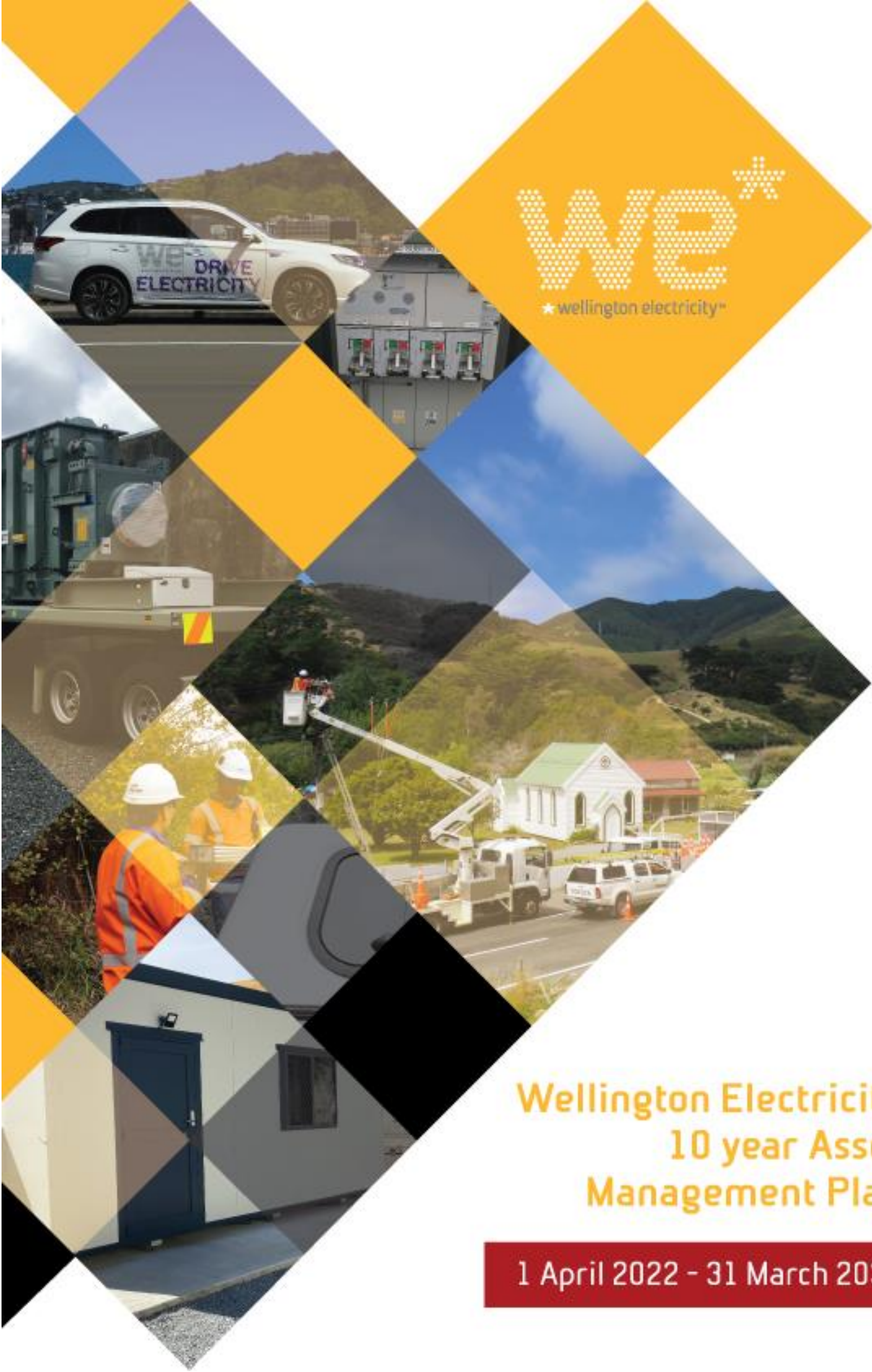

Wellington Electricity 10 year Asset Management Plan

1 April 2022 – 31 March 2032

Wellington Electricity

10 Year Asset Management Plan

1 April 2022 – 31 March 2032

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

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LIABILITY DISCLAIMER

Wellington Electricity Lines Limited (WELL) has prepared this Asset Management Plan (AMP) for public disclosure in accordance with the requirements of the Electricity Distribution Information Disclosure Determination, October 2012 (Consolidated in 2018).

Information, outcomes and statements in this version of the AMP are based on information available to WELL 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.

Neither WELL nor any other person involved in the preparation of this AMP will be liable, whether in contract, tort (including negligence), equity or otherwise, to compensate or indemnify any person for any loss, injury, or damage arising directly or indirectly from any person relying on this AMP, to the extent permitted by law.

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 (WELL) welcomes the opportunity to submit an updated Asset Management Plan (AMP) for the regulatory period 2022/23 to 2031/32. We confirm that this AMP has been prepared in accordance with the Commerce Commission's (the Commission) Electricity Distribution Information Disclosure Determination 2012 requirements.

Our operations over the last 12 months, despite the response to the COVID-19 pandemic, have continued to focus on delivering high levels of safety, reliability and service to our customers. WELL continues to proactively engage with WorkSafe, the Commission, the Electricity Authority (EA), the Climate Change Commission (CCC), and the Infrastructure Commission on improvements in safety and wellbeing performance, the price-quality path, market regulations, and the step changes required to meet the challenges of sustainable asset investment, so that customers can continue to receive the long term benefits from secure and affordable electricity infrastructure.

Health, safety, and wellbeing remain positive drivers for improved engagement with both our own staff and field staff engaged under an outsourced arrangement. This has been a challenge particularly with the ongoing restrictions of ongoing separated staff (work from home) arrangements to manage the pandemic response. In addition, there has been an increase in demand for connections in response to housing shortages and favourable economic conditions for developers. We continue to focus on improving safety behaviours and standards recognising that safety is an ongoing discipline that requires regular support. This is particularly relevant to maintaining wellness through more engaged conversations.

The field services agreement has continued to refine our work prioritisation and programming tools, and we have benefitted from improved low voltage (LV) network management. As a lifeline utility, we are proud to continue to deliver our community with a safe, reliable and secure energy delivery system, including under the uncertain circumstances of a pandemic.

During the year the Commission completed its investigation of WELL's exceedance of the Quality Path in 2016-2018, and concluded that the outage exceedances were beyond WELL's reasonable control and allowance levels were not sufficient to address all of the interruptions which occurred. WELL is pleased with the result of the result of the investigation, as it confirms that WELL continues to operate in line with good industry practice. There were good learnings from the investigation which WELL have adopted as part of our continuous improvement programme.

WELL continues to maintain a strong team effort across planning, real-time control and field implementation, which makes this network one of the best performing in New Zealand. Engagement continues with consumer groups on feeders experiencing vegetation outages. Our tree management practices are benefitting from the move from the traditional notification process to a more consultative approach with tree owners. We also eagerly await the Ministry of Business, Innovation and Employment's (MBIE) review of the Hazards from Trees Regulations.

This AMP reports on future plans still to be discussed with the Commission regarding how the Wellington Lifelines Regional Resilience Project is accommodated under Part 4 of the Commerce Act, for the long-term benefit of our customers. Good progress is being made with earthquake strengthening. We also welcome Transpower getting the green light from the EA that the benefit-cost for diversification of the Central Park grid exit point is a positive investment for consumers and hence should proceed directly.

We continue to invest in the network assets where they require replacement or maintenance to meet the required asset performance standards. Our maintenance management approach is prioritised based on asset health and asset criticality. This focuses expenditure on the highest ranked safety and reliability risk defects. These costs are expected to increase on the back of higher supply chain and material costs.

Despite stable network volumes over the last four years, the change in the economic environment has seen significant development in the region which is starting to affect network capacity headroom in some areas. Some large national operators and regional agencies have requested demand increases beyond the secure capacity of subtransmission and zone substation ratings. This will require an application to reopen the Default Price-quality Path (DPP) as the allowances for this investment was not anticipated for the 2020-25 regulatory period.

WELL made a submission to the CCC's Emissions Reduction Plan consultation process and await its publication in May 2022. The Plan is expected to recommend decarbonisation programmes to electrify transportation, transition from gas to electricity and to electrify manufacturing process heat. This will require greater investment and management of the electricity network than is contemplated from a business as usual DPP framework. Our engagement with the Commission's Input Methodology (IM) review programme this year considered how sustainability, affordability, and security of supply will be balanced to provide confidence for shareholders ahead of considering further investment in additional infrastructure that supports New Zealand's climate change initiatives. WELL is unable to anticipate the additional investment without understanding the supportive change in renewed IMs, so the AMP continues to be based on the current DPP allowances for the 2020-25 period until the IM review confirms regulatory settings which flexibly support climate change investment. Investment is likely to be delayed along with a dampened response to electrification projects until a sound regulatory investment framework is established from 1 April 2025.

WELL's move to Time of Use (ToU) prices for residential customers has been applied through by Traders to 40% of the eligible connections. ToU pricing is used to reward customers for shifting demand away from peak demand periods, delaying the cost of further network investment. Further work is required to coordinate initiatives like this through the supply chain for the benefit of customers.

WELL has collaborated with technology partner GreenSync and a wide range of stakeholders to develop the EV Connect Roadmap setting out changes needed to support the introduction of EVs and offer managed EV charging flexibility services. Changes include ensuring regulation and policy supports the action needed to connect EVs and that networks operators are appropriately funded. This forward-looking approach allows WELL to manage and support the pace of distributed energy resource (DER) adoption as well as other climate change initiatives to meet decarbonisation targets.

Being a member of the CK Infrastructure Holdings Limited group allows WELL to access skills and knowledge from our other electricity distribution businesses around the world and have direct access to international best practice in asset management.

In conjunction with our service providers and in alignment with its business strategy, WELL will continue to focus on the development of asset management strategies in parallel with the short to long term planning for the network for sustainable investment that delivers long term benefits for customers.

We welcome any comments or suggestions regarding this AMP.

Greg Skelton

Chief Executive Officer

Contents

Section 1

Executive Summary

1 Executive Summary

The purpose of this Asset Management Plan (AMP) is to communicate Wellington Electricity Lines Limited's (WELL's) approach for the safe, reliable, cost effective and sustainable long-term supply of electricity. The AMP explains how electricity supply will be delivered at a quality and price expected by electricity customers connected to the Wellington network.

1.1 Term Covered by the 2022 AMP

This AMP covers the 10-year period commencing 1 April 2022 through to 31 March 2032. It was approved by WELL's Board of Directors on 29 March 2022.

1.2 Key Elements of the 2022 AMP

Key elements of this AMP are:

- Electrification of transport;
- Network reliability: continued focus on network reliability management; and
- Network resilience.

Appendix B provides detail on the changes made since the 2021 AMP.

1.2.1 Electrification of Transport

Electrification of the transport fleet is a key focus for New Zealand to achieve the Government's decarbonisation targets, and has the potential to grow exponentially in the next decade. Electric vehicles (EVs) and other forms of electrified transportation will increase energy demand across the network when they plug in to charge.

The actual impact of these EVs connecting to the network at the same time for battery charging, depends on charger types, duration and connection capacity, but could be adding more than 150 MW (~25%) to the peak demand if not managed carefully. This will lead to a significant change in WELL's asset planning requirements and investment.

To support the increase in adoption of EVs, WELL has a number of EV specific work streams:

- **EV Charging Trial**: In late 2017 WELL conducted a trial to better understand the home charging behaviours of EV owners and how they could potentially affect the demand for electricity. The results of the trial have helped influence the design of EV pricing and provided an insight into customers' preferences for future EV charging services.
- **Time of Use (ToU) Prices**: WELL has introduced ToU prices which encourage EV users to charge their vehicles during less congested periods. Charging during less congested periods on the network means a larger network doesn't have to be built to cater for the expected increase in EVs. Avoiding having to build a larger network means that prices can be kept low.
- **EV Connect**: EV Connect is an industry-wide work programme that focuses on how more energy can be delivered through the existing network. The purpose of EV Connect is to support EV adoption while maintaining network security. This is part of an Energy Efficiency & Conservation Authority (EECA) Low

Emission Vehicle Contestable Fund (LEVCF) project that WELL has delivered in collaboration with its technology partner Greensync.

WELL has developed a roadmap of the industry changes needed to support the introduction of EVs and to offer manged EV charging flexibility services. The changes outlined in the EV Connect Roadmap include ensuring regulation and policy supports the action needed to connect EVs and that network operators are appropriately funded. The Electricity Code provides rules to ensure consumers can safely connect EVs in their homes. The Roadmap highlights the need for flexible regulation that allows stakeholders to test and develop new services without creating barriers that restrict or slow progress. For example, regulation is needed to ensure customer devices have the right technical specification to participate in the future flexibility services.

The EV Connect Roadmap can be found on the WELL website at https://www.welectricity.co.nz/about-us/major-projects/ev-connect/. WELL is now implementing the Roadmap actions, starting with setting up a Leadership Group. This year it will be looking to partner with flexibility providers to trial EV charging flexibility services.

1.2.2 Network Reliability

Wellington's electricity network is one of the most reliable in New Zealand due to the high proportion of underground cabling. However, the overhead network can be vulnerable to damage from storms and other external events. While large disruptions can occur and some interruption is expected, customers can reasonably expect to have supply returned without undue delay as their welfare and the region's economy will quickly suffer if the power stays off. For this reason, WELL is committed to providing customers with a reliable, cost-effective and secure electricity supply as determined by the price-quality regulation allowances.

The reliability performance of the network in the 2021/22 year was good, following similarly strong 2018/19, 2019/20, and 2020/21 year results.

The Commerce Commission (the Commission) has completed its investigation into WELL's non-compliance with the Quality of Supply standards for the 2016/17 and 2017/18 regulatory years, The Commission engaged engineering consultancy Nuttall Consulting to investigate and provide an expert opinion on the non-compliance.

Nuttall Consulting found that WELL's practices and actions were largely consistent with good industry practice. They agreed with WELL's analysis that the cause of the exceedances were largely outside of WELL's reasonable control as they were due to a period of unusually high wind events, a large number of car vs pole events, and damage resulting from the November 2016 Kaikoura earthquake event. Nuttall Consulting found that WELL has a very strong attitude to finding the causes of the exceedances and putting in place controls to improve reliability performance.

The Commission considered that the findings of the Nuttall report do not indicate any serious concerns with WELL's wider management of the network, or of its asset management practices in general. The Commission has confirmed that it will not be taking any enforcement action against WELL for these exceedances.

1.2.3 Resilience Initiatives

As a lifeline utility in accordance with the Civil Defence and Emergency Management Act 2002 (CDEM Act), WELL must ensure that it is able to function to the fullest possible extent, even though this may be at a reduced capacity, during and after an emergency. This can include one-off events such as storms and earthquakes. A concern for WELL is that the existing avenue of funding, via either the Default Price Path (DPP) allowances or the expensive Customised Price Path (CPP) process better suited to very large investments, does not cater for resilience programmes. This was shown by WELL's unique Streamlined CPP (SCPP) application which needed to be supported by a Government Policy Statement to address earthquake readiness following the 2016 Kaikoura earthquake.

WELL has investigated future resilience initiatives with the Wellington Lifelines Group to improve the network's ability to withstand High Impact Low Probability (HILP) events. These initiatives include:

- The evaluation of solutions with Transpower on the options to manage the single point of supply risk of the Transpower Central Park grid exit point in Brooklyn. The project is now moving ahead with Transpower establishing a project team to deliver the project by the end of 2026; and
- Expenditure for replacement of high vulnerability 33kV fluid-filled cables is being discussed to determine whether to bring forward replacement with a more durable cable material which, once installed, allows faster restoration of power following a major earthquake.

The expenditure for these items is not included in the cost forecasts in this AMP. The Central Park grid exit point work will be funded under a new customer connection contract with Transpower and recovered as a pass-through cost to end customers. The accelerated replacement of fluid-filled cables for resilience reasons sits outside of the existing regulatory framework, and would need support from regulatory agencies and further consultation with customers.

1.3 Service Levels

WELL continues to deliver services to customers and other stakeholders within the region at one of the highest availability levels in the country. In accordance with WELL's mission and stakeholder feedback, WELL has identified three service level measures for the period covered by the AMP. These are:

- Safety Performance;
- Customer Experience; and
- Reliability Performance.

1.3.1 Safety Performance

WELL continues to build on its strong foundation, set by past health and safety performance. Continual improvement in managing health and safety is at the core of WELL's values and involves ongoing review of health and safety practices, systems, controls (and their effectiveness) and documentation.

WELL welcomed the change in legislation to continue to improve workplace safety and focus on effective identification and management of risks to protect the welfare of workers engaged in delivering services, as well as the safety of the public. Within this context of continuous improvement, four primary measures are used:

- Incident and near miss reporting;
- Corrective actions from site visits;
- Lost Time Injury Frequency Rate (LTIFR); and

- Total Notifiable Event Frequency Rate (TNEFR).

Planning Period Targets and Initiatives

WELL's targets for the 10-year planning period are to:

- Maintain the number of addressed hazard observation events reported per annum at approximately 200;
- Maintain contractor engagement through site visit assessments at 400 per annum, while continually reducing resulting actions;
- Achieve a zero LTIFR over the whole period; and
- Achieve a zero TNEFR over the whole period.

During 2022 focus will be placed on the following areas to further improve safety performance:

- Reinforcement of WELL's safety brand "safer together";
- Increased emphasis on the Te Whare Tapa Whā principles of wellbeing (family, physical, mental, and spiritual) of staff and field workers via focussed programmes and engagements;
- Maintain the timeliness of close-out of assessments;
- Reinforce the application of the risk management framework and expand the risk assessment process with clear focus on critical risk and control management and principal/contractor communications;
- Maintain critical risk engagement visits to:
    - check that workers have received safety instructions and have adapted work practices or processes as a result;
    - engage with workers over work place safety and to help ensure WELL's critical risks are being effectively managed; and
    - ensure service provider workers understand all critical risk controls, especially where these interface with WELL risks.
- Continue to expand the consultation, coordination, and cooperation where work involves overlapping PCBU duties; and
- Increase strategic risk collaboration with contracted field service providers in development of practical and effective risk controls.

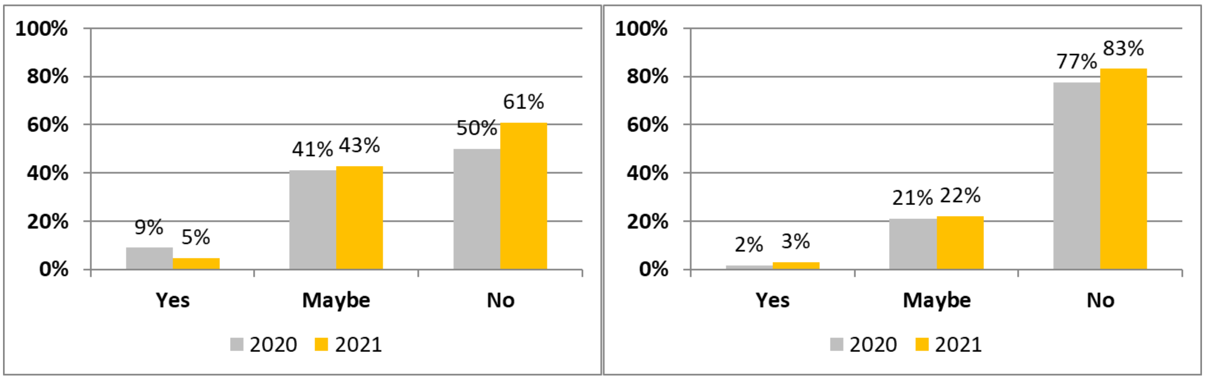
1.3.2 Customer Experience

It is important that WELL balances services that customers require with what value they place on these now and into the future. WELL uses insights received from customer engagement to test that the right service levels are being provided and to inform investment plans for the planning period.

In addition to good reliability and appropriate prices, customers increasingly expect accurate and timely information on their service and its status. Most customers accept occasional power cuts, but the ability to keep them informed as to when supply will be restored is also important (e.g. via an outage application). Ensuring good customer service means a reliable and effective information flow is a priority. To continue providing effective information to customers, WELL sets and tracks performance targets for the customer contact centre.

1.3.2.1 Customer Engagement

To understand the impact of outages on connected customers, WELL surveys the communities who have recently had an outage to understand whether the price-quality trade-off of the service they receive is appropriately balanced. Examples from results for two key questions from the survey undertaken in 2021 are shown in Figure 1-1.



Q1. Would you be prepared to pay a bit more for your power if it meant fewer power cuts?	*Q3. Would you be prepared to have slightly more power cuts if it meant your electricity bill was a bit lower?*

Figure 1-1 Sample of 2021 Customer Survey Results

These results suggest that customers are broadly satisfied with their current level of reliability and the price for delivering that service.

WELL engaged in a number of other initiatives aimed at improving customer, with some examples being:

- **Connections & Self-Service:** During 2021 a number of functionality improvements have been developed for the WELL website's self-service portal. These changes will be released in the first half of 2022 and will enable customers to be guided to the right channels for the services they wish to request. The changes are intended to enhance the experience for customers and remove a potential 'cost' hurdle for a significant number seeking a new connection to the network. For those customers seeking new connections that require extensions to the network, a fixed fee option will be provided to the majority of small to medium sized customer connection requests.

- **Community Engagement:** During 2021 WELL's plans for community engagement were again disrupted by the impacts of COVID-19. Staff were still able to meet with a number of customers who had lodged complaints, to better understand their experience and to help identify the root cause of their complaint. This is an important component of WELL's Root Cause Programme.

  During 2022 WELL will be developing alternate methods to engage with communities which will reduce the risks arising from COVID-19.

- **Root Cause Programme:** The Root Cause Programme targets people, process and system gaps which may have led to customers expressing dissatisfaction with our service. Staff of both WELL and its contractors meet to review complaints raised and work together to develop solutions to address those complaint causes. Within the 2021 year the programme achieved a 30% decrease in customer complaints received, helping to improve the customer experience.

In 2022, WELL will be delivering four new customer experience improvement programmes:

- **Self-service Improvement:** Continued development of the web-based self-service platform to further improve its functionality and to deliver an improved customer experience.

- **Service Improvement:** WELL continues to analyse and target for improvement the root causes of complaints received from customers and/or their retailers. As part of that programme WELL staff members will visit a number of customers who have reported poor service throughout the year to better understand their experiences.

- **Community Engagement:** WELL plans to continue engaging with communities most impacted by outages as part of the 'Worst Performing Feeder' programme. The programme aims to update customers on network activities in their area and to inform customers of what actions they can take to help improve their electricity supply, such as vegetation management. As noted above, WELL will be developing alternate methods to engage with communities to reduce the risks arising from COVID-19.

  In addition, as mentioned above in 'Service Improvement' a number of customers impacted by perceived poor service will be visited to better understand their experiences.

- **Planned Outage Publication:** Planned outages are currently sent by WELL to retailers, who in turn publish those outages to their customers. During 2021 WELL piloted the publication of planned outages within the outage reporting section on its website. This information provides an additional notification channel rather than replacing the current publication arrangement with retailers. During 2022 WELL plans to expand the planned outage publication service to include a wider number of planned outages. This will provide another option for customers to view updates on outages which may impact their electricity supply.

- **Community Education:** The Government's proposals to help New Zealand reduce its carbon emission levels are likely to result in increased demand for electricity and significantly impact the network. WELL will be developing a number of communication programmes to provide customers with an insight into those impacts. The programmes will inform customers about how WELL is planning to mitigate the impacts and how they can help shift electricity consumption away from the network's busy periods. The aim is to avoid or delay the need to build a bigger network and hence help to continue providing customers with low network prices.

1.3.3 Reliability Performance

The regulatory regime that applies to WELL sets reliability limits for each year. The DPP3 price-quality regime in place for 2021/22 to 2024/25 sets limits for outages based on historical performance during the reference period of 1 April 2009 to 31 March 2019.

The regulatory reliability limits for WELL are presented in Table 1-1.

Regulatory Year	2021/22-2024/25
Annual Unplanned SAIDI Limit	39.81
Annual Unplanned SAIFI Limit	0.6135
Period Planned SAIDI Limit	55.76
Period Planned SAIFI Limit	0.4429
Extreme Event - Customer Minutes Limit	6 million

Table 1-1 WELL Regulatory Reliability Limits

The SAIDI and SAIFI targets against historical performance are shown in Figure 1-2 to Figure 1-5. The 2021/22 year includes a forecast to account for March 2022.

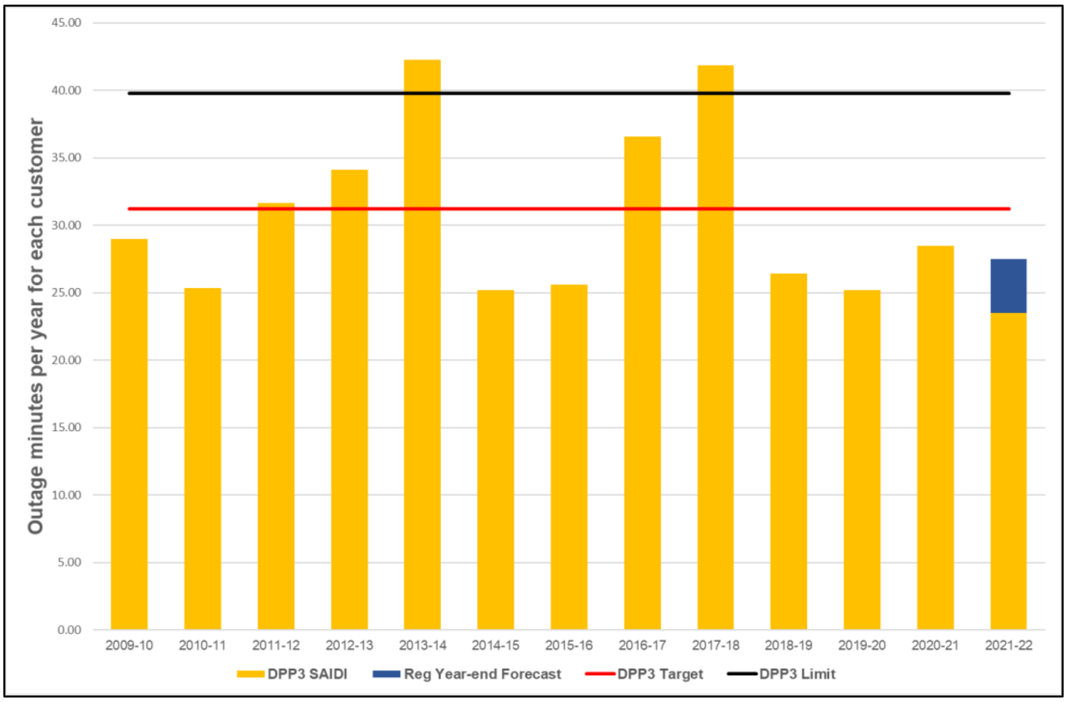


Figure 1-2 WELL Unplanned SAIDI Performance

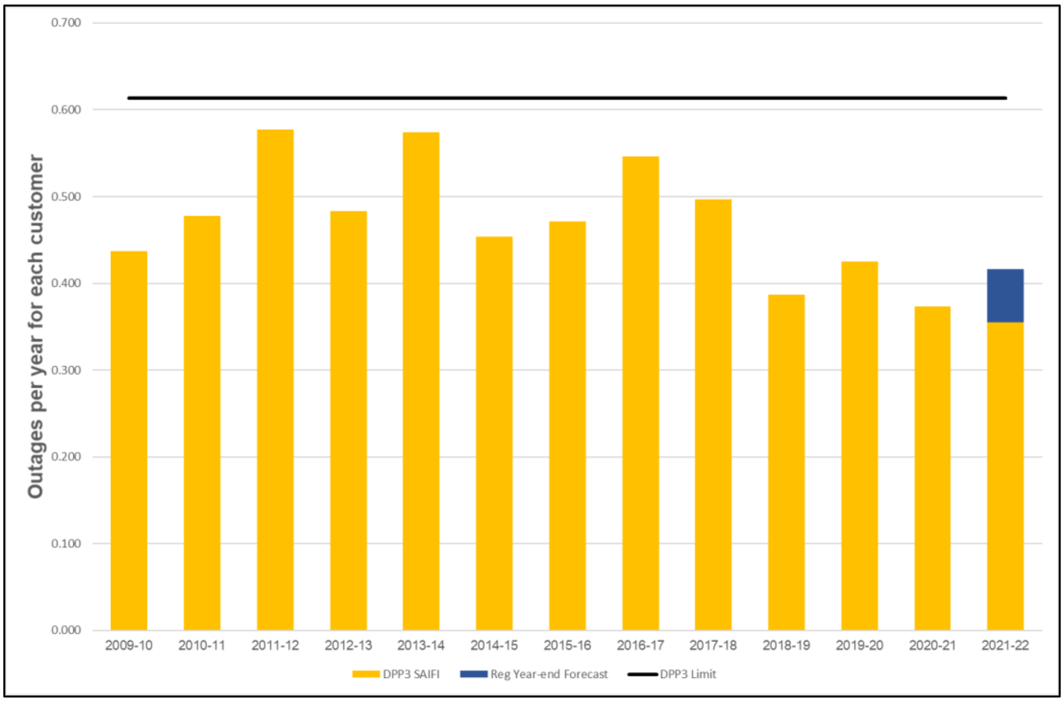


Figure 1-3 WELL Unplanned SAIFI Performance

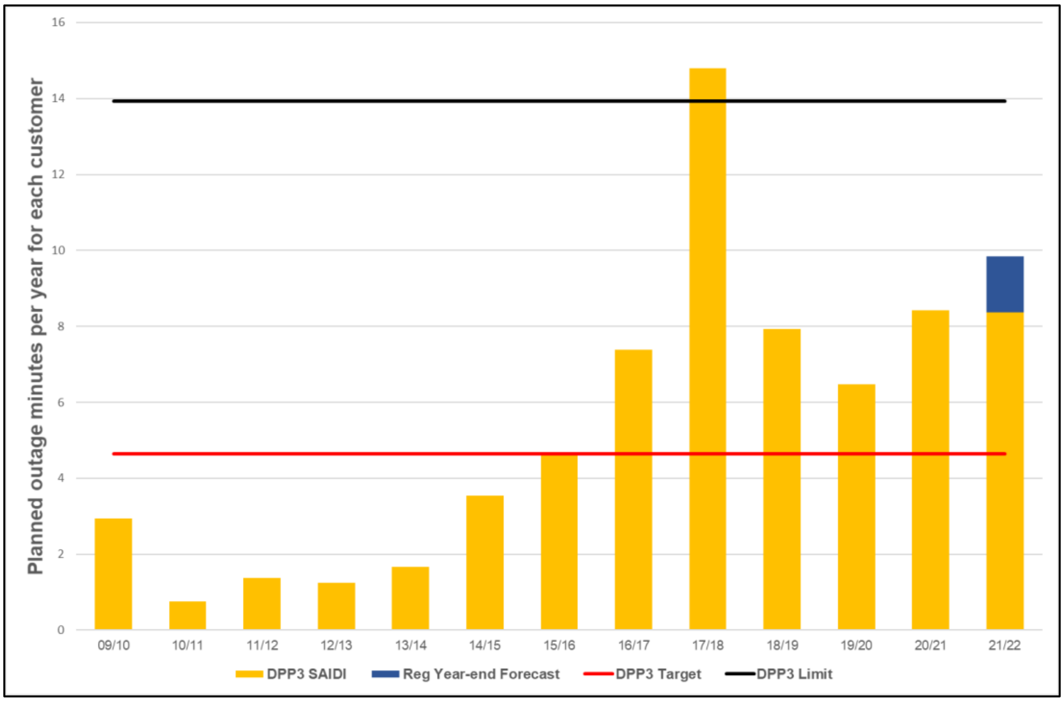


Figure 1-4 WELL Planned SAIDI Performance

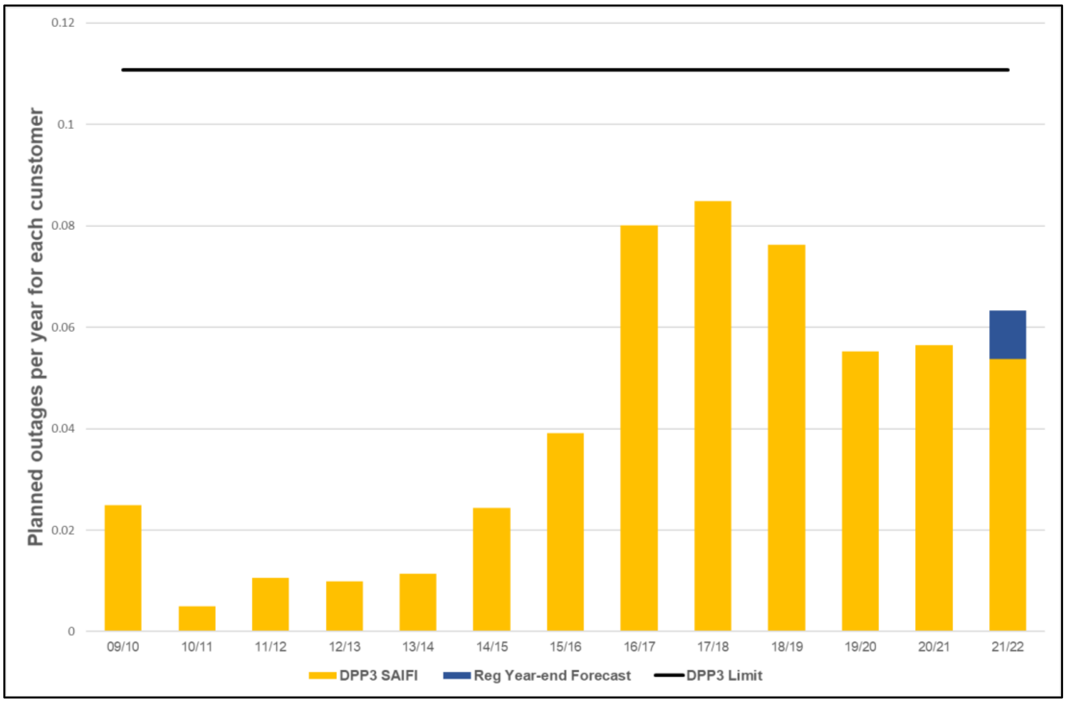


Figure 1-5 WELL Planned SAIFI Performance

WELL has consistently demonstrated a commitment to meet reliability targets. Analysis of the main causes of network performance and WELL's initiatives to respond in future years is provided in Sections 5 and 6.

WELL's targets for SAIDI and SAIFI are shown in Table 1-2. These targets assume that the SAIDI and SAIFI targets beyond 2025 will be calculated using the same methodology as the 2019 DPP3 determination.

Regulatory Year	2022/23	2023/24	2024/25	2025/26	2026/27	2027/28	2028/29	2029/30	2030/31	2031/32
Unplanned SAIDI target	31.20	31.20	31.20	31.20	31.20	31.20	31.20	31.20	31.20	31.20
Unplanned SAIFI target	0.480	0.480	0.480	0.480	0.480	0.480	0.480	0.480	0.480	0.480
Planned SAIDI target	10.00	10.00	10.00	10.00	10.00	10.00	10.00	10.00	10.00	10.00
Planned SAIFI target	0.067	0.067	0.067	0.067	0.067	0.067	0.067	0.067	0.067	0.067

Table 1-2 Network Reliability Performance Targets

WELL reliability targets for the planning period are:

- Meet the Unplanned SAIDI and SAIFI targets;
- Not exceed a Planned SAIDI of 10 minutes;[1] and
- Zero Extreme Events.

[1] The planned targets will be more difficult be meet because these are based on an average that includes the years between 2009 and 2015 with low levels of planned SAIDI/SAIFI.

1.4 Trend in Energy Consumption and Demand

The historic volume of energy supplied through the network declined at an average rate of approximately 0.7% per annum from 2012 to 2018 and then increased at an average rate of approximately 0.9% per annum from 2018 to 2021.

The past four years have seen stable volumes overall, as shown in Figure 1-6. Residential volumes have increased with an increase in new connections and Distributed Energy Resources (DERs) like EVs connecting to the network. The increase in residential energy use has been offset by a decrease in commercial and industrial volumes due to energy efficiency improvements and a decrease in the number of large commercial and industrial connections.[2]

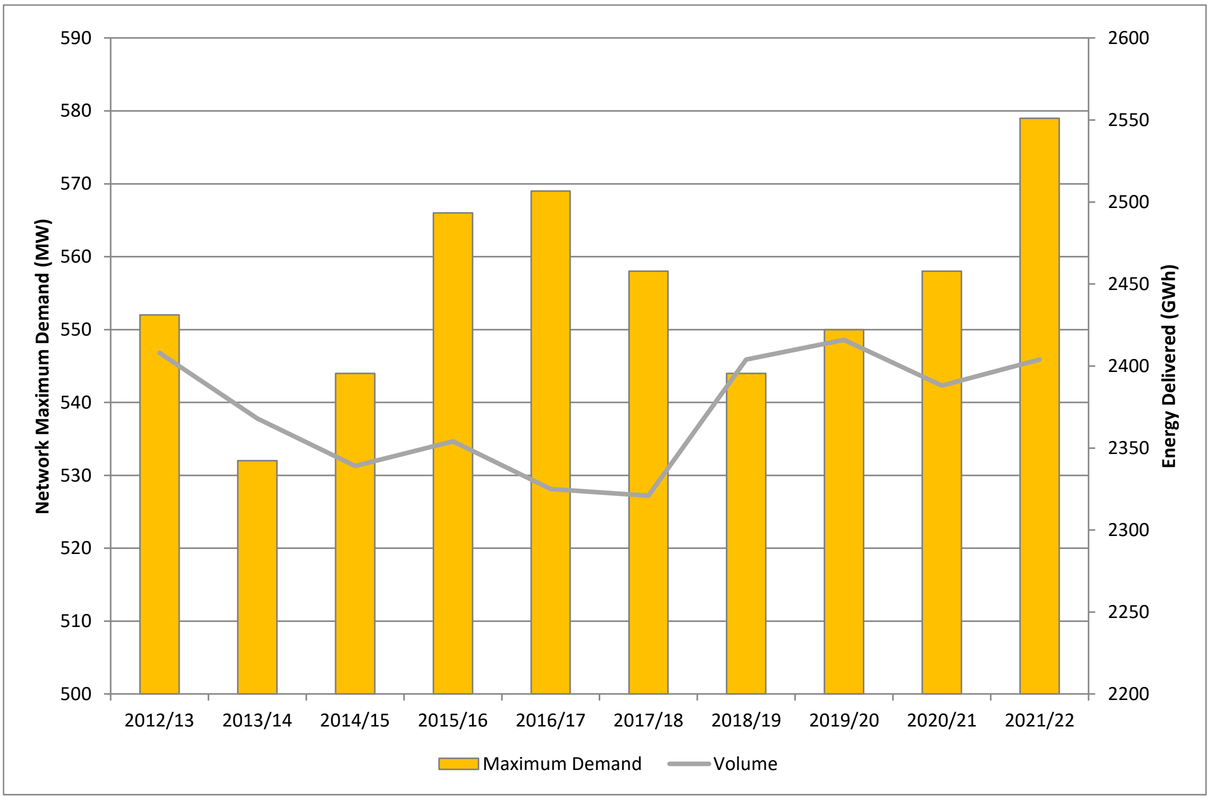


Figure 1-6 Trend in Maximum Demand and Energy Consumption

Actual consumption on the network will be driven by seasonal temperature variations and the associated customer responses, the uptake of emerging technologies, and the timing of large-scale one-off customer-led developments. WELL has a winter peaking network and a colder than usual winter or a higher uptake of EVs would drive both an increase in energy demand and consumption.

Changes in consumption patterns can also depend on clear cost reflective pricing signals to enable customers to make informed energy use decisions. Both the Electricity Authority and the Electricity Price Review highlighted the importance of clear pricing signals to manage congestion and to allow customers to make informed energy choices when they consider emerging technology.

[2] Impacted by COVID 19 with more work being done from home.

1.4.1 Demand Forecast

For several years the number of new dwellings consented annually in the Wellington region (across the four local authorities) has been increasing, driven by the growth in apartments within the Wellington CBD and subdivision growth along the northern belt. Figure 1-7 shows the number of new dwellings consented over the last seven years.

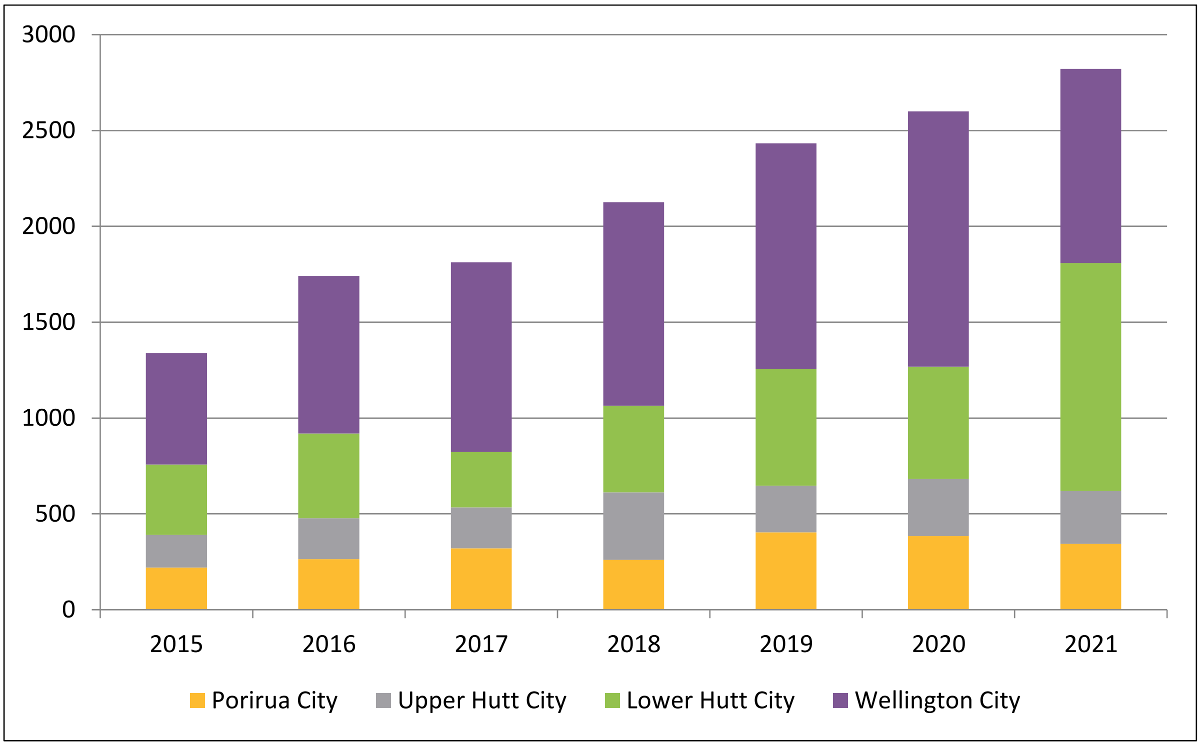


Figure 1-7 Number of New Dwellings Consented in the Wellington Region

Growth in peak demand drives system constraints and the need for additional investment, either in the network or an alternative means of providing or managing the capacity.

The sustained peak demand is forecast to grow in some localised areas of the network, driven by new commercial and residential developments. Generally, demand peaks within the Wellington region are driven by winter temperatures on the coldest days.

While the overall load in Wellington is traditionally winter peaking, recent trends have shown that a few of the zone substations within the Wellington city are now summer peaking.

Figure 1-8 illustrates the forecast peak demand (system maximum demand) for the last seven years and the forecast for the next 10 years.

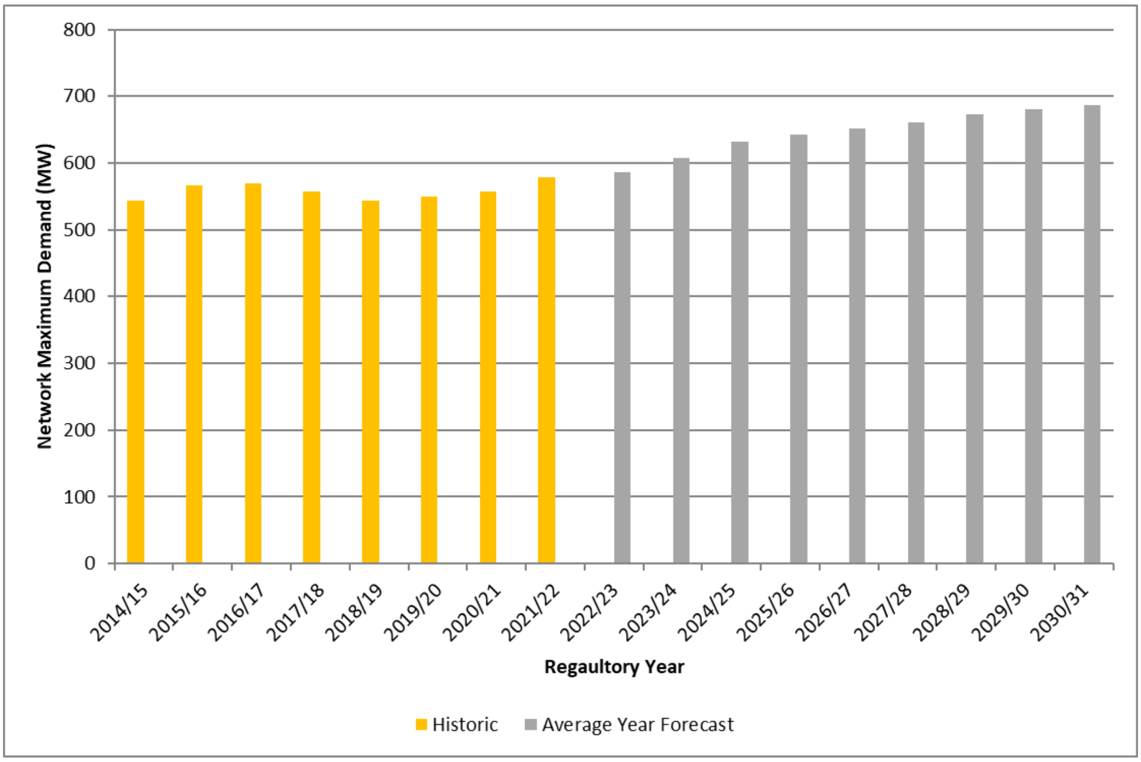


Figure 1-8 Network Historic and Forecast Maximum Demand

The evolution of technology supported by different pricing plans and business models will incentivise customer behaviour and technology choices which will help support decisions for efficient network investment. Therefore the investment profile in future years will continue to change as forecasts are updated.

1.5 Network Expenditure

1.5.1 Network Capital Expenditure

WELL separates the network capital expenditure forecast into five categories:

1. Asset Renewal - includes specific replacement projects identified in the fleet summaries and routine replacements that arise from condition assessment programmes. This is driven by the replacement of assets such as poles, switchgear and 11 kV/400 V substations.

2. Reliability, Safety and Environment - includes expenditure that is not directly the result of asset health drivers, including supply projects targeting the worst performing feeders and the seismic building reinforcement programme as well as other SCPP readiness works.

3. System Growth - driven by system development needs and is dependent on the timing and location of peak demand growth and other areas of growth on the network.[3]

4. Relocation Capital – expenditure required to relocate assets primarily due to roading projects and where the cost is normally shared with NZ Transport Agency.

[3] There has been an addition of extra expenditure for new technologies that has been incorporated into the System Growth category. This is currently not funded under the DPP, and has been added as an addition over and above existing allowances.

5. Customer Connection – includes the costs to deliver customer requested capital projects, such as new subdivisions, customer substations or connections.

The network capital expenditure, both historical and forecast, is shown in Figure 1-9.

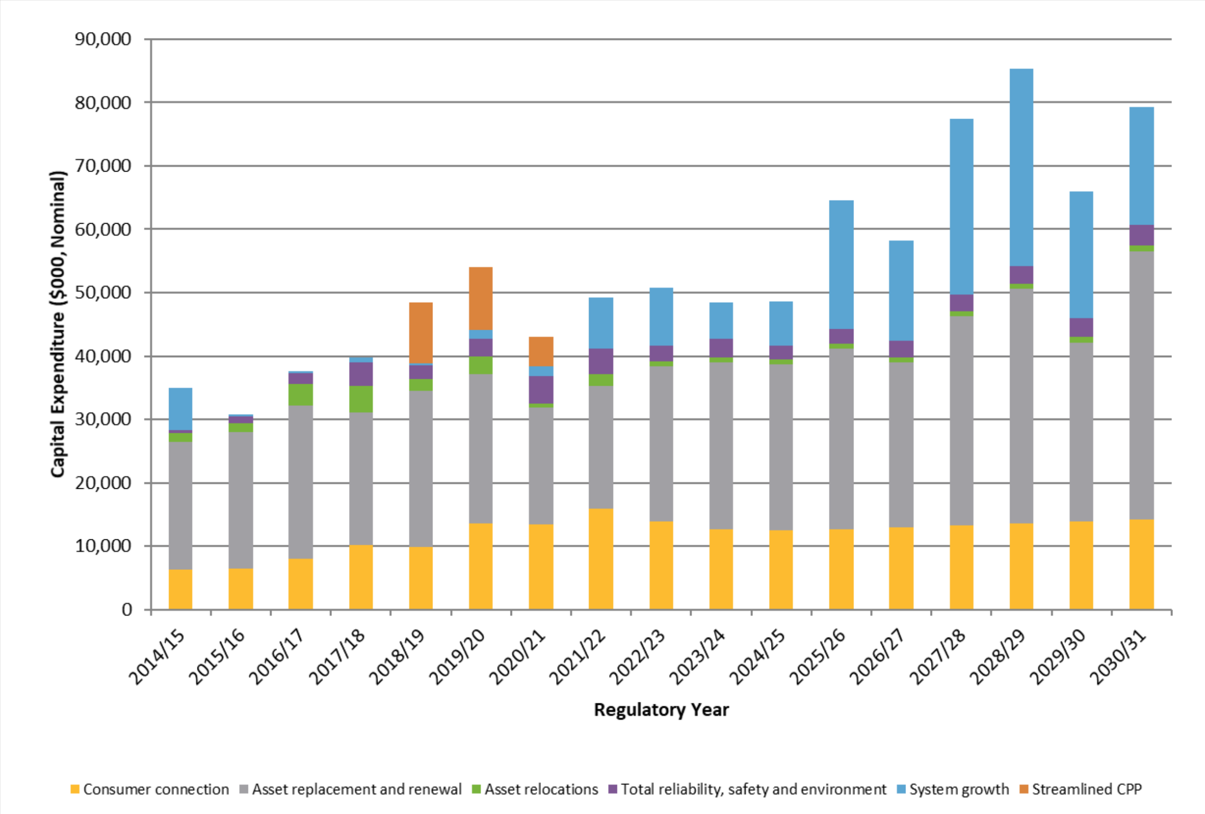


Figure 1-9 Network Capital Expenditure ($K in nominal prices)

The variability of the forecast capital expenditure is driven mainly by System Growth projects required to accommodate localised peak demand growth, and variability in the larger 33 kV cable and power transformer replacement projects in the Asset Renewal category.

1.5.2 Network Operational Expenditure

WELL separates network operational expenditure forecast into four categories:

1. Service interruptions and emergencies – includes work that is undertaken in response to faults or third party incidents, and includes equipment repairs following failure or damage.
2. Vegetation management – covers planned and reactive vegetation work, through a risk-based programme in addition to cut/trim zone administration.
3. Routine and corrective maintenance and inspection. This comprises:
    - Preventative Maintenance works – includes routine inspections and maintenance, condition assessment and servicing work undertaken on the network. The results of planned inspections and maintenance drive corrective maintenance or renewal activities;
    - Corrective maintenance works - includes work undertaken in response to defects raised from the planned inspection and maintenance activities; and

- Value added - covers customer services such as cable mark outs, stand over provisions for third party contractors, and provision of asset plans for the 'B4U Dig' programme, to prevent third party damage to underground assets.

4. Asset replacement and renewal - includes repairs and replacements that do not meet the requirements for capitalisation.

The network operational expenditure, both historical and forecast, is shown in Figure 1-10.

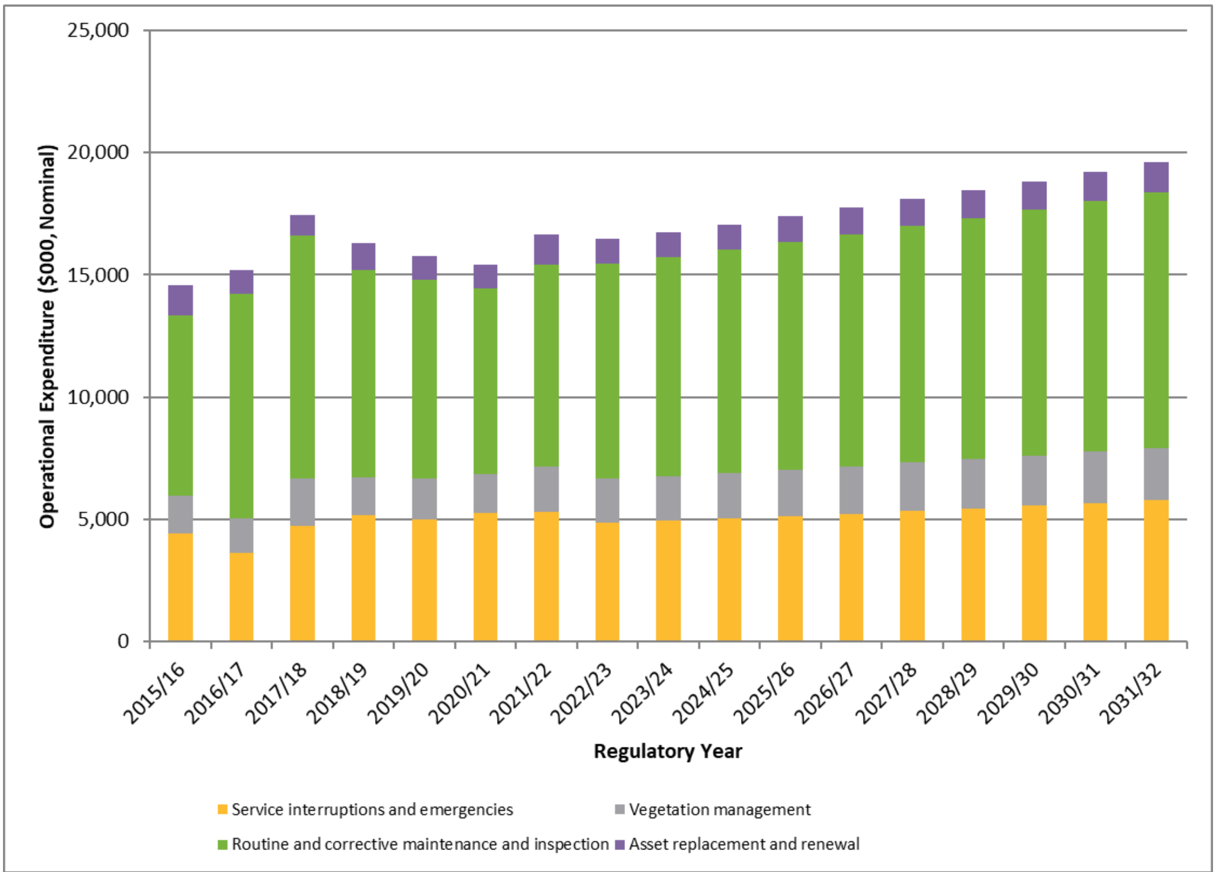


Figure 1-10 Network Operational Expenditure
($K in nominal prices)

1.6 Capability to Deliver

WELL has the organisational and external service provider structures in place required to implement this AMP. Where new business requirements exist beyond current practice, these will be assessed against the present business capability and, where necessary, further resources will be considered (whether financial, technical, or contractor resource) to achieve any new business or customer requirements.

As WELL is part of the CK Infrastructure Holdings Limited group it has access to relevant skills and experience from across the world. This provides WELL with direct access to international best practice systems and visibility of new technology trials.

WELL's Board of Directors and senior management team have reviewed this AMP against the business strategy to ensure alignment with business capability and priorities as well forecasted new technology developments.

Section 2

Introduction

2 Introduction

This Asset Management Plan (AMP) has been prepared in accordance with the Commerce Commission's (the Commission) Information Disclosure (ID) Determination, October 2012 (consolidated in April 2018). It describes WELL's long-term investment plans for the planning period from 1 April 2022 to 31 March 2032.

The document was approved for disclosure by the WELL Board of Directors on 29 March 2022.

2.1 Purpose of the AMP

The purpose of this AMP is to:

- Be the primary document for communicating WELL's asset management practices and planning processes to stakeholders;
- Describe how stakeholder interests are considered and integrated into business planning processes to achieve an optimum balance between the levels of service, price / quality positions, and cost effective investment; and
- Illustrate the interaction between this AMP, WELL's mission "*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"*, and its asset management objective *"to optimise the whole-of-life costs and the performance of the distribution assets to deliver a safe, cost effective, high quality service".*

WELL's asset management practices summarised in this AMP inform WELL's business planning processes including its annual Business Plan and Budget.

2.2 Structure of this Document

This AMP has been structured to allow stakeholders and other interested parties to understand WELL's business and the operational environment. The body of the AMP is structured into the following three categories:

- **Overview and Approach** which provides an overview of WELL and the approach taken to asset management;
- **Performance Targets and Levels of Service** which provides an overview of the various safety, customer and reliability targets that WELL is measured against and WELL's performance against those targets; and
- **10 Year Investment Plan** which describes WELL's assets, associated strategies, and investment profile over the planning period to meet the defined service levels.

Figure 2-1 illustrates the structure of this AMP.

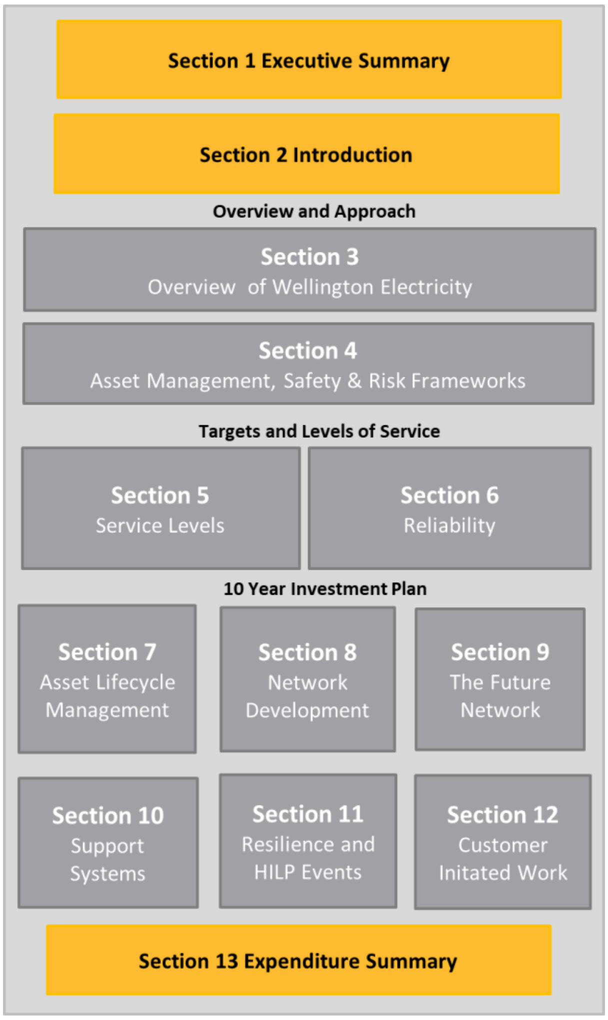


Figure 2-1 Structure of the 2022 AMP

2.3 Formats used in this AMP

The following formats are adopted in this AMP:

- Financial values are in constant price 2022 New Zealand dollars, except where otherwise stated;
- Calendar years are referenced as the year e.g. 2022. WELL's planning and financial years are aligned with the calendar year;
- Regulatory years are from 1 April to 31 March and are referenced as 20xx/xx e.g. 2022/23;
- All asset data expressed in figures, tables, and graphs is at 31 October 2021 unless otherwise stated;
- Installation Control Point (ICP) numbers are as at December 2021; and
- All asset quantities or lengths are quoted at the operating voltage rather than at the design voltage. For example, WELL has 17km of 33kV cable operating at 11kV. The length of these cables is incorporated into the statistics for the 11kV cable lengths and not the 33kV cables.

2.4 Investment Projections

The investments described in this AMP underpin WELL's business plan. The expenditure and projects are continually reviewed as new information is incorporated and asset management practices are further refined and optimised. The development of asset management strategies is driven by:

- The need to provide a safe environment that is free from harm for staff, contractors and the public;
- The need to understand customers ongoing requirements to maintain a reliable supply;
- The current understanding of the condition of the network assets and risk management;
- Assessment of load growth and network constraints;
- New and emerging technologies and their role in the future operations of WELL as a Distribution Network/System Operator to meet changing customer needs;
- Changes to business strategy driven by internal and external factors; and
- The impact of the regulatory regime.

Accordingly, specific investments within the next two to three years are relatively firm with plans towards the latter part of the 10-year period subject to an increasing level of uncertainty.

Further indicative forecasts have also been included into Section 11 for future works to further enhance the long term resilience of key network assets in preparation for a major catastrophe. These future works have not been included into the overall capex projections in Appendix C. This is due to the current regulatory mechanism being unable to feasibly support such expenditure.

The forecasts related to new technology trials have been included in Section 9 and have been included as part of the capex forecasts in the system growth category of Appendix C.

It is expected that reduced gas availability and the large scale transition of vehicle fleets from fossil fuels to electricity will drive a need for increased reinforcement of the network. This investment is likely to need to commence towards the end of the planning period. At the time of updating this AMP work has progressed to draft a 30-year model which will be further refined and shared with the Commission as part of the Input Methodology consultation. The aim is to indicate how expected future investment to meet the increase in energy demand from decarbonisation can be optimised and integrated with the fleet replacement programmes.

As described above, WELL's financial year and planning cycle are in calendar years. Therefore, project timings in this AMP are expressed in calendar years. However, consistent with information disclosure requirements, expenditure forecasts are based on the regulatory reporting period 1 April to 31 March.

Section 3

Overview of WELL

3 Overview of WELL

This section provides an overview of the WELL business, its mission and how this translates to the asset management framework. It also describes WELL's corporate structure, governance, asset management accountabilities, the area supplied, description of the network, the stakeholders and the changes that are occurring within the wider operating environment that will impact on investment decisions over the short to medium term.

3.1 Strategic Alignment of this Plan

WELL'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."***

The mission sets the context for all strategic and business planning. To achieve its mission WELL's business and asset management practices and policies must:

- Provide a safe environment that is free from harm for staff, contractors and the public;
- Deliver high quality outcomes for customers, accounting for the cost/quality trade-off; and
- Operate in the most commercially efficient manner possible within both the current and future regulatory environments.

The mission and these core principles are reflected in WELL's Business Plan. The Business Plan is shaped by both the internal and external business environment and defines the company's actions and outcomes to meet its mission.

This AMP is supported by WELL's asset management framework, objectives and strategies, which are used to form its 2022 Business Plan. It takes into account the interests of customers, stakeholders, and the changing operating environment (as discussed further in Section 3.6). Figure 3-1 illustrates this flow from WELL's mission to the Business Plan to the AMP.

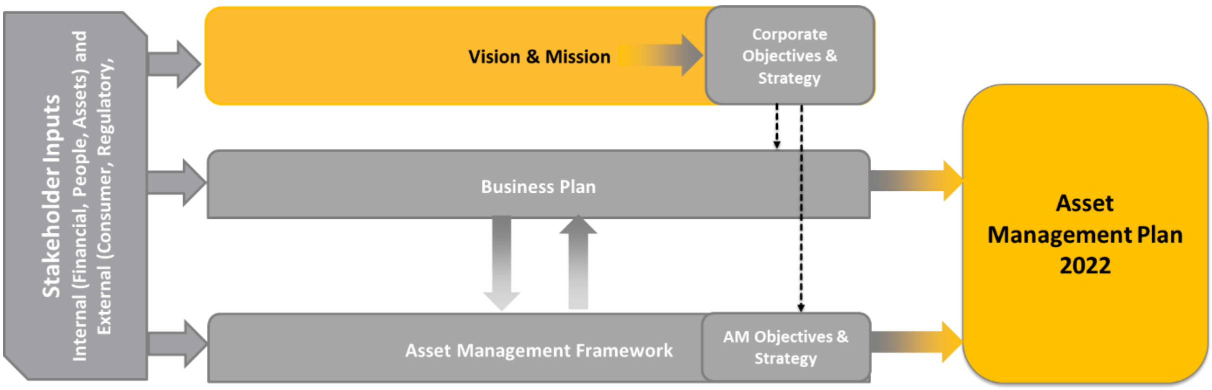


Figure 3-1 Interrelationship between WELL's Mission, the Business Plan, the Asset Management Framework and the AMP

The Asset Management Framework utilised by WELL is discussed further in Section 4.

3.2 Organisational Structure

3.2.1 Ownership

Cheung Kong Infrastructure (BVI) Limited and Power Assets Holdings Limited together own 100 per cent of WELL. Both shareholding companies are members of the CK Infrastructure Holdings Limited group of companies (CKI), and are listed on the Hong Kong Stock Exchange.

CKI has established a strong global presence with investments in electricity sectors of countries throughout the world. Having the support and backing of such an organisation puts WELL in a strong position to leverage a large amount of intellectual property, resources, and to access the latest developments in the electrical services industry.

WELL is part of a colloquium of electrical sector companies (such as Hong Kong Electric, CitiPower/ Powercor, United Energy, SA Power Networks and UK Power Networks[4]) which meets to discuss the latest developments in new technologies from around the globe.

In addition, WELL attends joint CKI technical conferences and safety conferences where the latest trends and initiatives from all business partners across the group are shared.

Further information is available on WELL's website, www.welectricity.co.nz.

3.2.2 Corporate Governance

The WELL Board of Directors (the Board) is responsible for the overall governance of the business. Consolidated business reporting is provided to the Board which includes health and safety reports, capital and operational expenditure reports against budget, and reliability statistics reports against targets.

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

3.2.3 Executive and Company Organisation Structure

The business activities are overseen by the CEO of WELL. The operation of WELL's business activities involves three groups of companies: WELL, International Infrastructure Services Company (IISC), and other Service Providers that contract to WELL.

IISC is a separate infrastructure services company, part of the CK Infrastructure Holdings Limited group which provides business support services to WELL. IISC provides the in-house financial, regulatory, asset management and planning functions as well as management of service delivery functions.

Safety is supported by the Quality, Safety and Environment (QSE) team, reporting directly to the CEO. This ensures that safety and risk management remain a prime focus and play a central role in all of WELL's activities.

WELL operates an outsourced services model for its field services and contact centre operations. These external service providers are contracted directly with WELL, with day to day management of the outsourced contracts provided by IISC. The overall company organisation structure is shown in Figure 3-2.

[4] Further details of electrical sector sister companies that are part of CK Infrastructure Holdings Limited group can be found on the website - www.cki.com.hk

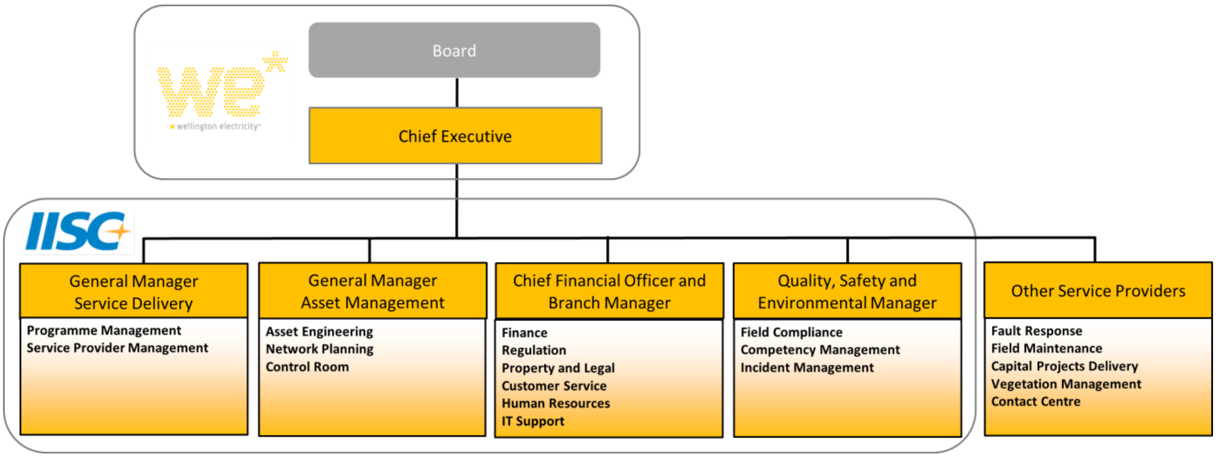


Figure 3-2 WELL Organisation Structure

3.2.4 Financial Oversight, Capital Expenditure Evaluation and Review

WELL has a Delegated Financial Authorities (DFA) framework, authorised by the Board, which governs the specific approval limits for the various levels of staff within the business.

3.2.4.1 Major Project Financial Approval and Governance

The policies for Authorisation and Payment of Project Expenditure together with the individual DFAs, define the procedure for authorisation of WELL's capital expenditure.[5]

Capital projects above $400,000 are reviewed and approved by the Capital Investment Committee (CIC), a subcommittee of the Board, who review the project business case and approves the expenditure.

The scope of the CIC is also to ensure that both an appropriate level of diligence has been undertaken and that the investment is in line with WELL's strategic direction. The CIC can approve network projects previously included in the budget or customer connection projects up to $2 million; otherwise the CIC refers their review for Board approval.

3.2.5 Asset Management Accountability

The WELL CEO heads the Executive Leadership team to implement the company mission. The CEO is accountable to the Board for overall business performance and direction.

The General Manager – Asset Management is accountable for asset engineering, network planning, standards, project approvals, works prioritisation, and the network control room. Responsibilities also include the management and introduction of new technology onto the network.

The General Manager – Service Delivery is accountable for delivery and management of capital and maintenance works and the associated safety, quality and environmental performance of these works. Responsibilities also include the management of outsourced field services contracts.

The Chief Financial Officer is accountable for all indirect business support functions including finance, customer service, regulatory management, legal and property management, human resources and information technology support.

[5] Approval of operational expenditure follows a similar process.

WELL's staff and its external service providers' personnel are competent to implement this AMP, with appropriate training programmes in place to ensure that competencies and capability remain current with good industry practice.

3.2.5.1 Asset Management Team

The Asset Management team's responsibilities are separated into three areas: asset engineering, network planning, and network control & operations. The responsibilities for each area are described in Table 3-1.

Asset Management Teams	Asset Management Responsibilities
Asset Engineering	• Safety-by-Design for asset replacements • Asset and network management • Condition based risk management • Reliable service levels for customers • Approval of asset management projects, plans, and budgets • Quality performance management • Network policies and standards • Technical engineering support • Development, prioritisation, and budget allocation of the 3-12 month combined capex and opex work plan • Analysis of asset data to inform decision making • WELL's thought leadership on core asset management applications
Asset Planning	• Safety-by-Design for new builds • Network load forecasting • Strategic network development and reinforcement planning • Large customer connection requests • Secondary system management • Introduction of new technology onto the network • Engineering support
Network Operations	• Network operations and safety • Outage management • Fault response and management • Control Room • Operationalising new technologies onto the network

Table 3-1 Asset Management Team Responsibilities

3.2.5.2 Service Delivery Team

The Service Delivery team responsibilities are separated into four areas: management of delivery of capital and maintenance works on the network, and management of the specialist contracts. The responsibilities for each area are described in Table 3-2.

