure 7-4) and compared with 2011/12.

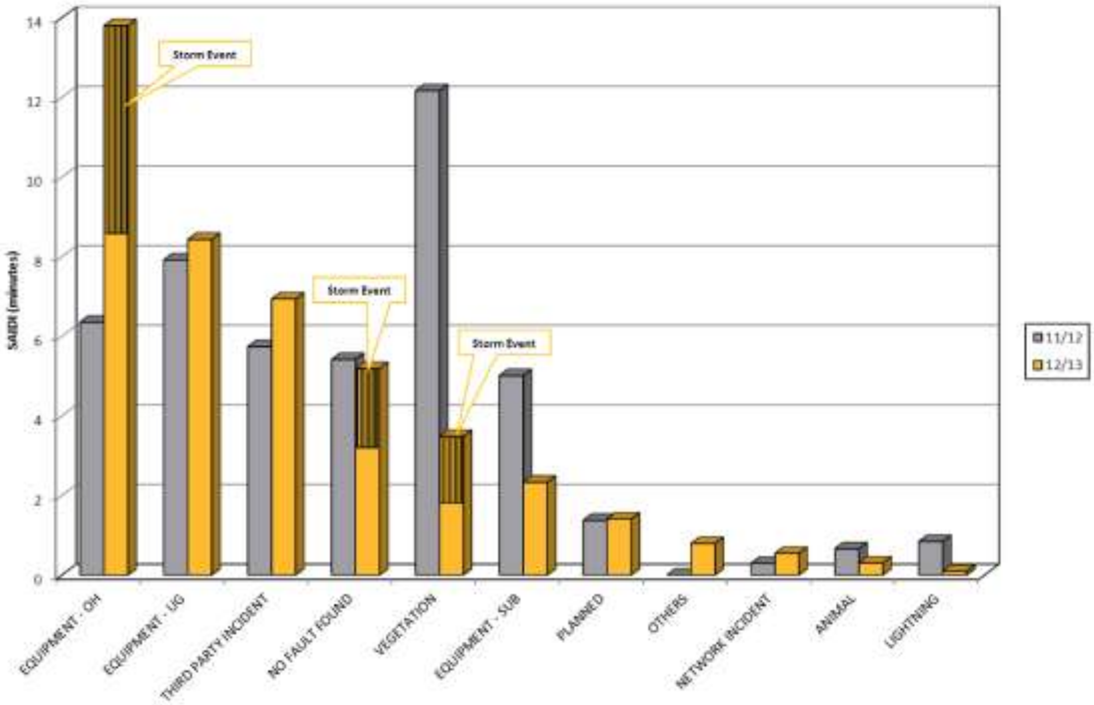


Figure 7-4 SAIDI Performance by Fault Type 2012/13

Figure 7-4 shows that the highest SAIDI reliability impact was due to overhead equipment failure followed by underground equipment failure, then third party incidents.

The impact of vegetation faults in 2011/12 was significantly higher than 2012/13 because of the four days of snow that occurred in August 2011. However, vegetation management has also improved as the vegetation management effort has focused on those feeders most prone to vegetation faults.

Most of the incidents where the cause of the fault was not found occurred during stormy weather and were most likely a result of transient vegetation or line clash events. More detailed post-fault investigation is now being carried out where the cause of a fault is not immediately apparent, to provide the information needed to guide possible remedial action to address the specific root cause.

As stated above the largest single outage that caused the high contribution from overhead equipment failure was due to the foreign object that simultaneously hit the under-hung protection communications cable and the 33kV Trentham 'A' line, resulting in the outage of the whole zone substation. The storm that caused this incident was extreme with recorded wind gusts of 100 – 140 kilometres per hour over a period of 17 hours, as shown in Figure 7-5 below.

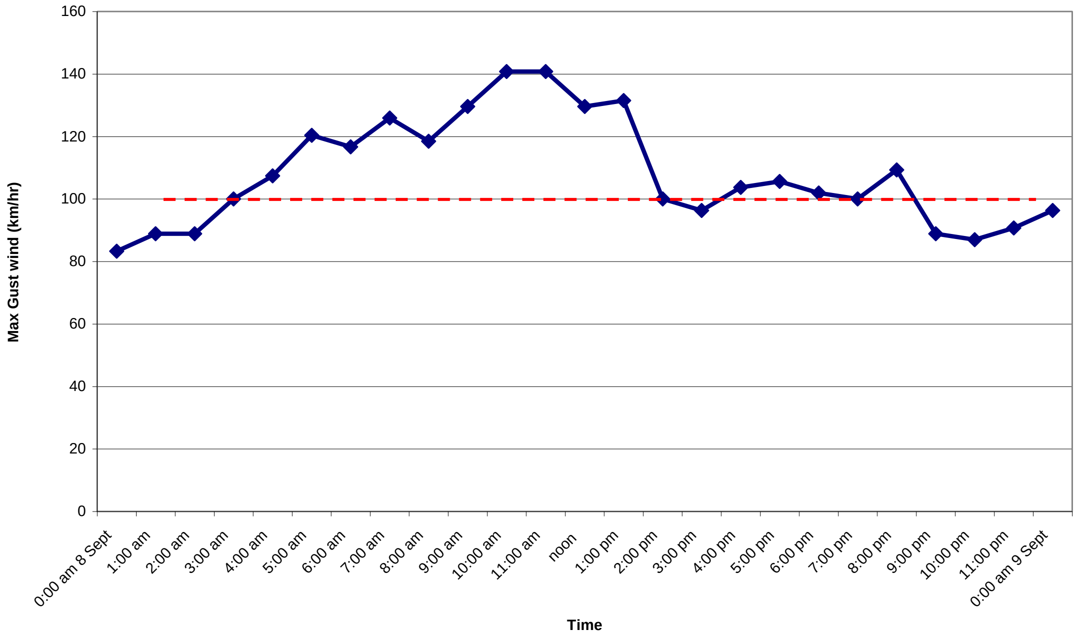


Figure 7-5 Winds measured at Mt. Kaukau (8 September 2012)

The SAIDI impact of different overhead equipment failure fault causes is shown in Figure 7-6. The number beside the fault causes represents the count of each fault cause. Foreign objects caused the most faults and this is mostly attributed to the Trentham outage. This one-off event will be mitigated by the use of a new pilot wire monitoring relay to prevent another prolonged outage.

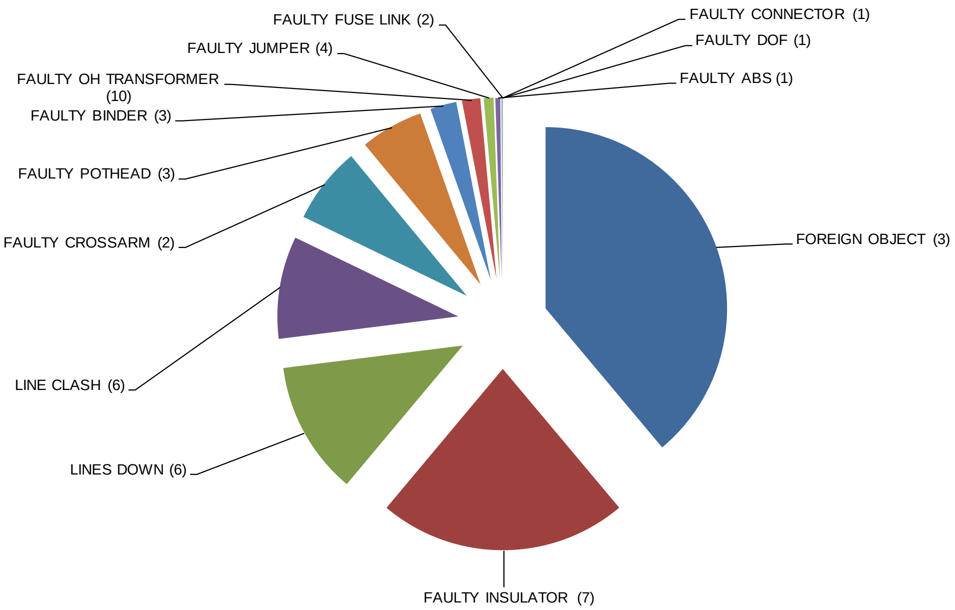


Figure 7-6 SAIDI impact of the Overhead equipment failure – Fault cause

The number of outages due to different types of overhead equipment failure in 2012/13 compared with 2011/12 is in Figure 7.7. (Fault causes with just one outage for both years are not shown.)

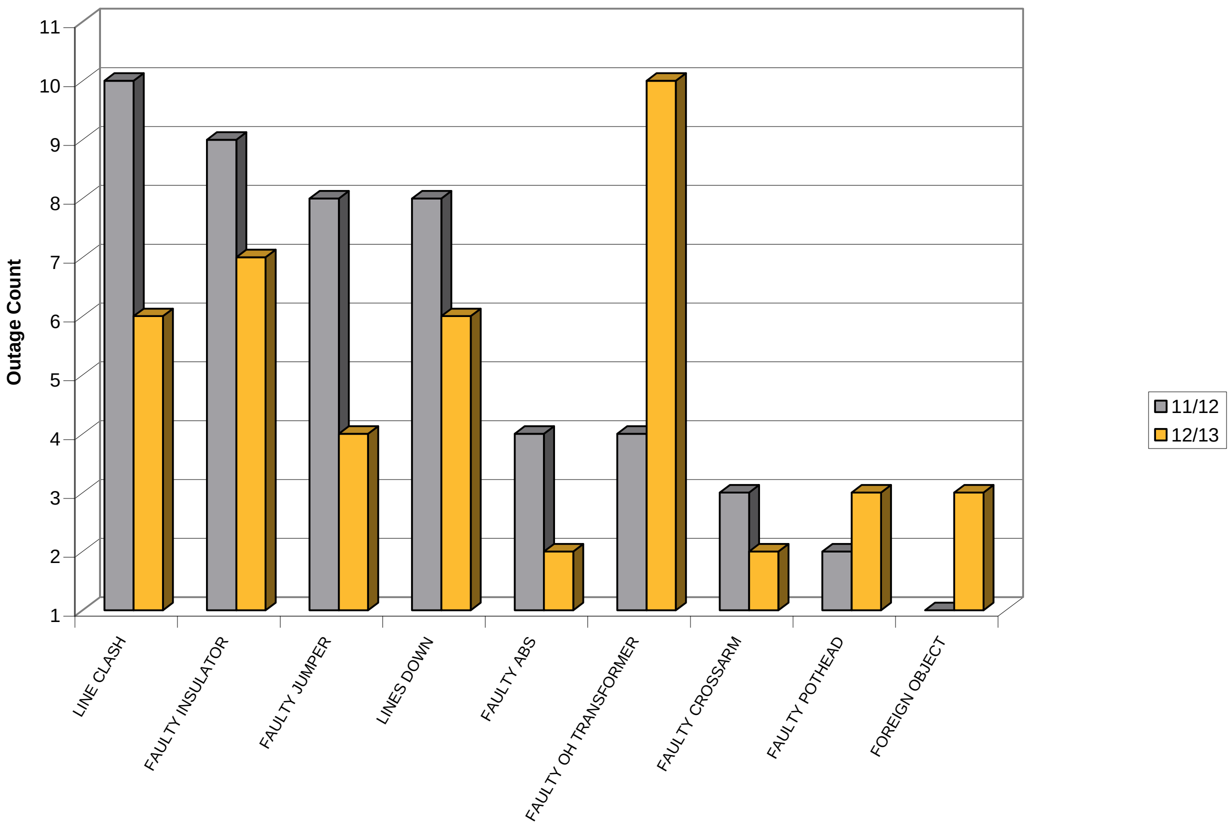


Figure 7-7 Outage Count of Overhead equipment failure – Fault cause

Figure 7-7 shows that the incidence of most causes of overhead equipment failures has reduced. This could be due to improved routine inspection where potential causes of overhead equipment are observed (and remedied through the defect process), although fatigue is not always visible.

The standout exception is the significant increase in the number of overhead transformer failures – attributable to the ageing transformers in the network. The majority of the failed transformers were installed in the rural areas and, because these transformers are generally small and serve few customers, the impact on SAIDI is also small as shown in Figure 7-6 above.

If the one outage of the Trentham zone substation is set aside, the impact of overhead equipment failures has generally decreased.

In comparison with 2011/12, the number of cable related faults increased in 2012/13 and likewise the SAIDI impact as shown in Figure 7-8.

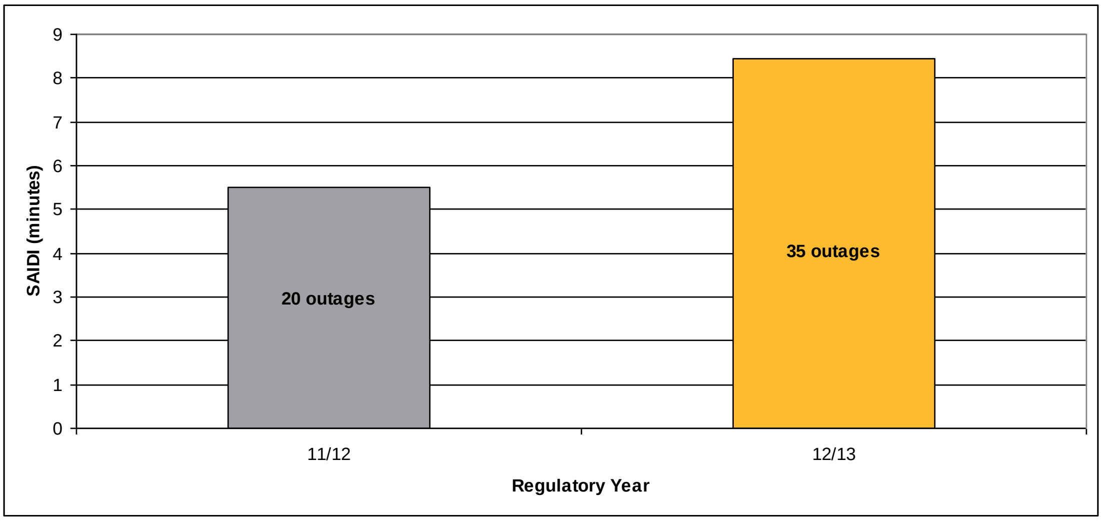


Figure 7-8 SAIDI impact due to Cable Fault

Third party incidents contributed 6.8 SAIDI minutes and were due to excavation works, vehicle collisions, third party tree cutting (tree contact), and third party contractors hitting the 11kV conductors (overhead contact). The Ultrafast Broadband (UFB) network project had a significant impact on the number of third party strikes due to the number of dig-in incidents as Chorus contractors installed the cable. Similarly, third party incidents due to landowners felling trees have increased since, as discussed in Section 6.3.1, landowners are now responsible for the control of trees that they own and many landowners prefer to cut their own trees rather than hiring a professional arborist.

The number of third party incidents by cause in 2012/13 is shown in Figure 7-9.

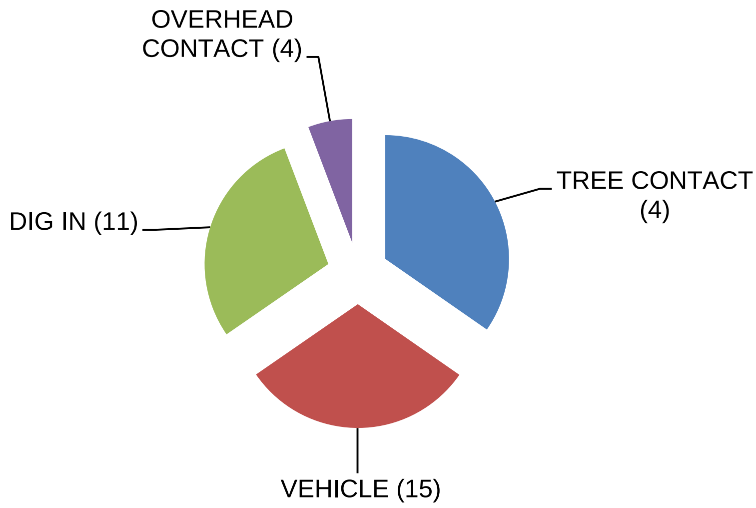


Figure 7-9 Third Party Incident Causes

In comparison with 2011/12, the number of outages for each fault cause due to third party incidents has increased. The SAIDI impact, however, decreased in the dig in and vehicle collision categories and increased in the tree contact and overhead contact – see Figures 7-10 and 7-11.

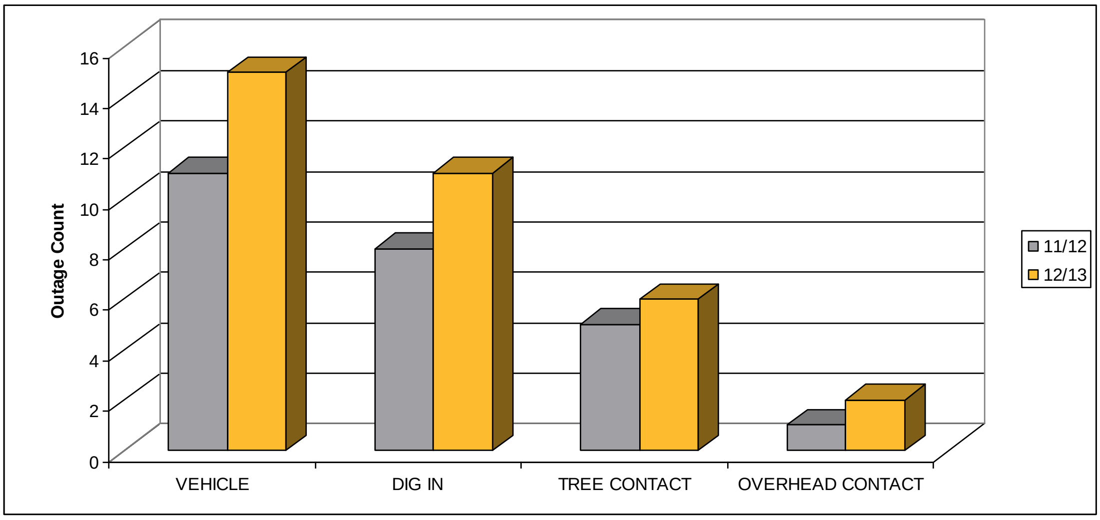


Figure 7-10 Outage Count of Third Party Incident – Fault cause

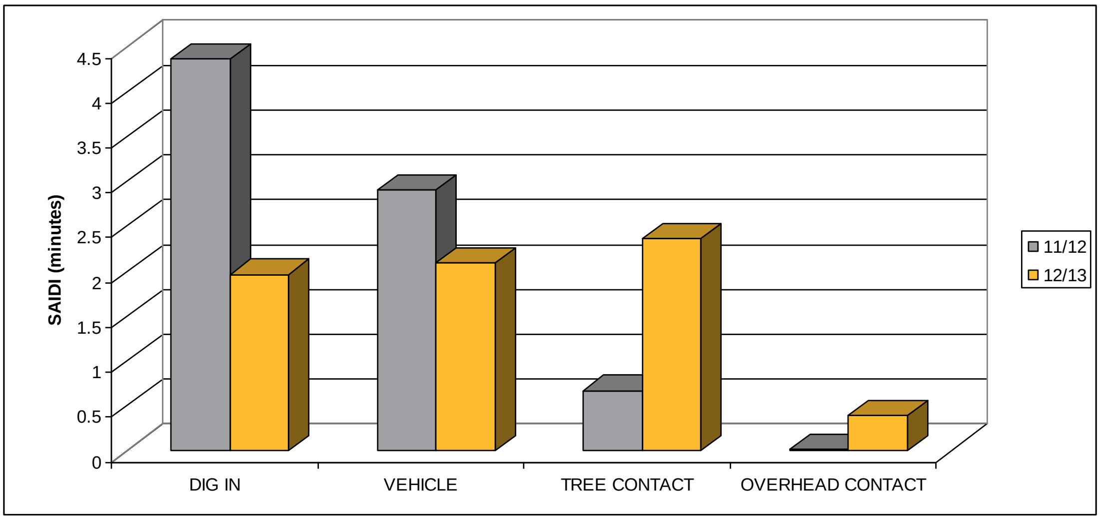


Figure 7-11 SAIDI impact of Third Party Incident – Fault cause

Controlled events that can affect network performance are planned network operations, or network equipment faults. Uncontrolled events are third party damage incidents, animal/bird interference, lightning strikes and vegetation contact outside controlled zones. A detailed analysis of data from the last five years provides the following breakdown between the SAIDI impact of controlled and uncontrolled events:

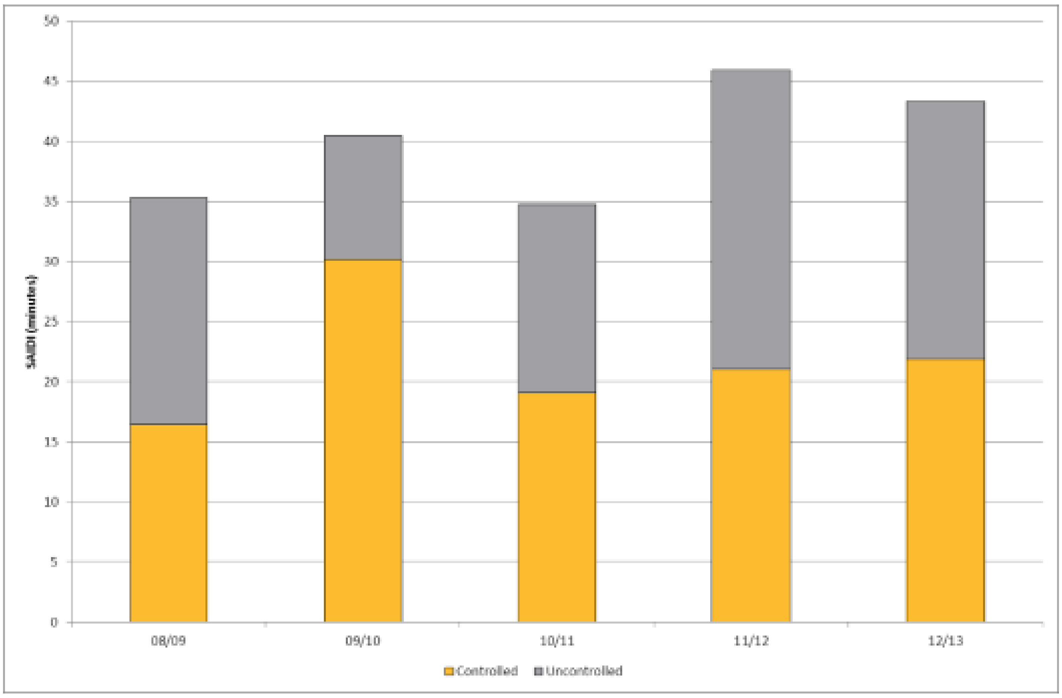


Figure 7-12 Summary of Controlled and Uncontrolled Events Impacting SAIDI Performance 2008-2013

In comparison to 2009/10, controlled events significantly reduced in 2010/11 and maintained at a similar level in 2011/12 and 2012/13. The main area of focus has been on reducing overhead network equipment failures, which contributed 18 SAIDI minutes in 2009/10. Improved inspection and condition assessment, as well as two large overhead rebuild projects, have led to a reduction to around 6-8 SAIDI minutes in the 2010 to 2013 period (if the impact of the extreme storm in September 2012 is set aside). This indicates that the corrective actions carried out to improve controlled events are effective, and these activities continue in areas where asset performance is below average.

The effect of uncontrolled events on SAIDI minutes has continued to rise since a low point in 2009/10. Some uncontrolled events could be reduced through engineering design (such as the undergrounding of lines); however, the cost/benefit trade-off needs to be considered and in most cases this approach would be uneconomic.

A distribution substation damaged by a fallen tree following a storm

7.3 Industry Comparison

Wellington Electricity was one of the three most reliable EDBs in New Zealand in 2012/13. The data presented in Figures 7-13 and 7-14 is sourced from the annual Information Disclosures made by Lines Businesses and made publically available.