Service Delivery Team	Asset Management Responsibilities
Network Portfolio	• Delivery of contestable network-initiated projects
Customer Portfolio	• Delivery of contestable customer-initiated projects
Totex	• Delivery of the corrective and preventative maintenance programmes, and exclusive capital works projects, under the Field Services Agreement (FSA)
Contract Management	• Delivery of reactive maintenance and value add services under the FSA • Management of specialist contracts, for example vegetation management, the Chorus agreement, and the Mill Creek maintenance contract

Table 3-2 Service Delivery Team Responsibilities

3.2.5.3 Commercial and Finance Team

The Commercial and Finance team responsibilities are described in Table 3-3.

Commercial and Finance Team	Asset Management Responsibilities
Commercial and Regulatory	• Compliance to regulatory requirements
Finance	• Adequate funding of asset management plans
Customer Manager	• Accountable for customer relations management including cost quality surveys
Legal and Property Manager	• Corporate risk management • Management of property and land
Information Technology	• Operational system maintenance and upgrades • Business support systems
HR Manager	• Capability of people to deliver Asset Management functions

Table 3-3 Commercial and Finance Team Responsibilities

3.2.5.4 QSE Team

The QSE team responsibilities are described in Table 3-4.

QSE Team	Asset Management Responsibilities
QSE	• Quality processes and procedures in place to manage delivery of asset management plans • Adherence to Health & Safety and Environmental legislation

Table 3-4 QSE Team Responsibilities

3.2.5.5 Other Service Providers

WELL outsources the majority of its field services tasks and its customer contact centre. WELL maintains the overarching accountability for health and safety of all contracted parties. Management of the field service provider contracts is the responsibility of the General Manager – Service Delivery. Management of the customer contact centre contract falls within the Chief Financial Officer's responsibilities.

The outsourced field operations and approved WELL service providers are summarised below, along with their contractual responsibilities:

- 24x7 fault dispatch and response, maintenance, capital works – Northpower;
- Contestable capital works – Northpower, Downer, Connetics etc.;
- Vegetation management – Treescape; and
- Customer contact centre – Telnet.

The contracts with outsourced service providers are structured to align with WELL's asset management objectives and to support continuous improvement in the integrity of the asset data held in WELL's information systems.

The roles and service provided by the service providers are explained in further detail in Section 4 (Asset Management Delivery).

3.3 Distribution Area

WELL is an Electricity Distribution Business (EDB) that provides infrastructure to support the distribution of electricity to approximately 172,000 customers in its network area, represented by the yellow-shaded area in Figure 3-3. The area encompasses the Wellington Central Business District (CBD), the large urban residential areas of Wellington City, Porirua, Lower Hutt and Upper Hutt, interspersed with pockets of commercial and light industrial load, and the surrounding rural areas. The area has few large industrial and agricultural loads.

Each local authority in the area (Wellington, Porirua, Hutt and Upper Hutt City Councils) has different requirements relating to permitted activities for an electrical distribution business. For example, differences exist in relation to road corridor access and environmental compliance. In addition to the local authorities, the entire network area comes under the wider control of the Greater Wellington Regional Council.

Prior to deregulation, network development in the region was the responsibility of two separate organisations and consequently the equipment utilised and the network design standards differed between the two historic network areas. One historic area now supplies the Southern region of WELL's network. The other historic area has been further split into the Northwest and Northeast areas to reflect the natural geographical and electrical split between the areas. These three areas are shown in Figure 3-3.

The three areas which are used for planning purposes are: Southern, defined as the area supplied by Wilton, Central Park and Kaiwharawhara Grid Exit Points (GXPs); Northwestern, defined as the area supplied by Takapu Road and Pauatahanui GXPs; and Northeastern, defined as the area supplied by Upper Hutt, Haywards, Melling and Gracefield GXPs. The network configuration for each of the three areas is described further in Section 3.4.

Figure 3-3 WELL Network Area

3.4 The Network

The total system length of WELL's network (excluding streetlight circuits) is 4,794 km, 64% of which is underground. The network is supplied from Transpower's national transmission grid through nine Grid Exit Points (GXPs). Central Park, Haywards and Melling GXPs supply the network at both 33 kV and 11 kV, and Kaiwharawhara supplies at 11 kV only. The remaining GXPs (Gracefield, Pauatahanui, Takapu Rd, Upper Hutt and Wilton) all supply the network at 33 kV only.

The 33 kV subtransmission system distributes the supply from the Transpower GXPs to 27 zone substations at N-1[6] security level. The 33 kV system is radial with each circuit supplying its own dedicated power

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

transformer, with the exception of Tawa and Kenepuru where two circuits from Takapu Road branch to supply four transformers (two at each substation). All 33 kV circuits supplying zone substations in the Southern area are underground while those in the Northwestern and Northeastern areas are a combination of overhead and underground. The total length of the 33 kV system is 195 km, of which 138 km is underground. A single line diagram of the subtransmission network is included in Appendix F.[7]

The 27 zone substations incorporate 52 33/11 kV transformers. Each zone substation has a pair of transformers with one supply from each side of a Transpower bus where this is available. The exception to this is Plimmerton and Mana, which each have a single 33 kV supply to a single power transformer. These substations are connected by an 11 kV tie cable and as a result they operate as a single N-1 substation with a geographic separation of 1.5 km.

The zone substations in turn supply the 11 kV distribution system which distributes electricity directly to the larger customers and to 4,464 distribution transformers located in commercial buildings, industrial sites, kiosks, berm-side and on overhead poles. The total length of the 11 kV system is approximately 1,781 km, of which 67% is underground. 71% of the 11 kV feeders in the Wellington CBD[8] are operated in a closed ring configuration, with the remainder being radial feeders that provide interconnections between neighbouring rings or zone substations.

The majority of customers are fed from the distribution substations via the low voltage (LV) distribution network. The total LV network length is approximately 2,818 km, of which 62% is underground. An additional 1,933 km of LV lines and cables are dedicated to providing street lighting services.

WELL's three network areas are described in further detail below.

3.4.1 Southern Area

The Southern Area network is supplied from the Central Park, Wilton, and Kaiwharawhara GXPs, which together supply Wellington City, the Eastern Suburbs and the CBD. Figure 3-4 illustrates the Southern Area subtransmission network configuration.

[7] Further information on the demarcation points between WELL and its stakeholders can be found in the WELL Distribution Code and on the WELL website.

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

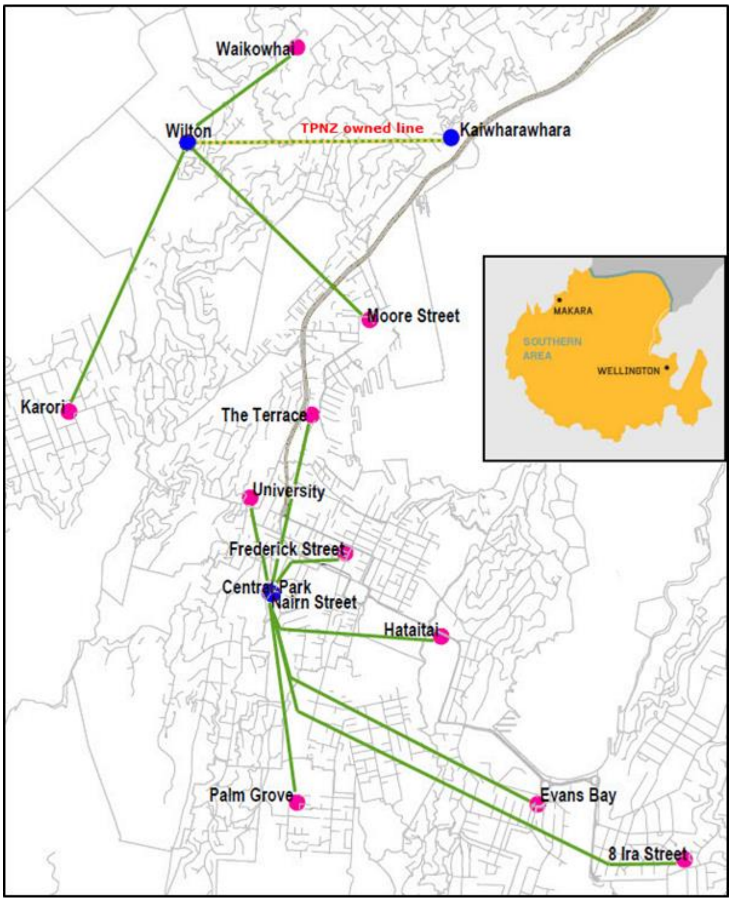


Figure 3-4 Wellington Southern Area Subtransmission Network

3.4.1.1 Central Park

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

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

Central Park GXP supplies seven WELL zone substations at Ira Street, Evans Bay, Hataitai, Palm Grove, Frederick Street, University, and The Terrace each via double circuit 33 kV underground cables. Central Park GXP also supplies the WELL Nairn Street switching station adjacent to Central Park at 11 kV via two underground duplex 11 kV circuits (four cables). The security of supply from Central Park has been identified as a risk and solutions are discussed in Section 11.

3.4.1.2 Wilton

Transpower's Wilton GXP comprises two 220/33 kV transformers (100 MVA units) operating in parallel, supplying their 33 kV indoor bus. Wilton supplies three WELL zone substations at Karori, Moore Street, and Waikowhai Street each via double circuit underground cables.

3.4.1.3 Kaiwharawhara

Kaiwharawhara is supplied by two 110 kV circuits from Wilton GXP, and has two 38 MVA 110/11 kV transformers in service. WELL takes 11 kV supply from Transpower's Kaiwharawhara GXP and distributes this via a WELL owned switchboard (with 14 feeders) located within the GXP.

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

3.4.1.4 Southern Area Summary

Supply Point	Connection Voltage (kV)	Maximum Demand – 2021 (MVA)	Firm Capacity[9] (summer/winter MVA)	Volumes – 2021 (GWh)	ICP Count
Central Park 33 kV	33	135	217/223	649	42,212
Central Park 11 kV	11	21	30	97	7,076
Wilton 33 kV	33	40	103/110	216[10]	12,715
Kaiwharawhara 11 kV	11	28	38/38	136	5,626
Total				**1,098**	**67,629**

Table 3-5 Summary of Southern Area GXPs

3.4.2 Northwestern Area

The Northwestern Area network is supplied from the Pauatahanui and Takapu Road GXPs, which supply Porirua City and the Tawa, Johnsonville, and Ngauranga areas of Wellington City. Figure 3-5 illustrates the Northwestern Area GXP and subtransmission network configuration.

[9] Firm Capacity is the N-1 transformer capacity.

[10] This includes 248 GWh injected by Mill Creek Generation

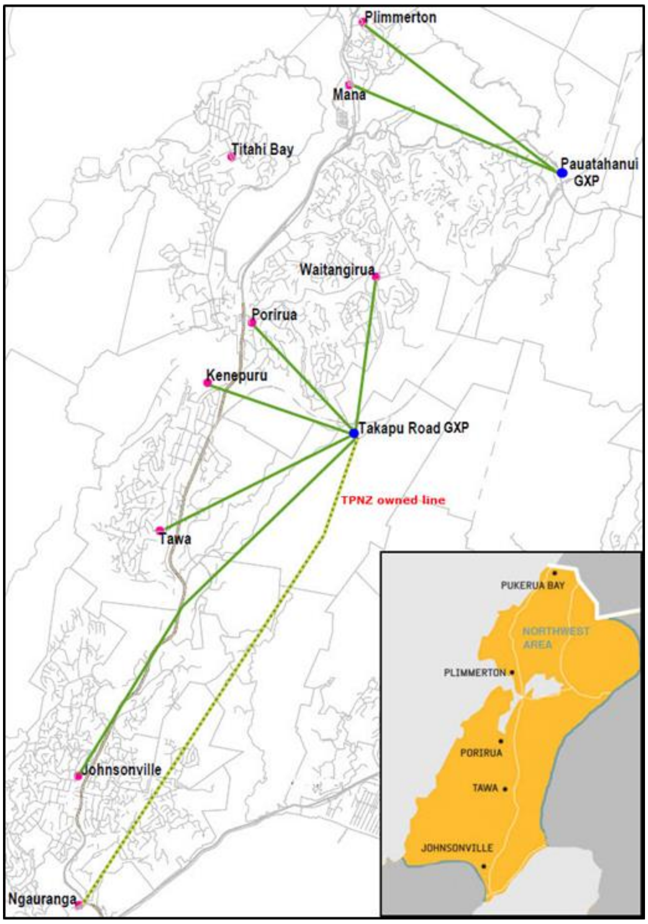


Figure 3-5 Wellington Northwestern Area Subtransmission Network

3.4.2.1 Pauatahanui

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

3.4.2.2 Takapu Road

Transpower's Takapu Road GXP comprises two parallel 110/33 kV transformers nominally rated at 90 MVA each supplying their 33 kV indoor bus. Takapu Road GXP supplies six WELL zone substations at Waitangirua, Porirua, Tawa, Kenepuru, Ngauranga and Johnsonville, each via double 33 kV circuits. These circuits leave the GXP as overhead lines across rural land and become underground cables at the urban boundary. Transpower has recently informed WELL that they intend to decommission the circuit from Takapu Road to Ngauranga Zone Substation, which is a 110 kV circuit being operated at 33 kV. The forecasts in this AMP have assumed that this circuit is still maintained and in operation.

3.4.2.3 Northwestern Summary

Supply Point	Connection Voltage (kV)	Maximum Demand – 2021 (MVA)	Firm Capacity (summer/winter MVA)	Volumes – 2021 (GWh)	ICP Count
Pauatahanui 33 kV	33	18	22/24	69	6,820
Takapu Rd 33 kV	33	93	111/116	421	34,296
Total				**490**	**41,116**

Table 3-6 Summary of Northwestern Area GXPs

3.4.3 Northeastern Area

The Northeastern Area network is supplied from the Upper Hutt, Haywards, Melling and Gracefield GXPs, which supply the Hutt Valley and the surrounding hills. Figure 3-6 illustrates the Northeastern Area subtransmission network configuration.

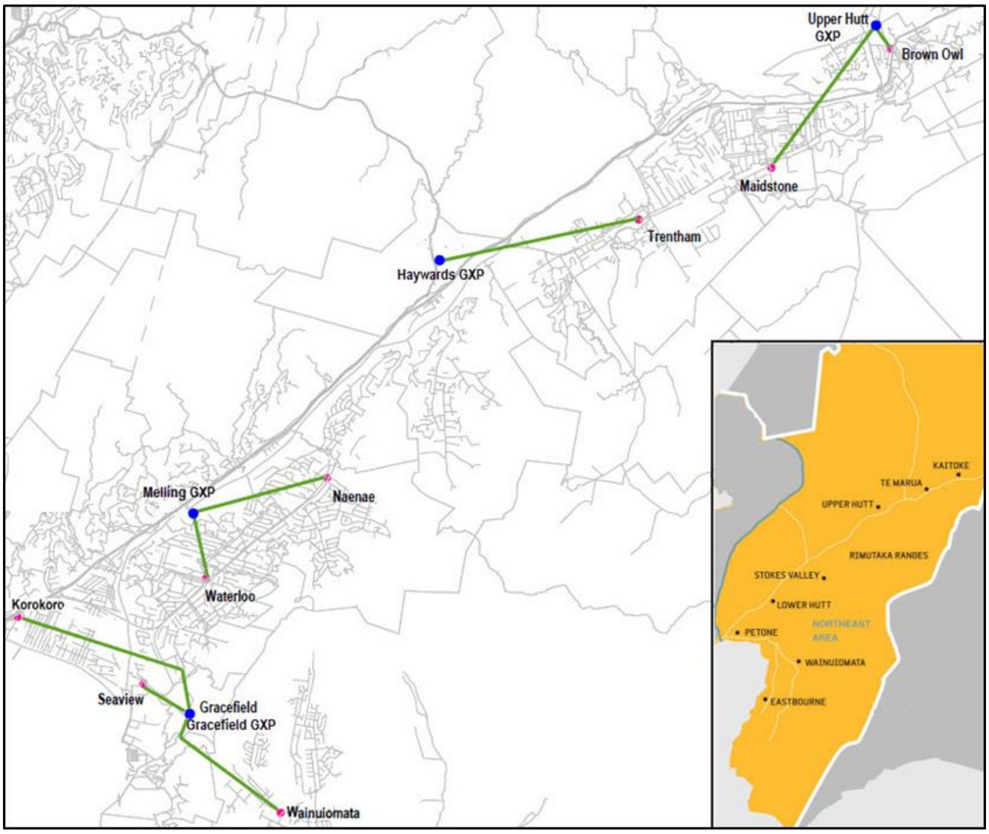


Figure 3-6 Wellington Northeastern Area Subtransmission Network

3.4.3.1 Upper Hutt

Transpower's Upper Hutt GXP comprises two parallel 110/33 kV transformers each nominally rated at 37 MVA supplying their 33 kV indoor bus. Upper Hutt GXP supplies Maidstone and Brown Owl zone substations each via double circuit 33 kV underground cables.

3.4.3.2 Haywards

Transpower's Haywards GXP comprises two parallel 110/33/11 kV transformers nominally rated at 60/30/30 MVA. WELL takes supply to two 33 kV circuits that supply Trentham zone substation. Haywards also includes a Transpower 11 kV switchboard, from which WELL takes supply to eight 11 kV feeders.

3.4.3.3 Melling

Transpower's Melling GXP comprises two parallel 110/33 kV transformers each nominally rated at 50 MVA supplying their 33 kV indoor bus. Melling supplies zone substations at Waterloo and Naenae via duplicated 33 kV underground circuits. Melling also includes a Transpower 11 kV switchboard fed by two parallel 110/11 kV transformers each nominally rated at 25 MVA, from which WELL takes supply to ten 11 kV feeders.

3.4.3.4 Gracefield

Transpower's Gracefield GXP comprises two parallel 110/33 kV transformers nominally rated at 85 MVA each supplying their 33 kV indoor bus. In late 2019, one of the two transformers had a winding fault and Transpower has temporarily installed a 60 MVA strategic spare. Transpower is analysing the winding fault which will lead to an agreed permanent solution at the site. Gracefield GXP supplies four WELL zone substations at Seaview, Korokoro, Gracefield and Wainuiomata each via double 33 kV circuits. The line to Wainuiomata is predominantly overhead while underground cables supply the other substations. WELL's Gracefield zone substation is located on a separate site adjacent to the GXP with short 33 kV cable sections connecting the GXP to the zone substation.

3.4.3.5 Northeastern Summary

Supply Point	Connection Voltage (kV)	Maximum Demand – 2021 (MVA)	Firm Capacity (summer/winter MVA)	Volumes – 2021 (GWh)	ICP Count
Gracefield 33 kV	33	62	76/80	281	19,351
Haywards 33 kV	33	15	25/25	68	5,380
Melling 33 kV	33	31	64/65	138	12,224
Upper Hutt 33 kV	33	30	51/53	137	11,560
Haywards 11 kV	11	17	30/30	70	6,837
Melling 11 kV	11	24	32/34	109	8,037
Total				**803**	**63,389**

Table 3-7 Summary of Northeastern Area GXPs

3.4.4 Embedded Generation

There is a wide range of embedded generation connected to the network, including 2,034 installations of PV with 7,881 kVA capacity. The largest embedded generation site is the 60 MW windfarm at Mill Creek which connects into WELL owned 33 kV circuits from Wilton. There are nine diesel generation sites with an installed capacity of 16.3 MVA, the largest being a 10 MVA installation at Wellington Hospital. The diesel generation serves as a mains fail backup and is not designed for backfeed operation. 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.

3.4.5 Embedded Distribution Networks

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

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

3.5 Regional Demand and Customer Mix

In 2021/22 WELL's network is forecast to deliver 2,404 GWh to customers around the region. The network maximum demand during winter 2021 was 579 MW. As illustrated in Figure 3-7, the historic volume of energy supplied through the network declined at an average rate of approximately 0.7% per annum from 2011 to 2018 and then increased at an average rate of approximately 0.9% per annum from 2018 to 2021.

The past four years have seen stable volumes overall. Residential volumes have increased with an increase in new connections and Distributed Energy Resources (DER) like EVs connecting to the network. The increase in residential energy use has been offset by a decrease in commercial and industrial volumes due to energy efficiency improvements and a decrease in the number of large commercial and industrial connections.

On the Wellington network, the period of maximum demand is usually in the winter when household heating is higher. The maximum demand trend is therefore highly dependent on mid-winter temperature – the colder the winter, the higher the demand on the network.

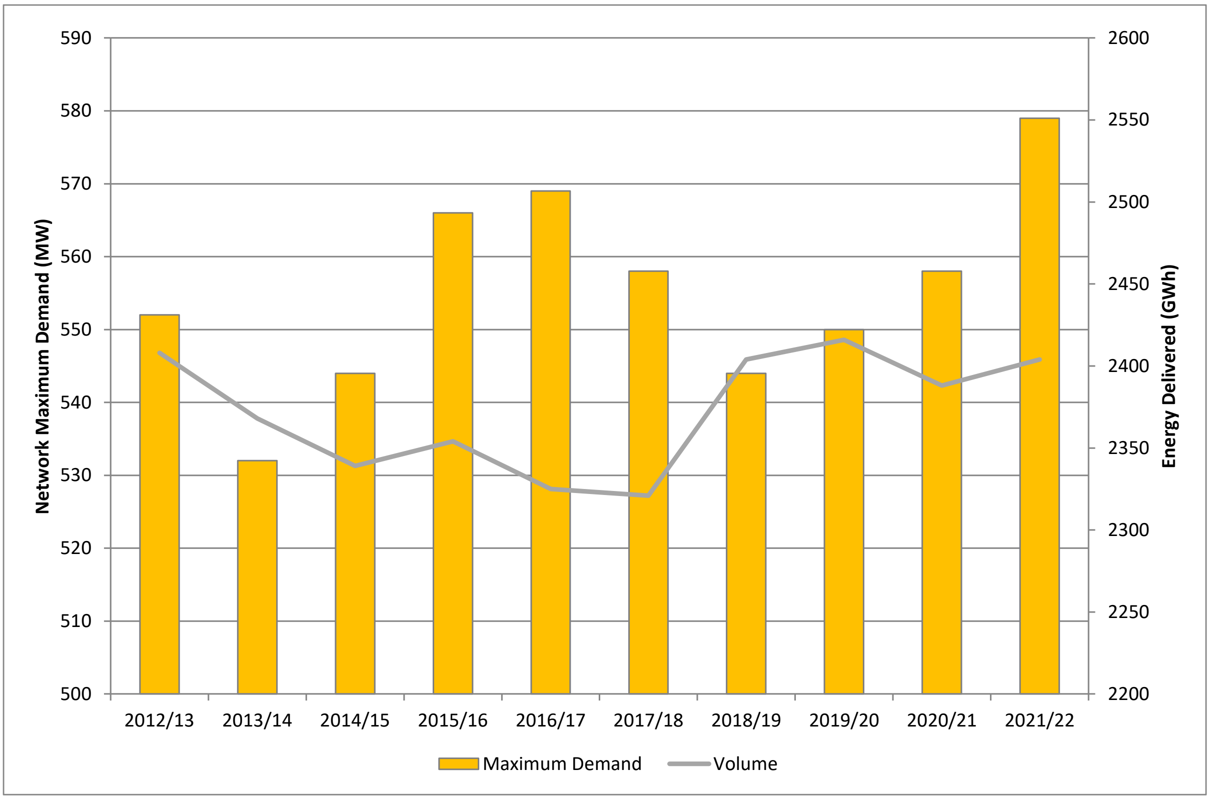


Figure 3-7 Maximum Demand and Energy Injected

As shown in Table 3-8, the overall customer mix on the Wellington network consists of approximately 90% residential connections.

Customer Type	ICP Count
Residential	154,608
Large Commercial	475
Medium Commercial	652
Small Commercial	15,236
Large Industrial	51
Small Industrial	254
Unmetered	859
Total	**172,135**

Table 3-8 WELL's Customer Mix as at February 2022

While the majority of customers connected to the network are residential, a number of customers have significant or strategically-important loads. These include:

- Parliament and government agencies;
- Hospitals, emergency services and civil defence;

- Council infrastructure such as water and wastewater pumping stations and street lighting;
- Major infrastructure providers such as NZTA, Wellington Airport and CentrePort;
- Large education institutions such as Victoria University, Massey University, Whitireia and Weltech;
- Network security sensitive customers such as the stock exchange, Weta Digital, Datacom, and Department of Corrections.

The number and density of these customers is atypical for a New Zealand distribution network. Therefore, the importance of WELL providing a reliable and resilient network is critical.

WELL's Customer Services team is responsible for managing the needs of retailers and customers. Major customers have specific needs which are met on a case by case basis. This includes managing the impact of network outages and asset management priorities. Customers who have significant electricity use, specific electricity requirements, or are suppliers of essential services are contacted prior to planned outages, as well as following any unplanned outages that impact their supply.

Customers' interests are identified and incorporated into asset management decisions through a number of mechanisms. These are discussed further in Section 3.6.

3.6 WELL's Stakeholders

WELL has identified nine key stakeholder groups whose interests are considered in the approach taken to asset management and required outcomes for the different stakeholder groups. These stakeholder groups are:

- Customers and the community at large;
- Retailers;
- Regulators;
- Transpower;
- Central and local government;
- Industry organisations;
- Staff and contractors;
- Debt Capital Market Funders; and
- Shareholders.

The characteristics of these groups are described below including how their interests are identified, what their interests and expectations are and how these are accounted for in WELL's asset management processes. The resulting service levels sought by stakeholders, once their interests have been accounted for, are described in Section 5.

3.6.1 Stakeholder Groups

3.6.1.1 Customers and the community at large

Customers' interests are identified through direct feedback (surveys, queries and complaints) and community engagement. Their interests include the safety of the public, the reliability of the network, and the price they pay for that reliability. These interests are accounted for in the asset management practices through meeting the regulated quality targets, public safety and customer engagement initiatives.

WELL uses its website and mobile application, public disclosure documents, newspapers, radio advertising, community and school visits and web notices to communicate with the public.

WELL also engages with communities in the new technology space such as recent EV trial projects. One trial used half-hourly metering data to measure the size and timing of electricity demand of both a group of EV-owning households (useful data was obtained for 77 of these in total), and a control group of non-EV owning households (860 in total). The objective of the EV Charging Trial was to better understand the scale of this new technology, how responsive demand is to price signals, and to form a base for the time-of-use tariffs that WELL has since implemented.

WELL continues to operate outage reporting applications on both web and mobile-device platforms. The applications provide information on the location and forecast restoration times for unplanned outages. Improving the customer experience by improving the accuracy of published estimated restoration times is a constant focus for WELL and its contractors. WELL is currently trialling publishing planned outages on its web and mobile platforms.

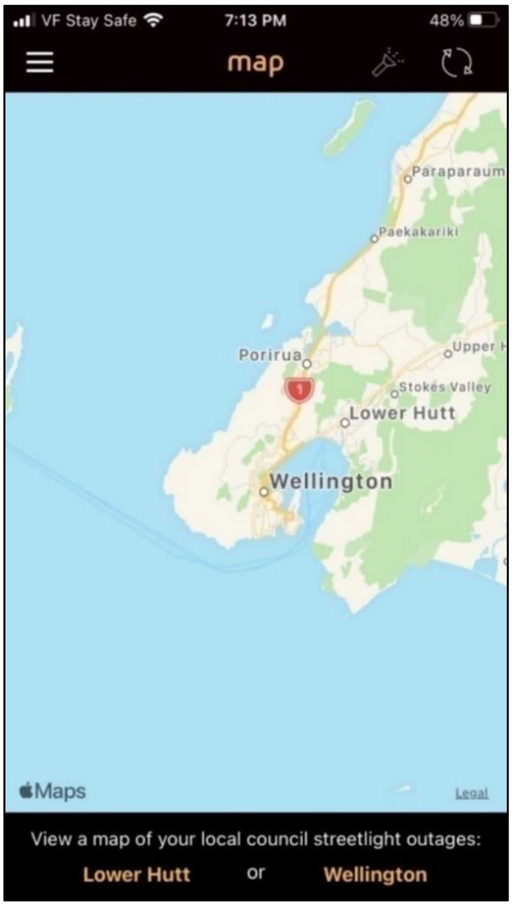


Figure 3-8 WELL's Web-based Application

The restrictions imposed by the government's response to COVID-19 impacted WELL's community engagement programme in 2020 and 2021. WELL will resume its community engagement programme once it is able to, prioritising those communities who have been most impacted by unplanned outages.

3.6.1.2 Retailers

Retailers are WELL's direct customers. They rely on the network to deliver energy which they sell to customers. Retailers ask that WELL assists in providing innovative products and services to benefit their customers.

Customer supply quality interests are accounted for through meeting the regulatory quality targets defined in the Commission's price-quality path and the service levels detailed in Section 5.

WELL consults with retailers prior to the implementation of changes to its line charge pricing structure to ensure that any proposed changes take note of retailer feedback.

3.6.1.3 Regulators

The main regulators for WELL are WorkSafe New Zealand, the Commerce Commission (the Commission) and the Electricity Authority (the Authority).

WorkSafe New Zealand is interested in the continuing improvement in workplace safety and effective identification and management of risk to protect the welfare of workers. These interests are accounted for in the asset management practices through a comprehensive set of health and safety, environmental, and quality policies and procedures. These include reporting requirements as well as the need to consult, cooperate and coordinate with Persons Conducting a Business or Undertaking (PCBUs). WELL has an audited Public Safety Management System (PSMS) that covers the management of assets installed in public areas to ensure that they do not pose a risk to public safety.

The Commission and the Authority are interested in ensuring that customers achieve a supply of electricity at a fair price commensurate with an acceptable level of quality that provides long term benefits to customers. These interests are accounted for in the asset management practices through planned compliance with reliability targets and price controls, compliance with legislation, engagement in regulatory development process and preparing information disclosures.

3.6.1.4 Transpower

Transpower's interests are identified through the Electricity Industry Participation Code, relationship meetings, direct business communications, annual planning documents, and grid notifications and warnings. Transpower is interested in sustainable revenue earnings from the allocation of connected and interconnected transmission assets, and require assurance that downstream connected distribution and generation will not unduly affect their assets. They have interests in the operation of the national grid including rolling outage plans, automatic under frequency load shedding (AUFLS) and demand side management. These interests are accounted for in WELL's asset management practices through implementation of operational standards and procedures, appropriate investment in the network, and regular meetings.

3.6.1.5 Central and Local Government

Central and local government interests are identified through legislation, regulations, regular meetings, direct business communications, and working groups. In addition to being a significant customer through street lighting, electrified public transport and water management, they are interested in compliance with legislative and regulatory obligations, appropriate lifelines obligations for emergency response and contingency planning to manage a significant civil defence event. These stakeholders want assurance that customers receive a safe, reliable supply of electricity at a competitive price, no environmental impact from the operation of the network, and appropriate levels of investment in the network to allow for projected growth. These interests are accounted for in WELL's asset management practices through compliance with legislation, engagement and submissions as required, engagement in policy development processes, Emergency Response Plans, and Environmental Management Plans.

The Kaikoura earthquake in November 2016 caused significant disruption in the region and has highlighted the importance of having a resilient electricity network. This work is described further in Section 11.

Central and local government will also have an interest in WELL's progress on supporting the Climate Change Commission's (CCC) decarbonisation initiatives. Through the EV Connect project WELL has engaged with the wider industry to consider what legislative, regulatory, or local government policy changes are needed to deliver the initiatives and what support may be needed from central and local government. This work is described in Section 9.

3.6.1.6 Industry Organisations

The interests of industry organisations such as Engineering New Zealand, Electricity Engineers Association and Electricity Networks Association are identified through regular contact at executive level, attendance at workshops, and involvement in working groups. Industry organisations expect that good industry practice is followed with a continuous improvement focus. These interests are accounted for in WELL's asset management practices through training and development of competencies, and alignment of asset strategies with industry frameworks and practices.

As a lifeline utility (an essential service), WELL also works closely with the Wellington Lifelines Group. The purpose of the Wellington Lifelines Group is to ensure that lifeline utilities provide continuity of operation where their service supports essential emergency response activities. Participation in this working group is described in Section 11.

3.6.1.7 Staff and Contractors

Staff and contractors' interests are identified through individual and team discussions, regular meetings, direct business communications, contractual agreements and staff culture surveys. They are primarily interested in a safe and enjoyable working environment, job satisfaction, fair reward for effort provided, mitigation of workplace risks and work continuity. These interests are accounted for in the asset management practices through health and safety policies and initiatives, performance reviews, and forward planning of work.

3.6.1.8 Debt Capital Market Funders

WELL accesses Debt Capital Markets to provide funding support for the investments outlined in this AMP. Banks and investors (through private placement issues) have provided funding to date. Their interests are accounted for in WELL's asset management practices through capital and operational forecasts that enable WELL's risk profile to be understood.

3.6.1.9 Shareholders

Shareholder interests are identified through governance, Board meetings, Board mandates, the business plan and strategic objectives. Shareholders expect safety to be non-negotiable, a fair return for their investment, compliance with legislation, good working relationships with other key stakeholders through meaningful engagement, and effective management of the network and business. These interests are accounted for by regular reporting on the asset management practices through governance processes, compliance with legislation, service levels and meeting budget.

3.6.2 Managing Potential Conflicts between Stakeholder Interests

Conflicts in stakeholder interests are managed on a case-by-case basis by balancing risks and benefits. This will often involve consultation with the affected stakeholders and the development of innovative “win-win” approaches. However, safety is the priority when managing a potential conflict in stakeholder interests. WELL will not compromise the safety of the public, its staff or service providers.

WELL is a member of the Utility Disputes Limited (UDL) scheme, which provides a dispute resolution process for resolving customer complaints. WELL’s Use of System Agreements provides a dispute resolution process for managing conflict with retailers.

3.7 Operating Environment

WELL operates within the context of the wider New Zealand business environment and the global economy. This includes the financial, legislative and regulatory environments, and the need for the business to assess changes in technology.

3.7.1 Legislative and Regulatory Environment

WELL is subject to a range of legislative and regulatory obligations. WELL meets these regulatory and legislative obligations by adopting best practice asset management policies and procedures that underpin this AMP. WELL regularly engages with the Authority and the Commission through participation in working groups, conferences, workshops, consultations on various matters, and regular information disclosures. The legislative and regulatory obligations are detailed below.

3.7.1.1 Health and Safety at Work Act 2015 (HSW Act 2015)

Building on its good safety and environmental record, and consistent with the requirements of the HSW Act 2015 as well as the company’s drive for continual improvement, WELL continues to focus on potential safety and environmental risk at the early stages of a project. Risk assessments are conducted with contractors prior to the project being awarded, with continual monitoring throughout the project lifecycle of potential changes in risk. The cost and time implications of this increased focus are factored into project budgets and schedules. WELL also reviews incidents with its service providers on a weekly basis and monitors the effectiveness of controls that are being put in place. Emphasis is placed on ensuring that engineering controls are prioritised ahead of process and administration controls.

The main aspects of the HSW Act 2015 that form the primary focus for WELL are:

- The concept of the ‘person conducting a business or undertaking’ (PCBU), including the duty of officers;
- Consultation, cooperation and coordination between PCBUs;
- Extension of hazard management to incorporate risk management at worker level; and
- Worker engagement, participation and representation.

The need to consult, cooperate and coordinate between PCBUs has continued to see improvements of the management of the interface boundary with all principal's that do work with WELL.

A compliance management system has been implemented by WELL that supports business processes relevant to the HSW Act 2015 as well as the NZS 7901 Public Safety Management obligations and timeframes that are reported quarterly to the Board.

3.7.1.2 Price Quality Compliance

WELL is subject to price and quality control contained within Part 4 of the Commerce Act 1986. From 1 April 2018 WELL was on a CPP for its earthquake readiness programme, which ran until 31 March 2021. WELL returned to the Default Price Path (DPP) on 1 April 2021.

3.7.1.3 Information Disclosure

WELL is subject to a range of annual public information disclosure requirements. To ensure accurate preparation and reporting of information, WELL's business processes and information systems are aligned to the Information Disclosure Determination 2012 to ensure that information is accurate and available in the prescribed form.

3.7.1.4 Use of Network Agreements and Default Distributor Agreements

Retailers contract with Electricity Distribution Businesses (EDBs) for the supply distribution services. WELL has a Default Distribution Agreement (DDA) with each retailer. The DDA agreement terms are provided in the Electricity Code.

3.7.1.5 Pricing Roadmap

WELL has published a pricing roadmap that outlines the development of its distribution pricing over the next 3-5 years. This includes the development of cost reflective pricing options to provide retailers and customers with clear price signals to encourage off-peak energy use.

3.7.1.6 Government Policy - Major Infrastructure Projects

Major infrastructure projects driven by government policy have an impact upon WELL's network. Ultra-fast Broadband (UFB) is a positive initiative for New Zealand and the rollout is currently being undertaken in Wellington by the telecommunications infrastructure provider Chorus. The rollout is governed by an interface management plan, contained within a pole connection agreement, to meet the safety obligations between the two PCBUs.

The NZTA Transmission Gully project is another major project which has required significant work to deviate WELL assets away from the road corridor and to provide new infrastructure to supply street lighting circuits.

The CCC's 2021 Advice to the Government included a number of policy recommendations that would impact network capacity if implemented, including:

- Electrification of New Zealand's transport fleet;
- Electrification of process heat in manufacturing; and
- Transition from gas to electricity.

These changes could significantly impact the loading and operation of the electricity distribution network, which, if not well managed, could slow down the decarbonisation programs or increase costs. WELL's view is that by collaborating with other industry stakeholders, the programmes can be supported at an optimal cost while maintaining a safe, secure, and reliable distribution network for all customers.

3.7.1.7 Requirements Driven by Local Authorities

WELL must comply with local authority requirements. WELL monitors notified resource consent applications and proposed changes to district plans, providing comment and submissions when required.

3.7.1.8 The Electricity (Hazards from Trees) Regulations 2003 (Tree Regulations)

WELL manages vegetation around its network in accordance with the requirements of the Tree Regulations, as vegetation close to network assets has the potential to interfere with the reliable and safe supply of electricity. The Tree Regulations prescribe distances from electrical conductors within which vegetation must not encroach. WELL is required to advise tree owners of their obligations for the safe removal of vegetation. WELL has a Vegetation Management Agreement in place with an external service provider to manage vegetation around the network. WELL's vegetation management programme has resulted in a reduction in the number of tree related faults on the network.

The Ministry of Business, Innovation and Employment (MBIE) is reviewing the Tree Regulations and currently awaiting Ministerial approval of recommended changes. The recommended changes correct issues with the current Tree Regulations, including making tree owners more responsible for meeting their obligations under the Electricity Act 1992.

3.7.2 The Changing Technology Environment

There continues to be much interest around smart grids and smart technologies and how these will impact transmission and distribution networks, metering, central generation and retailers. This new technology could also impact customers, with new markets developing for customers if they choose for their assets to be used for demand management.

The growth of new technologies in the energy storage and market trading environments have a significant effect on the development of smarter electrical networks, and the ability of WELL to influence energy consumption and energy trading. Greater visibility of energy transfer in the form of real time network monitoring and improved digitised data is required to enable WELL to adequately manage this space. WELL continues to monitor evolving technology trends and the uptake of new technology that is likely to impact on the electricity sector. This includes (but is not limited to) monitoring the uptake of commercial and residential solar panels (Photovoltaics or PVs) and energy storage systems, the increasing penetration of EVs in New Zealand's vehicle fleet, and the applicability and use of technology for network monitoring, design and operation. While the rate of uptake is uncertain, technology is likely to have an increasingly significant impact on customer behaviour as EVs, PVs, and battery storage become more affordable.

There is uncertainty about the impact that new technology will have, with some technology increasing energy transferred (e.g. EVs), while others will reduce energy transferred (e.g. PV).

Industry changes required to enable the introduction of this new technology include:

- New technology standards: Introduce new standards for new technology, allowing better and lower cost integration;

- Mandatory notification: Require customers who want to install new technology to apply to their lines company. This will ensure that the installation of the new technology complies with the standards of the network for two way power flows;
- Congestion standards: Introduce standards on how congestion is defined and require network congestion to be disclosed;
- Low voltage monitoring: Improve the monitoring of the network particularly LV with DERs where current monitoring is inadequate and where changes are most likely to be felt;
- Management of distributed resources: Investigate and trial a platform that enables the management of distributed energy resources;
- Support with efficient prices: Introduce efficient price signals that reflect the benefits new technology can provide and encourage the use of disruptive technology;
- Consumption data: Consumption data is needed to support the operation of new technology and the Electricity Code now provides a mechanism for data sharing between retailers and EDBs. The industry needs to decide what data is needed to support new technology, the best source of data, and how to collect, store and use the information; and
- Appropriate funding: Ensure the regulatory framework provides the allowances required to develop and implement new technology and to purchase demand management services from new technology providers.

Regulatory support is required to ensure these changes can be implemented.

As well as working with industry and regulators to ensure these changes are implemented in the short term, WELL continues to learn from others and to trial new technologies to further learn and prepare for the changes ahead. WELL believes testing new technology through trials is a prudent and flexible approach to manage the uncertainty associated with new and emerging technology, while avoiding the risk of overbuild in the short term. It is WELL's view that new technology will enable the monitoring and management of the LV network, and working closely with other industry participants will deliver the best long term solution for New Zealand.

WELL will continue to utilise its position as part of the CK Infrastructure Holdings Limited group to leverage experience with new technology from its global sister companies. This provides WELL with unique access to intellectual property and resources from across the globe. In addition, WELL collaborates with local EDBs to draw on the New Zealand specific experience within the emerging technologies market.

3.7.2.1 Electric Vehicles

The availability of affordable EVs has the potential to significantly alter electricity delivery and usage patterns. It is expected that the adoption rate of EVs in New Zealand will increase over the longer term based on:

- EVs offering lower running costs than traditional internal combustion engines due to the higher cost of fossil fuels and the higher efficiency of energy conversion from battery storage;
- New Zealand's high level of renewable energy generation (over 80%) being an ideal match for EVs which are seen as an appealing option for environmentally and cost-conscious customers; and

- Constantly evolving energy storage systems, electric drives and charging technologies that will improve the efficiency and range of EVs.

To support the swift adoption of EVs, WELL has a number of EV specific work streams:

- **EV Charging Trial**: In late 2017 WELL conducted a trial to better understand the home charging behaviours of EV owners and how they could potentially affect the demand for electricity. The results of the trial have helped influence the design of WELL's EV pricing and provided an insight into customers' preferences for future EV charging services.

- **Time of Use (ToU) prices**: WELL has introduced ToU prices which encourage EV users to charge their vehicles during less congested periods. Charging during less congested periods on the network means a larger network doesn't have to be built to cater for the expected increase in EVs. Avoiding having to build a larger network means that prices can be kept low.

- **EV Connect**: EV Connect is an industry-wide work programme that focuses on how more energy can be delivered through the existing network. The purpose of EV Connect is to support EV adoption while maintaining network security. One of the outcomes of the programme has been the delivery of an industry roadmap of the actions needed for distributions networks to accommodate the uptake of EVs. EV Connect is discussed in detail in Section 9.

WELL also supports the electrification of public transport as a significant means of reducing carbon emissions. WELL is supporting the regional and city councils to deliver new electric public transport services in Wellington.

3.7.3 The Financial Environment

WELL's financial performance is primarily determined by the regulatory price control set by the Commission, and the cost of debt funding available from global debt capital markets.

As noted earlier, WELL returned to the DPP on 1 April 2021 after its CPP expired on 31 March 2021. The DPP is the price path that most other price/quality regulated EDBs operate under. WELL regularly reviews which regulatory model is most appropriate, balancing the low-cost simplicity of the DPP against the ability to fund large capital programmes under a CPP.

Funding for innovation projects is available from Government initiatives such as the Low Emission Vehicle Contestable Fund (LEVCF). There is also an allowance of 0.1% of allowable revenue included in DPP3 for the part funding of projects to develop or deploy new technologies that reduce cost or increase quality for customers. It is expected that application mechanisms under Part 4 Clause 54Q of the Commerce Act 1986 could be exercised around energy efficiency by making particular new technology investments affordable under current allowances for traditional network operation and maintenance.

WELL is continuing to manage its financial performance in a prudent manner, ensuring expenditure is targeted at the highest priorities and maintaining the quality of supply under the price quality framework. WELL continues to access global debt capital markets to ensure it has appropriate financing facilities available to meet the investment plans outlined in this AMP.

Section 4

Frameworks

(Asset Management, Safety and Risk)

4 Asset Management, Safety and Risk Frameworks

This section describes WELL's asset management frameworks and risk management processes and governance. It also sets out WELL's approach to health, safety and quality. In summary the section covers:

- The asset management framework;
- The investment selection process;
- The asset management delivery process;
- Asset management documentation and control;
- The Asset Management Maturity Assessment Tool (AMMAT);
- Quality, safety and the environment (QSE); and
- Risk management.

4.1 Asset Management Framework

WELL's asset management framework is aligned with the company's vision, mission, corporate strategy and objectives and is reflected in this AMP. The framework reflects the principles of the international standard ISO 55000. The key components of the framework are shown in Figure 4-1.

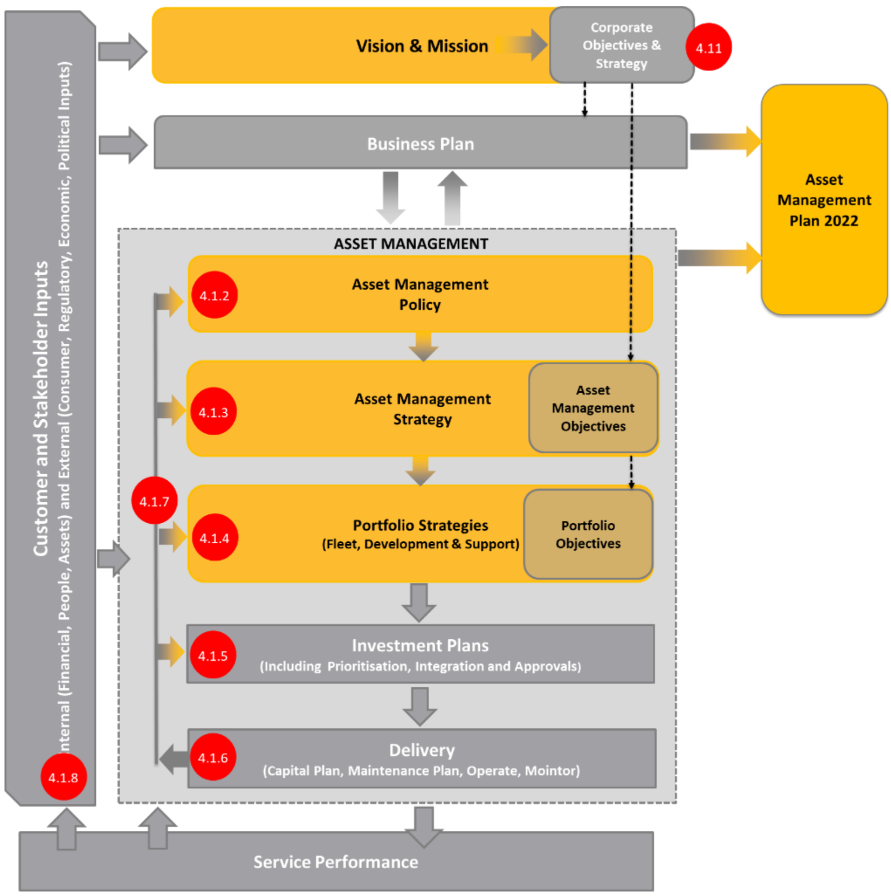


Figure 4-1 Asset Management Framework

WELL's asset management approach provides a clear line of sight between the company's mission, investment plans, how services are delivered and customer preferences. A high level summary of each major component of the Asset Management Framework is discussed in the following sections. Each section is referenced in the figure above.

4.1.1 Corporate Objectives

WELL's Corporate Objectives are expressed through its Corporate Mission and Values. They include the company performance objectives (including annual KPI's) and feature the company's safety, quality targets (both SAIDI and SAIFI) and customer service targets.

4.1.2 Asset Management Policy

The asset management policy establishes the formal authority for asset management within WELL.

It aligns with the company's mission 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".

The scope of the policy covers all the assets owned and operated by WELL for the purposes of providing electricity distribution services.

The objective of the policy is "that the business will optimise the whole of life costs and the performance of the distribution assets to deliver a safe, cost effective, high quality service to our customers."

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

- Has a strong safety focus regarding its employees, contractors and members of the public;
- Aligns with corporate objectives and plans;
- Is founded on customer service level expectations and engages stakeholders where appropriate on asset-related activities;
- Stays up to date with national and international asset management standards, trends and best practices;
- Complies with all applicable regulatory and statutory requirements;
- Aligns with the risk management framework;
- Assists with the development of staff capabilities and the engagement of external resources when required to continually improve asset management capability; and
- Provides a suitable long-term return on investment for shareholders.

4.1.3 Asset Management Strategy and Objectives

WELL's Asset Management Strategy builds on the Asset Management Policy to ensure a clear line of sight between the corporate objectives and the asset management objectives. WELL has identified five priority areas along with their associated key objectives:

- Safety and Environment: People, public and the environment are kept safe

- Customers: We provide an excellent service to our customers that matches their needs
- Network Performance: Provide a network that delivers to our customers' needs now and in the future
- Cost: Long term profitability driven by efficiency and innovation
- Capability: Continuous development to deliver performance and efficiency improvements

The Asset Management Strategy summarises the objectives and strategies in each of these five priority areas. The first four priority areas relate to aspects of WELL's performance. The fifth priority area relates specifically to asset management capability, which supports the other objectives. Sections 5 to 7 provide more detail on specific asset management objectives and strategies associated with these priority areas.

4.1.4 Portfolio Strategies

Portfolio strategies translate the Asset Management Strategy into specific strategies for each portfolio, link back to the objectives in the Asset Management Strategy, and detail any fleet-specific objectives. These portfolio strategies include asset fleet strategies, network development strategies, emerging technology, support systems, resilience, and customer initiated projects and relocations, which are discussed in Sections 7 to 12 respectively. Each strategy is used to develop Network Standards, work plans and programmes which include the activities and budgets presented in the 10 year AMP and five year business plan.

4.1.5 Investment Planning

WELL's investment plans are developed from the individual portfolio strategies. Investment planning includes integration, prioritisation and approval processes to ensure prudent financial investment. Investment planning is discussed further in Section 4.2.

4.1.6 Delivery

There are two components to delivery: delivery of the investment plans and management of the network in real time. The delivery of investment plans to meet the target customer service levels is discussed in Section 4.3.

The objective of WELL's real time network management is to manage the network safely and, when outages occur, to restore power safely and as quickly as practical, minimising the impact of outages on customers. WELL's outage management process is detailed in the Fault Restoration Standard.

4.1.7 Internal Feedback Loops

Essential inputs to each component of the Asset Management Framework include asset condition, network performance, and customer feedback. Performance reporting is provided to those responsible for each component of the Asset Management Framework, creating internal feedback loops within the framework. Each strategy and plan is refined and adjusted in response to the performance measures and customer feedback.

4.1.8 Stakeholder and Customer Inputs

Customer feedback is essential to ensuring that WELL is providing the services that customers want and at a level of quality they are willing to pay for. WELL regularly surveys its customers about whether they are happy with the current service quality. WELL also meets with community groups to test the balance between price and quality and/or to engage with customers in relation to topical events and issues which may be relevant to them. WELL's customers have consistently said they support current quality levels and do not want to fund a quality improvement. The Asset Management Framework reflects this by targeting reliability performance at current levels.

4.2 The Investment Selection Process

The investment selection process has five generalised stages, as illustrated in Figure 4-2.

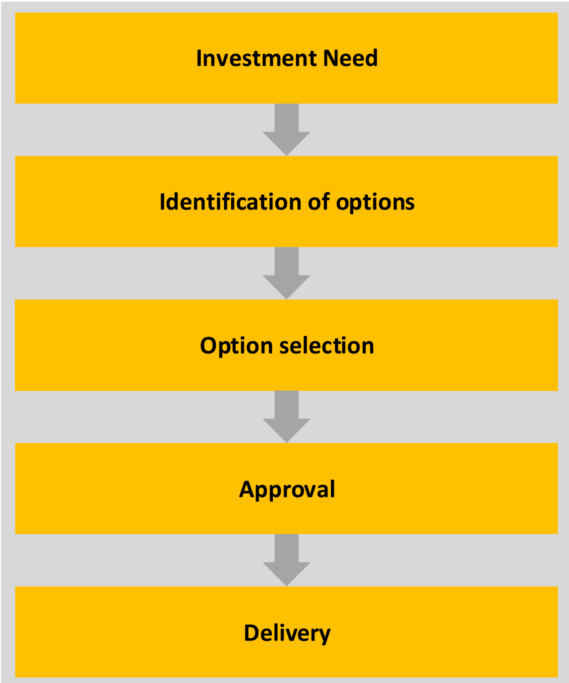


Figure 4-2 Investment Selection Process

4.2.1 Need Identification

The identification of the need to invest arises from multiple sources. For example, fleet strategies for asset replacements arise from asset condition assessment and detailed health and asset criticality evaluation, whereas the need for network development expenditure comes from forecasting peak load growth on the network and developers extending their subdivision or commercial investments.

4.2.1.1 Risk-based Approach

WELL takes a risk-based approach to "need identification". Management of risk is fundamental to the network development, asset maintenance, refurbishment and replacement programmes described in this AMP. Risks associated with network assets are managed:

- Proactively: Reducing the probability of asset failure by meeting security of supply criteria standards, capital and maintenance work programmes, enhanced working practices and the development of fleet strategies. The development of these strategies includes root cause analysis from the growing database of asset failure information, and predicts future corrective maintenance expenditure over time; and

- Reactively: Reducing the impact of a failure through business continuity planning and the delivery of an efficient fault response capability.

The risk of an asset failure is a combination of the likelihood of failure (largely determined by the condition of the asset) and the consequences of failure (determined by the immediate safety impact of the failure, the magnitude of any supply interruptions, any environmental consequences, 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 to allow it to continue in service, supported if necessary by additional inspection and preventative maintenance activities.

4.2.1.2 Prioritisation of Projects

The AMP represents the view for the next 10 years and is refined on an annual basis. Projects to be included in the expenditure programme for a year are subject to a top down review and prioritised in accordance with the sequence shown below.

1. Safety benefits to the public and personnel;
2. Non-discretionary projects;
3. Quality of supply and stakeholder satisfaction;
4. Risk to the network;
5. Strategic benefit; and
6. Commercial returns and investment recovery.

Non-discretionary projects include:

(i) HSE and Legal Compliance. WELL's top priority is to operate a safe and reliable network and thus projects needed to address safety concerns and/or meet legal requirements are given high priority.

(ii) Customer-initiated Projects. Provided WELL has received sufficient advanced notice, it will give appropriate priority to planning, designing and implementing projects required to meet the needs of commercial and industrial customers.

Under this approach, safety, legal compliance, the need to meet customer requirements, and risk mitigation are the critical elements that drive the inclusion of projects in the works programme.

4.2.2 Option Identification

Various options are identified and considered to address the investment need. These include:

- Non-network solutions such as demand side management (DSM) or distributed generation (DG). These could include investment by the customer in the case of residential/commercial solar DG, or by WELL in the case of grid-scale DG and/or battery storage;
- Repair or refurbishment of existing distribution assets;
- Replacement with new assets; and
- An extension or upgrade of the existing distribution network.

These investment options are considered to ensure the overall service levels sought by all stakeholders are achieved within regulatory allowances to balance the price/quality trade off. This is to align reliability with the cost that customers pay over the long term.

4.2.3 Option Selection Process

The option selection process describes the way in which network investments are taken from a list of appropriate options, refined to a short list of practicable options followed by detailed analysis and selection of a preferred option which is then documented in a business case for approval. The Works Plan is the repository for all network investments for the year ahead and includes projects funded solely by WELL as well as other customer-funded projects. The Works Plan is consistent with the first year of the AMP.

The process is as follows:

1. Outputs from the option identification process are developed into a business case, justifying the need for investment and recommending the preferred option.

2. Approved recommendations are entered into the draft Works Plan and prioritised in terms of safety, customer needs, budget, timelines and network criticality.

3. The Works Integration team develops, prioritises and allocates budget for the annual Works Plan based on a totex approach which combines and integrates capex and opex requirements to gain efficiency and effectiveness from service providers.

4. Following final prioritisation, a list of projects for the following year (i.e. the Works Plan) is prepared to inform the annual budget which is submitted for management approval and recommendation to the Board for approval.

4.2.4 Investment Approval

Investments are approved according to WELL's DFA structure which is described in Section 3.2.4.

4.3 Asset Management Delivery

The Works Plan is the repository for all network investments for the year ahead. It is used as the final document for tracking all network capital projects to be delivered for the year. Once approved, the Works Plan is managed by the Service Delivery team, with progress reported to the Executive and the Board.

4.3.1 Field Delivery

WELL utilises an outsourced model for the delivery of its field and construction work. The service providers used for the core field and network functions are:

- Fault response, maintenance, and minor capital works – Northpower;

- Contestable capital works – Northpower, Downer, Connetics, Ventia etc.;

- Vegetation management – Treescape; and

- Contact centre – Telnet.

All outsourced agreements are subject to WELL's health and safety policies and management plan. It is the responsibility of the General Manager Service Delivery to ensure that this and all field based work is managed to deliver value to the business.

The services provided are described in further detail below.

4.3.1.1 Fault Response, Maintenance and Minor Capital Works

Northpower Ltd has been WELL's primary field service provider responsible for fault response and maintenance since 2011. In 2018 WELL ran a contestable process for a new field services contract. Northpower was successful and have been contracted as the field services provider under a new Field Services Agreement (FSA) through to 2023.

The FSA delivers a number of strategic outcomes for WELL. It is structured to ensure alignment with WELL's asset management objectives and to improve the integrity of the asset data held in WELL's information systems. The FSA covers the following services:

- Fault management – 24/7 response for fault restoration;
- Preventative maintenance – asset inspection and condition monitoring including the capture and storage of asset condition data and reporting this information;
- Corrective maintenance – remedial maintenance on defective assets;
- Value added services – safety disconnects and reconnects, critical cable standovers during excavation, and provision of buried asset plans provided to third parties;
- Minor connection services and livening; and
- Management services – network spares, updating of geographical information systems (GIS) and other supplementary services as required.

The FSA includes key result areas (KRAs) and performance targets that Northpower is required to meet, with incentives for high levels of achievement. The cost of work undertaken is based on commercially tendered unit rates. The FSA is managed with a series of regular meetings to cover off key functional areas between WELL and Northpower.

4.3.1.2 Contestable Capital Works Projects

Contestable capital works include:

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

Contestable capital works projects are competitively tendered. They are delivered under either independent contractor agreements (ICAs) or the FSA if Northpower is the successful tenderer. These agreements outline the terms and performance requirements the work is to be completed under and include KPIs or KRAs, defects liability periods, insurance and liability provisions, and also reflect the requirements of the HSW Act. All contracts are managed on an individual basis, and include structured reporting and close out processes including field auditing during the course of the works.

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

4.3.1.3 Vegetation Management

This outsourced contract for vegetation management was tendered competitively in 2018 with Treescape being successful with a new contract being awarded. The contract provides for vegetation management as per the Tree Regulations, as well as improving landowner awareness of tree hazards.

Management of this contract is the responsibility of the General Manager Service Delivery in a similar manner to the Northpower FSA with regular meetings and performance incentives in place.

4.3.1.4 Contact Centre

The Contact Centre provides management of customer and retailer service requests, outage notification to retailers and handling general enquiries. Management of this contract is the responsibility of the Chief Financial Officer.

4.4 Asset Management Documentation and Control

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

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

All documents such as policies, specifications, drawings, operations and maintenance standards, and guidelines follow the structure of the controlled document process, with a formalised review and approval process for new and substantially revised documents. The documents are made available via intranets and extranets 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.

4.5 Asset Management Maturity Assessment Tool (AMMAT)

The AMMAT is a self-assessment questionnaire based on PAS55 Assessment Methodology. There are six assessment areas, each focusing on the way that the organisation manages either its processes or its people:

- Asset strategy and delivery;

- Communication and participation;
- Competency and training;
- Documentation, controls, and reviews;
- Structure, capability and authority; and
- Systems, integration and information management.

WELL's Asset Management Maturity Assessment is provided in Appendix C. The graph in Figure 4-3 gives a summary of the results.

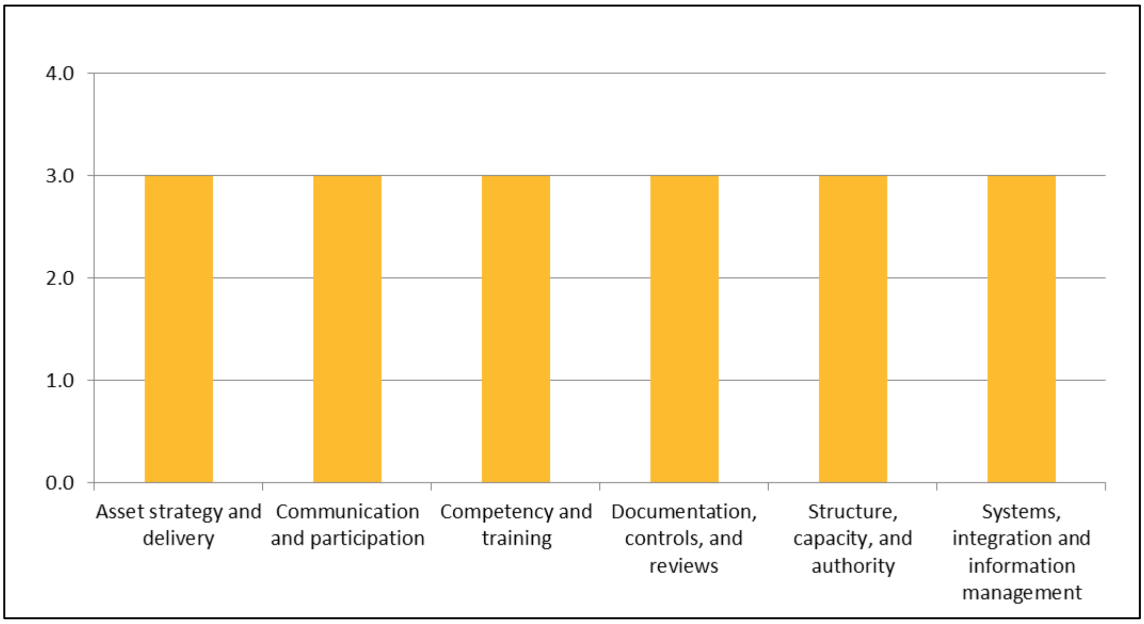


Figure 4-3 Summary of the Maturity Assessment 2022

Development of areas beyond Maturity Level 3 for individual aspects of the AMMAT will be considered by WELL where the need is clear, cost effective and justifiable.

4.6 Quality, Safety and the Environment (QSE)

WELL is committed to provide excellence in QSE outcomes through application of the following principles:

- Members of the public are not harmed by the operation, maintenance and improvement of WELL's assets;
- All employees and contractors undertake their work in a safe environment using safe work practices;
- The wellbeing (physical and mental) of staff and field workers is a key focus;
- Controls, such as policies, plans, and competencies are effective for minimising impacts to the environment;
- Processes such as audit and review procedures are in place to ensure high quality outcomes are consistently achieved; and

- Continuous improvement is a key goal.

To support these principles, WELL maintains a comprehensive set of health and safety, environmental, and quality policies and procedures which, together with the wider business policies and standards, are routinely reviewed and updated.

In accordance with WELL's mission, health and safety is given top priority and is a core business value. A Board Health and Safety Committee meets regularly to be updated on metrics, workplace safety and initiatives, issues and to provide guidance to management. As illustrated in Figure 4-4, a formalised safety leadership structure is in place to help ensure that health and safety leadership is provided throughout the business.

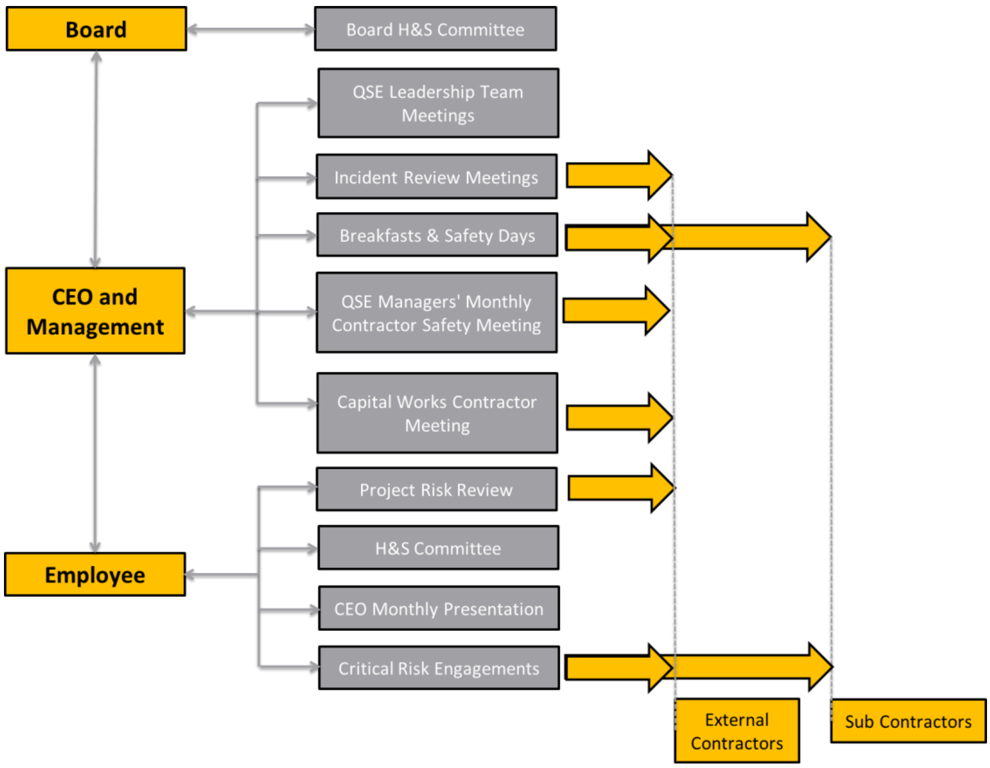


Figure 4-4 WELL's Safety Leadership Structure

WELL holds a monthly Safety Leadership Committee (QSE Leadership Team) meeting to monitor performance, discuss emerging trends or new issues and progress on key improvement areas. The CEO and general managers are part of the QSE Leadership team. WELL employees and contractors work together via a process involving consultation, collaboration and coordination to help deliver safe work practices, make appropriate use of plant and equipment (including protective clothing and equipment), and review that controls are being managed and report on incidents, near misses and hazard observations.

In a similar manner, quality and environmental outcomes are managed by WELL via consultation, co-operation and co-ordination. All employees and contractors are required to:

- Take all reasonable steps to ensure that business activities provide an outcome that minimises environmental impacts and promotes a sustainable environment for future generations;

- Take all reasonable steps to ensure the delivery of goods, products and services are to an acceptable standard and meet the quality expectations of the business; and

- Identify and report any defects or non-conformances to enable improvement in the systems or performance to maintain quality outcomes.

WELL's QSE outcomes and processes are discussed in more detail below. The associated performance objectives and measures are described in Section 5.

4.6.1 Safety Regulation

WorkSafe New Zealand (WorkSafe) is the work health and safety regulator. Worksafe's functions include:

- Monitoring and enforcing compliance with work health and safety legislation;
- Providing guidance, advice and information on work health and safety; and
- Compliance to the Health and Safety at Work Act 2015.

The Health and Safety at Work Act 2015 (HSW Act) came into effect in 2016. Consistent with the HSW Act, WELL continues to develop closer relationships with other organisations and stakeholders where an interface with network assets exists. The HSW Act requires a greater level of consultation, co-operation and co-ordination in relation to health and safety duties and issues. This brought about a number of changes in the way WELL conducts its outsourced field activities. These changes include the ongoing requirement for due diligence and governance from Board level down and across all parties involved in the supply continuum. All personnel including contractors and volunteers become workers for the purposes of the HSW Act. The fundamental obligation to protect workers, the public, and property from harm, remains the core consideration with effective planning and solid communication being paramount to safe and effective work management.

4.6.2 Public Safety Management Systems (PSMS)

WELL has a Public Safety Management System (PSMS) framework, built on policies, procedures and guidelines relevant to the safe design and management of the assets. The PSMS helps ensure that assets installed in public areas do not pose a risk to public safety. The PSMS meets the compliance requirement for electricity distributors to implement and maintain a safety management system for public safety set out in Regulations 47 and 48 of the Electricity (Safety) Regulations 2010.

The PSMS also meets the requirements of NZS 7901:2008 Electricity and Gas Industries - Safety Management Systems for Public Safety. The certification body Telarc recertified WELL against the requirements of NZS 7901 in 2021 and confirmed that WELL was compliant with regulatory requirements.

Telarc. Registered
Public Safety NZS 7901

WELL continues to invest significant resources to raise awareness in the community of the potential risk of living and working near electricity assets. WELL provides public 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. It 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.

4.6.2.1 School Safety Programme

WELL runs an education programme for schools which educates children about electrical safety. The Stay Safe programme is aimed at primary school aged children and offered for delivery in schools around the Wellington region. 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, which contains interactive safety games and information targeted at young children and parents regarding network safety and electrical safety around the home. There is also a link to the website in the School Safety Programme section of WELL's website.

4.6.2.2 Media Advertising

WELL actively raises public awareness about the dangers of living and working around network assets. WELL undertakes radio safety campaigns which cover 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. Radio safety campaigns were conducted in 2021 relating to vegetation management, major event preparedness, and safety in lines down situations.

4.6.2.3 Safety Seminars and Mail Outs

In order to help prevent third party contact with the network, WELL works closely with civil contracting companies (third party contractors working around WELL assets) and other organisations that, through the nature of their work, need to get closer to the network than normally allowed. This may be in the form of a planning discussion or on-site safety seminars which raise 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 WELL mails out letters to various contracting sectors focusing on infringements impacting safety around the network.

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

4.6.2.4 Contractors' Safety Booklet

WELL has produced a safety publication targeted at civil contractors and those working near, but not accessing, the WELL network. This booklet *"we* all need to work safely"*, last revised in February 2020, is handed to those attending safety workshops and in mail outs to various contracting sectors that interface with the network.

4.6.2.5 Information Services

WELL provides an information service to reduce the risk of public safety and incidences of damage to assets or property. The service is available through a 24 hour freephone number.

This includes services such as:

- Service Map requests
- Private and Strategic Cable Locations[11]
- Close Approach requests
- Standovers

[11] Other cable locations are now provided via a direct service by cable location companies.

- High Load Permits
- High Load Escorts

The additional risk created by the extra work around WELL poles is being carefully managed in terms of the HSW Act by formal contractual conditions and consultation, co-operation and co-ordination between parties involved in the UFB installation work.

4.6.3 Workplace Safety and Initiatives

As WELL has the following workplace safety initiatives in place.

4.6.3.1 Staff Health and Safety Committee (H&S Committee)

The H&S Committee represents WELL's employees and meets bi-monthly to address issues raised by Workgroup Representatives or reported through WELL's Health and Safety Management System (1FiCS). The H&S Committee is made up of seven volunteers and deals with concerns ranging from Emergency Preparedness & Response to faulty appliances that need repair or replacement.

4.6.3.2 Safety Breakfasts

WELL regularly arranges safety breakfasts for all its external 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 300 people are catered for at these sessions.

4.6.3.3 Annual Worker Safety Workshop

WELL arranges a half day safety seminar for all its workers and closely associated PCBUs and their key workers on an annual basis. The aim of these seminars is to reinforce WELL's desired behaviours through direct interface with keynote speakers and other subject matter experts.

4.6.3.4 Critical Risk Engagements

All WELL staff undertake engagement visits to sites where contractors are working on the network. The engagement visits are used to confirm understanding and implementation of corrective actions and to discuss safety systems and opportunities for improvement.

4.6.3.5 Workplace Safety Training and Competence

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

WELL ensures its personnel are trained and competent in safety matters through providing, for example:

- CPR / First Aid refresher sessions every six months;
- Work Type Competency (WTC) training;
- Restricted area access training;
- Defensive driving training; and

- Basic Traffic Control management.

4.6.3.6 Incident Review Meetings

WELL holds weekly internal meetings involving the outsourced service providers to review and address reported hazard observations, near misses and incidents. A key objective of these meetings is to prevent incidents occurring or recurring, and to use lessons learnt for continuous improvement.

4.6.3.7 Safety Alerts

When the need arises, WELL issues Safety Alerts to all its service providers highlighting a safety concern and listing any actions required to reduce the concern.

4.7 Risk Management

WELL aligns its risk approach with that of its parent company by adopting the Enterprise Risk Management (ERM) – Integrated Framework Risk Management – Principles and Guidelines standard. This provides a structured and robust framework to managing risk, which is applied to all business activities, including policy development and business planning. WELL's risk management framework is discussed in Section 4.7.2.

Risk management is an integral part of good asset management practice. WELL's approach to managing asset-specific risks is discussed in Section 7.

4.7.1 Risk Management Accountabilities

WELL's Board has overall responsibility for the governance of the business, including approval of the risk management framework. Board oversight of the risk management process is delegated to the Audit and Risk Committee, a sub-committee of the Board. This Committee is updated three times a year by the CEO as part of the regular management reporting functions. This is in line with the risk management framework.

The CEO is accountable for the performance of the business and as such the effectiveness of the controls being employed to manage the risk. While the CEO is held accountable by the Board, the management team have assigned responsibilities for ensuring controls are implemented and well managed so that risks are reduced to an acceptable level. The responsibility for controls is assigned to managers and bi-annually reviewed to ensure they remain relevant and that the risk environment has been assessed for new risks or changes to the risk profile. Some of the key controls are listed in Section 4.7.3.

4.7.2 Risk Management Framework

WELL's approach to risk management is illustrated in Figure 4-5.

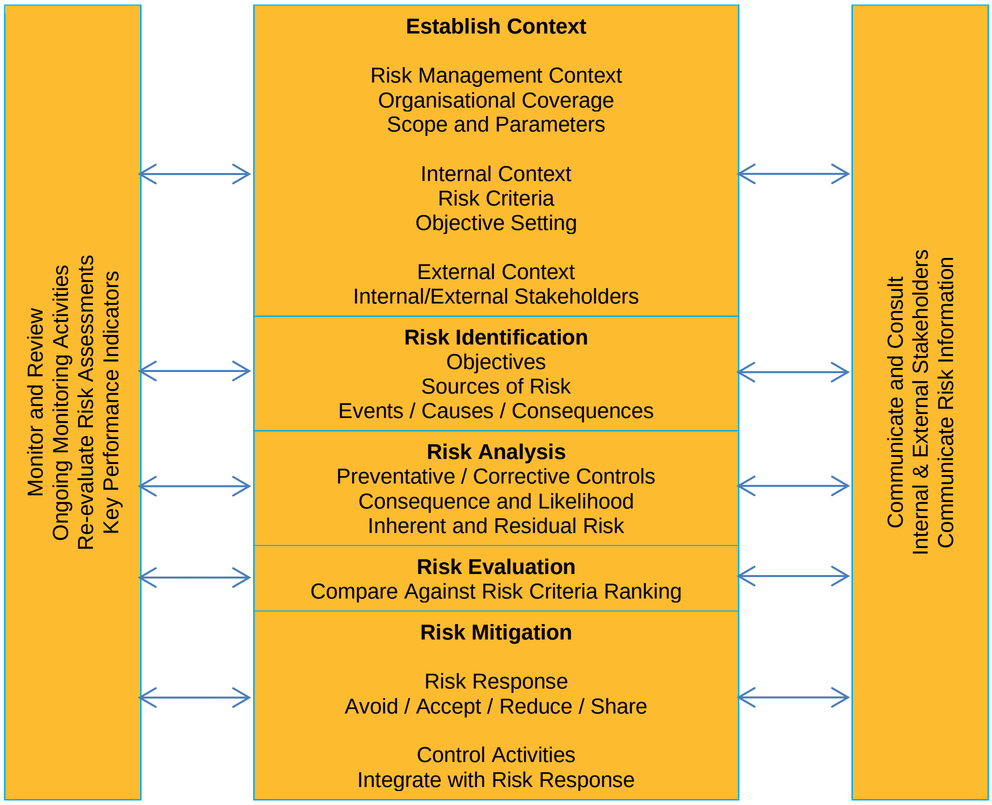


Figure 4-5 WELL's Risk Management Process

The risk management process as illustrated above covers the following five process steps:

Establish Context. This takes into account company objectives, the operating environment (discussed in Section 3.7), and risk criteria.

Risk Identification. Risks are identified through operational and managerial processes. WELL has grouped its risk into seven categories. Section 4.7.3 describes the controls used to mitigate the risks. The seven categories of risks are:

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

Risk Analysis. Analysis is undertaken using both qualitative and quantitative measures and assessed in terms of likelihood (chance of the event occurring) and consequence (impact of the event occurring). Where applicable, the consequence and likelihood tables have been developed to deliver WELL's asset planning objectives. Consequence scales reflect levels of consequence for each criteria ranging from extreme (the level that would constitute a complete failure and threaten the survival of the business), to minimal (a level that would attract minimum attention or resources). Likelihood scales have been developed depending on the chance or the likelihood of the event occurring. The risk rating is plotted on a risk chart with its likelihood score on the y-axis and overall consequence on the x-axis. The risk profiling matrices shown in Figure 4-6 are used to determine the level of the risk or risk rating.

LIKELIHOOD	CONSEQUENCE				
	Minimal	Minor	Moderate	Major	Extreme
Almost Certain	Medium	High	High	High	High
Likely	Medium	Medium	High	High	High
Possible	Low	Medium	Medium	High	High
Unlikely	Low	Low	Medium	Medium	High
Almost Never	Low	Low	Low	Medium	Medium

Figure 4-6 Qualitative Risk Matrix

Risk Evaluation. Requires the evaluation of risk likelihood and consequence by assessing the results of a risk analysis. This evaluation of risk is used to identify controls that could be put in place to mitigate the risks identified and the priorities of each risk mitigation strategy.

Risk Mitigation. Risk mitigation utilises controls to mitigate the risk. Controls can include procedures and processes that eliminate or isolate the risk source, changing the likelihood and consequence of the risk occurring, sharing the risk with another party or parties (e.g. contracts and insurance), and/or accepting the risk by informed decision. Controls mitigate the likelihood or consequence of the risk which reduces the inherent risk score to give a residual risk rating.

4.7.3 Key Business Risks and Controls

Rankings of risk events and control effectiveness were updated in December 2021, identifying no current extreme residual risks and only one high residual risk.

In total, 46 business risks were assessed by WELL. Table 4-2 shows the 10 highest risks ranked according to their residual ratings, and then by their inherent risk ratings.

	Event	Inherent Rating	Residual Rating
1	Catastrophic earthquake and/or Tsunami that causes significant damage to Company assets.	High	High
2	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.	High	Medium
3	Non-optimum starting price adjustment.	High	Medium
4	Exploitation of IT security.	High	Medium
5	Injury or Damage caused or loss suffered to third parties.	High	Medium
6	Sub-optimal performance or failure of network assets.	High	Medium
7	Non-compliance with Electricity Act and Regulations.	High	Medium
8	Non-compliance with the Health and Safety at Work Act 2015.	High	Medium
9	Inadequate management and/or supervision of contracted (i.e. outsourced) activities (including contractor resources).	High	Medium
10	Mismanagement of a crisis and emergency affecting the network.	High	Medium

Table 4-1 Summary of 10 Highest Business Risks

The business identified over 200 unique controls that aim to mitigate the causes and consequences across the identified risks. The 10 most frequently used controls for managing risk across the business are:

- Insurance process including engagement of qualified brokers;
- Board and Board Committees and Reporting Structure;
- Contractor Management System and Processes
- Auditing and Compliance (external and internal);
- Management Monitoring, Reporting and Review;
- Purchasing and Procurement Policy and Processes;
- Asset Management Policies, Strategies, Standards, and Plans;
- Education, Training and Development Policies and Programs;
- Delegations of Financial Authority; and
- Incident reporting and Investigation processes and standards.

4.7.3.1 Insurable Risks and Insurance Premiums

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

The balance (85% by replacement value) of WELL's network is not insured. As such, the customer retains the risk on the uninsured portion of the network. WELL would have to apply for a CPP following a significant event to request additional funding (and an associated price increase) to repair the network. WELL does not insure its subtransmission and distribution assets as insurance cover for these types of assets (poles, cables, wires etc.) is currently only available from a small number of global reinsurers, is very expensive, has high deductibles, and typically excludes damage from windstorm events.

Illustrating this by way of example, if WELL were to insure poles, cables and wire assets with a policy limit of $500 million, it would need to pay a 10% deductible of $50 million before any insurance payments would be provided. In addition, the annual insurance premium for such cover is expected to exceed $50 million, which has increased recently in line with other general insurance costs, and is not considered economic. Ex post recovery of the full costs is therefore the regulatory recovery mechanism for managing this risk.

4.7.3.2 Insurance Cover

WELL renews its insurances in two tranches:

1. Industrial Special Risks (ISR) Insurance, which 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.

Section 5

Service Levels

5 Service Levels

WELL is committed to operating a sustainably profitable electricity distribution business which provides customers with a safe, reliable, cost effective and high quality energy delivery system. This section describes WELL's targeted service levels to achieve this objective. The measures and targets presented flow directly from the mission and Business Plan. This section also explains the basis for measuring the service level performance and how WELL has performed historically.

There are four areas where services levels have been established:

- Safety Performance;
- Reliability Performance;
- Asset Efficiency; and
- Customer Experience.

This Section now includes a complete set of performance targets, including:

- Service levels which retailers apply on behalf of customers. These targets reflect the service levels outlines in the current Use of Network agreements with retailers;
- Reliability targets set as part of the price/quality regulation under Part 4 of the Commerce Act 1986; and
- WELL's own service levels used to measure performance against its Mission Statement.

The Reliability Performance objectives and strategies are discussed in greater detail in Section 6.2 separately to the rest of the other Service Levels due to the complexity and detailed discussions included. The service levels also incorporate feedback received from the stakeholder groups discussed in Section 3.6.

5.1 Consolidated Service Level Measures in Retailer Agreements

WELL has service level targets which retailers apply on behalf of their customers. Previously these service levels were included in the agreements with each retailer. WELL has consolidated its service measures and targets that were previously provided in retailer agreements, into this AMP. The Default Distributor Agreement (DDA) refers to these AMP service levels, rather than providing the service levels directly in the agreement itself.

Retailers can find the service levels previously provided in their agreements with WELL in Section 5.5 which details Customer Experience Service Levels. As a minimum, all of the service level measures and targets previously provided in the Use of Network agreement have been included. WELL has consolidated its service levels and standards to:

- Provide clarity and transparency about the levels of quality that WELL will provide. Publishing different service measures in multiple documents could lead to confusion and misunderstanding;
- Ensure service standards are aligned with its regulatory quality obligations and that the standards are at a level that can be delivered within its regulatory allowances;

- Provide WELL with the ability to adjust and refine its service standards to any changes in its price path and regulatory obligations; and
- Allow WELL to transparently link the service standards to the work programmes, operations and funding provided in this AMP.

WELL now provides its service levels in the AMP, rather than in agreements with retailers, because legislation protecting customers and the regulatory framework for distribution businesses has evolved since the current agreements with retailers were developed. The Consumer Guarantees Act, the Utility Disputes framework and price/quality regulation under Part 4 of the Commerce Act provide better consumer protections than those provided in previous retailer agreements (i.e. the Use of Network Agreements). Specifically:

- The Consumer Guarantees Act provides sufficient (and arguably more appropriate) remedies for customers than Service Guarantee Payments included in retailer agreements, which are arbitrary and can be administratively burdensome on all parties. WELL does not believe the existing service guarantee scheme or credit payments provided an effective incentive framework. Both have rarely been needed on the Wellington network. By comparison, WELL spends considerably more in providing individual reparations as part of our in-house complaints process.
- The Commerce Commission regulates service quality and price under Part 4 of the Commerce Act 1986. WELL is penalised for not meeting its quality targets with the penalties passed back to customers as a price decrease. WELL believes that any penalties or payments relating to quality must relate, or at least be consistent, with the price path. This allows a distributor to be adequately funded to provide the level of service a customer is willing to pay for, i.e. price and quality are balanced.
- WELL has an internal disputes resolution process that resolves the majority of customer complaints. WELL also participates in the Utilities Disputes process. The Utilities Disputes process provides a back stop for issues that are unable to be resolved internally and is rarely required.

5.2 Safety Performance Service Levels

WELL has continued to build on the foundation set by past health and safety performance. It is a member of the Electricity Engineers Association (EEA) and supports initiatives the EEA undertakes in providing leadership, expertise and information on technical, engineering and safety issues across the New Zealand electricity industry.

Continual improvement in managing health and safety is core to WELL and involves ongoing review of health and safety practices, systems and documentation.

WELL welcomes the Worksafe New Zealand legislation as an ongoing approach of continual improvement to workplace safety and a focus on effective identification and management of risk to protect the welfare of workers engaged in delivering services, and the safety of the public.

Within this context of continuous improvement, four primary measures have been adopted:

- Incident, near miss and hazard observation reporting;
- Corrective actions from site visits closed;
- Lost Time Injury Frequency Rate (LTIFR); and

- Total Notifiable Event Frequency Rate (TNEFR).

LTIFR and TNEFR are lagging indicators of safety performance, while hazard observation reporting and site visits to engage and consult with the workforce are leading indicators that help build a supportive safety culture and reinforce positive safety behaviours. Past performance and targets for the planning period for each measure are set out below.

5.2.1 Lost Time Injury Frequency Rate

WELL's staff and contractors recorded three Lost Time Injuries (LTI) incidents in the industry reporting year ending June 2021. This resulted in a LTIFR for that period of 6.46 per million hours worked and a two year rolling average of 5.27 per million hours worked. The trend in LTIFR is shown in Figure 5-1.

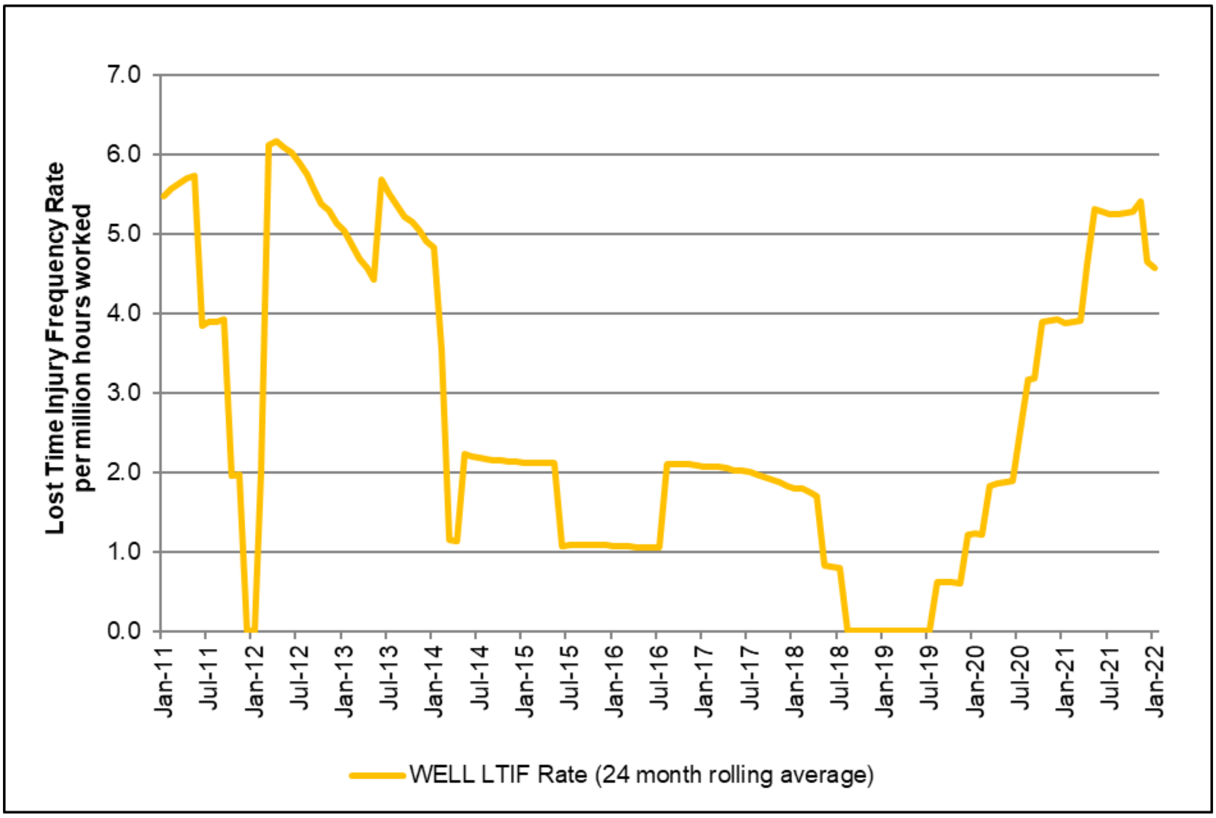


Figure 5-1 Lost Time Injury Frequency Rate

WELL is actively monitoring the trends in LTI which are primarily lower severity, non-electrical, soft tissue injuries in an ageing workforce requiring time off work for recuperation. WELL is aware of the balance between focussing on the network related critical risks and non-network related risks and is actively working with service providers to ensure a balance is achieved.

In 2019, WELL launched its safety brand "Safer Together" to develop a more open transparent reporting culture. This has reduced barriers to injury reporting, which has resulted in an increase in reported LTIs that may have historically gone unreported.

5.2.1.1 Planning Period Target

WELL's target for the 10-year planning period is to achieve a zero LTIFR over the whole period.

5.2.2 Total Notifiable Event Frequency Rate

The HSW Act introduced "notifiable events" which comprise notifiable injuries, notifiable illness, notifiable incidents and fatalities. The reference to "serious harm" within Section 16 of the Electricity Act 1992 was replaced with Section 23 of the HSW Act with reference to "notifiable injury, illness or incident".

This is a lagging performance measure that commenced in 2016 and is included in all service provider performance indicators.

WELL's staff and contractors recorded no Notifiable Events in 2021. This resulted in a 2021 TNEFR of 0.00 per million hours worked and a two year rolling average of 0.00.

5.2.2.1 Planning Period Target

WELL's target for the 10 year planning period is to achieve a zero TNEFR over the whole period.

5.2.3 Incident and Near Miss Reporting

During 2021 WELL continued to implement initiatives aimed at increasing reporting rates of hazard observations and near miss events. Increased reporting is a measure of a mature safety culture and allows for continuous improvement from small incidents which in turn reduces the likelihood of serious events.

Total event reporting in 2021 was 418 events reported. Approximately 99% of all reported events were classified as minor, 0.7% were classified as moderate, whilst 0% were of a serious nature. The total number of proactive reports received during 2021 was 122. These 122 are further broken down to 10 near miss events and 112 hazard observation reports. Reporting figures are slightly up on previous years, primarily due to increased awareness of the effects of COVID-19 strategies.

Gathering hazard observation data allows WELL to both identify potential sources of harm to workers and the public, and to identify emerging trends prior to any harm occurring. It allows WELL to have confidence that outsourced service providers are assessing work sites under their control for any unforeseen locality introduced sources of harm which have not been identified during works planning.

Near miss data allows WELL to examine instances where harm could have occurred given slightly different circumstances and review critical controls for effectiveness.

WELL defines a near miss as any unplanned event with a release of energy which could have caused adverse consequences to workers but which did not do so. A hazard observation is defined as being similar to a near miss where potential for harm exists, but where a release of energy has not occurred.

5.2.3.1 Planning Period Target

WELL's current expectation for the 10 year planning period is to maintain the number of addressed hazard observation events reported per annum to approximately 200.

5.2.4 Corrective Actions from Site Visits

The WELL Field Assessment Standard provides for the categorisation of corrective actions resulting from field compliance assessments of worksites by severity and monitoring of close-out times.

There has been a decrease in the ratio of corrective actions identified per assessment against 2015 levels, as shown in Figure 5-2. Monitoring continues to help ensure that this trend is continued. A continued focus in 2017-2021 was compliance with temporary traffic management requirements, adherence to network standards, and public safety around worksites.

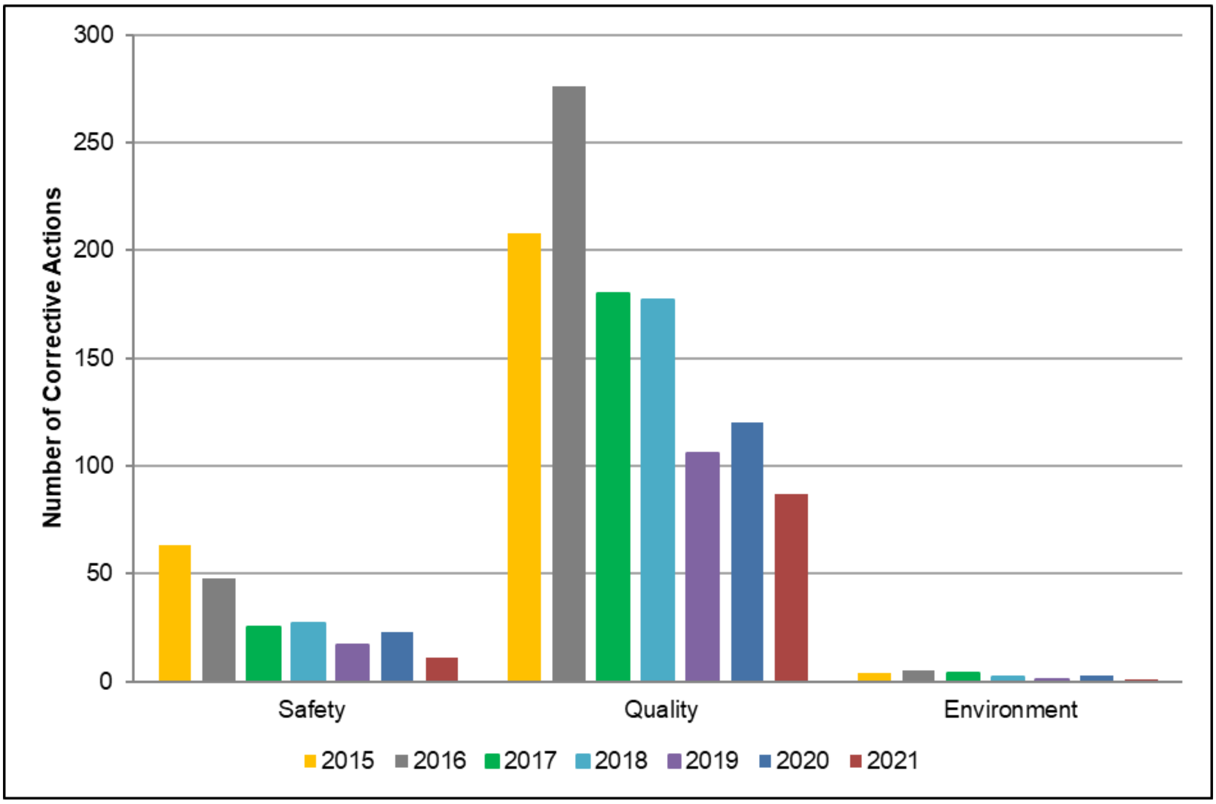


Figure 5-2 Corrective Actions arising from Assessments 2015-2021

5.2.4.1 Planning Period Target

WELL's target for the 10 year planning period is to maintain the current level of field compliance assessments of approximately 400 assessments per year while reducing all three types of corrective actions.

5.2.5 Health and Safety Initiatives

During 2022 focus will be placed on the following areas to further improve safety performance:

- Reinforcement of WELL's safety brand "safer together";
- Increased emphasis on the Te Whare Tapa Whā principles of wellbeing (family, physical, mental, and spiritual) of staff and field workers via focussed programmes and engagements;
- Maintain the timeliness of close-out of assessments;
- Reinforce the application of the risk management framework and expand the risk assessment process with clear focus on critical risk and control management and principal/contractor communications;
- Maintain critical risk engagement visits to:
    - check that workers have received safety instructions and have adapted work practices or processes as a result;

- engage with workers over work place safety and to help ensure WELL's critical risks are being effectively managed; and
- ensure service provider workers understand all critical risk controls, especially where these interface with WELL risks.

- Continue to expand the consultation, coordination, and cooperation where work involves overlapping PCBU duties; and
- Increase strategic risk collaboration with contracted field service providers in development of practical and effective risk controls.

5.3 Reliability Performance

5.3.1 Reliability Measures

Network reliability is measured using two internationally recognised performance indicators, SAIDI[12] and SAIFI[13]. When taken together SAIDI and SAIFI indicate the availability of electricity supply to the average customer connected to the network.

- SAIDI is a measure of the total time, in minutes, electricity supply is not available to the average customer connected to the network in the measurement period; and
- SAIFI is a measure of the total number of supply interruptions that the average customer experiences in the measurement period. It is measured as a number of interruptions[14].

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

- Interruptions caused by the unavailability of supply at a GXP, as a result of automatic or manual load shedding directed by the transmission grid operator[15], or as a result of some other event external to the WELL 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 WELL to understand customer service and 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. In practice such interruptions do not have a material impact on measured system reliability.

The SAIDI and SAIFI targets against WELL's historical performance are shown in Figure 5-3 to Figure 5-6. The 2021/22 year includes a forecast to account for the March 2022 month shown in dark blue.

[12] System Average Interruption Duration Index
[13] System Average Interruption Frequency Index
[14] Due to the effect of averaging, SAIFI is reported as a non-integer number.
[15] 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.

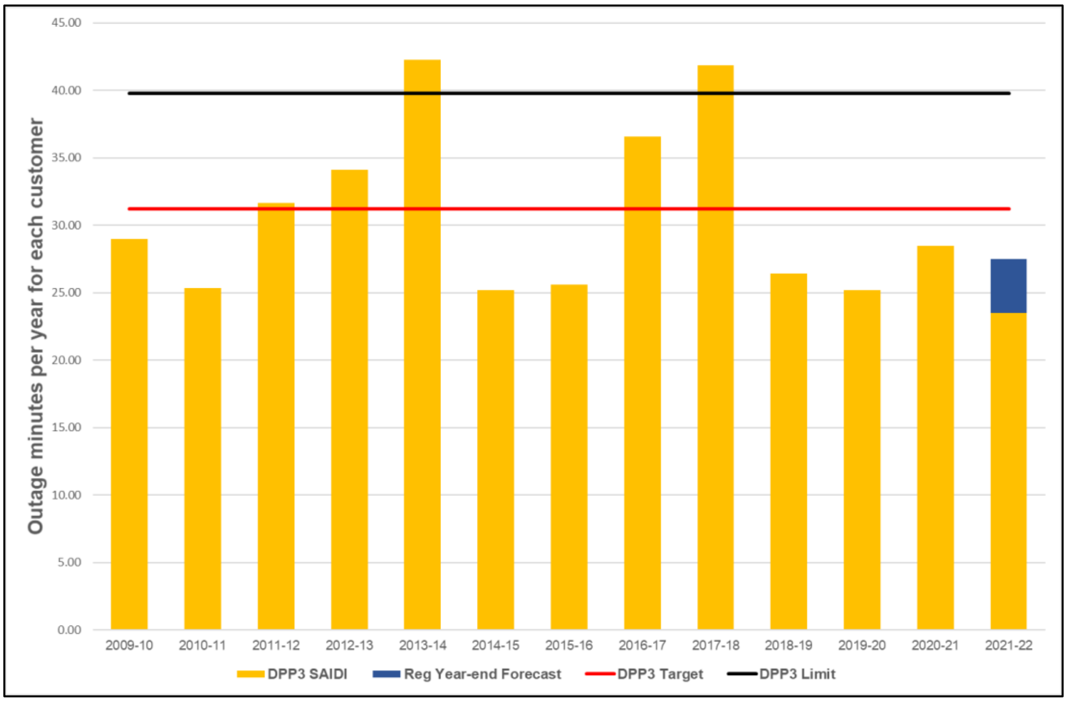


Figure 5-3 WELL Unplanned SAIDI Performance

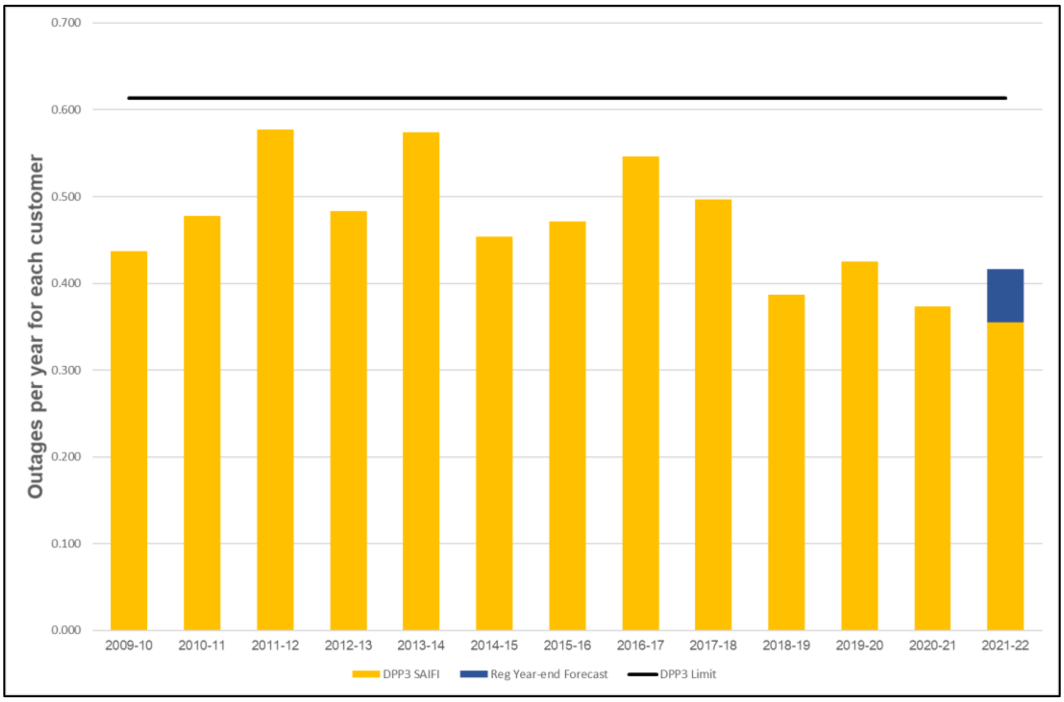


Figure 5-4 WELL Unplanned SAIFI Performance

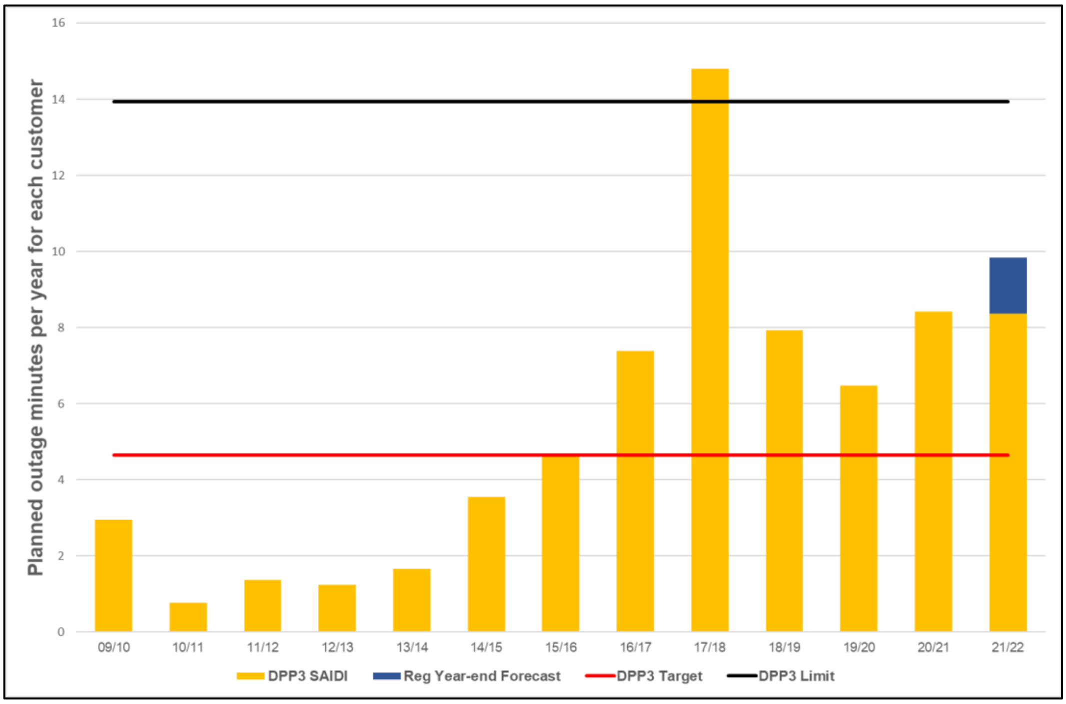


Figure 5-5 WELL Planned SAIDI Performance

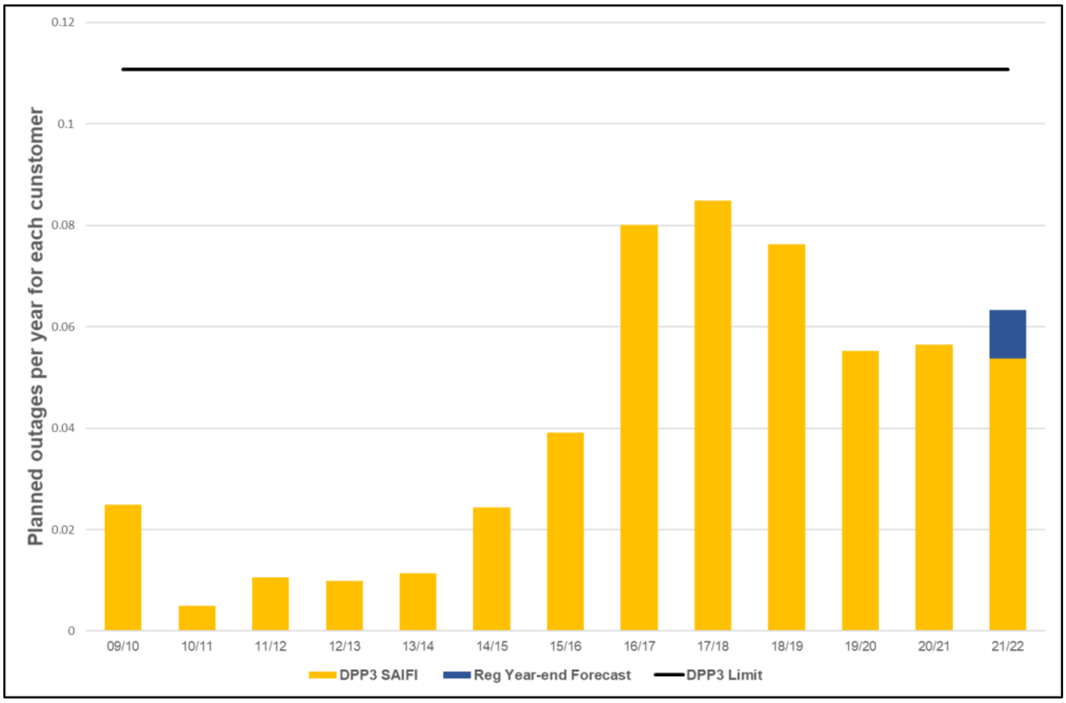


Figure 5-6 WELL Planned SAIFI Performance

WELL's reliability targets align with its asset management network reliability objectives as follows:

- Maintain overall network reliability at historical acceptable levels;
- Deliver the cost-quality trade-offs that customers request; and
- Meet regulatory standards on power quality (discussed in Section 8.1).

5.3.2 Process for Measuring Reliability Performance

This section explains how reliability performance is recorded and validated.

5.3.2.1 Outage Data Collection

The control system WELL uses to record SAIDI and SAIFI information is the PowerOn Fusion (PoF) SCADA network management system (the system). The system is used for the real-time management and monitoring of the high voltage network. Specifically, the system provides information about the status of the network, including customer connection points and devices like circuit breakers and fuses. The system automatically records outage information (including SAIDI and SAIFI details) in a database for all planned and unplanned outages of 11 kV and greater (the high voltage network), including details about the length of the outage and how many customers were impacted.

All of the outage information is then error checked and validated daily by the Network Control Team Leader and an Asset Engineer to ensure it is correct. The reviewed data is recorded in the reliability report sheet.

The process to record and validate network performance information for planned and unplanned outages is shown in Figure 5-7.

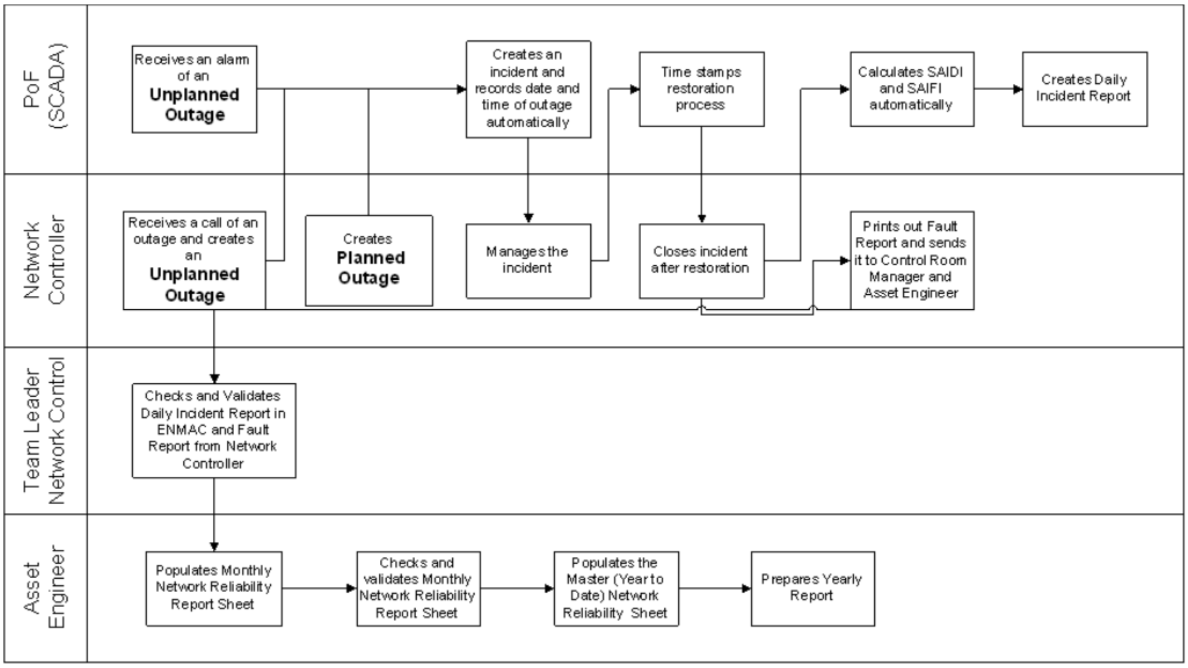


Figure 5-7 WELL Reliability Measurement Process

For unplanned outages, the system identifies there has been a fault, automatically logs the incident and time stamps when it occurred. Any subsequent switching operations are also recorded and time stamped.

For faults on devices that are not directly monitored by the system, the outage is recorded from the time of the first customer phone call relating to the high voltage fault. Subsequent switching operations are manually recorded and time stamped within the system.

5.3.2.2 Data validation and review

After an outage is resolved, an outage report is generated which includes notes from the network controllers on duty. The information is then validated for the following:

- Date outage started and ended;
- Time outage started and ended;
- Duration of outage;
- Number of customers impacted;
- Total customers minutes lost (based on switching operations);
- Total customer number (on network);
- SAIDI for outage;
- SAIFI for outage;
- Fault type; and
- Fault cause.

The data is reviewed for accuracy. Particular attention is given to non-system faults where the information is manually entered by the network controller. Systems faults are automatically generated and rarely have errors. The Network Control Team Leader reviews all faults and approves the daily fault reports as accurate.

The Asset Engineer then compiles the reviewed individual event reports into a monthly network reliability report which is used for monthly reporting of SAIDI and SAIFI indices. The monthly reports are then aggregated into the master database from which WELL's regulatory quality reporting is derived.

5.3.2.3 Planned outages

For planned outages, the proposed switching operations are entered into the system by the Network Controller prior to the event. During the event, the system creates an incident and the Network Controller enters the time the operation occurred. Planned events are validated by the network controllers and the Network Control Team Leader by referring to the specific job documents. The validation process considers whether LV back feeds or portable generation have been used to ensure there was no loss of supply.

5.3.3 Industry Comparison

WELL was one of the most reliable EDBs in New Zealand in 2020/21 as shown in Figure 5-8 and Figure 5-9. The data source is the annual Information Disclosures made by EDBs and made publicly available in August 2021. The benchmarking analysis shows that WELL's system reliability indices (i.e. SAIDI, SAIFI) are currently performing well against comparable networks in New Zealand (shaded in green).

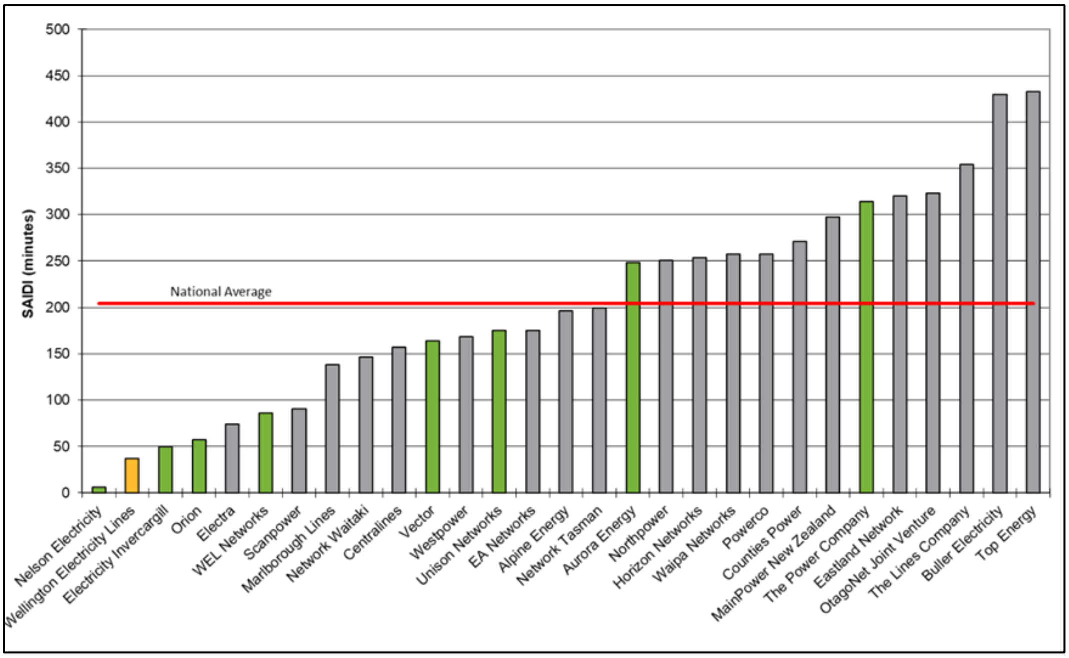


Figure 5-8 National SAIDI by EDB for 2020/21

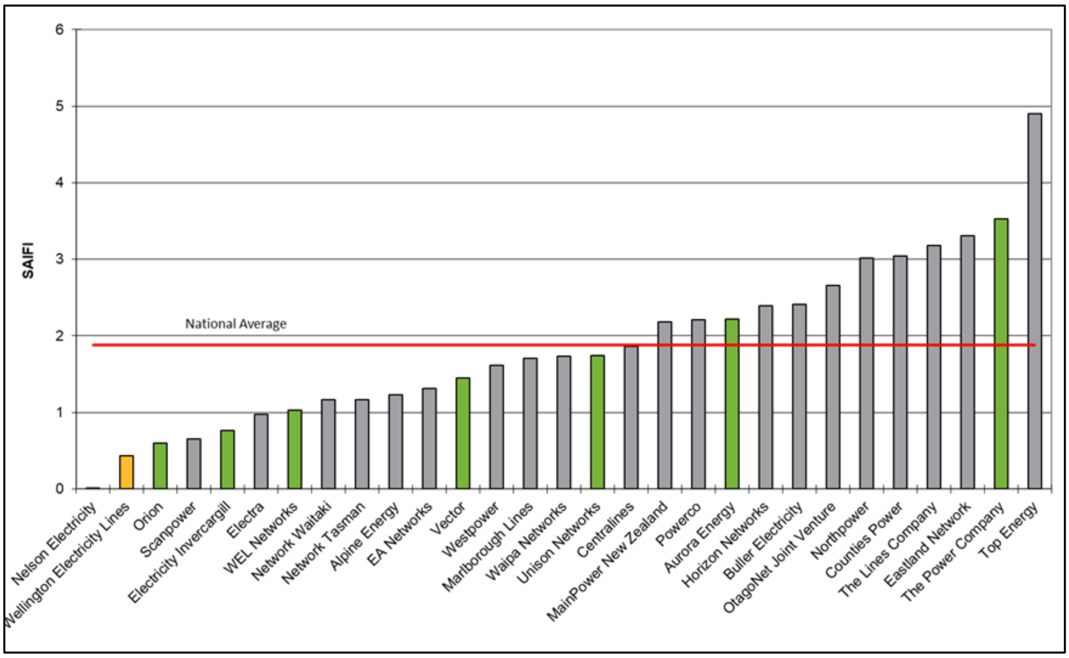


Figure 5-9 National SAIFI by EDB for 2020/21

5.3.4 Reliability Performance in 2021/22

WELL's unplanned network performance for the 2021/22 regulatory year was under the annual limit of 39.81 minutes for SAIDI and under the annual limit of 0.614 for SAIFI.

WELL's SAIDI performance in 2021/22 across a range of fault causes is shown as a waterfall chart in Figure 5-10. The fault causes represented in the chart are:

- Overhead network faults;
- Underground network faults;

- Substation faults;
- Car versus pole faults;
- Other third party faults;
- Major event days; and
- Other outage types.

Overhead faults have been further separated into those caused by asset failure, and those that were not (non-asset failure outages include those caused by vegetation, lightning, and animals). Major event days are listed as a separate category in order to account for normalisation.

Each of these categories is shown as either being smaller (coloured in green) or larger (coloured in red) than their average contribution during the reference period, with the whiskers on the chart being the standard deviation of the reference period data.

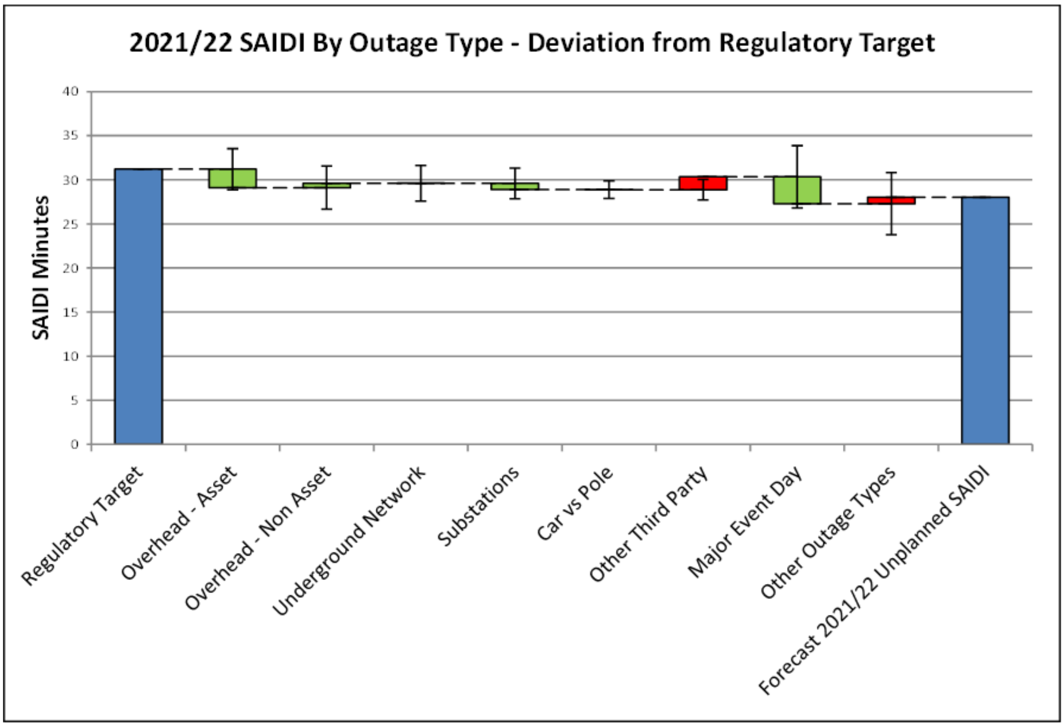


Figure 5-10 Waterfall Chart of 2021/22 SAIDI Performance by Outage Type

The equivalent chart for 2020/21 is shown in Figure 5-11.

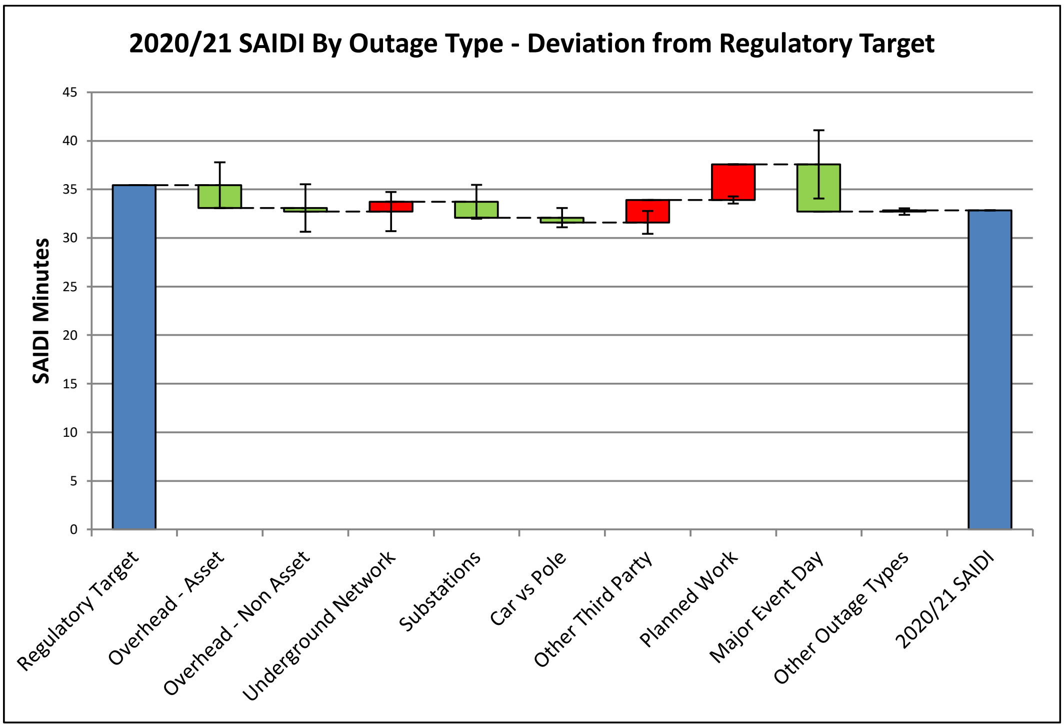


Figure 5-11 Waterfall Chart of 2020/21 SAIDI Performance by Outage Type

Comparing the two years shows that each year's performance is driven by different fault categories and there is no discernible trend in performance.

5.3.5 Reliability Contribution by Network Area

Figure 5-12 and Figure 5-13 show the SAIDI and SAIFI contributions from each network area, representing the availability of electricity supply to the average customer in each region (as opposed to the total number of customers supplied by the network). These charts highlight the difference between the reliability of Wellington city, due to its predominantly underground construction, and the overhead areas supplying the Hutt Valley and Porirua.

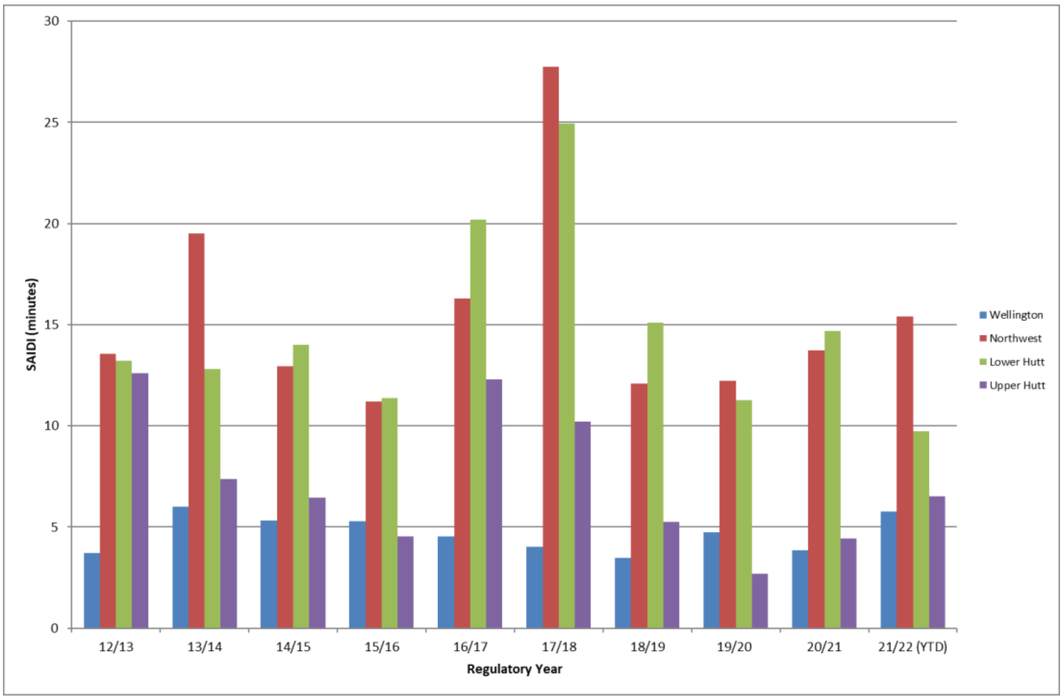


Figure 5-12 SAIDI Performance by Area

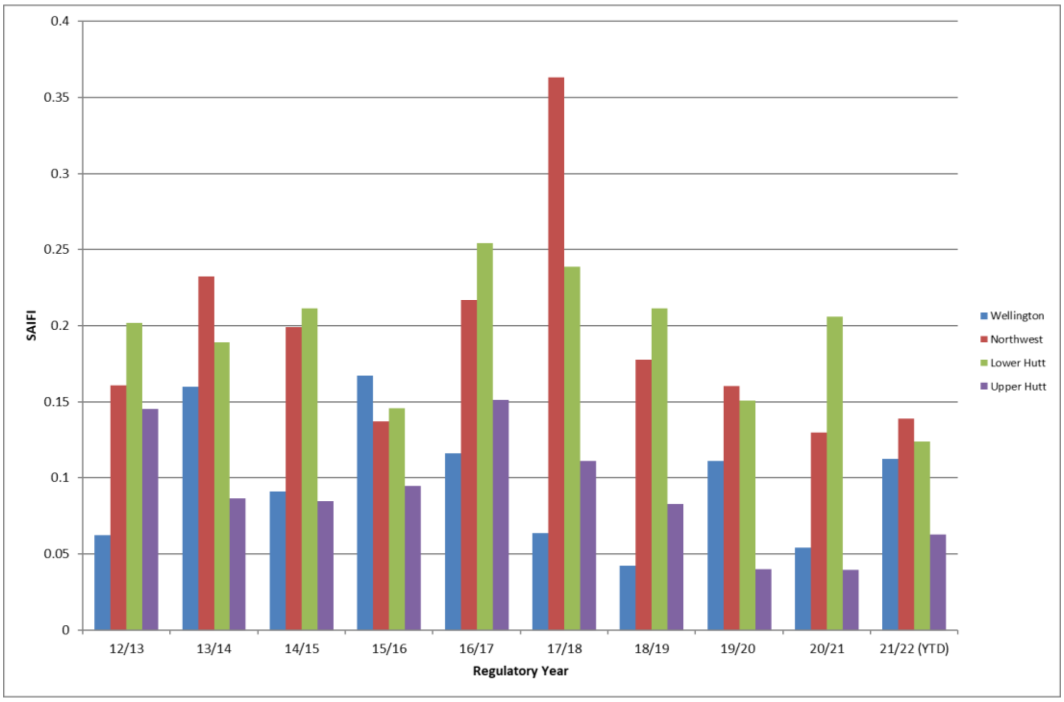


Figure 5-13 SAIFI Performance by Area

5.4 Asset Efficiency Service Levels

The load factor or utilisation of an asset reflects customer demand profiles, the geography of the region and historic network design and configuration decisions. WELL's predominantly urban network results in a higher than average utilisation and load density. The asset performance levels relate to the effectiveness of WELL's fixed distribution assets.

5.4.1 Planning Period Levels

WELL aims to maintain the high level of utilisation of assets at current levels, and in line with other networks that display similar characteristics. WELL has a very high customer density but below average energy density per ICP. Table 5-1 illustrates the level of performance for each measure over the planning period together with key measures of network density.

	Load factor %	Distribution transformer capacity utilisation %	Loss ratio %	Demand density kW/km	Volume density MWh/km	Connection point density ICP/km	Energy intensity kWh/ICP
Industry average[16]	57.9	43.4	5.6	40.7	185.9	12.5	15,819
WELL	48.8	52.2	4.8	116.5	473.6	35.6	13,303
Target 2022-2032	>50%	>40%	<5%	-	-	-	-

Table 5-1 WELL Asset Efficiency Levels to 2032

WELL is expected to remain at the current levels over the planning period.

5.5 Customer Experience Service Levels

It is important that WELL balances services that customers require with the value they place on these now and into the future. WELL has set the following asset management objectives related to customer service levels:

- Understand our customers' needs and the value they place on our services;
- Deliver excellent customer service;
- Adjust quality and types of innovative services to match customer needs;
- Reduce unit costs over time; and
- Implement whole-of-life least cost solutions.

WELL uses the insights received from its 'Voice of Customer' (VOC) programme to better understand the critical areas of concern for customers, their perceptions of the service provided and to inform investment plans for the planning period. Examples of VOC inputs are: surveys conducted with customers recently impacted by outages, community engagement events and analysis of the feedback received from customers through WELL's various contact channels.

In 2021, WELL engaged in a number of customer experience and community engagement initiatives, with some examples being:

- **Connections & Self-Service:** During 2021 a number of functionality improvements have been developed for the WELL website's self-service portal. These changes will be released in the first half of 2022 and will enable customers to be guided to the right channels for the services they wish to request.

[16] Values as per the Pricewaterhouse Coopers (PwC) Electricity Line Business 2021 Information Disclosure Compendium.

The changes are intended to enhance the experience for customers and remove a potential hurdle for a significant number of customers seeking a new connection to the network. For those customers seeking new connections that require extensions to the network, a fixed fee option will be provided to the majority of small to medium sized customer connection requests.

Community Engagement: During 2021 WELL's plans for community engagement were again disrupted by the impacts of COVID-19. Staff were still able to meet with a number of customers who had lodged complaints, to better understand their experience and to help identify the root cause of their complaint. This is an important component of WELL's Root Cause Programme. During 2022 WELL will be developing alternate methods to engage with communities which will reduce the risks arising from COVID-19.

In the first half of the year, WELL hosted a stand at Wellington's Home and Living Show which showcased the potential impacts to WELL's network of future increases in EV charging. Customers were shown an animated video which provided information about how they can help reduce those impacts while benefiting at the same time. This is one component of an ongoing programme to raise public awareness of the potential impacts to WELL's network (and their electricity supply) arising from the Government's initiatives to reduce New Zealand's carbon emissions.

- **Root Cause Programme:** The Root Cause Programme targets people, process, and system gaps which may have led to customers expressing dissatisfaction with the service they have received. Staff of both WELL and its contractors meet to review complaints raised and work together to develop solutions to address those complaint causes. Within the 2021 year the programme achieved 30% decrease in customer complaints received, helping to improve the customer experience.

In 2022, WELL will be delivering the following new customer experience improvement programmes:

- **Self-service Improvement:** Continued development of the web-based self-service platform to further improve its functionality and to deliver an improved customer experience.

- **Service Improvement:** WELL continues to analyse and target for improvement the root causes of complaints received from customers and/or their retailers. As part of that programme WELL staff members will visit a number of customers who have reported poor service throughout the year to better understand their experiences.

- **Community Engagement:** WELL plans to continue engaging with communities most impacted by outages as part of the 'Worst Performing Feeder' programme. The programme aims to update customers on network activities in their area and inform customers of actions they can take to help improve their electricity supply, such as vegetation management. As noted above, WELL will be developing alternate methods to engage with communities to reduce the risks represented by COVID-19.

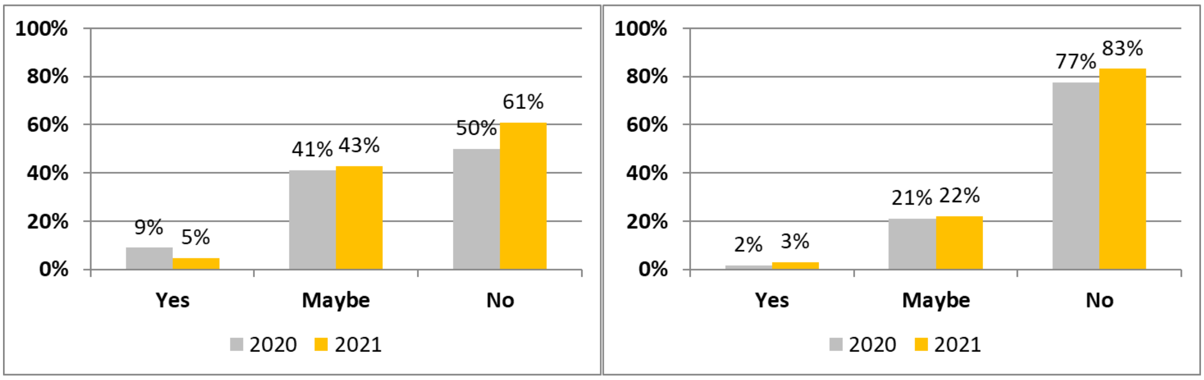
  In addition, as mentioned above in 'Service Improvement' a number of customers impacted by perceived poor service will be visited to better understand their experiences.

- **Planned Outage Publication:** Planned outages are currently sent by WELL to retailers, who in turn publish those outages to their customers. During 2021 WELL piloted the publication of planned outages within the outage reporting section on its website. This information provides an additional notification channel rather than replacing the current publication arrangement with retailers. During 2022 WELL plans to expand the planned outage publication service to include a wider number of planned outages. This will provide another option for customers to view updates on outages which may impact their electricity supply.

- **Community Education:** The Government's proposals to help New Zealand reduce its carbon emission levels are likely to result in increased demand for electricity and significantly impact the network. WELL will be developing a number of communication programmes to provide customers with an insight into those impacts. The programmes will inform customers about how WELL is planning to mitigate the impacts and how they can help shift electricity consumption away from the network's busy periods. The aim is to avoid or delay the need to build a bigger network and hence help to continue providing customers with low network prices.

5.5.1 Customer Engagement

WELL conducts a monthly customer survey to understand customer perceptions across a range of factors and includes questions which seek to understand whether customers perceive that the price-quality trade-off they receive is appropriately balanced. The monthly survey group ("Monthly Outage Sample") consists of customers who have recently experienced an outage, on the basis that they are more engaged on the issue and are better positioned to provide a considered response to queries. The results of that survey are compared in Figure 5-14 for two of the key price-quality trade-off questions.



Q1. Would you be prepared to pay a bit more for your power if it meant fewer power cuts?	*Q3. Would you be prepared to have slightly more power cuts if it meant your electricity bill was a bit lower?*

Figure 5-14 Sample of 2021 Customer Survey Results

For Question 1, the percentage of people willing to pay a bit more for power in return for fewer power cuts remains low, with the majority of customers expressing that they are not prepared to pay more for fewer power cuts. This result is consistent with previous years, but with an 11% reduction in the 'No' response and a 4% reduction in the 'Yes'.

The results for Question 3 suggest that customers are broadly satisfied with their current level of reliability and the price of delivering that service. This view is supported by WELL's position (marked by the yellow diamond) in the low SAIDI / low price[17] quadrant of the benchmarking analysis in Figure 5-15, compared to other EDBs represented as grey diamonds.

[17] WELL uses revenue per ICP as a proxy for price given the availability of data this information disclosure.

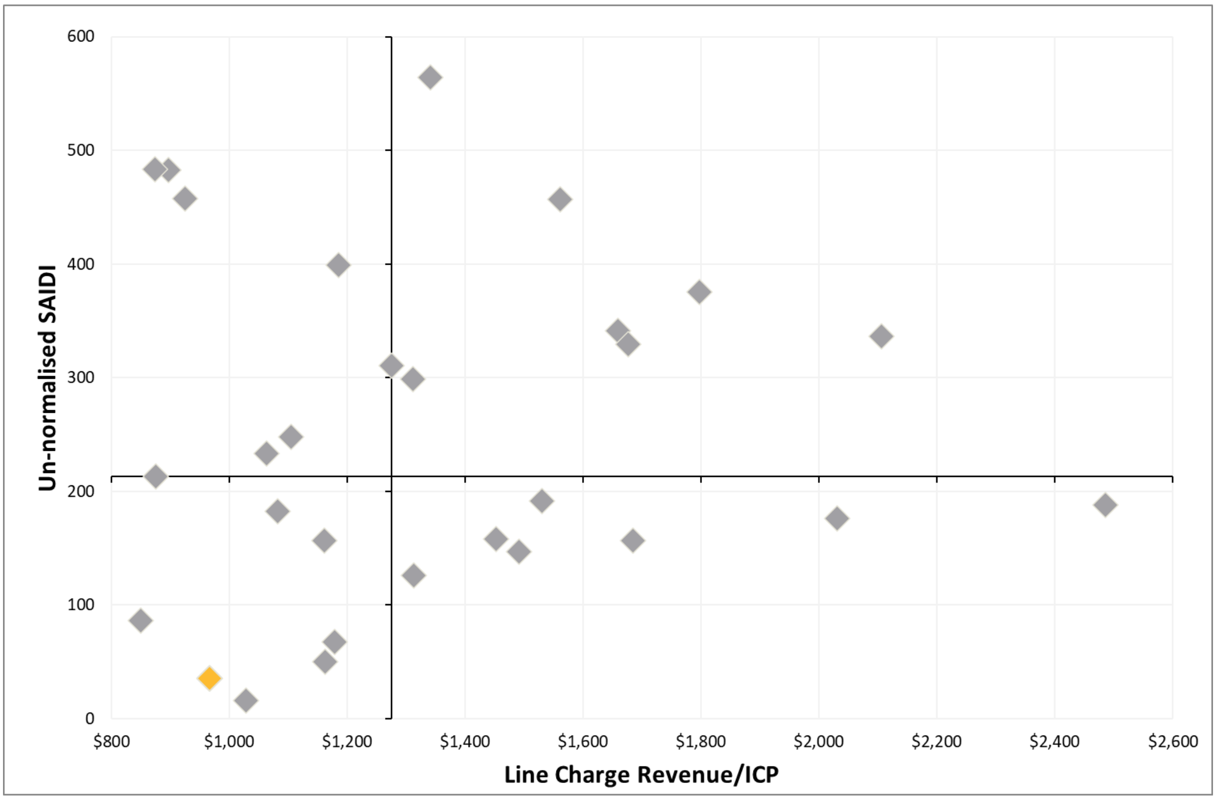


Figure 5-15 Quality vs Price Benchmarking Analysis (2019-2021)[18]

A copy of the same set of questions is available within the Consultation page on the Wellington Electricity website.[19] At this point in time the sample set of data collected from customers responding via the website is too small to provide a material comparison.

In the past year WELL's engagement programme with communities was impacted by the various restrictions imposed by the government response to COVID-19. WELL plans to recommence engagement with communities, prioritising efforts to those most impacted by unplanned outages as part of the 'Worst Performing Feeder' programme.

The goal of the engagement is to better understand customer experiences and use their opinions to help develop and improve the level of service. For customers in rural communities, the latter point is particularly important in relation to vegetation management. WELL also uses these opportunities to provide customers with practical advice on what they can do to safeguard themselves and their households for unplanned outage situations, and improve their security of supply.

WELL also regularly engages with city councils in the Wellington region with regards to the Tree Regulations and the issuing of trim and cut notices. This is a practice that will be continued as it helps support WELL to maintain reliability levels for customers.

5.5.2 Power Restoration Service Levels

WELL has two power restoration service levels: Urban and Rural. These service levels reflect previous feedback from customers and are agreed between WELL and all retailers. An Urban Fault is defined as a

[18] Data sourced from https://www.comcom.govt.nz/regulated-industries/electricity-lines/electricity-distributor-performance-and-data/information-disclosed-by-electricity-distributors

[19] https://www.welectricity.co.nz/about-us/consultation/

network fault that results in complete loss of supply to one or more points of connection within an urban area. A Rural Fault is any fault resulting in complete loss of supply to one or more points of connection in a rural area. The geographical regions categorised by the urban and rural power restoration areas are shown in Figure 5-16.

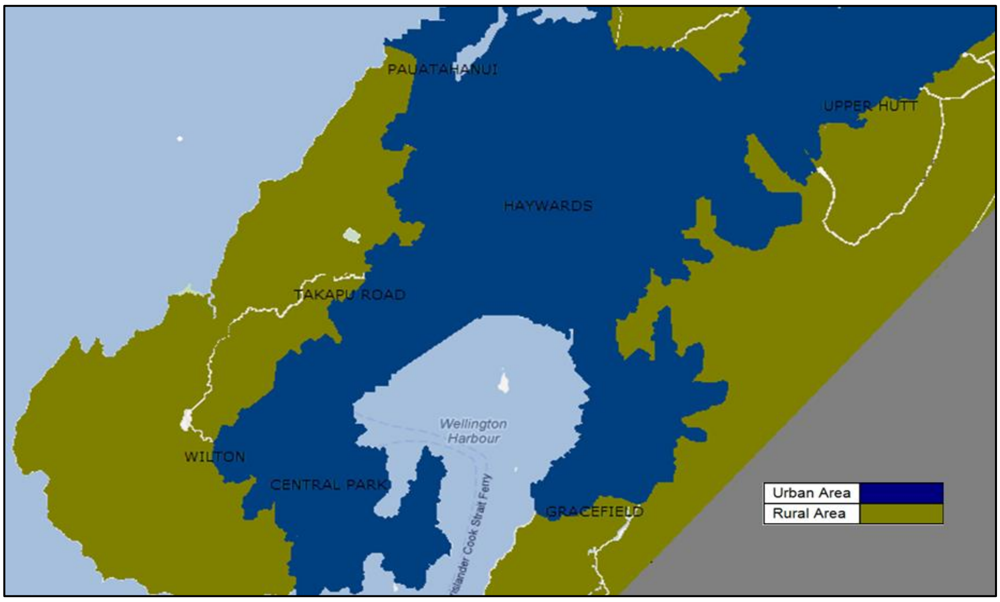


Figure 5-16 Geographical Map of Power Restoration Areas

5.5.2.1 Planning Period Targets

The targets for the power restoration service levels remain consistent over the planning period 2022-2032, as set out in Table 5-2.