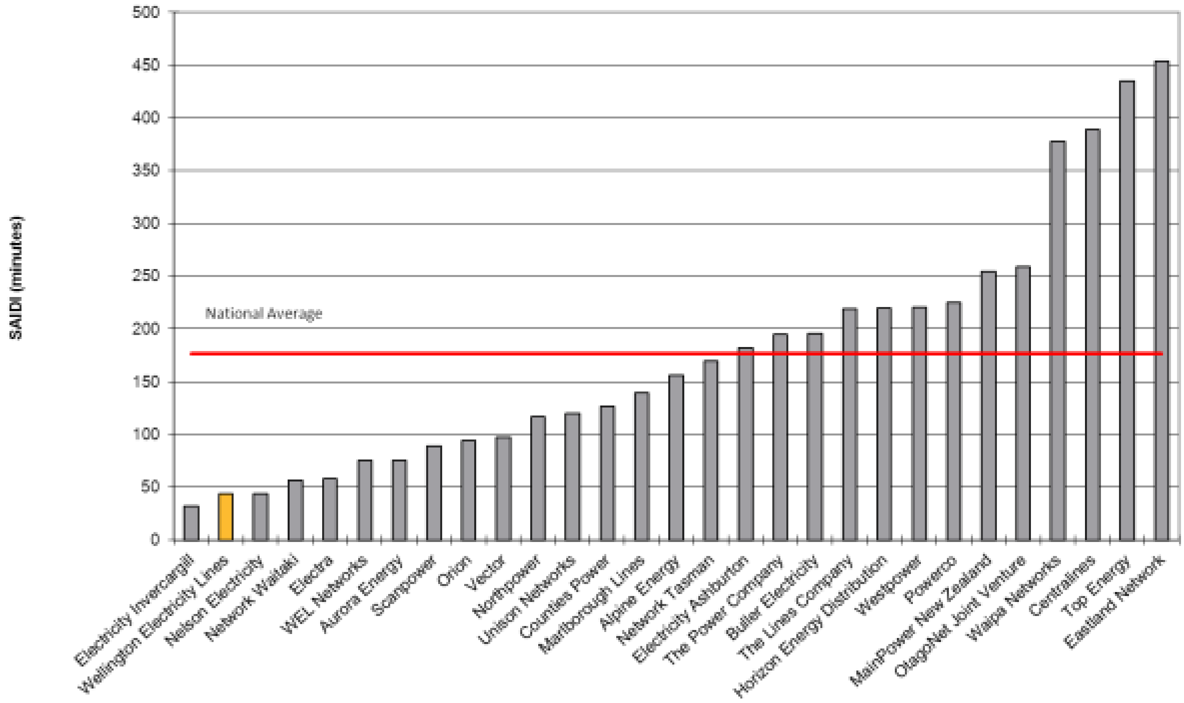


Figure 7-13 National SAIDI by EDB for 2012/13

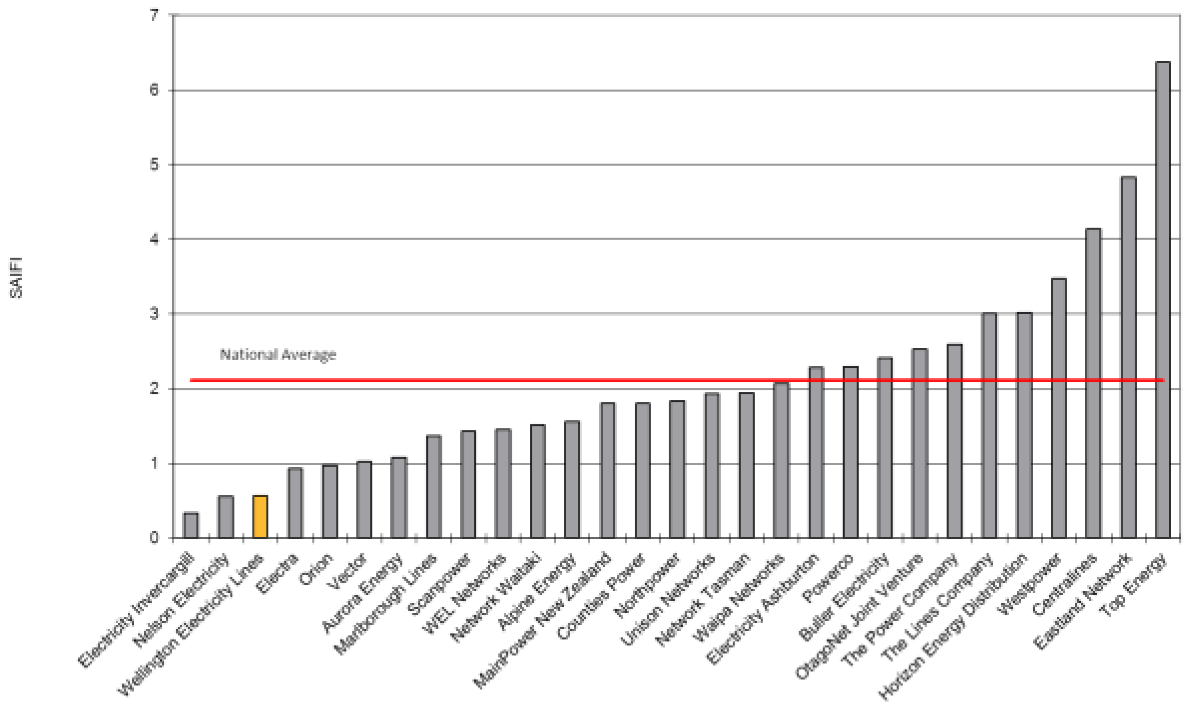


Figure 7-14 National SAIFI by EDB for 2012/13

Consumer satisfaction with the quality of supply delivered by Wellington Electricity is supported by a survey, last carried out in late 2011.

This survey concluded that consumers regard:

- Continuity ("keeping the power on") and restoration ("getting the power back on") as the first and second most important components of electricity line services;
- Wellington Electricity's performance in regard to continuity and restoration as either excellent or very good; and
- Limiting price rises as important, leading to price-quality trade-offs for the service level received.

7.3.1 Benchmarking Analysis

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 2012/2013 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 %.

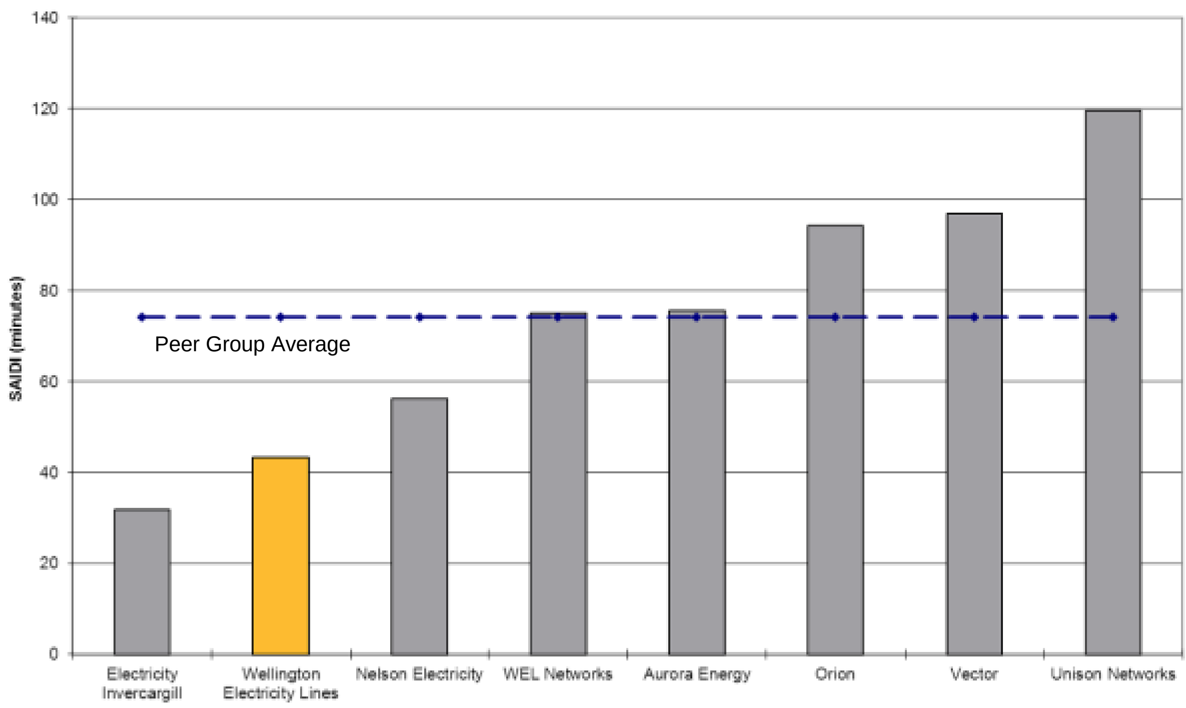


Figure 7-15 Peer Group SAIDI Comparison 2012/13

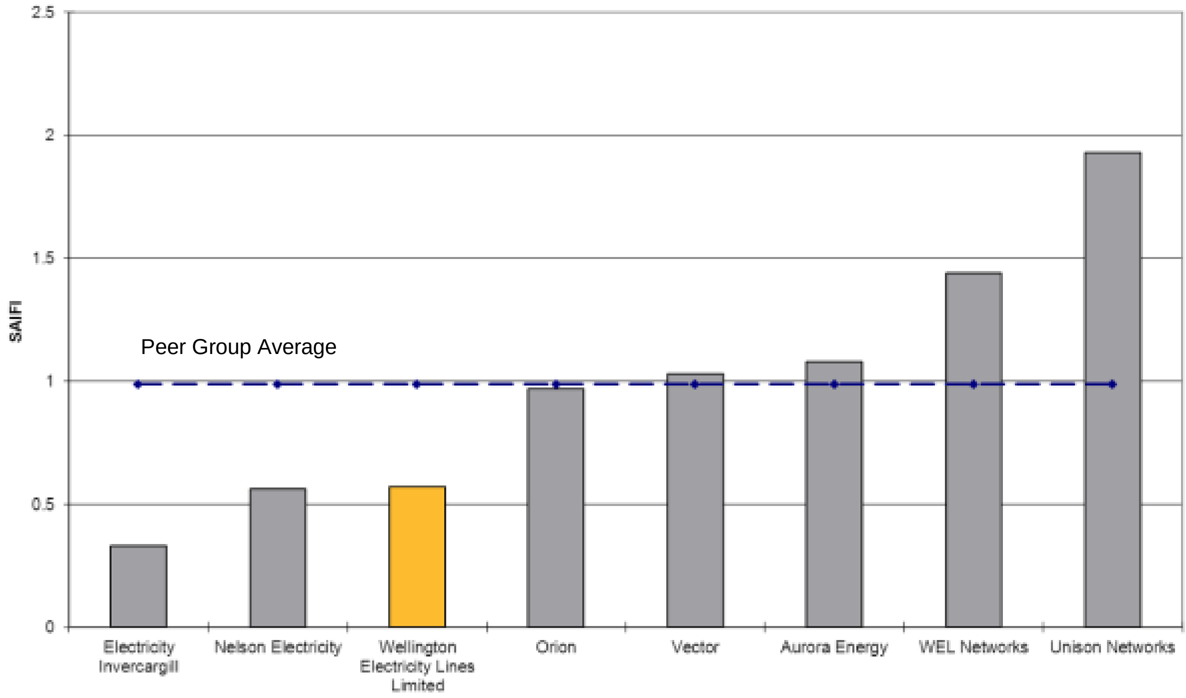
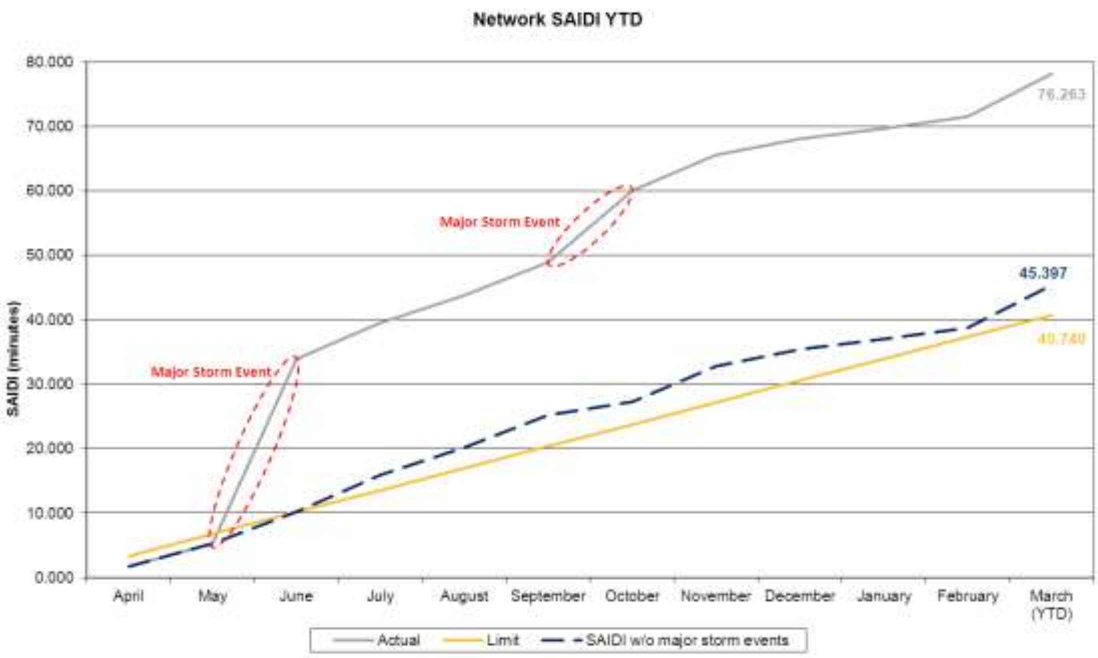


Figure 7-16 Peer Group SAIFI Comparison 2012/13

The benchmarking analysis shows that Wellington Electricity's system reliability index (i.e. SAIDI, SAIFI) are in the upper quartile of the peer group. This supports the claim that Wellington Electricity is currently performing well against comparable networks in New Zealand.

7.4 Network Reliability Performance (2013/14 Year to Date)

The normalised Wellington network performance for 11 months of the 2013/14 regulatory year is tracking over the Year to Date (YTD) targets of 31.075 minutes for SAIDI and 0.476 for SAIFI.



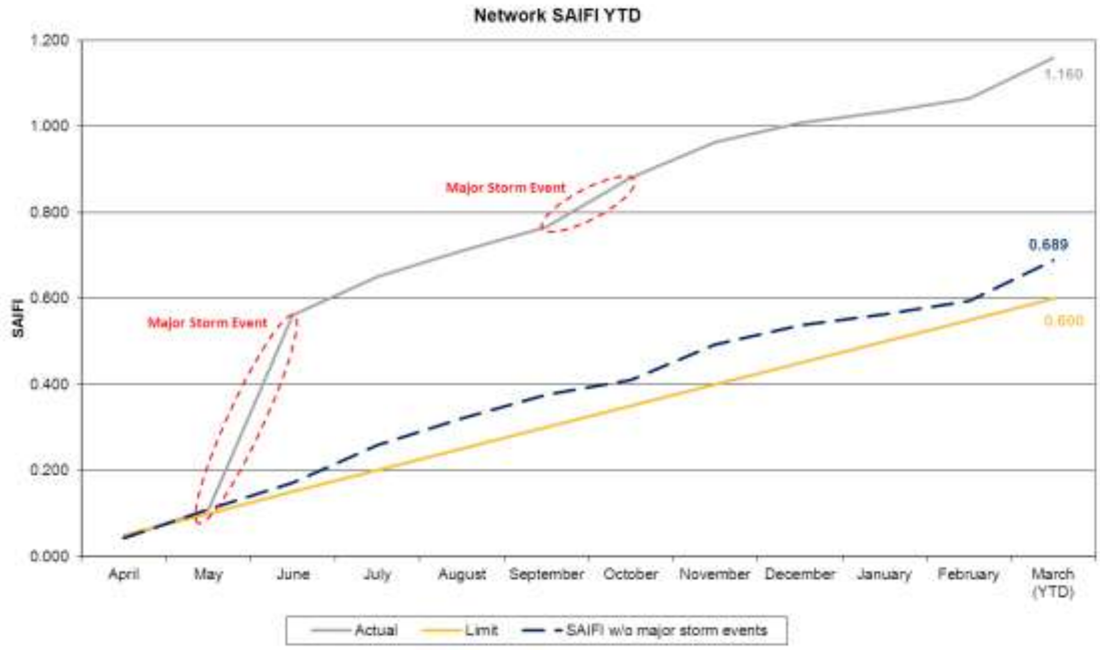


Figure 7-17 SAIDI and SAIFI for 2013/14 YTD

Two major storm events in 2013 significantly affected the network and triggered the declaration of a major event response for Wellington Electricity. In both storms, trees and wind borne debris were blown into the overhead network damaging assets and interrupting supply which caused multiple outages.

The first major storm on 20 June 2013 was of a magnitude similar to the “Wahine storm” of 1968 and resulted in widespread network outages. The storm started at approximately 5pm and registered a maximum gust wind of 100kph at that time – wind speeds at 200kph at approximately 7pm. The maximum gust wind speed was over 100kph continuously from the early evening of 20 June until the end of 21 June or approximately 30 hours, as shown in Figure 7-18.

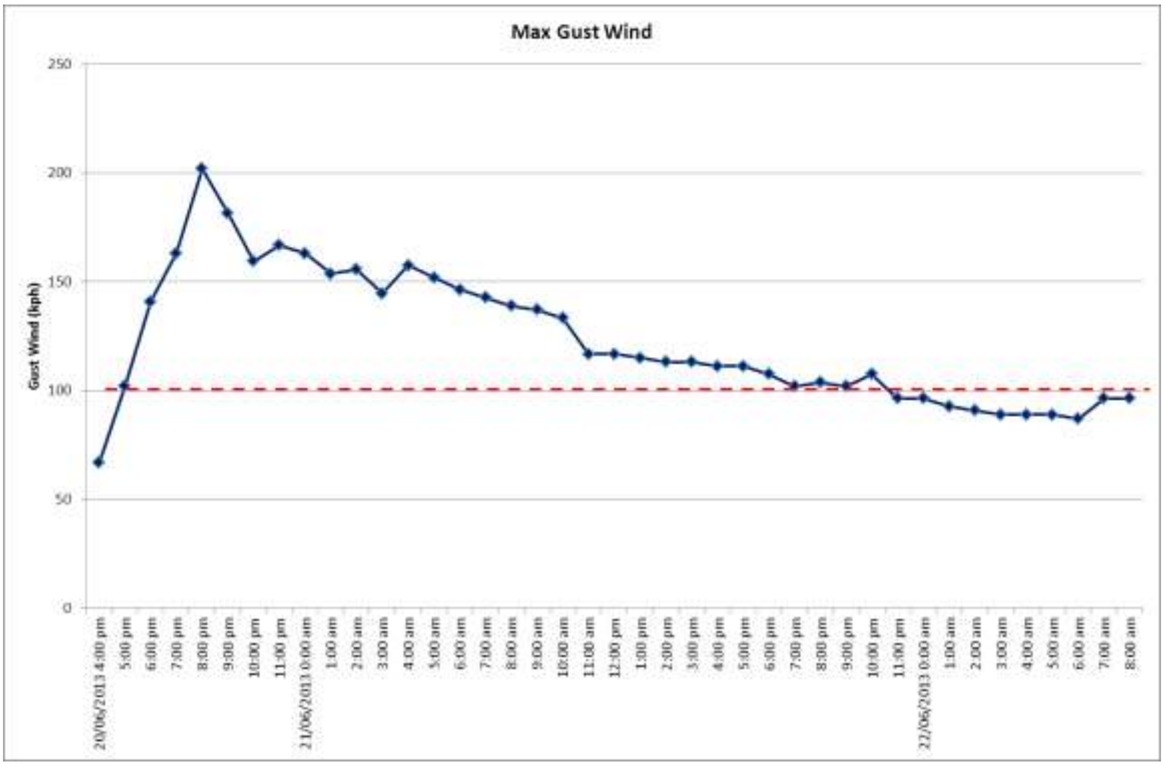


Figure 7-18 20 – 22 June 2013 Storm Max Gust Wind per hour

The storm was described by National Institute of Water and Atmospheric Research (NIWA) as the worst storm in 37 years. It damaged houses, roads and seawalls, as well as closing schools and leaving thousands without power across the Wellington Region. All flights in and out of the city were grounded and a ferry broke its mooring.

The storm caused significant damage to the Wellington network and at its peak resulted in 30,000 homes and businesses being without power. Conditions were so dangerous that Wellington Electricity stopped responding crews from carrying out repairs, until the storm had subsided in the early morning of 21 June.

Roads were blocked by fallen trees or were sufficiently damaged to make them impassable. Other roads were closed due to landslips. Transport links around the Wellington Region were severely affected resulting in traffic congestion on the motorway.

The damaged network assets affected customers in both urban and rural areas. Wind gusts uprooted trees, damaged houses and flung debris (including trampolines) into the 11kV lines. The majority of the outages were caused by trees that fell through lines damaging poles and conductors as well as by tree branches falling onto 11kV lines. Other causes were airborne debris, conductors breaking or detached from the insulators and poles broken due to the very high winds.

The affected areas in the Wellington network were widespread. Prolonged outages were due to the unsafe conditions in which to repair lines, because of the extended period of the storm. It was difficult for the responding crew to patrol and clear the lines immediately. Aerial patrols by helicopter could not commence until the third day, when wind speeds dropped to safe operational levels. When the storm had slightly subsided, mobilisation of crews was hampered by blocked roadways, and traffic congestion due to the rail links being out of service. 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 Treescape (Wellington Electricity's vegetation contractor). There were also a large number of more isolated HV and LV outages which had to be repaired and restored.

During the response to this event, it was difficult to work at night to restore supply due to the continued poor weather, as well as access difficulties into some areas. It was also difficult to work safely during this time. Wellington Electricity tripled the normal field crew workforce by bringing in 150 additional staff from around the country to restore power as quickly as possible, but without compromising the safety of the responding crew.

Crews responding following the June 2013 storms

In addition to widespread network repairs, Wellington Electricity crews responded to, and made safe, over 3,000 customer service calls for lines down or equipment damage. A large number of these were customer owned service lines, which in many cases Wellington Electricity contractors repaired at no cost to the homeowner.

During this period, there were approximately 60,222 customers affected by the HV faults and more by LV faults. The total contribution to reliability indicators for the events during the storm was:

	SAIDI	SAIFI
Actual	136.51	0.431
MED boundary value	9.724	0.237

Two out of the three days were categorised as “Major Event Days” (MED). The MED boundary value was substituted and the SAIDI and SAIFI were normalised to 9.724 minutes and 0.237 respectively over the two-day storm period.

The second major storm that hit the Wellington region was on 14 October 2013. The storm commenced at approximately 3am when a maximum wind gust of 100kph was recorded, and wind gusts peaked with a 167kph gust at approximately 5pm. The maximum wind gust speed exceeded 100kph for approximately 22 hours continuously. The sustained high winds resulted in 124 low voltage outages, 24 11kV outages, and 2 33kV outages affecting approximately 18,552 customers.

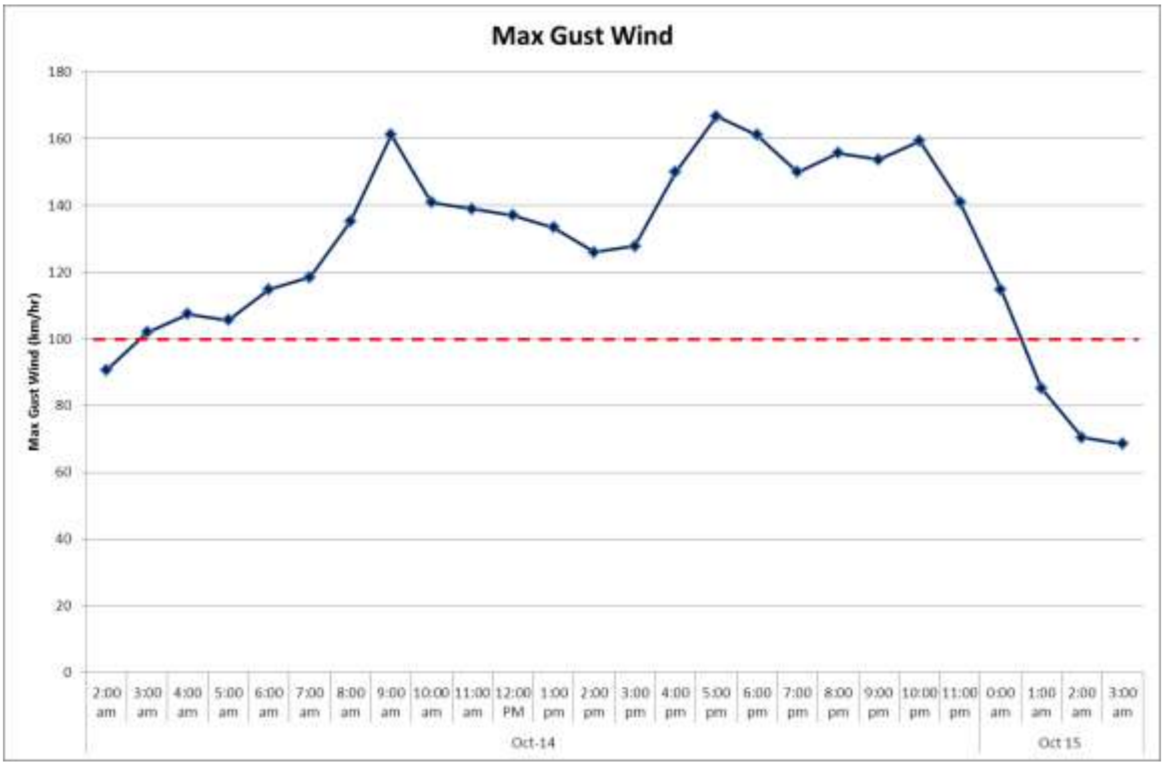


Figure 7-19 14 October 2013 Storm Max Gust Wind per hour

The total SAIDI and SAIFI recorded from the storm was 9.040 minutes and 0.080, respectively. These were both lower than the MED boundary value so no substitution was required.

Additionally, two major earthquakes hit the region during 2013 and caused two outages of the Karori zone substation, which had a significant impact on the total SAIFI for the year.

Trees through lines during the June 2013 storm

7.4.1 Summary of Fault Causes

The five year historical reliability charts below show improvements in the numbers and impact of most fault types following a bad year in 2011/12. The increase in the SAIDI due to overhead equipment failure, vegetation, and unknown cause faults in the current regulatory year is primarily due to the two extreme storms that hit Wellington region in 2013 as discussed in section 7.4.