	Urban	Rural
Maximum time to restore power	3 hours	6 hours

Table 5-2 Standard Power Restoration Service Level Targets 2022-2032

5.5.3 Notification of Faults and Outages

In addition to reliability and appropriate prices, customers increasingly expect accurate, timely information on their service and its status. Most customers accept occasional power cuts if they are kept informed of restoration times after a fault. Ensuring a reliable, effective information flow is therefore a priority for achieving good customer service. In support of this priority, WELL sets and tracks performance targets for its Contact Centre. WELL is also developing plans to ensure customers impacted by prolonged outages are kept informed with more detailed status updates than would normally be provided for unplanned outages of a shorter duration.

Retailers hold the direct relationship with the end-customer. WELL will pass outage information to the retailer who will then inform customers. WELL's service levels for the notification outages focus on the time taken to inform retailers. These notification service levels are set out in Table 5-3 (Unplanned outages) and Table 5-4 (Planned outages).

Outage Type	Notification Action	Notification Service Level
Area Network Fault	Provide retailer(s), to the extent reasonably known at the time,: • A description of the reason for the interruption; • The area affected; and • An expected time for restoration.	Within 5 minutes of fault being notified to WELL
Service Interruption	Provide retailer(s) with status updates	Within 5 minutes of new information becoming available; and At intervals no greater than 30 minutes
Expected (advised) restoration time likely to be exceeded	Notify retailer(s)	Not less than 10 minutes before the existing restoration time elapses
Partial or full restoration of supply	Notify retailer(s)	Within 5 minutes of partial or full restoration of supply

Table 5-3 Unplanned Outage Notification Service Levels

Outage Type	Notification Action	Notification Service Level
Upcoming planned outage	Notify retailer(s)	10 working days
Semi-planned outage for emergency repairs	Inform retailer(s)	As soon as is reasonably practicable

Table 5-4 Planned Outage Notification Service Levels

5.5.4 Notification of New Connections

After receiving an application for a new connection, WELL passes connection details on to the retailer so the retailer can liaise with the end-customer. Table 5-5 provides WELL's notification timeframes for new connections.

New Connection	Notification to Retailer
Receipt of application	1 working day
Connection approval if no site visit is required	2 working days
Where application requires network expansion before approval	2 working days
Where connection approval requires conditions to be met prior, a site visit; and/or network expansion	1 working day

Table 5-5 New Connection Notification Timeframes

5.5.5 Connection, Disconnection, Capacity Change Timeframes

Table 5-6 provides the timeframes for new connections, disconnections and capacity changes.

Activity	Requirements	Time to Action
Livening a new connection	Dependent on: • All necessary equipment in place; • Network upgrades or extensions not required; and • All other necessary requirements met.	4 working days
Temporary disconnections	If retailer provides authority to do so. If retailer requests more than 20 disconnections (whether Vacant Site, Permanent or Temporary) or re-connections in any one day WELL may not be able to meet this service level.	1 working day
Notification of capacity change request	WELL will advise retailer within the same timeframe whether or not the request is accepted and the requirements in respect of the Point of Connection that must occur prior to capacity change being made.	1 working day
Capacity change where only a fuse change is required	If the capacity change requested is likely to interrupt the supply to other end-customers, the capacity change may be delayed.	1 working day
Vacant Site Disconnection or a Permanent Disconnection	Provided that: • Access is available; and • There is an accessible isolating device (fuse) which isolates only the requested Point of Connection If retailer requests more than 20 disconnections (whether Vacant Site, Permanent or Temporary) or re-connections in any one day WELL may not be able to meet this service level.	2 working day
Reconnections after a Vacant Site Disconnection (field-energise an existing Point of Connection)	Service level only applies where there is an accessible isolating device (fuse) which isolates only the requested Point of Connection.	1 working day

Table 5-6 New Connection, Disconnection and Capacity Change Timeframes

5.5.6 Supply Quality Investigations

Where a retailer notifies WELL about a supply quality problem on the network, WELL will investigate the problem and respond to the retailer detailing the nature of the problem. Table 5-7 sets out WELL's response timeframes for supply quality investigations.

Supply Quality Investigations	Time to Action
Investigate problem and respond to the retailer detailing the nature of the problem	7 working days
Where investigation cannot be completed within 7 working days, provide an estimate of the additional time needed	Within 7 working days

Table 5-7 Supply Quality Investigation Timeframes

5.5.7 End-Customer Complaints

WELL receives end-customer complaints and enquires via its contact centre and has adopted the Utilities Disputes Code of Practice for managing complaints. All 'Times to Action' (timeframes in which WELL responds to complaints and enquires) comply with the Utilities Disputes rules and protocols. These are set out in Table 5-8.

Customer Complaints and Enquiries	Time to Action
Acknowledge receipt of a complaint or enquiry	2 working days
Respond to an enquiry; or Advise that more time is needed and provide a reason for the time extension	8 working days
Resolve complaint; or Advise that more time is needed and provide a reason for the time extension	10 working days

Table 5-8 Complaint and Enquiry Response Timeframes

5.5.8 Contact Centre Service Levels to Customers

WELL measures the service level performance of its Contact Centre through a set of key performance indicators (KPIs). Feedback from customers, the results of call observations and regular operational reviews are used as inputs into an ongoing performance improvement programme with the Contact Centre.

5.5.8.1 Contact Centre Targets

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

1. Grade of Service (GOS) (A1) - This measures the percentage of calls which are answered within a set threshold of 30 seconds. The target is for 85% of calls to be answered within this timeframe.

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

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

4. Outage Communications (B1): This is a measure of the time taken to initially notify of an outage. Retailers will be notified, and the WELL website updated, within five minutes of Telnet receiving notice of an outage affecting 10 or more customers. Note that this initial notification, and all subsequent updates, also update the WELL website and OutageCheck smartphone app.

5. Outage Communications (B2): This is a measure of ongoing outage updates. Retailers and the WELL website/outage app will be updated with changes (if any) to affected customer numbers and Estimated Time of Restoration (ETR) at least every 30 minutes (+/- 5 minutes) during the outage.

6. Outage Communications (B3): This KPI measures that more accurate ETR information is provided within a reasonable time. Within 90 minutes of Telnet receiving notice of an outage affecting 10 or more customers, Telnet will contact the Network Control Room (NCR) or Northpower (as appropriate) to get an accurate updated ETR. Retailers and the WELL website/OutageCheck app will be updated.

7. Outage Communications (B4): This is a measure of ongoing outage updates for more prolonged outages. Retailers and the WELL website/OutageCheck app will be updated with changes (if any) to affected customer numbers and ETR at least every 120 minutes (+/- 5 minutes) during the outage.

8. Outage Communications (B5): This is a measure of the time taken to notify outage restoration. Retailers will be notified, and the WELL website/OutageCheck app updated, within five minutes of Telnet receiving notice of outage restoration.

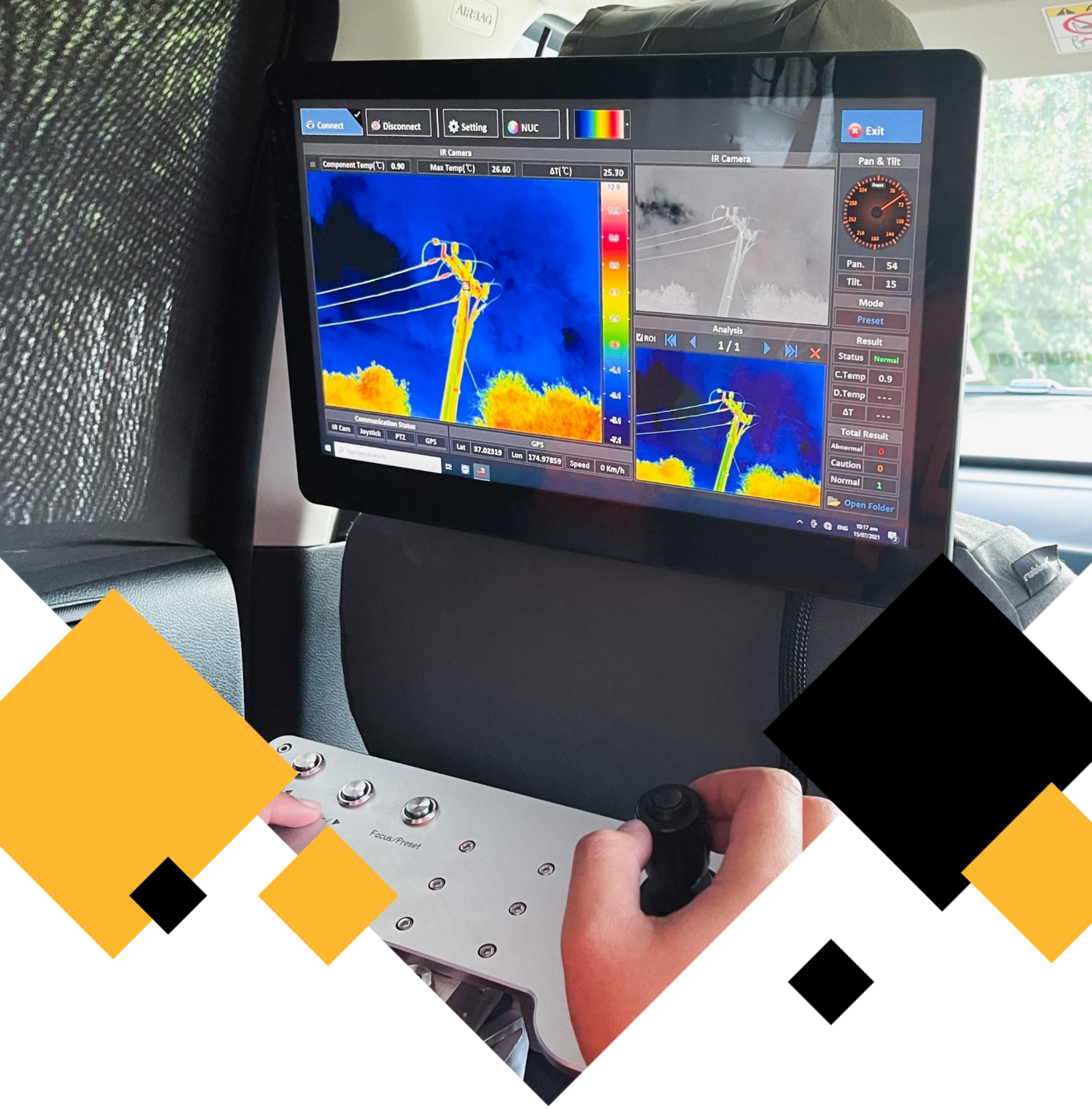
9. Call Quality (C1): This is the measure of call quality. Each month between 10 and 20 random call recordings are monitored by the Contact Centre and WELL against 16 quality criteria. The respective scores are compared and discussed to identify potential opportunities for call quality improvement, with a target quality score of 85% or better.

5.5.8.2 Planning Period Targets

The Contact Centre service level targets are to provide consistent performance over the planning period 2022-2032. These are shown in Table 5-9.

SL	Service Element	Measure	Target
A1	Grade of Service	Average service level across all categories	>=85%
A2	Call response	Average wait time across all categories	<20 seconds
A3	Missed calls	Total missed/abandoned calls across all categories	<4%
B1	Initial Outage Notification	Energy retailers notified and the WELL website updated within the time threshold	<5 minutes
B2	Ongoing Outage Updates	Regular outage status updates provided	every 30 minutes
B3	Estimated Time of Restoration (ETR) Accuracy	Accurate ETR provided within the time threshold from initial outage notification	<1.5 hours
B4	Ongoing ETR Updates	Regular status updates to prolonged outages provided within the time threshold	within 2 hours
B5	Restoration Notification	Energy retailers notified and the WELL website updated within the time threshold from the time of restoration	<5 minutes
C1	Call Quality	Agent performance against 16 key quality criteria for a random selection of calls	>=85%

Table 5-9 Customer Satisfaction Service Level Targets 2022-2032



Section 6

Reliability Performance

6 Reliability Performance

Electricity is an essential service for the community. While large disruptions can occur, and some interruption is expected, customers also reasonably expect to have supply returned without undue delay, as their welfare and the region's economy will quickly suffer if the power stays off for prolonged periods. For this reason, WELL is committed to providing customers with a consistent level of reliable and secure electricity supply under normal conditions. This commitment recognises that customers do accept some level of interruption, rather than pay higher prices to avoid less frequent or lower probability events.

The performance of the network in the 2021/22 year was good, following positive results for the prior three years. These four years follow on from a regulatory quality non-compliance in 2016/17 and 2017/18 which has been investigated by the Commission. That investigation found that WELL's practices and actions were largely consistent with good industry practice, and that the primary causes of the non-compliance were beyond WELL's reasonable control.

This section explains how network reliability is managed. The structure of the section is:

- Reliability performance limits and targets;
- Reliability strategies;
- How WELL forecasts reliability;
- Feeder reliability analysis;
- Reliability controls, and
- Commerce Commission investigation.

6.1 Reliability Performance Limits and Targets

The regulatory regime that applies to WELL sets reliability limits for each year. The DPP3 price-quality regime in place for 2021/22 to 2024/25 set limits for outages that are based on the historical performance during a reference period of 1 April 2009 to 31 March 2019. Unplanned outage limits are set at two standard deviations above the reference period average, while planned outage limits are set at 300% of the reference period average. The regulatory limits for WELL are presented in Table 6-1.

Regulatory Year	2021/22-2024/25
Annual Unplanned SAIDI Limit	39.81
Annual Unplanned SAIFI Limit	0.6135
Period Planned SAIDI Limit	55.76
Period Planned SAIFI Limit	0.4429
Extreme Event Customer Minutes Limit	6 million

Table 6-1 WELL Regulatory Reliability Limits

Figure 6-1 shows the last 12 years of actual unplanned SAIDI renormalised using the DPP3 methodology, against the DPP3 unplanned SAIDI limit. This historical performance supports WELL's confidence that it will continue to be able to meet these limits, and that it is adequately funded to maintain network reliability at current levels.

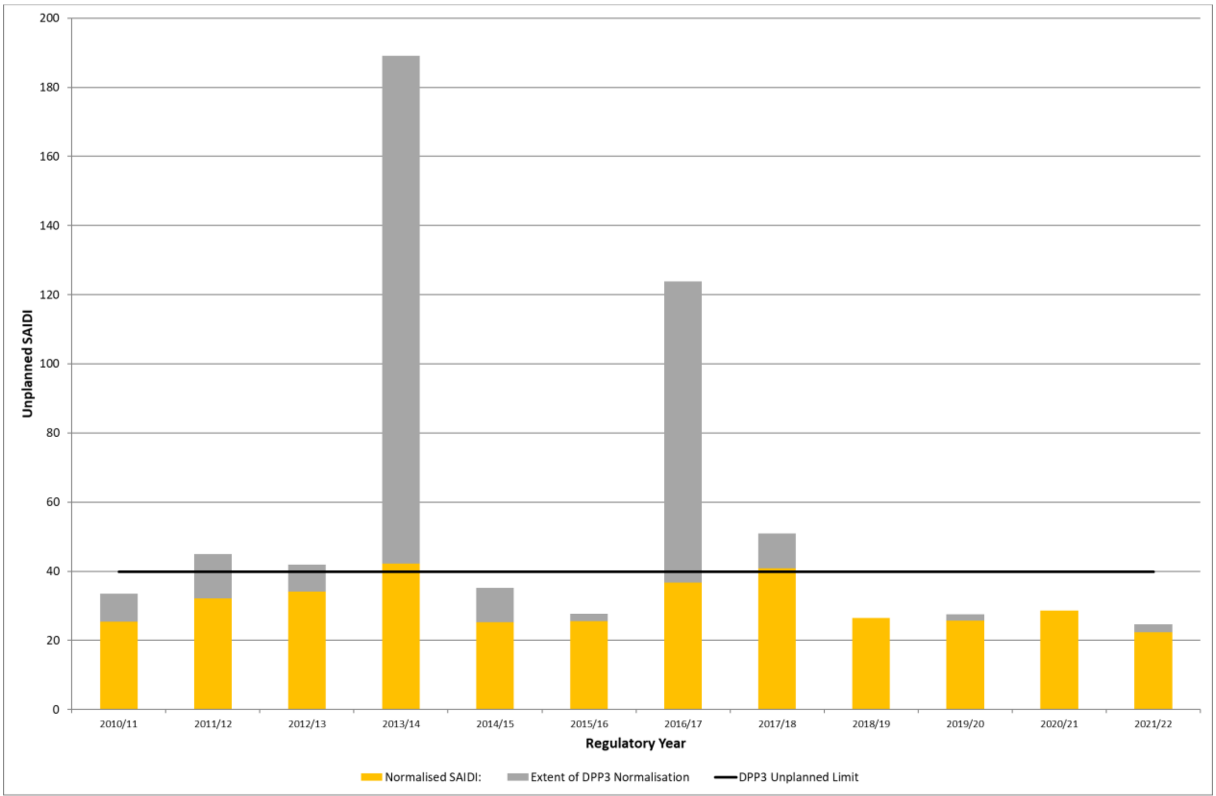


Figure 6-1 DPP3 Normalisation Applied to Historical Performance

WELL's targets for SAIDI and SAIFI are shown in Table 6 2. These targets assume that the SAIDI and SAIFI targets beyond 2025 will be calculated using the same methodology as the 2019 DPP3 determination.

Regulatory Year	2022/23	2023/24	2024/25	2025/26	2026/27	2027/28	2028/29	2029/30	2030/31	2031/32
Unplanned SAIDI target	31.20	31.20	31.20	31.20	31.20	31.20	31.20	31.20	31.20	31.20
Unplanned SAIFI target	0.480	0.480	0.480	0.480	0.480	0.480	0.480	0.480	0.480	0.480
Planned SAIDI target	10.00	10.00	10.00	10.00	10.00	10.00	10.00	10.00	10.00	10.00
Planned SAIFI target	0.067	0.067	0.067	0.067	0.067	0.067	0.067	0.067	0.067	0.067

Table 6-2 Network Reliability Performance Targets

6.1.1 Extreme Event Compliance Standard

DPP3 introduced an Extreme Event compliance standard. The purpose of this standard is to identify events with an extreme impact on customers that would otherwise not be captured by the other quality measures due to the effect of Major Event Day (MED) normalisation. Wellington Electricity's Extreme Event standard is set at 6,000,000 customer minutes, which currently equates to 35.3 SAIDI minutes. The standard excludes outages caused by external factors such as storms and third party interference.

WELL has reviewed the areas of its network at risk of experiencing an Extreme Event, and these are summarised in Table 6-3.

Extreme Event	Outage Duration to Exceed Standard	Possible Solutions to Reduce Consequence
33kV Cable Fire at Central Park GXP	2 hours	• Cables within the switchroom already have intumescent coatings - completed. • Expansion of the site to increase redundancy (see Section 11.5.1).
Loss of Wainuiomata Zone Substation	17 hours	• Fire suppression was installed in Wainuiomata switchroom during 2021. • Pre-establish mobile substation and generation connection points. Work occurring during 2022. • Contracting distributed energy resources.[20] • Consider accelerated replacement of oil switchgear with vacuum gear.
Loss of Karori Zone Substation	25 hours	• Pre-establish generation connection points. • Contracting distributed energy resources.

Table 6-3 Top Three WELL Extreme Event Risks

6.2 Reliability Strategies

From a reliability management perspective, WELL defines three types of outages; unplanned, planned and High Impact Low Probability (HILP). The strategies relating to these outage types are provided in Table 6-4.

Outage type	Relevant Strategies
Unplanned	Asset Fleet, Network Development
Planned	Planned Outage
HILP	Resilience

Table 6-4 Strategies Relating to Different Types of Outages

6.2.1 Unplanned Outages

Asset Fleet Strategies

Asset fleet strategies focus on the management of a specific asset fleet and are discussed in Section 7. The fleet strategies are a predictive tool used to develop the actions needed to achieve targeted future reliability levels. A fleet strategy includes a risk assessment of an asset class which considers population characteristics, and asset health and criticality indicators. The output is a list of asset management actions for the fleet which are needed to achieve expected asset performance and reliability (for example, how often

[20] Refer to Section 9 that explains current and future planned new technology trials.

to test the assets, when to replace, when to paint etc.). The fleet strategies drive asset condition and asset reliability - key factors influencing the current and future likelihood of unplanned outages and ultimately the customer service provided.

The asset fleet strategies also manage the consequence of potential outage, directing asset investment to more critical assets, e.g. those that service a larger number of customers.

The fleet strategies include forecasting which is used to estimate future population replacement rates, and are a key input into forecast fleet expenditure. These forecasting methods are described in Section 7.2.

Secondary Asset Fleet Strategy

The secondary asset fleet strategy provides the protection and fault indication requirements to effectively manage network security to limit the consequence of unplanned outages. This strategy is discussed in Section 7.5.9.

Network Development Strategies

Network development strategies and plans ensure that the network remains at the targeted security levels, which helps maintains the integrity of the network when outages occur. These strategies are discussed in Section 8.

6.2.2 HILP Outages

Resilience Strategy

A specific portfolio strategy is the resiliency strategy discussed in Section 11. The resiliency strategy outlines the investment needed to mitigate against HILP events. Following the 2016 Kaikoura earthquake there has been a heightened awareness by stakeholders to the risk of major earthquakes in the region, and this has led to a major investment in this area. Although this is not captured by the quality standards, WELL's improved readiness for a major event is valued by our stakeholders and customers.

6.2.3 Planned Outages

Planned Outage Strategy

The planned outage strategy is a collection of guidelines and initiatives that govern planned outage management. The guidelines and initiatives minimise the impact of planned outages, the risks associated with reconfiguring the network, and include the protocols for communicating with customers when a planned outage is required.

6.3 Annual Reliability Reporting

Figure 6-2 shows WELL's reporting structure for reliability performance management and includes the associated regular meetings to support each level of governance and management, and the key reports provided.

The majority of reports include progress against annual reliability targets. If the reports highlight areas of concern, they will normally also provide recommendations to update reliability controls. These recommendations are escalated to the level required to make a decision if a trade-off is required against another company performance indicator. Governance decisions are formally noted in the Board papers and minutes.

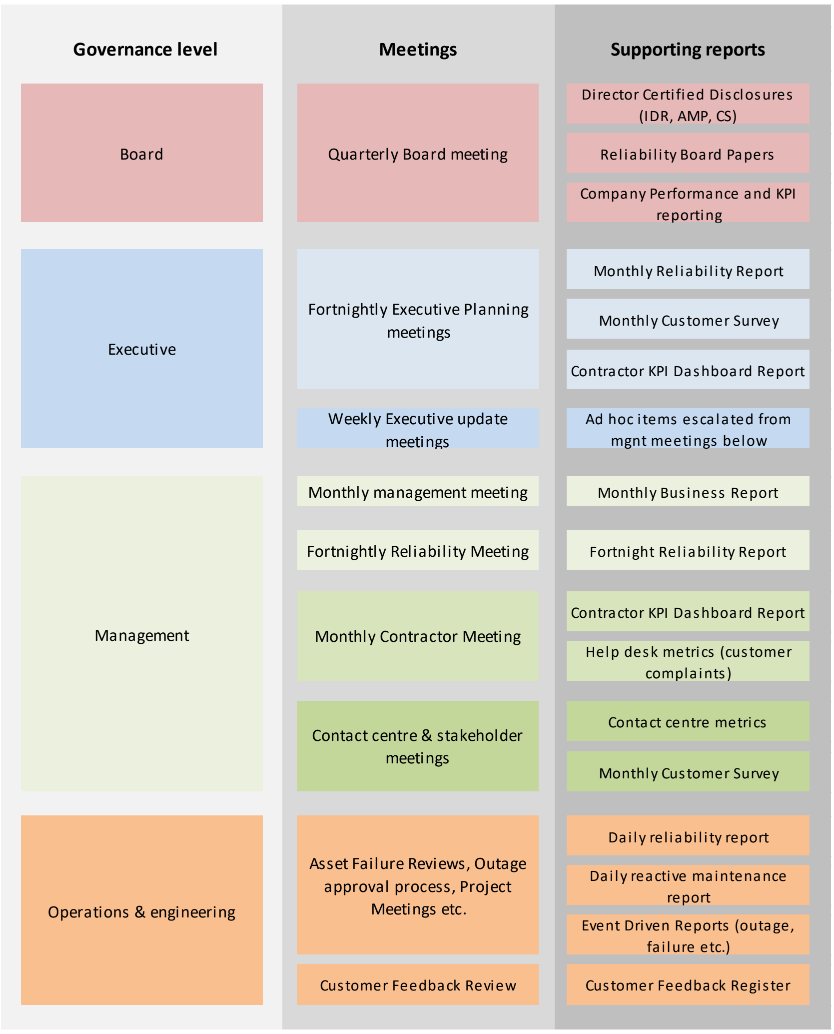


Figure 6-2 WELL's Reporting Structure

WELL's monthly reporting includes forecasts of the year-end SAIDI and SAIFI result for the current regulatory year, to monitor the overall effectiveness of existing reliability controls.

6.3.1 Forecasting SAIDI by Fault Type

The forecast by SAIDI type is based on the historic monthly distribution of SAIDI due to each cause. This forecast method takes year to date SAIDI by outage cause, and scales it by the proportion of annual SAIDI due to that cause that has historically occurred each month. A waterfall chart is used to display this data, with an example given in Figure 6-3.

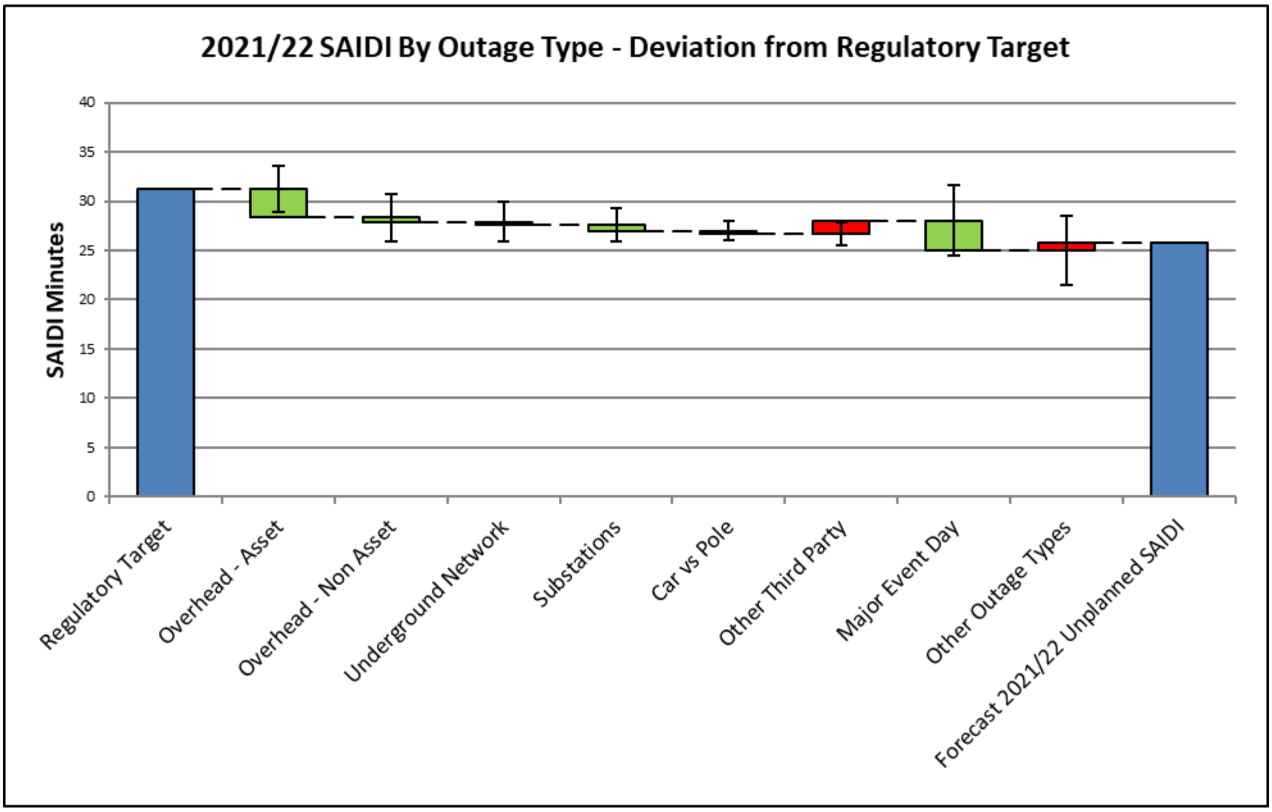


Figure 6-3 Waterfall Chart of 2021/22 SAIDI Performance by Outage Type

This forecast highlights the drivers of the year's performance, and any significant outliers are clearly shown in the context of the standard deviation in the reference period. The chart provides an indication of the effectiveness of controls by outage type, and a trigger to investigate additional controls.

This forecasting method has been actively used since October 2017. The information is included in monthly reporting to the Executive and network performance updates to the Board.

6.4 Annual Feeder Performance Reviews

At the end of a regulatory year, feeders are ranked by a number of reliability performance measures:

- Total SAIDI accrued by the feeder;
- Total SAIFI accrued by the feeder;
- The sum of reliability penalties incurred under price-quality regulation due to the feeder (as a means of combining SAIDI and SAIFI into a single measure); and
- Total number of faults occurring on the feeder.

Feeders that are in the top ten of at least one of the criteria are classed as Worst Performing Feeders. Faults on these feeders are reviewed to determine whether there is a common root cause that could cost effectively be addressed.

Remedial actions identified by this review are fed back into the work programme, where the resulting activities are carried out either under corrective maintenance or as a network project, depending on the scope of the work required.

Each Worst Performing Feeder has a documented reliability improvement plan. These plans, which are controlled documents approved by the General Manager Asset Management, contain the following information:

- A description of the feeder (e.g. length, geography, customer type and number);
- A summary of the fault history of the feeder for the last five years, detailing the number of outages by cause type, and the resulting SAIDI and SAIFI;
- More detailed discussion of the primary causes of outages on the feeder, including examination for trends;
- Any findings from outage investigations relevant to the feeder;
- Any relevant links to the fleet portfolio strategies;
- A recommended 10 year Reliability Improvement Programme, comprising actions and timeframes; and
- The forecast expenditure over the next ten years to implement the Reliability Improvement Programme, split into Planned Capex, Corrective Capex, Corrective Opex, and Vegetation Management.

Each reliability improvement plan also includes a visualisation of the location and magnitude of the last three years' outages. An example is provided in Figure 6-4. This graphic highlights the specific areas of the feeder responsible for poor performance, identifies worst served customers, and assists the effective targeting of remedial actions.

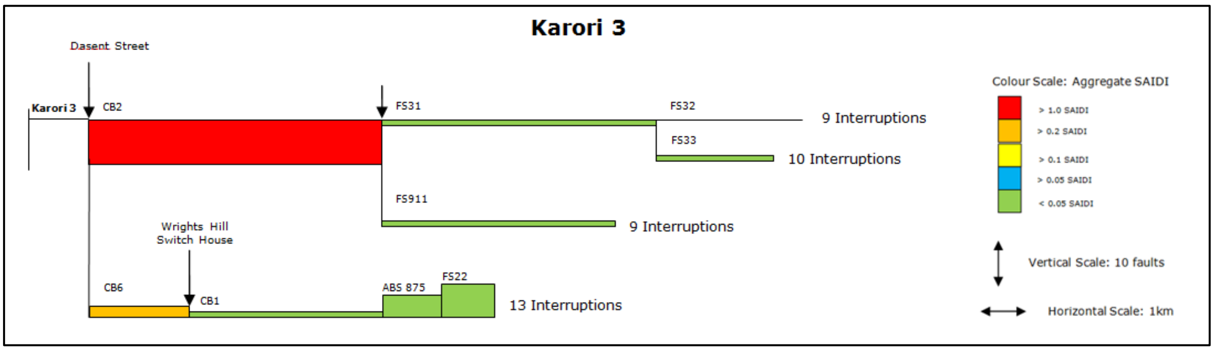


Figure 6-4 Example Feeder Outage Visualisation (Four Years)

6.5 Controls by Outage Cause

6.5.1 Planned Outages

Planned outages require balancing customer requirements with the need to safely undertake the maintenance and renewal of the network.

Outage Peer Review

All requests for planned outages are reviewed by the WELL Network Operations team. Each outage is scrutinised to ensure that all cost-effective steps have been taken to minimise customer impact.

Temporary Generation

WELL has used temporary diesel generation to support planned outages since 2018, originally funded through the DPP2 reliability incentive scheme. The significant reduction in incentive rates for DPP3 has meant that while temporary generation is continuing to be used where appropriate, this is at a reduced level from prior years as the cost of providing generation will exceed the value placed on planned outages by the Commission, unless it is of benefit to a large number of customers. WELL has updated its decision matrices that support the use of temporary generation for both planned and unplanned outages. WELL is exploring modern alternatives to diesel generation as part of its commitment to decarbonisation.

6.5.2 Overhead Equipment

Outage Investigations

All unplanned outages larger than 0.45 SAIDI minutes are investigated by the WELL Asset Engineering team, to understand root causes and recommend improvements. This process has previously identified patterns in component failure, for example specific types of overhead line connectors, resulting in changes to work practices and network standards that will reduce the impact these components have on network reliability in the future.

Conductor Sampling

WELL is collecting samples of conductors from areas that it is undertaking overhead line rebuilds. These samples are being analysed for fatigue and corrosion to assist with building a predictive model of conductor condition, and provide a better understanding of future conductor replacement requirements.

6.5.3 Vegetation

Vegetation outages have the potential to significantly impact customers in the overhead sections of the network. WELL has taken significant steps to control the risk posed to the network by trees.

Community Engagement

WELL has engaged with Community Boards in areas impacted by vegetation faults to explain the performance and to highlight ways that local communities can improve the reliability of their power supply by helping to manage trees. One aspect of this approach is the potential for coordinating the outages and traffic management for trees being cut along an entire line. This would reduce the costs that tree owners face in meeting their responsibilities under the regulations.

Risk-based Vegetation Control

WELL and Treescape developed a risk-based approach to managing vegetation outside the regulated zones, which was implemented in 2017. All parts of the network are now assigned a potential reliability consequence, which establishes the level of detail required for tree assessments in that area. Each tree is then assessed for its likelihood of failure, with the level of detail required for this assessment being determined by the potential consequence. The likelihood and consequence are combined to determine the reliability risk the tree poses, and the cost-benefit of cutting it to reduce that risk. Even though the regulations do not give WELL a right to manage vegetation outside of the regulated zones, the risk-based approach has provided WELL with a tool for engaging with tree owners about the potential impact of their trees on the reliability of the power supply.

Covered Conductors

Covered conductors have been being installed in areas prone to vegetation-related outages since 2018. These projects have proven effective at eliminating the reliability impact of wind-borne debris (e.g. branches and bark) in the areas where they have been installed, as shown in Figure 6-5. WELL has purchased a quantity of conductor covers, which is available to be installed as areas of need are identified.

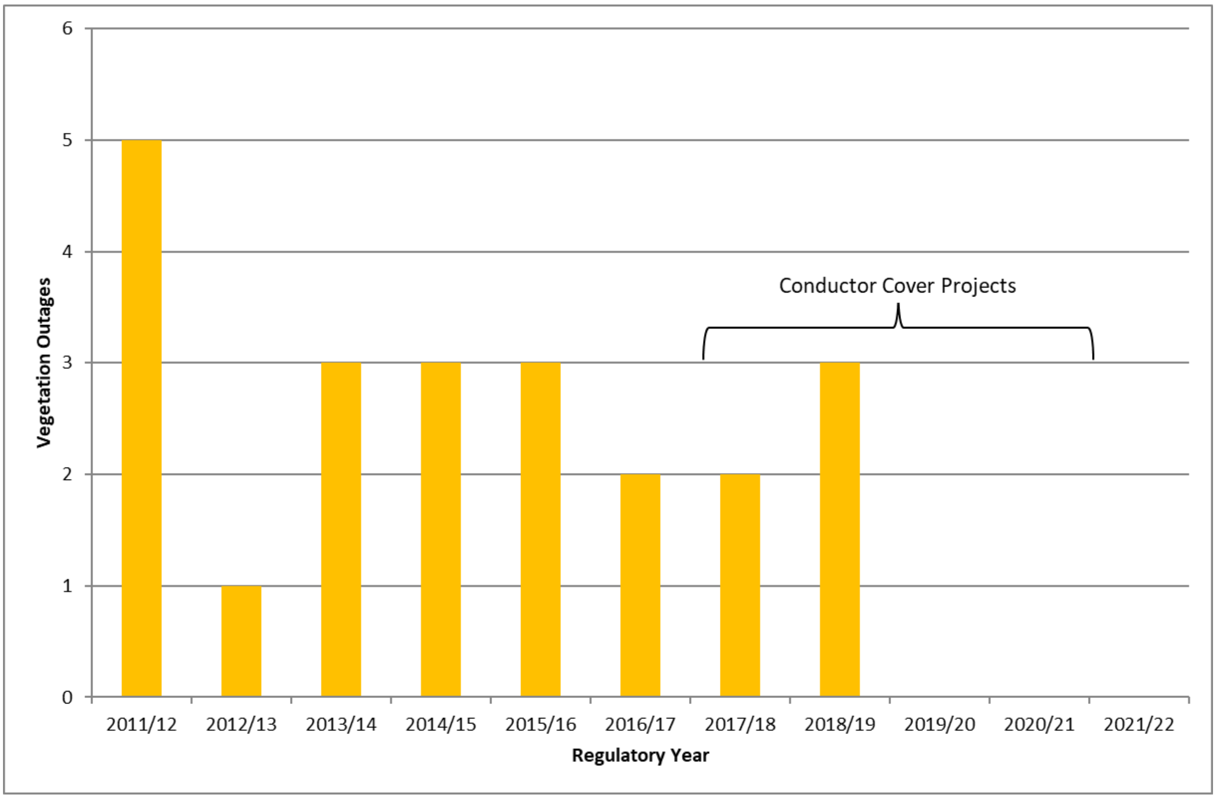


Figure 6-5 Vegetation Outages in Covered Conductor Areas

6.5.4 Underground Equipment

WELL has been trialling cable testing technology by testing poor performing cables with a variety of diagnostic tools. The purpose of this proactive trial is to gain sufficient understanding of the results produced by these tools and match them to actual cable performance to provide confidence of their suitability as a condition assessment tool to:

- Determine whether a tested cable needs to be pro-actively replaced (either in total or of a targeted section);
- Build a predictive model of cable condition; and
- Forecast future replacements.

6.5.5 Car versus Pole Incidents

WELL's approach to car versus pole incidents is to reduce the response time for making the incident site safe, which assists emergency services and reduces the impact on customers. WELL is exploring the use of temporary measures such as interrupter cable and temporary pole stands to further reduce the time taken to restore power following an incident.

6.6 Commerce Commission Investigation

The Commission has completed its investigation into WELL's non-compliance with the Quality of Supply standards for the 2016/17 and 2017/18 regulatory years, The Commission engaged engineering consultancy Nuttall Consulting to investigate and provide an expert opinion on the non-compliance.

Nuttall Consulting found that WELL's practices and actions were largely consistent with good industry practice. They agreed with WELL's analysis that the cause of the exceedances were largely outside of WELL's reasonable control as they were due to a period of unusually high wind events, a large number of car vs pole events, and damage resulting from the November 2016 Kaikoura earthquake event. Nuttall Consulting found that WELL has a very strong attitude to finding the causes of the exceedances and putting in place controls to improve reliability performance.

The Commission considered that the findings of the Nuttall report do not indicate any serious concerns with WELL's wider management of the network, or of its asset management practices in general. The Commission has confirmed that it will not be taking any enforcement action against WELL for these exceedances.[21]

6.6.1 Investigation Recommendations

While the investigation concluded that the causes of the non-compliance were largely outside of WELL's reasonable control, it also identified some areas where Nuttall Consulting considered that WELL's procedures and policies could be improved. The recommendations are:

- WELL should improve its quantitative analysis of reliability performance to better identify in a more timely manner worsening trends, emerging issues and the causes of poor reliability. This would allow it to better predict the risk of future non-compliance;
- WELL should document a strategic reliability management plan which would describe its processes for investigating risks and developing controls;
- Reports to the Board and management have focused on past and year-to-date performances. These should also include a forward-looking analysis of the likelihood and severity of risk, and the likelihood of breaches occurring as a result of current performance outcomes and events;
- WELL should encourage active challenge at the various management levels; and
- Development of a sense of urgency in reporting the risk of non-compliance with quality standards may enable WELL to change the outcome during an assessment period.

WELL welcomes the feedback on its processes, and the recommendations of further improvements that can be made. WELL has made a commitment to its Board that these recommendations will be implemented in 2022.

[21] "Compliance Advice Letter to Wellington Electricity Lines Limited – 26 October 2021" Commerce Commission October 2021 https://comcom.govt.nz/__data/assets/pdf_file/0032/268682/Compliance-advice-letter-to-Wellington-Electricity-Lines-Limited-26-October-2021.pdf

Section 7

Asset Lifecycle Management

7 Asset Lifecycle Management

This section provides an overview of WELL's assets, and its maintenance, refurbishment and replacement strategies over the planning period. The objective of these strategies is to optimise operational, replacement and renewal capital expenditure on network assets, whilst ensuring that the network is capable of meeting the service level targets and mitigating risks inherent in running an electricity distribution network.

In summary, the section covers:

- Asset fleet summary;
- Risk-based asset lifecycle planning;
- Asset health and criticality analysis;
- Maintenance practices;
- Asset maintenance and renewal programmes; and
- Asset replacement and renewal summary.

7.1 Asset Fleet Summary

A summary of the population for each of the Information Disclosure Requirements (IDR) categories and asset class is shown in Table 7-1.

IDR Category	Asset Class	Section	Measurement Unit	Quantity
Subtransmission	Subtransmission Cables	7.5.1	km	138.4
	Subtransmission Lines	7.5.3.2	km	56.8
Zone Substations	Zone Substation Transformers	7.5.2.1	number	52
	Zone Substation Circuit Breakers	7.5.2.2	number	367
	Zone Substation Buildings	7.5.2.3	number	27
Distribution and LV Lines	Distribution and LV Lines	7.5.3.3	km	1,660.4
	Streetlight Lines	7.5.3.3	km	818.0
	Distribution and LV Poles	7.5.3.1	number	39,574
Distribution and LV Cables	Distribution and LV Cables	7.5.4	km	2,938.2
	Streetlight Cables	7.5.4	km	1,126.9
Distribution Substations and Transformers	Distribution Transformers	7.5.5.1	number	4,464
	Distribution Substations	7.5.5	number	3,830

IDR Category	Asset Class	Section	Measurement Unit	Quantity
Distribution Switchgear	Distribution Circuit Breakers	7.5.6	number	1,277
	Distribution Reclosers	7.5.7.1	number	17
	Distribution Switchgear - Overhead	7.5.7.2	number	2,619
	Distribution Switchgear - Ground Mounted/Ring Main Units	7.5.6	number	2,315
Other Network Assets	Low Voltage Pits, Pillars and Cabinets	7.5.6.1	number	18,570
	Protection Relays	7.5.8.2	number	1,445
	Load Control Plant	7.5.9.4	number	25

Table 7-1 Asset Population Summary

7.2 Risk-Based Asset Lifecycle Planning

Risk-based asset lifecycle planning consists of the following:

- Design, construction and commissioning according to network standards, including the use of standardised designs and equipment where appropriate;
- Condition-based risk assessments;
- Routine asset inspections, condition assessments and servicing of in-service assets;
- Evaluation of the inspection results in terms of public and worker safety, meeting customer service levels, performance expectations and control of risks;
- Maintenance requirements and equipment specifications to address known issues; and
- Repair, refurbishment or replacement of assets when required.

Throughout all of these stages, ensuring the safety of the public and workers is the highest priority.

WELL takes a risk-based approach to asset lifecycle planning. The preventative maintenance programme is based on each maintenance task having a set cycle based on a known reliability history and is also influenced by any trends in the degradation of asset condition that may occur across a fleet. Corrective maintenance tasks identified during preventative maintenance are prioritised for repair according to severity and consequential risk to safety and network performance.

Standardised designs are used for high volume assets, including overhead and underground construction, distribution substations, and distribution switchgear. This approach ensures:

- Familiarity for contractors, increasing the safety and efficiency of construction and operation;

- Procurement benefits, through reduced lead times and increased stock availability; and
- Economic benefits, as standard products generally have lower cost than customised or non-standard ones.

High value asset replacements such as subtransmission cables and zone substation assets are designed to meet the specific needs of the project and the requirements of relevant network standards.

Electricity distribution assets have a long but finite life expectancy and eventually require replacement. Premature asset replacement is costly as the service potential of the replaced asset is not fully utilised. Equally, replacing assets too late can increase the risk of safety incidences and service interruptions for customers. Asset replacement planning therefore requires the costs of premature replacement to be balanced against the risks of asset failure, public or contractor safety and the deterioration of supply reliability that will occur if critical assets are allowed to fail in service. Hence, there is a balance to be found between the cost of maintaining an asset in service and the cost to replace it.

This section focuses on the different asset classes and provides insight into the condition and maintenance of each class. This section also provides an overview of maintenance and renewal and refurbishment programmes.

7.3 Asset Health and Criticality Analysis

WELL uses the EEA Asset Health Indicator Guide - 2016. This methodology specifies a number of health indices for each asset class, which are rated on a scale of H5 to H1. Each scale represents a life-cycle phase with varying needs for, or benefits from, replacement. Each of the phases are termed and influenced by end-of-life drivers. The scale is shown in Figure 7-1.

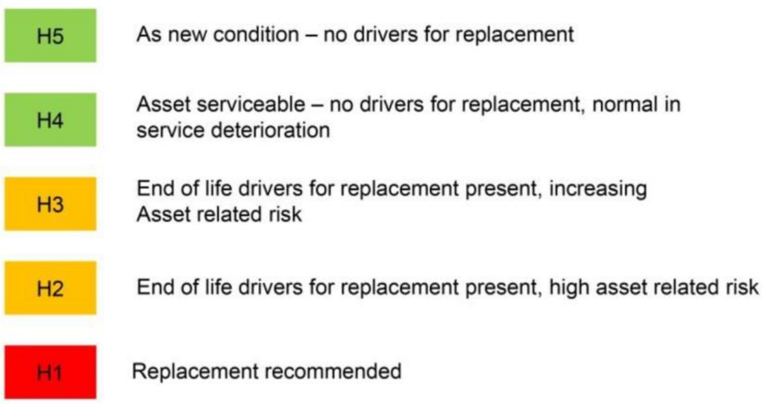


Figure 7-1 EEA Asset Health Indicator Scale

The overall Asset Health Indicator (AHI) is determined by its worst health index, further reduced by any indices scoring less than H4.

Asset Health Analysis does not take into account asset criticality or consequence of failure, so WELL developed an Asset Criticality Indicator (ACI) using the same methodology as Asset Health Analysis, incorporating factors such as number of customers affected, load type and firm capacity. Asset criticality is scored on a scale of I5 (very low impact) to I1 (major impact).

The result of this analysis is a health-criticality matrix for each major asset class, with the asset location on the matrix giving an indication of risk. Each number in the matrix gives the quantity of assets, in units or circuit km depending on the asset type, falling into that particular combination of health and criticality. As an example, the health-criticality matrix for power transformers on the WELL network is shown in Figure 7-2 and further discussed in Section 7.5.2.

		Lowest Impact		**Asset Criticality**			Highest Impact	
		5.0	4.0	3.0	2.5	2.0	1.5	1.0
Worst Health	1.0							
	1.5				2			
Asset Health	2.0				4			
	2.5				2			
	3.0			2	20		7	2
	4.0			2	8		1	2
Best Health	5.0							

Figure 7-2 Example Health-Criticality Matrix (Power Transformers)

The form of asset risk forecasting used for each fleet varies depending on the type of asset being modelled.

Low volume high value assets such as power transformers are extensively monitored, with a wide range of condition data available from the maintenance programme to support the decisions for managing individual units. The Asset Health-Criticality matrix is used to identify assets at elevated risk, allowing detailed study of specific units to better understand their risk and determine an appropriate response.

For **high volume low value assets** such as poles and distribution transformers, it is not cost-effective to undertake extensive diagnostic testing on an individual basis. These units are replaced when their condition reaches the replacement criteria. The fleets are modelled using survival curves based on historic condition and replacements, to estimate a future replacement profile, without identifying which specific assets are forecast to require replacement in a particular year.

High volume linear assets such as cables and conductors tend to be repaired on failure, with replacement driven through the reliability analysis described in Section 6. The performance of these assets is modelled using fault per km rates.

Short life assets such as batteries are replaced at a set frequency, without any asset modelling. Preventative maintenance is used to confirm the asset has not failed prematurely, which in turn is used to ensure the replacement frequency is appropriate.

7.4 Maintenance Practices

7.4.1 Maintenance Standards

WELL currently contracts Northpower as its field services provider to undertake the network maintenance programme under a FSA. Maintenance of all assets is undertaken according to standards that have been developed by WELL.

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

Vegetation management is provided by Treescape and is carried out in accordance with WELL policies and the Electricity (Hazards from Trees) Regulations 2003.

7.4.2 Maintenance Categories

Maintenance is categorised into the following areas:

- **Service interruptions and emergencies.** Work that is undertaken in response to faults or third party incidents and includes equipment repairs following failure or damage, and the contractor management overhead involved in holding resources to ensure appropriate response to faults.
- **Vegetation management.** Planned and reactive vegetation work.
- **Routine and corrective maintenance and inspection.** This comprises:
    - **Preventative maintenance works.** Routine inspections and maintenance, condition assessment and servicing work undertaken on the network. The results of planned inspections, and maintenance, drive corrective maintenance or renewal activities.
    - **Corrective maintenance works.** Work undertaken in response to defects raised from the planned inspection and maintenance activities.
    - **Value added.** Customer services such as stand over provisions for third party contractors, and provision of asset plans for the 'B4U Dig' programme, to prevent third party damage to underground assets.
- **Asset replacement and renewal.** Reactive repairs and replacements that do not meet the requirements for capitalisation.

The forecast maintenance expenditure for 2022-2032 is summarised by asset class throughout this section.

7.5 Asset Maintenance and Renewal Programmes

This section describes WELL's approach to preventative maintenance and inspections. It also sets out the maintenance activities undertaken for each asset class and commentary is provided on renewal and refurbishment policies or criteria plus known systematic issues. The IDR categories (with their associated asset classes) covered are:

- Subtransmission (Cables);
- Zone substations;
- Distribution and LV lines;
- Distribution and LV cables;
- Distribution substations and transformers;
- Distribution switchgear; and
- Other network assets.

The description for each asset class is structured in the following manner:

- A summary of the fleet;
- Any fleet-specific objectives;
- Maintenance activities relevant to the asset class;
- The health-criticality risk of the fleet and the approach adopted to forecast future condition;
- The approach to renewals for the class including life extension activities and innovations; and
- A summary of forecast expenditure for fleet renewals and maintenance.

7.5.1 Subtransmission Cables

Fleet Overview

WELL owns approximately 138 km of subtransmission cables operating at 33 kV. These comprise 50 circuits connecting Transpower GXPs to WELL's zone substations. Approximately 32 km of subtransmission cable is XLPE construction and requires little maintenance. The remainder is of paper-insulated construction, with a significant portion of these cables being fluid- or gas-filled. A section of the subtransmission circuits supplying Ira Street zone substation are oil-filled PIAS (paper insulated aluminium sheath) cables rated for 110 kV but operating at 33 kV. There are also two 33 kV cables operating at 11 kV which are treated as subtransmission cables supplying Titahi Bay substation. Each individual circuit is modelled using WELL's Asset Health and Criticality systems. The lengths and age profile of this asset class are shown in Table 7-2 and Figure 7-3.

Construction	Design Voltage	Percentage	Quantity
Paper Insulated, Oil Pressurised	33 kV	30.0%	41.6km
Paper Insulated, Gas Pressurised	33 kV	34.8%	48.1km
Paper Insulated	33 kV	5.5%	7.5km
XLPE Insulated	33 kV	23.4%	32.4km
Paper Insulated, Oil Pressurised	110 kV	6.3%	8.7km
Total			**138.4km**

Table 7-2 Summary of Subtransmission Cables

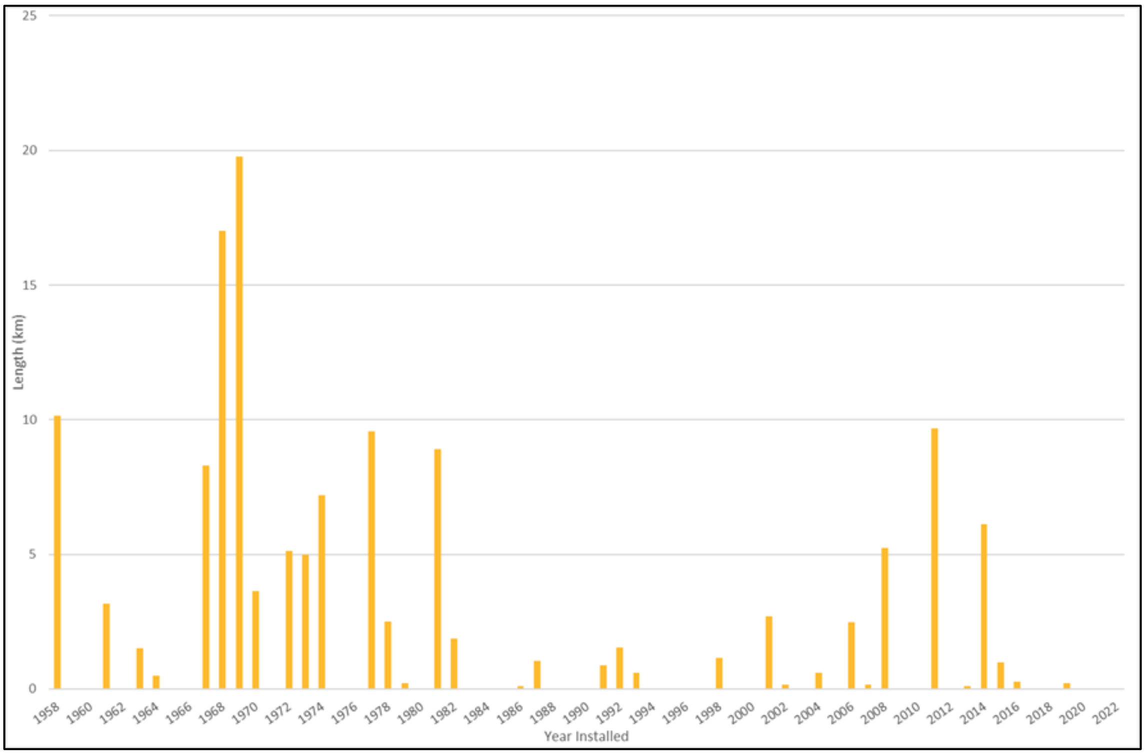


Figure 7-3 Age Profile of Subtransmission Cables

<u>Fleet Objectives</u>

In addition to WELL's broader asset management objectives that apply across the entire network, WELL has the following fleet-specific objectives for the subtransmission cable fleet:

Priority Area	Objective
Safety and Environment	No injuries resulting from working on and around subtransmission cables. Manage the environmental impact of fluid lost from fluid-filled cables.
Customer	Mitigate risk of potential decrease in service or price shock caused by subtransmission cable replacement.
Network Performance	Avoid incurring SAIDI and SAIFI resulting from the tripping of 33kV cables.

Table 7-3 Fleet Specific Objectives for Subtransmission Cable Fleet

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
Cable fluid injection equipment inspection	Inspection and minor maintenance of equipment in substations, kiosks and underground chambers.	6 monthly
Subtransmission route regular patrol	Patrol of cable route; replace missing or damaged cable markers.	Weekly

Table 7-4 Inspection and Routine Maintenance Schedule for Subtransmission Cables

In conjunction with the above routine maintenance schedule, all fluid-filled cables have pressure continuously monitored via the centralised SCADA system, with Management oversight through a monthly reporting process. This monitoring provides information that identifies cables where fluid is leaking, and allows unexpected pressure changes to be promptly investigated.

Objective condition assessment on cables with fluid pressurisation is limited to leakage rates as a number of cable condition assessment techniques, including partial discharge testing, are not applicable to these types of cables. The main modes of failure of these cables is stress on the joints and resulting failure, and sheath failures allowing fluid leaks and areas of low pressurisation along the length of the cable. Accordingly, the leaks and the cable can be repaired before the electrical insulation properties are compromised.

The historic fault information for each cable is used to assess and prioritise the need for cable replacement, as well as determining the strategic spares to be held. Strategic spares for subtransmission cables are outlined in Table 7-5.

Strategic Spares	
Medium lengths of cable	Medium lengths of fluid filled cable are held in store to allow replacement of short sections following damage, to allow repairs without requiring termination and transition to XLPE cable.
Standard joint fittings	Stock is held to repair standard fluid filled joints. A minimum stock level is maintained.
Termination/transition joints	Two gas to XLPE cable transition joints are held in storage to allow the replacement of failed transition joints or damaged sections of gas filled cables with non-pressurised XLPE cables where necessary.
Emergency Overhead Line Spares	WELL has designed alternative overhead line routes for all fluid filled subtransmission cables to prepare for the possibility of significant damage post a major earthquake. WELL has procured sufficient spares to construct 19km of emergency overhead 33kV lines.

Table 7-5 Spares for Subtransmission Cables

Cable Condition and Failure Modes

Gas-filled cables

Gas-filled cables are pressurised with nitrogen. They have been in use internationally since the 1940s but have largely been phased out in favour of fluid filled or solid insulated cables. WELL is the only distributor that still has gas-filled cable in service in New Zealand, although there are still some in Australia. Gas cables require close monitoring of cable performance to manage any deterioration and consequent reduction in levels of service. Some of these cables have been repaired as a result of third party damage or after gas leaks have been found.

Figure 7-4 shows the trend in gas leakage from WELL's gas-filled cables for the 12 months to the end of February 2022.

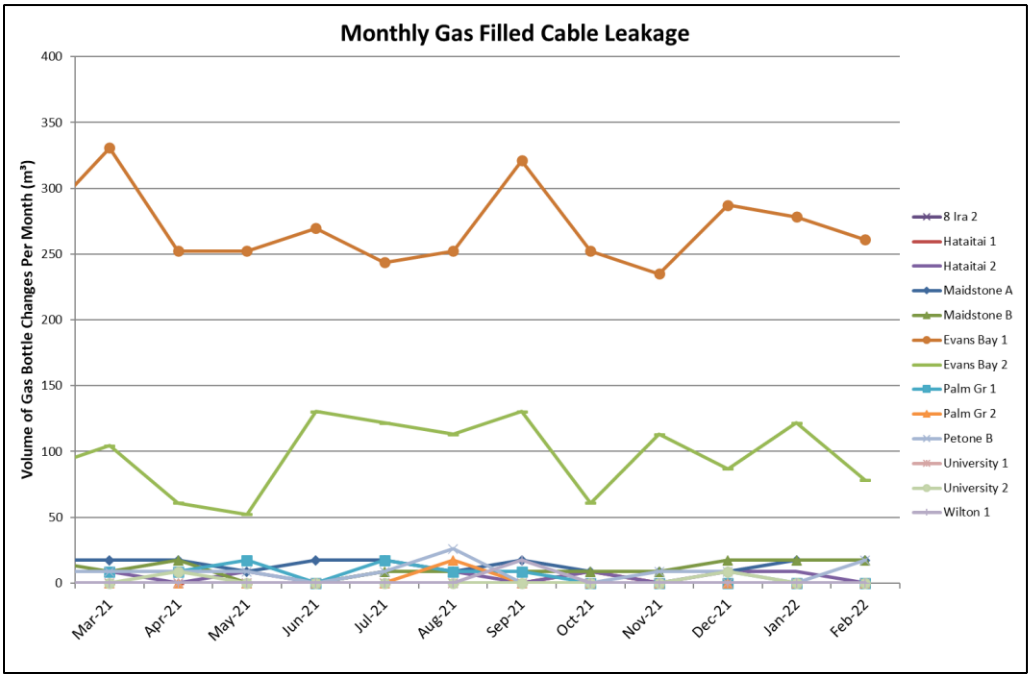


Figure 7-4 Monthly Gas Filled Cable Leakage (as at February 2022)

Fluid-filled Cables

Fluid-filled cables were installed in the WELL network from the mid-1960s until 1991. Some circuits have experienced fluid leaks but in general the condition of the cables remains good for their age. The environmental impacts of leaks are mitigated through the use of biodegradable cable fluid.

Figure 7-5 shows the trend in fluid leakage from WELL's fluid-filled cables for the 12 months to the end of February 2022.

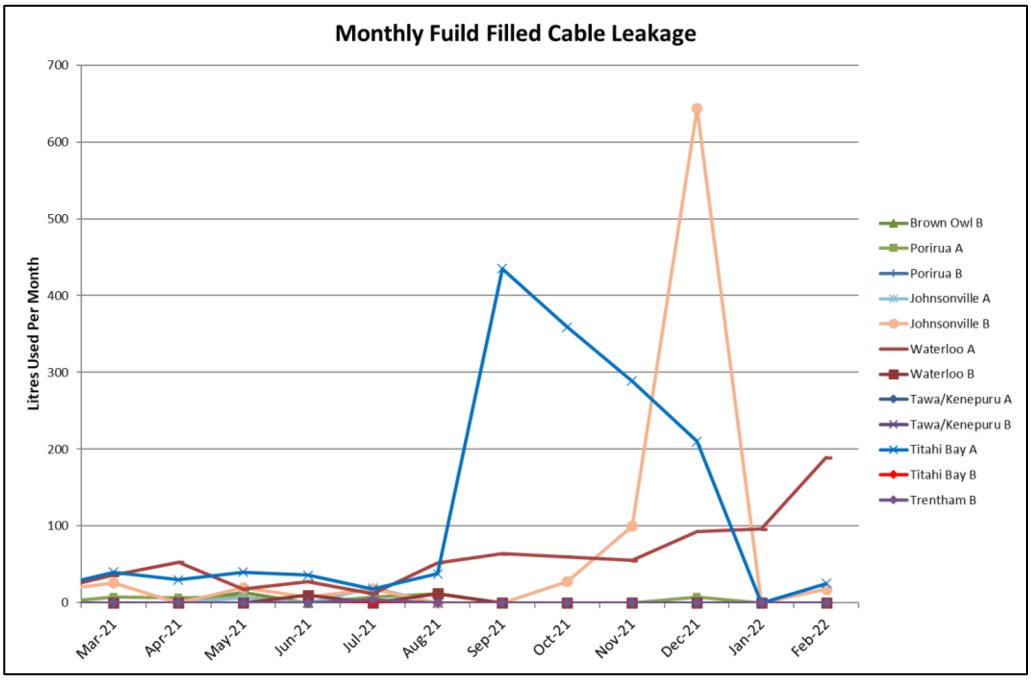


Figure 7-5 Monthly Fluid Filled Cable Leakage (as at February 2022)

Fluid Leaks in 2021

During 2021 fluid leaks developed on three cables: Waterloo A, Titahi Bay A, and Johnsonville B.

The Waterloo A cable was identified as leaking in March 2021 but while planning for the leak location was in progress, the leak slowed to below the level at which location work is effective. Some preliminary tasks were completed on this cable to facilitate future leak location work.

The Titahi Bay A cable has been leaking since early 2019 at a rate below the location threshold. In late August this became more serious, and work began to locate and repair the leak. Location work progressed over the following months and the cable was repaired and returned to service shortly before the end of the year.

The Johnsonville B cable began leaking in October 2021. The leak was located on an item of fluid pressure equipment in December and temporarily repaired, with the full repair being completed in January 2022.

Paper and Polymeric Cables

Approximately 30% of WELL's subtransmission cable has solid insulation of either oil-impregnated paper or XLPE. These cables are relatively new compared to the fluid-filled installations and are in good condition, with the exception of University discussed below.

Forecast Future Condition

The future condition of the subtransmission cable fleet is modelled using Asset Health and Criticality Analysis. The analysis categorises cables by risk, triggering further study of the assets with the greatest risk.

The solid insulated cables are performing well. For fluid-filled cables, the only end of life drivers that degrade over time are sheath integrity, termination condition, and fluid leaks. All of these factors are monitored through the maintenance programme. There appears to be a relationship between age and leakage trends for gas cables, with the health indicator moving from H4 to H3 between 50-60 years of age, and starting to move to H2 beyond 60 years. No such relationship is apparent in the fluid-filled cable fleet, with leaks to date being sporadic rather than due to age-related deterioration.

Aside from the circuits detailed in the Renewal and Refurbishment section below, no further renewal triggered by health is expected to be required during the period covered by this AMP. The potential acceleration of cable replacements for resilience reasons is discussed in Section 11.

Subtransmission Asset Health and Criticality Analysis

The Asset Health and Criticality Analysis results in the health-criticality matrix shown in Figure 7-6, with individual circuit scores and ratings being presented in Table 7-6. Where a circuit comprises multiple cable types, for example a predominantly gas-filled cable that includes a section of XLPE cable, the health indices are calculated independently for each cable type, with the lowest health index governing the AHI of the circuit as a whole.

		Lowest Impact		**Asset Criticality**				Highest Impact
Asset Health		5.0	4.0	3.0	2.5	2.0	1.5	1.0
Worst Health	1.0				5.1			
	1.5				9.8		3.6	
	2.0							
	2.5			34.5	56.1			
	3.0							
	4.0			2.5	3.4	10.3		
Best Health	5.0						10.5	

Figure 7-6 Subtransmission Cable Circuit Health-Criticality Matrix (km)

Subtransmission Circuit	Primary Type	AHI	ACI	Rating
Evans Bay 1	Gas	1.0	2.9	
University 1 & 2	Gas/XLPE	1.6	1.9	
Evans Bay 2	Gas	1.8	2.8	
Tawa A & B	Fluid	1.9	2.9	
Frederick Street 1 & 2	XLPE	5.0	1.8	
Palm Grove 1 & 2	XLPE	5.0	1.8	
Terrace 1 & 2	XLPE	5.0	1.9	
Maidstone A & B	Gas	2.6	2.9	
Karori 1 & 2	Gas	2.7	2.7	
Hataitai 1 & 2	Gas	2.7	2.9	
Johnsonville A & B	Fluid	2.7	2.9	
Porirua A & B	Fluid	2.7	2.9	
Waterloo A	Fluid	2.7	2.9	
Ira Street 1 & 2	Fluid	2.8	2.9	
Kenepuru A & B	Fluid	2.9	2.9	
Waikowhai Street A & B	Gas	2.7	3.0	
Korokoro A & B	Fluid	2.8	3.0	
Trentham A & B	Fluid	2.8	3.0	
Waitangirua A & B	Fluid	2.8	3.0	
Brown Owl A & B	Fluid	2.9	3.0	
Naenae A & B	Fluid	2.9	3.0	
Waterloo B	Fluid	2.9	3.0	
Moore Street 1 & 2	XLPE	4.0	2.0	
Wainuiomata A & B	PILC	4.0	2.0	
Ngauranga A & B	XLPE	4.0	2.9	
Seaview A & B	PILC	4.0	2.9	
Gracefield A & B	PILC	4.0	3.0	
Mana	XLPE	4.0	3.0	
Plimmerton	XLPE	4.0	3.0	

Table 7-6 Health Criticality Scores for Subtransmission Cable Circuits

Outcome of Asset Health and Criticality Analysis

The highest priority subtransmission cable circuits, and significant changes since the 2021 AMP, are discussed below.

University

The gas-filled University cables were largely replaced in 2006, however approximately 500 metres of gas cable remains in each circuit. These cables have a high criticality due to University Zone Substation supplying a portion of the Wellington CBD.

Both circuits experienced faults on their XLPE sections during 2015, and laboratory analysis of cable samples revealed issues around premature ageing of the cable insulation due to thermal degradation. Full replacement of both the gas-filled and XLPE cables are expected to be required within the next 10 years. A feasibility study of replacement options will be undertaken during 2021, with replacement currently planned to occur in 2025.

Evans Bay

The Evans Bay subtransmission circuits were installed in 1958 and are the oldest gas cables on the network. After leaking at a consistent rate for five years, Circuit 1 experienced a significant increase in gas leakage in April 2019. The location of the leak has not been able to be positively identified. The leak has stabilised and has not continued to deteriorate.

In October 2019 the Evans Bay Circuit 2 developed a small leak. Investigation during 2020 failed to positively identify the location of the leak. The performance of the cable is stable, and contingency plans are in place to mitigate various possible outage scenarios.

In early 2020, a project was approved to install a 33kV bus at Evans Bay which will be supplied from the two Ira Street cables (which run through the Evans Bay substations) and Evans Bay Circuit 2. This will create a subtransmission ring with sufficient capacity to supply both Evans Bay and Ira Street zone substations with N-1 security, and reduce the criticality of the Evans Bay cables. Further detail of this project is provided in Section 8.4. The longer term plan is to run new cables to Evans Bay in 10-15 years, in conjunction with planned transport projects. The expectation is that installation of new cables will be coordinated as part of the transport corridor work.

Karori

The Karori subtransmission cables are currently in good health with no history of poor performance. They are however the gas-filled cables with the highest Asset Criticality Index after Frederick Street and University, due to the substation's location on the periphery of the network, with limited 11 kV ties to neighbouring zone substations. Renewal of these cables is proposed to occur by 2029.

Tawa

A leak developed on the fluid-filled cable on the Tawa A circuit in 2017. This leak was identified as occurring within a stop joint in Morgan Place. The joint was excavated in November 2017 and repairs undertaken. The performance of this joint and cable will continue to be monitored. To date, there has been no further leaking.

Condition assessment using an unmanned aerial vehicle (UAV) in 2020 identified corrosion on the cable trifurcating boxes at Bing Lucas Drive that had not been visible to routine ground-based inspections. The damage has been temporarily repaired, however the terminations are expected to require complete replacement in the near future. This will involve the replacement of the remaining 450m of fluid-filled cable in each circuit, from the terminations through to Tawa zone substation. This work is proposed to occur in 2024.

Titahi Bay

In August 2021 it was identified that an ongoing leak on the Titahi Bay A cable, operated at 11kV, had become more serious and required action. Location work proceeded through the remainder of the year, with the leak being found and repaired in December 2021. Levels are now back to normal and the cable pressure will continue to be monitored.

Waterloo

A leak was identified on the fluid-filled Waterloo A circuit during 2021, however this leak was of a low rate and not able to be located using available techniques. The rate of leakage increased in December 2021 and location work is currently underway.

Renewal and Refurbishment

There are few cost-effective options for refurbishment or extension of life of subtransmission cables once major leaks, discharge or electrical insulation breakdown has occurred. In most cases the most cost-effective solution is replacement of sections, or the entire length of cable. Due to the cost of transition joints, it is likely to be more economical to replace sections end to end in their entirety.

Significant projects for the renewal of subtransmission cables over the next 12 months are listed in Table 7-7.

Project	Description
University 33kV Cable	Feasibility study of replacement options for the gas-filled and XLPE cables of the Central Park – University circuits.
Tawa 33kV Cable	Feasibility study of replacement options for the oil-filled cables of the Takapu Road – Tawa circuits.

Table 7-7 Subtransmission Cable Projects for 2022/23

Expenditure Summary for Subtransmission Cables

Table 7-8 details the expected expenditure on subtransmission cables by regulatory year.

Expenditure Type	2022/23	2023/24	2024/25	2025/26	2026/27	2027/28	2028/29	2029/30	2030/31	2031/32
Tawa Cable Replacement	-	500	1,000	-	-	-	-	-	-	-
University Cable Replacement	-	-	700	3,200	-	-	-	-	-	-
Karori Cable Replacement	-	-	-	-	-	4,000	8,000	-	-	-
Maidstone Cable Replacement	-	-	-	-	-	-	-	-	8,700	8,700
Capital Expenditure Total	**-**	**500**	**1,700**	**3,200**	**-**	**4,000**	**8,000**	**-**	**8,700**	**8,700**
Preventative Maintenance	95	94	93	93	93	93	92	92	92	92
Corrective Maintenance	500	500	500	500	500	500	500	500	500	500
Asset Renewal and Replacement Opex	328	328	328	328	328	328	328	328	328	328
Operational Expenditure Total	**923**	**922**	**921**	**921**	**921**	**921**	**920**	**920**	**920**	**920**

Table 7-8 Expenditure on Subtransmission Cables ($K in constant prices)

7.5.2 Zone Substations

7.5.2.1 Zone Substation Transformers and Tap Changers

Fleet Overview

WELL has 52 33/11 kV power transformers in service on the network and one spare unit. WELL's power transformer fleet is mature, with the youngest transformers being the pair at University Zone Substation (manufactured in 1986). Even so, most power transformers are in very good condition due to their being mostly indoors and loaded to less than 50% of their nameplate rating. The age profile for zone substation transformers is shown in Figure 7-7.

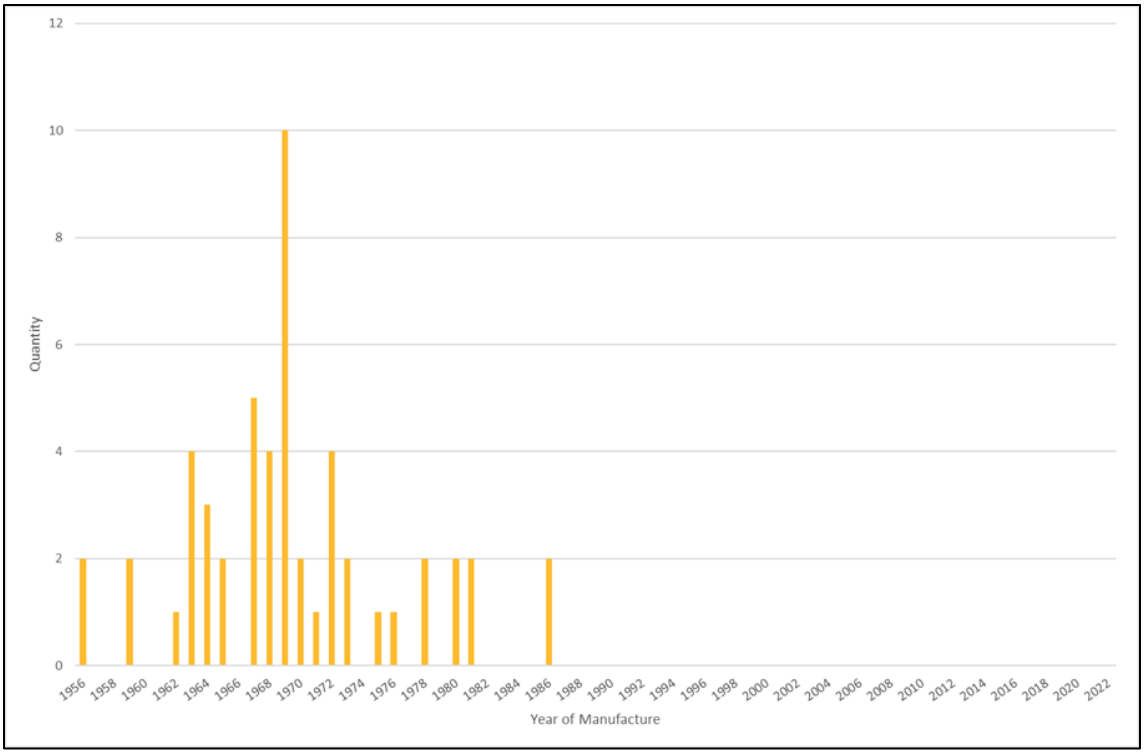


Figure 7-7 Age Profile of Zone Substation Transformers

The mean age of the transformer fleet is 52 years.

Fleet Objectives

In addition to WELL's broader asset management objectives that apply across the entire network, WELL has the following fleet-specific objectives for the power transformer fleet:

Priority Area	Objective
Safety and Environment	No injuries resulting from working on and around power transformers. No public safety risk due to power transformers.
Customer	Mitigate risk of potential decrease in service or price shock caused by unforecasted power transformer replacement.
Network Performance	Avoid incurring SAIDI and SAIFI resulting from unavailability of power transformers.

Table 7-9 Fleet Specific Objectives for Power Transformer Fleet

Maintenance Activities

The following routine planned inspection, testing and maintenance activities are undertaken on zone substation power transformers:

Activity	Description	Frequency
Transformer main tank oil test	Dissolved gas analysis (DGA) testing of transformer main tank oil including furan analysis.	Annually
Transformer tap changer oil test	Dissolved gas analysis (DGA) testing of transformer tap changer oil.	Annually
Transformer maintenance, protection and AVR test	De-energised transformer maintenance, inspection and testing of transformer, diagnostic tests as required. Gas injection for testing of Buchholz. Testing of temperature gauge and probe. Confirmation of correct alarms. Test AVR and ensure correct operation and indications.	4 yearly
OLTC maintenance	Programmed maintenance of OLTC.	4 yearly

Table 7-10 Inspection and Routine Maintenance Schedule for Zone Substation Transformers

Strategic Spares

WELL holds critical spares for the power transformers and tap changers as detailed in Table 7-11.

Strategic Spares	
Tap changer fittings	WELL 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.
Spare transformers	One spare power transformer is located at Petone Zone Substation. This unit was refurbished in 2018. Should additional spare transformers be required, one will be taken from any of a number of substations that are lightly loaded with sufficient distribution network back-feed options. These include Gracefield and Trentham.
Mobile Substations	WELL owns two mobile substations that comprise trailer-mounted 10MVA 33/11kV transformers and containerised 33kV and 11kV switchgear.

Table 7-11 Spares Held for Zone Substation Transformers

Transformer Condition

All zone substation transformers are operated within their ratings, are regularly tested, and have routine condition assessments undertaken. Where evidence of heating is present, corrective maintenance such as tightening or renewing internal connections outside of the core or tap changer maintenance is undertaken, if economic. The most common issue is 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 analysis provides an estimated Degree of Polymerisation (DP) value for the paper insulation which provides an initial overview of the transformer condition. Furan analysis undertaken with the DGA oil tests in 2020 shows the DP of the majority of transformers to be above 450 indicating at least 25 years of remaining life in the insulation. Once a transformer DP reaches 300, a paper sample will be taken to confirm the accuracy of the furan analysis.

The deterioration of barrier boards on Fuller tap changers has started to manifest on some of the older units in service. This leads to oil migration between tap changer and the main tank. The levels of migration are being monitored via ongoing oil sampling and DGA analysis.

During 2020, an internal fault within the Palm Grove T1 tap changer resulted in an unplanned outage of the transformer. The issue was due to a failed connector within the tap changer. Careful inspection of the tap changer internals did not show cause for concern and the transformer was returned to service. In June 2021, there was a serious internal failure in this tap changer which caused an extended outage of the transformer. This failure highlighted that some tap changers have a sealed oil compartment which does not have the typical gas-operated relay to protect against internal failures. Work is underway to install temperature sensors on these compartments.

The future condition of the power transformer fleet is modelled using Asset Health and Criticality Analysis. The analysis categorises transformers by risk, triggering further study of the assets with the greatest risk.

Transformer Asset Health and Criticality Analysis

The Asset Health and Criticality Analysis results are shown in the health-criticality matrix in Figure 7-8, with individual transformer scores and ratings being presented in Table 7-12.

		Lowest Impact		**Asset Criticality**			Highest Impact	
Asset Health		5.0	4.0	3.0	2.5	2.0	1.5	1.0
Worst Health	1.0							
	1.5			1	2			
	2.0			2	1			
	2.5				2			
	3.0			10	12	3	6	
	4.0			5	5	1	2	
Best Health	5.0							

Figure 7-8 Power Transformer Health-Criticality Matrix

Transformer	Substation	AHI	ACI	Rating
Evans Bay T1 & T2	Evans Bay	1.8	2.9	
Mana	Mana-Plimmerton	1.8	3.0	
Frederick Street T1 & T2	Frederick Street	3.0	1.9	
Ngauranga B	Ngauranga	2.0	2.8	
Gracefield A	Gracefield	2.0	3.0	
Waitangirua A	Waitangirua	2.0	3.0	
Palm Grove T1 & T2	Palm Grove	3.0	1.8	
University T1 & T2	University	3.0	1.9	
Moore Street T1 & T2	Moore Street	3.0	2.0	
Wainuiomata A	Wainuiomata	3.0	2.0	
Terrace T1 & T2	Terrace	4.0	1.7	
Tawa A & B	Tawa	2.9	2.9	
Waikowhai Street T1	Waikowhai Street	2.9	3.0	
Hataitai T1 & T2	Hataitai	3.0	2.9	
Ngauranga A	Ngauranga	3.0	2.8	
Johnsonville A & B	Johnsonville	3.0	2.9	
Karori T1 & T2	Karori	3.0	2.9	
Kenepuru B	Kenepuru	3.0	2.9	
Porirua A & B	Porirua	3.0	2.9	
Seaview A & B	Seaview	3.0	2.9	
Brown Owl A	Brown Owl	3.0	3.0	
Korokoro A & B	Korokoro	3.0	3.0	
Plimmerton	Mana-Plimmerton	3.0	3.0	
Naenae B	Naenae	3.0	3.0	
Trentham A	Trentham	3.0	3.0	
Waikowhai Street T2	Waikowhai Street	3.0	3.0	
Waitangirua B	Waitangirua	3.0	3.0	
Waterloo B	Waterloo	3.0	3.0	
Wainuiomata B	Wainuiomata	4.0	2.0	
Ira Street T1 & T2	Ira Street	4.0	2.9	
Kenepuru A	Kenepuru	4.0	2.9	
Maidstone A & B	Maidstone	4.0	2.9	
Gracefield B	Gracefield	4.0	3.0	
Trentham B	Trentham	4.0	3.0	
Waterloo A	Waterloo	4.0	3.0	
Brown Owl B	Brown Owl	4.0	3.0	
Naenae A	Naenae	4.0	3.0	

Table 7-12 Health Criticality Scores for Power Transformers

Outcome of Asset Health and Criticality Analysis

A large number of units are in better health than would be expected for their age. This is due to a number of factors, particularly the proportion of units located indoors and therefore less vulnerable to corrosion, and loading on transformers being kept below 50% for security reasons. Exceptions to this are noted below.

Evans Bay

The transformers at Evans Bay were installed in 1959 and have the lowest health indices in the network. These transformers have experienced an increasing number of problems in recent years, mostly relating to the mechanical performance of the tap changer and excessive leaks due to deterioration of valves, flanges, gaskets and radiators. To date corrective works have been possible and the transformers returned to service.

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. A project to replace these transformers is underway for completion by the end of 2022.

Mana

The Mana transformer is a South Wales unit that was manufactured in 1963 and has exhibited a low estimated DP value based on Furan Analysis of 395. The DGAs on this unit show no concerning signs in terms of combustible gases, carbon monoxide or carbon dioxide, however acidic content has been on a steady increase over the past years. Online monitoring has been fitted to the transformer to provide a more detailed estimate of end of life, and this is indicating that replacement is not required within the horizon of this AMP.

Palm Grove

The Palm Grove transformers are in good condition, but have high criticality due to the peak loading and number of customers supplied by the substation. Their asset health is marked down slightly due to the noise created by their forced cooling and the proximity of residential neighbours. The proposed development path outlined in Section 8 indicates that the most cost-effective option to manage the transformer health in the short term is to deload the transformers on the 11 kV system during the three days a year that the load exceeds the transformer rating, while planning for replacement with larger units by 2025. Section 8 also makes allowance for ring reinforcement from 2025 onwards which will provide a greater ability to shift load between zone substations.

There have been multiple failures with the tap changer on Palm Grove T1, and this is now being replaced with a modern vacuum type tap changer. Maintenance and diagnostic testing results have shown that the transformer appears to be in reasonable condition for its age.

Ngauranga

Ngauranga has the oldest power transformers installed in WELL's network. These transformers are generally reliable but have experienced problems with the tap changer diverter switches in the past. These issues will be monitored and corrective repairs undertaken as required. It is expected that replacement due to condition would be required towards the end of the planning period, however as identified in Section 8.5, replacement of the transformers is planned for 2025 due to capacity constraints.

Frederick Street

Frederick Street has a high criticality index due to its location in Wellington CBD and the number of customers it supplies. The transformers are in good condition, however in early 2014 the DGA results on T1 and T2 indicated elevated levels of ethylene and moisture respectively. In both cases, the absence of other key gases suggested there were no major problems with either unit so the oil was filtered and routine monitoring has continued.

Waikowhai Street

The transformers at Waikowhai Street substation are in good condition. They are fitted with vertical Reinhausen tap changers which are the only two of this kind on the network. These are more difficult to maintain and are refurbished on a 6-8 yearly cycle. The tap changer maintenance planned for 2021 was delayed due to the task's reliance on technicians based in Australia, however it is now planned to occur in 2022 once New Zealand's borders reopen.

Tawa

The Tawa transformers are currently in an acceptable condition, however DP trending indicates that they are aging faster than similar transformers in the network. The DP will be monitored to determine whether the decline is a continuing trend, in which case they are expected to require replacement in 2031.

University 1

University 1 is showing a lower degree of polymerisation than University 2. This is attributed to a historic loading imbalance which has since been resolved. While the DP result is low it is still indicating an estimated remaining life of 25 years so replacement is not expected to be required within the planning period. The condition of both units will continue to be monitored through the routine maintenance programme.

Renewal and Refurbishment

Where a transformer is identified for relocation, refurbishment is generally performed if it is economic to do so based on the condition and residual life of the transformer. A non-invasive test to determine the moisture content of the winding insulation is used to inform the assessment of whether a major transformer refurbishment would be economic.

The following projects have been provided for in the asset maintenance and replacement forecasts for the planning period:

- Ongoing preventative maintenance including testing and inspections;
- Transformer replacements at Evans Bay[22] zone substation; and
- Ongoing transformer refurbishment costs.

Transformer replacement projects that are triggered by capacity constraints rather than asset health and criticality, including Ngauranga and Porirua, are detailed in Section 8.

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 will be considered if supported by a business case. For power transformers in the WELL network the testing and inspection programme will aid in getting the best life from the transformer and also ensure optimal timing for unit replacement.

Significant projects for the renewal of power transformers over the next 12 months are listed in Table 7-13.

[22] There are two transformers replaced at Evans Bay substation for asset health reasons. There are also two transformers to be replaced at each of Ngauranga and Palm Grove substations for capacity reasons (refer to Section 8).

Project	Description
Evans Bay	Install replacement units.
Palm Grove	Replace tap changer on T1.

Table 7-13 Power Transformer Projects for 2022/23

Expenditure Summary for Power Transformers

Table 7-14 details the expected expenditure on power transformers by regulatory year.

Expenditure Type	2022/23	2023/24	2024/25	2025/26	2026/27	2027/28	2028/29	2029/30	2030/31	2031/32
Palm Grove T1 Tap Changer Replacement	90	-	-	-	-	-	-	-	-	-
Evans Bay Transformer Replacements	2,200	-	-	-	-	-	-	-	-	-
Tawa Transformer Replacement	-	-	-	-	-	-	-	-	2,500	4,000
Capital Expenditure Total	**2,290**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**2,500**	**4,000**
Preventative Maintenance	215	215	215	215	215	215	215	215	215	215
Corrective Maintenance	120	120	120	120	120	120	120	120	120	120
Operational Expenditure Total	**335**	**335**	**335**	**335**	**335**	**335**	**335**	**335**	**335**	**335**

Table 7-14 Expenditure on Power Transformers
($K in constant prices)

7.5.2.2 Zone Substation Switchboards and Circuit Breakers

Fleet Overview

11 kV circuit breakers are used in zone substations to control the power injected in to the 11 kV distribution network. There are 367 circuit breakers located at zone substations on the WELL network. The most common single type is the Reyrolle Pacific type LMT circuit breaker. An age profile of these circuit breakers is shown in Figure 7-9.

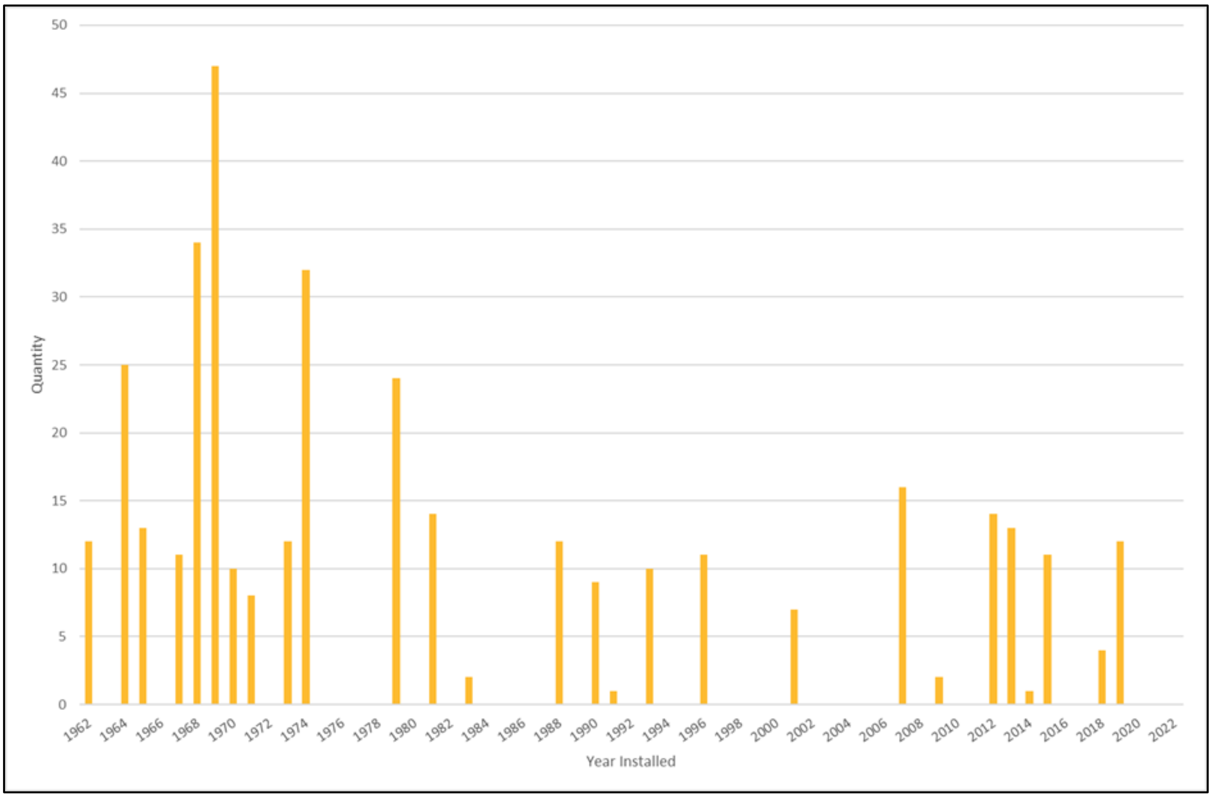


Figure 7-9 Age Profile for Zone Substation Circuit Breakers

The average age of zone substation circuit breakers in the Wellington Network is approximately 40 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 vacuum or SF_6 interrupters. The majority of circuit breakers are still oil-filled and require relatively higher maintenance regimes.

The use of transformer feeders avoids the need for 33 kV circuit breakers at zone substations. However, there are two 33 kV Nissin KOR oil circuit breakers at Ngauranga which have been in service at this site for 29 years. Originally manufactured in the 1960s, they were installed in 1993 when the substation was constructed. These breakers will be decommissioned once the communications systems from Takapu Road have been upgraded. Until then, a spare unit has been obtained from Transpower.

Category	Quantity
33 kV Circuit Breakers	2
11 kV Circuit Breakers	365

Table 7-15 Summary of Zone Substation Circuit Breakers

Manufacturer	Breaker Type	Quantity
Nissin	Oil (33 kV)	2
Reyrolle (RPS)	Oil	257
	Vacuum	92
Siemens	SF_6	16
Total		**367**

Table 7-16 Summary of Zone Substation Circuit Breakers by Manufacturer

Fleet Objectives

In addition to WELL's broader asset management objectives that apply across the entire network, WELL has the following fleet-specific objectives for the zone substation circuit breaker fleet:

Priority Area	Objective
Safety and Environment	No injuries resulting from working on and around circuit breakers.

Table 7-17 Fleet Specific Objectives for Zone Substation Circuit Breaker Fleet

Maintenance Activities

The following routine planned inspection, testing and maintenance activities are undertaken on metal clad switchboards and circuit breakers at zone substations:

Activity	Description	Frequency
General Inspection of 33 kV 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 11 kV Circuit Breaker	Visual inspection of equipment and condition assessment based upon visible defects. Thermal image of accessible connections. Handheld PD and Ultrasonic scan.	Annually
33 kV 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
11 kV 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
11 kV 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
11 kV Switchboard Major Maintenance	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

Activity	Description	Frequency
11 kV Circuit Breaker - Annual Operational Check	Back-feed supply, arrange remote and local operation in conjunction with NCR to ensure correct operation and indication.	Annually
PD Location by External Specialist	External specialist to undertake partial discharge location service.	Annually

Table 7-18 Inspection and Routine Maintenance Schedule for Zone Substation Circuit Breakers

Strategic Spares

Given the high number of circuit breakers in service on the WELL network, it is important to keep adequate quantities of spares to enable fast repair of defects. The largest quantity of circuit breakers on the network is the Reyrolle type LMT, which is used predominantly at zone substations, and WELL holds large numbers of spares for these circuit breakers. Furthermore, the RPS (formerly Reyrolle Pacific) switchgear factory is located in Petone which means that spares are available within short timeframes if required for LMT type switchgear. An overview of strategic spares held for circuit breakers is shown in Table 7-19.

Strategic Spares	
Circuit breaker trucks	At least one circuit breaker truck of each rating (or the maximum rating where it is universal fitment) is held for each type of withdrawable circuit breaker on the network.
Trip/Close coils	Spare coils held for each type of circuit breaker and all operating voltages.
Spring charge motors	Spare spring charge motors held for each voltage for the major types of switchgear in service.
Current transformers and primary bars	Where available, spare current transformers and primary bars are held to replace defective units. In particular, 400 A current transformers for Reyrolle LMT are held, as this type of equipment has a known issue with partial discharge.
Mobile switchboard	WELL owns a containerised 11kV mobile switchboard.

Table 7-19 Spare Parts Held for Circuit Breakers

Switchgear Condition and Failure Modes

The switchgear installed on the WELL network is generally in very good condition. The equipment is installed indoors, has not been exposed to extreme operating conditions, and has been well maintained.

Examples of switchgear in poorer condition include: partial discharge (particularly around cast resin components), corrosion and compound leaks that are visible externally, slow or worn mechanisms and unacceptable contact wear. The majority of these defects are easily identified and remedied under corrective maintenance programmes.

The future condition of the zone substation circuit breaker fleet is modelled using Asset Health and Criticality Analysis of switchboards. The analysis categorises switchboards by risk, triggering further study of the assets with the greatest risk.

Based on the condition assessment carried out as part of the preventative maintenance routine, assets are identified for replacement, or targeted inspection and maintenance programmes are put in place to manage risks until replacement is possible. A large number of older circuit breakers are still in service and are in excellent condition due to regular maintenance over their service life.

Reyrolle LMT - Partial Discharge (PD)

Reyrolle LMT circuit breakers were installed on the network from late 1960s onwards and there are over 600 units in service on the WELL network.

Older LMT circuit breakers are prone to developing partial discharge on resin current transformers and bushings, which can be cost-effectively resolved by the refurbishment of these components using a retrofit kit. All circuit breakers are surveyed with a handheld partial discharge meter as part of their routine annual general inspection, with zone substation circuit breakers receiving a full partial discharge survey annually from an industry specialist. Corrective maintenance is undertaken when high levels of PD are detected. At this stage there do not appear to be any other type issues with LMT.

Circuit Breaker Asset Health and Criticality Analysis

The Asset Health and Criticality Analysis results are shown in the health-criticality matrix in Figure 7-10, with individual switchboard scores and ratings being presented in Table 7-20.

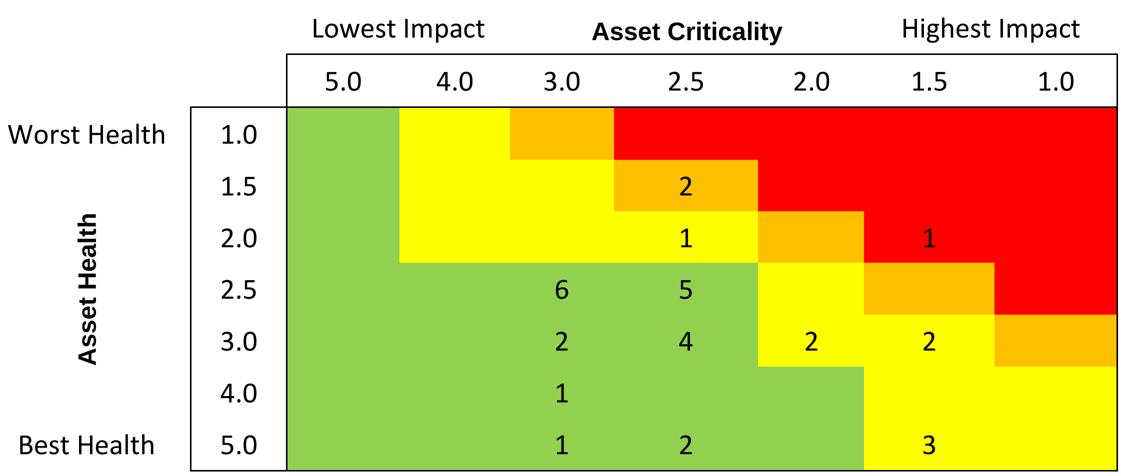


Figure 7-10 Zone Substation Switchboard Health-Criticality Matrix

11 kV Switchboard	Model	AHI	ACI	Rating
Frederick Street	LM23T	2.0	1.9	
Kenepuru	LM23T	1.9	2.9	
Mana	LM23T	1.9	2.9	
Hataitai	LM23T	2.0	2.9	
University	LMT	3.0	1.9	
Nairn Street	LMT	3.0	1.9	
Moore Street	LM23T	3.0	2.0	
Wainuiomata	LMT	3.0	2.0	
Palm Grove	LMVP	5.0	1.8	
Kaiwharawhara	LMVP	5.0	1.9	
Terrace	NX-PLUS	5.0	1.9	
Johnsonville	LM23T	2.9	2.9	

11 kV Switchboard	Model	AHI	ACI	Rating
Maidstone	LM23T	2.9	2.9	
Plimmerton	LM23T	2.9	2.9	
Porirua	LM23T	2.9	2.9	
Brown Owl	LM23T	2.9	3.0	
Korokoro	LM23T	2.9	3.0	
Naenae	LM23T	2.9	3.0	
Trentham	LM23T	2.9	3.0	
Waitangirua	LM23T	2.9	3.0	
Waterloo	LMT	2.9	3.0	
Ngauranga	LMT	3.0	2.9	
Ira Street	LM23T	3.0	2.9	
Seaview	LM23T	3.0	2.9	
Tawa	LM23T	3.0	2.9	
Petone	LM23T	3.0	3.0	
Titahi Bay	LMT	3.0	3.0	
Waikowhai Street	LMT	4.0	3.0	
Evans Bay	LMVP	5.0	2.9	
Karori	LMVP	5.0	2.9	
Gracefield	LMVP	5.0	3.0	

Table 7-20 Health-Criticality Scores for Zone Substation Switchboards

Outcome of the Asset Health Analysis

Frederick Street

The Reyrolle LMT switchboard at Frederick Street had had a number of stages of PD mitigation work since 2015. Subsequent PD testing has indicated that this ongoing work had been successful, it has also showed adjacent circuit breakers with high PD levels that have been masked previously. Further PD mitigation works will occur on these adjacent circuit breakers in 2022/23 involving the two-breaker incomer for power transformer T1. Apart from the partial discharge issue, the switchboards are in good health but have high criticality due to their location in the Wellington CBD.

Kenepuru

A new source of partial discharge was identified at Kenepuru during the 2020 survey. This is associated with the incomer for power transformer T2. The circuit breaker will be retrofitted with new components in 2022.

Mana and Hataitai

The partial discharge at these sites is suspected to be due to a guide bar on the LMVP trucks not being earthed. The installation of a leaf spring is expected to resolve this issue.

Renewal and Refurbishment

WELL's fleet of zone substation circuit breakers is generally in good condition. Assuming that the partial discharge mitigation refurbishments continue to be successful, no zone substation circuit breakers are expected to require replacement for health reasons during the next five years. During the period 2025-2030, three zone substation switchboards will exceed 60 years of age. There is no indication that replacement of these switchboards needs to be driven purely by age, however their condition will continue to be monitored through routine inspections and maintenance.

Significant projects for the renewal of zone substation circuit breakers over the next 12 months are listed in Table 7-21.

Project	Description
Frederick Street	Partial discharge mitigation on the Frederick Street T1 incomer.
Kenepuru	Partial discharge mitigation on the Kenepuru T2 incomer.

Table 7-21 Zone Substation Circuit Breaker Projects for 2022/23

Expenditure Summary for Zone Substation Circuit Breakers

Table 7-22 details the expected expenditure on zone substation circuit breakers by regulatory year.

Expenditure Type	2022/23	2023/24	2024/25	2025/26	2026/27	2027/28	2028/29	2029/30	2030/31	2031/32
Partial Discharge Mitigation	195	-	-	-	-	-	-	-	-	-
Capital Expenditure Total	**195**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**
Preventative Maintenance	130	130	130	130	130	130	130	130	130	130
Corrective Maintenance	20	20	20	20	20	20	20	20	20	20
Operational Expenditure Total	**150**	**150**	**150**	**150**	**150**	**150**	**150**	**150**	**150**	**150**

Table 7-22 Expenditure on Zone Substation Circuit Breakers
($K in constant prices)

7.5.2.3 Zone Substation Buildings and Equipment

Fleet Overview

There are 27 zone substation buildings, three major 11 kV switching station buildings, and two load control buildings at Transpower's Melling and Haywards substations. The buildings are typically standalone, although some in the CBD are close to adjacent buildings or, in the case of The Terrace, located inside a larger customer-owned building.

All WELL's zone substation buildings have a seismic rating of at least 67% of New Building Standard (NBS) at Importance Level 4.

The age profile of the major substation buildings is shown in Figure 7-11. The average age of the buildings is 50 years. There are five locations where WELL does not own the land under the zone substation and has a long-term lease with the landowner.

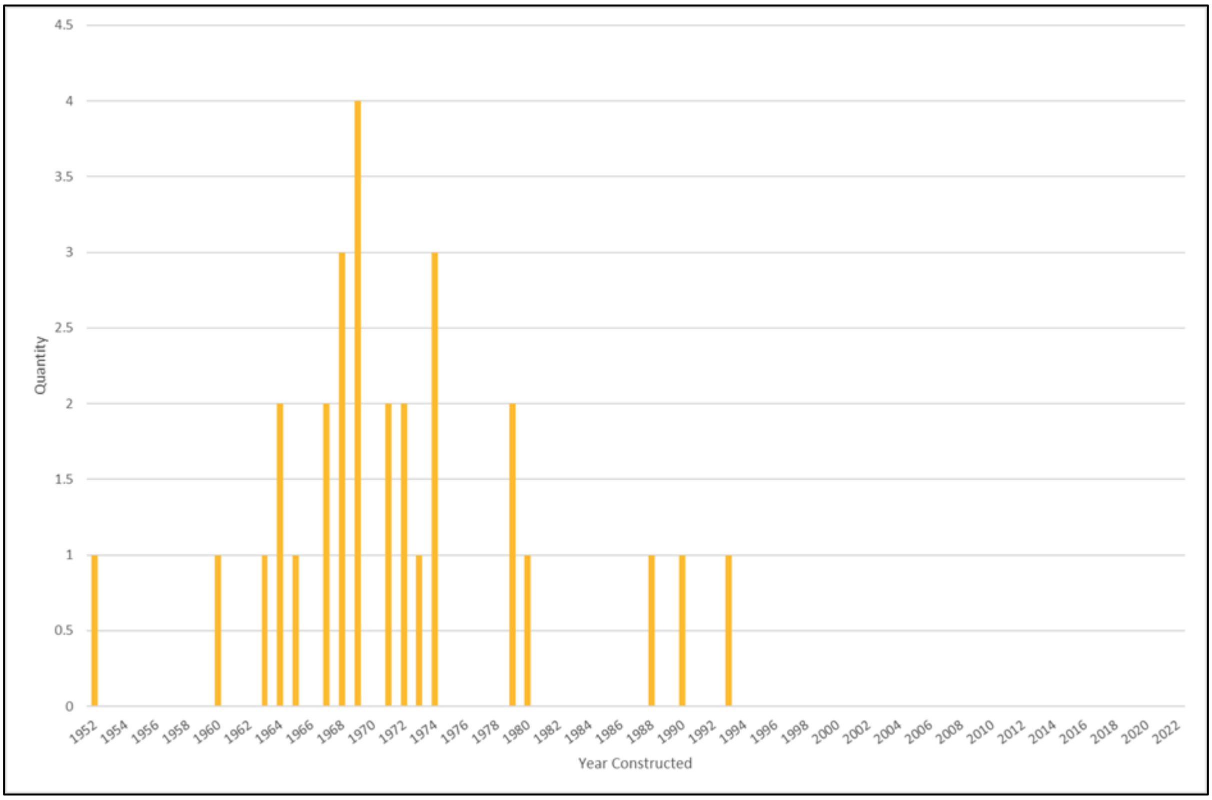


Figure 7-11 Age Profile of Major Substation Buildings

Fleet Objectives

In addition to WELL's broader asset management objectives that apply across the entire network, WELL has the following fleet-specific objectives for zone substation buildings:

Priority Area	Objective
Safety and Environment	No zone substations to be an earthquake risk.
Network Performance	Ensure weather-tightness to prevent damage to internal equipment.

Table 7-23 Fleet Specific Objectives for Zone Substation Buildings

Maintenance Activities

The following routine planned inspection, testing and maintenance activities are undertaken on zone 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	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

Table 7-24 Inspection and Routine Maintenance Schedule for Zone Substations and Equipment

Routine zone substation inspections are undertaken quarterly and include the building and other assets such as lighting, fire systems, security systems, fans, heaters and safety equipment. The grounds and ripple injection spaces are also maintained to ensure access, security, condition and safety. Where appropriate, annual building warrant of fitness inspections are carried out and any defects rectified. Building maintenance varies depending upon the site and minor defects are corrected as they are identified.

Renewal and Refurbishment

The substation building refurbishment programme includes tasks such as roof replacement, exterior and interior painting, security and fencing improvements to maintain the assets in good condition on an as-needed basis.

Given the average age of substation buildings, WELL 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. WELL 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.

WELL completes seismic investigations prior to undertaking any major substation work and this may lead to additional seismic strengthening works. The seismic reinforcing of substation buildings and how this risk is managed is discussed in Section 11.

Expenditure Summary for Zone Substation Buildings

Table 7-25 details the expected capex expenditure funded via the DPP allowances on zone substation buildings by regulatory year.

Expenditure Type	2022/23	2023/24	2024/25	2025/26	2026/27	2027/28	2028/29	2029/30	2030/31	2031/32
Naenae Zone Substation Seismic Strengthening	140	-	-	-	-	-	-	-	-	-
Reactive Capital Expenditure	200	200	200	200	200	200	200	200	200	200
Capital Expenditure Total	**340**	**200**	**200**	**200**	**200**	**200**	**200**	**200**	**200**	**200**
Preventative Maintenance	100	100	100	100	100	100	100	100	100	100
Corrective Maintenance	265	265	265	265	265	265	265	265	265	265
Operational Expenditure Total	**365**	**365**	**365**	**365**	**365**	**365**	**365**	**365**	**365**	**365**

Table 7-25 Expenditure on Zone Substation Buildings ($K in constant prices)

7.5.3 Overhead Lines

7.5.3.1 Poles

The total number of poles owned by WELL, including subtransmission distribution lines and low voltage lines, is 39,574. Of this number, 20.4% are wooden poles and 79.2% are concrete poles. The remaining 0.4% of poles are fibreglass or steel. Another 16,484 poles are owned by other parties but have WELL assets such as cross arms and conductors attached, for example telecommunication poles owned by Chorus, or the poles owned by Wellington City Council. A summary of the poles either owned by WELL, or with WELL assets attached, is shown in Table 7-26.

Pole Owner	Wood	Concrete/Other	Total
WELL	8,063	31,511	39,574
Customer	6,019	586	6,605
Chorus	7,106	340	7,446
Wellington City Council	1,401	1,032	2,433
Total	**22,589**	**33,469**	**56,058**

Table 7-26 Summary of Poles

The average age of concrete/ other poles is 29 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 40 years. Cross arms are predominantly hardwood. WELL has recently approved the use of lighter composite poles on the network for use in areas with difficult access that requires hand carrying of replacement poles. There is also an ongoing trial of composite cross arms underway.

An age profile of poles owned by WELL is shown in Figure 7-12.

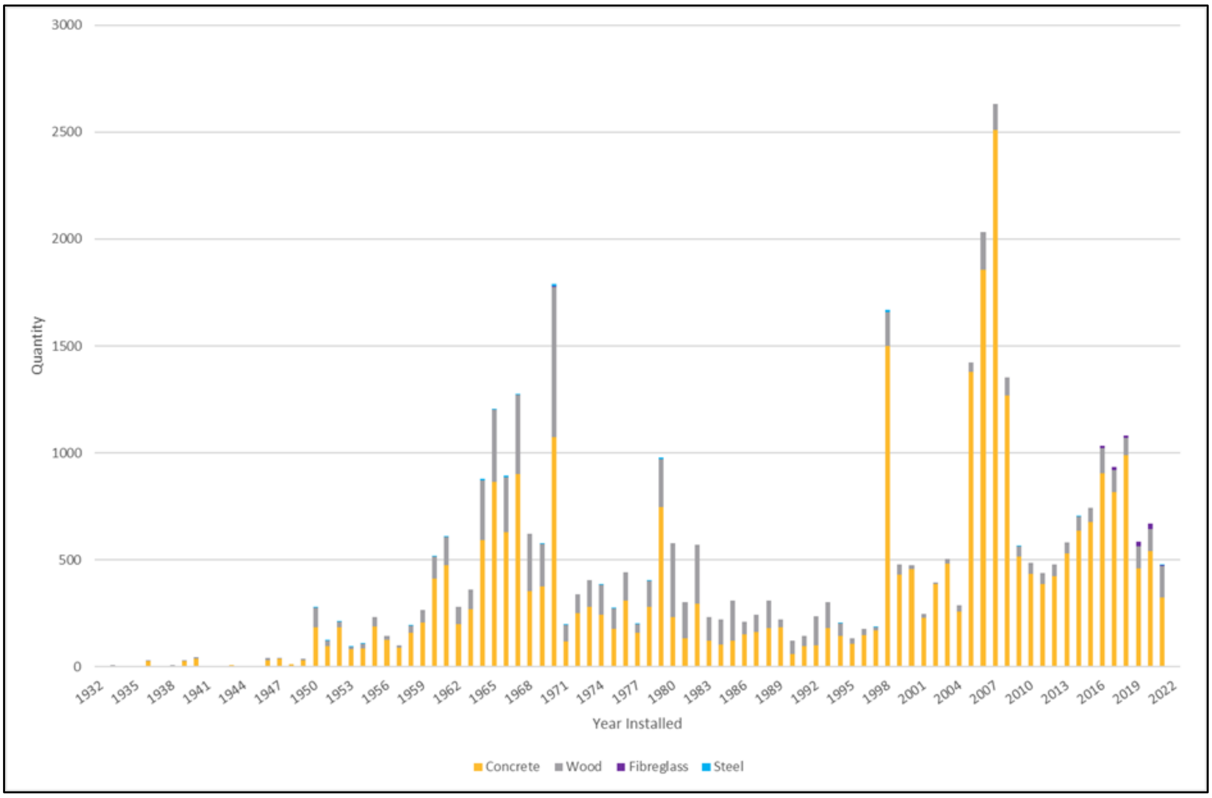


Figure 7-12 Age Profile of Poles

As WELL does not own customer service lines or poles, on-going work required to advise customers of their responsibilities relating to these privately owned lines. Owners are notified of any identified defects or when hazards are identified on customer owned poles or service lines.

WELL has an interest in customer poles that are considered as works as defined in the Electricity Act 1992. An example is for a pole supplying multiple customers along a private right of way. WELL occasionally replaces customer/private poles in agreement with the original pole owner. WELL then takes responsibility for the ongoing testing and maintenance of the new poles.

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

7.5.3.2 Subtransmission Lines

WELL's 56.8km of 33 kV subtransmission overhead lines are predominantly AAC conductor on both wood and concrete poles. Overhead line was used for subtransmission in the Hutt Valley and Porirua areas, converting to underground cable at the urban boundary. Subtransmission overhead lines are typically located on rural or sparsely developed land, although they are also in some other locations where difficult access would have made underground cable installation problematic. A summary and age profile of the subtransmission lines is shown in Figure 7-13.

Category	Quantity
33 kV Overhead Line	56.8km

Table 7-27 Summary of Subtransmission Lines

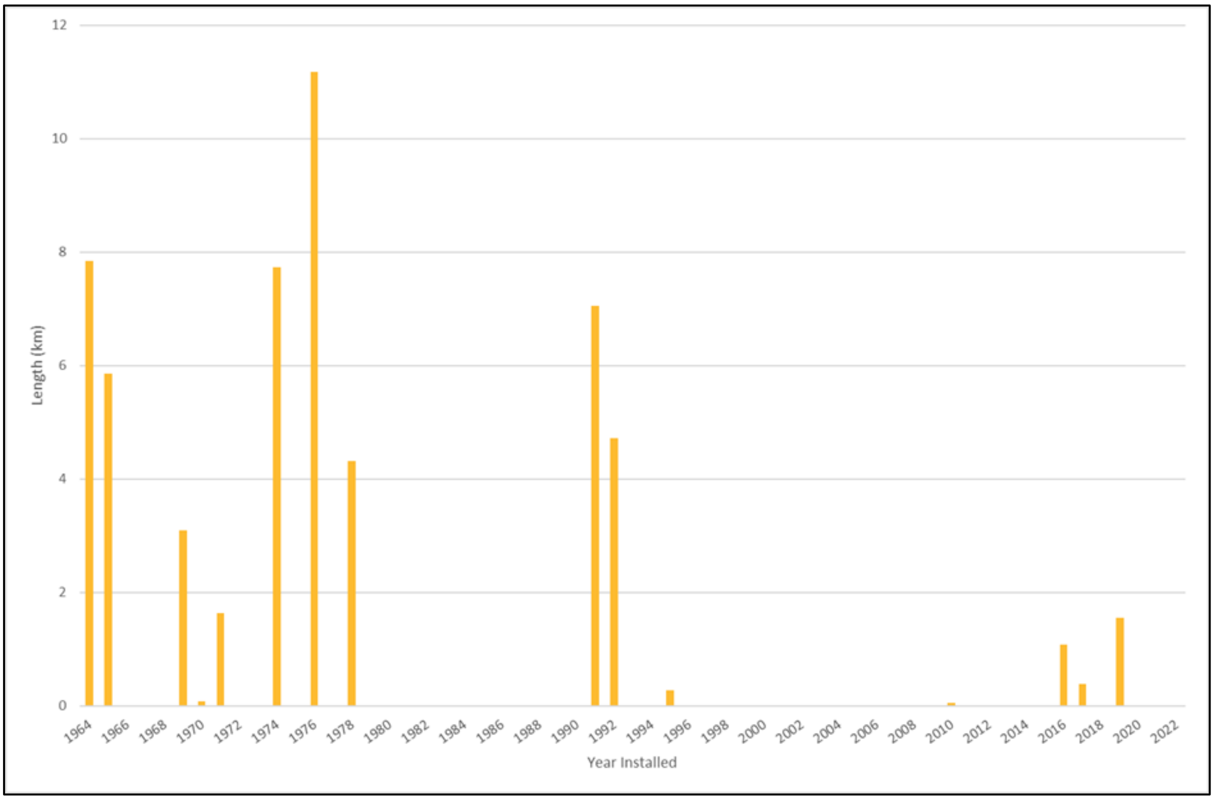


Figure 7-13 Age Profile of Subtransmission Line Conductors

7.5.3.3 Distribution and Low Voltage Conductors

Overhead conductors are predominantly aluminium conductor (AAC), with older lines being copper. In some areas aluminium conductor steel reinforced (ACSR) conductors have been used, with these having aluminised steel cores giving them greater corrosion resistance than standard ACSR with a galvanised steel core. New line reconstruction utilises all aluminium alloy conductor (AAAC). Small sections of covered conductor (CCT) have been used in locations with a history of outages due to windborne debris. Most low voltage conductors are PVC covered, and low voltage aerial bundled conductor (LV ABC) has been used in a small number of tree encroachment areas, subject to District Plan allowances. Figure 7-14 shows the age profile of overhead line conductors.

Category	Quantity
11 kV Line	587.8 km
Low Voltage Line	1,072.6 km
Streetlight Conductor	818.0 km

Table 7-28 Summary of Distribution Overhead Lines

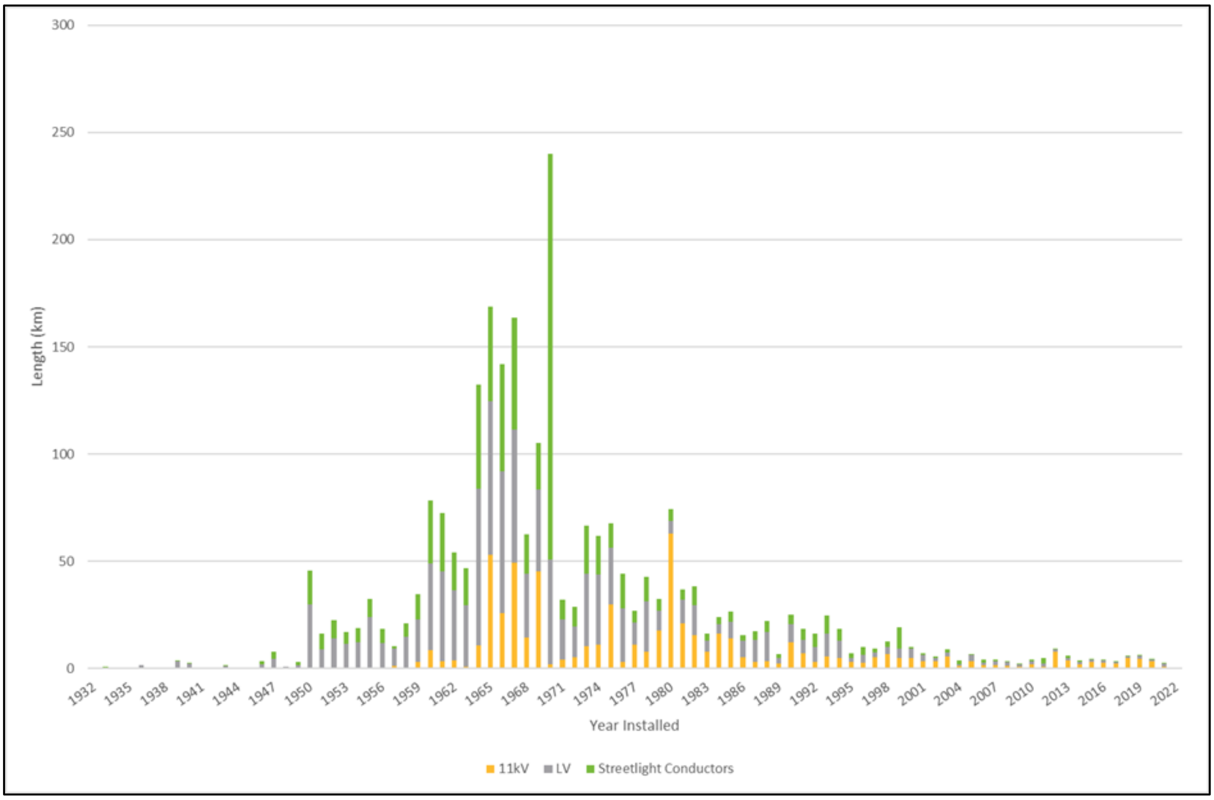


Figure 7-14 Age Profile of Distribution Overhead Line Conductors

Fleet Objectives

In addition to WELL's broader asset management objectives that apply across the entire network, WELL has the following fleet-specific objectives for the pole and overhead line fleets:

Priority Area	Objective
Safety and Environment	No injuries/fatalities resulting from working on and around poles. Zero unassisted pole failures.
Customer	Ensure customers are aware of their responsibilities regarding privately-owned poles.
Network Performance	Avoid outages due to pole failure.

Table 7-29 Fleet Specific Objectives for Pole and Overhead Line Fleets

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, steel pole and composite 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, invasive inspection below groundline where Deuar testing cannot be completed, tagging and reporting of results.	5 yearly
LFI inspections	Visual inspection of line fault passage indicator, testing in accordance with manufacturer recommendation.	Annually
LFI battery replacement	Removal of unit, assessment of condition and replacement of on-board battery, replacement onto live line using hot stick.	8 yearly

Table 7-30 Inspection and Routine Maintenance Schedule for Poles and Overhead Lines

All overhead lines are programmed for an annual visual inspection to determine any immediately obvious issues with the lines, condition of components such as crossarms and insulators, and to note any prospective vegetation or safety issues. In addition, all connectors in the current carrying path get a thermal scan to identify any high resistance joints which could potentially fail due to heating. These inspections drive a large part of the overhead corrective maintenance works and also contribute to asset replacement programmes for insulators and cross arms.

The replacement of conductor is determined on the lengths of conductor identified as having deteriorated to the criteria for replacement, as a result of annual inspections and analyses. This has historically used a visual based criteria and historical failure rates. Assessment is moving to using a condition-based replacement profile based on a predictive model currently under development.

Pole Condition

WELL has been using the Deuar MPT40 to test its wooden pole population since 2011. The testing programme ensures the detection of structural issues along the length of the pole, including below ground level, and provides remaining life indicators and an assessment of the suitability of the pole to support the mechanical loading being applied to it. Approximately 1,800 poles are Deuar tested every year.

Approximately three-quarters of the poles installed in the Wellington area are concrete, which are durable and in good condition. The majority of the remainder are timber poles, which are tested and replaced in accordance with their Deuar serviceability index results or where there are visible structural defects.

Common condition issues with timber poles are deterioration of pole strength due to internal or external decay. Poles which are leaning, have head splits or incur third party damage, may necessitate pole remediation or replacement.

Common condition issues with concrete poles include cracks, spalling (loss of concrete mass due to corrosion of the reinforcing steel), leaning poles and third party damage.

A significant contributor to leaning poles on the Wellington network is third party attachments. There are existing agreements to support telecommunications cables from Vodafone and Chorus on network poles. WELL has a standard that governs third party attachments to network poles. This standard will ensure future connections to poles for telecommunications infrastructure meet WELL's requirements and do not have an injurious effect on the network or the safety of contractors and members of the public. Third party network operators are 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.

Figure 7-15 shows the health-criticality matrix of WELL's fleet of poles. Pole asset health is determined by the pole's condition, while asset criticality is determined by the voltage of the lines connected to the pole and the number of customers that they supply.

		Lowest Impact		**Asset Criticality**				Highest Impact
		5.0	4.0	3.0	2.5	2.0	1.5	1.0
Worst Health	1.0	29	4	6	4	-	-	-
Asset Health	2.0	540	118	159	30	2	-	-
	3.0	9,766	1,851	2,051	703	5	-	-
	4.0	8,097	1,148	1,399	439	-	9	-
Best Health	5.0	8,030	1,893	2,459	894	3	5	-

Figure 7-15 Pole Health-Criticality Matrix

The forecast future condition of the pole fleet is modelled using survival curves.

Figure 7-16 shows the survival curves for poles and crossarms. The survival curves for poles are derived from the age at which poles have been tagged. There is currently insufficient data to forecast the expected end of life for concrete poles. The survival curve for crossarms is based on the age at which a crossarm is identified as having a defect that requires replacement of the arm.

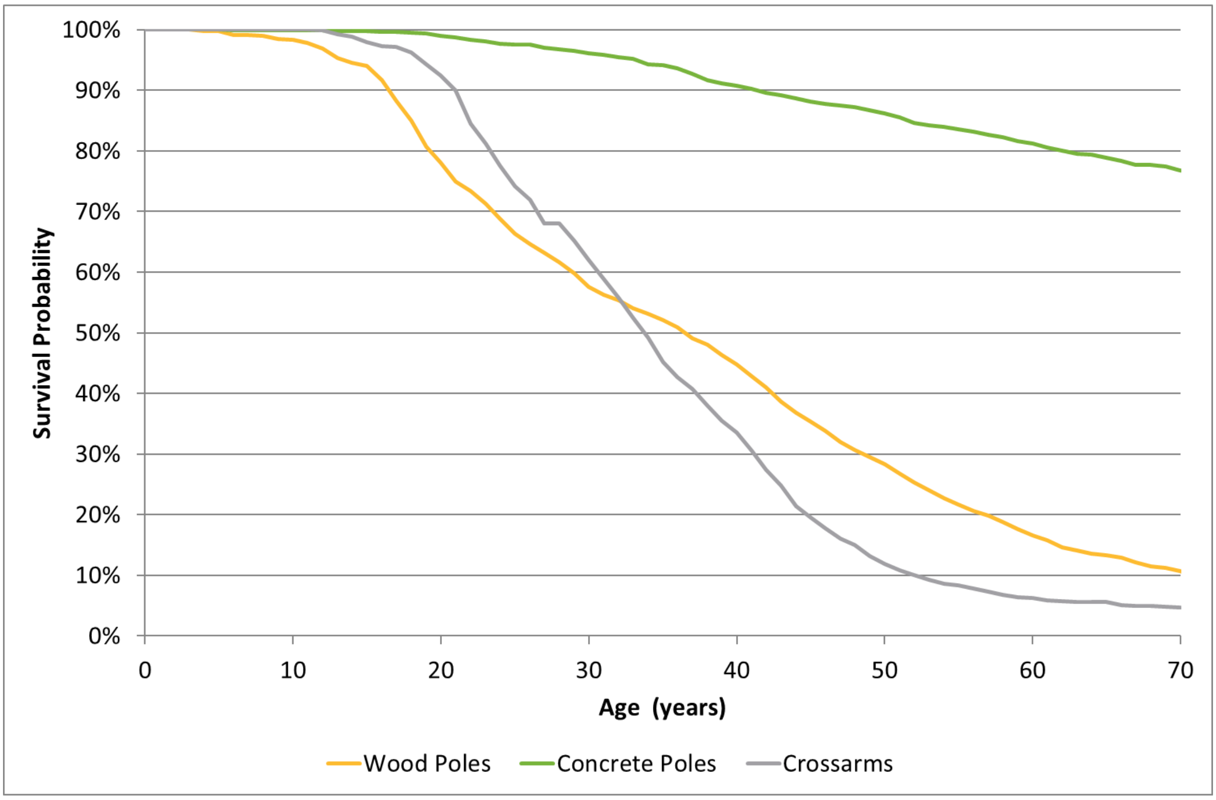


Figure 7-16 Pole and Crossarm Survival Curves

<u>Overhead Line Condition</u>

Pin type insulators are no longer used for new 33 kV or 11 kV line construction as they develop reliability issues later in life such as split insulators due to pin corrosion, or leaning on cross arms due to the bending moment on the pin causing the cross arm hole to wear. There is no programme to proactively replace existing pin type insulators but replacement occurs when defects are identified, when cross arms require replacement or during feeder reliability improvement projects. All new insulators are of the solid core post type as these do not suffer the same modes of failure as pin insulators, and 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 AAC lines that have historically been used on the Wellington network. A number of Fargo sleeve type automatic line splices have failed in service. These sleeves were only suitable for a temporary repair. The failure mode for Fargo sleeves is likely to be vibration related and can cause feeder faults when exposed to high vibrations. Fargo sleeves are no longer used on the network and are replaced with full tension compression sleeves as they are found. Alternatively the span will be re-conductored if the joints are not suitably located for replacement.

Failure modes and effect analysis undertaken in 2016 and 2017 have shown that most of the failures classified as conductor failures were actually connector failures. This has resulted in an extensive review of the connector fleet installed on the overhead network. The result of this review is a deeper understanding of the rate of ageing that has occurred on connectors within the WELL network. The increased rate of ageing due to the proximity of overhead circuits to marine salt pollutants has resulted in the approval of protective gel coverings for bimetallic wedge type connectors to protect them from accelerated deterioration due to exposure to the elements. These connectors get a protective covering whenever they are installed and all existing installations are reviewed when work is being done to be either replaced with a covering or to have a covering installed.

The forecast future condition of the overhead line conductor and connector fleet is modelled using failures per kilometre of conductor installed. Figure 7-17 shows the failure rates for conductors, jumpers, and connectors.

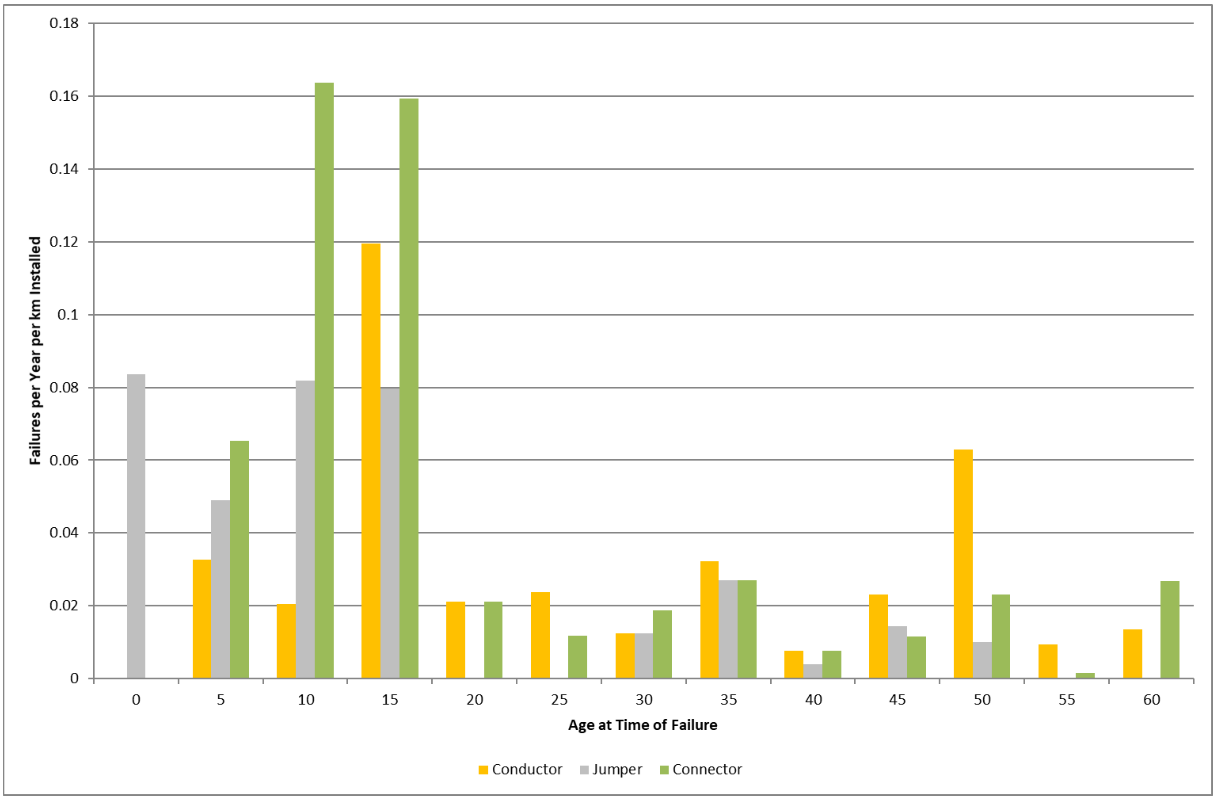


Figure 7-17 Overhead Conductor and Connector Failure Rate by Age

Renewal and Refurbishment – Poles

Wooden poles that are Deuar tested 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 or have a major structural defect, and are programmed for replacement within three months. Yellow tagged poles have a serviceability index of 0.5 to 1.0, or have moderate structural defects, and are programmed for replacement within 12 months. Blue tags are used to identify poles that have a reduced ability to support design loads but a serviceability index greater than 1.0, with these poles to have further engineering investigation within three months. For all pole tag colours the climbing of tagged poles by contractors is prohibited.

WELL is assessing options for extending the life of wooden poles. In 2017 it conducted a trial of pole reinforcement technology with the reinforcement of nine yellow tagged poles. The purpose of this trial was to assess suitability of reinforcement under Section 41(3)(b) of the Electricity (Safety) Regulations 2010 as a means of deferring pole replacement until multiple poles in the same area require replacement, in particular seeking efficiency in pole replacement costs. The reinforced poles are being monitored through inspection and Deuar testing in order to gain confidence in the technology before any decision is made about whether to adopt reinforcement as an option to assist with managing the fleet.

Concrete poles are replaced following an unsatisfactory visual inspection. The main replacement criteria are poles with large cracks, structural defects, spalling or loss of concrete mass. The severity of the defects determines whether the pole is given a red or yellow tag for replacement within three and 12 months respectively.

All replacement poles are concrete except where the location requires the use of timber or composite poles for weight, access constraints or loading design. Poles on walkways and hard to reach areas are normally replaced with light softwood poles or composite poles because they can be carried in by hand. Cranes are used where practicable but have limited reach in some areas of Wellington. WELL does not normally favour the use of helicopters in erecting poles due to the cost and the need to evacuate residents around the pole location.

The required number of pole replacements per year is forecast by rolling the population through the survival curves, to estimate the number of poles reaching end of life each year. The replacement rate of poles is forecast to decline until 2035 as the population of wooden poles is progressively replaced with concrete poles, before increasing as the older concrete poles start reaching end of life. As noted earlier, there is significant uncertainty in the model for the expected life of concrete poles, and this forecast will continue to be updated in coming years in order to improve the prediction of when this increase will occur.

Renewal and Refurbishment – Lines

Since 2009, WELL has invested in renewal of overhead lines in areas that have particularly high SAIDI and SAIFI or to address public safety concerns. Areas of Newlands, Johnsonville, Karori, Wainuiomata and Korokoro have been progressively reconductored, and have had all the line hardware, crossarms and poor condition poles replaced. These feeders have had a significant improvement in performance since this work was completed.

The relatively large number of failures occurring in the 5-20 year age bracket has been identified as being due to corrosion of Ampact wedge connectors, causing the connector to fail or the jumper/conductor to fail at the point of connection. This has been addressed through the instruction to fit Gelpact covers to any exposed Ampacts when undertaking planned work on the pole.

The rate of conductor failure shows that an extensive conductor replacement programme is not required within the period of this Plan, aside from work targeted at Feeder Reliability Improvement as identified in Section 6.

Significant projects for the renewal of overhead lines over the next 12 months are listed in Table 7-31.

Project	Description
Plimmerton Feeders	Further refurbishment stages of Plimmerton 11
Johnsonville Feeders	Further refurbishment stages of Johnsonville 10
Karori Feeders	Further refurbishment stages of Karori 3
Maidstone Feeders	Line refurbishment of Katherine Mansfield Road
Haywards Feeders	Further refurbishment stages of Haywards 2822 and Haywards 2842

Table 7-31 Overhead Line Projects for 2022/23

Expenditure Summary for Overhead Lines

Expenditure Type	2022/23	2023/24	2024/25	2025/26	2026/27	2027/28	2028/29	2029/30	2030/31	2031/32
Feeder Reliability Projects	2,097	2,094	2,094	2,242	2,288	2,334	2,382	2,497	2,713	2,854
Pole Replacement Programme	6,048	6,505	6,205	5,964	6,291	6,277	6,129	5,994	5,951	5,927
Reactive Capital Expenditure	825	825	825	825	825	825	825	825	825	825
Capital Expenditure Total	**8,970**	**9,424**	**9,124**	**9,031**	**9,404**	**9,436**	**9,336**	**9,316**	**9,489**	**9,606**
Preventative Maintenance	743	732	721	712	703	701	698	697	693	686
Corrective Maintenance	892	892	892	892	892	892	892	892	892	892
Operational Expenditure Total	**1,635**	**1,624**	**1,613**	**1,604**	**1,595**	**1,593**	**1,590**	**1,589**	**1,585**	**1,578**

Table 7-32 Expenditure on Overhead Lines
($K in constant prices)

7.5.4 Distribution and LV Cables

Fleet Overview

WELL'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 increase the risk of third party strikes during underground construction work.

Wellington CBD is operated in a closed 11 kV primary ring configuration, with short radial feeders interconnecting neighbouring rings or zone substations. This part of the network uses automatically operating circuit breakers, with differential protection on cables 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.

Outside the Wellington CBD, the 11 kV 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.

Category	Quantity
11 kV cable (incl. risers)	1,192.3 km
Low Voltage cable (incl. risers)	1,745.9 km
Streetlight cable	1,126.9 km

Table 7-33 Summary of Distribution Cables

Approximately 86.3% of the underground 11 kV cables are PILC and PIAS and the remaining 13.7% are newer XLPE insulated cables. The majority of low voltage cables are PILC or PVC insulated and a much smaller number are newer XLPE insulated cables.

An age profile of distribution cables of both voltages is shown in Figure 7-18.

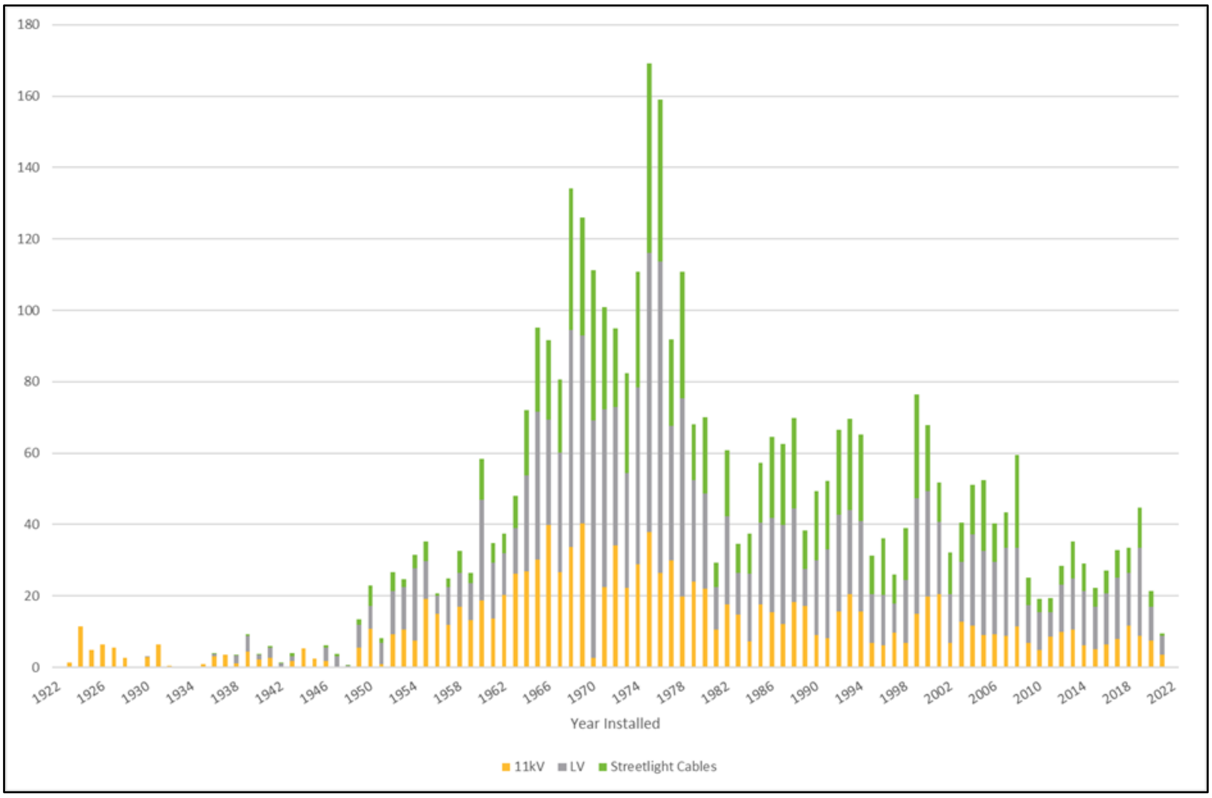


Figure 7-18 Age Profile of Distribution Cables

Fleet Objectives

In addition to WELL's broader asset management objectives that apply across the entire network, WELL has the following fleet-specific objectives for the distribution cable fleet:

Priority Area	Objective
Safety and Environment	No injuries resulting from working on and around 11 kV and LV cables.
Customer	Mitigate risk of potential decrease in service or price shock caused by under-forecast of cable replacement required. Avoid repeat 11kV outages due to cable condition.
Cost	Reduce cable replacement costs.

Table 7-34 Fleet Specific Objectives for Distribution Cable Fleets

Maintenance Activities

Maintenance of the underground distribution cable network is limited to visual inspection and thermal imaging of cable terminations. WELL has been trialling cable testing technology by testing poor performing cables with a variety of diagnostic tools. The purpose of this trial is to gain sufficient understanding of the results produced by these tools and match them to actual cable performance to provide confidence of their suitability as a condition assessment tool to:

- Determine whether a tested cable needs to be pro-actively replaced (either in total or to a targeted section);
- Build a predictive model, and
- Forecast future replacements.

The cable testing trials undertaken to date are listed in Table 7-35.

Year	Testing
2016	Online PD testing of Central Park 33kV cables, Haywards 11kV cables and one distribution cable.
2017	Further online PD testing of Haywards 11kV cables and three distribution cables.
2018	DAC-PD and VLF-TD testing of 60 Seaview Rd and Hutt Rec A 11kV cables. VLF-PD testing of Haywards 11kV cables.
2019	VLF-PD testing of eight distribution cables.
2020	DAC-PD testing of a sample of PILC-XLPE transition joints. Acoustic surveying of outdoor cable terminations.
2021	DAC-PD testing of recent cable repairs.

Table 7-35 Cable Testing Trials

Distribution Cable Condition

Underground cables usually have a long life and high reliability as they are not subjected to environmental hazards however, as these cables age, performance is seen to decrease. External influences such as third party strikes, inadvertent overloading, or even rapid increases in load within normal ratings can reduce the service life of a cable. Some instances of failure are due to workmanship on newer joints and terminations (which can be addressed through training and education), whilst others are due to age, environment or external strikes. Figure 7-19 shows the health criticality matrix for WELL's fleet of 11kV cable, by cable length.

		Lowest Impact		**Asset Criticality**				Highest Impact
		5.0	4.0	3.0	2.5	2.0	1.5	1.0
Worst Health	1.0			0.0	0.3			
Asset Health	2.0	0.2	3.8	8.4	1.2	16.6	12.3	
	3.0	47.2	148.3	323.2	85.3	65.9	86.6	1.2
	4.0	38.1	47.6	116.2	34.6	39.0	24.8	0.6
Best Health	5.0	13.6	13.6	44.7	13.5	9.1	4.9	1.7

Figure 7-19 11 kV Cable Health-Criticality Matrix (km)

The forecast future condition of the distribution cable fleet is modelled using failures per unit installed, with a cable unit being defined as the network average segment length of 150m, to allow a direct comparison between the failure rates of cables and their accessories. Figure 7-20 shows the failure rates for cables, joints, and terminations.