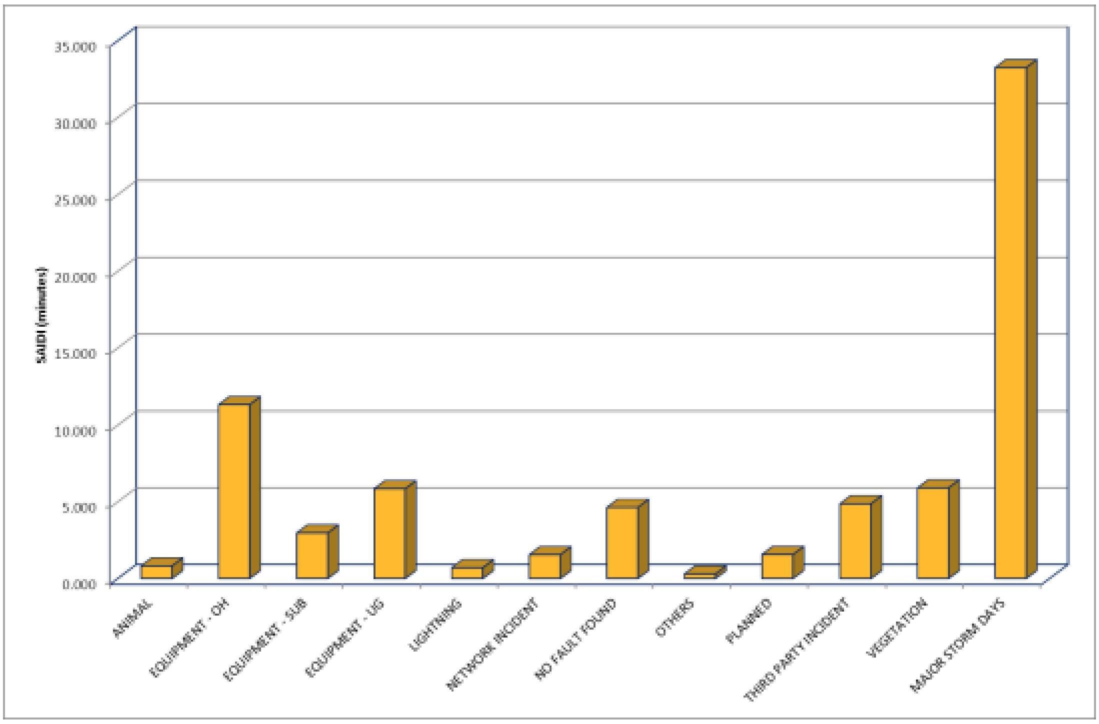


Figure 7-20 Five Year Average SAIDI per Fault Type 2009-2014 YTD

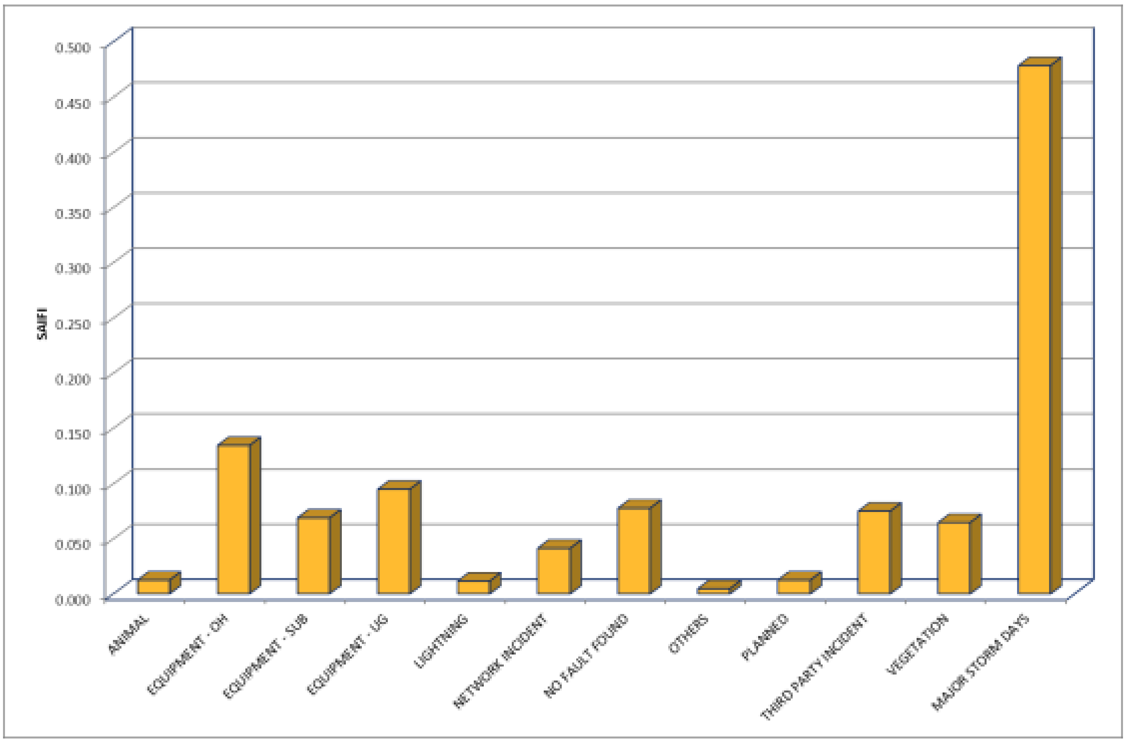


Figure 7-21 Five Year Average SAIFI per Fault Type 2009-2014 YTD

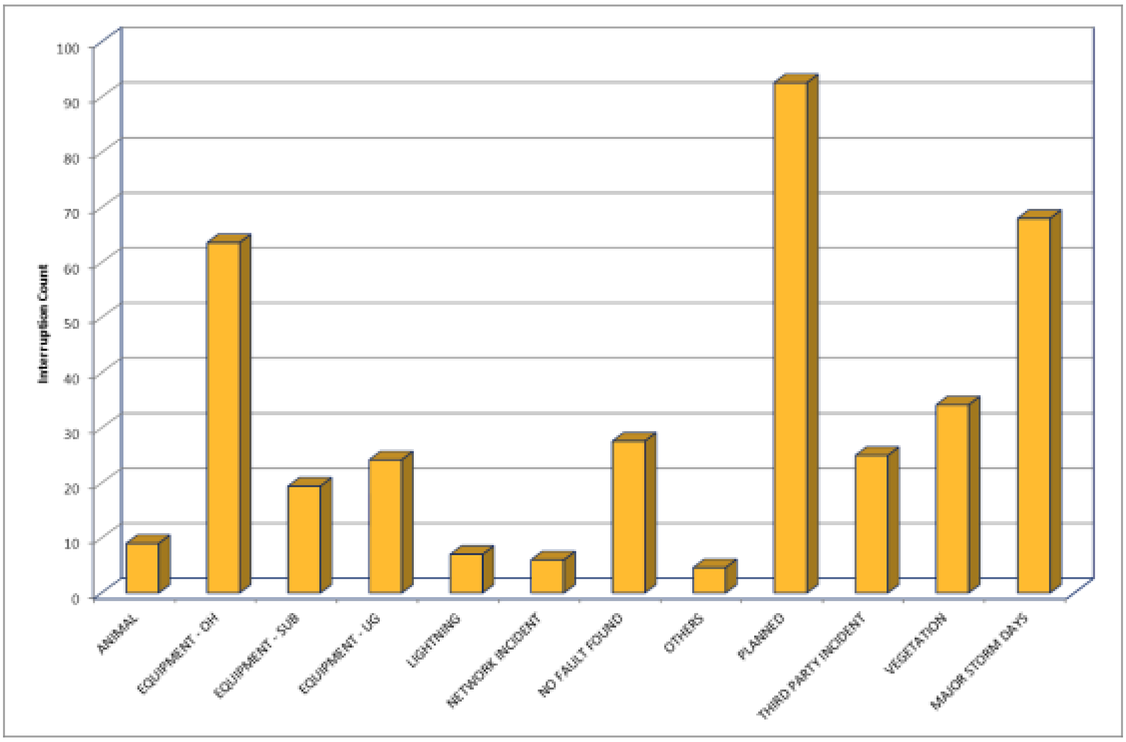


Figure 7-22 Five Year Historical Count per Fault Type 2009-2014 YTD

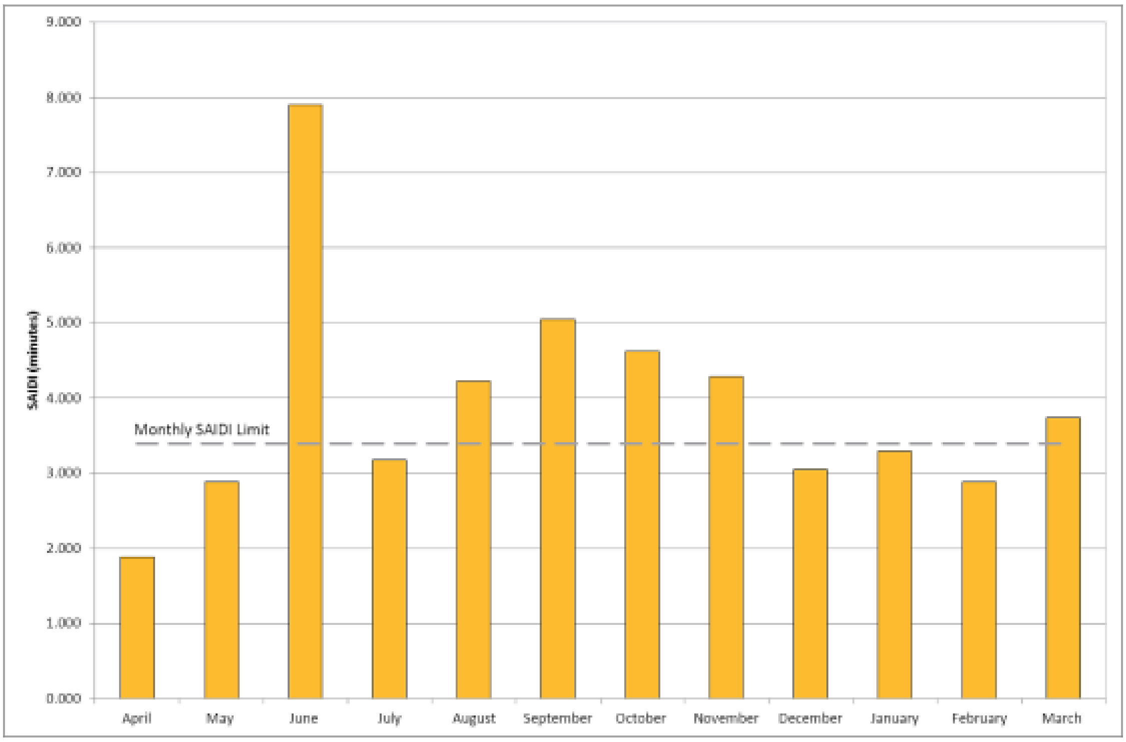


Figure 7-23 Five Year SAIDI Rolling Average per Month 2009-2014 YTD

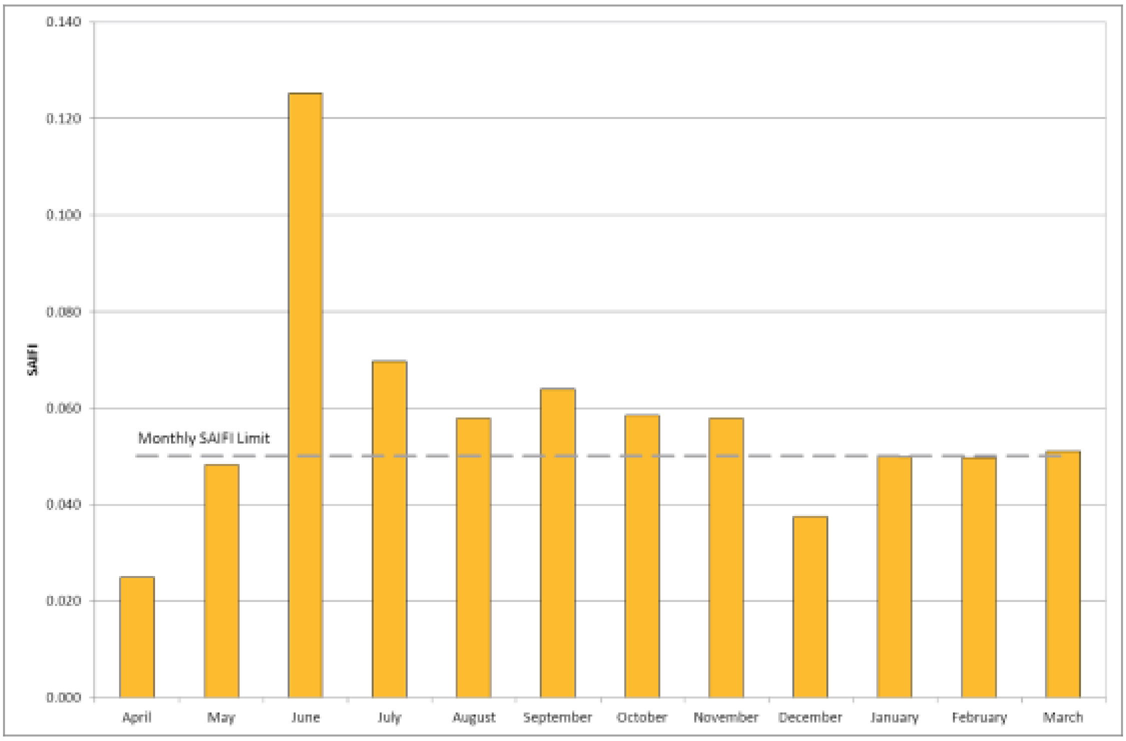


Figure 7-24 Five Year SAIFI Rolling Average per Month 2009-2014 YTD

The rolling averages in Figures 7-23 and 7-24 show that network reliability is worst during the winter and spring months of June to November, predominantly due to significant numbers of overhead equipment faults. This indicates that environmental factors have a significant impact on network performance. Other fault types do not show clear trends over the year.

The summary SAIDI and SAIFI by fault cause is described below. "Major Event Day" as a fault cause has the highest impact on SAIDI largely due to the two major storms that hit the Wellington Region. Two days of one event exceeded the MED SAIDI value 9.724 minutes.

Overhead Equipment

Overhead equipment failure outages generally occur during days of strong winds or stormy weather. Many overhead equipment failures are due to broken conductors or failed connections. The condition of overhead conductors is observed during routine inspections, although fatigue is not always visible. Increased focus is on identifying suspect connector types on the overhead network, such as Fargo automatic line splices, which have failed during strong winds and are being progressively replaced.

Underground Equipment

Underground equipment failures are due to cable and cable joint failures. Cable systems generally have a long life and high reliability as they are subject to fewer environmental hazards. However, as the cables age, their performance is seen to decrease. External influences such as third party strikes, inadvertent overloading, or even unusual high loading within normal "design limits" can lead to shortening of the service life of cable systems. To minimise possible failures, vulnerable sections of cable are identified using diagnostic tests (such as insulation resistance, VLF and partial discharge) and proactively replaced.

Third Party Incidents

The third party incidents contributed 4.43 SAIDI minutes in 2012/13 and were primarily due to vehicle collisions. The Ultrafast Broadband (UFB) network installation also had a significant impact on the number of third party incidents due to the number of dig-in strikes by Chorus contractors installing the UFB cable. The number of third party incidents has decreased in the 2013/14 year to date.

Vegetation

Vegetation related outages are generally due to trees not being trimmed by landowners. Wellington Electricity has completed the (free) first cut and trim and keeping trees clear of overhead lines is now the responsibility of landowners under the Electricity (Hazards from Trees) Regulations 2003. Wellington Electricity and its vegetation management contractor, Treescape, are working with landowners and TLAs to address vegetation management issues.

Substation Equipment

Substation equipment failure has decreased in the 2013/14 year to date. The most significant substation equipment failure in 2011/12 was a one-off event when the network was in an abnormal state during planned work and this amplified the SAIDI and SAIFI impact. Improved controls are now in place to manage abnormal system loadings during planned works. In 2012/13 there were no substation failures with a major SAIDI or SAIFI impact due to the improved management of substation equipment maintenance.

No Fault Found

Most of the incidents where no fault was identified occurred during stormy weather and were most likely the result of vegetation or line clash transient events. After a ‘no fault found’ event the affected feeders are patrolled to identify areas where reliability improvements are possible.

7.5 Asset Management Focus Areas

Asset management focus areas are identified through trend analysis of data from previous years with the current year to date information included for reference. Where trends are identified, targeted asset management strategies can be implemented. This section provides discussion on initiatives undertaken in the past years and the effect they have had on network performance.

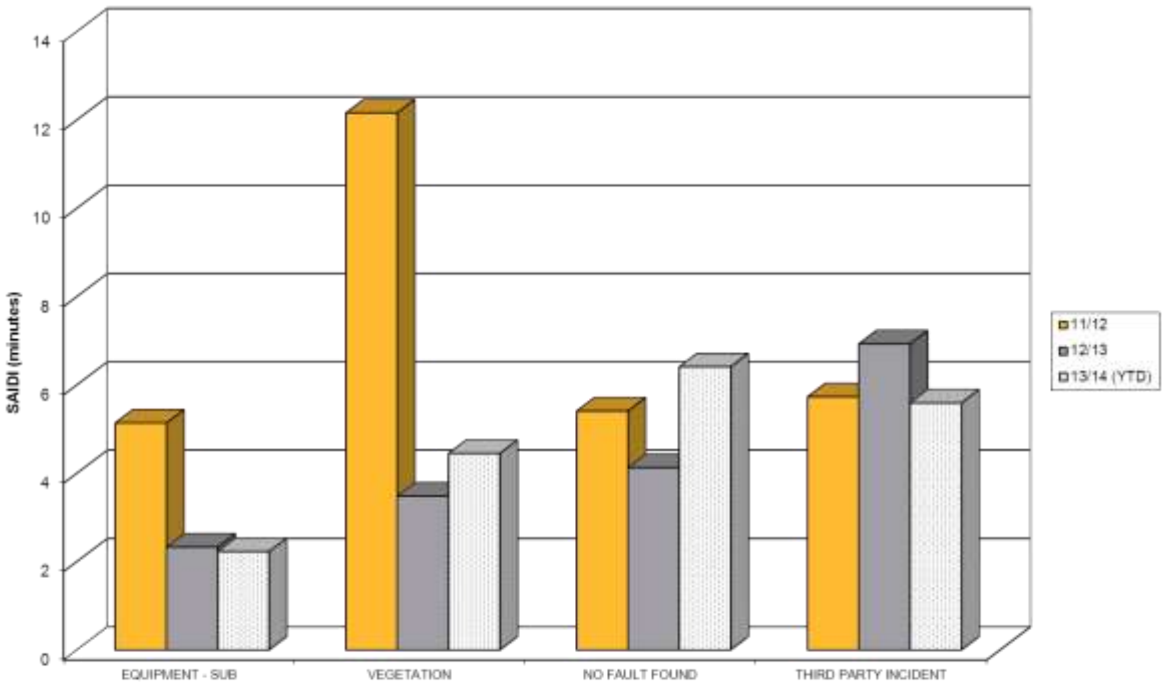


Figure 7-25 SAIDI by Asset Management Focus Areas

Substation equipment issues, particularly the failure of LMT Reyrolle switchgear to operate under fault conditions (due to auxiliary switch issues), were the focus area in 2011/12. There has been a significant improvement in the failure rate of substation equipment following maintenance on this switchgear type.

With regard to vegetation management, Treescape has continually made contact with the owners of the trees that are encroaching on, and presenting potential hazards to, overhead lines. As detailed above, there are tree owners who have been reluctant to meet their obligations under the tree regulations.

‘No fault found’ outages usually occur on overhead feeders with the most common causes being tree branches touching lines during stormy weather, debris falling on the line and then clearing, conductor clashes and bird strikes. For every fault classified as ‘no fault found’, a line patrol is carried out at the earliest opportunity to investigate the fault, and to identify possible causes. Feeders with recurring ‘no fault found’ outages are subject to more thorough, targeted inspection regimes, which may lead to corrective maintenance or replacement activities.

Wellington Electricity has commenced further education of the public regarding the hazards of power lines and risks to network assets. Radio advertising is being targeted at the key causes of third party incidents such as vehicle contact, overhead line contact, and promoting the 'dial before you dig' service (specifically to reduce the number of underground cable strikes).

7.5.1 Maintenance Activities

Both planned and corrective maintenance activities are being undertaken on a targeted basis to address identified reliability problems. Examples include improved condition assessment of overhead lines and components, and more regular maintenance of substation protection and circuit breakers to ensure correct operation. Where practicable, certain asset types are being replaced to address known performance issues. This strategy will help to maintain reliability through improved equipment condition and performance. The costs associated with these programmes will increase over time. Unfortunately, with tight regulatory control over business revenue, there is limited scope to recover significant increases in costs associated with increased maintenance and asset replacement activities.

7.5.2 Maintenance and Inspection Standards

Wellington Electricity has reviewed and improved upon previous maintenance standards and practices on its network, including condition assessment and asset information capture. By improving the inspection process, and through better analysis of data, investment and maintenance is increasingly better focussed. For example, Wellington Electricity conducts a detailed survey of overhead lines and components in high wind areas to see whether their integrity is sufficient to meet the higher wind loads experienced.

7.5.3 Worst Performing Feeders

The method used to determine the worst performing feeders in 2012/13 was similar to the approach used for 2011/12. The performance of each feeder in 2012/13 was compared to its performance over the previous two years. Any significant increase in SAIDI and SAIFI or the number of interruptions meant a feeder was included in the list. The identified worst performing feeders are grouped as follows:

- Feeders with high SAIDI and SAIFI and 4 or more interruptions: Melling 7 (MEL7), Brown Owl 3 (BRO 3), Naenae 6 (NAE6), Wainuiomata 3 (WAI3); and
- Feeders showing significant increase in SAIDI or SAIFI with 3 or more outages: Wainuiomata 12 (WAI12), Waitangirua 11 (WAN11).

Reliability improvements and corrective maintenance programmes were carried out on these feeders during 2013/14 and the resulting improvements are notable, as shown in the graphs below.

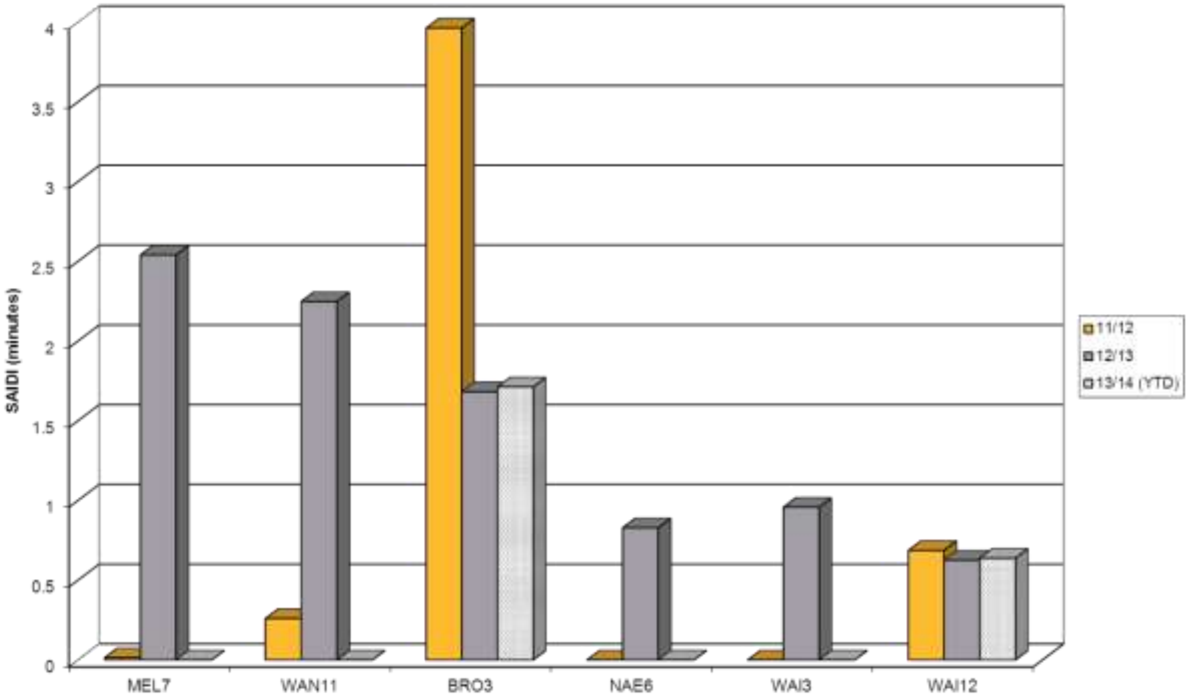


Figure 7-26 Improvement of the Worst Performing Feeders (2011/12 to 2013/14 YTD) - SAIDI

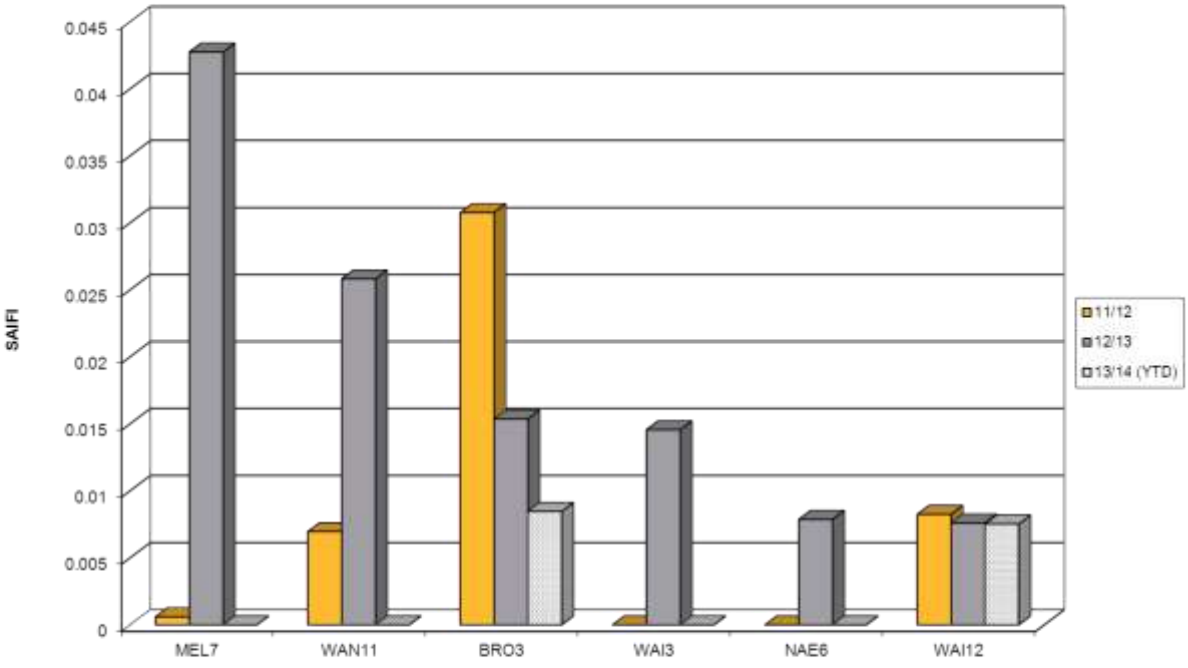


Figure 7-27 Improvement of the Worst Performing Feeders (2011/12 to 2013/14 YTD) - SAIFI

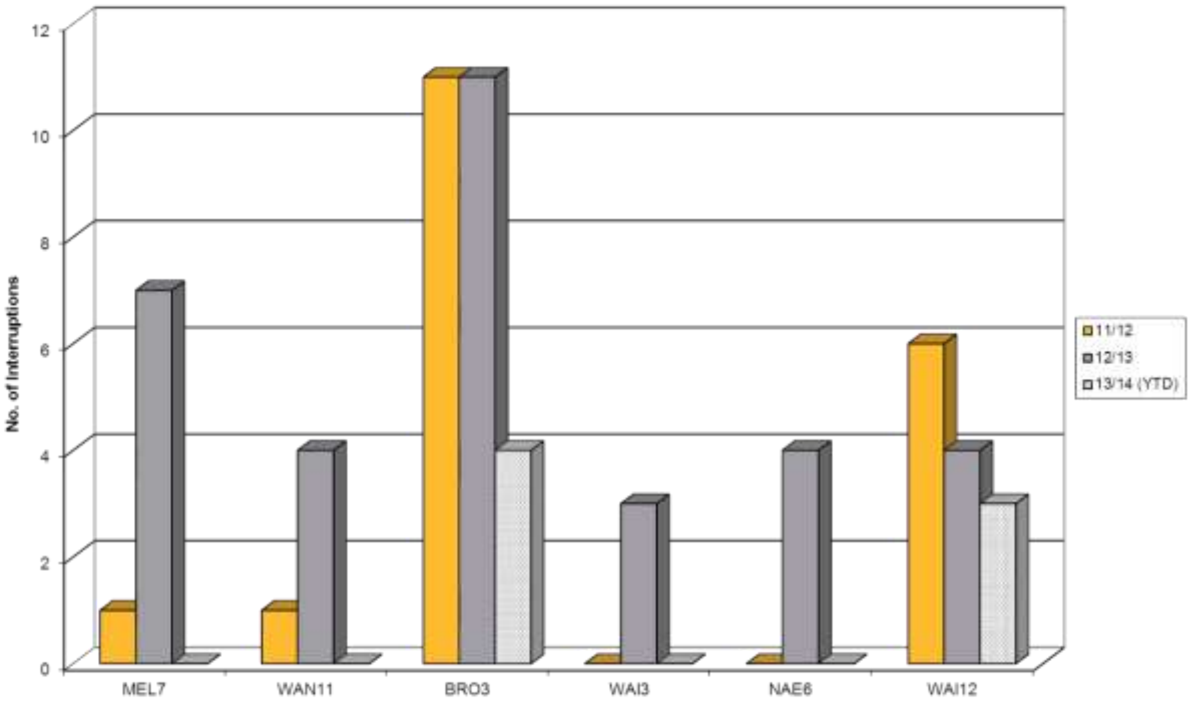


Figure 7-28 Improvement of the Worst Performing Feeders (2011/12 to 2013/14 YTD) by Number of Interruptions

Although the worst performing feeders identified in 2012/13 have improved in terms of SAIDI and SAIFI, the identified reliability programmes will still be carried out (where these are still to be completed) to ensure there is no further decline in performance.