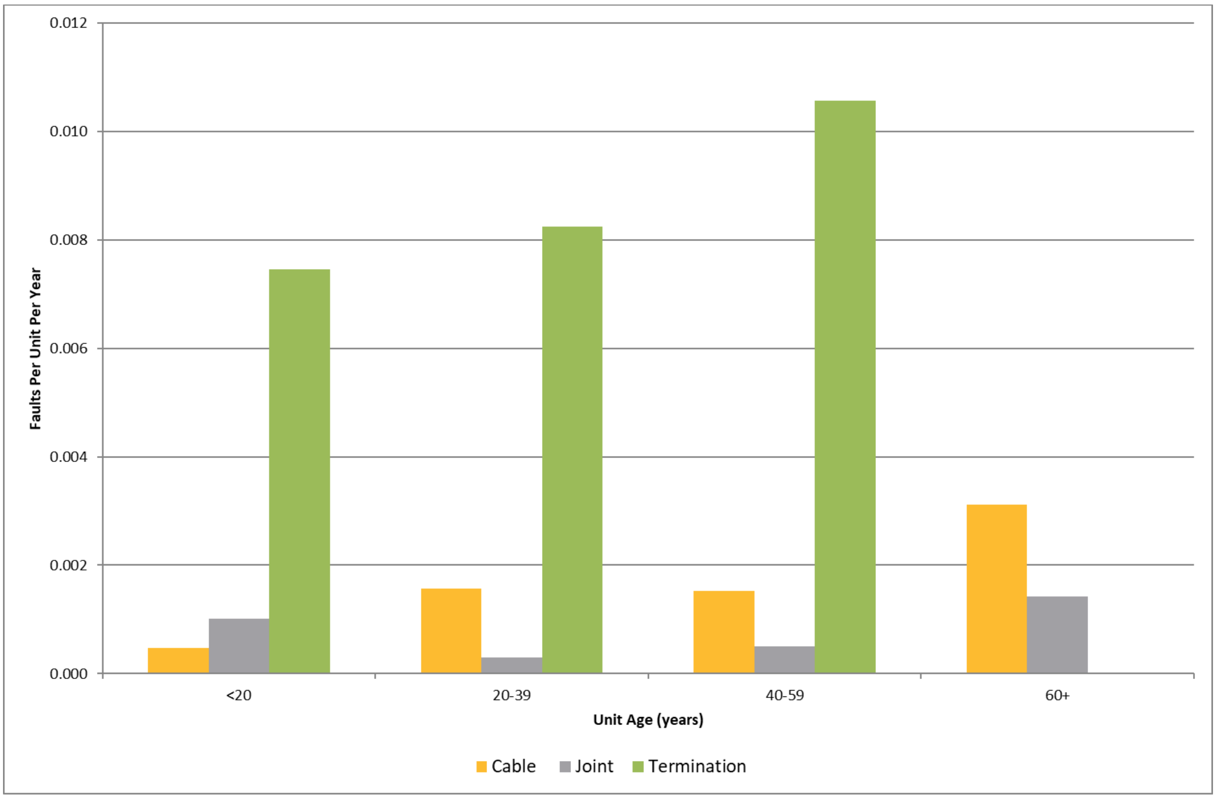


Figure 7-20 11 kV Cable Failure Rate by Age

The failure rate data indicates that outdoor terminations are clearly the weakest component of the cable system, with age-based deterioration apparent in the failure rates, however failure rates for the oldest terminations are still relatively low at 1.1%/year.

There is also a trend of increased rates of cable failure by age from 60 years onwards, although the failure rate is not high enough to indicate that significant lengths of cable are at end of life.

Applying the average failure rates to the fleet, combined with an estimate of the customer impact of each potential failure, produces a forecast of the underlying trend in future performance due to cable condition without intervention, which is presented in Figure 7-21.

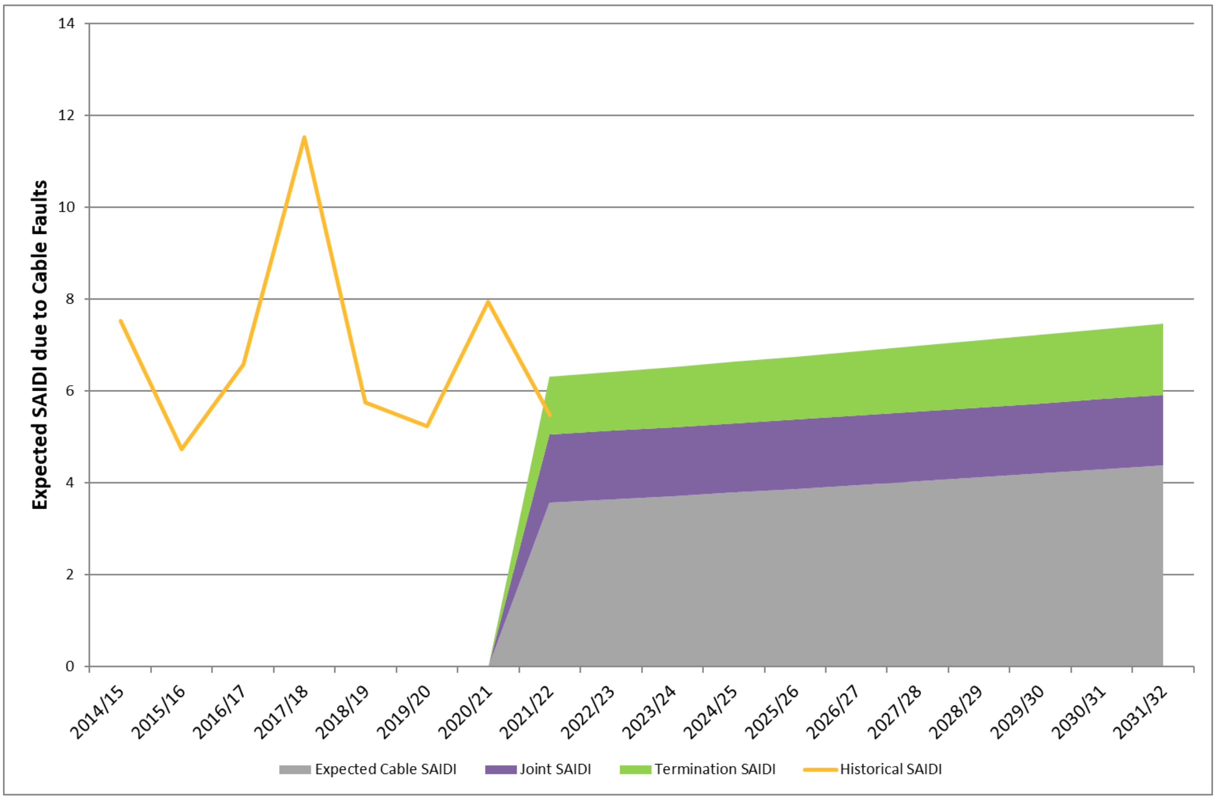


Figure 7-21 Forecast Cable Fleet Performance Trend without Intervention

Renewal and Refurbishment

The volume of cable installed and the high unit cost of replacement makes the 11kV cable network a significant risk for WELL. Allowing the fleet to run to failure would result in a gradual reduction in quality of supply as shown in Figure 7-21, whereas proactive replacement carries significant financial cost without being guaranteed to mitigate the risk of deteriorating performance. WELL has adopted a strategy for managing its 11kV cable fleet that seeks to minimise the impact on customers, in terms of both quality of supply, and cost.

The cable fleet strategy, set out below, targets specific areas of the forecast future performance in order to maintain the reliability of the fleet at current levels:

- Cable terminations represent low-hanging fruit due to their accessibility. A programme of condition assessment will identify deteriorating cable terminations, allowing them to be replaced before they fail;
- Investment in modern cable diagnostics equipment will improve the understanding of cable condition, and allow targeted replacement of the cable sections posing the greatest risk to quality of supply;
- Increasing the number of circuit breakers and remote controlled switches on the underground network will reduce the impact of each cable fault;

- The early failure of cable fittings, particularly younger than 20 years, is being controlled through training and monitoring requirements for cable jointer competency, and close cooperation with cable fitting suppliers to investigate and understand the causes of any failures; and
- Cable fitting technology will continue being reviewed, to ensure the joints and terminations approved for use on the network are suitable for Wellington conditions.

Expenditure Summary for Distribution and LV Cable

Table 7-36 details the expected expenditure on distribution and LV cable by regulatory year.

Expenditure Type	2022/23	2023/24	2024/25	2025/26	2026/27	2027/28	2028/29	2029/30	2030/31	2031/32
Asset Replacement and Renewal Capex	500	500	500	500	500	1,000	1,000	1,000	1,000	1,000
Reactive Capital Expenditure	2,050	2,050	2,050	2,050	2,050	2,050	2,050	2,050	2,050	2,050
Capital Expenditure Total	**2,550**	**2,550**	**2,550**	**2,550**	**2,550**	**3,050**	**3,050**	**3,050**	**3,050**	**3,050**
Corrective Maintenance	67	67	67	67	67	67	67	67	67	67
Operational Expenditure Total	**67**	**67**	**67**	**67**	**67**	**67**	**67**	**67**	**67**	**67**

Table 7-36 Expenditure on Distribution and LV Cable
($K in constant prices)

7.5.5 Distribution Substations

7.5.5.1 Distribution Transformers

Fleet Overview

Of the distribution transformer population, 59% are ground mounted and 41% are pole mounted. The pole mounted units are installed on single and double pole structures and are predominantly three phase units rated between 10 and 200 kVA. The ground-mounted units are three phase units rated between 100 and 2,000 kVA. WELL holds a variety of spare distribution transformers to allow for quick replacement following an in-service failure. 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 coastal, a transformer may not reach this age due to corrosion. The age profile of distribution transformers is shown in Figure 7-22.

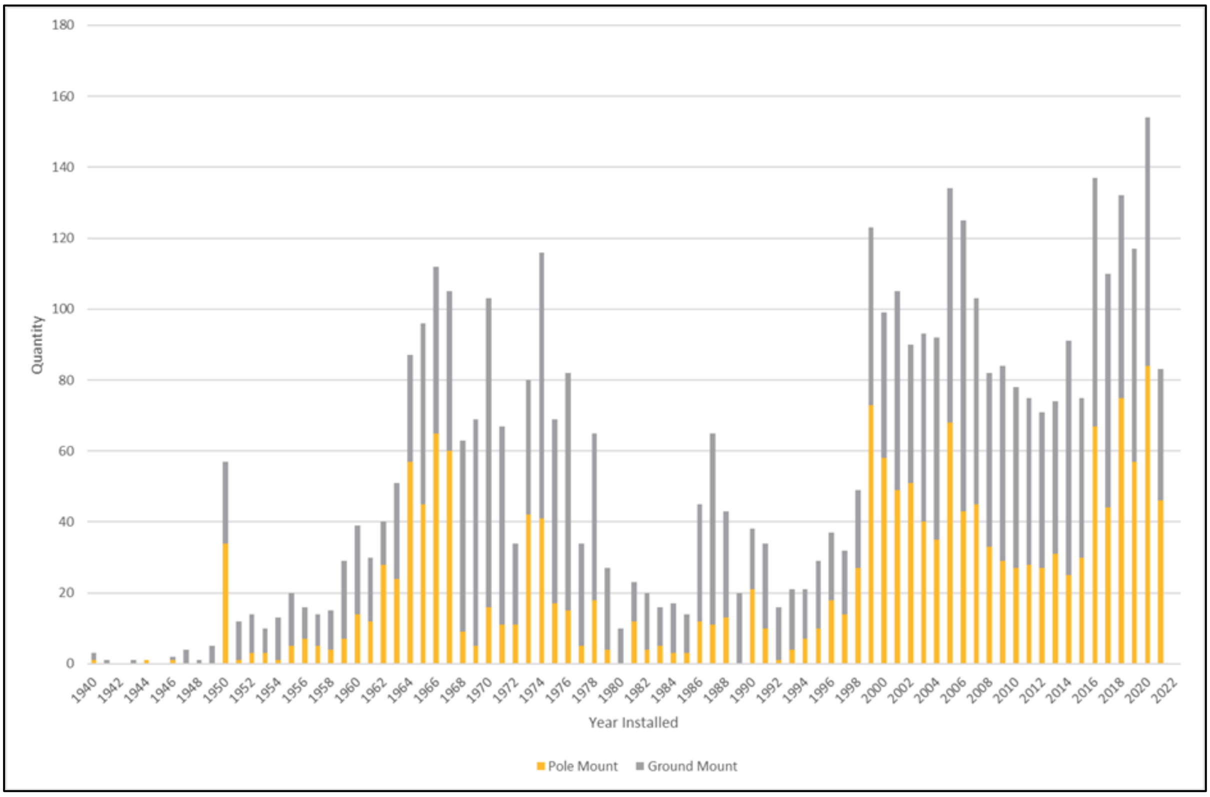


Figure 7-22 Age Profile of Distribution Transformers

In addition to pole and integral pad mount berm substations, WELL owns 524 indoor substation kiosks and occupies a further 629 sites that are customer owned (typically of masonry or block construction or outdoor enclosures). A summary of WELL's distribution transformers and substations is shown in Table 7-37.

Category	Quantity
Distribution transformers	4,464
Distribution transformers – Total	**4,464**
WELL owned substations	3,803
Customer owned substations containing WELL owned equipment	629
Distribution substations – Total	**4,432**

Table 7-37 Summary of Distribution Transformers and Substations

Fleet Objectives

In addition to WELL's broader asset management objectives that apply across the entire network, WELL has the following fleet-specific objectives for distribution transformers and substations:

Priority Area	Objective
Safety and Environment	No distribution substations to be earthquake prone. Substations located in road reserve to not be a risk to public safety. Compliance with asbestos regulation is maintained.
Customer	Meet customer needs for provision of information relating to transformers installed inside their buildings.
Network Performance	Ensure weather-tightness to prevent damage to internal equipment.

Table 7-38 Fleet Specific Objectives for Distribution Transformers and Substations

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	General programme of ground and building maintenance for distribution substations.	Ongoing
Fire Alarm Test	Inspect and test passive fire alarm systems.	3 monthly
Visual Inspection and Thermal Image (Ground Mount Transformer)	Visual inspection of equipment, and condition assessment based upon visible defects. Thermal image of accessible connections. Handheld PD and Ultrasonic scan.	Annual
Visual Inspection and Thermal Image (Pole Transformer)	Visual inspection of equipment, and condition assessment based upon visible defects. Thermal image of accessible connections.	Annual
Transformer oil test	Dissolved gas analysis of transformers 1000kVA and larger.	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

Table 7-39 Inspection and Routine Maintenance Schedule for Distribution Transformers

Type issues that have been identified with the fleet of distribution transformers are as follows.

Internal Bushing Transformers

Ground-mounted transformers manufactured by Bonar Long, Bryce and ASEA were installed between 1946 and 1999, with 36 such units currently in service. Many of these transformers have internal 11 kV bushings, with cambric cables being terminated inside the transformer tank. This does not pose a problem during normal operation, however if the switchgear at the site requires replacement, then the cables and hence the transformer will also need to be replaced.

Distribution Transformer Condition

Figure 7-23 shows the health-criticality matrix of WELL's fleet of distribution transformers, including both pole-mounted and ground-mounted units. Distribution transformer asset health is comprised of type issues and the unit's condition ranking, while asset criticality is determined by the number and type of customers connected to the transformer.

Asset Health \ Asset Criticality (Lowest Impact → Highest Impact)	5.0	4.0	3.0	2.5	2.0	1.5	1.0
Worst Health 1.0		1	2				
2.0	8	18	32		2		
3.0	452	618	1,542		585		
4.0	150	300	595		87		
Best Health 5.0	3	19	61		3		

Figure 7-23 Distribution Transformer Health-Criticality Matrix

The forecast future condition of the distribution transformer fleet is modelled using survival curves. Figure 7-24 shows the survival curves for ground and pole mounted distribution transformers. Ground mounted transformers are further divided into those located indoors (including berm substations), and those located outdoors.

These survival curves are based on the age at which a transformer is identified as having a defect that is best resolved through transformer replacement. Notable from these curves is the significant additional life gained by housing transformers under cover (representing 54% of WELL's distribution transformer fleet), and the similarity between pole-mounted and outdoor ground-mounted transformers, with the earlier onset of failure for pole-mounted transformers reflecting their greater exposure to lightning and their lower accessibility for repairs.

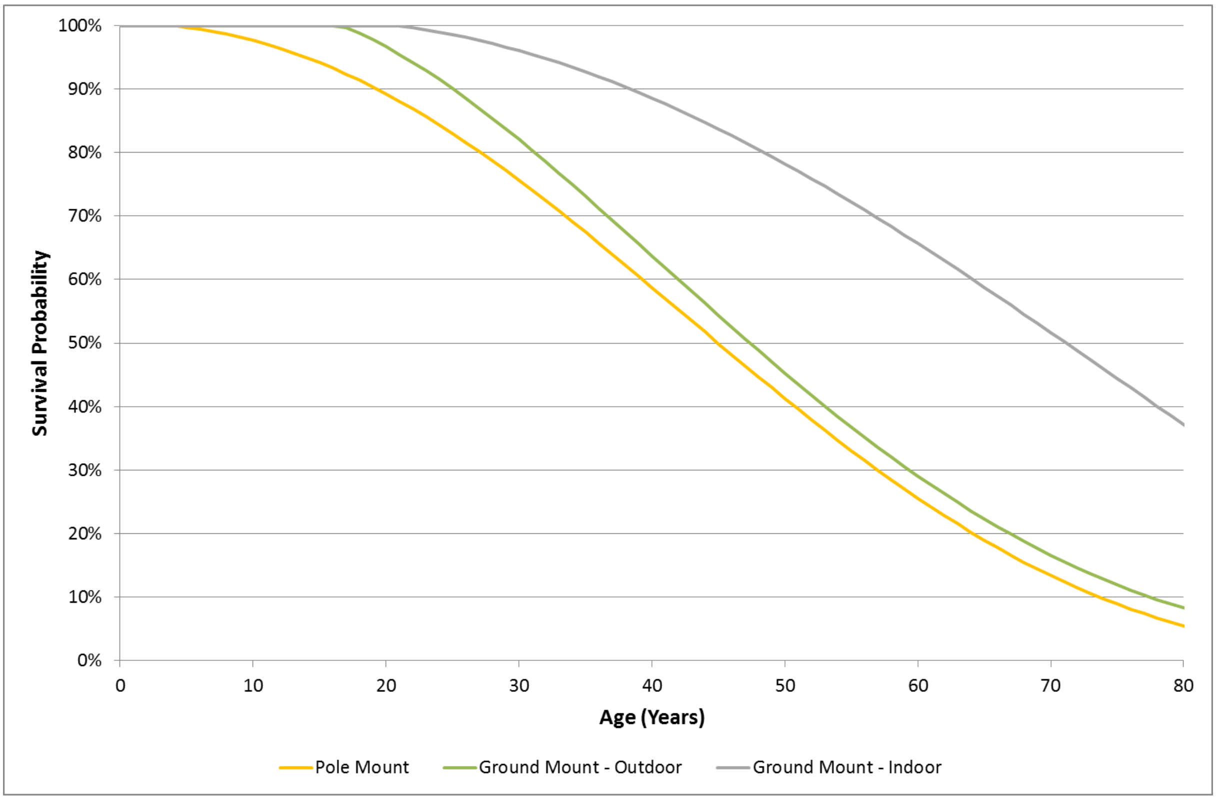


Figure 7-24 Distribution Transformer Survival Curves

Renewal and Refurbishment

If a distribution transformer is found to be in an unsatisfactory condition during its regular inspection, it is programmed for corrective maintenance or replacement. In-service transformer failures are investigated to determine the cause. This assessment determines if the unit is to be repaired, refurbished, or scrapped depending on cost and residual life of the unit. Typical condition issues include rust, heavy insulating fluid 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 and is driven by condition.

In addition to the transformer unit itself, the substation structures and associated fittings are inspected and replaced as needed. Examples include distribution earthing, substation canopies and kiosk building components (such as weather tightness improvements). Some renewals may be costly and time consuming as a large number of berm substations in the Hutt Valley area are an integral substation unit manufactured during the 1970s and 1980s by the likes of Tolley Industries. Replacement of these units requires complete foundation replacement and extensive cable works. Consideration was given to developing a compatible replacement, and a prototype unit installed, however it was found that the reduced civil cost was offset by the additional cost for purchasing a specialised transformer rather than a standard design.

WELL uses canopy type substations with independent components (LV switchgear, HV switchgear and transformer under an arc-fault rated metal canopy) for new installations where practicable, however cost and space constraints mean integral substations are still sometimes 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.

Expenditure Summary for Distribution Substations

Table 7-40 details the expected expenditure on distribution substations by regulatory year. The capitalised lease capex item relates to the new accounting standard that now treats operating leases as a capital item. The capitalised lease items relate to leased land and property for substations.

Expenditure Type	2022/23	2023/24	2024/25	2025/26	2026/27	2027/28	2028/29	2029/30	2030/31	2031/32
Seismic Strengthening	318	676	-	-	-	-	-	-	-	-
Asset Replacement and Renewal Capex	2,354	2,751	2,938	2,808	3,048	3,048	2,788	3,008	2,988	2,598
Reactive Capital Expenditure	1,782	1,782	1,782	1,782	1,782	1,782	1,782	1,782	1,782	1,782
Capitalised Leases	133	44	-	11	-	212	802	498	655	41
Capital Expenditure Total	**4,587**	**5,253**	**4,720**	**4,601**	**4,830**	**5,042**	**5,372**	**5,288**	**5,425**	**4,421**
Preventative Maintenance	715	715	715	715	715	715	715	715	715	715
Corrective Maintenance	600	600	600	600	600	600	600	600	600	600
Operational Expenditure Total	**1,315**	**1,315**	**1,315**	**1,315**	**1,315**	**1,315**	**1,315**	**1,315**	**1,315**	**1,315**

Table 7-40 Expenditure on Distribution Substations ($K in constant prices)

7.5.6 Ground Mounted Distribution Switchgear

Fleet Overview

This section covers ring main units (RMUs) and switching equipment that are often installed outdoors. It does not include zone substation circuit breakers, which were discussed in Section 7.5.2. There are 1,277 distribution circuit breakers and 2,315 other ground-mounted switches in the WELL network. 11 kV circuit breakers are used in the 11 kV distribution network to increase the reliability of supply in priority areas such as in and around the CBD and they are also used as protection when installing transformers 750kVA and above. Other ground-mounted switches include fuse switches for the protection of distribution transformers, and load break switches to allow isolation and reconfiguration of components on the network, often with multiple switches combined in a single ring main unit.

The age profiles of distribution circuit breakers and ground-mounted switchgear are shown in Figure 7-25 and Figure 7-26.

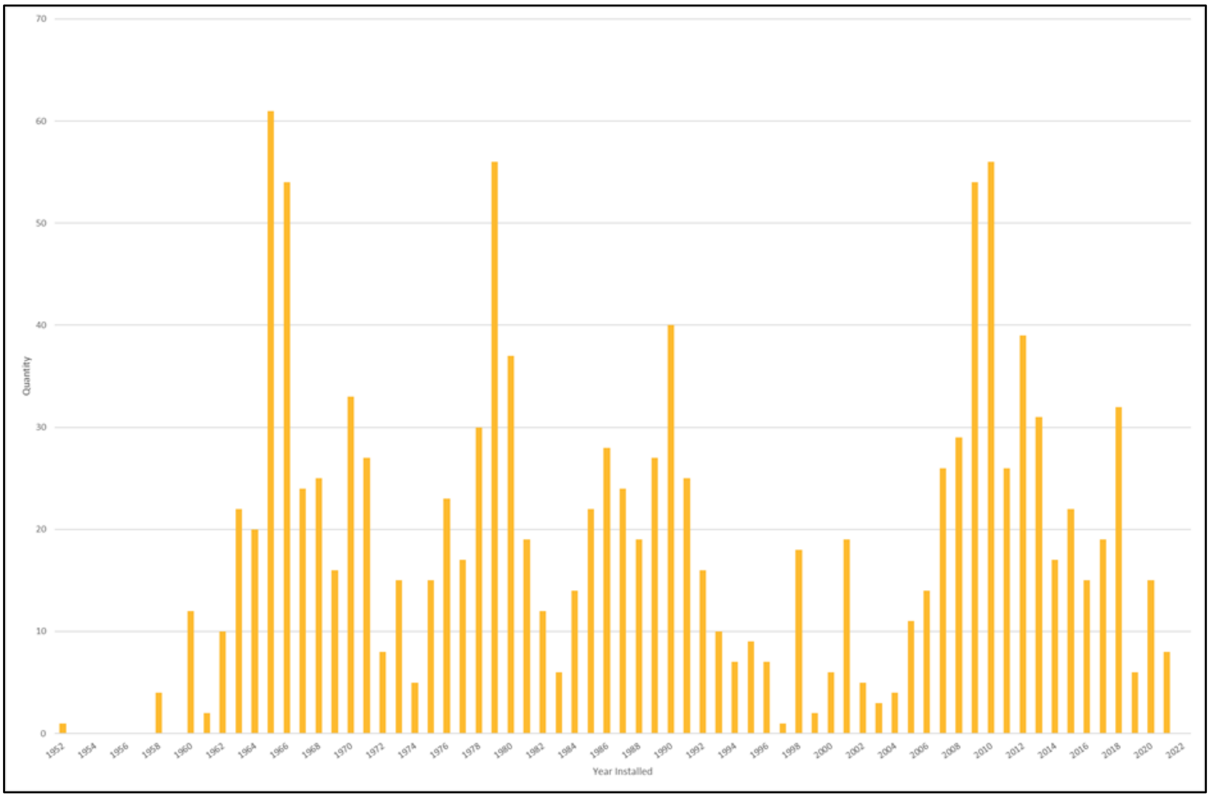


Figure 7-25 Age Profile for Distribution Circuit Breakers

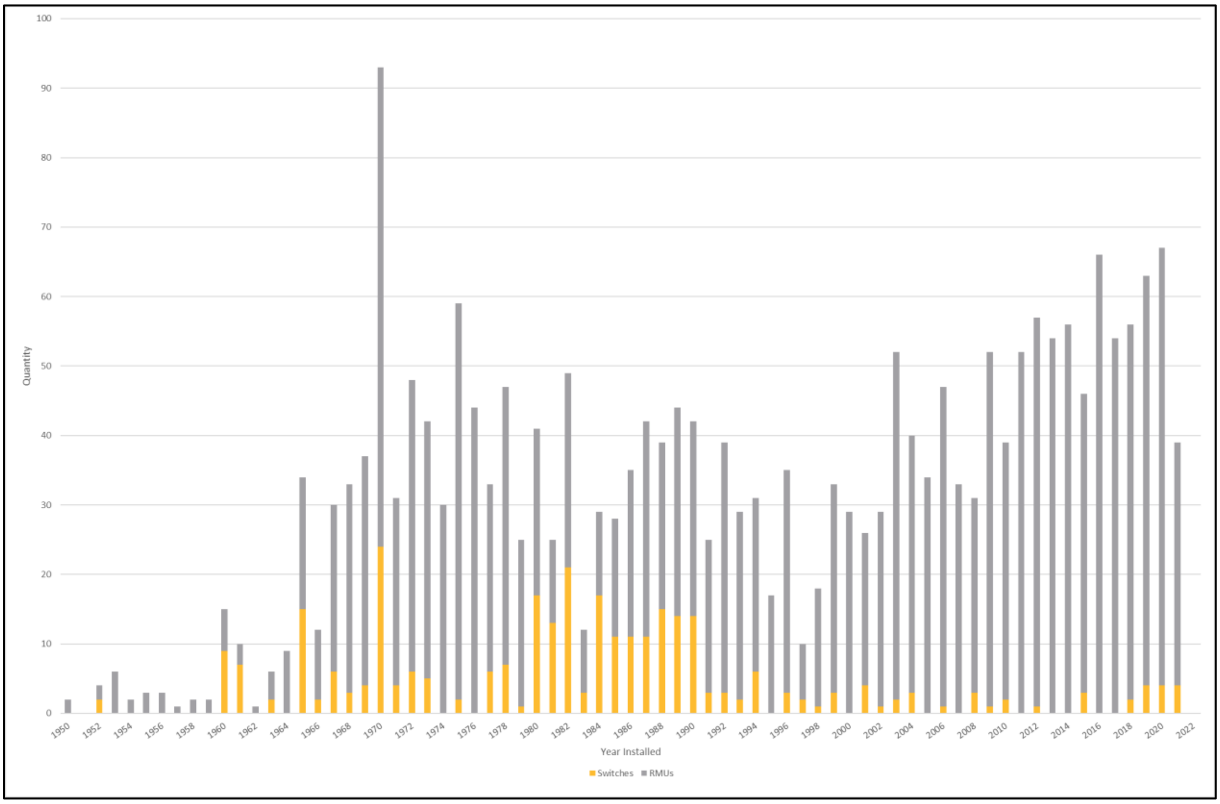


Figure 7-26 Age Profile of Other Ground Mounted Distribution Switchgear

The average age of distribution circuit breakers in the network is around 33 years, while the average age of ring main units is 26 years. A summary of circuit breakers and ground mounted distribution switchgear, of both stand-alone and ring main unit types, is shown in Table 7-41 and Table 7-42.

Category	Quantity
Distribution Circuit Breakers	1,277
Oil Insulated Switches	296
Oil Insulated RMUs	170
SF_6 Insulated Switches	6
SF_6 Insulated RMUs	856
Resin Insulated Switches	14
Resin Insulated RMUs	973

Table 7-41 Summary of Ground Mounted Distribution Switchgear

Manufacturer	Breaker Type	Quantity
ABB	SF_6	28
AEI	Oil	47
BTH	Oil	52
Entec	Vacuum	13
GEC/Alstom	Oil	50
Hawker Siddeley	Vacuum	21
Merlin Gerin / Schneider	SF_6	340
Reyrolle	Oil	608
	Vacuum	63
South Wales	SF_6	36
Statter	Oil	19[23]
Total		**1,277**

Table 7-42 Summary of Distribution Circuit Breakers by Manufacturer

Fleet Objectives

In addition to WELL's broader asset management objectives that apply across the entire network, WELL has the following fleet-specific objectives for ground mounted distribution switchgear.

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

Priority Area	Objective
Safety and Environment	No injuries resulting from working on and around distribution switchgear. Minimise the loss of SF_6 to the environment.
Network Performance	Distribution switchgear to be safe to operate live, to minimise customer impact during switching.

Table 7-43 Fleet Specific Objectives for Ground Mounted Distribution Switchgear

Maintenance Activities

The following routine planned inspection and maintenance activities are undertaken on ground mounted distribution switchgear and associated equipment:

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.	Triggered by Inspection Results
Circuit Breaker Maintenance (Oil CB)	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	5 yearly
Switch 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
Circuit Breaker Maintenance (Vacuum or Gas CB)	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	5 yearly
Switch Maintenance (Vacuum or Gas Switch)	Clean and maintain switch unit, check terminations and cable compartments. Ensure correct operation of unit. Check gas / vacuum levels.	Triggered by Inspection Results
11 kV Switchboard Major Maintenance	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	10 yearly

Table 7-44 Inspection and Routine Maintenance Schedule for Distribution Switchgear

Distribution Switchgear Condition

The switchgear installed on the WELL 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 and requires replacement when the condition deteriorates to a point that is no longer cost effective to repair. Common condition issues experienced include mechanical wear of both the enclosure/body as well as operating mechanisms, electrical discharge issues or poor oil condition and insulation levels.

Figure 7-27 shows the health-criticality matrix of WELL's fleet of ground-mounted distribution switchgear. Distribution switchgear asset health is comprised of type issues and the unit's condition ranking, while asset criticality is determined by the 11 kV feeder that the unit is connected to.

		Lowest Impact		**Asset Criticality**			Highest Impact	
		5.0	4.0	3.0	2.5	2.0	1.5	1.0
Worst Health	1.0			4				
	1.5	16	43	143	17		1	
Asset Health	2.0	2	2	3	1			
	2.5	92	241	542	180	231	180	
	3.0	88	147	436	67	304	139	
	4.0	33	35	128	41	168	101	
Best Health	5.0	14	20	58	14	7	12	

Figure 7-27 Distribution Switchgear Health-Criticality Matrix

Specific condition issues for distribution switchgear are:

Schneider Ringmaster

The switch unit in the red risk category of Figure 7-27 is a Schneider Ringmaster RMU which has suffered gas depressurisation while in service and is planned for replacement during 2022. A number of these events have occurred in recent years, with the first recorded loss of gas occurring in 2011 after about 10 years in service. These have been identified as only affecting RMUs and not Ringmaster circuit breakers. The affected RMUs were manufactured between 2000 and 2005, and 96 of these units are currently in service. A loss of gas does not cause the electrical failure of the unit, however depressurised units are placed under operational restrictions until their replacement, so that they cannot be operated live. The cautious monitoring of the gas levels before operating the RMUs has been reinforced to switching staff.

The manufacturer has identified that the most likely cause of failure is stress fractures in the resin gas tank moulding due to temperature cycling, combined with a higher gas pressure being used for RMUs manufactured over the affected period. The failure is not believed to be related to the design of the switchgear, and the switchgear remains approved for installation on the network.

Solid Insulation Magnefix

In 2019 WELL set up a working group that included service providers and industry experts to investigate potential application of preventative maintenance optimisation to Magnefix switchgear. During the maintenance of Magnefix units there is often very little required to be done beyond cleaning the unit and checking that the contacts are in good order. In-service failures are rare, with previous failures largely being attributed to either issues with cable terminations or occurring during operating. This indicates that if a unit is functioning properly and is in good condition then it can be expected to continue functioning without being removed from service for maintenance. The Magnefix investigation determined that the need for maintenance of Magnefix switchgear can be satisfactorily predicted through visual, thermal, and partial discharge inspections, rather than being purely time-based, reducing the need to switch these units and allowing maintenance resource to be prioritised to maintenance of oil-filled switchgear.

Older Magnefix units have grease-filled termination boxes. Thermal cycling of the units can result in the grease migrating into the cable, potentially compromising the phase-to-phase insulation inside the termination. These units are identified through the routine inspection programme, and operational restrictions are placed on them prohibiting live operation until outages can be arranged to top up the grease to the appropriate level.

There are also 13 sites with Krone KES 10 switchgear, which is also of solid insulation design. These are replaced when the condition deteriorates to a point where repair and maintenance are no longer cost effective.

Long and Crawford

As at October 2021, there is one Long and Crawford RMU remaining in service, installed in 1983. This unit is installed in an indoor substation so has been operating in a benign environment. Other networks have experienced catastrophic failures of Long and Crawford fuse switches. WELL imposed operational restrictions on Long and Crawford RMUs to prevent the fuse compartments being opened while the switchgear is alive, and requiring their substations to be vacated for 30 minutes after the switchgear is relivened. A programme to replace Long and Crawford RMUs commenced in 2016, with this last unit to be replaced during 2022.

Statter

As at October 2021, there are 39 sites with Statter switchgear, with 102 units in service including circuit breakers, oil switches and fuse switches, installed between 1960 and 1990.

In recent years, there have been instances where Statter switchgear has failed to operate requiring operating restrictions to be in place until the unit is repaired or replaced. Statter switchgear is nearing 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 a large number of customers. These will be replaced with modular secondary class circuit breakers to maintain reliability levels. There is an ongoing programme for the replacement of Statter switchgear which is planned for completion in the 2027 calendar year.

Renewal and Refurbishment

HV Distribution Switchgear (Ground Mounted)

As noted above, this section excludes zone substation circuit breakers, which are discussed in Section 7.5.2.2.

Any minor defects or maintenance issues are addressed on-site during inspections. This may include such maintenance as topping up oil reservoirs, replacing bolts, rust treatment and paint repairs. Major issues that cannot be addressed on site usually result in replacement of the device. In addition to previously identified programmes for replacing specific switchgear, WELL has an ongoing refurbishment and replacement programme for other ground mounted distribution switchgear.

Oil insulated switchgear is no longer installed, with vacuum or gas (SF_6) insulated types now being used. WELL has also recently approved the use of newer types of solid insulation ring main units. In rare cases, when any switchgear device fails, the reason for the failure is studied and a 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 are being replaced based on the risk assessment for that type.

Significant projects for the renewal of ground mounted switchgear over the next 12 months are listed in Table 7-45.

Project	Description
DSIR Computer Substation	Replacement of Long and Crawford switchgear
WR Grace C Substation	Replacement of 11kV switchgaer
Mountbatten Grove A Substation	Replacement of 11kV switchgear
Shell Substation	Replacement of 11kV switchgear

Table 7-45 Ground Mounted Switchgear Projects for 2022/23

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 Southern Area has a large number of open LV distribution boards in substations and a safety programme to cover these with clear Perspex covers has been completed. WELL prohibits live work between the transformer bushings and the low voltage fusegear, and work in situations where items may contact live busbars.

The overall performance of LV distribution switchgear and fusing is good and there are no programmes underway to replace this equipment.

Expenditure Summary for Ground-mounted Switchgear

Table 7-46 details the expected expenditure on ground-mounted switchgear by regulatory year.

Expenditure Type	2022/23	2023/24	2024/25	2025/26	2026/27	2027/28	2028/29	2029/30	2030/31	2031/32
Long and Crawford Replacement Programme	229	-	-	-	-	-	-	-	-	-
Statter Replacement Programme	1,352	2,473	2,436	2,456	2,643	1,542	-	-	-	-
Partial Discharge Mitigation	300	300	300	300	300	300	300	300	300	300
Other Asset Replacement and Renewal Capex	540	643	624	604	580	2,552	3,347	3,320	3,340	3,343
Reactive Capital Expenditure	400	400	400	400	400	400	400	400	400	400
Capital Expenditure Total	**2,821**	**3,816**	**3,760**	**3,760**	**3,923**	**4,794**	**4,047**	**4,020**	**4,040**	**4,043**
Preventative Maintenance	527	475	577	295	393	472	417	501	279	360
Corrective Maintenance	400	400	400	400	400	400	400	400	400	400
Operational Expenditure Total	**927**	**875**	**977**	**695**	**793**	**872**	**817**	**901**	**679**	**760**

Table 7-46 Expenditure on Ground-mounted Switchgear ($K in constant prices)

7.5.6.1 Low Voltage Pits and Pillars

Fleet Overview

Pillars and pits provide the point for the connection of customer service cables to the WELL 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 18,570 LV units (link pillars, pits, cabinets, under veranda boxes, and boards) in service on WELL's network. These are used to parallel adjacent LV circuits to provide back feeds during outages, as well as providing the ability to sectionalise large LV circuits. A high-level breakdown of types is listed in Table 7-47.

Type	Quantity
Customer service pillar	14,094
Customer service pit	2,604
Link pillars, pits and cabinets	1,872
Total	**18,570**

Table 7-47 Summary of LV Units

An age profile of LV Units (pillars, pits, cabinets and boards) is shown in Figure 7-28.[24]

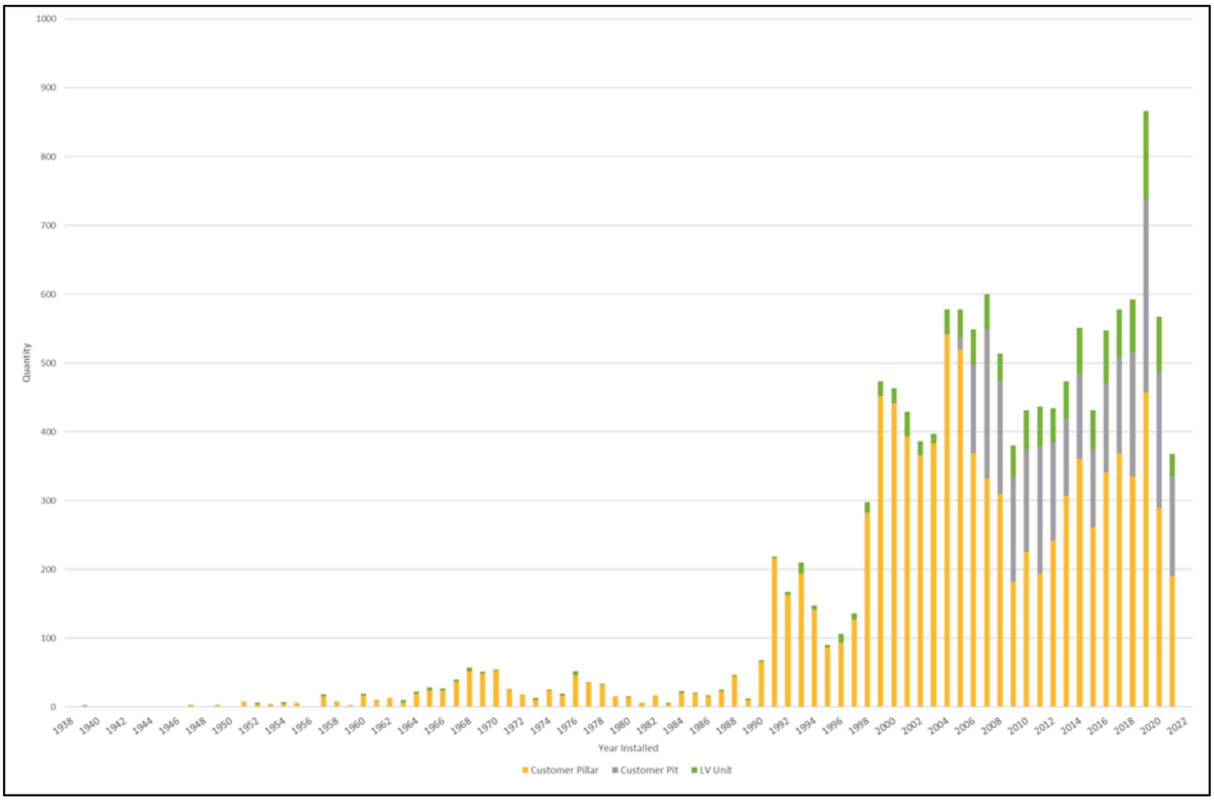


Figure 7-28 Age Profile of Pillars, Pillars and Cabinets

Fleet Objectives

In addition to WELL's broader asset management objectives that apply across the entire network, WELL has the following fleet-specific objectives for low voltage equipment:

Priority Area	Objective
Safety and Environment	No injuries resulting from working on and around LV units. LV units located in Road Reserve to not be a risk to public safety.

Table 7-48 Fleet Specific Objectives for Low Voltage Equipment

Maintenance Activities

The following routine planned inspection and maintenance activities are undertaken on low voltage pits and pillars, for either customer service connection and fusing or network LV linking:

[24] There are 4,678 low voltage pillars, pits, cabinets and LV boards that have unknown installation dates and these have not been included in the age profile.

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

Table 7-49 Inspection and Routine Maintenance Schedule for LV Pits and Pillars

WELL includes a loop impedance test to check the condition of the connections from the fuses to the source in its underground pillars inspection regime. Where practical, damaged pillars are repaired but otherwise a new pillar or a pit is installed.

Renewal and Refurbishment

Pillars are generally replaced following faults or reports of damage. Pillars with a high likelihood of future repeat damage by vehicles are replaced with pits. When large groups of older pillars, such as concrete or 'mushroom' type, are located and their overall condition is poor they are replaced as repair is impractical or uneconomic.

There are a number of different variants of service connection pillars on the network that are being replaced in small batches, particularly under-veranda service connection boxes in older commercial areas.

There is an ongoing replacement of underground link boxes around Wellington City driven by the condition of some of these assets. The link boxes are either jointed through, where the functionality is no longer required, or replaced entirely to provide the same functionality. Link boxes are replaced following an unsatisfactory inspection outcome, and it is expected that fewer than 10 will require replacement every year.

Expenditure Summary for Low Voltage Pits and Pillars

Table 7-50 details the expected expenditure on low voltage pits and pillars by regulatory year.

Expenditure Type	2022/23	2023/24	2024/25	2025/26	2026/27	2027/28	2028/29	2029/30	2030/31	2031/32
Asset Replacement and Renewal Capex	150	150	150	150	150	150	150	150	150	150
Reactive Capital Expenditure	1,400	1,400	1,400	1,400	1,400	1,400	1,400	1,400	1,400	1,400
Capital Expenditure Total	**1,550**	**1,550**	**1,550**	**1,550**	**1,550**	**1,550**	**1,550**	**1,550**	**1,550**	**1,550**
Preventative Maintenance	150	150	150	150	150	150	150	150	150	150
Corrective Maintenance	120	120	120	120	120	120	120	120	120	120
Operational Expenditure Total	**270**	**270**	**270**	**270**	**270**	**270**	**270**	**270**	**270**	**270**

Table 7-50 Expenditure on Low Voltage Pits and Pillars ($K in constant prices)

7.5.7 Pole-mounted Distribution Switchgear

7.5.7.1 Reclosers and Gas Switches

Fleet Overview

Automatic circuit reclosers are pole mounted circuit breakers that provide protection for the rural 11 kV overhead network. The majority of the 17 reclosers on the network are vacuum models with electronic controllers, with only one being an older hydraulic type. The individual types of auto-reclosers are shown in the Table 7-51.

Manufacturer	Insulation	Model	Quantity
G&W	Solid/Vacuum	ViperS	16
Reyrolle	Oil	OYT	1
Total			**17**

Table 7-51 Summary of Recloser Types

The age profile of WELL's reclosers is shown in Figure 7-29.

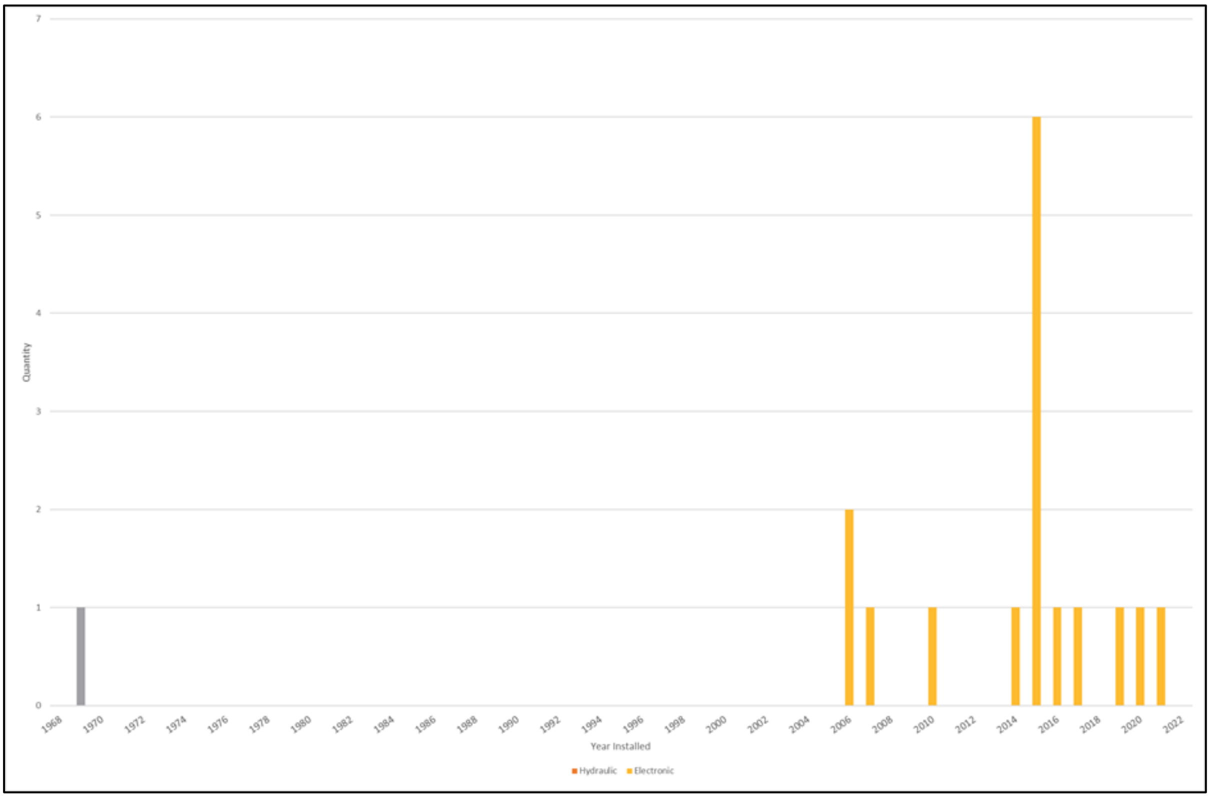


Figure 7-29 Age Profile of Reclosers

Fleet Objectives

In addition to WELL's broader asset management objectives that apply across the entire network, WELL has the following fleet-specific objectives for reclosers:

Priority Area	Objective
Safety and Environment	Ensure use of reclosing complies with best industry practice for public safety.
Customer	Ensure reclosers are functioning correctly to minimise customer disruption.

Table 7-52 Fleet Specific Objectives for Reclosers

Maintenance Activities

The following routine planned inspection, testing and maintenance activities are undertaken on reclosers:

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 Operational Check	Bypass unit or back feed, arrange remote and local operation in conjunction with NCR to ensure correct operation and indication.	Annually
Recloser Service	Maintenance of hydraulic recloser, inspect and maintain contacts, change oil as required, prove correct operation.	3 yearly
Inspection and Testing of Batteries	Routine visual inspection of batteries, chargers and associated equipment inside electronic recloser control panel. Discharge test of batteries to confirm health	1 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

Table 7-53 Inspection and Routine Maintenance Schedule for Auto Reclosers

Renewal and Refurbishment

One major contributor towards network performance in rural areas is having reliable and appropriately placed reclosers in service. The majority of the units in service are relatively new, in good condition and performing as expected, however all types of hydraulic recloser have experienced failures in recent years. Refurbishment proved ineffective at returning failed hydraulic reclosers to effective service, and units have proactively been replaced with electronic reclosers, with the final unit planned for replacement during 2021.

Due to the high number of customers being interrupted under fault conditions, the number of reclosers installed on the system was reviewed in 2018. A standard defining the optimal number and placement of sectionalising devices such as reclosers was published in 2018 which will assist in defining these numbers going forward.

Expenditure Summary for Reclosers

Table 7-54 details the expected expenditure on reclosers by regulatory year.

Expenditure Type	2022/23	2023/24	2024/25	2025/26	2026/27	2027/28	2028/29	2029/30	2030/31	2031/32
Asset Replacement and Renewal Capex	-	-	-	-	-	-	-	-	-	-
Capital Expenditure Total	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**
Preventative Maintenance	9	10	11	12	12	13	14	15	15	15
Corrective Maintenance	10	10	10	10	10	10	10	10	10	10
Operational Expenditure Total	**19**	**20**	**21**	**22**	**22**	**23**	**24**	**25**	**25**	**25**

Table 7-54 Expenditure on Reclosers
($K in constant prices)

7.5.7.2 Overhead Switches, Links and Fuses

Fleet Overview

Overhead switchgear is used for breaking the overhead network into sections, and providing protection to pole mounted distribution transformers, and cables at overhead to underground transition points. A summary of the quantities of different categories of overhead switches is shown in Table 7-55.

Category	Quantity
Gas Switches	75
Air Break Switches	297
Knife Links	28
Dropout Fuses	2,208
Dropout Sectionalisers	11
Total	**2,619**

Table 7-55 Summary of Pole Mounted Distribution Switchgear

The age profiles of these devices are shown in Figure 7-30.

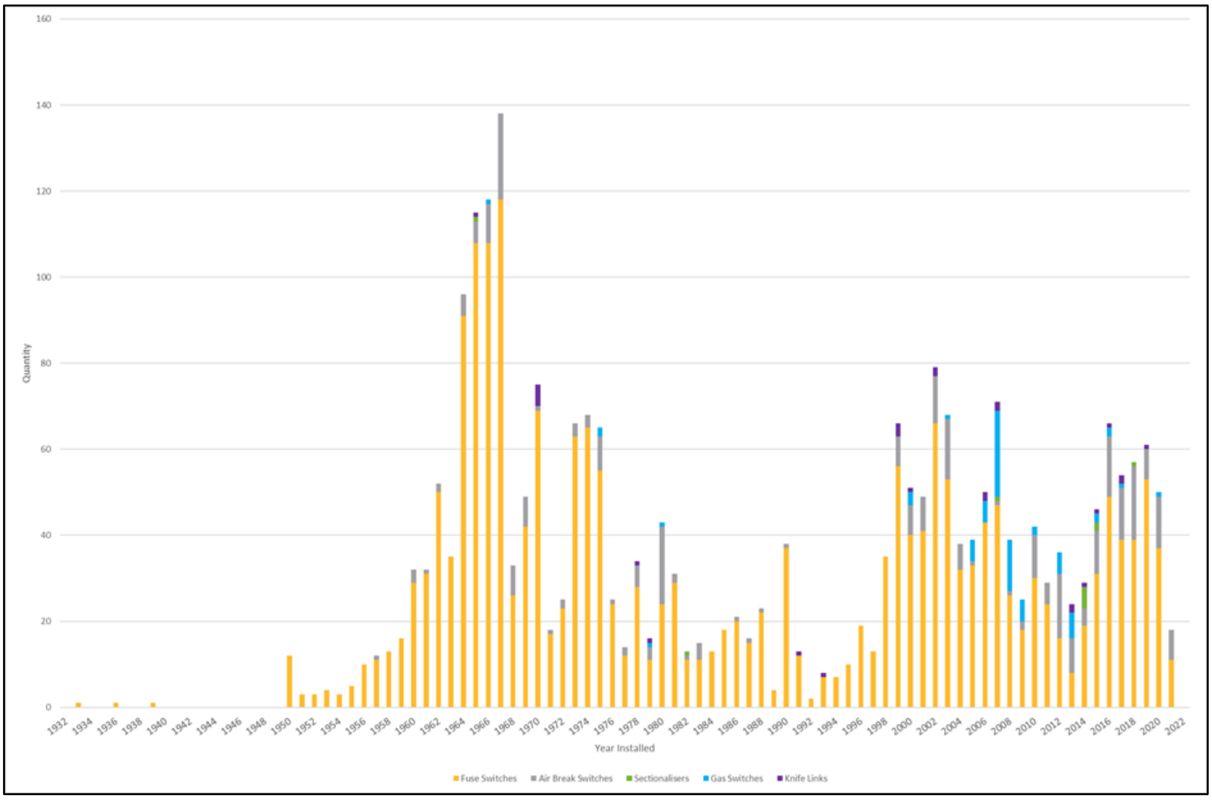


Figure 7-30 Age Profile of Overhead Switchgear and Devices

Fleet Objectives

In addition to WELL's broader asset management objectives that apply across the entire network, WELL has the following fleet-specific objectives for pole mounted switchgear:

Priority Area	Objective
Safety and Environment	No injuries resulting from working on and around overhead switchgear. Overhead switchgear located in Road Reserve to not be a risk to public safety.

Table 7-56 Fleet Specific Objectives for Pole Mounted Switchgear

Maintenance Activities

The following routine planned inspection, testing and maintenance activities that are undertaken on overhead switches, links and fuses are shown in Table 7-57.

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 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

Table 7-57 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 the annual overhead line survey. The large quantity and low risk associated with fuses does not justify an independent inspection and maintenance programme.

Condition of Overhead Switches, Links and Fuses

Generally, the condition of overhead equipment on the network is good. The environment subjects equipment to wind, salt spray, pollution and debris, which causes a small number of units to fail annually. Common modes of deterioration are corrosion of steel frame components and operating handles, mechanical damage to insulators, as well as corrosion and electrical welding of contacts. In harsh environments, fully enclosed gas insulated switches with stainless steel components are used.

A problem has previously been identified with in-line links, which started to show signs of failure when used on copper conductor and subjected to fault currents. This situation was monitored over the course of 2017 and a specialist metallurgist was engaged to identify the root cause of failures. The analysis undertaken has shown that the common point of failure has been on temporary links and the application techniques of live line clamps. A temporary suspension on the use of in-line links (and removal of those that were already on the network) was put in place until better quality assurance processes with regards to installation were agreed with the field services provider.

The coastal environment around Wellington causes accelerated corrosion on galvanised overhead equipment components and, where possible, stainless steel fittings are used as they have proven to provide a longer and more cost effective solution.

The forecast future condition of the overhead switch fleet is modelled using survival curves, shown in Figure 7-31. The survival curve is based on the age at which switches have been replaced.

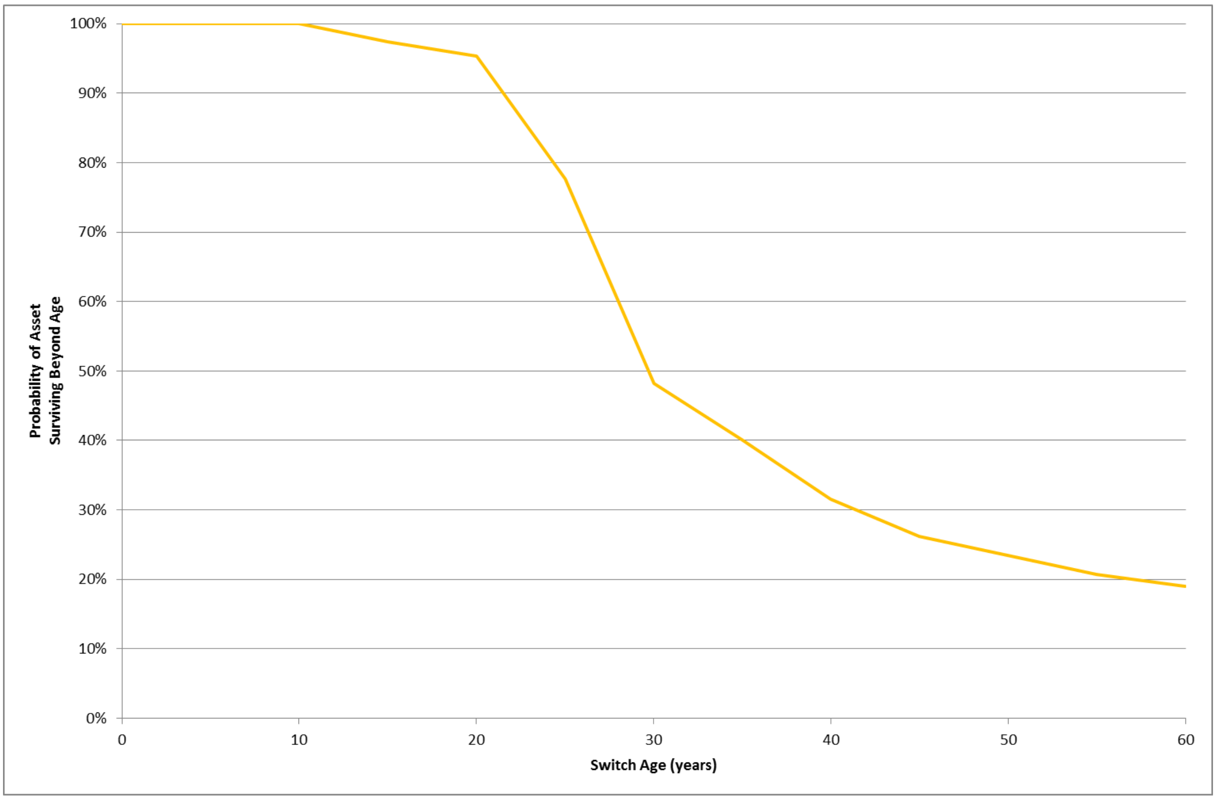


Figure 7-31 Overhead Switch Survival Curve

Renewal and Refurbishment

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 as reactive capital expenditure following a poor condition assessment result from the routine inspections, or at the time of pole or cross arm replacement if the condition of the switch justifies this at that time.

The forecast number of overhead switch replacements per year is forecast by rolling the population through the survival curve.

Expenditure Summary for Overhead Switchgear

Table 7-58 details the expected expenditure on overhead switchgear by regulatory year.

Expenditure Type	2022/23	2023/24	2024/25	2025/26	2026/27	2027/28	2028/29	2029/30	2030/31	2031/32
Reactive Capital Expenditure	91	94	100	104	117	123	138	170	181	179
Capital Expenditure Total	**91**	**94**	**100**	**104**	**117**	**123**	**138**	**170**	**181**	**179**
Preventative Maintenance	150	150	150	150	150	150	150	150	150	150
Corrective Maintenance	25	25	25	25	25	25	25	25	25	25
Operational Expenditure Total	**175**	**175**	**175**	**175**	**175**	**175**	**175**	**175**	**175**	**175**

Table 7-58 Expenditure on Overhead Switchgear
($K in constant prices)

7.5.8 Other System Fixed Assets

7.5.8.1 Substation DC Systems

Fleet Overview

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. WELL has a number of historic DC system voltages within its substations, including 24V, 30V, 36V, 48V, and 110V, however 24V has been adopted as the standard for all new or replacement installations.

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
10 Second battery discharge test.	10 second battery discharge test for battery banks rated less than 65 Ah, measurement and reporting of results.	Annually
Comprehensive battery discharge test.	Comprehensive battery discharge test for battery banks rated 65 Ah and larger, measurement and reporting of results.	2 yearly

Table 7-59 Inspection and Routine Maintenance Schedule for Zone Substation Battery Banks

Valve regulated lead acid batteries are now the only type of battery used. Maintenance is based on the recommendations of IEEE–1188 (IEEE Recommended Practice for Maintenance, Testing and Replacement of Valve Regulated Lead Acid Batteries for Stationary Applications).

Battery and Charger Condition

The overall condition of the battery population is very good. Battery chargers are also generally in good condition. Many have SCADA supervision so the NCR is notified if the charger has failed. Given the low value and high repair cost of battery chargers, they are repaired only where it is clearly economic.

Battery Replacement

WELL has a total of 552 battery banks across 297 sites. Batteries are a critical system for substation operation, but are low cost items. WELL's policy is that all batteries are replaced at 80% of their design life rather than implementing an extensive testing regime. For sites with higher ampere-hour demand, 10-year life batteries are used. For smaller sites, or communications batteries where the demand is lower, batteries are installed with 5-year lives. WELL is standardising the voltages used for switchgear operation as well as communications equipment as part of primary plant replacement.

Expenditure Summary for Substation Batteries

Table 7-60 details the expected expenditure on substation batteries by regulatory year.

Expenditure Type	2022/23	2023/24	2024/25	2025/26	2026/27	2027/28	2028/29	2029/30	2030/31	2031/32
Asset Replacement and Renewal Capex	250	250	250	250	250	250	250	250	250	250
Capital Expenditure Total	**250**	**250**	**250**	**250**	**250**	**250**	**250**	**250**	**250**	**250**
Preventative Maintenance	72	72	72	72	72	72	72	72	72	72
Corrective Maintenance	10	10	10	10	10	10	10	10	10	10
Operational Expenditure Total	**82**	**82**	**82**	**82**	**82**	**82**	**82**	**82**	**82**	**82**

Table 7-60 Expenditure on Substation Batteries ($K in constant prices)

7.5.8.2 Protection Devices

Fleet Overview

Protection devices are assets that automatically detect abnormal conditions and indicate a potential primary equipment fault. This ensures that the system remains safe, stable, and that damage to equipment is minimised whilst service life is maximised. Protection assets are also installed to limit the number of customers affected by an equipment failure.

On the HV system there are 1,445 protection devices in operation. The majority of these are electromechanical devices. The remainder use solid state electronic or microprocessor technology. Protection devices are generally mounted as part of a substation switchboard but can also be housed in dedicated panels.

WELL has assigned a Tier system to differentiate between the various sections of the distribution network as presented in Figure 7-32. This serves to enable a clear reference for asset management planning and expenditure forecasting. The types of protective devices and their individual applications vary dependant on the level of security required and the risk to supply.

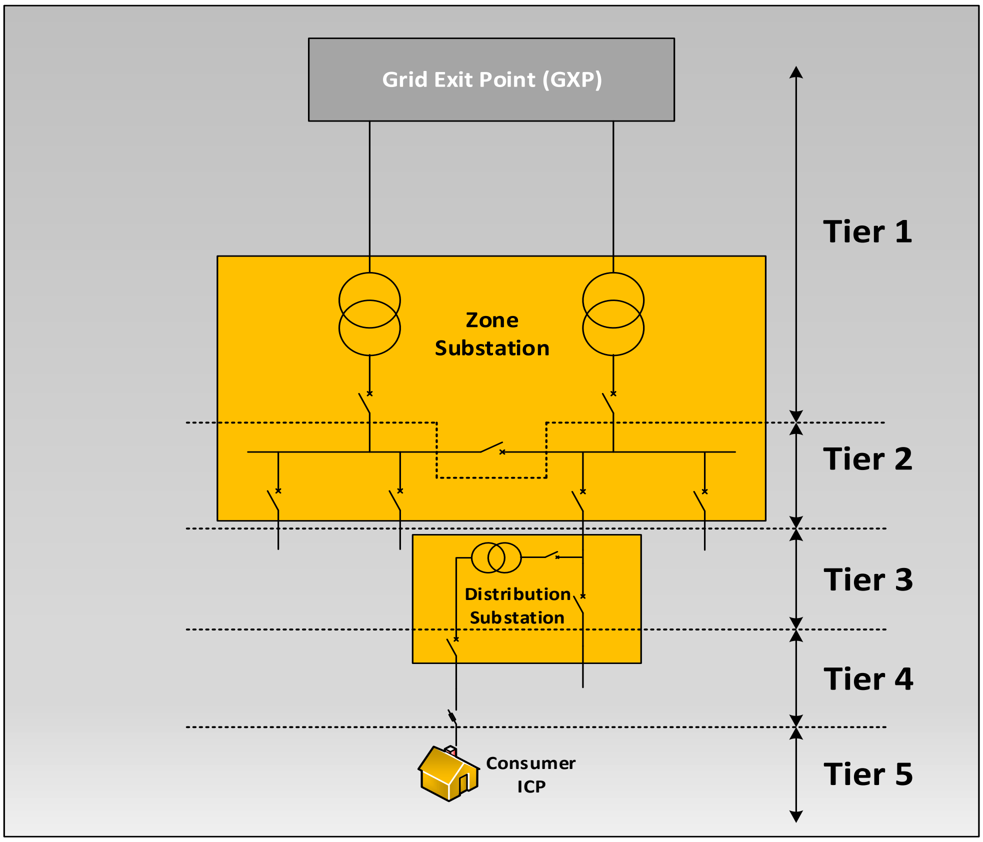


Figure 7-32 WELL Protection Tier System

Differential protection is used on all Tier 1 systems across the network and is also widely used on Tier 2 systems in the Southern Area This is to provide the optimum level of protection when running a closed ring network topology. 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) protection is employed.

Outside of the Southern Area, Tier 2 is generally enabled with OC/EF protection, supplemented by auto-reclosers on rural feeders, and fuses on rural spur lines.

Fuses are used for protection of 11kV distribution transformers up to 1 MVA, with OC/EF relays protecting larger transformers. Fuses are generally used on the LV system for the protection of cables and LV equipment however Low Voltage Circuit Breakers are also used where larger transformers pose increased arc flash risk or where there are special considerations such as bi-directional powerflow.

Automatic Under Frequency Load Shedding (AUFLS) relays are installed at 19 zone substations. These are programmed to trip feeders in the event of the system frequency dropping below certain set points, as required by the System Operator.

The age profiles of these devices are shown in Figure 7-33.

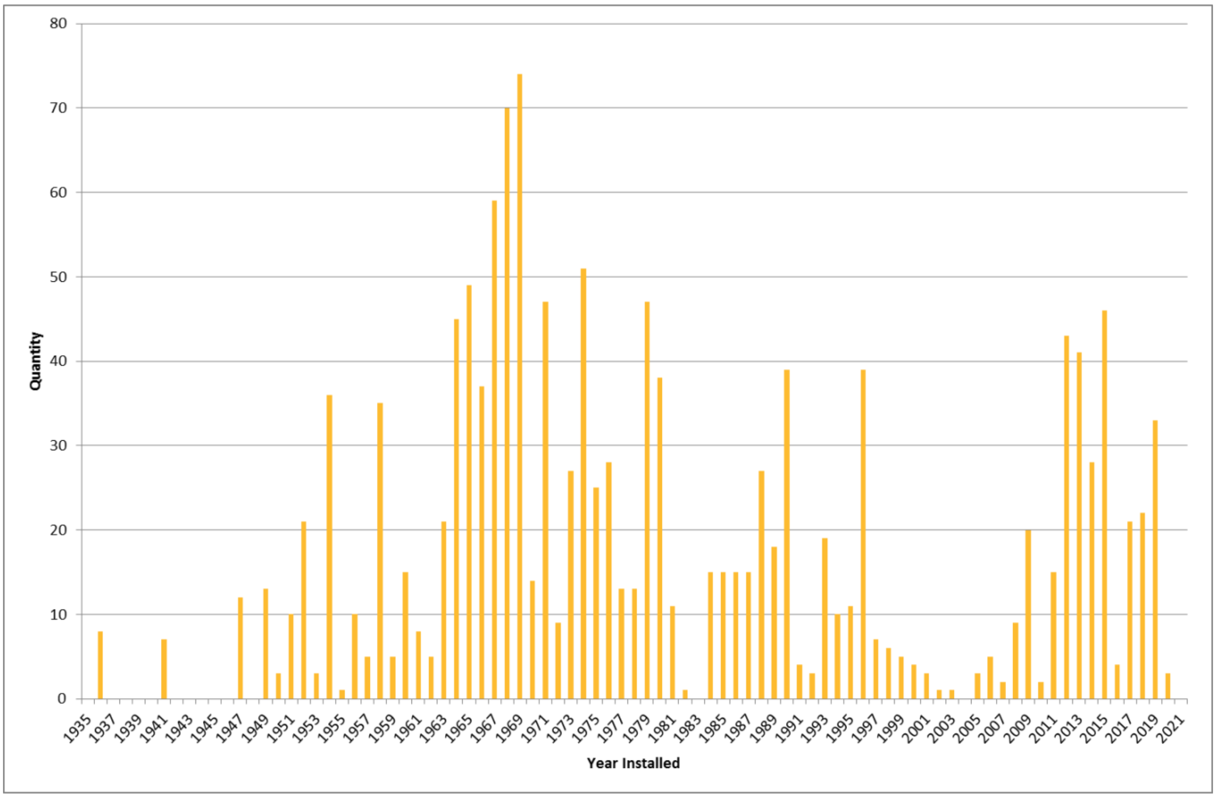


Figure 7-33 Age Profile of Protection Relays

The WELL Network Protection Standard can be referred to for a more detailed account of the protection devices and systems that are used on the WELL network and their application.

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 (Tier 1 & 2) 5 yearly (Tier 3)
Protection Testing for Numerical Devices	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 (Tier 1 & 2) 5 yearly (Tier 3)
Numerical Relay Battery Replacement	Replacement of backup battery in numeric relay.	4 yearly (Tier 1 & 2) 5 yearly (Tier 3)

Table 7-61 Inspection and Routine Maintenance Schedule for Protection Relays

The testing of differential protection also serves to test the copper pilot cables between substations. Upon a failed test, the degree of health is assessed against the requirements of the device type and the protection service is either moved to healthy conductors on the pilot cable or the cable is flagged for repairs. Due to deteriorating outer sheaths on pilot cables, some early pilot cables are now suffering from moisture ingress and subsequent degradation of insulation quality and these are attended to by either moving the pilot routes or repairing and replacing cables.

Renewal and Replacement

WELL takes a risk-based approach to protection device replacement strategies. Generally, protective devices have a long service life and WELL's fleet is in good condition. Rarely does a protective device fail in-service, and deterioration is identified during routine maintenance testing.