The method used to determine the worst performing feeders for the current 2013/14 year was different from the 2012/13 year. This time there were three factors considered, SAIDI, SAIFI and the number of interruptions a feeder experiences in a year. The top 20 feeders from each category were subject to more intense scrutiny. Determining which feeders were the “worst performing” was based on whether a feeder was featured in each of the three categories below:

SAIDI – if the feeder has as SAIDI greater than or equal to 0.50 minutes;

SAIFI – if the feeder has a SAIFI greater than or equal to 0.005: and

No. of Interruptions – if the feeder has greater than or equal to 2 interruptions

Or, was included if the feeder performance had deteriorated significantly since the previous period in any of the three factors.

The worst performing feeders identified are shown in the figures below

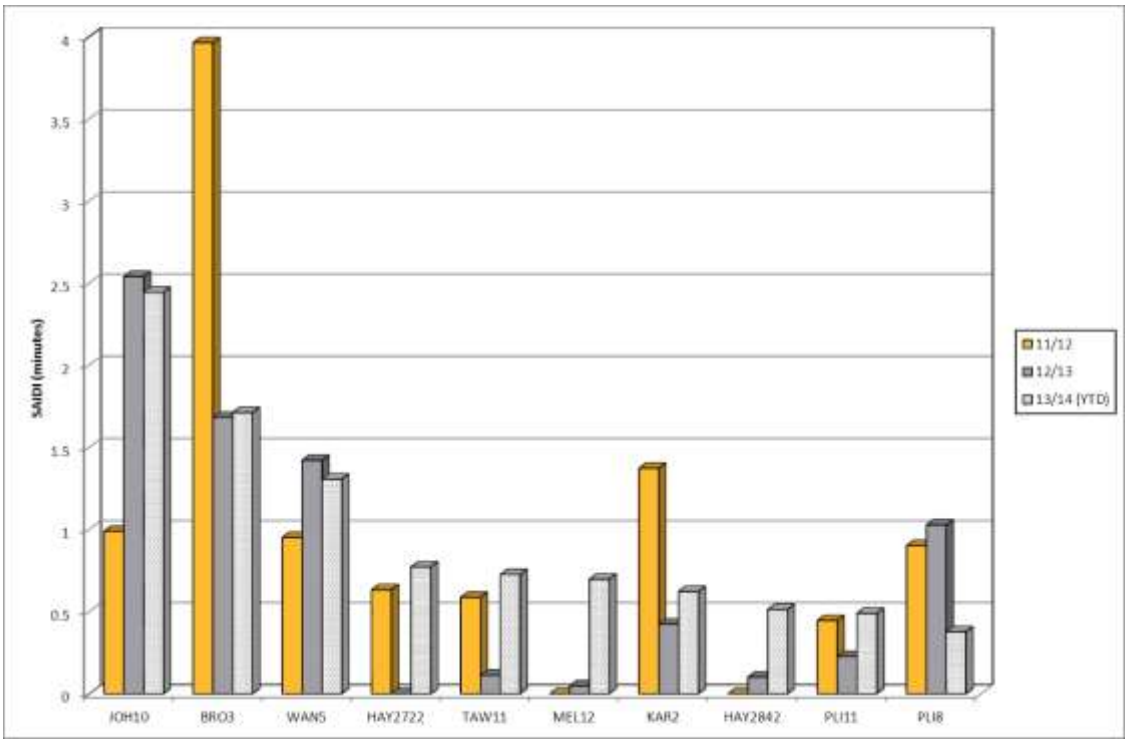


Figure 7-29 SAIDI of Worst Performing Feeders (2013/14 YTD)

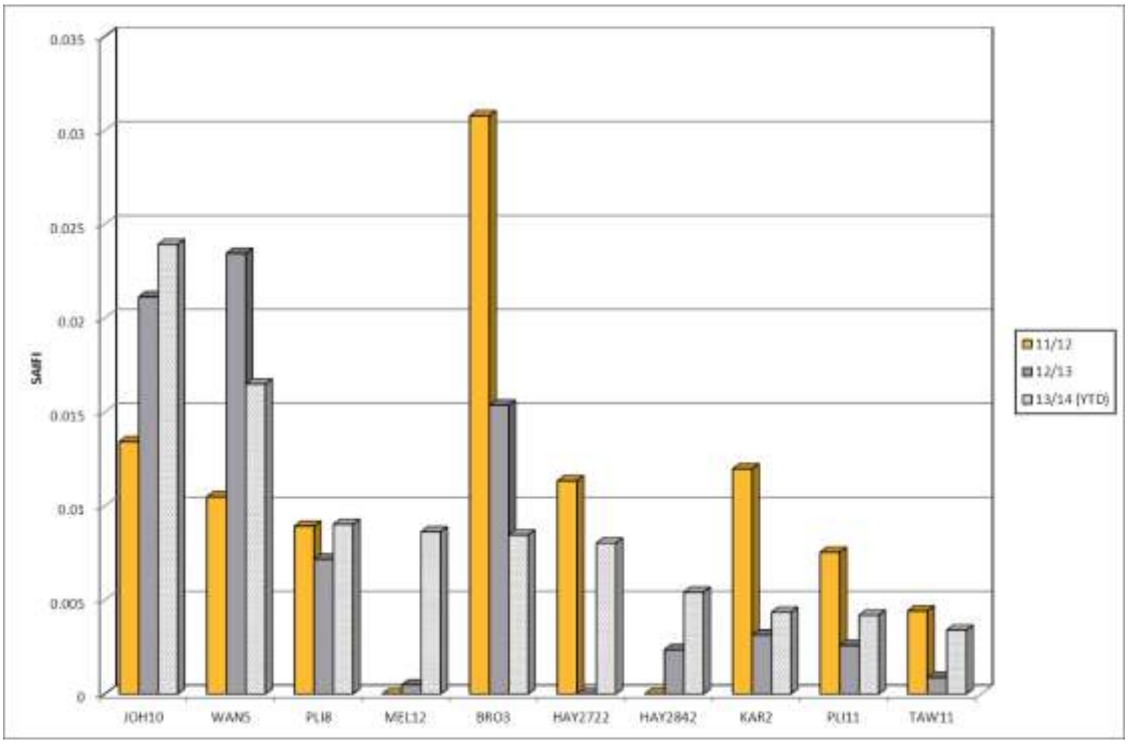


Figure 7-30 SAIFI of Worst Performing Feeders (2013/14 YTD)

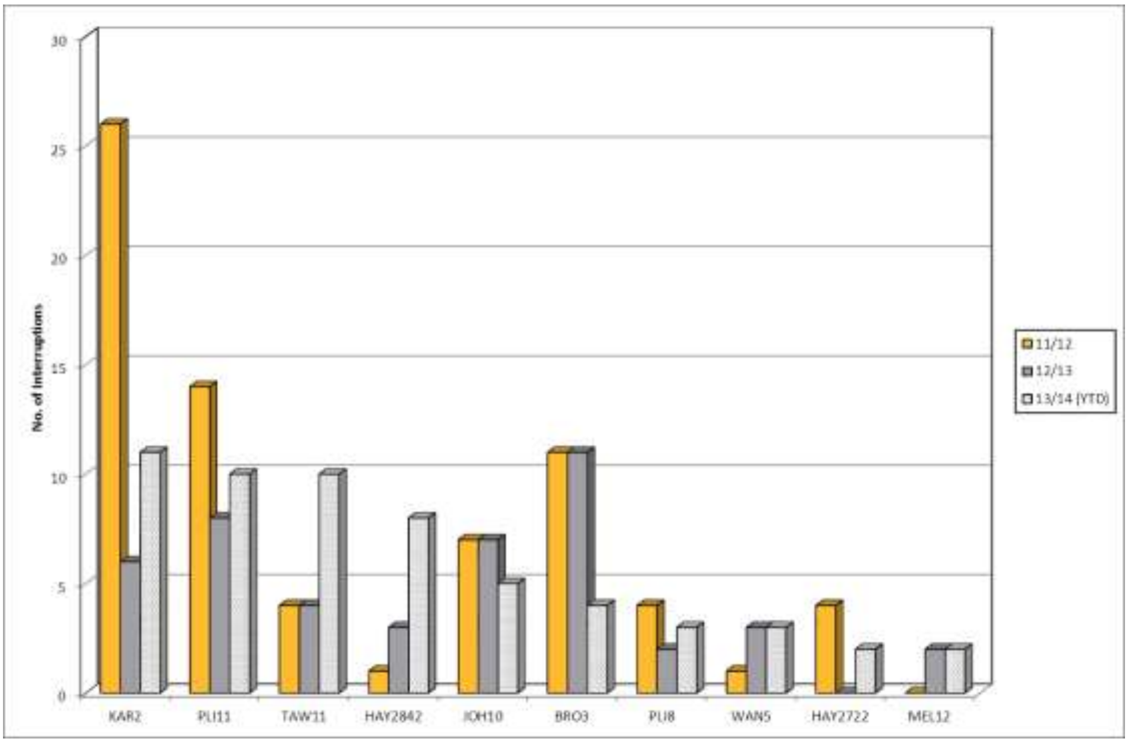


Figure 7-31 Interruption Count of Worst Performing Feeders (2013/14 YTD)

In summary, the worst performing feeders for 2013/14 are:

Feeder	2013/14 YTD Performance		
	SAIDI	SAIFI	No. of Interruptions
Johnsonville 10	2.44	0.02	5
Brown Owl 3	1.71	0.01	4
Waitangirua 5	1.31	0.02	3
Haywards 2722	0.77	0.01	2
Tawa 11	0.72	0.00	10
Melling 12	0.70	0.01	2
Karori 2	0.62	0.00	11
Haywards 2842	0.51	0.01	8
Plimmerton 11	0.49	0.00	10
Plimmerton 8	0.38	0.01	3

Figure 7-32 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 maintenance process, where the resulting activities are carried out either under corrective maintenance (OPEX), or as a network project (CAPEX), depending on the scope of the work required. It should be noted that although these are the “worst performing feeders” on the Wellington Electricity network, the worst feeder contributes less than 5% to the total network annual SAIDI and SAIFI. The remedial action undertaken or planned for each of the 10 worst performing feeders in 2013/14 is discussed in Section 7.5.4 below.

7.5.4 Reliability Improvement Programme

Johnsonville 10

Johnsonville 10 supplies a mixture of urban and rural load, with 931 consumers, predominantly located in the urban area, with only around 150 consumers in the rural area of Ohariu Valley. The majority of faults have occurred on the overhead lines in the area of Clifford Road, Ohariu Road and Cunliffe Street. A line refurbishment project in these areas is programmed in 2014. This will include line reconductoring, selected pole, crossarm replacements and insulator replacements.

Brown Owl 3

Brown Owl feeder 3 is a combination of underground cables and overhead lines and supplies 1,009 consumers. The overhead line supplies consumers in Akatarawa Road, which is heavily forested. Most of the faults on this feeder have been due to trees on the line. Brown Owl 3 will remain a priority feeder under watch by Wellington Electricity and Treescape.

Waitangirua 5

Waitangirua feeder 5 is a fully underground feeder in the area of Whitby East and Whitby West supplying 1,292 consumers. The two cable faults which occurred on the feeder in the past year are not conclusive evidence that the feeder's reliability is declining, as there was no common link between them. The underground cable was installed in 1975 and is expected to still be reliable. Cable diagnostic tests will be used to identify areas of cable with declining insulation performance to determine whether further failures are likely and whether cable replacement is required.

Haywards 2722, Tawa 11, Haywards 2842

Haywards 2722, Tawa 11, and Haywards 2842 are feeders with a combination of underground cables and overhead lines.

The overhead lines on Haywards 2722 are in the Pinehaven area, Tawa 11 supplies lines in Horokiwi Road, and Haywards 2842 in Manor Park and Belmont. All of these areas are heavily forested. Most of the fault causes in the last couple of years were due to trees on the line. These are priority feeders under watch by Wellington Electricity and Treescape.

Melling 12

Melling feeder 12 is a combination of underground cables and overhead lines and serves 857 consumers in the areas of Avalon and Taita. The feeder had two incidents of overhead equipment failures, one broken jumper on an air break switch (ABS) and a faulty insulator. The feeder was thoroughly inspected and corrective actions carried out to ensure reliability can be maintained.

Karori 2

Karori 2 supplies both urban load around Karori, where it is entirely underground, and the nearby large rural areas of Wrights Hill and Makara where it is overhead. The majority of the faults recorded on this feeder come from the Makara and the South Makara overhead section, which supplies about 190 consumers. It is a highly forested rural area and faults are usually due to animal and bird strikes, third party incidents, overhead equipment failures, as well as a number of undetermined causes.

A line refurbishment project in the Makara Road area is programmed to be completed in 10 stages .The first two stages have been completed and the third stage will commence in 2014. Similarly, in the South Makara area a line refurbishment project is programmed in 2014, which will improve the reliability in the area.

Plimmerton 11

Plimmerton feeder 11 is a rural feeder with the majority of the circuit being overhead lines running along Grays Road and Paekakariki Hill Road. Its circuit length is 54 kilometres but there are only 190 connected consumers. Faults recorded in this area are mostly due to vegetation, animals, vandalism, and third party incidents. A detailed pole-by-pole inspection of this feeder primarily identified vegetation issues. This feeder has been included in the priority feeder under watch by Wellington Electricity and Treescape.

Plimmeton 8

Plimmerton feeder 8 comprises mostly overhead lines in Plimmerton and Pukerua Bay and supplies 737 customers. No fault cause has been found for most of the faults that have occurred on this feeder, but it is suspected they have been caused by vegetation. This feeder is a priority feeder under watch by Wellington Electricity and Treescape.

7.5.5 Other Reliability Initiatives

All overhead feeders are subject to an annual inspection and other network equipment is inspected and maintained at prescribed intervals. Other initiatives to improve the speed and accuracy of fault finding and restoration include:

<u>Fault Passage Indicators</u>

Line fault indicators are widely used on the overhead network and earth fault indicators used on the underground network. These aid in the identification of faulty sections of the network and are particularly useful in areas that are difficult to access or where long feeders have many spur lines and tee points.

<u>Line Circuit Breakers / Autoreclosers</u>

Auto reclosers are used on most rural feeders to provide a fast, automated reclose function to clear transient faults such as bird strike, vegetation or line clashes in stormy weather. The use of automatic reclosers in strategic areas of the network also reduces the number of consumers affected in the event of a permanent fault on that feeder.

<u>Remote controlled overhead switches</u>

Remote overhead switches are used to enable remote operation of the network by the NCR, in conjunction with a fault man on the ground, to improve isolation and restoration times.

Removing equipment with operational restrictions

Across the network there are types of equipment with fault operation restrictions, in particular Yorkshire SO-HI switchgear. Being unable to operate these assets increases fault identification and response times. Replacement of SO-HI is underway, with equipment on high SAIDI feeders being given priority.

Overhead line refurbishments

Starting in 2010, a strong focus has been placed on the maintenance of overhead lines, particularly on the worst performing feeders. Ngauranga feeder 4, for example, had previously been the worst performing feeder on the network. In response, the feeder was subject to a more detailed inspection and an overhead line refurbishment carried out on the section of the feeder that had the most number of faults in the last five years. This refurbishment included replacement of conductor, cross arms, insulators and other line hardware. Overhead line improvements were also made to Korokoro feeder 9, and Ngauranga feeder 9, which have both experienced a dramatic improvement in reliability.

Overhead line refurbishment is a continuing programme. Two other feeders, Wainuiomata 7 (Coast Road) and Karori 2 (Makara) were on the list of worst performing feeders and are currently undergoing line refurbishments. These will be carried out in stages over the next 10 years. Two stages for both feeders have been finished and both projects are expected to be fully complete in 2022. These programmes have started with the worst performing sections, progressing through to the more reliable sections.

Another line refurbishment is underway on Ngauranga 9 – stage 1 was completed in 2013 and stage 2 is due to be completed in 2014. Additionally, as Johnsonville feeder 10 has shown overhead equipment reliability issues in 2013/14, a line refurbishment on this feeder is programmed for 2014. As performance is found to deteriorate in other parts of the network, these will be considered for refurbishment.

Installation of SCADA indication and control on distribution substations

In some areas, the installation of SCADA indication and control at selected distribution substations will improve the restoration time of a faulted section of a feeder. This SCADA would be installed at distribution substations on feeders with high numbers of consumers, separated by circuit breakers with protection relays (a legacy design of the Wellington Electricity network). It will provide for faster restoration of supply since it will allow the feeder to back-fed from another feeder faster through remote switching, following identification of the faulted network area. Network analysis is in progress to determine where the installation of SCADA indication and control on distribution substations will be most beneficial and cost effective. Examples are Normandale Bridge, Melling Railway and Churton Park substations – to be considered in the 2014 and 2015 programmes for protection and control. These improvements will be considered following the identification of root cause issues in order to reduce fault occurrences, achieve operational improvements and reduce response time after a fault has occurred.

8 Risk Management

8.1 Introduction

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 controls that are in place to manage identified risks need to be 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 5 and 6, management of these risks is fundamental to planning the network development, asset maintenance, refurbishment and replacement programmes described in this AMP.

The controls for each risk are considered in developing standard work practices. The level of control to lower each risk to an acceptable level will differ depending on the risk tolerance of key stakeholders and the circumstances and environment in which the risk may occur.

Risks associated with system assets are managed:

- Proactively - reducing the probability of asset failure through 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. Sections 5 and 6 of this AMP describe these network planning and asset maintenance strategies in some detail. In addition, Wellington Electricity's design standards, which are not described in detail in this AMP, are aligned with industry best practice and 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 detailed later in this section.

8.2 Risk Accountability and Authority

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.

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 is effective. Each risk control owner monitors the risk control and contributes towards the risk reporting framework.

In developing and implementing the risk management strategy, the CEO meets with senior management regularly to review business risks and controls. Strategic and operational risks categories are reviewed and reported in a risk register, while more detailed operational risks are captured in risk control procedures and processes. The risk management strategy and process is aligned with other CKI group companies ensuring consistency across the wider global business.

8.3 Risk Framework

Wellington Electricity adopts the Risk Management Standard ISO31000:2009 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 and residual 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 a risk register to capture the above information.

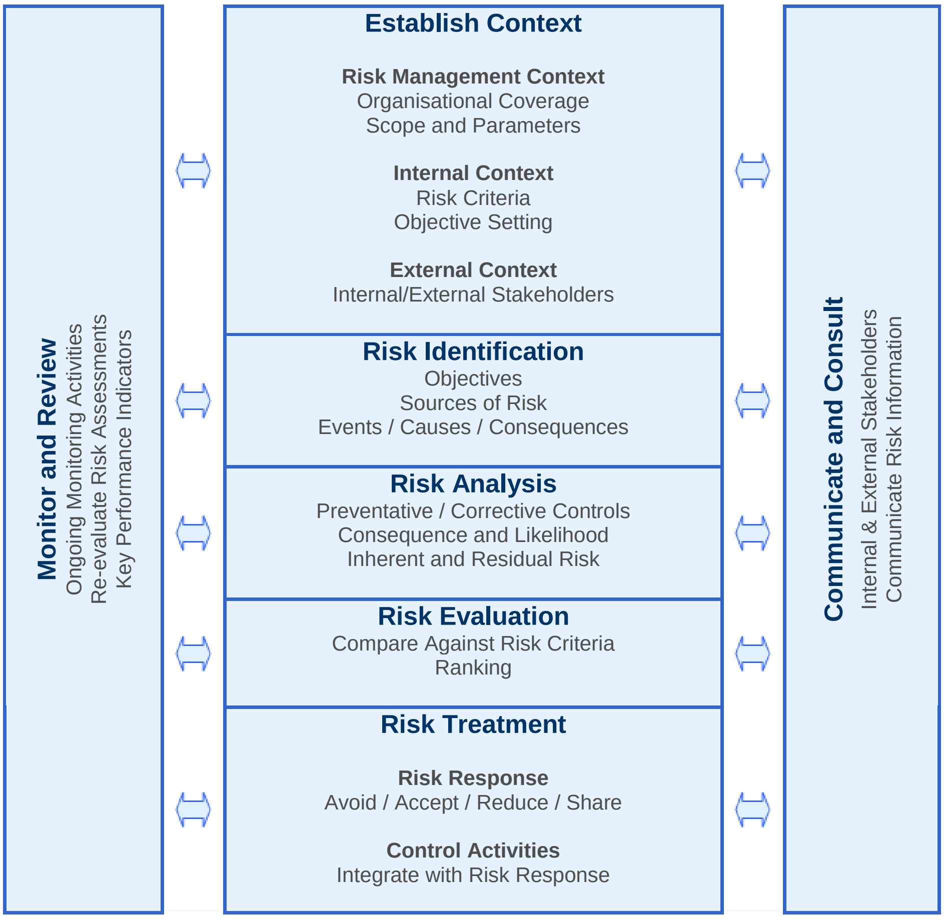


Figure 8-1 Risk Assessment Process

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.

8.4 Risk Rating

The magnitude of the consequences of a possible risk event needs to be based on the ***most likely or most realistic*** impact on the business and its stakeholders. The following risk profiling matrix is used to determine the level of the risk or risk rating based on a function of consequence and likelihood.

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 8-2 Levels of Risk Rating

Wellington Electricity uses the following consequence and likelihood criteria:

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

8.5 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 can be 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.

Risk score	Inherent Risk (Before Controls) 9500 / Extreme	Residual Risk (After Controls) 400 / High
Likelihood	95	25
	Almost Certain	Likely
Consequence	100	16
Compliance	Major	Minor
Customer Service / Reliability	Major	Minor
Employee Satisfaction	Major	Minor
Environment	Moderate	Minimal
Financial	$1m to $5m	$100k to $500k
Health & Safety	Major	Moderate
Reputation	Major	Minor

Figure 8-3 Example of Risk Scoring

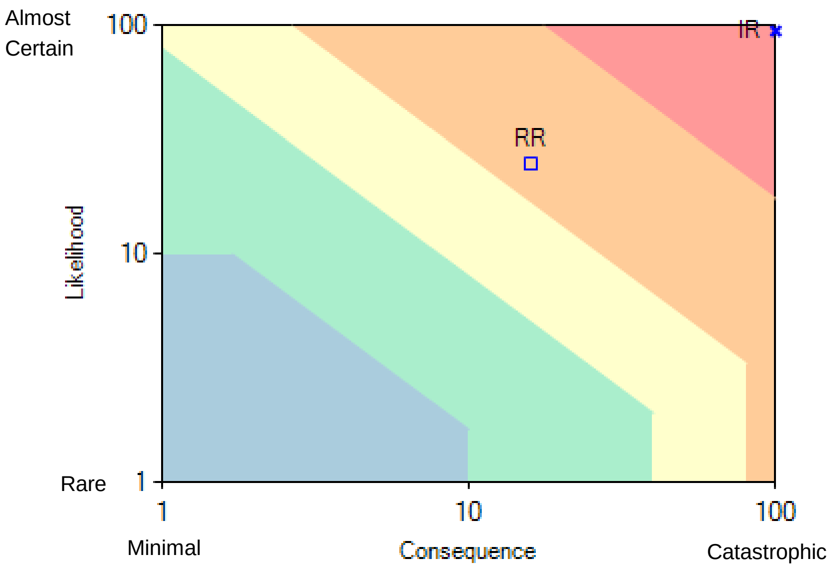


Figure 8-4 Example of Risk Methodology Application

8.6 Risk Application Example – Johnsonville Zone Reinforcement

8.6.1 Overview

As part of the ongoing analysis of network development planning it was determined that the subtransmission link between Transpower's Takapu Road GXP and Wellington Electricity's Johnsonville zone substation was not able to provide adequate capacity following an N-1 contingency event at times of high load. The N-1 capacity of the subtransmission link is constrained by the underground section of the circuit with a rating of 20/14.5MVA (winter/summer). The peak load at Johnsonville zone substation is approximately 22/15MVA (winter/summer) leading to a subtransmission N-1 shortfall in the order of 2MVA for winter peaks. As part of the subtransmission link, the zone substation power transformers and incoming switchgear are also constrained, as the subtransmission circuits were matched to the capacity and rating of the transformers and switchgear.

Johnsonville zone substation is supplied by two 33kV circuits from the Takapu Road GXP, which start as an overhead line through rural land and then change to underground cables for the last 5 kilometres into Johnsonville. Should a subtransmission fault occur at or near peak demand periods, some load can be transferred to adjacent zone substations via the 11kV distribution system. Initial high level studies indicate that the capacity of the 11kV distribution system is limited and insufficient to allow for load transfer away from Johnsonville as loads begin to grow in the short to medium term.

The Johnsonville area is experiencing higher than average growth (1.5% vs. system average of 0.4%-0.5%) as it has a large number of residential subdivisions being developed. Growth is forecast to continue given its proximity to the motorway and Wellington City and the presence of large tracts of undeveloped land. Commercial developments requiring loads in excess of 1MVA are currently in progress.

A detailed study was conducted which considered asset capability and loadings, network constraints, security and reliability criteria and overall business impacts.

8.6.2 Network Loading Constraints

Should a subtransmission circuit fault occur, the loading on the remaining circuit will be above cyclic ratings as illustrated in Figure 8-5. The most severe constraint is imposed by the winter cable rating, although summer cable rating limits are also an issue to a lesser extent. Transformer ratings are breached less frequently than the cable ratings. In the event of a cable or transformer outage, it is likely to be a long duration outage, with sustained overloading as subtransmission cables and zone transformers generally require long repair windows following a forced outage.

The 11kV distribution system has the ability to accommodate the temporary transfer of about 15% of peak load (3MVA) to adjacent substations by reconfiguring the open points. This type of temporary transfer will, however, compromise reliability due to increase in feeder loading of the adjacent feeders, increased consumer numbers on the feeder leading to higher than normal SAIDI and SAIFI impacts and significantly reduced post-contingency network switching capacity.

In emergency conditions a further 2MVA of load is estimated to be able to be dumped by offloading hot water load. This can be problematic to restore as the restored load will be much higher than the load initially dropped (as water cools down and thermostats switch back on). Both of these situations lead to no further capacity to deal with post-contingency events elsewhere in the area.

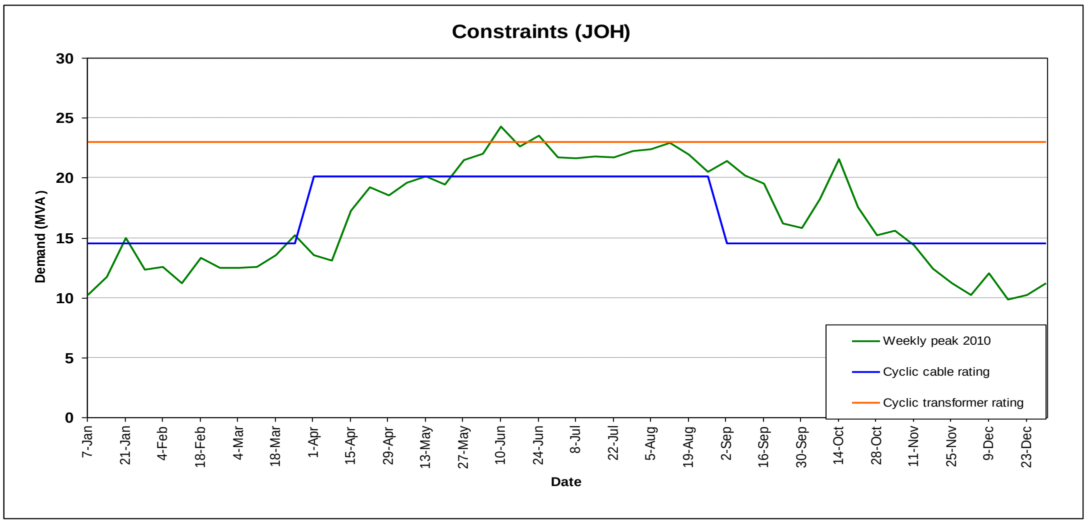


Figure 8-5 Johnsonville subtrans N-1 Equipment and Zone Tx Capacity Constraints (2010)

The constraint analysis illustrates that should a subtransmission cable be out of service at peak load times in the winter, the remaining cable will be loaded above its long-term cyclic rating. The frequency and magnitude of operation above rating is high at present, and exceeds Wellington Electricity's security criteria (Figure 8-6), and will increase as load growth continues in the area. Overloads will be more frequent during the winter period than in the summer.

Type of Load	Security Criteria
Mixed commercial / industrial / residential substations	N-1 with a break for 98% of the time in a year For the remaining times, supply will be restored within 3 hours following an interruption

Figure 8-6 Wellington Electricity's Security Criteria for Subtransmission Network

The load duration curve in Figures 8-7 and 8-8 illustrate that the overloading at Johnsonville has exceeded Wellington Electricity's network security criteria.

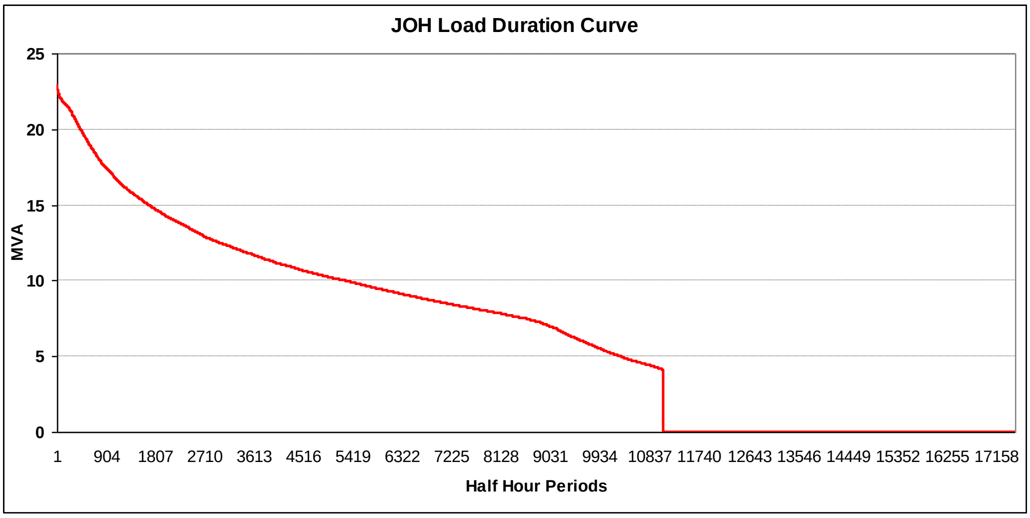


Figure 8-7 Load Duration Curve for Johnsonville Zone Substation

System Loading - Present	
Sub transmission single circuit rating	20.10 MVA
Circuit load at 98% availability	20.45 MVA
Subtransmission N-1 availability	97.5%

Figure 8-8 Wellington Electricity's Network Security Criteria Exceeded

8.6.3 Asset Capability and Loadings

There are two 11.5/23MVA 33/11kV transformers installed at Johnsonville; both were manufactured in 1969 and are in good overall condition as indicated by recent transformer and tap changer oil testing (DGA).

The 11kV switchgear comprises a board of 11 units of Reyrolle LMT with oil filled circuit breakers in acceptable condition. The switchgear fault rating is 13.1kA and the prospective fault current on the Johnsonville bus is 8.67kA, well within switchgear ratings.

The 0.35in^2 3c 33kV Al PIAS oil filled cables have circuit lengths of 5.05km and were installed in 1969. These cables are generally reliable and have not experienced modes of failure similar to gas cables installed on the network. The overhead section of these circuits is constructed from 'Butterfly' 19/4.64 bare AAC conductor which has a rating of 31/45 MVA summer/winter. This line is of the same age as the cables and is in good condition with an adequate rating. The circuit constraint exists in the underground cable, and also the transformer ratings.

Winter	**Circuit**	**Maximum Continuous Ratings**		
Temp=15C	1	281A (16.1MVA)		
STR = 1.2 C m/w	2	281A (16.1MVA)		
		Long-term Cyclic Ratings		
	1	351A (20.1MVA)	**367A (21.0MVA)**	Out of service
	2	351A (20.1MVA)	Out of service	367A (21.0MVA)
Summer		**Maximum Continuous Ratings**		
Temp = 23C	1	193A (11.03MVA)		
STR =2.15 C m/w	2	193A (11.03MVA)		
		Long-term Cyclic Ratings		
	1	240A (13.7MVA)	**254A (14.5MVA)**	Out of service
	2	240A (13.7MVA)	Out of service	254A (14.5MVA)

Figure 8-9 Johnsonville 33kV Subtransmission cable ratings

The risks can be summarised as follows:

1. Should a subtransmission fault occur on one circuit during peak load times, there will be a shortfall in network capacity at the Johnsonville zone substation which may not be met through switching at 11kV. This shortfall will occur if the contingency coincides with peak load, and is forecast to get worse as load grows in the area;
2. New consumer connection loads cannot be connected without adding to the loadings in the area, and therefore further compromising network security;
3. The disclosed security criteria for subtransmission supply to the Johnsonville zone substation has been exceeded and this situation will further deteriorate as load grows; and
4. Further transfer of load to other feeders without further network reinforcement will increase reliability issues, in particular with regard to consumer numbers on each feeder impacting SAIDI and SAIFI metrics, as well as potentially overloading the 11kV network.

8.6.4 Reinforcement Risk Assessment Process

Non-network options including distributed generation and demand side management have been considered but after evaluation were deemed not to be effective to address the risks identified at Johnsonville zone substation.

Three network options were identified:

Option 1 - the installation of an additional 33kV subtransmission circuit from Takapu Rd GXP to Johnsonville zone substation to operate in parallel with the existing circuits, plus reinforcement of the 11kV switchboard and circuit breaker ratings by retrofitting new circuit breakers. This was discounted based on the current acceptable condition of network assets and cost.

Option 2 – Transfer load to a new zone substation. This option would involve building a new zone substation of a similar configuration to Johnsonville, located within the Grenada Village area, to move load away from existing zone substations. This new zone substation would provide capacity for the high levels of growth occurring north of Johnsonville.

The 33kV subtransmission supply for this new zone substation would be from the existing Ngauranga 33kV overhead line which is presently leased from Transpower. (Resource management consenting would be required for the 33kV route.)

The benefits of this option are that it provides a long-term solution to create more capacity, and improves network security through adding another in-feed to the high growth Johnsonville area. The disadvantages of this option are the relatively high costs and long timelines associated with developing a new substation.

This option was not recommended as a short term solution for Johnsonville, as the development timeframe would be longer than ideal to address the immediate risks. However, it will need to be considered in the medium term if load growth continues at forecast rates.

Option 3 – Transfer load to an existing adjacent zone substation. The Ngauranga zone substation is adjacent to Johnsonville, has lower utilisation than Johnsonville, has experienced lower growth in recent years and has lower forecast load growth. Utilising this existing network capacity is a means of deferring major investment in new subtransmission capacity in the short to medium term.

This option involves reconfiguring the Johnsonville distribution feeders (JOH05 and JOH11) so that a portion of the 11kV load is supplied from a new 2.2km long Ngauranga feeder.

This option provides a medium term solution but as loads in the area continue to grow the N-1 capacity of the Johnsonville subtransmission system will once again be reached. A new zone substation (as per option 2) is forecast to be required north east of the existing Johnsonville substation in five years. This time frame may be extended if growth rates slow.

Option 3 was preferred and considered the most appropriate as it provides a short to medium term solution within a short construction time frame. Figure 8-10 shows the risk likelihood for the preferred option 3.

	Inherent Risk (existing system)	Residual Risk (option 3)
Likelihood	Should either a subtransmission or distribution fault occur during peak load times, there will be a shortfall in network capacity at the Johnsonville zone substation which could not be met through switching or load control. This shortfall will only occur if the contingency coincides with peak load **Classification** - Likely	The probability of a shortfall following the load transfer works is negligible **Classification** - Rare

Figure 8-10 Risk Likelihood for Preferred Option 3

	Inherent Risk (existing system)	Residual Risk (option 3)
Financial consequences	Loss of revenue and potential claims for compensation from affected consumers **Classification** - < $100k	No consequences. **Classification** – No impact
Health & Safety consequences	No H+S consequences **Classification** – No impact	No consequences **Classification** – No impact
Environment consequences	No environmental consequences **Classification** – No impact	No consequences **Classification** – No impact
Reputation consequences	Blackouts will attract some negative media coverage **Classification** - Moderate	No consequences **Classification** – No impact
Compliance consequences	No compliance issues **Classification** – No impact	No consequences **Classification** – No impact
Customer Service / Reliability consequences	Blackouts will affect consumers and impact on network reliability metrics **Classification** – Moderate	No consequences **Classification** – No impact

	Inherent Risk (existing system)	Residual Risk (option 3)
Employee satisfaction consequences	No consequences **Classification** – No impact	No consequences **Classification** – No impact

Figure 8-11 Risk Consequence for Preferred Option

Risk Analysis	Inherent	Residual
Likelihood	**25**	**3**
	Likely	Rare
Consequence	**16**	**0**
Financial	<$100k	No impact
Health & Safety	No Impact	No Impact
Environment	No Impact	No Impact
Reputation	Moderate	No Impact
Compliance	No Impact	No Impact
Customer Service / Reliability	Moderate	No Impact
Employee Satisfaction	No Impact	No Impact
Level of Risk (Risk Rating)	**392**	**0**
	High	Not Assessed

Figure 8-12 Risk Analysis Table for Option 3

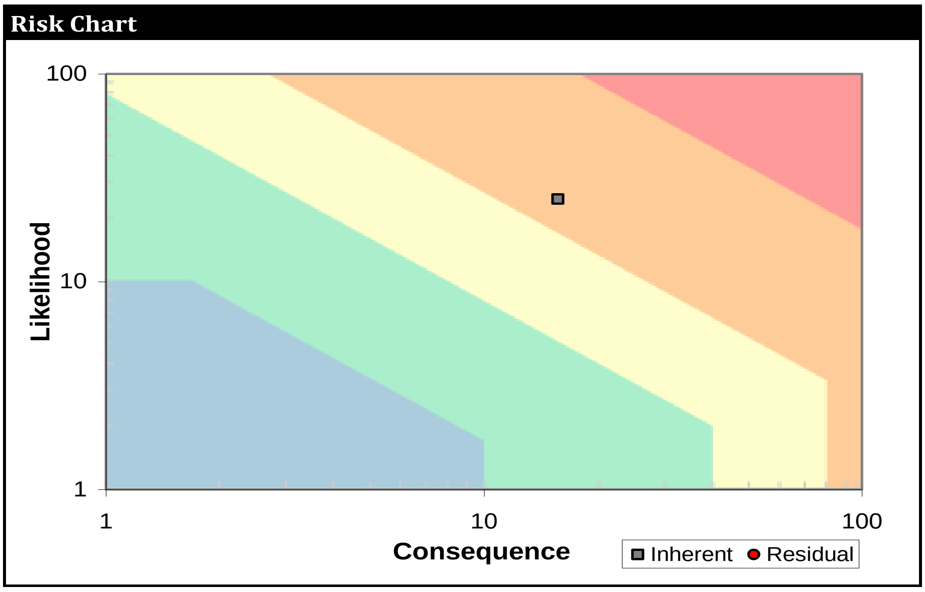


Figure 8-13 Risk Analysis Chart for Option 3

Note that the residual risk is zero and therefore does not show on the chart in Figure 8-13.

The outcome and recommendation of this risk analysis was collated into a business case and presented to the CIC in June 2011. The business case was approved and the cable reinforcement project completed in January 2012.

8.7 Risk Based Approach to Asset Management

The risk of an asset failure is a combination of the probability 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 revisions made to the Field Service Agreement in 2011, 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 5 and 6) is based on an assessment of the risk that each potential project carries.

8.8 Risk and Hazard Identification

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 problem and appropriate mitigation action.

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

8.9 Specific Network Risks

There are a number of areas within a network business where certain types of assets can exhibit performance that is sub-optimal, or they 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.

Rank	Event	Inherent Rating	Residual Rating
1	Inadequate management and/or supervision of contracted (i.e. outsourced) activities (including contractor resources)	Extreme	High
2	Injury or Damage caused or loss suffered to third parties	Extreme	High
3	Catastrophic earthquake and/or Tsunami that causes significant damage to Company assets	High	High
4	Sub-optimal performance or failure of network assets	Extreme	Medium
5	A loss of connection supply from transmission assets	Extreme	Medium
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
7	Release or spread of hazardous materials, Electromagnetic Fields (EMF) or noise to land, ecosystems or atmosphere	Extreme	Medium
8	Mis-Management of a crisis and emergency affecting the Network	Extreme	Medium
9	Failure of a retailer, customer, supplier or contractor to perform their contracted obligations, including financial obligations	Extreme	Medium
10	Taxation authorities dispute Business' position on tax treatments	Extreme	Medium

Figure 8-14 Summary of Top Ten Network Risks

The risk profiling process identified no (current) extreme residual risks and three 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.

Each risk has a risk treatment plan to reduce the residual risk as far as practicable. These risk treatment plans will be managed in conjunction with the risk owners and monitored to ensure that Wellington Electricity is taking proactive steps to mitigate the risk. The risk treatment plans include a simple cost benefit analysis to assess the practicability of the improvement options and assist decision making. The plans also document the acceptance of the risk at this level. Reporting on the status of high-level business risks is made to the SMT and the Board via the Audit and Risk Committee.

The 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

Ranking	Control Name
7	Incident Reporting & Investigation processes and standards
8	Crisis & Emergency Management System
9	Contract Management and Documentation
10	Auditing and Compliance

Figure 8-15 Summary of Top Ten Network Risk Controls

8.10 Network Resilience

New Zealand and the Wellington region in particular, is seismically active with known fault lines. There is a risk from liquefaction in some areas and risk from tsunami 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. During 2013, two strong earthquakes in Seddon affected the Wellington area, causing superficial 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 roading networks.

Wellington Electricity has developed a suite of Emergency Response Plans to respond to a number of incidents and events which would affect our network. These include Business Continuity, Crisis Management and Major Event Management Plans as described in Section 8.12. In preparing for the 2012 Lifelines Report (refer to 8.10.2), improvements to these plans were identified. Further learnings from the June 2013 storm are also being incorporated into these plans.

8.10.1 Reinforcement and 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 earthquake 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 do include seismic resilience expenditure to meet Building Code compliance, which will need to be recovered through future lines charges.

The assessment of building strength and the subsequent reinforcement is a legislative change imposed by local government resulting in an increase in costs for Wellington Electricity. The costs of these additional network resilience investments has been included in forecast capital and operating expenditure. In addition to improving the strength of buildings, Wellington Electricity has identified other areas where the resilience of the network could be enhanced through strategic investment, which is discussed below.

Improving the resilience of earthquake prone buildings supports local communities and the economy to return to normal as soon as possible after an earthquake event. The report by the National Infrastructure Unit "Infrastructure 2012: National State of Infrastructure Report: A Year on from the National Infrastructure

Plan"[16] considers the level of resilience of New Zealand's infrastructure and whether the current regulatory settings facilitate the level of investment needed to meet long-term infrastructure needs.

There have been a number of lessons learned from the Canterbury earthquakes regarding the benefits of resilience investment. Orion identified that an upfront investment of $6 million on strengthening buildings in the 1990s resulted in savings of approximately $60 million in the reconstruction of its network and also significantly reduced the time required to restore supply following the earthquakes. Based on this ratio of 10%, if applied to Wellington Electricity network, an investment of around $30 million now would protect around $300 million of assets from earthquake damage, or improve supply restoration times which provides a significant economic benefit to stakeholders. Wellington Electricity has identified, in addition to the building seismic issues discussed above, the following areas where resilience can be improved on the network:

- Subtransmission cables - The two subtransmission cables supplying a single zone substation are usually installed over the same route and are thus at risk of a common mode failure, as occurred in Christchurch following the earthquakes. In conjunction with local authorities, Wellington Electricity is identifying suitable routes for emergency overhead lines in order to reduce the time required to restore supply following such an event. This is discussed further in Section 8.10.5; and
- Storing strategic spares in various locations around the Wellington Region, so that the equipment required to construct certain emergency overhead lines is readily available.

The forecast expenditures in this AMP include provisions for completing these initiatives. This earthquake resilience expenditure will improve the security of supply into Wellington, reduce restoration times for vulnerable cable assets and enable substation buildings to remain operational following an earthquake.

At the time of writing, the Building (Earthquake-prone Buildings) Amendment Bill 2013 is being considered by Parliament to "improve the system for managing earthquake prone buildings". If passed into law, this will increase Wellington Electricity's obligations to assess and strengthen substation buildings, with a corresponding increase in costs to the business. The impact on the seismic programme, should this Bill pass into law, is not yet known. However, it is likely to increase the number of buildings to be assessed by around 150, and reduce the time allowed for building strengthening by at least 5 years. This would increase the requirement for capital investment over the period 2015-2020 above what is provided for in the forecasts included in this AMP.

The expenditure forecasts in this AMP include the additional investment shown in Figure 8-16 to address earthquake resilience improvements for buildings to meet requirements under current legislation and to provide for emergency overhead line corridor development for restoration of key subtransmission supplies. Further details of Wellington Electricity's short-term plans for improving the resilience of its substation buildings is provided in Section 8.10.4 and emergency overhead lines in Section 8.10.5.

For the avoidance of doubt, this investment does not include expenditure that will be necessary to meet the additional requirements of the Building (Earthquake-prone Buildings) Amendment Bill 2013, should this Bill be passed into law.

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[16] *Infrastructure 2012: National State of Infrastructure Report: A Year on from the National Infrastructure Plan* prepared by National Infrastructure Unit, The Treasury, http://www.infrastructure.govt.nz/plan/2011implementation/2012report

Investment Area	Total	2014/15	2015/16 to 2017/18	2018/19 to 2022/23
Substation Seismic Assessment (OPEX)	$1.6 million	$0.8 million	$0.8 million	-
Substation Seismic Strengthening (CAPEX)	$26.4 million	$1.2 million	$11.2 million	$14.0 million
Emergency OH Line Project Planning (OPEX)	$0.3 million	$0.1 million	$0.2 million	-
Emergency OH Line Project Strategic Spares (CAPEX)[1]	$0.75 million	-	$0.75 million	-

1: 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.

Figure 8-16 Overview and Cost Estimate for Resilience Investments

8.10.2 Wellington Lifelines Group (WeLG)

Wellington Electricity is an active participant in the Wellington Lifelines Group (WeLG). WeLG 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 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. Further work is required to better understand the interdependencies between the various utilities, and what each parties' needs are. The report was published in 2013. Wellington Electricity will continue to engage with WeLG.

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.

8.10.3 Identification and Management of High Impact Low Probability Events

Wellington Electricity identifies High Impact Low Probability (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.

8.10.3.1 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. These plans are detailed in section 8.12; and
- Recovery – understand requirements for contingency plans to invoke a staged and controlled restoration of network assets and supply capability.

8.10.4 Seismic Reinforcing of Equipment and Buildings

Wellington Electricity is proactive in surveying and identifying potential seismic issues with regards to 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.

Figure 8-17 Zone Substation Power Transformer Seismic Restraint Footing

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 a new building. 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 30 IEPs from Councils to date. Wellington Electricity has also contracted independent local structural consultants who have assessed and reviewed the resilience of 59 buildings - in response to unfavourable council IEPs or in relation to planned capital works improvements. The independent structural consultants have assessed and confirmed that 15 buildings are earthquake prone buildings meeting less than 34% of the New Building Standard (NBS). In 2011, one building (70 Adelaide Rd) was reinforced to 67% of NBS, and there are designs in progress for the strengthening of several sites in 2014. When strengthening work proceeds, this will bring the substation above 34% NBS and they will no longer be classified as earthquake prone. It is not always efficient to bring the building up to 67% NBS; however 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.

Wellington Electricity has embarked on a programme of assessment of substation buildings with the aim of assessing between 50 and 100 buildings per annum over the period to 2016, to understand the risk associated with its building-type substations. At the completion of this work, a more accurate assessment of the required level of capital investment will be known. This is also discussed in Section 6.4 (Maintenance and Renewal Programmes).

Accordingly, Wellington Electricity has reviewed its policy on the categorisation, assessment and management of substation building seismic strength and requirements for reinforcing. The revised policy provides the business guidance on the risk and importance of each Wellington Electricity owned substation building and establishes the priority that would be required for the programme of reinforcement works.

Wellington Electricity's design and construction standards and specifications for new construction comply with current seismic design codes.

The known sites that require seismic upgrades (as a result of having strength < 34% of NBS) during the planning period are:

Substation	Building Type	Year Assessed	NBS Result	Current Action
Newtown	Distribution Sub	2011	14%	Design in progress, to strengthen 2014
Chaytor St	Distribution Sub	2012	33%	Design scheduled for early 2014
Herd St	Distribution Sub	2012	15%	
9 Duncan Tce	Distribution Sub	2012	25%	Design scheduled for early 2014
21 Tory Street	Distribution Sub	2013	8%	Design in 2014
176 Wakefield St	Distribution Sub	2013	30%	
Cornwell Street	Distribution Sub	2013	16%	To be demolished
Ghuznee Street	Distribution Sub	2013	8%	Design in 2014
Karori	Zone Substation	2013	20%	Design completed, to strengthen 2014
Naenae	Zone Substation	2013	20%	
Gracefield	Zone Substation	2013	30%	Design and strengthen 2014
449 Jackson St	Distribution Sub	2013	20-33%	
Moana Rd	Distribution Sub	2013	20-33%	
Rutherford St	Distribution Sub	2013	20-33%	
Evans Bay	Zone Substation	2013	20-33%	Design 2014, Strengthen 2015

Figure 8-18 Known Sites that Require Seismic Upgrade

One of these sites, Cornwell St, has been found to be earthquake prone but, as described in Section 6, a project has been approved to decommission this substation and it will therefore be demolished.

The sites with their NBS Result highlighted in yellow 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.

8.10.5 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. Wellington Electricity has engaged with WCC 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 has 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 2014 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 will be undertaken in 2014.

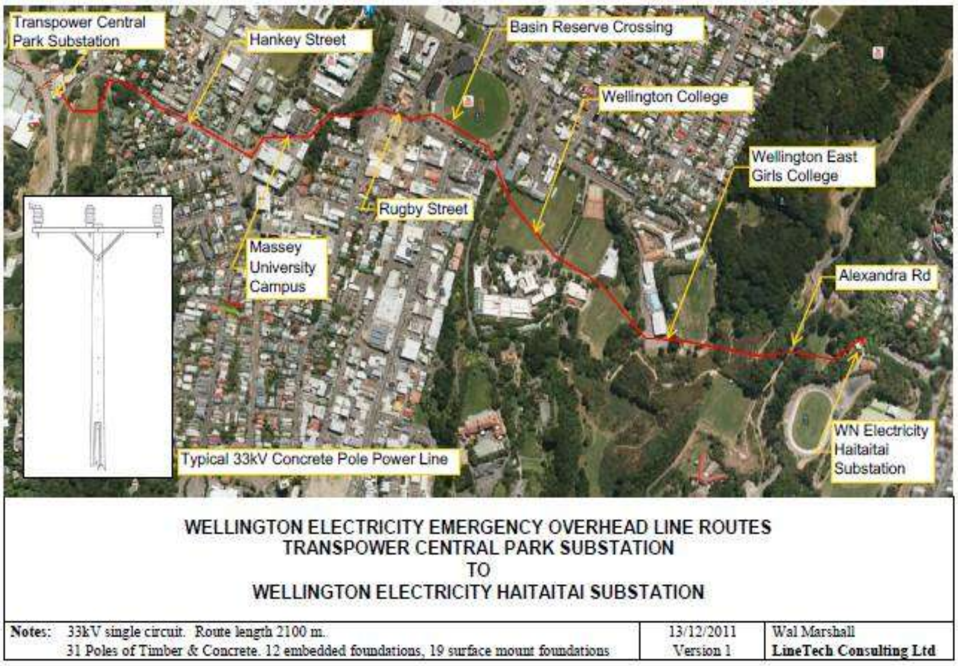


Figure 8-19 33kV Emergency Overhead Line Corridors (Example only)

The prototype of the surface foundation structure shown in Figure 8-20 has been fabricated and a testing regime is being developed to prove the concept in 2014. 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.