Once a device has been identified as unable to perform its primary function, it is replaced immediately using a critical spare. If the performance is adequate but showing signs of deterioration, the device is earmarked to be included into existing replacement programs. The protection replacement programmes focus on device condition, functionality and the inherent risk posed to the network. Replacement is often coordinated with other projects especially for assets such as switchgear and transformers.

Tier 1 protection has the highest importance and requires the greatest level of security, therefore has a higher priority for replacement. At the time of primary equipment replacement, if required, the opportunity is taken to upgrade associated protection schemes to meet the current standards. To date, electromechanical devices have provided reliable service and are expected to remain in service for the life of the switchgear they are housed in. For newer numeric devices, it is not expected that they will provide the same length of service as the switchgear.

The following programmes and projects are included in the asset replacement[25] and maintenance budgets:

- Ongoing replacement of devices with identified risk;
- Annual preventative maintenance program;
- Tier 1 replacement programme;
- Tier 2 replacement programme; and
- Tier 3 replacement programme.

In addition to replacement programs, WELL is adhering to a philosophy of continuous improvement by reviewing and optimising protection management processes and creating application guides, testing and commissioning documents.

Expenditure Summary for Protection Relays

Table 7-62 details the expected expenditure on protection relays by regulatory year.

[25] The Authority is proposing to replace AUFLS with an Extended Reserves scheme. This may require replacement of existing AUFLS relays in order to meet the new requirements, however the timing, technical specifications and funding mechanisms for this are not currently known, and as such this work has not been included in this AMP.

Expenditure Type	2022/23	2023/24	2024/25	2025/26	2026/27	2027/28	2028/29	2029/30	2030/31	2031/32
Tier 1 Replacement Programme	400	400	800	800	800	800	-	-	-	-
Tier 2 Replacement Programme	300	300	300	300	300	300	600	600	600	600
Tier 3 Replacement Programme	-	-	-	-	-	300	300	300	300	300
Capital Expenditure Total	**700**	**700**	**1100**	**1100**	**1100**	**1400**	**900**	**900**	**900**	**900**
Preventative Maintenance	130	130	130	130	130	130	130	130	130	130
Corrective Maintenance	10	10	10	10	10	10	10	10	10	10
Operational Expenditure Total	**140**	**140**	**140**	**140**	**140**	**140**	**140**	**140**	**140**	**140**

**Table 7-62 Expenditure on Protection Relays
($K in constant prices)**

7.5.8.3 SCADA and Communications Assets

Fleet Overview

The WELL Supervisory Control and Data Acquisition (SCADA) system comprises a series of communication assets, housed in different locations, and interlinked using several media types. The Master Station is at the top of the topology and there are many other components scaling down to the end device known as the Remote Terminal Unit (RTU). The SCADA Master Station is a GE PowerOn Fusion system, commissioned in early 2016. A legacy Foxboro system has been retained to provide the automatic load control function until an alternative system is implemented. Both the SCADA and Load Control Master Stations are being considered for replacement, with more detail provided in Section 10.

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 field equipment at sites provisioned for SCADA. More specifically, SCADA is used to:

- Monitor the operation of the HV network from a central control room by remotely indicating key parameters such as voltage and current at key locations;
- Permit the remote control of selected field 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 RTUs at each remote location and is transmitted to the SCADA master station through dedicated communication links. Control signals travel in the opposite direction over the same communications links.

The most common communication links are copper pilot and fibre optic cables. Typically the copper pilots are WELL owned while some of the fibre links are WELL owned and others are under lease agreements.

An age profile of SCADA RTUs is shown in Figure 7-.

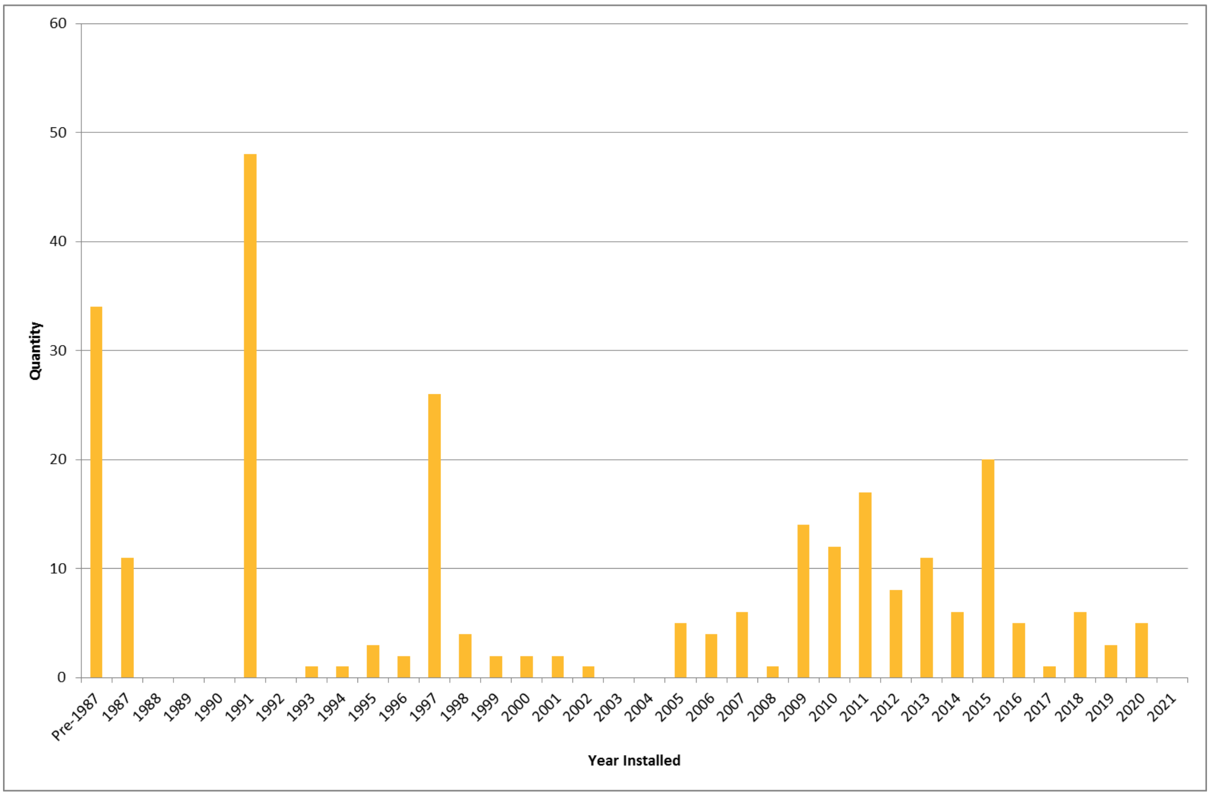


Figure 7-34 Age Profile of SCADA RTUs

To date, WELL has approximately 275 SCADA provisioned sites, utilising multi-generational RTUs and communication protocols.

Maintenance Activities

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. Maintenance is broken into two categories:

(a) Hardware support is provided as required by Wellington based maintenance contractors; and

(b) Software maintenance and support is provided by external service providers.

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 by the respective service providers of the IP network infrastructure.

The SCADA front end processors have Uninterruptible Power Supply (UPS) systems to provide backup supply and there is a UPS system providing supply to the operator terminals in the NCR. This is subject to a maintenance programme provided by the equipment supplier. In addition, these units have their self-diagnostics remotely monitored and have dual redundancy of converters and batteries to provide a high level of supply security in the unlikely event of failure.

SCADA System Component Challenges

SCADA Radio

Analogue radio is still used by WELL to service a small number of non-critical sites via the Conitel protocol. Along with the age of equipment and availability of spares, there are a number of constraints to using such a system which include limited address range, no time stamping, and a diminishing capability of interfacing with devices. New sites utilising radio are implemented using public cellular infrastructure on a private APN.

Legacy Remote Terminal Units (RTUs)

Many legacy RTUs remain in service on the network. These legacy devices are no longer manufactured and are difficult to repair, so as they fail they are interchanged with modern alternatives.

Common Alarms

Many Common Alarm units remain in service on the network. These are a custom-built device, placed in non-critical "ringed" distribution substations to give an indication to the NCR of a substation event. These units are not economically viable to repair and have low functionality, and there is an active programme to replace these units with modern RTUs.

PAS Replacement Project

There are two Siemens Power Automation System (PAS) units that act as a protocol converter between Siemens IEC61850 field devices located at three sites and the DNP3.0 SCADA master station. The PAS units are now end of life and work is underway to replace them.

Renewal and Refurbishment

The asset replacement budget provides for the ongoing replacement of obsolete RTUs throughout the network. Obsolete RTUs that may have a significant impact on network reliability are identified, with replacement priority being given to the zone and major switching substations.

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

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 to improve communication system reliability. Furthermore, the TCP/IP infrastructure will also allow other non-SCADA substation-based equipment to be deployed.

The priority of the substation RTU replacement programme will align with other secondary asset replacement programmes. An RTU replacement 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.

The following programmes and projects are included in the asset replacement and maintenance budgets:

- Zone RTU Replacement Programme;
- Common Alarm Replacement Programme;
- Distribution RTU Replacement;
- Conitel Replacement;

- Substation Data Network Augmentation, and
- End of Life RTU Replacement (Reactive).

Expenditure Summary for SCADA and Communications Assets

Table 7-63 details the expected expenditure on SCADA and communications assets by regulatory year.

Expenditure Type	2022/23	2023/24	2024/25	2025/26	2026/27	2027/28	2028/29	2029/30	2030/31	2031/32
Zone RTU Replacement Programme	700	-	700	700	350	-	-	-	-	-
Common Alarm Replacement Programme	120	240	240	240	240	240	240	240	240	240
Distribution RTU Replacement Programme	-	200	200	200	200	200	200	200	200	200
Conitel Replacement	-	-	-	-	150	300	300	300	300	300
Substation Data Network	800	2,800	-	500	500	500	500	500	500	500
Reactive Capital Expenditure	100	100	100	100	100	100	100	200	200	200
Capital Expenditure Total	**1,720**	**3,340**	**1,240**	**1,740**	**1,540**	**1,340**	**1,340**	**1,440**	**1,440**	**1,440**
Corrective Maintenance	20	20	20	20	20	20	20	20	20	20
Operational Expenditure Total	**20**	**20**	**20**	**20**	**20**	**20**	**20**	**20**	**20**	**20**

Table 7-63 Expenditure on SCADA and Communications Assets ($K in constant prices)

7.5.9 Other Network Assets

7.5.9.1 Metering

WELL does not own any metering assets on customer premises as these are owned by retailers and metering service provider companies.

WELL-owned check meters are installed at GXPs, and Maximum Demand Indicator (MDI) meters are installed in a 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 customer 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. This is further discussed in Section 9.

Check meters are not proactively maintained; however their output is continuously monitored by SCADA and compared to the Transpower revenue meters. Alarms are triggered where the discrepancy between the Transpower revenue meters and WELL's check meters exceeds an acceptable tolerance.

7.5.9.2 Generators and Mobile Substations

WELL owns six mobile generators and a fixed generator supporting the disaster recovery control room site. WELL makes use of one of the mobile generators at its corporate office and two at its disaster recovery data centres, while the others are used to reduce the impact of outages on customers. WELL also owns two mobile 33/11 kV 10MVA mobile substations, and one mobile 11 kV switchboard.

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

7.5.9.3 Voltage Regulation

Voltage is regulated at the zone substations using Automatic Voltage Regulator Relays (AVRRs) to control the power transformer tap changer. Several sites have been identified as having AVRRs which are no longer supported by suppliers and a risk upon failure.

7.5.9.4 Load Control Equipment

Fleet Overview

WELL 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 customer premises, to control street lighting and also to provide tariff signalling on behalf of retailers using the network. All ripple injection is controlled automatically by the Foxboro master station but can also be controlled remotely from the NCR.

There are 25 ripple injection plants on the network, predominantly located at GXPs and zone substations. The Southern area has a 475Hz signal injected into the 33 kV network with one plant for each of the Wilton and Central Park GXPs and two plants injecting at the Kaiwharawhara 11 kV point of supply. The Northeast and Northwest areas have a 1050Hz signal injected at 11 kV at each zone substation.

An age profile of ripple plant is shown in Figure 7-.

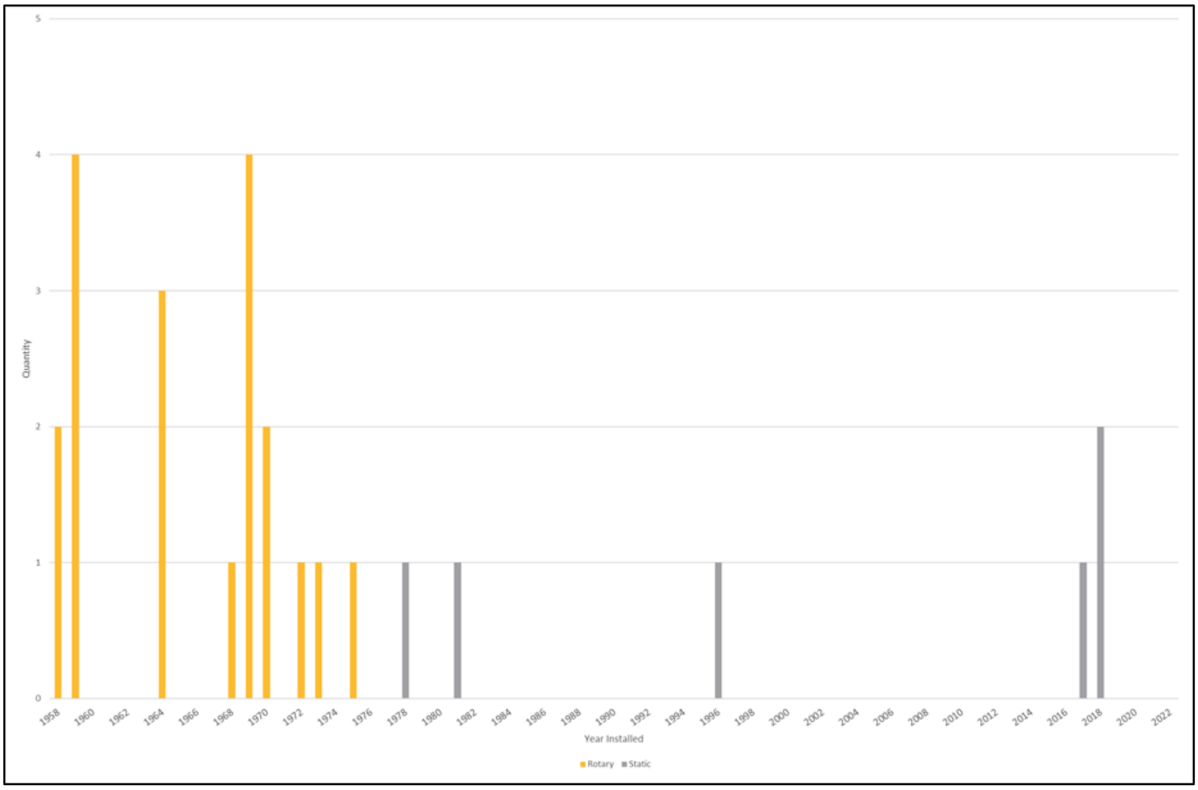


Figure 7-35 Age Profile of Ripple Plant

Maintenance Activities

The following routine planned inspection, testing and maintenance activities are undertaken on load control equipment. WELL owns the injection plants located at substations and the blocking cells at GXPs, but does not own the customer receivers.

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

Table 7-64 Inspection and Routine Maintenance Schedule for Ripple Plant

Strategic Spares

The spares held for load control plant is shown in Table 7-65.

Strategic Spares	
Injection plant	A spare 24kVA rotary motor-generator set is held for the 11 kV ripple system in the Hutt Valley. The spare 300kVA solid state transmitter at Frederick Street was used in 2017 during a breakdown. A new spare has been sourced and purchased. An assortment of coupling cell equipment is held in store.
Controllers	A spare Load Control PLC is kept as a strategic spare.

Table 7-65 Spares Held for Load Control Plant

Renewal and Refurbishment

The existing load control plant is generally reliable, with repairs and maintenance undertaken as required. WELL has no immediate plans to replace any ripple injection plant due to age or condition but is currently reviewing its load control asset strategy which may recommend investment during the planning period. This is discussed in Section 9.

Primary Equipment

The rotary injection plants in the Hutt Valley area, while old, are easily maintained and repaired. Interconnectivity at 11 kV allows the ripple signal to be provided from adjacent substations in the event of failure. The load on the plants has increased over the years and at some sites the coupling capacitors have been identified as a risk and are replaced with suitably sized units.

Load Control Master Station

The load control master station is planned for replacement in 2024. This is discussed in Section 10.

Load Control Programmable Logic Controller (PLC)

The load control PLCs are housed at the site of ripple injection and are responsible for coordinating the onsite operation of the ripple plant. These are at the end of their technical life and a replacement programme has been developed.

Expenditure Summary for Other Network Assets

Table 7-66 details the expected expenditure other network assets by regulatory year.

Expenditure Type	2022/23	2023/24	2024/25	2025/26	2026/27	2027/28	2028/29	2029/30	2030/31	2031/32
Load Control PLC Replacement Programme	-	-	-	-	-	120	120	120	120	120
Reactive Capital Expenditure	300	300	300	300	300	300	300	300	300	300
AVRR Replacement Programme	125	125	125	125	125	-	-	-	-	-
Capital Expenditure Total	**425**	**425**	**425**	**425**	**425**	**420**	**420**	**420**	**420**	**420**
Preventative Maintenance	68	68	68	68	68	68	68	68	68	68
Corrective Maintenance	100	100	100	100	100	100	100	100	100	100
Operational Expenditure Total	**168**	**168**	**168**	**168**	**168**	**168**	**168**	**168**	**168**	**168**

Table 7-66 Expenditure on Other Network Assets ($K in constant prices)

7.5.10 Assets Located at Bulk Electricity Supply Points Owned by Others

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

7.5.10.1 33 kV and 11 kV Lines, Poles and Cables

WELL 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.

7.5.10.2 11 kV switchgear

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

7.5.10.3 Protection Relays and Metering

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

7.5.10.4 SCADA, RTUs and Communications Equipment

WELL owns SCADA RTUs and associated communications equipment at all GXPs.

7.5.10.5 DC Power Supplies and Battery Banks

WELL owns battery banks and DC supply equipment at all GXPs.

7.5.10.6 Load Control Equipment

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

7.6 Asset Replacement and Renewal Summary for 2022-2032

The total projected capital budget for asset replacement and renewal for 2022 to 2032 is presented in Table 7-67. This includes provisions for replacements that arise from faults and condition assessment programmes during the year. For the later years in the planning horizon, these projections are less certain in nature. Whether they proceed will depend on the risks to the network and the risks relative to other asset replacement projects. Should the consequence of failure increase, or the asset deteriorates faster than expected, then renewal may need to be brought forward. Conversely, should the risk level decrease then the project may be able to be deferred until later in the planning period or an alternative found.

Asset Category	2022/23	2023/24	2024/25	2025/26	2026/27	2027/28	2028/29	2029/30	2030/31	2031/32
Subtransmission	-	500	1,700	3,200	-	4,000	8,000	-	8,700	8,700
Zone Substations	2,685	200	200	200	200	200	200	200	2,700	4,200
Distribution Poles and Lines	6,873	7,330	7,030	6,789	7,116	7,102	6,954	6,819	6,776	6,752
Distribution Cables	2,550	2,550	2,550	2,550	2,550	3,050	3,050	3,050	3,050	3,050
Distribution Substations	4,269	4,577	4,720	4,601	4,830	5,042	5,372	5,288	5,425	4,421
Distribution Switchgear	4,462	5,460	5,410	5,414	5,590	6,467	5,735	5,740	5,771	5,772
Other Network Assets	3,095	4,715	3,015	3,515	3,315	3,410	2,910	3,010	3,010	3,010
Total	**23,934**	**25,332**	**24,625**	**26,269**	**23,601**	**29,271**	**32,221**	**24,107**	**35,432**	**35,905**

Table 7-67 System Asset Replacement and Renewal Capital Expenditure Forecast ($K in constant prices)

A breakdown of forecast preventative maintenance expenditure by asset category is shown in Table 7-68. This budget is relatively constant, and is set by the asset strategies and maintenance standards that define inspection tasks and frequencies.

Asset Category	2022/23	2023/24	2024/25	2025/26	2026/27	2027/28	2028/29	2029/30	2030/31	2031/32
Subtransmission	95	94	93	93	93	93	92	92	92	92
Zone Substations	445	445	445	445	445	445	445	445	445	445
Distribution Poles and Lines	743	732	721	712	703	701	698	697	693	686
Distribution Cables	-	-	-	-	-	-	-	-	-	-
Distribution Substations	715	715	715	715	715	715	715	715	715	715
Distribution Switchgear	836	785	888	607	705	785	731	816	594	675
Other Network Assets	270	270	270	270	270	270	270	270	270	270
Total	**3,104**	**3,041**	**3,132**	**2,842**	**2,931**	**3,009**	**2,951**	**3,035**	**2,809**	**2,883**

Table 7-68 Preventative Maintenance by Asset Category ($K in constant prices)

The forecast corrective maintenance expenditure by asset category is shown in Table 7-69. This excludes capitalised maintenance, which is instead incorporated into the Asset Renewal and Replacement expenditure forecast in Table 7-67. These forecasts are based on historical trends and forecast asset replacements, however 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.

Asset Category	2022/23	2023/24	2024/25	2025/26	2026/27	2027/28	2028/29	2029/30	2030/31	2031/32
Subtransmission	828	828	828	828	828	828	828	828	828	828
Zone Substations	405	405	405	405	405	405	405	405	405	405
Distribution Poles and Lines	892	892	892	892	892	892	892	892	892	892
Distribution Cables	67	67	67	67	67	67	67	67	67	67
Distribution Substations	600	600	600	600	600	600	600	600	600	600
Distribution Switchgear	555	555	555	555	555	555	555	555	555	555
Other Network Assets	140	140	140	140	140	140	140	140	140	140
Total	**3,487**	**3,487**	**3,487**	**3,487**	**3,487**	**3,487**	**3,487**	**3,487**	**3,487**	**3,487**

Table 7-69 Corrective Maintenance by Asset Category ($K in constant prices)

7.6.1 Reliability, Safety and Environmental Programmes for 2022-2032

Asset management expenditure that is not directly the result of asset health drivers is categorised into quality of supply and other reliability, safety and environmental expenditure. Quality of supply projects target the worst performing feeders. Other reliability, safety and environmental projects include the BAU seismic programme. The total projected capital budget for these categories is presented in Table 7-70.

Programme	2022/23	2023/24	2024/25	2025/26	2026/27	2027/28	2028/29	2029/30	2030/31	2031/32
Feeder Reliability Projects	2,097	2,094	2,094	2,242	2,288	2,334	2,382	2,497	2,713	2,854
Total Quality of Supply	**2,097**	**2,094**	**2,094**	**2,242**	**2,288**	**2,334**	**2,382**	**2,497**	**2,713**	**2,854**
Seismic Programme	458	676	-	-	-	-	-	-	-	-
Total Other Reliability, Safety and Environment	**458**	**676**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**

Table 7-70 Reliability, Safety and Environmental Capital Expenditure ($K in constant prices)

7.6.2 Asset Management Expenditure

The total capital and operational expenditure forecasts are shown in Table 7-71 and Table 7-72. The operational expenditure forecast does not include non-maintenance related operational expenditure. Service interruptions and emergency maintenance 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 down into asset category detail levels.

Category	2022/23	2023/24	2024/25	2025/26	2026/27	2027/28	2028/29	2029/30	2030/31	2031/32
Asset Replacement & Renewal	23,934	25,332	24,625	26,269	23,601	29,271	32,221	24,107	35,432	35,905
Reliability, Safety & Environment	458	676	-	-	-	-	-	-	-	-
Quality of Supply	2,097	2,094	2,094	2,242	2,288	2,334	2,382	2,497	2,713	2,854
Total Capital Expenditure on Asset Replacement Safety and Quality	**26,489**	**28,102**	**26,719**	**28,511**	**25,889**	**31,605**	**34,603**	**26,604**	**38,145**	**38,759**

Table 7-71 Asset Management Capital Expenditure Forecast ($K in constant prices)

Category	2022/23	2023/24	2024/25	2025/26	2026/27	2027/28	2028/29	2029/30	2030/31	2031/32
Service interruptions & emergency maintenance	4,754	4,741	4,744	4,733	4,737	4,737	4,737	4,737	4,737	4,737
Vegetation management	1,764	1,757	1,757	1,757	1,757	1,757	1,757	1,757	1,757	1,757
Routine & corrective maintenance and inspection maintenance	8,642	8,607	8,606	8,601	8,600	8,599	8,597	8,595	8,594	8,594
Asset replacement & renewal maintenance	990	979	975	990	985	985	985	985	985	985
Total Network Operational Expenditure	**16,150**	**16,084**	**16,082**	**16,081**	**16,079**	**16,078**	**16,076**	**16,074**	**16,073**	**16,073**

Table 7-72 Network Operational Expenditure Forecast
($K in constant prices)

Section 8

System Growth and Reinforcement

8 System Growth and Reinforcement

This section sets out WELL's network development plan over the next 10 years. The purpose of network development is to safely deliver the level of capacity and security of supply required to achieve, over the planning period, the service levels and network performance described in Sections 5 and 6.

Planning for development investment requires ongoing monitoring of the need for projects and the investment timing to ensure it is efficient and that customers are receiving the price and quality outcomes they expect.

In addition to considering historical growth trends, this 2022 AMP forecast includes confirmed and highly likely customer development projects. This forecast growth drives a need for significant projects such as the Porirua zone substation rebuild, Plimmerton zone substation upgrade and network extension, and construction of a new zone substation at Grenada to increase capacity in the surrounding areas.

Other possible customer development proposals signalled but not yet confirmed are indicated in this AMP, although they are not used to set the network development plan. WELL will continue to monitor these developments and propose appropriate network development in response to the expected demand growth.

Network reinforcement planning is also considered in conjunction with development requirements from condition-based and resiliency-based projects. The penetration of emerging technologies has a large impact on LV reticulation, with a comparatively lower impact on HV network. Timing of changes due to emerging technologies, such as electrification, will be driven by climate change policies. Section 9 presents WELL's response and initiatives relating to climate change.

WELL continues to monitor policy changes and developments in the emerging technologies space. A work programme has been initiated to carry out detailed modelling of the impacts and scope of required network upgrades to inform the funding mechanism, which is discussed in Section 9.

This section covers:

- Network planning policies and standards;
- Demand forecasting;
- System growth capex for primary assets;
- System growth capex for secondary assets; and
- System growth expenditure summary.

8.1 Network Planning Policies and Standards

The purpose of these policies and standards is to ensure the network delivers the service levels and network performance discussed in Sections 5 and 6.

The policy and standards cover the following areas:

- Security criteria – specifies the network capacity (including levels of redundancy) required to ensure the level of reliability is maintained;
- Technical standards – voltage levels, power factor and harmonic level standards to ensure the network remains safe and secure, and that overall network costs are minimised;
- Standardised designs – these reduce design costs and minimise spare equipment holding costs, leading to lower overall project and maintenance costs;
- The impact of embedded generation on planning;
- The use of non-network solutions within the planning process;
- The definition of asset capacity utilised for planning purposes; and
- Demand forecasting policies and methodology.

Each of these is discussed in the following sections.

8.1.1 Security Criteria

The design of WELL's network is based on the security criteria shown in Table 8-1 (subtransmission criteria) and Table 8-2 (distribution criteria).

The security criteria are consistent with industry practice[26] and are designed to:

- Match the security of supply with customer requirements;
- Optimise capital and operational expenditure without a significant increase in supply risks; and
- Increase asset utilisation and reduce system losses.

The security criteria accept there is a small risk that supply may be interrupted, and cannot be backfed, if a fault occurs during maximum demand times. This is a balance of risk and cost and is considered a prudent approach rather than removing the small risk altogether.

The WELL subtransmission network consists of a series of radial circuits from Transpower's GXPs to the zone substations. The zone substations do not have a 33 kV bus and the subtransmission circuits connect directly onto the high voltage terminals of the 33/11 kV power transformers. In the Southern Area the 11 kV bus is normally operated open to restrict fault levels. Within the Northwestern and Northeastern areas the 11 kV bus is operated closed. The network utilises equipment cyclic capacity to meet peak demand and provide N-1 security. At the zone substations where the 11 kV bus is normally operated open, there will be a brief

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

interruption to customer following a subtransmission, transformer, or incomer cable fault, while the bus tie is closed. This is considered to satisfy the N-1 security criteria.

Subtransmission

The length of time (defined as a percentage) when the subtransmission network cannot meet N-1 security is defined for each category of customer. Limits are also set on the maximum load that would be lost for the occurrence of a contingency event. The peak demand at a zone substation is calculated based on the security criteria applied at that zone substation. This differs from the anytime maximum demand which is measured over a 30 minute period and can occur as a result of abnormal system operations.

Table 8-1 shows the applicable security criteria for the subtransmission network.

Type of Load	Security Criteria
CBD	N-1 capacity[27], 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 substations	N-1 capacity for 98% of the time in a year. For the remaining times, supply will be restored within 3 hours following an interruption.

Table 8-1 Security Criteria for the Subtransmission Network

Distribution

Table 8-2 shows the applicable security criteria for the distribution network.

Type of Load	Security Criteria
CBD or high density industrial	N-1 capacity 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 capacity for 98% of the time in a year. For the remaining times, supply will be restored within 3 hours following an interruption.
Predominantly residential and including feeders rural	N-1 capacity 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.
HV direct / LV Supply to customer	Loss of supply upon failure unless customer specified a higher security requirements. Supply restoration dependent on repair time.

Table 8-2 Security Criteria for the Distribution Network

[27] A brief supply interruption of up to five minutes may occur following an equipment failure while the network is reconfigured.

Basis for the criteria

While the reliability of WELL's HV distribution system is high, notwithstanding the difficult physical environment in which the system must operate[28], in most situations 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 maximum demand is very small.

The security criteria do not apply to faults on distribution transformers, the low voltage network or to failures of connection assets used to supply individual customer, which are typically designed for 'N' security. In such situations an interruption will last for the time taken to make a repair.

The security criteria also 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. WELL has emergency plans in place to prioritise response and repair efforts to assist mitigating the impact of such situations (as discussed in Section 11) but, when they occur, longer supply interruptions than shown in the tables are possible.

Most of the 11 kV feeders in the Wellington CBD, in some locations around Wellington city suburbs, and in the Porirua commercial centre are operated in a closed ring configuration with radial secondary feeders interconnecting neighbouring rings or zone substations. This arrangement provides a high level of security and hence a high level of supply reliability. The urban 11 kV network outside these areas typically comprises radial feeders with a number of mid-feeder switchboards with circuit breakers.

Most of the radial feeders are connected through normally open interconnectors to other feeders so that, in the event of an equipment failure, supply to customer can be switched to neighbouring feeders. To allow for this flexibility, distribution feeders are not operated at their full thermal rating under normal system operating conditions. The maximum feeder utilisation factor at which WELL operates the distribution feeders during normal and contingency operation is identified in Table 8-3. This is a guideline limit and signals the point where greater analysis is required. The actual post contingency loading and implementation of any required solutions is determined using contingency analysis.

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 or Radial section of Mesh Ring	66	100

Table 8-3 11 kV Feeder Utilisation during Normal and Contingency Operation

[28] Much of WELL'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.

A customer may desire a level of security above that offered by a standard connection. Should this arise, WELL offers a range of alternatives that provides different levels of security at different costs (price/quality trade off). The customer can then choose to pay for a higher level of security to meet their needs for the load that are being supplied.

8.1.2 Voltage Levels

Subtransmission voltage is nominally 33 kV in line with the source voltage at the supplying GXP. The voltage used at the distribution level is nominally 11 kV. The LV distribution network supplies the majority of customers at nominally 230 V single phase or 400 V three phase. By agreement with customers, supply can also be connected at 11 kV or 33 kV depending upon the load requirements.

Regulation 28 of the Electricity (Safety) Regulations 2010 requires that standard LV supply voltages (230 V single phase or 400 V 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 WELL zone substation transformers are fitted with on-load tap changers (OLTC) controlled by voltage regulation systems 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. Future Distributed Energy Resources (DER) will be required to implement suitable power quality response modes to meet supply quality requirements.

8.1.3 Fault Levels

WELL operates its 11 kV network to restrict the maximum fault level to 13 kA which ensures the fault rating for several legacy makes and models of switchgear is not exceeded. Restriction of fault levels is achieved by operating all zone substations supplied from Central Park and Wilton GXPs with a split 11 kV bus such that each zone substation transformer is supplying an independent bus section. The prospective fault level at all other zone substations does not exceed 13 kA. New switchgear is typically rated for 25 kA for use within zone substations and 21 kA for use within the distribution network.

8.1.4 Power Factor

All connected customers are responsible for ensuring that their demand for reactive power does not exceed the maximum level allowed, or the power factor limits specified in WELL’s network pricing schedule and connection requirements. The power factor of a customer’s load measured at the metering point must not be lower than 0.95 lagging at all times. Corrective action may be requested by WELL if the customer’s power factor falls below this threshold.

8.1.5 Acceptable Harmonic Distortion

Harmonic currents result from the normal operation of nonlinear devices on the power system. Voltage distortion results as these currents cause nonlinear voltage drops across the system. Harmonic distortion levels are defined by magnitudes and phase angle of each individual harmonic component. It is also common to use a single quantity, the “Total Harmonic Distortion” (THD), as a measure of the magnitude of harmonic distortion. Current and voltage harmonic levels are to be within the 5% THD limit specified in the Electrical Safety Regulations 2010 at the point of supply to the customer.

8.1.6 Standardised Designs

The implementation of standardised designs for common developments allows for improvements in safety by design principles, significant reduction in design expenditure and reduces the requirement for review and assessment. Standardised designs also aid in consistency in installation, commissioning and maintenance processes, thus improving familiarity for field staff and potentially reducing the cost of implementation.

Standardised designs are implemented for the purpose of asset and installation specification. At present, design standards are utilised for protection design, zone substation and distribution level earthing and LV reticulation as well as designs for underground subdivisions.

There is no standardisation of high voltage (HV) network augmentation because these are project by project dependent.

8.1.7 Energy Efficiency

The processes and strategies used by WELL that promote the energy efficiency of the network are:

- Network planning – to design systems that do not lead to high losses or inefficient distribution 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; 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).

8.1.8 Non-Network Solution Policy

Non-network solutions include load control, demand side management solutions, use of emerging technologies and network reconfigurations.

WELL's load control system is used to reduce maximum demand on the network by moving load to low load periods to optimise investment in network capacity. This has the effect of deferring demand-driven network investments. The use of the load control system has also resulted in providing an effective means of promptly returning supply to customer following network outages.

WELL specifies equipment for use that incorporates new technologies where it is practicable and economic to do so. This means that new technologies will be implemented if the benefits to the network and stakeholders meet or exceed the additional costs incurred in procuring, installing and using them. Therefore, it is unlikely that wide scale replacements of existing assets will occur; rather new equipment will be introduced as existing assets reach their end of life or are replaced due to a requirement for a change in capacity or functionality.

There is also a great level of uncertainty with the fast-changing nature of the emerging technologies. WELL's approach is described in Section 9. To date the cost of implementing emerging technologies have been found to be significantly higher than the alternative network-based solutions. WELL will continue with the development of a future pricing roadmap to keep the network efficient and enable the introduction of new technology with minimal network impact.

The options available typically include:

- Open point shifts using existing infrastructure to reduce loading on highly loaded feeders;
- Operational changes to better utilise existing network capacity over construction of redundant capacity; and
- Consideration of the cost effectiveness of demand side management to alleviate localised network constraints.

These non-network solutions will be implemented prior to any network investment. WELL currently monitors feeder loading using SCADA alarm limits to provide indication prior to thermal overload of assets. Where there is risk of exceeding the thermal overload limits due to equipment failure or constraints, network controllers are able to:

- Initiate shedding of hot water load to shave load during maximum demand periods; and
- Fine tune network open points to optimise feeder loading and feeder customer numbers.

8.1.9 Impact of Distributed Energy Resource

The magnitude of small distributed generation currently installed within the WELL network is relatively low[29] and is expected to remain relatively low across the first half of the planning period. This assumption will be monitored and re-assessed in the event of large scale uptake of distributed generation in the future and annually in the AMP process. WELL welcomes enquiries from third parties interested in installing embedded generation and has a connection policy, as described below.

8.1.9.1 Connection Policy

WELL has a Distribution Code and Network Connection Standard that includes the procedures for assessment and connection of distributed generation in line with Part 6 of the Electricity Industry Participation Code 2010.

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 the proposal meets the following requirements will be considered in developing a technical and commercial solution with stakeholders:

- The expected level of generation at peak demand times (availability of the service at peak demand times determines the extent that it will off-set network investment);
- The service must comply with relevant technical codes and not interfere with other customers;
- 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
- Ability to provide visibility of local network conditions where the DER is managed by a provider.

[29] Installed capacity, excluding standby generation and Mill Creek (connected at 33 kV), is only 15.8MVA, or 0.3% of the system demand.

If the above issues can be managed, and the dispatch of generation can be co-ordinated with system peaks or constraints, then the use of distributed generation as part of a demand side management programme benefits WELL and its customers.

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

8.1.10 Asset Capacity Definition

Primary assets in WELL network are classified into the following hierarchy of categories with planning criteria and operational requirements for the different assets shown in Table 8-4.

Primary Asset Categories	Asset Boundary	Security Planning Criteria
Tier 0 – Upstream Asset	GXP Feeder CB Cable Termination and above	National Grid Planning Criteria
Tier 1 – Subtransmission	From GXP CB Cable Termination to ZS 11 kV Bus before Feeder CB	Subtransmission Security Criteria, Maximum Continuous Branch Rating (MCBR)
Tier 2 – HV Feeder Distribution	From ZS Feeder CB to Distribution Substation HV Distribution Substation Ring Switch before teed connection to HV Load switch	Distribution Security Criteria, MCBR
Tier 3 – HV Distribution Substation	From Distribution Substation load switch to LV Bus	Distribution Security Criteria, MCBR
Tier 4 – LV Feeders	From LV Feeder switch to customer demarcation point	Distribution Security Criteria, Peak demand and After Diversity Maximum Demand (ADMD), MCBR
Tier 5 – Customer Assets (HV direct or LV)	From network demarcation point	Peak demand, Customer provided equipment rating

Table 8-4 Security Criteria for the Distribution Network

In general, for 11 kV and 33 kV network planning purposes, the maximum continuous ratings are used, whereas the cyclic ratings are used for planned operational activities and the emergency overload ratings are for unplanned contingency events.

Asset capacity is further defined as follows:

- Power transformers – The transformer ratings include the continuous asset capacity (based on a continuous uniform load profile), the cyclic capacity and a short duration (2 hour) emergency overload rating (dependent on the maximum operating temperature of the transformer);
- Subtransmission cables/lines – Thermal conductor capacity is determined through CYMCAP modelling, considering the effect of soil resistivity, the load profile and resulting thermal inertia, mutual heating due to adjacent conductors and configuration of installation. Soil and ambient temperature variations between seasons are also allowed for, providing a set of normal, cyclic and emergency ratings;

- Maximum Continuous Branch Rating (MCBR) – This is determined based on the lowest rated component of the circuit, i.e. a transformer may be rated to 36 MVA while the supplying cable is only capable of 21 MVA and 17 MVA during winter and summer respectively. Thus the effective MCBR is limited to the seasonal rating of the cable;

- LV distribution transformers and circuits – Asset capacity in this category is largely driven by the usage pattern and demand response from individual customers. Section 9 outlines the development plans and trial projects that have direct interface with LV connections.

The capacity of all HV network elements is modelled in the DigSILENT PowerFactory network model providing a tool to analyse network integrity against the security standard.

8.2 Demand Forecast 2022 to 2031

Growth in peak demand drives system constraints and the need for additional investment, either in the network or an alternative means of providing or managing the capacity. This section describes WELL's methodology and assumptions utilised to determine the peak demand forecast for the network.

Peak demand is forecast to grow in most areas of the network, driven by new commercial and residential developments. There is also a strong correlation between peak demand and seasonal conditions. Generally, demand peaks within the Wellington Region are driven by winter temperatures on the coldest days.

While the overall WELL load is traditionally winter peaking, recent trends have shown that a few of the zone substations within the Wellington City are now summer peaking.

8.2.1 Demand Forecast Methodology

There is a strong correlation between the demand profile and the ambient temperature and it is generally different for summer (November to April) and winter (May to October) periods, shown in Figure 8-1 In addition, the rating of some network assets such as cables can vary depending on ambient temperature conditions.

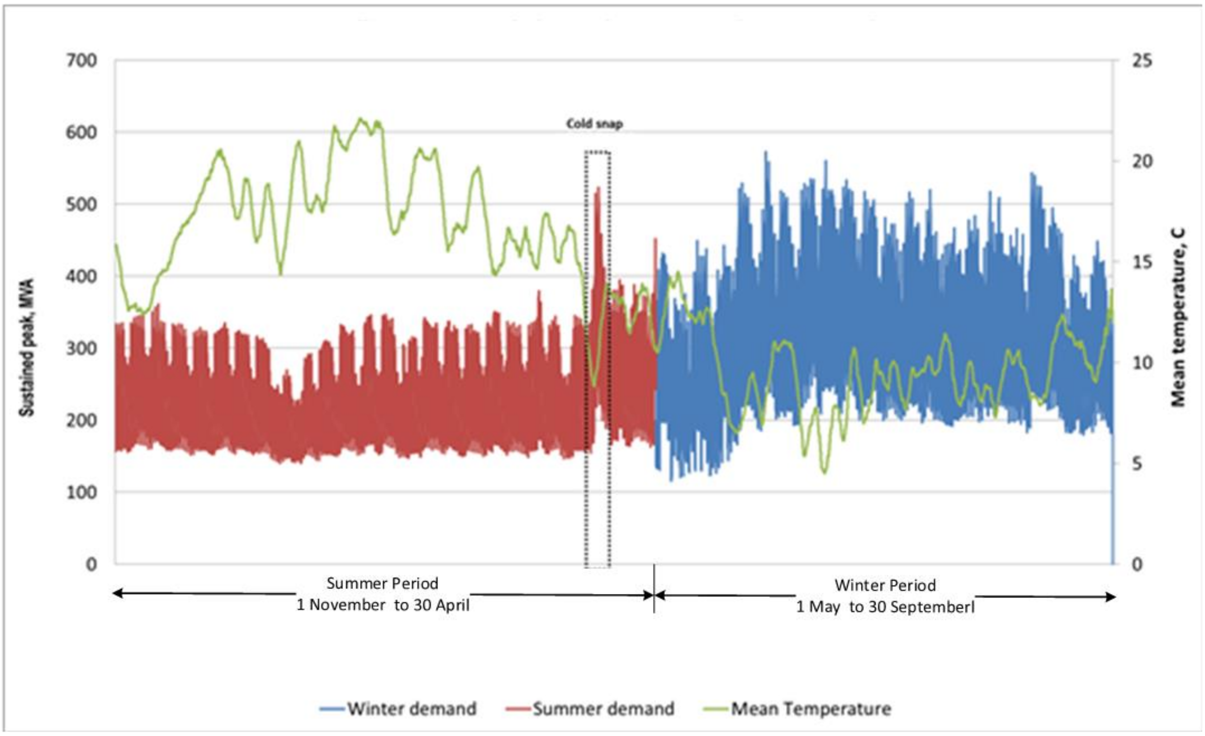


Figure 8-1 - Wellington Network Summer and Winter Demand Variation

WELL develops separate summer and winter demand forecasts using historical trends in peak demand with the addition of confirmed future step changes as follows:

1. For each zone substation, historical summer and winter demand trends are analysed to establish:

   a) an average peak demand forecast growth rate based on the subtransmission security criteria defined in Table 8-1 (ie 99.5 percentile for zone substations within the CBD and 98 percentile for all other zone substations); and

   b) a high and low variance from the average peak demand to determine a band of uncertainty in the forecast. The high and low variance includes:

      - confirmed and all known highly likely future step change demand; and
      - confirmed and all known highly likely future EV/PV developments. EV/PV penetration is still low and does not yet have a significant step change impact on the peak demand. Climate change policies will have an impact on the rate and timing of accelerated EV/PV adoption.

2. An additional scenario consisting of signalled possible future step changes in demand is added to the high variance for a sensitivity assessment.

At the subtransmission level, the 60th percentile between the high and low range of the summer and winter peak demand forecast values is used for planning purposes and is termed, the Likely Peak Demand (LPD).

The 60th percentile allows for a sufficient margin of error given the load at risk and the scale of augmentation investment typically required when a constraint is identified at the subtransmission level. This is plotted against the applicable N-1 subtransmission capacity constraints to determine the subtransmission security of supply.

The growth scenarios are aggregated 'bottom-up' from feeder level to provide GXP, region and system wide forecasts allowing for diversity at each level. An overview of the demand forecast methodology is shown in Figure 8-2.

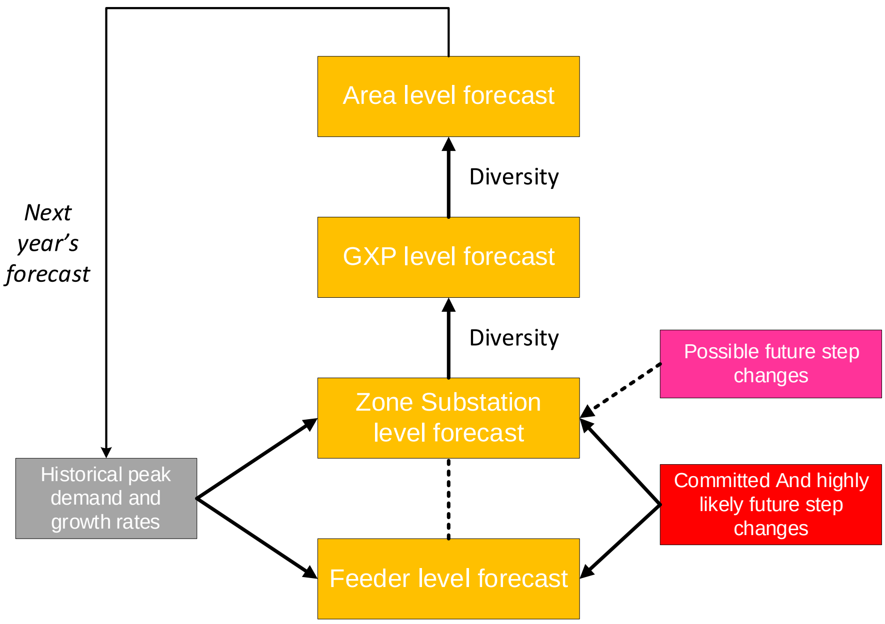


Figure 8-2 Demand Forecasting Methodology

This model is used to determine when subtransmission and feeder level constraints are likely to occur and provides an annual maximum demand that can be used in load flow modelling.

8.2.1.1 Forecasting Assumptions and Inputs

The peak demand forecast for the current planning period is based on the following assumptions:

- The use of load control is assumed to remain as per current practice;
- No allowance is made for any significant demand changes due to major weather events or unforeseen network condition causing significant outages or abnormal operation of the network;
- Impact from disruptive technologies such as PV or distributed generation, as discussed in Section 9; and
- Half-hourly demand data per zone substation feeder is captured by the SCADA system. The demand at each GXP is metered through the time-of-use revenue metering.

In order to calculate the peak demand, the forecast is based on the following information and apply assumptions listed earlier in this section:

- Step change loads, based on confirmed and highly likely customer connection requests, are included in the forecast;
- Diversity factors[30] that provide peak coincident demand are calculated from historical recorded data; and
- Typical demand profiles based on the majority load type in the zone.

[30] Diversity factors represent the difference in times of peak demand between different sites.

These assumptions, data sets and trend analysis are reviewed each year and the expected impacts of any changes are incorporated into the forecast.

To aid in deciding the appropriate response WELL has categorised future load step changes as:

- Confirmed:
  - network connection offer signed.
- Highly likely:
  - from local council plans assessment of development potential that is close to eventuating or is highly likely to proceed; or
  - signalled by the developer that is close to or is highly likely to be having a contract signed.
- Possible:
  - from local council plans assessment of development potential; or
  - signalled by the developer still at exploring development options and WELL has not received an application for connection.

8.2.2 Step Change Loads

Confirmed and highly likely step change loads are accounted for in the load forecast. These step change loads may be the result of:

- Major developments that introduce large new loads onto the network with a total connection capacity above 450 kVA or ADMD capacity above 200 kVA;
- New electricity generation that is expected to reduce peak demand; or
- Load reductions caused by the movement or closure of businesses.

The magnitude and location of the step change loads used in the base demand forecast are identified through customer connection requests that are either confirmed or are highly likely to eventuate.

In addition to the above, there are likely to be future possible step change loads identified through customer connection requests, developments detailed in the local council District Plans and through consultation with city councils, developers, and large customers. A number of property developers and businesses have flagged developments that may create new loads on the network. As it is uncertain if these step change loads will occur, WELL has not included them in the base demand forecast. From history, we know these will not all occur, and others may also eventuate. These additional possible step load changes are indicated as an additional scenario above the base demand forecast. WELL will continue to monitor progress on these possible step change loads and will investigate options to mitigate system constraints as possible step change load growth is confirmed.

The step change demand profile represents a material proportion of the change in network peak demand. The actual outcome from step change demands is uncertain, and difficult to estimate more than 12 months in advance.

8.2.3 Demand Change Due to DER Penetration

New technologies such as DER devices, as discussed in Section 9, will impact future network load patterns and the overall system demand forecast.

Figure 8-3 illustrates the potential impact DER penetration would have on a typical zone substation demand forecast.

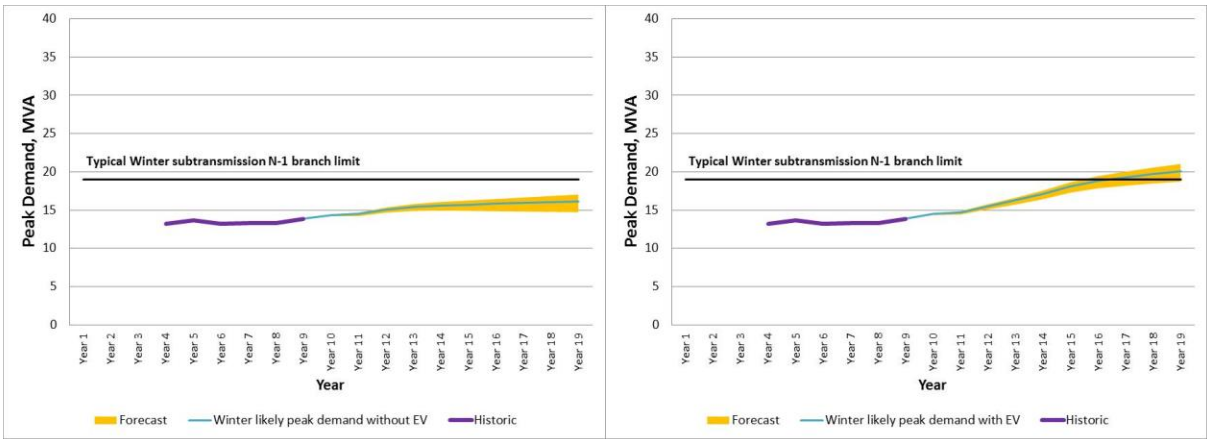


Figure 8-3 Forecast Impact of DER on Demand Forecast for a Typical Zone Substation

There remains significant uncertainty, including degree of counterbalance between impact of DER devices, policy change, load changes in response to signals from the network (e.g. price signal change) and technology change. On this basis, the load forecast in this section has not included results from the DER penetration study. The load forecast will however, include any committed or highly likely significant EV/PV development proposals.

WELL will continue to monitor and analyse the impact of DER and will update future demand forecasts with the results of this analysis.

8.2.4 Typical Load Profiles

Typical annual demand profiles for the CBD and residential loads are shown in Figure 8-4 and Figure 8-5. These graphs illustrate that peak CBD loads are relatively flat throughout the year with a slight trend towards a summer peak due to air conditioning load whereas residential loads peak in winter, mostly driven by domestic heating.

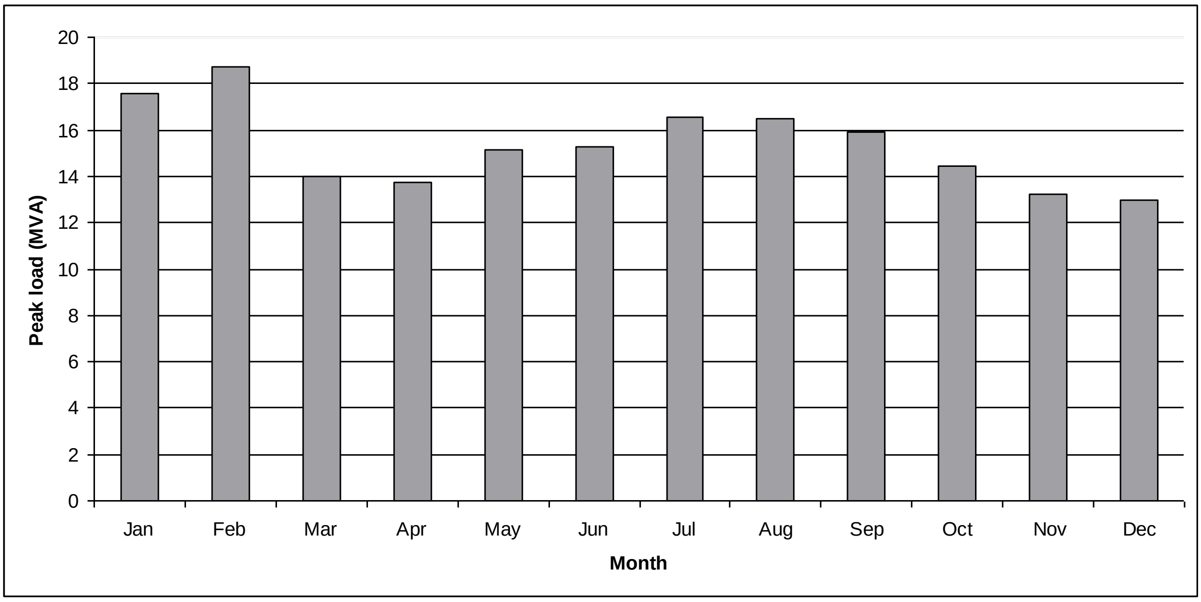


Figure 8-4 Typical CBD Monthly Peak Load Profile

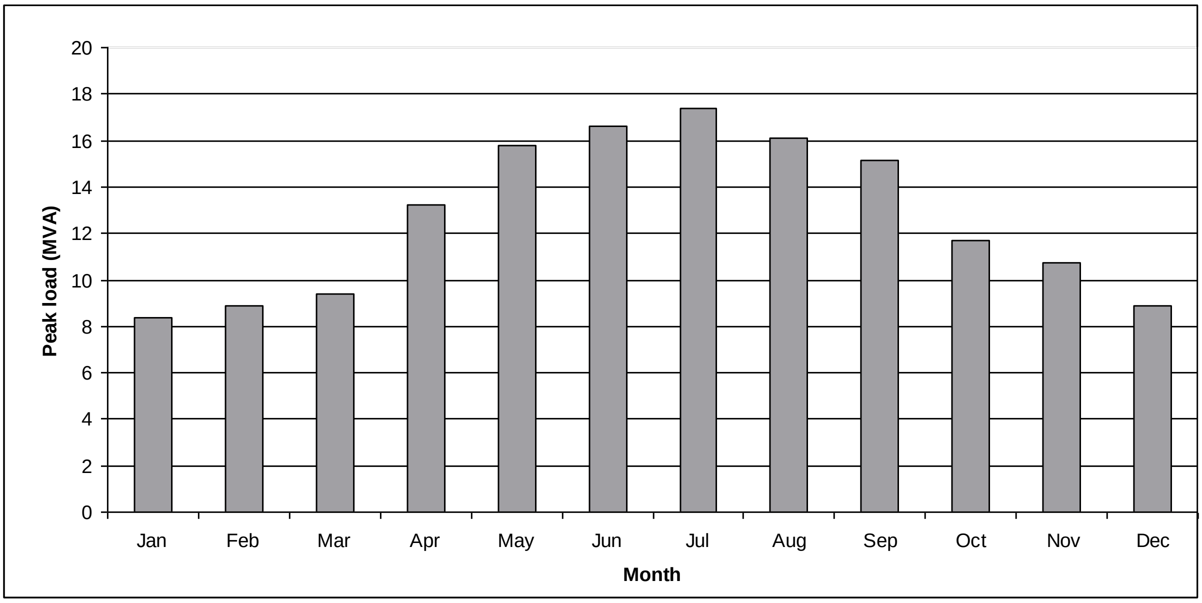


Figure 8-5 Typical Residential Monthly Peak Load Profile

Typical daily demand profiles are shown in Figure 8-6 and Figure 8-7. These graphs illustrate that the CBD daily profile peaks and then remains relatively flat through the day, whereas the residential load profile has the typical morning and early evening peaks especially for the winter period. These profiles are subject to change as the uptake of electric vehicles and demand management technologies changes over time.

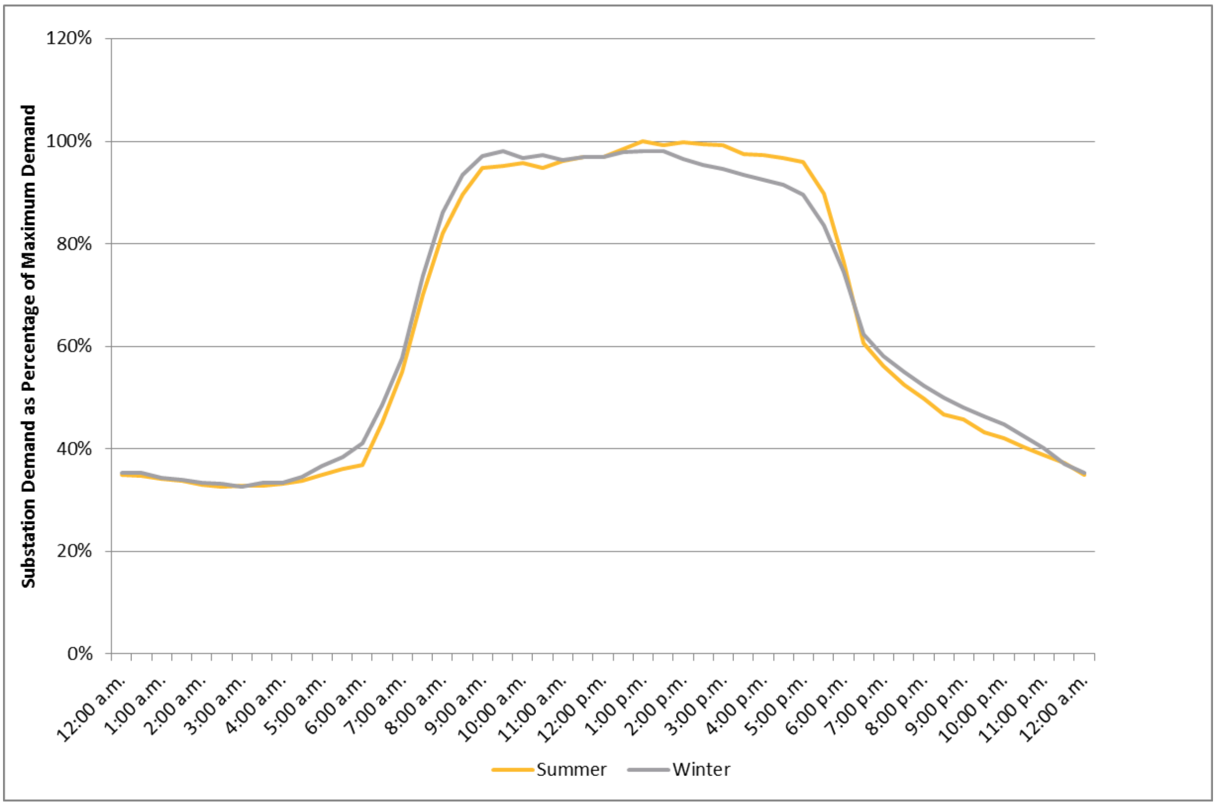


Figure 8-6 Typical CBD Zone Substation Daily Load Profile

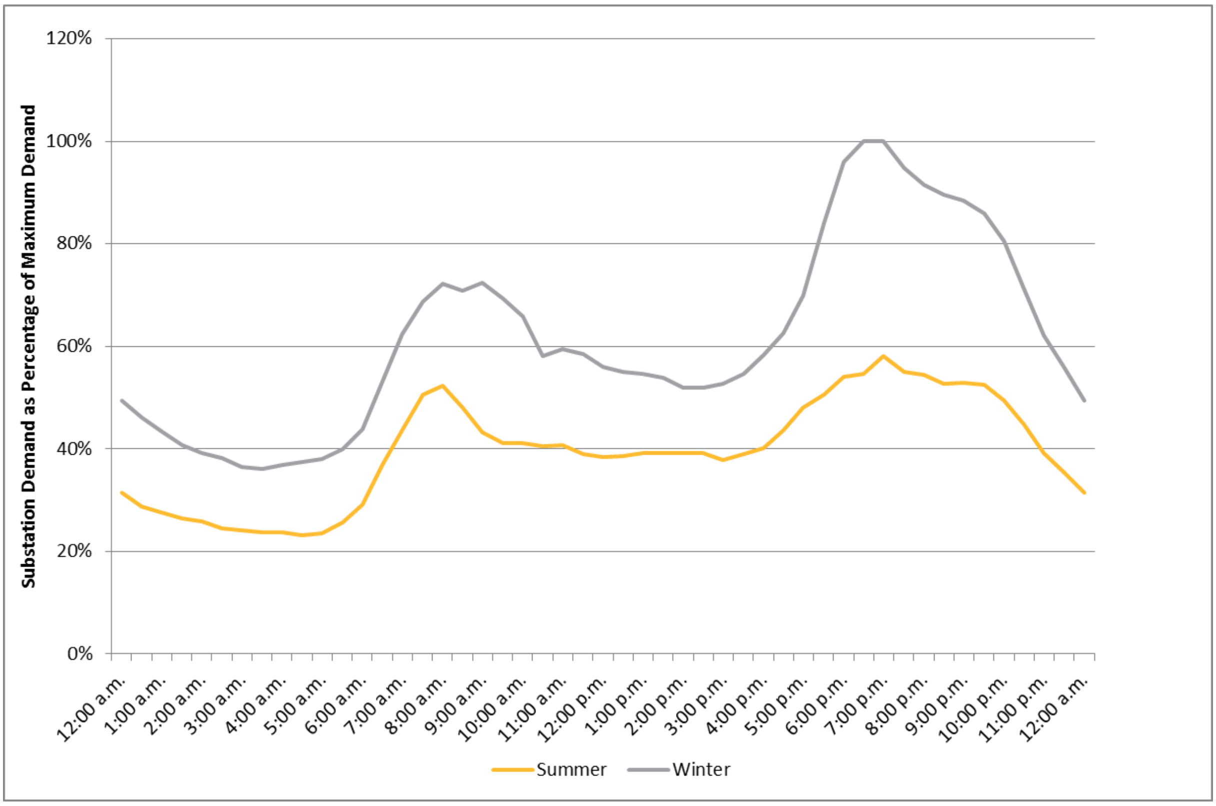


Figure 8-7 Typical Residential Zone Substation Daily Load Profile

8.2.5 Wellington Regional Maximum Demand Forecast

Table 8-5 shows the network maximum demand forecast to 2031. These figures assume an average winter. In practice the actual maximum demand will be influenced by whether the winter is milder or colder than average.

Network	Maximum Demand (MW)										
	2021 Actual	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031
System Maximum Demand (MW)	579	592	598	605	612	620	628	636	644	653	662

Table 8-5 Forecast Network Maximum Demand

Table 8-6 shows the contribution of each GXP and DG to the 2021 winter maximum demand.

Location	2021 Coincident Maximum Demand (MW) – 9 August 2021 Block 37														
	Central Park	Gracefield	Haywards	Kaiwharawhara	Melling	Pauatahanui	Takapu Road	Upper Hutt	Wilton	Mill Creek	Wellington Wind	Silverstream	Southern Landfill	Other Small DG[2]	Total
Coincident Maximum Demand (MW)	179	69	34	26	62	21	105	34	0	48	0	2	0	1	**579**

Notes:

1. This is the system maximum demand as opposed to 98 percentile peak demand used for the demand forecast.

2. The other small DG is not included in the total coincident maximum demand value as we do not have accurate metering data for the DG. We assumed 1 MW embedded in our system.

Table 8-6 2021 Coincident Maximum Demand

The maximum network demand is expected to grow at a rate of approximately 1% p.a. over the next five years. The growth includes step change loads such as:

- Committed or highly likely public transport electrification upgrades and new EV charging stations within the Wellington Electricity network;
- Planned residential developments in the Porirua Northern Growth Area, Churton Park, Aotea, Whitby, Grenada North and Upper Hutt areas; and
- Expansion plans of a number of commercial and industrial customers.

Beyond five years, the rate of growth in peak demand is driven by a number of factors including:

- A number of buildings within the Wellington CBD that are currently undergoing re-development. High efficiency HVAC systems, better insulation and customer side demand monitoring typically result in a reduction in demand for an existing connection point;

- Adoption of new technologies such as EVs, residential and commercial batteries and reduction of gas connections; and
- Customer response to pricing signals and policy changes.

8.2.6 Network Area Step Change Development

This section provides a high level summary of confirmed local step change development in each network area.

8.2.6.1 Southern – Step Change Developments

Peak demand in the Southern Area has been flat or in decline in recent years but is expected to increase due to public transport electrification upgrades and a number of new buildings planned over the coming years. The new building developments are expected within the inner city and along the water front, around the Parliamentary Precinct and a new development at Victoria University.

Energy consumption within the Southern Area network has also been flat due to a general trend towards energy efficiency.

Confirmed and highly likely developments in the Southern Area include:

- Public transport electrification upgrades and new EV charging stations;
- Industrial development in Kaiwharawhara;
- New government and ministerial buildings in Thorndon;
- Residential and commercial development within the Wellington CBD;
- Commercial development in Newtown;
- Industrial, commercial and residential development in Mirimar; and
- Residential and commercial development in Rongotai and Wellington's southern coast.

8.2.6.2 Northwestern - Step Change Developments

The Northwestern Area is continuing to grow organically with the strongest level of residential development within WELL's network. There is relatively high interest for new residential subdivisions in the suburbs of Kenepuru, Whitby, Grenada North and Churton Park. Aotea, currently supplied from Porirua and Waitangirua zone substations, is still an area of growth.

Confirmed and highly likely developments in the Northwestern Area include:

- Public transport electrification upgrades;
- Housing New Zealand plans to build an additional 1,500 units over the next 10 years in Eastern Porirua, expected to contribute an average of 300 kVA to the peak demand annually;
- Residential development north of Plimmerton, the Pauatahanui-Judgeford area and Whitby;
- Industrial development in Porirua and Tawa; and

- Commercial development in Grenada North.

There is limited capacity and HV supply coverage around the existing network boundaries, particularly in Titahi Bay, Plimmerton, and Pauatahanui. WELL will work closely with customers on network expansion requirements for new connections and capacity upgrade projects.

8.2.6.3 Northeastern - Step Change Developments

Peak demand in the Northeastern Area is expected to marginally increase due to localised residential and commercial developments. This is driven by planned residential sub-divisions and expansion plans of industrial customers in the Trentham and Maidstone zone substation supply areas.

Confirmed and highly likely developments in the Northeastern Area include:

- Public transport electrification upgrades;
- Residential developments in Upper Hutt, Manor Park, Naenae, Waterloo, Wainuiomata, and Wallaceville;
- Commercial and residential developments in Petone;
- Commercial developments in Trentham and Taita; and
- Expansion of industrial loads in Gracefield and Seaview.

There is limited capacity and HV supply coverage around the existing network boundaries, particularly in Upper Hutt and Wainuiomata. WELL will work closely with customers on network expansion requirements for new connections and capacity upgrade projects.

8.2.7 GXP and Zone Level Demand Forecasts

The following tables show the GXP and zone substation level forecast for each area within the Wellington network. Table 8-7 shows the GXP level forecast by area and Table 8-8 shows the zone substation level forecast by area. For both tables, the base maximum demand value for the forecast is for the last 12 months and area totals are coincident peak demand values.

Area	GXP[31]	Actual and Forecast Peak Demand[32] (MVA)										
		2021 Actual	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031
Southern	Central Park 33 kV	135	135	139	144	149	151	151	153	155	157	158
	Central Park 11 kV	21	22	24	24	24	24	25	25	25	25	26
	Wilton 33 kV	40	44	45	46	47	47	48	49	49	50	51
	Kaiwharawhara 11 kV	28	29	29	39	39	40	41	41	42	43	43
Northwestern	Pauatahanui 33 kV	18	18	18	19	20	21	22	22	23	24	25
	Takapu Rd 33 kV	93	93	98	103	105	106	110	114	115	116	117
Northeastern	Gracefield 33 kV	62	65	66	67	68	68	70	71	72	73	74
	Haywards 33 kV	15	16	18	18	18	19	20	20	21	21	21
	Melling 33 kV	32	32	34	35	35	35	35	36	36	37	37
	Upper Hutt 33 kV	31	32	35	36	36	37	37	37	38	38	38
	Haywards 11 kV	17	18	20	20	20	20	20	20	20	20	21
	Melling 11 kV	24	23	24	25	25	25	25	25	26	26	26

Table 8-7 Wellington Area GXP Level Forecast

[31] Transpower's published P90 forecasts at the GXP level allow for a large margin of uncertainty, prudent for transmission level planning and as such, are not consistent with WELL's forecasts which are less conservative for the purposes of subtransmission and distribution planning.

[32] Forecast values are for the normal growth average seasonal temperature case correspond to the 60th percentile deduced from the peak demand range and include step change loading due to planned load transfer or confirmed customer connections.

Area	Zone	Actual and Forecast Peak Demand[33] (MVA)										
		2021 Actual	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031
Southern	8 Ira Street	16	16	17	18	18	18	19	19	19	20	20
	Evans Bay	12	14	14	18	19	19	20	21	21	22	23
	Frederick Street	28	29	30	30	31	31	31	31	32	32	32
	Hataitai	18	18	18	18	18	19	20	21	21	21	21
	Palm Grove	25	26	26	26	29	29	27	27	27	27	26
	Terrace	24	26	26	26	26	26	26	26	26	26	27
	University	18	18	19	19	20	20	20	20	21	21	21
	Nairn Street	22	24	24	24	24	25	25	25	25	25	26
	Karori	15	16	16	17	18	18	19	19	20	20	21
	Moore Street	21	21	22	23	23	23	23	24	24	24	24
	Waikowhai Street	14	14	14	15	15	15	15	15	15	15	15
Northwestern	Mana	9	9	9	10	10	10	10	10	10	11	11
	Plimmerton	9	9	9	10	10	11	12	12	13	14	14
	Johnsonville	21	21	21	21	21	21	21	22	21	21	21
	Kenepuru	12	12	12	12	12	12	12	13	13	13	13
	Ngauranga	11	11	13	14	15	16	16	16	16	16	16
	Porirua	22	22	23	24	25	25	26	26	27	27	27
	Tawa	15	15	17	18	18	18	17	16	16	16	16
	Waitangirua	15	15	17	17	18	18	18	18	19	20	20
Northeastern	Gracefield	11	14	14	14	14	15	15	16	16	17	17
	Korokoro	21	22	23	23	23	23	23	23	23	24	24
	Seaview	15	15	15	15	15	15	15	15	15	16	16
	Wainuiomata	16	17	17	17	18	18	18	18	18	18	19
	Trentham	15	16	18	18	18	19	20	20	21	21	21
	Naenae	15	15	17	17	18	18	18	18	18	19	19
	Waterloo	16	17	17	17	18	18	18	18	18	18	19
	Brown Owl	15	16	16	16	17	17	17	17	17	17	17
	Maidstone	15	17	19	20	20	20	20	21	21	21	22

Table 8-8 Wellington Area Zone Substation Level Forecast

Some zone substations predominately supplying commercial areas within the Wellington region may show a reduction in 2021 actual demand compared to historical trends. This is likely due to the impact COVID-19 had on commercial electricity demand.