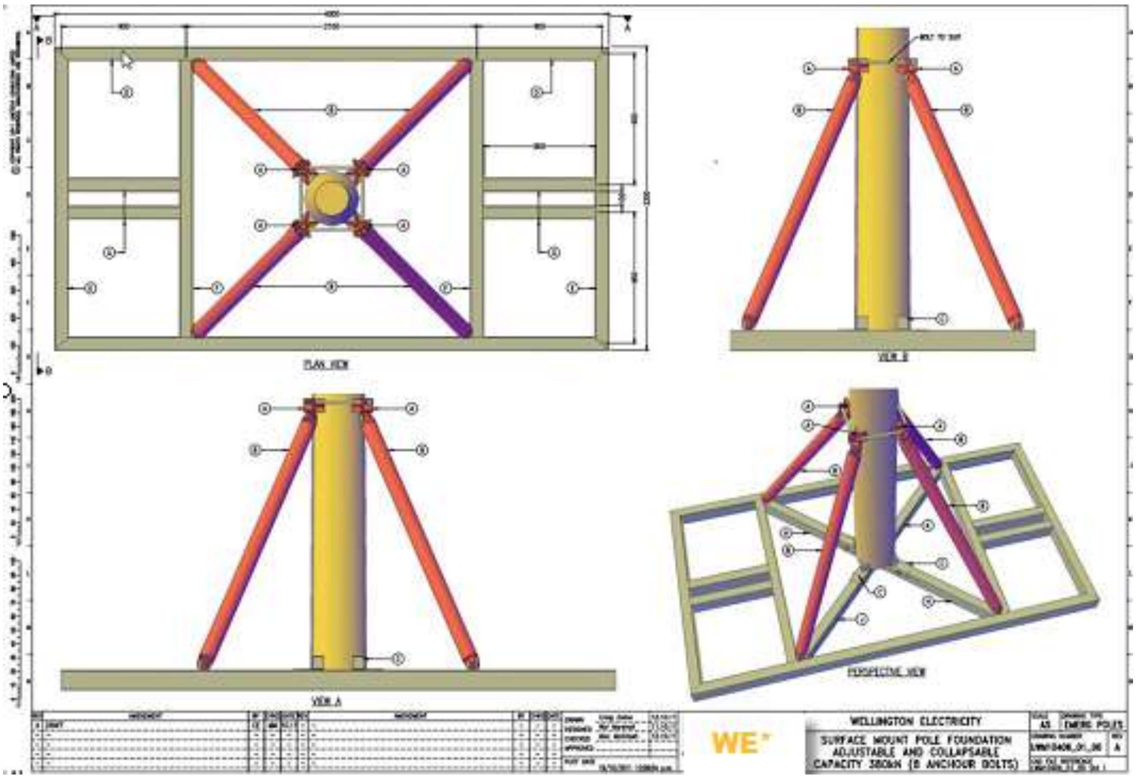


Figure 8-20 33kV Pole Structure Supports (Example only)

8.11 Insurance

8.11.1 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 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 2012, 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 indicated a low probability of a significant seismic event from known earthquake faults and, in any event, estimated losses to insured assets were within existing insurance limits.

Wellington Electricity will continue to work with the wider CKI 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, insurance capacity for Wellington based risks has become more difficult to source. Accordingly, Wellington Electricity has engaged other markets, notably the Australian, Singapore and London markets, to ensure competitive insurance cover is maintained.

8.11.2 Insurable Risks and Increased Insurance Premiums

Tightening of the insurance markets has resulted in Wellington Electricity's Business Interruption insurance cover now being solely linked to revenue loss only from insured assets that sustain damage. A significant number (80% by replacement value) of electricity distribution and transmission assets are not insured.

Wellington Electricity insures around 20% 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. Wellington Electricity does not insure its transmission and distribution assets (lines and cables) as insurance cover is very restricted and expensive. Insurance cover for these types of assets (poles, cables and wires etc) is currently only available from a small number of global reinsurers and typically excludes damage from windstorm events. Consumers would also have to pay significantly higher lines charges to cover the expensive premium cost.

The significant increase in insurance premiums experienced in 2011 and 2012 is forecast to continue, albeit at a lesser rate for the next few years. Given the significant cost and restrictive nature of additional insurance cover, Wellington Electricity will seek to recover the fair and reasonable cost for restoring power supplies following a major natural disaster such as a significant earthquake, from customers in the same way that Orion did following the 2010 and 2011 Canterbury earthquakes. However, it is expected that the proposed resilience expenditure identified elsewhere in this AMP, will assist in lowering the post-event cost of restoration for consumers in such a scenario.

8.12 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 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.

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

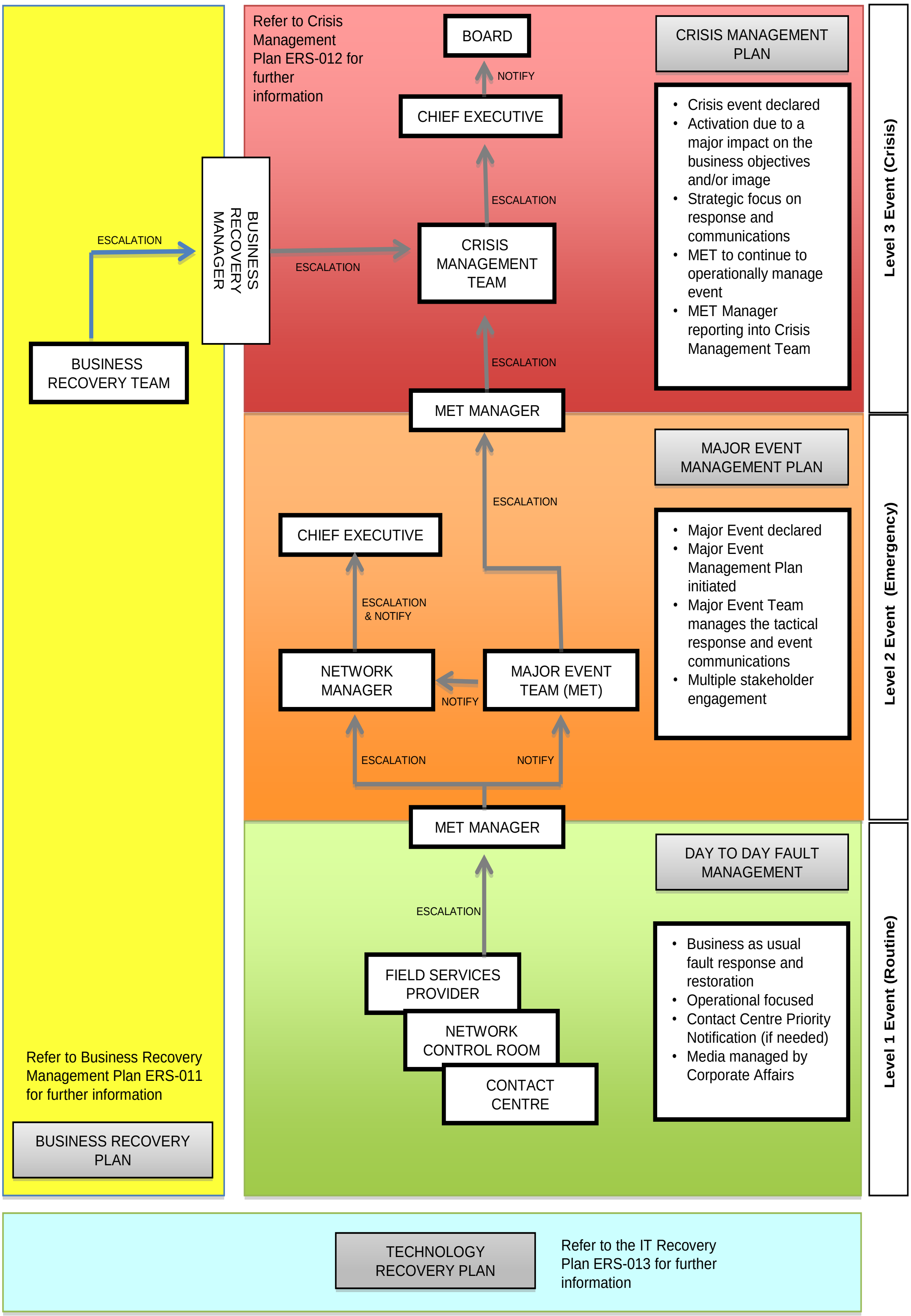


Figure 8-21 Emergency Response Escalation Framework

8.12.1 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. This plan was tested during 2012 in conjunction with the Major Event Management Plan simulation.

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

8.12.2 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 2011 and 2012 to stress test the MEMP process and the major event team roles and responsibilities. This plan was not simulated in 2013; however the major storms in June 2013 put this plan into action in a live situation as the business responded to one of the largest storms to hit the area in the past 50 years. Several “real life” learnings from the storm, response, which could not have been foreseen during simulations, have fed back into business continuity plans.

8.12.3 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 desktop simulation exercise was completed in 2011 and again in 2012, which assisted in identification of the necessary business recovery infrastructure provisions and key business recovery timeframes. This plan will be tested again during 2014.

8.12.4 Information Technology Recovery Plan

The purpose of this plan is to ensure that Wellington Electricity IT systems are able to 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 tested in 2012 and a number of improvements were identified and actioned.

8.12.5 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. The plan can escalate to the MEMP if required.

8.12.6 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.

8.12.7 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.

8.12.8 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.

8.12.9 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.

9 Quality, Safety and Environmental

Wellington Electricity is committed to excellence in meeting Quality, Safety and Environmental (QS&E) requirements through the following principles:

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

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

Safety is a priority business value. Wellington Electricity employees and contractors are required to 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 incidents, near misses and accidents.

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

9.1 Community and Public Safety

9.1.1 Public Safety Management System (PSMS)

Wellington Electricity has developed a Public Safety Management System (PSMS) that defines policies, procedures and guidelines relevant to the safe design and management of assets that are installed in public areas. The PSMS sets out procedures for the management of these assets to ensure they do not pose a risk to public safety. It meets the requirement for EDBs to implement and maintain a safety management system for public safety in accordance with Regulation 47 and 48 of the Electricity Safety Regulations 2010 (ESR).

The PSMS also meets the requirements of NZS 7901:2008, Electrical and Gas Industries – Safety Management Systems. In 2012, the certification body Telarc assessed Wellington Electricity against the requirements of NZS 7901. Some minor non-conformances were identified in the audit report and these were addressed accordingly. A revisit by Telarc in February 2014 confirmed that Wellington Electricity is compliant with annual certification requirements.

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

9.1.3 School Safety Programme

Wellington Electricity has developed an education programme for schools, which teaches children about electrical safety. The Stay Safe programme is aimed at primary school aged children and delivered in schools around the Wellington Region by Wellington Electricity. The programme involves showing a DVD, an 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.

To date Wellington Electricity has visited 52 schools and presented to over 4,850 young primary school students.

9.1.4 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.

9.1.5 Media Advertising

Wellington Electricity understands the importance of raising public awareness about the dangers of living and working around our network assets. In 2011 Wellington Electricity initiated a radio safety campaign that covered 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 2012 a new radio safety campaign was launched, which refreshed the message of safety with similar themes. Wellington Electricity will continue raising awareness of tree hazards in 2014 through newspaper advertising.

9.1.6 Safety Seminars and Mail Outs

In order to prevent third party contact with the Wellington Electricity network, the Quality Safety and Environmental Manager periodically delivers safety seminars to civil contracting companies (third party contractors working around Wellington Electricity assets). The safety seminar raises awareness of safe working practices when working around the network and particularly 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. Since 2009, over 200 local contractors have received training in working safely around the network.

9.1.7 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 you need to work safely* is handed to those attending safety workshops and in mail-outs to various contracting sectors that interface with the network.

9.1.8 Information and Value Add Services

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

The table below shows the number and type of information service requests over the last four years.

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

Figure 9-1 Summary of Information Service Requests 2010-2013

In 2013, there were increases in the number of Service Map Requests, Close Approach permits issued, and Standovers, There has been a reduction in Cable Locations since 2012 when there was a significant increase in calls relating to cable locations, which is attributed primarily to commencement of the Government funded UltraFast Broadband (UFB) project in the Wellington Region. Cable locations are still sitting at higher numbers than 2010 and 2011. Unfortunately, Chorus and its contractors continue to strike Wellington Electricity cables.

9.2 Workplace Safety

9.2.1 Safety Breakfasts and Safety Day

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 publicly recognise and celebrate examples of good safety behaviour and practice. On average, over 200 people are catered for at the sessions, with breakfast cooked by the Wellington Electricity management team.

In 2013, Wellington Electricity ran a Safety Day for all internal personnel and Contractors at an offsite location. This consisted of two half day sessions, comprising a range of safety messages, videos and presentations, as well as key note speakers on the topic of workplace safety. This day was intended to raise awareness of safety, to increase worker engagement, and to provide real world messages in a way that many could relate to. This day was well received and feedback was positive and is expected to become an annual event.

9.2.2 Site Safety Visits

An initiative launched in 2011 provides for Wellington Electricity personnel to undertake familiarisation visits to sites where contractors were working on the network. The site safety visits are used to discuss safety systems and opportunities for improvement.

During 2012 57 site safety visits were undertaken, increasing to 66 site safety visits in 2013. The goal for 2014 is to get employees into the field for at least five site visits.

9.2.3 Safety Leadership Committees

Wellington Electricity holds a monthly Safety Leadership Committee meeting to monitor performance, discuss emerging trends or new issues and progress on key improvement areas.

During 2012, Wellington Electricity established a staff Health, Safety and Environmental Committee. This staff committee is working towards attaining tertiary level ACC accreditation for Wellington Electricity.

9.2.4 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 they are doing.

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.

9.3 Health and Safety Performance

9.3.1 Overview

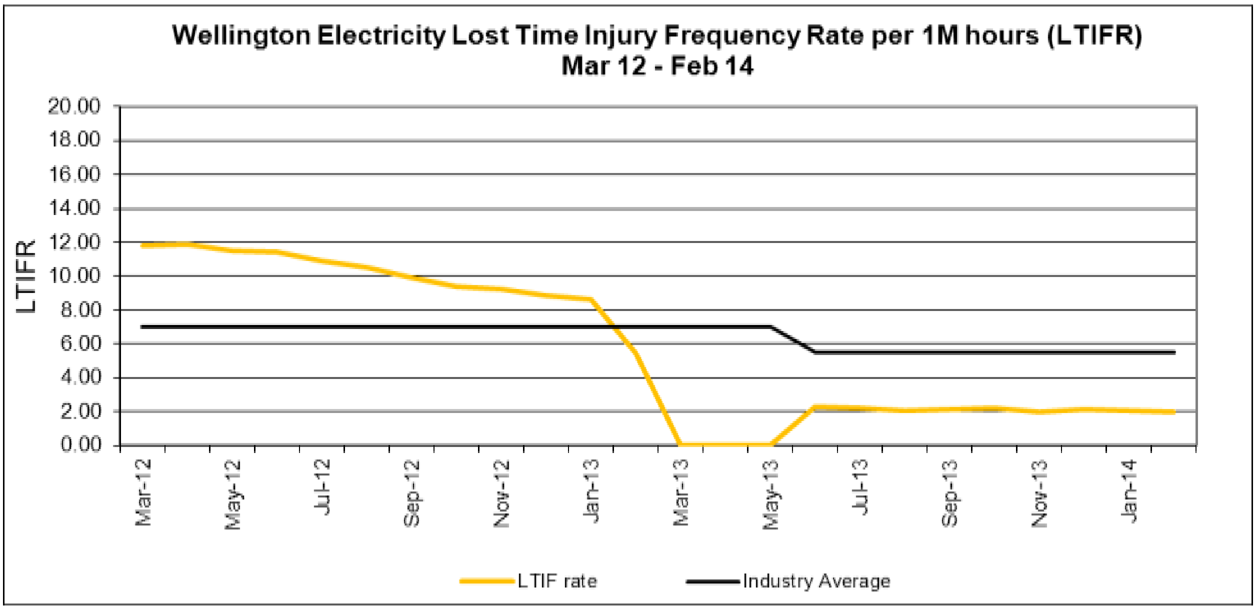
Wellington Electricity has continued to build on its strong foundations of past HSE performance and has noted some significant improvements during 2013. In addition to those previously detailed, notable performance improvements include:

- A positive change in safety culture through an increase in the reporting of events that 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, more timely close-out 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.

9.3.2 Lost Time Injury Frequency

Wellington Electricity recorded one lost time injury (LTI) incident during 2013, which occurred during the major storms in June 2013; this resulted in a LTI Frequency Rate (LTIFR) of 2.09 per million hours worked.

This is considered a major accomplishment, given that the only injury resulting in lost time occurred during the major storm event, when over 200 workers were restoring power on the network over a 10-day period. The worker was injured whilst clearing vegetation from fallen lines. The severity rating of the injury was moderate and the injured worker has been rehabilitated back into the workforce.



(Source: Industry Average – Electricity Engineers Association)

Figure 9-2 Lost Time Injury Frequency Rate

9.3.3 Incident and Near Miss Management

During 2013, Wellington Electricity continued to implement initiatives aimed at increasing the reporting rates of “incidents” or “near miss” events. Total event reporting increased slightly in 2013 to a total of 416 events. Approximately 60% of all reported events were classified as minor, 27% were classified as moderate, whilst only 11% were of a serious nature. The total number of “near miss” events reported during 2013 was 174, 80% of the previous year’s “near miss” reports. This reduction in “near miss” reports is offset by an increased focus on hazard management resulting in 94 new field hazards reported.

Reporting of loss events (an incident which resulted in some form of loss, damage or injury) during 2013 also decreased with a total of 155 incidents reported. The majority of these were of a minor nature and very few resulted in more than minor loss.

9.3.4 Contractor 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’s technical standards. There has been significant focus during 2013 on the quality of project manager field assessments. Actions include one-on-one training with the Wellington Electricity Field Compliance Assessor, attendance at a traffic management course, setting targets for the number of assessments to be undertaken by project managers, improved scrutiny of the quality of assessment reports and provision of report writing and corrective action identification guidance.

While the number of corrective actions has increased in the last two years, as shown in Figure 9-3, this is due to an increase in the number of assessments. Since 2011, there has been a decrease in the ratio of corrective actions identified per assessment which is encouraging. Monitoring will continue to ensure that this trend is continued and improved upon.

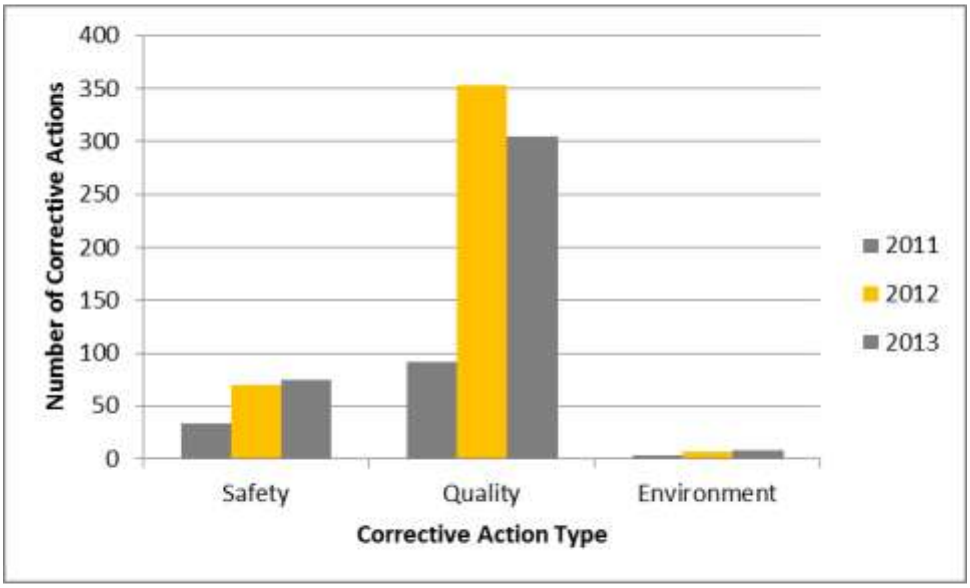


Figure 9-3 Corrective Actions arising from Assessments 2011-2013

The majority of the safety actions were a result of non-compliance with Wellington Electricity personnel protective equipment (PPE) requirements. This ratio of event type demonstrates consistency with previous years' findings. Wellington Electricity is actively addressing this issue with its contractors.

A number of improvements have been made during 2013. 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 2014 focus will be placed on the following areas to further improve performance:

- Continuing to increase the timeliness of close out of assessments;
- Reducing the number of corrective actions identified; and
- Reducing the number of high classification events.

9.3.5 Continual Improvement

Continual improvement in managing health and safety at Wellington Electricity involves ongoing review of health and safety related documents in accordance with the document management system to ensure they are aligned with current business practice and requirements.

With the introduction of the Worksafe Act, the business has engaged with Directors to ensure obligations and responsibilities are well understood, as well as the opportunity for worksite due diligence with Directors visiting active work sites where possible.

9.3.6 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 NZ electricity industry.

In 2013 Wellington Electricity continued to support its 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 provides valuable industry safety benchmarks and feedback, which is helping the industry drive improvements in work place health and safety.

9.4 Environmental Performance

Wellington Electricity has received no environmental infringement notices from TLAs during the period since the last AMP was disclosed. Wellington Electricity routinely monitors the activities of contractors working on its network. Inspections and 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

9.5 Territorial Local Authorities

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

10 Performance Evaluation

10.1 Review of Progress Against the Previous AMP

The following table provides a comparison of forecast financial performance against actual for the 2012/13 regulatory period. The variance for CAPEX was -5% and the OPEX variance was -1%.

Category	Actual ($000)	Forecast ($000)	% Variance	
Capital Expenditure: Consumer Connection	5,033	5,318	-5%	
Capital Expenditure: System growth	3,720	3,764	-1%	
Capital Expenditure: Asset Replacement and Renewal	16,853	17,767	-5%	
Capital Expenditure: Asset Relocation	952	935	2%	
Capital Expenditure: Reliability, Safety and Environment	833	978	-15%	Note 1
Network Capital Expenditure	**27,391**	**28,762**	**-5%**	
Operational Expenditure: Service Interruptions and Emergencies	3,093	3,766	-18%	Note 2
Operational Expenditure: Vegetation Management	1,091	1,126	-3%	
Operational Expenditure: Routine and Corrective Maintenance and Inspection	7,290	6,655	10%	Note 3
Operational Expenditure: Asset replacement and Renewal	614	625	-2%	
Network Operational Expenditure:	**12,088**	**12,172**	**-1%**	

Figure 10-1 Financial Performance for 2012/13

The following notes explain the variance of Actual to Forecast (from the previous plan) in the financial performance table:

Note 1: Capital Expenditure: Reliability, Safety and Environment

The variance is due to the timing of various reinforcement projects.

Note 2: Operational Expenditure: Service Interruptions and Emergencies

The variance is due to less incident related maintenance on the network as a result of fewer faults occurring on the network.

Note 3: Operational Expenditure: Routine and Corrective Maintenance and Inspection

The variance is largely due to a reallocation of a portion of the management services fee expenditure from Business Support into this category, to better reflect the nature of services provided.

10.2 Evaluation of Performance against Target

The service targets that Wellington Electricity has adopted are described in detail in Section 4 (Service Levels). These targets include:

- Network reliability (SAIDI, SAIFI);
- Contact Centre service levels;
- Power restoration times; and
- Faults per 100 circuit-km.

10.2.1 SAIDI & SAIFI

The comparison of target and actual SAIDI and SAIFI for the year 2012/13 is provided below:

	Target 2012/13	Limit 2012/13	Actual 2012/13	Variance to Target
SAIDI	33.90	40.74	43.29	+27.7%
SAIFI	0.52	0.60	0.57	+9.6%

Figure 10-2 Network Reliability Performance for 2012/13

The targets for 2012/13 were set based on the historic averages of SAIDI and SAIFI reliability data for the period 2004 to 2009. As discussed in Section 7, Wellington Electricity has exceeded both its reliability target and DPP regulatory limit[17] for SAIDI, and also exceeded its SAIFI target but was under its regulatory SAIFI limit in 2012/13. This is illustrated in the SAIDI graph for the period since 2004, which shows the actual network performance. The graph shows that SAIDI performance is relatively steady but with a trend upwards in the past few years, as a result of an increase in high impact events primarily extreme weather.

[17] DPP regulatory limits are explained in Section 4.1.1.

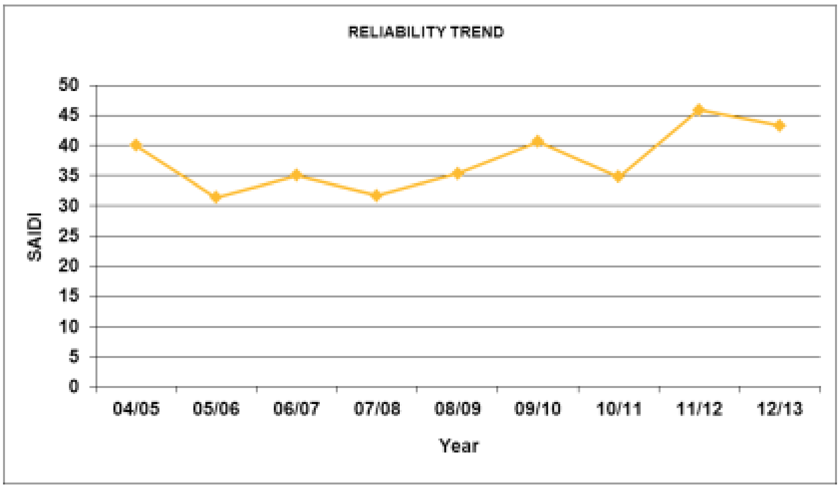


Figure 10-3 Historical SAIDI for Wellington Network 2004 to 2013

10.2.2 Contact Centre Service Level

The following tables indicate that the Contact Centre is providing a high level of service supported by positive customer experience and high levels of retailer satisfaction.

A - General Contact Centre Service Levels

SL	Service Element	2013 Target	Actual 2013
A1	Overall Service Level	80%	83.4%
A2	Call response	20 seconds	34.06 seconds
A3	Missed calls	4%	3.6 %

Figure 10-4 General Contact Centre Service Performance for 2013

B - Customer Experience

SL	Service Element	2013 Target	Actual 2013
C1	Specific Contact Centre experience	80%	84.49%

Figure 10-5 Contact Centre Customer Experience Performance for 2013

C - Energy Retailer Satisfaction

SL	Service Element	2013 Target	Actual 2013
D1	Overall retailer satisfaction with Contact Centre performance	80%	94%

Figure 10-6 Contact Centre Retailer Satisfaction Performance for 2013

10.2.3 Power Restoration Time

	Less than 3 hours	More than 3 hours	More than 6 hours
Maximum time to restore power	77.03%	16.27%	6.7%

Figure 10-7 Power Restoration Time Performance for 2012/13

10.2.4 Faults per 100 Circuit-km

	Target 2012/13	Actual 2012/13
Faults per 100 circuit-km	12.2	12.3

Figure 10-8 Faults per 100 Circuit-km Performance for 2012/13

10.3 Gap Analysis

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 2014.

Section	Item	Description
Items incomplete from the 2013 AMP brought forward		
2.7.5	Field Services Agreement Implementation	Vegetation management contract to be reviewed and implemented during 2013 for 2014 commencement
		Completed: The vegetation management contract with Treescape was renewed in 2013 for the period through to 2015
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. A second load control terminal has been installed to provide redundancy in the meantime. A business case to support the replacement will be completed following the development of a company load control strategy, including the wider load control asset base

Section	Item	Description
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
		In Progress: Maintenance Database enhancements were implemented in 2013, and a business case was approved for the implementation of SAP PM. The SAP PM project is underway and will "go-live" in June 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
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 2014. Process review and possible use of SAP Materials Movement (MM) programme following the SAP PM implementation
5.1	Design and Construction Standards	Further updates to the design and construction standard drawings will continue during 2013 and into 2014
		In Progress: A number of network design standards were created or updated during 2013, and the review of the overhead construction standard drawings is almost complete. This will continue through 2014 and be extended to underground construction standards. The goal is to produce a Design and Construction Manual by the end of 2014
5.2	Prioritisation of Capital Works	Completion of a project prioritisation tool, and implementation within the business following the work undertaken in 2012
		Completed: A project prioritisation tool was completed during 2013, and will be used to assist with prioritising the 2014-24 budgets
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

Section	Item	Description
		In Progress: The original draft Network Development Plan will be completely revised for 2014. This includes revisiting the load forecasting methodology and outputs, ensuring the network model is up to date and factoring in detailed studies of the CBD, Grenada and Whitby where major network augmentation is required within the planning period
6.1	Asset Lifecycle Planning	Continued development of asset lifecycle plans for all asset categories
		In Progress: Detailed asset strategies for all the major asset classes will be developed during 2014
6.4.9	Telecommunications on poles policy	Finalisation of the draft Telecommunications on Poles technical standard, and circulation to telecommunications providers who access Wellington Electricity poles
		Completed: This standard was finalised, approved and implemented in 2013. This standard forms a core part of the agreement with Chorus for installation of UFB on the Wellington Electricity network
6.4.14	Communications Strategy	Finalisation and implementation of the Communications Strategy will occur during 2013
		Completed: The strategy was completed during 2013 and tendering for the operations and maintenance contracts of the communications network is underway at the time of writing this plan
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: A further 150 sites will be assessed during 2014, and work will be tendered for reinforcement at Newtown, Karori and Gracefield 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 two Wellington City and CBD routes have been developed. Presentation and consultation with WCC will be held in 2014 at completion of the remaining routes. A prioritised list of routes for the Hutt Valley and Porirua areas will be developed during 2014

Section	Item	Description
9	Health, Safety and Environmental Improvements	Further review of corporate QSE policies Completion of development of Work Type Competency training programmes and material
		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 2014
Items identified from the 2013 AMP brought forward		
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 2014, and an appropriate optimised sourcing strategy determined in consultation with contracting service providers
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 following compilation 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 following compilation of the revised Network Development Plan
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 (should Paraparaumu be supplied from 220kV as proposed) 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 2014
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 in 2014, a forward plan of all fluid filled cable replacements will be developed
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 during 2014, a plan for the relocation of transformers will be finalised. Refer to Section 6 of this AMP
6.4.8	Load Control Replacement Strategy	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 is being 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 2014
6.4.9	Poles and Overhead Lines	Further work to be completed on below ground life extension techniques for poles to optimise the repair vs. replacement decision for unserviceable poles

Section	Item	Description
		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
6.5	Operating Expense by Asset Category	Wellington Electricity are 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
7.5.4	Worst Performing feeders – reliability improvement programme	Cable diagnostic testing needs to occur to understand the long-term performance expectations of the worst performing feeders with underground cable sections. Identification of overhead equipment failure types is understood, however cable performance is a work in progress
		Completed: Cable diagnostic testing (off-line Partial Discharge) testing was undertaken on a sample of worst performing 11kV cables in 2013 and the results aligned with past performance, allowing for targeted replacement of cable sections and joints as required. This test method will be used in future for cable diagnostic testing
8.9	Specific Network Risks	To provide summary of network risk controls in place
		Completed: The top 10 risk controls are listed in this AMP. Specific network risk controls and their effectiveness are documented within internal business reports
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
		In Progress: The June 2013 storm tested a number of key business processes and systems under Major Event conditions. Mutual aid from other EDBs was called upon, although not under a formal agreement

Figure 10-9 Progress on Gaps Identified in the 2013 AMP

There remain gaps and improvement initiatives that have been identified in a number of key business areas as requiring to be addressed in 2014. These gaps and areas for improvement are referred to throughout this AMP in the sections where they occur and are summarised below:

Section	Item	Description
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
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
2.7.5	Contact Centre	Renegotiate the contract for the outsourced Wellington Electricity contact centre
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
2.8.1.1	SCADA	Upgrade the SCADA master station software to PowerOn Fusion
2.8.1.1	SCADA	Prepare a business case for introduction of new software to replace the TrendSCADA data historian tool
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 2015 AMP
3.4.7.1	Substation TCP/IP Communications	Finalise the forward communication strategy for inclusion in the 2015 AMP. This will include renewal of outsourced communications contracts
4.3.1	Consumer engagement	Undertake consumer engagement to measure consumer satisfaction with the service levels provided by Wellington Electricity
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
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
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

Section	Item	Description
6.4.6.3	Switchgear replacement programme	Prepare a longer term switchgear renewal programme targeting both equipment make and model (type replacement)
6.4.8.2	Ripple injection plant	Develop an investment strategy for the replacement of existing ripple injection plant
8.12.3	Business Recovery Management Plan	Test the Business Recovery Management Plan

Figure 10-10 Gaps and Improvements Identified in the 2014 AMP

10.4 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.

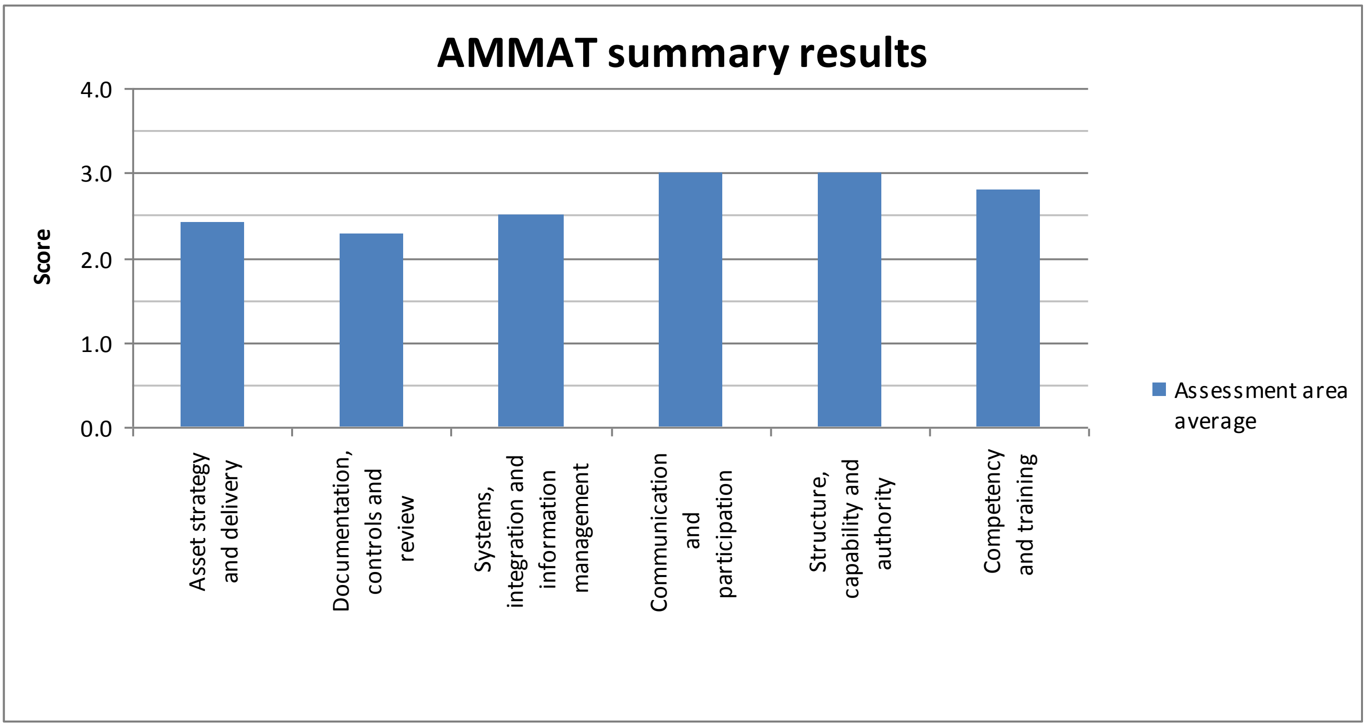


Figure 10-11 Summary of the AMMAT Assessment 2013

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 2013 and 2014
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 2013 and 2014
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 2013 and 2014
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	During 2013 WE worked to improve the control of outsourced activities focussing on quality management practices to provide for the compliant delivery of the organisational strategic plan, asset management policy and strategy

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 will be developed and included in the next AMP
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 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	Various systems are in place for the management of asset management information and data. The primary system is GIS. A business review is currently being carried out for the adoption of a proprietary asset management system such as SAP	2	Through the investigation of a SAP PM maintenance system, the information systems needs will be thoroughly assessed and documented
64	Information management	How has the organisation ensured its asset management information system is relevant to its 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	Various systems are in place for the management of asset management information and data. The primary systems are GIS and MMS. A business review is currently being carried out for the adoption of a proprietary asset management system such as SAP	2	Through the investigation of a SAP PM maintenance system, the information systems needs will be thoroughly assessed and documented

No	Function	Question	Maturity Level Comment	Evidence - Summary	Score	Development Strategy
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 2013 and 2014, a summary of all asset related risks can be compiled and provided in future plans where appropriate
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 is in the process of 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	The outputs from the risk management process are included for the requirement to control the risk. Work is ongoing to develop a long-term resource strategy based on the asset management forecast which is derived from asset knowledge, risk management and future work programmes.	2	Development of a resource map will occur during 2013 for driving the resource strategy for future years.
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 phase. 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

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 strategies identified above. Provision of feedback into the strategy documents to ensure effectiveness

Appendix A Information Schedules

Company Name **Wellington Electricity Lines Limited**
AMP Planning Period **1 April 2014 – 31 March 2024**

SCHEDULE 11a: REPORT ON FORECAST CAPITAL EXPENDITURE

This schedule requires a breakdown of forecast expenditure on assets for the current disclosure year and a 10 year planning period. The forecasts should be consistent with the supporting information set out in the AMP. The forecast is to be expressed in both constant price and nominal dollar terms. Also required is a forecast of the value of commissioned assets (i.e., the value of RAB additions)
EDBs must provide explanatory comment on the difference between constant price and nominal dollar forecasts of expenditure on assets in Schedule 14a (Mandatory Explanatory Notes).
This information is not part of audited disclosure information.

sch ref 1,516

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 14**	**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**
9	**11a(i): Expenditure on Assets Forecast**			**$000 (in nominal dollars)**										
10		Consumer connection		5,608	6,670	7,417	8,171	7,740	7,602	8,189	8,547	8,974	10,055	10,306
11		System growth		4,564	8,166	7,934	8,661	6,746	6,679	8,290	8,303	8,171	7,961	8,160
12		Asset replacement and renewal		20,379	18,683	18,864	19,491	25,467	27,310	26,230	26,207	27,053	29,417	30,001
13		Asset relocations		687	1,033	1,171	1,245	1,192	1,207	1,310	1,341	1,388	1,522	1,560
14		Reliability, safety and environment:												
15		Quality of supply		824	322	25	27	31	31	31	32	33	34	-
16		Legislative and regulatory		-	-	-	-	-	-	-	-	-	-	-
17		Other reliability, safety and environment		379	2,527	3,894	4,061	4,193	4,104	4,229	4,379	4,533	4,690	3,851
18		**Total reliability, safety and environment**		1,203	2,849	3,919	4,089	4,223	4,135	4,260	4,411	4,566	4,724	3,851
19		**Expenditure on network assets**		32,442	37,401	39,305	41,656	45,368	46,932	48,280	48,810	50,151	53,678	53,879
20		Non-network assets		1,832	1,748	1,246	1,399	4,991	500	500	500	500	500	500
21		**Expenditure on assets**		34,274	39,149	40,551	43,056	50,359	47,432	48,780	49,310	50,651	54,178	54,379
22														
23	*plus*	Cost of financing		360	376	385	394	402	411	421	430	440	450	460
24	*less*	Value of capital contributions		4,166	5,700	6,355	6,967	6,610	6,518	7,029	7,318	7,668	8,567	8,781
25	*plus*	Value of vested assets		-	-	-	-	-	-	-	-	-	-	-
26														
27		**Capital expenditure forecast**		30,468	33,825	34,581	36,482	44,152	41,325	42,171	42,422	43,423	46,061	46,058
28				-	-	-	-	-	-	-	-	-	-	-
29		Value of commissioned assets		28,165	33,825	34,581	36,482	44,152	41,325	42,171	42,422	43,423	46,061	46,058
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 14**	**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**
32				**$000 (in constant prices)**										
33		Consumer connection		5,608	6,437	6,908	7,343	6,713	6,363	6,615	6,663	6,751	7,299	7,220
34		System growth		4,564	7,881	7,389	7,784	5,851	5,590	6,697	6,472	6,146	5,779	5,717
35		Asset replacement and renewal		20,379	18,029	17,568	17,517	22,088	22,858	21,187	20,428	20,350	21,355	21,018
36		Asset relocations		687	997	1,091	1,119	1,034	1,010	1,058	1,046	1,044	1,105	1,093
37		Reliability, safety and environment:												
38		Quality of supply		824	311	23	24	27	26	25	25	25	25	-
39		Legislative and regulatory		-	-	-	-	-	-	-	-	-	-	-
40		Other reliability, safety and environment		379	2,439	3,626	3,650	3,637	3,434	3,416	3,413	3,410	3,404	2,698
41		**Total reliability, safety and environment**		1,203	2,750	3,649	3,675	3,664	3,460	3,441	3,438	3,435	3,429	2,698
42		**Expenditure on network assets**		32,442	36,094	36,605	37,439	39,349	39,281	38,997	38,047	37,726	38,967	37,746
43		Non-network assets		1,832	1,717	1,202	1,325	4,640	456	448	440	432	424	417
44		**Expenditure on assets**		34,274	37,811	37,806	38,763	43,990	39,738	39,445	38,487	38,158	39,392	38,162
45														
46	**Subcomponents of expenditure on assets (where known)**													
47		Energy efficiency and demand side management, reduction of energy losses		-	-	-	-	-	-	-	-	-	-	-
48		Overhead to underground conversion		-	-	-	-	-	-	-	-	-	-	-
49		Research and development		-	-	-	-	-	-	-	-	-	-	-

		Current Year CY	CY+1	CY+2	CY+3	CY+4	CY+5	CY+6	CY+7	CY+8	CY+9	CY+10
	for year ended	31 Mar 14	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
Difference between nominal and constant price forecasts		$000										
Consumer connection		-	233	510	827	1,027	1,239	1,574	1,885	2,223	2,756	3,086
System growth		-	285	545	877	895	1,089	1,594	1,831	2,024	2,182	2,443
Asset replacement and renewal		(0)	653	1,296	1,974	3,379	4,452	5,043	5,779	6,702	8,062	8,983
Asset relocations		-	36	80	126	158	197	252	296	344	417	467
Reliability, safety and environment:												
Quality of supply		(0)	11	2	3	4	5	6	7	8	9	-
Legislative and regulatory		-	-	-	-	-	-	-	-	-	-	-
Other reliability, safety and environment		0	88	267	411	556	669	813	966	1,123	1,285	1,153
Total reliability, safety and environment		0	99	269	414	560	674	819	973	1,131	1,295	1,153
Expenditure on network assets		0	1,307	2,700	4,218	6,019	7,650	9,282	10,763	12,425	14,711	16,133
Non-network assets		-	32	45	74	351	44	52	60	68	76	83
Expenditure on assets		0	1,339	2,745	4,292	6,369	7,694	9,334	10,822	12,493	14,786	16,216

11a(ii): Consumer Connection

		Current Year CY	CY+1	CY+2	CY+3	CY+4	CY+5
	for year ended	31 Mar 14	31 Mar 15	31 Mar 16	31 Mar 17	31 Mar 18	31 Mar 19
*Consumer types defined by EDB**		$000 (in constant prices)					
Substation		2,106	3,203	2,684	2,804	2,342	2,210
Subdivision		1,754	1,462	2,249	2,418	2,333	2,216
High Voltage Connection		438	24	24	24	24	24
Residential customers		1,287	1,689	1,893	2,039	1,956	1,854
Public Lighting		22	58	58	58	58	58
**include additional rows if needed*							
Consumer connection expenditure		5,608	6,437	6,908	7,343	6,713	6,363
Capital contributions funding consumer connection	*less*	3,743	4,504	4,828	5,143	4,699	4,446
Consumer connection less capital contributions		1,865	1,933	2,080	2,200	2,014	1,917

11a(iii): System Growth

		Current Year CY	CY+1	CY+2	CY+3	CY+4	CY+5
Subtransmission		3,055	-	-	-	-	-
Zone substations		177	5,644	5,292	5,575	4,190	4,003
Distribution and LV lines		195	-	-	-	-	-
Distribution and LV cables		1,031	1,978	1,855	1,954	1,468	1,403
Distribution substations and transformers		-	259	243	256	192	184
Distribution switchgear		-	-	-	-	-	-
Other network assets		107	-	-	-	-	-
System growth expenditure		4,564	7,881	7,389	7,784	5,851	5,590
Capital contributions funding system growth	*less*	-	-	-	-	-	-
System growth less capital contributions		4,564	7,881	7,389	7,784	5,851	5,590

Row			Current Year CY	CY+1	CY+2	CY+3	CY+4	CY+5
104		for year ended	31 Mar 14	31 Mar 15	31 Mar 16	31 Mar 17	31 Mar 18	31 Mar 19
105	**11a(iv): Asset Replacement and Renewal**		**$000 (in constant prices)**					
106		Subtransmission	85	591	576	574	724	749
107		Zone substations	1,844	2,600	2,533	2,526	3,185	3,296
108		Distribution and LV lines	11,656	4,254	4,145	4,133	5,211	5,393
109		Distribution and LV cables	230	709	691	689	869	899
110		Distribution substations and transformers	1,998	1,548	1,508	1,504	1,896	1,962
111		Distribution switchgear	3,971	5,943	5,791	5,775	7,281	7,535
112		Other network assets	596	2,385	2,324	2,317	2,922	3,024
113		**Asset replacement and renewal expenditure**	20,379	18,029	17,568	17,517	22,088	22,858
114	*less*	Capital contributions funding asset replacement and renewal	-	-	-	-	-	-
115		**Asset replacement and renewal less capital contributions**	20,379	18,029	17,568	17,517	22,088	22,858
116	**11a(v):Asset Relocations**							
117		*Project or programme**						
118		Asset relocations	687	997	1,091	1,119	1,034	1,010
119		[Description of material project or programme]	-	-	-	-	-	-
120		[Description of material project or programme]	-	-	-	-	-	-
121		[Description of material project or programme]	-	-	-	-	-	-
122		[Description of material project or programme]	-	-	-	-	-	-
123		**include additional rows if needed*						
124		All other asset relocations projects or programmes	-	-	-	-	-	-
125		**Asset relocations expenditure**	687	997	1,091	1,119	1,034	1,010
126	*less*	Capital contributions funding asset relocations	422	997	1,091	1,119	1,034	1,010
127		**Asset relocations less capital contributions**	264	-	-	-	-	-
128								
129	**11a(vi):Quality of Supply**							
130		*Project or programme**						
131		Titahi Bay Backup Protection	67	-	-	-	-	-
132		Programme - Fault Passage Indicators	-	44	23	24	27	-
133		Wainuiomata Coast Rd - Upgrade	208	199	-	-	-	-
134		Karori - Reliability improvement	148	37	-	-	-	-
135		Ngauranga - Reconductoring	213	-	-	-	-	-
136		**include additional rows if needed*						
137		All other quality of supply projects or programmes	188	31	-	0	-	26
138		**Quality of supply expenditure**	824	311	23	24	27	26
139	*less*	Capital contributions funding quality of supply	-	-	-	-	-	-
140		**Quality of supply less capital contributions**	824	311	23	24	27	26
141								
142	**11a(vii): Legislative and Regulatory**							
143		*Project or programme**						
144		[Description of material project or programme]	-	-	-	-	-	-
145		[Description of material project or programme]	-	-	-	-	-	-
146		[Description of material project or programme]	-	-	-	-	-	-
147		[Description of material project or programme]	-	-	-	-	-	-
148		[Description of material project or programme]	-	-	-	-	-	-
149		**include additional rows if needed*						
150		All other legislative and regulatory projects or programmes	-	-	-	-	-	-
151		**Legislative and regulatory expenditure**	-	-	-	-	-	-
152	*less*	Capital contributions funding legislative and regulatory	-	-	-	-	-	-
153		**Legislative and regulatory less capital contributions**	-	-	-	-	-	-

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

		Current Year CY	CY+1	CY+2	CY+3	CY+4	CY+5
	for year ended	31 Mar 14	31 Mar 15	31 Mar 16	31 Mar 17	31 Mar 18	31 Mar 19
*Project or programme**		$000 (in constant prices)					
Programme - Earthing Compliance		299	225	225	225	269	317
Programme - Asbestos Removal		-	83	83	83	63	117
Seismic Strengthening		-	1,963	3,050	3,050	2,988	2,800
-		-	-	-	-	-	-
-		-	-	-	-	-	-
**include additional rows if needed*							
All other reliability, safety and environment projects or programmes		80	168	268	292	318	200
Other reliability, safety and environment expenditure		379	2,439	3,626	3,650	3,637	3,434
less Capital contributions funding other reliability, safety and environment		-	-	-	-	-	-
Other reliability, safety and environment less capital contributions		379	2,439	3,626	3,650	3,637	3,434

11a(ix): Non-Network Assets

	Current Year CY	CY+1	CY+2	CY+3	CY+4	CY+5
Routine expenditure						
*Project or programme**						
Control Room	160	-	-	-	-	-
Software	90	777	544	600	368	207
IT Infrastructure	1,546	939	658	725	4,272	250
**include additional rows if needed*						
All other routine expenditure projects or programmes	36	-	-	-	-	-
Routine expenditure	1,832	1,717	1,202	1,325	4,640	456
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	1,832	1,717	1,202	1,325	4,640	456

Company Name	**Wellington Electricity Lines Limited**
AMP Planning Period	**1 April 2014 – 31 March 2024**

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 14**	**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**
9	**Operational Expenditure Forecast**	**$000 (in nominal dollars)**										
10	Service interruptions and emergencies	3,684	4,115	4,353	4,495	4,641	4,791	4,946	5,107	5,273	5,444	5,620
11	Vegetation management	1,150	1,249	1,331	1,384	1,440	1,497	1,557	1,620	1,685	1,752	1,823
12	Routine and corrective maintenance and inspection	8,343	8,573	9,020	9,335	9,497	9,523	9,893	10,276	10,674	11,088	11,517
13	Asset replacement and renewal	615	693	738	768	799	831	864	899	935	972	1,011
14	**Network Opex**	13,793	14,630	15,442	15,982	16,376	16,642	17,261	17,902	18,567	19,256	19,972
15	System operations and network support	4,224	4,785	5,070	5,243	5,422	5,607	5,799	5,997	6,202	6,414	6,633
16	Business support	10,870	13,953	14,961	15,695	16,495	17,373	18,343	19,242	20,208	21,249	22,373
17	**Non-network opex**	15,094	18,738	20,031	20,938	21,918	22,980	24,142	25,239	26,410	27,663	29,006
18	**Operational expenditure**	28,886	33,367	35,474	36,920	38,294	39,622	41,402	43,141	44,977	46,919	48,978
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 14**	**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**
21		**$000 (in constant prices)**										
22	Service interruptions and emergencies	3,684	3,975	4,062	4,050	4,039	4,028	4,017	4,006	3,995	3,984	3,973
23	Vegetation management	1,150	1,206	1,241	1,247	1,253	1,259	1,265	1,271	1,276	1,282	1,288
24	Routine and corrective maintenance and inspection	8,343	8,281	8,416	8,412	8,266	8,007	8,034	8,060	8,087	8,114	8,141
25	Asset replacement and renewal	615	669	689	692	695	699	702	705	708	712	715
26	**Network Opex**	13,793	14,131	14,408	14,402	14,254	13,992	14,017	14,042	14,067	14,091	14,117
27	System operations and network support	4,224	4,622	4,730	4,725	4,720	4,714	4,709	4,704	4,699	4,694	4,689
28	Business support	10,870	13,477	13,959	14,143	14,358	14,606	14,896	15,093	15,310	15,550	15,815
29	**Non-network opex**	15,094	18,099	18,689	18,868	19,077	19,321	19,605	19,797	20,009	20,243	20,504
30	**Operational expenditure**	28,886	32,230	33,097	33,270	33,331	33,313	33,622	33,839	34,076	34,335	34,621
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	1,133	1,471	1,471	1,670	1,896	2,153	2,445	2,776	3,015	3,275	3,557
37	** Direct billing expenditure by suppliers that direct bill the majority of their consumers*											
38												
39		*Current Year CY*	*CY+1*	*CY+2*	*CY+3*	*CY+4*	*CY+5*	*CY+6*	*CY+7*	*CY+8*	*CY+9*	*CY+10*
40	for year ended	**31 Mar 14**	**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**
41	**Difference between nominal and real forecasts**	**$000**										
42	Service interruptions and emergencies	-	140	292	444	601	763	930	1,101	1,278	1,460	1,648
43	Vegetation management	-	43	89	137	187	238	293	349	408	470	534
44	Routine and corrective maintenance and inspection	-	292	604	923	1,231	1,517	1,859	2,216	2,587	2,974	3,376
45	Asset replacement and renewal	-	24	49	76	104	132	162	194	227	261	296
46	**Network Opex**	-	499	1,034	1,580	2,122	2,650	3,244	3,860	4,500	5,165	5,854
47	System operations and network support	-	163	340	518	703	893	1,090	1,293	1,503	1,720	1,945
48	Business support	-	476	1,002	1,552	2,138	2,766	3,447	4,149	4,898	5,699	6,558
49	**Non-network opex**	-	639	1,342	2,070	2,841	3,659	4,537	5,442	6,401	7,419	8,503
50	**Operational expenditure**	-	1,138	2,376	3,650	4,963	6,309	7,780	9,302	10,901	12,584	14,357

Company Name	**Wellington Electricity Lines Limited**
AMP Planning Period	**1 April 2014 – 31 March 2024**

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.	1.00%	2.00%	25.00%	53.00%	19.00%	3	3.00%
11	All	Overhead Line	Wood poles	No.	2.00%	12.00%	53.00%	17.00%	16.00%	3	14.00%
12	All	Overhead Line	Other pole types	No.	-	-	-	-	-	N/A	-
13	HV	Subtransmission Line	Subtransmission OH up to 66kV conductor	km	-	6.00%	93.00%	1.00%	-	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	-	-	27.00%	73.00%	-	3	-
16	HV	Subtransmission Cable	Subtransmission UG up to 66kV (Oil pressurised)	km	-	17.00%	83.00%	-	-	3	-
17	HV	Subtransmission Cable	Subtransmission UG up to 66kV (Gas pressurised)	km	21.00%	22.00%	57.00%	-	-	3	14.00%
18	HV	Subtransmission Cable	Subtransmission UG up to 66kV (PILC)	km	-	20.00%	80.00%	-	-	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.	-	-	75.00%	25.00%	-	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.	-	25.00%	75.00%	-	-	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.	3.00%	7.00%	75.00%	15.00%	-	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.	5.60%	5.60%	81.40%	7.40%	-	4	7.40%
46	HV	Distribution Line	Distribution OH Open Wire Conductor	km	1.00%	15.00%	73.00%	11.00%		3	1.00%
47	HV	Distribution Line	Distribution OH Aerial Cable Conductor	km	2.00%	10.00%	87.00%	1.00%		3	1.00%
48	HV	Distribution Line	SWER conductor	km	-	-	-	-	-	N/A	-
49	HV	Distribution Cable	Distribution UG XLPE or PVC	km	1.00%	5.00%	33.00%	61.00%		3	-
50	HV	Distribution Cable	Distribution UG PILC	km	3.00%	4.00%	82.00%	11.00%		3	2.00%
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.	8.00%	17.00%	50.00%	25.00%	-	3	10.00%
53	HV	Distribution switchgear	3.3/6.6/11/22kV CB (Indoor)	No.	5.00%	3.00%	66.00%	26.00%	-	3	10.00%
54	HV	Distribution switchgear	3.3/6.6/11/22kV Switches and fuses (pole mounted)	No.	2.00%	8.00%	54.00%	36.00%	-	3	10.00%
55	HV	Distribution switchgear	3.3/6.6/11/22kV Switch (ground mounted) - except RMU	No.	5.00%	10.00%	75.00%	10.00%	-	3	10.00%
56	HV	Distribution switchgear	3.3/6.6/11/22kV RMU	No.	2.00%	14.00%	51.00%	33.00%		3	15.00%
57	HV	Distribution Transformer	Pole Mounted Transformer	No.	1.00%	8.00%	56.00%	35.00%		3	2.00%
58	HV	Distribution Transformer	Ground Mounted Transformer	No.	1.00%	13.00%	58.00%	28.00%		3	3.00%
59	HV	Distribution Transformer	Voltage regulators	No.	-	-	-	-	-	N/A	-
60	HV	Distribution Substations	Ground Mounted Substation Housing	No.	1.00%	9.00%	66.00%	24.00%		3	3.00%
61	LV	LV Line	LV OH Conductor	km	1.00%	19.00%	75.00%	5.00%		2	1.00%
62	LV	LV Cable	LV UG Cable	km	1.00%	5.00%	61.00%	33.00%	-	2	2.00%
63	LV	LV Streetlighting	LV OH/UG Streetlight circuit	km	5.00%	5.00%	75.00%	15.00%	-	1	2.00%
64	LV	Connections	OH/UG consumer service connections	No.	2.00%	4.00%	90.00%	4.00%	-	1	1.00%
65	All	Protection	Protection relays (electromechanical, solid state and numeric)	No.	3.00%	12.00%	59.00%	26.00%	-	3	10.00%
66	All	SCADA and communications	SCADA and communications equipment operating as a single system	Lot	18.00%	31.00%	20.00%	31.00%		3	18.00%
67	All	Capacitor Banks	Capacitors including controls	No.	-	-	-	-	-	N/A	-
68	All	Load Control	Centralised plant	Lot	5.00%	25.00%	65.00%	5.00%	-	3	5.00%
69	All	Load Control	Relays	No.	-	-	-	-	-	N/A	-
70	All	Civils	Cable Tunnels	km	-	-	100.00%	-	-	3	-

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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	73%	24	77%	No constraint within +5 years	
10	Brown Owl	16	23	N-1	7	69%	23	67%	No constraint within +5 years	
11	Evans Bay	16	24	N-1	11	69%	24	69%	No constraint within +5 years	
12	Frederick St	28	36	N-1	13	78%	36	67%	No constraint within +5 years	Previous constraint addressed by new Bond St Zone Substation
13	Gracefield	12	23	N-1	12	54%	23	51%	No constraint within +5 years	
14	Hataitai	17	23	N-1	11	76%	23	74%	No constraint within +5 years	
15	Johnsonville	16	23	N-1	9	71%	23	69%	No constraint within +5 years	Previous constraint addressed by new Grenada Zone Substation
16	Karori	17	24	N-1	7	72%	24	71%	No constraint within +5 years	
17	Kenepuru	11	23	N-1	9	50%	23	48%	No constraint within +5 years	
18	Korokoro	19	23	N-1	11	83%	23	81%	No constraint within +5 years	
19	Maidstone	16	22	N-1	12	71%	22	74%	No constraint within +5 years	
20	Mana-Plmtn	19	16	N-1	12	121%	16	123%	Transformer	Capacity shortfall - High Load Growth in Whitby area
21	Moore St	29	36	N-1	14	81%	36	67%	No constraint within +5 years	
22	Naenae	15	23	N-1	11	65%	23	65%	No constraint within +5 years	
23	Nairn St	20	30	N-1	16	67%	30	56%	No constraint within +5 years	
24	Ngauranga	14	12	N-1	10	113%	12	117%	Transformer	High Load Growth in Woodridge area
25	Palm Grove	28	24	N-1	13	117%	30	95%	Subtransmission circuit	Sub-trans circuit and Transformers are to be upgraded within the next five years
26	Porirua	18	20	N-1	14	90%	20	91%	No constraint within +5 years	
27	Seaview	15	22	N-1	12	70%	22	70%	No constraint within +5 years	
28	Tawa	16	16	N-1	13	100%	16	106%	Transformer	High Load growth in Tawa/Grenada area
29	The Terrace	31	36	N-1	21	87%	36	79%	No constraint within +5 years	
30	Trentham	17	23	N-1	10	74%	23	79%	No constraint within +5 years	
31	University	24	24	N-1	21	101%	24	89%	Subtransmission circuit	Circuit rating
32	Waikowhai	17	19	N-1	10	89%	19	92%	No constraint within +5 years	
33	Wainuiomata	18	20	N-1	3	89%	23	78%	No constraint within +5 years	
34	Waitangirua	16	16	N-1	11	100%	16	107%	Transformer	High load growth in Waitangirua area
35	Waterloo	20	23	N-1	14	86%	23	85%	No constraint within +5 years	
36	Bond Street					-	30	67%	No constraint within +5 years	New Zone Substation

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

12b(ii): Transformer Capacity

	(MVA)
Distribution transformer capacity (EDB owned)	1,420
Distribution transformer capacity (Non-EDB owned)	18
Total distribution transformer capacity	1,438
Zone substation transformer capacity	1,095

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SCHEDULE 12C: REPORT ON FORECAST NETWORK DEMAND

This schedule requires a forecast of new connections (by consumer type), peak demand and energy volumes for the disclosure year and a 5 year planning period. The forecasts should be consistent with the supporting information set out in the AMP as well as the assumptions used in developing the expenditure forecasts in Schedule 11a and Schedule 11b and the capacity and utilisation forecasts in Schedule 12b.

sch ref

7 12c(i): Consumer Connections

sch ref		Current Year CY	CY+1	CY+2	CY+3	CY+4	CY+5
8	*Number of ICPs connected in year by consumer type*	**Number of connections**					
9		*Current Year CY*	*CY+1*	*CY+2*	*CY+3*	*CY+4*	*CY+5*
10	for year ended	**31 Mar 14**	**31 Mar 15**	**31 Mar 16**	**31 Mar 17**	**31 Mar 18**	**31 Mar 19**
11	*Consumer types defined by EDB**						
12	Domestic	900	899	897	898	901	899
13	Large Commercial	5	6	6	5	5	5
14	Large Industrial	2	2	3	2	2	2
	Medium Commercial	10	9	11	10	10	10
	Small Commercial	150	151	149	152	148	151
15	Small Industrial	-	-	-	-	-	-
16	Unmetered	25	25	26	25	26	25
17	**Connections total**	1,092	1,092	1,092	1,092	1,092	1,092
18	**include additional rows if needed*						
19	**Distributed generation**						
20	Number of connections	100	100	100	100	100	100
21	Installed connection capacity of distributed generation (MVA)	1.5	61.5	1.5	1.5	1.5	1.5

22 12c(ii) System Demand

sch ref			Current Year CY	CY+1	CY+2	CY+3	CY+4	CY+5
23			*Current Year CY*	*CY+1*	*CY+2*	*CY+3*	*CY+4*	*CY+5*
24		**Maximum coincident system demand (MW)** for year ended	**31 Mar 14**	**31 Mar 15**	**31 Mar 16**	**31 Mar 17**	**31 Mar 18**	**31 Mar 19**
25		GXP demand	540	521	526	532	537	543
26	*plus*	Distributed generation output at HV and above	2	25	25	25	25	25
27		**Maximum coincident system demand**	542	545	551	556	562	567
28	*less*	Net transfers to (from) other EDBs at HV and above	-	-	-	-	-	-
29		**Demand on system for supply to consumers' connection points**	542	545	551	556	562	567
30		**Electricity volumes carried (GWh)**						
31		Electricity supplied from GXPs	2,446	2,396	2,383	2,371	2,359	2,347
32	*less*	Electricity exports to GXPs	-	-	-	-	-	-
33	*plus*	Electricity supplied from distributed generation	11	50	50	50	50	50
34	*less*	Net electricity supplied to (from) other EDBs						
35		**Electricity entering system for supply to ICPs**	2,458	2,446	2,433	2,421	2,409	2,397
36	*less*	Total energy delivered to ICPs	2,335	2,323	2,312	2,300	2,289	2,277
37		**Losses**	123	122	122	121	120	120
38								
39		**Load factor**	52%	51%	50%	50%	49%	48%
40		**Loss ratio**	5.0%	5.0%	5.0%	5.0%	5.0%	5.0%

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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 14**	**31 Mar 15**	**31 Mar 16**	**31 Mar 17**	**31 Mar 18**	**31 Mar 19**
10	**SAIDI**						
11	Class B (planned interruptions on the network)	1.4	1.3	1.3	1.3	1.3	1.3
12	Class C (unplanned interruptions on the network)	75.6	49.1	49.1	49.1	49.1	49.1
13	**SAIFI**						
14	Class B (planned interruptions on the network)	0.01	0.01	0.01	0.01	0.01	0.01
15	Class C (unplanned interruptions on the network)	1.12	0.71	0.71	0.71	0.71	0.71

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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 consitent 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 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.		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 organization 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).

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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.

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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(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. 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 of asset 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	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. Work is advanced on a long term strategic resource map relative to asset management organisational delivery requirements.		It is essential that the plan(s) are realistic and can be implemented, which requires appropriate resources to be available and enabling mechanisms in place. This question explores how well this is achieved. The plan(s) not only need to consider the resources directly required and timescales, but also the enabling activities, including for example, training requirements, supply chain capability and procurement timescales.	The management team with overall responsibility for the asset management system. Operations, maintenance and engineering managers. If appropriate, the performance management team. 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 strategies 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.

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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
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.

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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
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	Good solid accountability for Asset Management responsibility from CEO, through Network GM and through Network Team fuctional 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. Work is advanced on a long term strategic resource map relative to asset management organisational delivery requirements.		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 needed to functional policies, standards, processes and the asset management information system. Work is advanced on a long term strategic resource map relative to asset management organisational delivery requirements.		There is a need for an organisation to demonstrate that it has considered what resources are required to develop and implement its asset management system. There is also a need for the organisation to demonstrate that it has assessed what development plan(s) are required to provide its human resources with the skills and competencies to develop and implement its asset management systems. The timescales over which the plan(s) are relevant should be commensurate with the planning horizons within the asset management strategy considers e.g. if the asset management strategy considers 5, 10 and 15 year time scales then the human resources development plan(s) should align with these. Resources include both 'in house' and external resources who undertake asset management activities.	Senior management responsible for agreement of plan(s). Managers responsible for developing asset management strategy and plan(s). Managers with responsibility for development and recruitment of staff (including HR functions). Staff responsible for training. Procurement officers. Contracted service providers.	Evidence of analysis of future work load plan(s) in terms of human resources. Document(s) containing analysis of the organisation's own direct resources and contractors resource capability over suitable timescales. Evidence, such as minutes of meetings, that suitable management forums are monitoring human resource development plan(s). Training plan(s), personal development plan(s), contract and service level agreements.
49	Training, awareness and competence	How does the organisation identify competency requirements and then plan, provide and record the training necessary to achieve the competencies?	3	There is the requirement for defined levels of management / technical and AM competencies through Job Descriptions / standard Key competency requirements. These are reviewed six monthly through performance reviews. These are also being reviewed with the intention of developing an AM competencies framework within 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 / standard Key competency requirements. These are reviewed six monthly through performance reviews. These are also being reviewed with the intention of developing an AM competencies framework within 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.		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 AM information and data. The primary system is GIS. A business review has been carried out for the adoption of a propriétry asset management system which is SAP PM and implementation of this system is currently underway, due for completion mid-2014.		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 consitency 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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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	Various systems are in place for the management of AM information and data. The primary system is GIS. A business review has been carried out for the adoption of a proprietry asset management system which is SAP PM and implementation of this system is currently underway, due for completion mid-2014.		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 risks have been implimented 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?	2	The outputs from the risk management process are included for the requirement to control the risk. Work is ongoing to develop a long term resource strategy based on the asset management forecast which is derived from asset knowlege, risk management and future work programmes.		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. Senior Policy Analyst at Powercor 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 AM policies, procedures and processes in place which deal with the management of assets during the design to commissioning phase. There are procedures to determine how these are derived and prioritised within the asset management plan.There are gaps covering projects accelerated and not inlcuded 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 good general; inspection plan in place with remedial actions derived around proritisation of critical defects. Further work is being carried out in standardising the level of consistency across the the inspection and condition assessment proces 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 SMT 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 performance management. Gaps in data and data quality exist however this is being addressed through a proactive review audit review 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	Audits are taken on major faults and asset related failures over a selected threshold value. All asset related failures, Incidents and Near misses are reproted and logged through a defined process with trending carried out on failures, incidents, near misses and defects. Corrective actions are managed through a weekly review and action process.		Widely used AM standards require that the organisation establishes implements and maintains process(es) for the handling and investigation of failures incidents and non-conformities for assets and sets down a number of expectations. Specifically this question examines the requirement to define clearly responsibilities and authorities for these activities, and communicate these unambiguously to relevant people including external stakeholders if appropriate.	The organisation's safety and environment management team. The team with overall responsibility for the management of the assets. People who have appointed roles within the asset-related investigation procedure, from those who carry out the investigations to senior management who review the recommendations. Operational controllers responsible for managing the asset base under fault conditions and maintaining services to consumers. Contractors and other third parties as appropriate.	Process(es) and procedure(s) for the handling, investigation and mitigation of asset-related failures, incidents and emergency situations and non conformances. Documentation of assigned responsibilities and authority to employees. Job Descriptions, Audit reports. Common communication systems i.e. all Job Descriptions on Internet etc.

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SCHEDULE 13: REPORT ON ASSET MANAGEMENT MATURITY (cont)

Question No.	Function	Question	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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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 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 regieme		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 implimented 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.		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. Interatction with AM practitioners outside of the electricity sector is limited.		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.

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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
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 capital expenditure:
The difference represents inflation and real input price escalation of 3.6% per year.

Non network capital expenditure:
The difference represents inflation and real input price escalation of 1.8% per year.

The rates have been obtained from publicly available information in the Orion Customised Price Path Determination, Transpower's Individual Price Path regulatory submissions and labour cost inflation based on observed differentials in a remuneration consultant's survey versus Statistics New Zealand's Labour Cost Index.

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 real input price escalation of 3.5% per year.

The rates have been obtained from publicly available information in the Orion Customised Price Path Determination and labour cost inflation based on observed differentials in a remuneration consultant's survey versus Statistics New Zealand's Labour Cost Index.

Appendix B Asset Management Plan Assumptions

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
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

Area	Possible impact and variation to plan	Assumption	Reason for assumption
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 of between 1.8% and 3.6% per year	Based upon current market information
Quality targets	Any increase in quality targets, or alteration in the assessment method, may lead to increased level of investment to improve network performance	The quality targets for the Wellington Electricity business in the period 2010 – 2015 will be maintained as per the Commerce Commission's decision paper on the default price path (November 2009). Internal targets for the period 2015-19 will remain the same as the present period, however due to the increasing number of extreme weather events the regulatory limits will increase. The underlying performance of the network, excluding these major events, is not expected to materially deteriorate	Quality targets are regulated and won't change until 2015. After 2015 changes may occur if the same calculation methodology is adopted. Based on the recent performance of the network, due to the number of extreme weather events, quality limits are likely to increase unless the methodology changes

Area	Possible impact and variation to plan	Assumption	Reason for assumption
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. It is assumed that the reset DPP for the period after 2014/15 will continue to encourage Wellington Electricity to invest in the network to meet the quality targets	Quality targets are set for a five year period with the next review due in 2015
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
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 allowed regulated return on investment impact on shareholders and may lead to either increased or reduced expenditure	The reset DPP will provide a WACC sufficient to incentivise shareholders to continue to invest in the network to ensure a sustainably profitable business	Starting price provided by the Commerce Commission has not had a negative impact on the ability to provide a recovery for the investment made by the business

Area	Possible impact and variation to plan	Assumption	Reason for assumption
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
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 C 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	2.2
3.2 Details of the background and objectives of the **EDB**'s asset management and planning processes	2.4
3.3 A purpose statement which-	
3.3.1 makes clear the purpose and status of the **AMP** in the **EDB**'s asset management practices. The purpose statement must also include a statement of the objectives of the asset management and planning processes	2.2
3.3.2 states the corporate mission or vision as it relates to asset management	2.4
3.3.3 identifies the documented plans produced as outputs of the annual business planning process adopted by the **EDB**	2.4
3.3.4 states how the different documented plans relate to one another, with particular reference to any plans specifically dealing with asset management	2.4
3.3.5 includes a description of the interaction between the objectives of the **AMP** and other corporate goals, business planning processes, and plans	2.4
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	2.5
3.5 The date that it was approved by the **directors**	2.5
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	2.6

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** 3.7.2 executive—an indication of how the in-house asset management and planning organisation is structured 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	2.7.1 2.7.2 2.7.5
3.8 All significant assumptions: 3.8.1 quantified where possible 3.8.2 clearly identified in a manner that makes their significance understandable to interested persons, including 3.8.3 a description of changes proposed where the information is not based on the **EDB**'s existing business 3.8.4 the sources of uncertainty and the potential effect of the uncertainty on the prospective information 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.	1.3 and Appendix B
3.9 A description of the factors that may lead to a material difference between the prospective information disclosed and the corresponding actual information recorded in future disclosures	Appendix B
3.10 An overview of asset management strategy and delivery	2.9 and 2.10
3.11 An overview of systems and information management data	2.8
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	2.8.5
3.13 A description of the processes used within the **EDB** for- 3.13.1 managing routine asset inspections and **network** maintenance 3.13.2 planning and implementing **network** development projects 3.13.3 measuring **network** performance.	2.10.1 to 2.10.5

Information Disclosure Requirements 2012 clause	AMP section
3.14 An overview of asset management documentation, controls and review processes	2.11
3.1.5 An overview of communication and participation processes	2.12
3.16 The **AMP** must present all financial values in **constant price New Zealand dollars** except where specified otherwise;	1.1
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.	N/A
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.	3.1 to 3.2
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.	3.3
4.3 If **sub-networks** exist, the **network** configuration information referred to in subclause 4.2 above must be disclosed for each **sub-network**.	N/A

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.	3.4
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**.	3.4
<u>Service Levels</u> 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**.	4.1 4.2
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**.	4.1.1
7. Performance indicators for which targets have been defined in clause 5 above should also include- 7.1 **Consumer** oriented indicators that preferably differentiate between different consumer types; 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.	4.1.2.1 4.1.2.2 4.1.2.3

Information Disclosure Requirements 2012 clause	AMP section
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.	4.3
9. Targets should be compared to historic values where available to provide context and scale to the reader.	4.1
10. Where forecast expenditure is expected to materially affect performance against a target defined in clause 5 above, the target should be consistent with the expected change in the level of performance.	N/A
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;	5.1
11.2 Planning criteria for network developments should be described logically and succinctly. Where probabilistic or scenario-based planning techniques are used, this should be indicated and the methodology briefly described;	5.2
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;	5.6
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.	5.6
11.5 A description of strategies or processes (if any) used by the **EDB** that promote the energy efficient operation of the **network**.	5.6.3
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**.	5.5
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.	5.2

Information Disclosure Requirements 2012 clause	AMP section
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.	5.7 and 5.9
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.	5.8, 5.10, 5.11, 5.12, 5.14
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**.	5.16
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.	5.9

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.	5.10
Lifecycle Asset Management Planning (Maintenance and Renewal) 12. The **AMP** must provide a detailed description of the lifecycle asset management processes, including— 12.1 The key drivers for maintenance planning and assumptions; 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**.	6.1 to 6.3
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.	6.4 and 6.5

Information Disclosure Requirements 2012 clause	AMP section
<u>**Non-Network Development, Maintenance and Renewal**</u> 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; 13.2 development, maintenance and renewal policies that cover them; 13.3 a description of material capital expenditure projects (where known) planned for the next five years; 13.4 a description of material maintenance and renewal projects (where known) planned for the next five years.	6.7
14. **AMP**s must provide details of risk policies, assessment, and mitigation, including— 14.1 Methods, details and conclusions of risk analysis; 14.2 Strategies used to identify areas of the **network** that are vulnerable to high impact low probability events and a description of the resilience of the **network** and asset management systems to such events;	8
15. AMPs must provide details of performance measurement, evaluation, and improvement, including— 15.1 A review of progress against plan, both physical and financial;	10
15.2 An evaluation and comparison of actual service level performance against targeted performance;	7 and 10
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.	10.4
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.	10.3
<u>**Capability to deliver**</u> 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; 16.2 The organisation structure and the processes for authorisation and business capabilities will support the implementation of the AMP plans.	2.13

Appendix D Glossary of Terms

AAC	All Aluminium Conductor
AAAC	All Aluminium Alloy Conductor
ABS	Air Break Switch
ACSR	Aluminium Conductor Steel Reinforced
AMP	Asset Management Plan
CB	Circuit Breaker
CBD	Central Business District
CCT	Covered Conductor Thick
CEO	Chief Executive Officer
CKI	Cheung Kong Infrastructure Holdings Limited
Cu	Copper
DC	Direct Current
DGA	Dissolved Gas Analysis
DTS	Distributed Temperature Sensing
EDO	Expulsion Drop-out
FPI	Fault Passage Indicators
GWh	Gigawatt Hour
GIS	Geographical Information System
GXP	Grid Exit Point
HV	High Voltage
ICP	Installation Control Point
IEEE	Institute of Electrical and Electronic Engineers
IISC	International Infrastructure Services Company (NZ Branch)
km	Kilometre
KPI	Key Performance Indicator
kV	Kilovolt
kVA	Kilovolt Ampere
kW	Kilowatt
LV	Low Voltage
LVABC	Low Voltage Aerial Bundled Conductor

MW	Megawatt
MVA	Mega Volt Ampere
NICAD	Nickel Cadmium Battery
Nilstat ITP	Protection Relay
ODV	Optimised Deprival Value/Valuation
O&M	Operating and Maintenance
PAHL	Power Asset Holdings Limited
PDC	Polarisation Depolarisation Current
PIAS	Paper Insulated Aluminium Sheath Cable
PILC	Paper Insulated Lead Cable
PLC	Programmable Logic Controller
PVC	Polyvinyl Chloride
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
VRLA	Valve Regulated Lead Acid Battery
W/S	Winter / Summer
XLPE	Cross Linked Polyethylene Cable