8.3 Overview of the Network Development and Reinforcement Plan (NDRP)

The NDRP describes the identified need, options and investment path for the network over the next 10 years. Each of the three network areas are largely electrically independent and have a different set of challenges however planning for each network area uses a consistent methodology.

The discussion for each area is structured in accordance with the network hierarchy of GXP level requirements, subtransmission and zone substations and then distribution level investments. The GXP level discussion has been developed with reference to Transpower's Transmission Planning Report (TPR) and other formal discussions with Transpower regarding their proposed development plans.

The NDRP for each network area is described in the following respective sections. Each section provides a summary of the NDRP and is structured as follows:

- Potential GXP developments;
- Identified subtransmission development needs;
- Identified HV distribution network development needs; and
- A summary of network development plan and expected expenditure profile.

Options for resolving each subtransmission development need are summarised in Appendix D.

[33] Forecast values are for the normal growth average seasonal temperature case correspond to the 60th percentile deduced from the peak demand range and include step change loading due to planned load transfer or confirmed customer connections.

8.4 Southern Area NDRP

This section provides a summary of the Southern Area NDRP.

8.4.1 GXP Development Plans

The Southern network is supplied from four GXP points at three locations, Central Park, Wilton and Kaiwharawhara. Transpower owns all supply transformers and the switchgear at the GXPs. The transformer capacity and the peak system demand are set out in Table 8-9. The forecast in Table 8-9 considers only committed developments.

GXP	Continuous Capacity (MVA)	Cyclic Summer / Winter Capacity (MVA)	Peak Demand (MVA)	
			2021	2031
Central Park 33 kV	2x100 1x120	2 x 108/112 1 x 146/147	135	158
Central Park 11 kV	2x25	29/30	21	26
Wilton 33 kV	2x100	103/110	40[34]	51[9]
Kaiwharawhara 11 kV	2x30	38/38	28	43

Table 8-9 Southern Area GXP Capacities

The development need at each GXP is discussed below.

8.4.1.1 Central Park GXP

The peak demand on the Central Park GXP in 2021 was 156 MVA.

The Central Park 33 kV bus is normally operated closed and supplies eight zone substations on 16 subtransmission feeders, two 33/11 kV transformers and an 11 kV bus. The zone substations supplied from Central Park GXP are:

- 8 Ira Street, Evans Bay, Frederick Street, Hataitai, Palm Grove, The Terrace and University at 33 kV; and
- Nairn Street at 11 kV.

Each zone substation is supplied from two separate bus sections to provide N-1 security.

Many of the investment needs identified at Transpower GXPs have been detailed in Transpower's Transmission Planning Report. WELL and Transpower have been investigating options for site diversity to improve CBD supply resilience. The preferred option is to move assets including one 110/33 kV transformer, 33 kV switchgear and associated protection, to a site near Central Park that would operate in parallel with the existing Central Park GXP. This is discussed further in Section 11.

[34] Wilton 33 kV ADMD peak demand excluding West Wind generation.

8.4.1.2 Wilton GXP

The peak demand on the Wilton GXP in 2021 was 40 MVA. Wilton supplies zone substations at Karori, Moore Street, Waikowhai Street each via double 33 kV circuits.

The Wilton 110 kV bus consists of three sections and provides supply diversity and resilience as each of the three Central Park circuits are terminated to an individual bus section.

Transpower has also undertaken a risk assessment of a loss of key assets at Wilton, such as the entire 220 kV or 110 kV 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.

8.4.1.3 Kaiwharawhara GXP

The peak demand on the Kaiwharawhara GXP in 2021 was 28 MVA. The Kaiwharawhara GXP supplies the Kaiwharawhara zone substation directly from the 110/11 kV transformer LV circuit breakers.

Transpower has no planned works at Kaiwharawhara based on current demand forecasts.

Figure 8-8 shows the load duration curve against the subtransmission N-1 ratings.

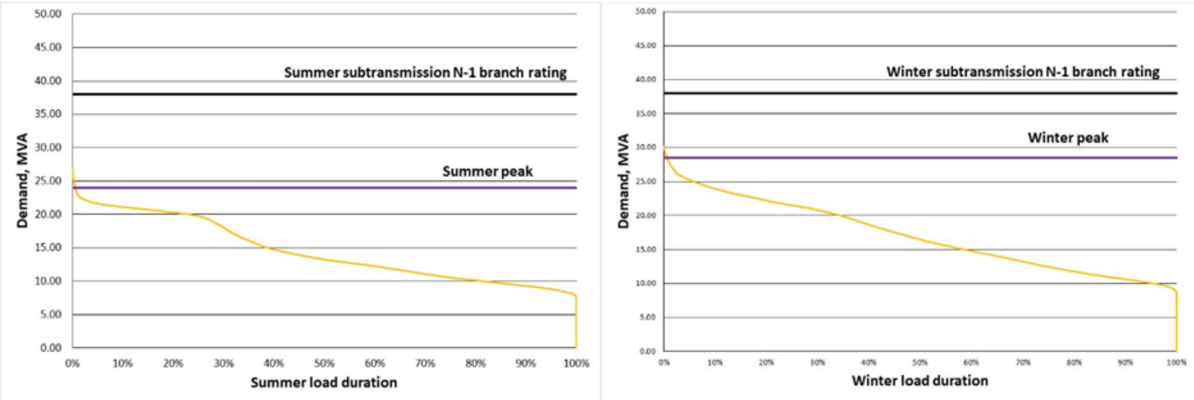


Figure 8-8 Kaiwharawhara Load Duration Curve

Based on the estimated growth scenarios and step change growth accounted for within the planning period, the load at Kaiwharawhara is forecasted to change as shown in Figure 8-9. The subtransmission capacity constraints are plotted for comparison.

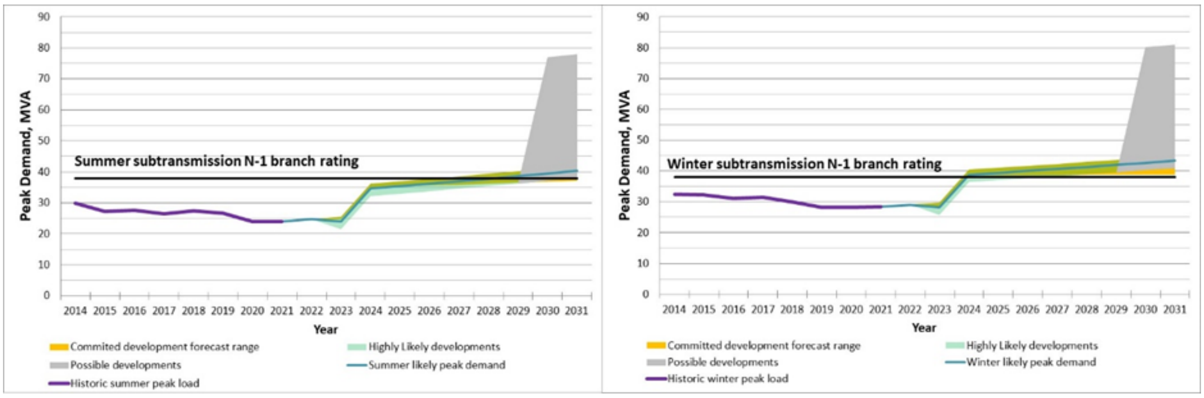


Figure 8-9 Kaiwharawhara Demand Forecast

The Kaiwharawhara winter demand is forecast to exceed the subtransmission N-1 capacity from 2024. WELL plans to shift some load from Kaiwharawhara to Naugranga. This will defer exceeding the Kaiwharawhara N-1 limits until about 2028, however the situation is complicated by additional requests for connections at Ngauranga and constraints to the site. There is also a potential large EV load coming up towards the end of the AMP period.

WELL continues to monitor the load growth and will investigate options to mitigate the system constraints as possible step load growth gets confirmed.

8.4.2 Subtransmission Network Development Needs

This section describes the identified security of supply constraints and development needs for the Southern Area subtransmission network.

A supply capacity and demand overview of each zone substation is listed in Table 8-10. Assets causing capacity constraints are shown in red text in the table.

Zone Substation	Season	Subtransmission N-1 branch rating (MVA)		Constraining Branch Component[35]	Peak Demand (MVA)		Date Constraints are Binding	ICP Counts as at 2021
		Existing	Post - committed network upgrade		2021	2031		
Existing constraints								
Frederick Street	Winter	23.2	30[1]	33kV cable	27.8	32.1	Existing	7,289
	Summer	19.5	30[1]	33kV cable	21.8	24.6		
Palm Grove	Winter	20	N/A	33/11kV transformer	25.3	27.5	Existing (Winter)	10,506
	Summer	20	N/A	33/11kV transformer	17.4	19.4		
Forecasted constraints								
Nairn Street	Winter	22	N/A	11kV incomer cables	21.8	25.6	2022 (Winter)	7,074
	Summer	22	N/A	11kV incomer cables	15.7	21.2		
8 Ira Street	Winter	20	N/A	33/11kV transformer	16.0	20.0	2026	4,908
	Summer	15	N/A	33kV cable	12.0	19.0		
Karori	Winter	21	N/A	33kV cable	14.8	17.9	2025 (Summer)	6,094
	Summer	11	N/A	33kV cable	9.6	11.9		
Waikowhai Street	Winter	15	N/A	33/11kV transformer	14.2	15.1	2031 (Winter)	5,785
	Summer	13	N/A	33kV cable	9.0	9.9		
Not Constrained								
Evans Bay	Winter	19	24[2]	33kV cable	12.3	22.5	Not Constrained	4,891
	Summer	15	24[2]	33kV cable	9.6	24.0		
The Terrace	Winter	30	N/A	33/11kV transformer	24.2	26.3	Not Constrained	1,555
	Summer	30	N/A	33/11kV transformer	24.4	26.5		
Hataitai	Winter	22	N/A	33kV cable	17.7	21.4	Not constrained	6,840
	Summer	13	N/A	33kV cable	10.5	14.2		
Moore Street	Winter	30	N/A	33/11kV transformer	19.7	21.9	Not constrained	833
	Summer	30	N/A	33/11kV transformer	20.9	24.2		
University	Winter	20	N/A	33/11kV transformer	17.9	21.0	Not constrained	6,208
	Summer	20	N/A	33kV cable	13.6	15.6		

Notes
1. Frederick Street incomer cable replacement project scheduled for completion early 2022. This will increase the 33 kV subtransmission N-1 capacity to 30 MVA.
2. Evans Bay new 33kV bus and transformer replacement project scheduled for completion mid 2023. This will increase the subtransmisison limits and avoid the forecast constraint from 2029 based on existing equipment ratings.

Table 8-10 Southern Area Zone Substation Capacities

[35] Subtransmission branch consists of incoming 33kV circuits, the 33/11kV transformer and the 11 kV incomer circuit breakers

At the subtransmission level, WELL's planning criterion is to maintain N-1 capacity down to the 11 kV incomer level based on equipment maximum continuous rating (MCR).[36]

A typical subtransmission circuit in the area is configured in the following manner:

- Cabling at 33 kV to the zone substation supply transformers. This consists of a double circuit arrangement terminating to separate supply transformers. Cables are operated at the cyclic rating. The magnitude of cyclic rating is determined by the ambient temperature (summer and winter) and pre-event loading of 50%;
- Zone substation 33 kV/11 kV supply transformers, in the continuous rating of 20-30 MVA range, fitted with oil circulation pumps and cooling fans to provide a higher cyclic rating; and
- 11 kV cabling from the 11 kV terminations of the transformers to the incomers on the switchboard which can potentially constrain the subtransmission circuit rating if undersized, is also considered a component of the subtransmission circuit.

Subtransmission constraints can be quantified in terms of duration of potential overload assessed against the security criteria using a load duration curve. Forecasted constraints are quantified in terms of when the risk of overload is likely to occur based on the forecast peak demand for a given year.

The development needs for the Southern Area at the subtransmission and distribution level are outlined in the following sections.

8.4.2.1 8 Ira Street

The peak load supplied by 8 Ira Street is currently within the N-1 capacity of the subtransmission circuits. Table 8-11 shows the seasonal constraint levels and the minimum off load requirements.

Circuit	Season	Constraining N-1 branch rating (MVA)	Peak Demand @ 2021 (MVA)	Minimum off load for N-1 @ peak (MVA)
8 Ira Street	Winter	20.0	16.0	0*
	Summer	15.0	12.0	0
* This table shows the 98th percentile station peak load. The potential overload at maximum demand occurs for short periods of time and is within the equipment short-term rating.				

Table 8-11 Current 8 Ira Street Subtransmission Constraints

Following a fault on the subtransmission system, WELL currently closes the 11 kV bus tie and restores supply to customers. Figure 8-10 shows the load duration curve against the subtransmission N-1 ratings.

[36] Maximum continuous rating (MCR) vs cyclic capacity: MCR is used for capacity planning to cover peak and cyclic rating (for a specified limited duration) is used for operations to cover short-term peak loading and contingencies.

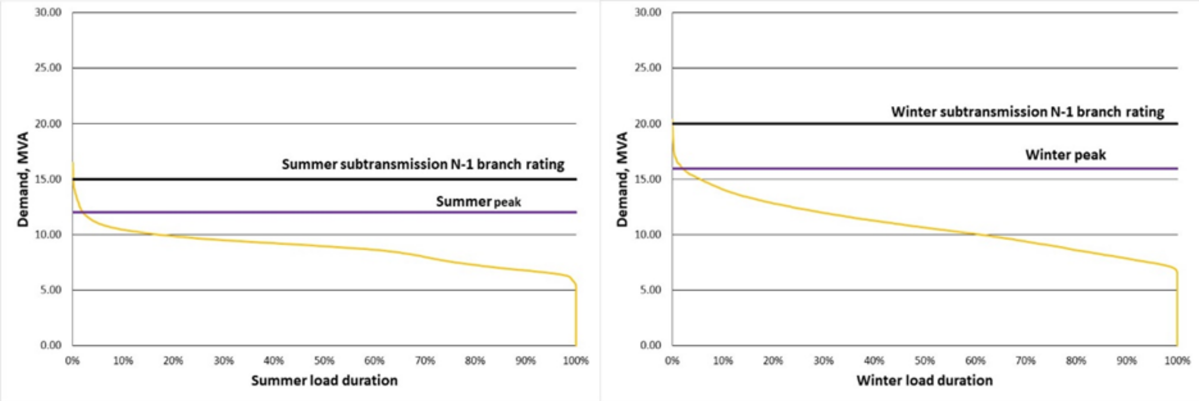


Figure 8-10 8 Ira Street Load Duration Curve

The load duration curve shows the proportion of load at risk. This analysis uses a load duration curve based on 30 minute periods and is higher than the peak.

Based on the estimated growth scenarios and step change growth accounted for within the planning period, the load at 8 Ira Street is forecasted to change as shown in Figure 8-11. The subtransmission capacity constraints are plotted for comparison.

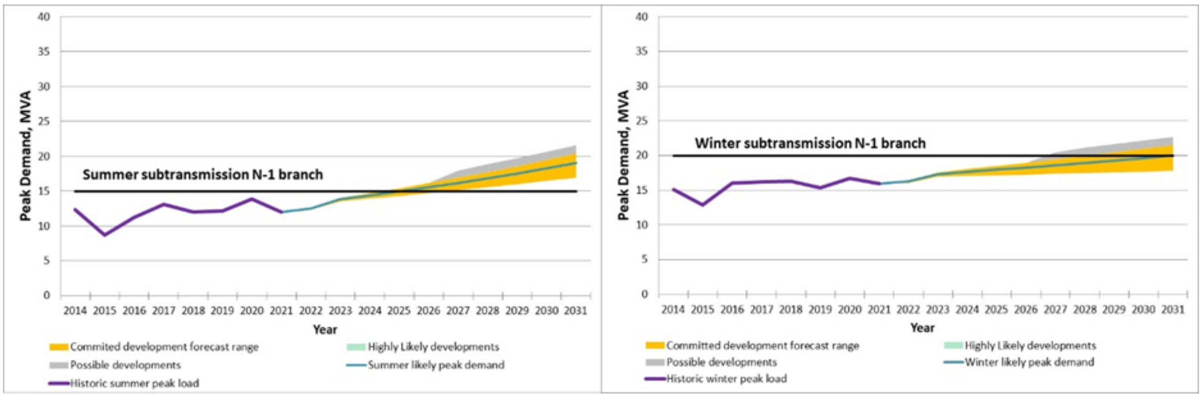


Figure 8-11 8 Ira Street Demand Forecast

The 8 Ira Street summer peak demand is forecast to exceed the subtransmission N-1 capacity from 2026.

WELL continues to monitor the load growth and will investigate options to mitigate the system constraints if and when step load growth are confirmed. WELL will manage the summer load until asset replacement or significant step change in load is confirmed.

8.4.2.2 Evans Bay

The peak demand supplied from Evans Bay is currently within the N-1 capacity of the subtransmission circuits. Table 8-12 shows the seasonal constraint levels and the minimum off load requirements on each circuit.

Circuit	Season	Constraining N-1 branch rating (MVA)	Peak Demand @ 2021 (MVA)	Minimum off load for N-1 @ peak (MVA)
Evans Bay	Winter	19.0	12.3	0
	Summer	15.0	9.6	0

Table 8-12 Current Evans Bay Subtransmission Constraints

Following a fault on the subtransmission system, WELL currently closes the 11 kV bus tie and restores supply to customers through partially off-loading Evans Bay to adjacent zone substations. Figure 8-12 shows the load duration curve against the subtransmission N-1 ratings.

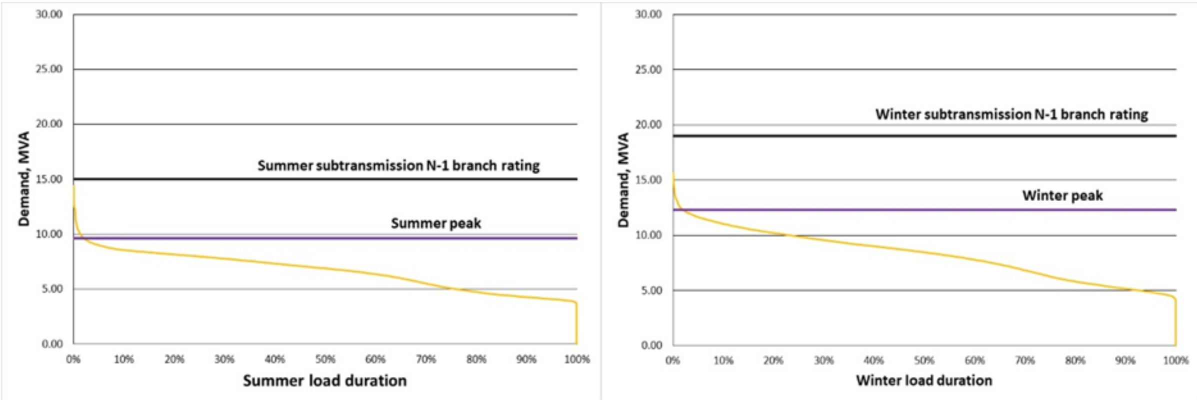


Figure 8-12 Evans Bay Load Duration Curve

The load duration curve shows the proportion of load at risk. This analysis uses a load duration curve based on 30 minute periods and is higher than the peak.

Based on the estimated growth scenarios and step change growth accounted for within the planning period, the load at Evans Bay is forecasted to change as shown in Figure 8-13. The subtransmission capacity constraints are plotted for comparison.

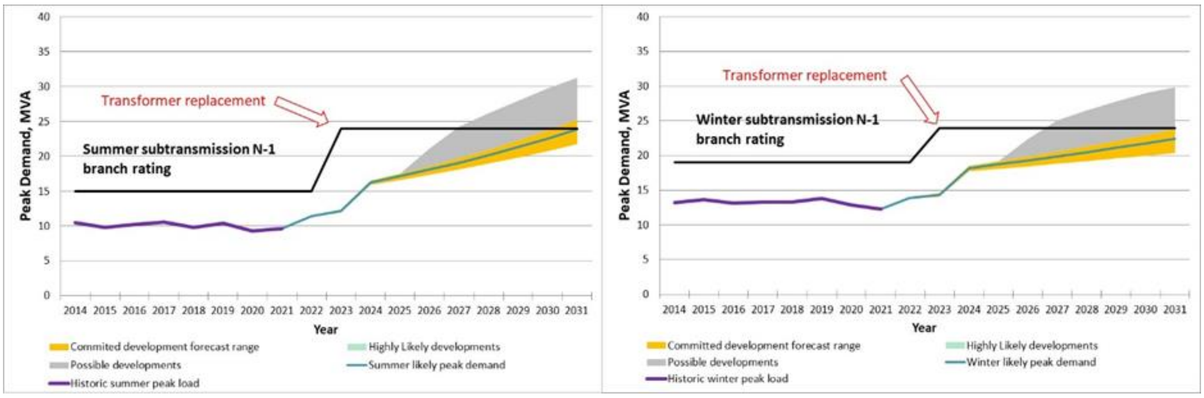


Figure 8-13 Evans Bay Demand Forecast

WELL has initiated a project, scheduled for completion mid-2023, to:

- Install a 33kV bus at Evans Bay to increase system security to Evans Bay, due to the failing health of the existing subtransmission 33kV cables; and
- Replace the existing 33/11kV transformers due to their condition and future capacity requirement.

Following this project, the Evans Bay peak demand is forecast to be within the subtransmission N-1 capacity for the next ten years.

8.4.2.3 Frederick Street

The peak demand supplied by Frederick Street currently exceeds the N-1 capacity of the subtransmission supply cables. Table 8-13 shows the seasonal constraint levels and the minimum off load requirements on each circuit.

Circuit	Season	Constraining N-1 branch rating (MVA)	Peak Demand @ 2021 (MVA)	Minimum off load for N-1 @ peak (MVA)
Frederick Street	Winter	23.2	27.8	4.6
	Summer	19.5	21.8	2.3

Table 8-13 Current Frederick Street Subtransmission Constraints

Following a fault on the subtransmission system, WELL currently closes the 11 kV bus tie and restores supply to customers through partially off-loading Frederick Street to an alternative zone substation.

Figure 8-14 shows the load duration curve against the N-1 cyclic ratings of transformer and subtransmission cable. The load duration curve shows the proportion of load at risk. The loading exceeds the cable's N-1 summer cyclic rating for approximately 3.9% of the time in summer and the cable's N-1 winter cyclic rating for approximately 11.9% of the time in winter. This analysis uses a load duration curve based on 30 minute periods and is higher than the peak.

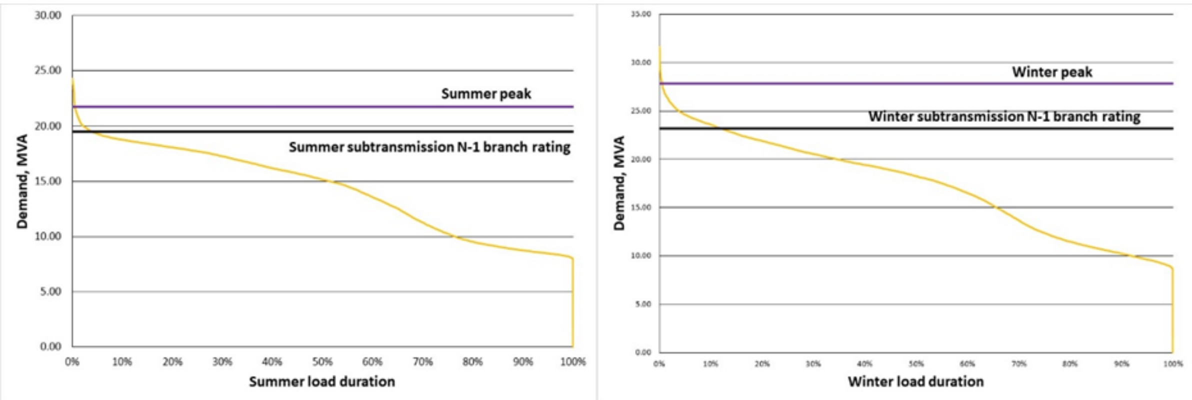


Figure 8-14 Frederick Street Load Duration Curve

Based on the estimated growth scenarios and step change growth accounted for within the planning period, the load at Frederick Street is forecasted to change as shown in Figure 8-15. The subtransmission capacity constraints are plotted for comparison.

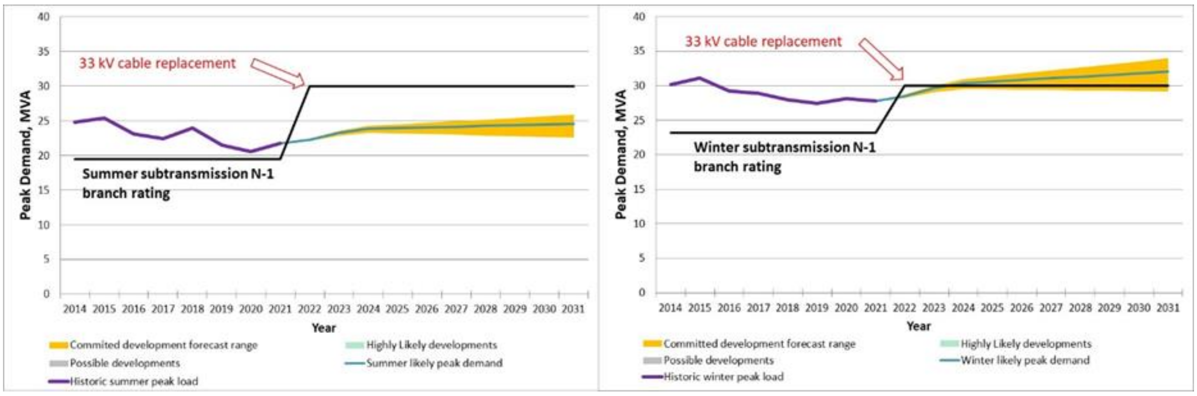


Figure 8-15 Frederick Street Demand Forecast

WELL has a project to replace the Frederick street subtransmission cables with higher capacity cables, scheduled for completion in early 2022. The upgraded Frederick Street cables can allow for load to be shifted between Frederick Street and The Terrace zone substations to defer The Terrace transformer replacement timeline.

8.4.2.4 Hataitai

The peak demand supplied from Hataitai is currently within the N-1 capacity of the subtransmission circuits. Table 8-14 shows the seasonal constraint levels and the minimum off load requirements on each circuit.

Circuit	Season	Constraining N-1 branch rating (MVA)	Peak Demand @ 2021 (MVA)	Minimum off load for N-1 @ peak (MVA)
Hataitai	Winter	22.0	17.7	0
	Summer	13.0	10.5	0

Table 8-14 Current Hataitai Subtransmission Constraints

Following a fault on the subtransmission system, WELL currently closes the 11 kV bus tie and restores supply to customers. Figure 8-16 shows the load duration curve against the subtransmission N-1 ratings. The load duration curve shows the proportion of load at risk. This analysis uses a load duration curve based on 30 minute periods and is higher than the peak.

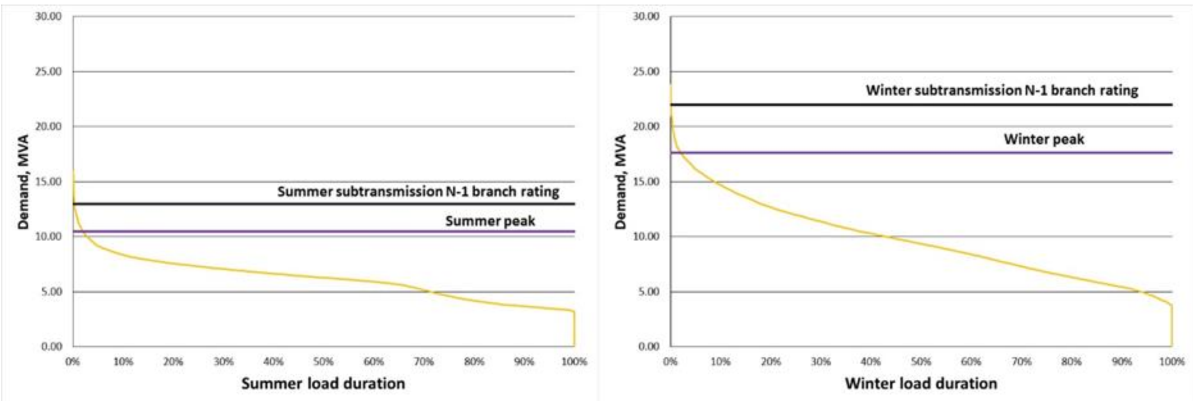


Figure 8-16 Hataitai Load Duration Curve

Based on the estimated growth scenarios and step change growth accounted for within the planning period, the load at Hataitai is forecasted to change as shown in Figure 8-17. The subtransmission capacity constraints are plotted for comparison.

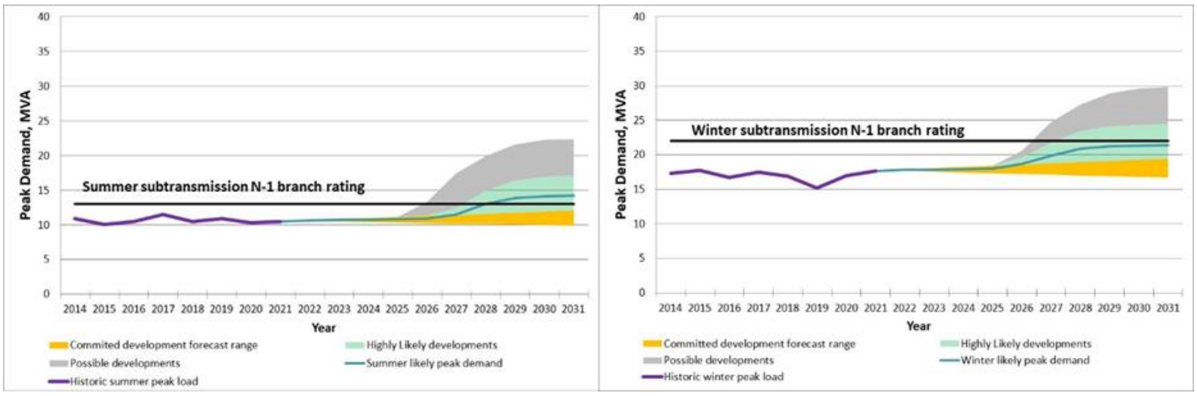


Figure 8-17 Hataitai Demand Forecast

The Haitaitai peak demand is forecast to exceed the winter and summer subtransmission N-1 capacity by 2027 due to a planned transfer of load from Palm Grove to Hataitai. A possible alternative option to transferring the load between the zone substations is to build a new zone substation in Newtown to relieve the load at the surrounding zone substations.

8.4.2.5 Karori

The peak demand supplied from Karori is currently within the N-1 capacity of the subtransmission circuits. Table 8-15 shows the seasonal constraint levels and the minimum off load requirements on each circuit.

Circuit	Season	Constraining N-1 branch rating (MVA)	Peak Demand @ 2021 (MVA)	Minimum off load for N-1 @ peak (MVA)
Karori	Winter	20.0	15.1	0*
	Summer	11.0	9.6	0

* This table shows the 98th percentile station peak load. The potential overload at maximum demand occurs for short periods of time and is within the equipment short-term rating.

Table 8-15 Current Karori Subtransmission Constraints

Following a fault on the subtransmission system, WELL currently closes the 11 kV bus tie and restores supply to customers and partially off-loading Karori to an adjacent zone substations.

Figure 8-18 shows the load duration curve against the subtransmission N-1 ratings.

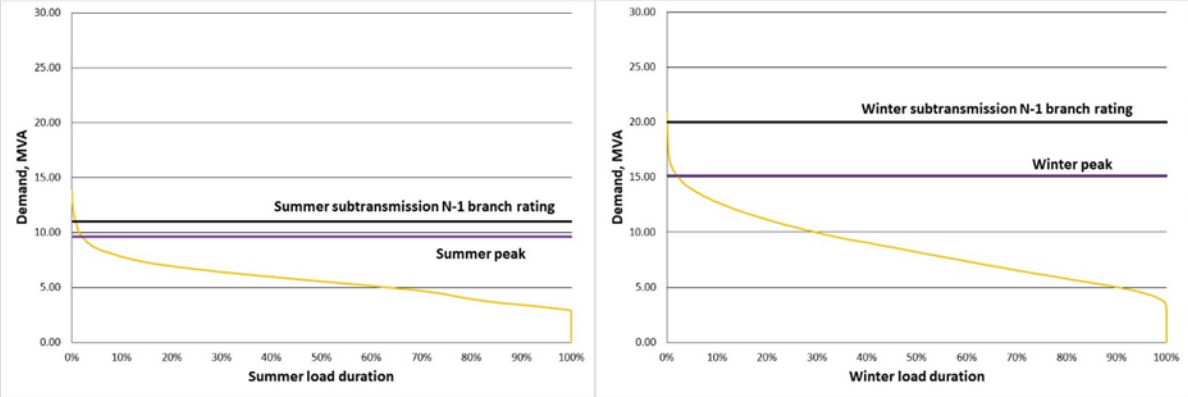


Figure 8-18 Karori Load Duration Curve

The load duration curve shows the proportion of load at risk. This analysis uses a load duration curve based on 30 minute periods and is higher than the peak. Based on the estimated growth scenarios and step change growth accounted for within the planning period, the load at Karori is forecasted to change as shown in Figure 8-19. The subtransmission capacity constraints are plotted for comparison.

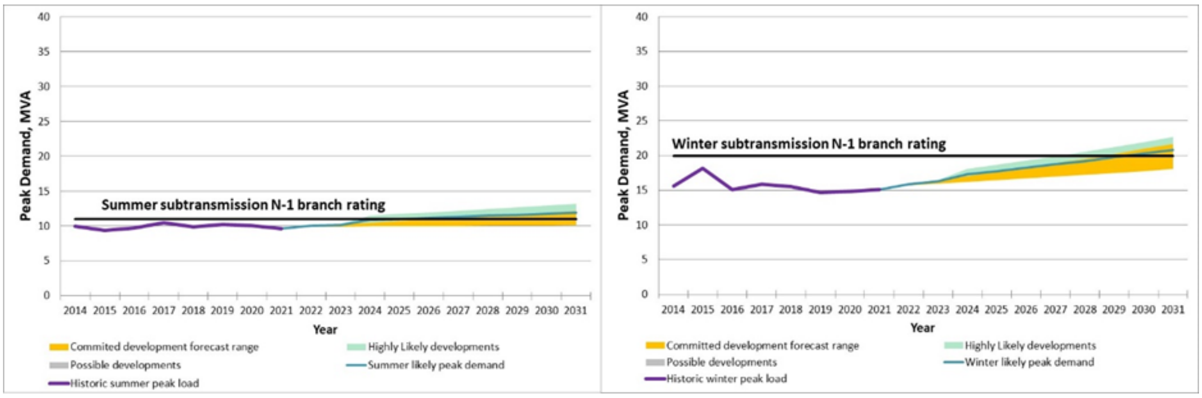


Figure 8-19 Karori Demand Forecast

The Karori summer peak demand is forecast to exceed the subtransmission N-1 capacity from 2025.

WELL continues to monitor the load growth and will investigate options to mitigate system constraints as possible step load growth gets confirmed. WELL will also manage the summer load until asset replacement or significant step change in load is confirmed.

8.4.2.6 Moore Street

The peak demand supplied from Moore Street is currently within the N-1 capacity of the subtransmission circuits. Table 8-16 shows the seasonal constraint levels and the minimum off load requirements on each circuit.

Circuit	Season	Constraining N-1 branch rating (MVA)	Peak Demand @ 2021 (MVA)	Minimum off load for N-1 @ peak (MVA)
Moore Street	Winter	30.0	19.7	0
	Summer	30.0	20.9	0

Table 8-16 Current Moore Street Subtransmission Constraints

Following a fault on the subtransmission system, WELL currently closes the 11 kV bus tie and restores supply to customers through partially off-loading Moore Street to adjacent zone substations.

Figure 8-20 shows the load duration curve against the subtransmission N-1 ratings.

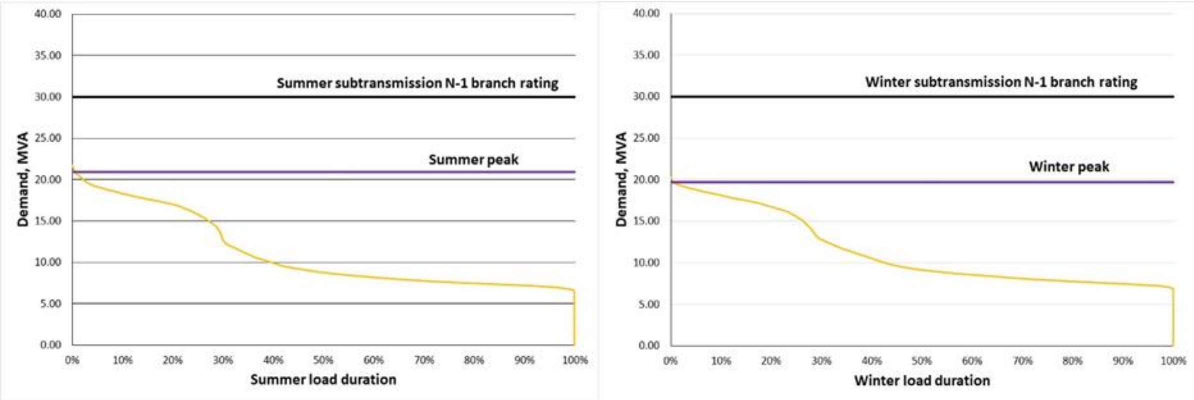


Figure 8-20 Moore Street Load Duration Curve

The load duration curve shows the proportion of load at risk. This analysis uses a load duration curve based on 30 minute periods and is higher than the peak.

Based on the estimated growth scenarios and step change growth accounted for within the planning period, the load at Moore Street is forecasted to change as shown in Figure 8-21. The subtransmission capacity constraints are plotted for comparison.

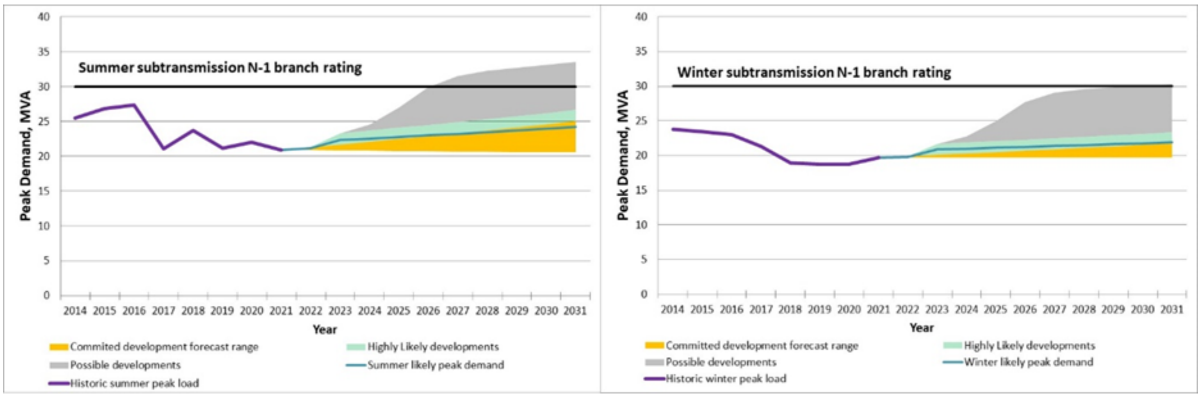


Figure 8-21 Moore Street Demand Forecast

The Moore Street peak demand is forecast to be within the subtransmission N-1 capacity for the next ten years.

8.4.2.7 Nairn Street

The peak demand supplied from Nairn Street currently is within the N-1 rating of the subtransmission circuits. Table 8-17 shows the seasonal constraint levels and the minimum off load requirements on each circuit.

Circuit	Season	Constraining N-1 branch rating (MVA)	Peak Demand @ 2021 (MVA)	Minimum off load for N-1 @ peak (MVA)
Nairn Street	Winter	22.0	21.8	0*
	Summer	22.0	15.7	0
* This table shows the 98th percentile station peak load. The potential overload at maximum demand occurs for short periods of time and is within the equipment short-term rating.				

Table 8-17 Current Nairn Street Subtransmission Constraints

Following a fault on the subtransmission system, WELL currently closes the 11 kV bus tie and restores supply to customers through partially off-loading Nairn Street to adjacent zone substation.

Figure 8-22 shows the load duration curve against the subtransmission N-1 ratings.

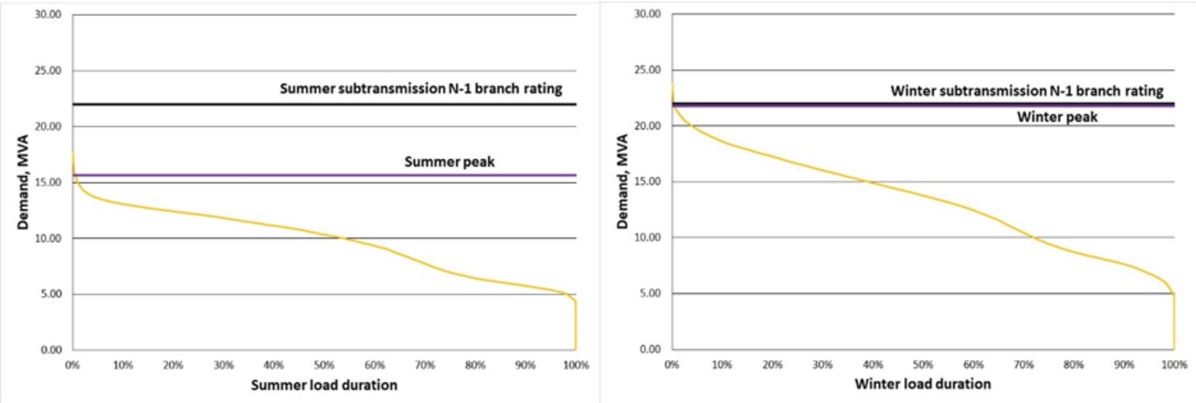


Figure 8-22 Nairn Street Load Duration Curve

The load duration curve shows the proportion of load at risk. This analysis uses a load duration curve based on 30 minute periods and is higher than the peak.

Based on the estimated growth scenarios and step change growth accounted for within the planning period, the load at Nairn Street is forecasted to change as shown in Figure 8-23. The subtransmission capacity constraints are plotted for comparison.

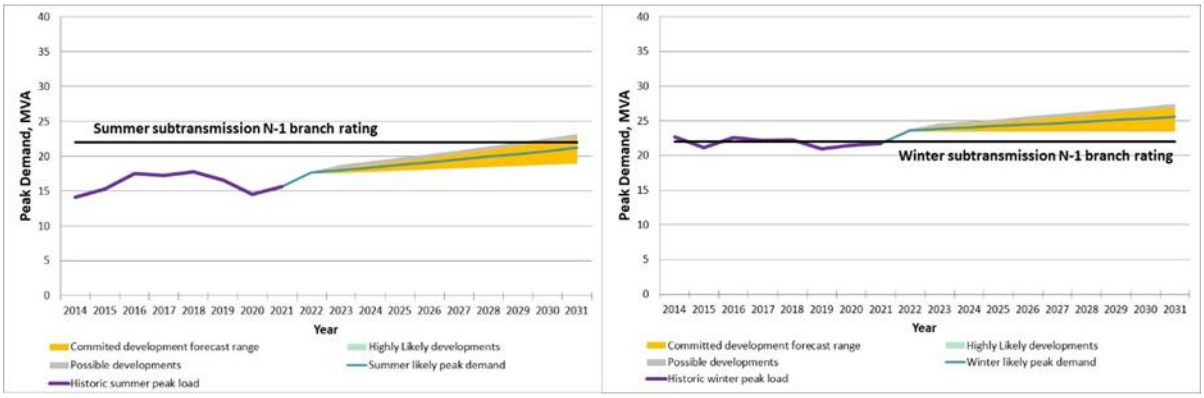


Figure 8-23 Nairn Street Demand Forecast

The Nairn Street winter peak demand is forecast to exceed the existing subtransmission N-1 capacity from 2022. WELL continues to monitor the load growth and will investigate options to mitigate system constraints as possible step load growth gets confirmed. The N-1 constraint can be managed in real time by transferring load to another zone substation.

8.4.2.8 Palm Grove

The winter peak demand at Palm Grove currently exceeds the N-1 capacity of the two 20 MVA transformers as shown in Table 8-18. Following an outage of a single subtransmission circuit at Palm Grove during peak demand periods, the bus-tie is closed and switching is performed to move load to adjacent zones. The magnitude of load at risk and duration is summarised in Figure 8-24.

Circuit	Season	Constraining N-1 branch rating (MVA)	Peak Demand @ 2021 (MVA)	Minimum off load for N-1 @ peak (MVA)
Palm Grove	Winter	20.0	25.3	5.3
	Summer	20.0	17.4	0.0

Table 8-18 Current Palm Grove Subtransmission Constraints

The back-feed switching must also be sequenced to maintain supply to Wellington Hospital as supply interruptions of any duration to the hospital are unacceptable. Capital Coast District Health Board (CCDHB) has requested a higher security of supply and resilience at Wellington Hospital. In 2018 WELL completed a detailed solution design for security improvements and additional capacity that will provide another point of supply to the hospital from another zone substation.

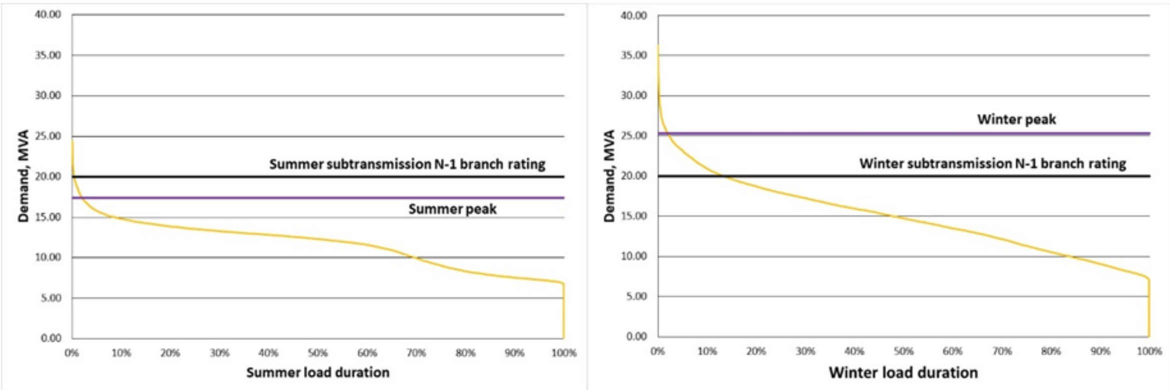


Figure 8-24 Palm Grove Load Duration Curve

The winter peak demand exceeds the existing transformer N-1 capacity for approximately 13.4% of the time, which exceeds the security criteria for a CBD zone substation. This is expected to increase due to organic and step change load growth, as well as the impact of the additional capacity at the public hospital, private hospital and EV buses. This load duration curve is based on 30 minute periods and is higher than the peak.

Based on the growth scenarios and the development accounted for within the planning period, the load at Palm Grove is forecasted to grow as shown in Figure 8-25.

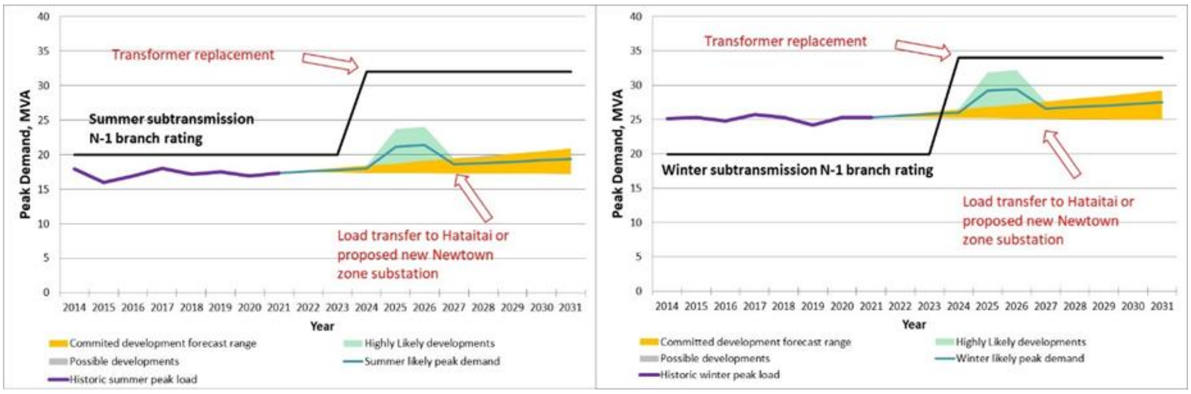


Figure 8-25 Palm Grove Demand Forecast

To manage the load at Palm Grove zone substation, WELL plans to:

- Replace the existing Palm Grove transformers with higher capacity transformers to match the N-1 capacity of the 33 kV subtransmisison cables by early 2025; and
- Transfer some load to either Hataitai zone substation or a new zone substation at Newtown by approximately 2027.

WELL will manage the Palm Grove load operationally by shifting load to adjacent zone substations to relieve overloads until the Palm Grove transformers are replaced.

8.4.2.9 The Terrace

The peak demand at The Terrace is currently within the N-1 capacity of the subtransmission circuits as shown in Table 8-19.

Circuit	Season	Constraining N-1 branch rating (MVA)	Peak Demand @ 2021 (MVA)	Minimum off load for N-1 @ peak (MVA)
The Terrace	Winter	30.0	24.2	0
	Summer	30.0	24.4	0

Table 8-19 Current The Terrace Subtransmission Constraints

Figure 8-26 shows the load duration curve against the subtransmission N-1 capacity. The load duration curve shows the proportion of load at risk. This analysis uses a load duration curve based on 30 minute periods and is higher than the peak.

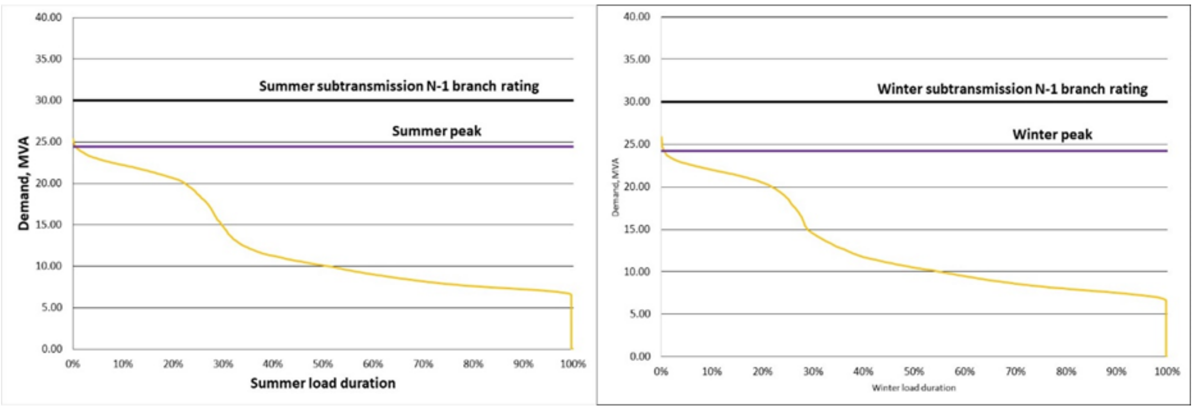


Figure 8-26 The Terrace Load Duration Curve

Based on the estimated growth scenarios and step change growth accounted for within the planning period, the load at The Terrace is forecasted to change as shown in Figure 8-27. The subtransmission capacity constraints are plotted for comparison.

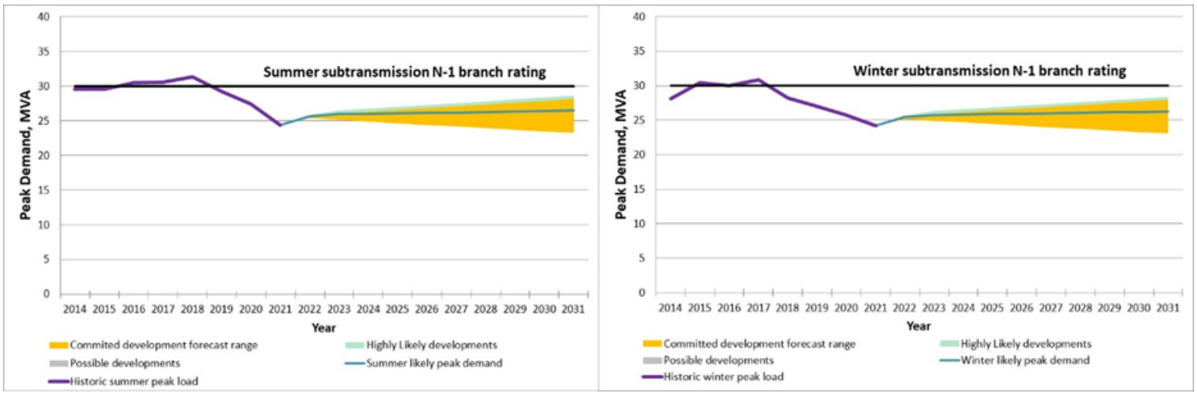


Figure 8-27 The Terrace Demand Forecast

WELL continues to monitor the load growth and will investigate options to mitigate the system constraints as possible step load growth gets confirmed.

8.4.2.10 University

The peak demand supplied from University is currently within the N-1 capacity of the subtransmission circuits. Table 8-20 shows the seasonal constraint levels and the minimum off load requirements on each circuit.

Circuit	Season	Constraining N-1 branch rating (MVA)	Peak Demand @ 2021 (MVA)	Minimum off load for N-1 @ peak (MVA)
University	Winter	20.0	17.9	0
	Summer	20.0	13.6	0

Table 8-20 Current University Subtransmission Constraints

Following a fault on the subtransmission system, WELL currently closes the 11 kV bus tie and restores supply to customers through partially off-loading University to adjacent zone substations.

Figure 8-28 shows the load duration curve against the subtransmission N-1 ratings.

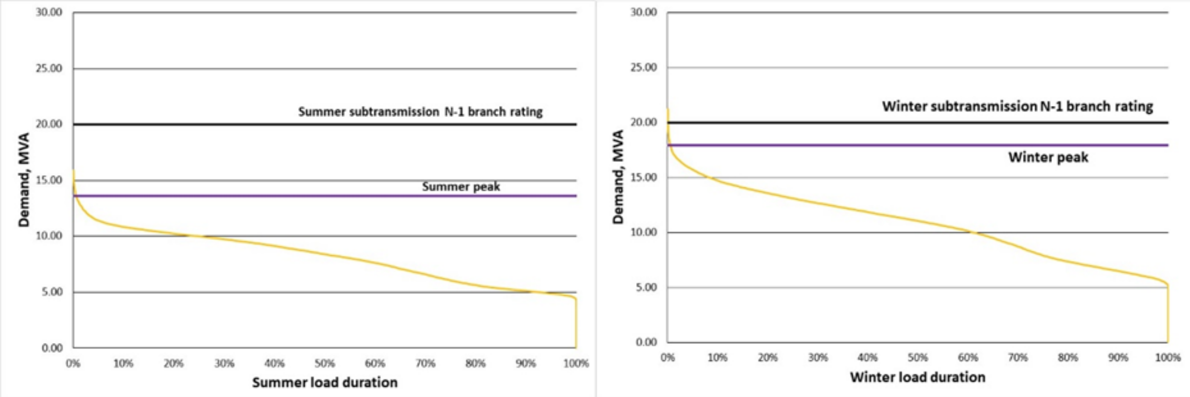


Figure 8-28 University Load Duration Curve

The load duration curve shows the proportion of load at risk. This analysis uses a load duration curve based on 30 minute periods and is higher than the peak.

Based on the estimated growth scenarios and step change growth accounted for within the planning period, the load at University is forecasted to change as shown in Figure 8-29. The subtransmission capacity constraints are plotted for comparison.

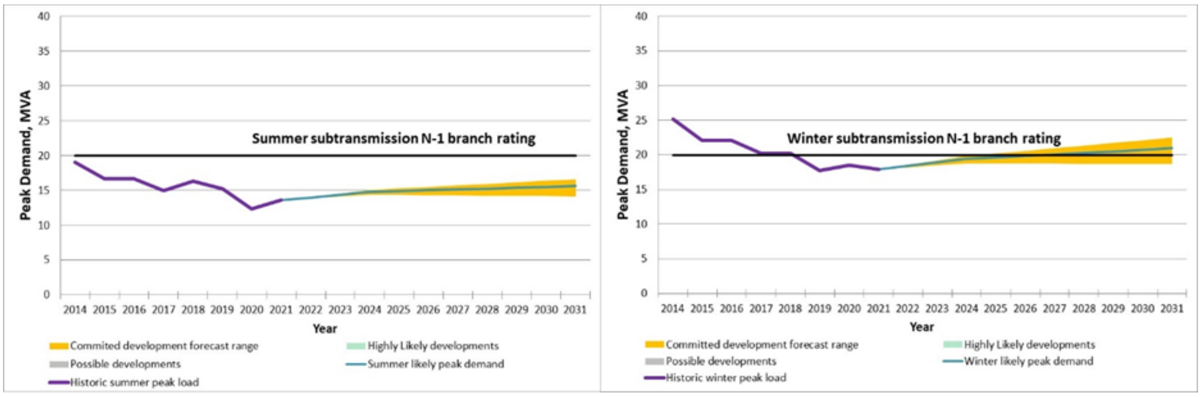


Figure 8-29 University Demand Forecast

The University winter peak demand is forecast to exceed the winter subtransmission N-1 capacity by 2027.

WELL continues to monitor the load growth and will investigate options to mitigate the system constraints as possible step load growth gets confirmed.

8.4.2.11 Waikowhai Street

The peak demand supplied from Waikowhai Street is currently within the N-1 capacity of the subtransmission circuits. Table 8-21 shows the seasonal constraint levels and the minimum off load requirements on each circuit.

Circuit	Season	Constraining N-1 branch rating (MVA)	Peak Demand @ 2020 (MVA)	Minimum off load for N-1 @ peak (MVA)
Waikowhai Street	Winter	15.0	14.2	0
	Summer	13.0	9.0	0

Table 8-21 Current Waikowhai Street Subtransmission Constraints

Following a fault on the subtransmission system, WELL currently closes the 11 kV bus tie and restores supply to customers through partially off-loading Waikowhai Street to an alternative zone substation.

Figure 8-30 shows the load duration curve against the subtransmission N-1 ratings. The load duration curve shows the proportion of load at risk. This analysis uses a load duration curve based on 30 minute periods and is higher than the peak.

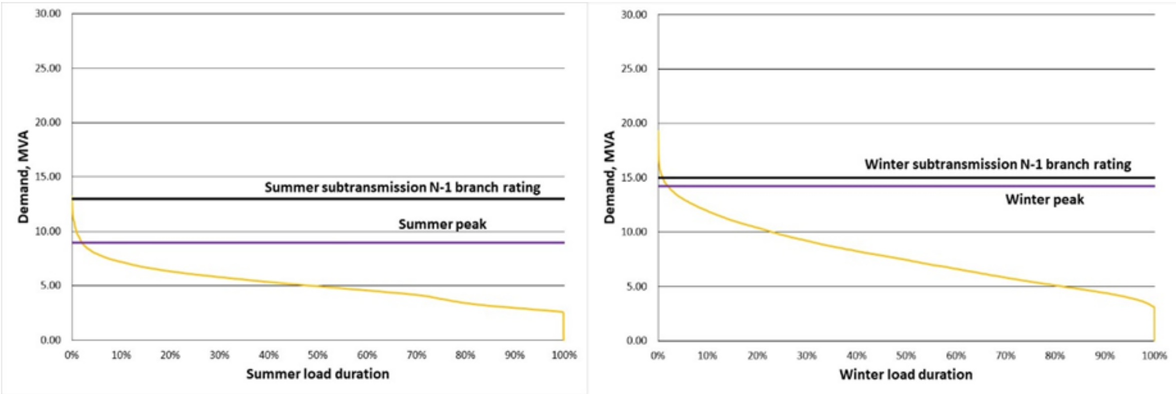


Figure 8-30 Waikowhai Street Load Duration Curve

Based on the estimated growth scenarios and step change growth accounted for within the planning period, the load at Waikowhai Street is forecasted to change as shown in Figure 8-31. The subtransmission capacity constraints are plotted for comparison.

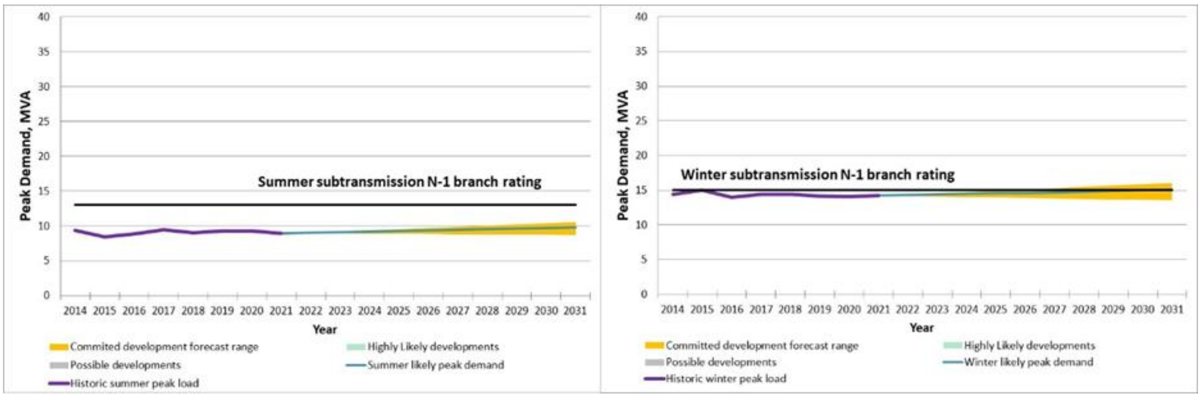


Figure 8-31 Waikowhai Street Demand Forecast

The Waikowhai Street winter peak demand is forecast to exceed the subtransmission N-1 capacity from 2030.

WELL continues to monitor the load growth and will investigate options to mitigate the system constraints as possible step load growth gets confirmed.

8.4.3 HV Distribution Network Development Needs

The distribution network supplying the Wellington CBD is a highly meshed system with overlapping supply boundaries resulting in a high level of inter-dependency between sites. Development options for the Wellington CBD therefore need to consider these inter-dependencies and the effect on the Wellington CBD network as a whole.

Each zone substation supplies the respective 11 kV distribution network, with most zone substations having inter-connectivity via switched open points to adjacent zones. The most critical distribution level issues are those associated with:

- Meshed ring feeders supplying a high number of customers; and
- Links between zone substations which can be used for load transfer.

Table 8-22 shows where the applicable security criteria for normal operating conditions are exceeded, based on forecast demand growth and confirmed step load changes, and an estimation of when the constraints bind. This is used to determine whether further contingency analysis of each individual feeder is required. Alongside each feeder is the priority level of the planning and investment requirements.

Feeder	Loading criteria	Zone Substation	Length of section exceeding loading criteria	Present Loading	+5 years Loading	Feeder ICP Count	Priority
Current							
EVA CB2/4	50%	Evans Bay	5,333 m	61%	107%	2,737	High
FRE CB13/14	50%	Frederick Street	745 m	73%	83%	2,956	Low
KAI CB6/7/9/10 (radial sub feeder)	67% (radial sub feeders)	Kaiwharawhara	4,564 m	92%	94%	2,989	High
KAR CB3/6	50%	Karori	3,040 m	80%	105%	3,691	High
MOO CB1/2	50%	Moore Street	643 m	51%	55%	340	Low
NAI CB8/12	50%	Nairn Street	494 m	62%	72%	693	Medium
NAI CB11/13	50%	Nairn Street	438 m	59%	66%	2,754	Low
NAI CB11/13 (radial sub feeder)	67%	Nairn Street	639 m	79%	88%	2,754	Low
NAI CB14	67%	Nairn Street	1,200 m	69%	78%	2,754	Low
PAL CB2/3/6	67%	Palm Grove	1,263 m	68%	75%	3,947	Medium
PAL CB8/10/12	67%	Palm Grove	1,115 m	72%	80%	5,332	Low
PAL CB8/10/12 (radial sub feeder)	67%	Palm Grove	619 m	80%	88%	5,332	Low
UNI CB8/10	67%	University	2,006 m	68%	78%	2,203	High

Feeder	Loading criteria	Zone Substation	Length of section exceeding loading criteria	Present Loading	+5 years Loading	Feeder ICP Count	Priority
Within Five Years							
FRE CB3/4/5/8	75%	Frederick Street	534 m	Less than 75%	75%	2,650	Low
IRA CB8/9	50%	8 Ira Street	1,163 m	Less than 50%	55%	404	Low
IRA CB 11	67%	8 Ira Street	662 m	Less than 67%	72%	708	Low
UNI CB12	67%	University	255 m	64%	74%	1,313	High

Table 8-22 Distribution Level Issues

Feeder protection settings are typically set for protection of the feeder breaker and an allowable short time overload of the cables. The sudden loss of a single feeder in a meshed ring may result in the transfer of load to the remaining feeders, and protection settings are designed to avoid a trip of the feeder protection relays at the zone substation when this occurs. The loading figures are somewhat worst-case because in most scenarios an isolated 11kV feeder section will also disconnect a small amount of load which will reduce the contingency load transferred to the remaining feeders. The network solution to fix a highly loaded feeder is unlikely to require the full length of the feeder to be upgraded, and it may just need a tactical upgrade of a short length or a reconfiguration of feeder open points.

Table 8-23 shows the results of the contingency analysis performed on the meshed ring feeders in the Southern Area which currently exceeds the security criteria. Overloading feeder segments for each contingency scenario are shown as well as the location of worst-case loading. The contingency loading calculation is based on the current peak demand for each feeder recorded for 2021.

Meshed Ring	Feeder out of service	Overloaded in-service feeder(s)	Length of overloaded feeder section	Loading on the in-service feeder sections
Current				
EVA 2/4	EVA CB02 Out	EVA CB04	1,988 m	129%
	EVA CB04 Out	EVA CB02	1,561 m	130%
FRE 3/4/5/8	FRE CB03 Out	FRE CB04 & 5 & 8	451 m	111%
FRE 13/14	FRE CB14 Out	FRE CB13	1,721 m	129%
IRA 8/9	IRA CB08 Out	IRA CB09	385 m	109%
KAR 3/6	KAR CB03 Out	KAR CB06	1,935 m	157%
	KAR CB06 Out	KAR CB03	1,106 m	139%
NAI 8/12	NAI CB08 Out	NAI CB12	733 m	122%
	NAI CB12 Out	NAI CB08	4,635 m	125%
NAI 11/13	NAI CB13 Out	NAI CB11	1,578 m	104%

Meshed Ring	Feeder out of service	Overloaded in-service feeder(s)	Length of overloaded feeder section	Loading on the in-service feeder sections
PAL 2/3/6	PAL CB06 Out	PAL CB02	927 m	138%
PAL 8/10/12	PAL CB12 Out	PAL CB08 & 10	2,035 m	125%
UNI 8/10	UNI CB08 Out	UNI CB10	1,150 m	125%
	UNI CB10 Out	UNI CB08	856 m	124%
Within 5 years				
FRE 3/4/5/8	FRE CB03 Out	FRE CB04 & 5 & 8	1,131 m	133%
	FRE CB04 Out	FRE CB03 & 5 & 8	534 m	108%
	FRE CB08 Out	FRE CB03 & 4 & 5	752 m	103%
KAR 3/6/10	KAR CB03 Out	KAR CB06 & 10	1,322 m	139%
	KAR CB06 Out	KAR CB03 & 10	1,264 m	153%
	KAR CB10 Out	KAR CB03 & 6	1,105 m	133%
PAL 2/3/6	PAL CB03 Out	PAL CB02 & 6	836 m	102%
	PAL CB06 Out	PAL CB02 & 3	1,792 m	148%

Table 8-23 Meshed Ring Feeder Contingency Analysis

WELL is aware of a number of possible future step load changes identified through customer connection requests, developments detailed in the local council District Plans and through consultation with city councils, developers, and large customers. A number of property developers and businesses have also flagged developments that may create new loads on the network.

The actual outcome and impact of these possible future step change demands is uncertain, and difficult to estimate, and has not been included in the assessment above. WELL is aware some steps loads are compensated by load being reduced in other areas. WELL will continue to monitor progress with these possible step change demands and develop timely solutions to resolve any network issues arising from the step load change demands as they are confirmed.

8.4.4 Summary of Network Development Plan

This section summarises the options available to meet the development needs described above.

As the distribution network within the Southern Area is highly meshed, the development options for the Wellington CBD are comprised of a combination of the individual solutions required to meet each need. Each individual solution is not mutually exclusive because there are options that meet several needs for the same investment.

8.4.4.1 Non-network Solutions

Prior to any investment in any infrastructure being considered, the first step is to implement non-network solutions, discussed in Section 8.1.8. to defer investment.

8.4.4.2 Projects for 2022/23

Table 8-24 lists projects currently underway or planned to start over the next 12 months.

Project	Description
Frederick Street 33 kV Cable Replacement	Replacement of two gas-filled 33kV cables from Central Park to Frederick Street, to resolve the capacity constraint identified in Section 8.4.2.3. The two new 33 kV cables are scheduled to be commissioned in early 2022. An associated protection upgrade is scheduled for completion mid to late 2022.
Evans Bay 33 kV Bus	Construction of a 33kV bus at Evans Bay substation. Detailed design and installation will occur through to 2023/24.

Table 8-24 Southern Area Projects for 2021/22

8.4.4.3 Development Plan Summary

A summary of the development plan for this area is listed in Table 8-25. This information is an extract from the NDRP, which provides detailed development options and feasibility analysis.

Each constraint is identified as an individual issue, but the overall development plan for the region is optimised through a shortlisting process. The most feasible solution may not be the replacement of the constrained asset itself, for example some subtransmission constraints can be solved through 11 kV distribution level configuration change or managed operationally by shifting load to adjacent zone substations to relieve overloads.

Detailed project planning and option engineering will be completed at the project scope development and approval stage.

Project	Description	Constraint Relieved	Target Completion Date (Regulatory year)	Investment Amount (M)
Subtransmission				
Frederick Street 33 kV Cable	Replace the existing Frederick Street 33 kV incomer cables with higher capacity cables	Frederick Street 33 kV subtransmission capacity	2022/23	$9.3
Evans Bay 33 kV Bus	New Evans Bay 33 kV bus	Evans Bay 1 – 33 kV cable condition	2023/24	$5.0
Palm Grove transformer replacement	Replace existing Palm Grove 33/11 kV transformers with higher capacity units	Palm Grove 33/11 kV transformer capacity	2025/26	$4.5
Evans Bay and 8 Ira Street 11 kV feeder reconfiguration	Use 8 Ira Street and Evans Bay 11 kV feeder ties to manage maximum demand during contingency. Monitor load growth in the next five years.	8 Ira Street 33 kV subtransmission capacity	2026/27	$0
Distribution				
Nairn Street 11kV feeder reconfiguration	Reconfigure the Nairn Street 11 kV feeders to transfer some load to the University zone substation	Nairn Street 11/13 ring feeder capacity Nairn Street 14 ring feeder capacity	2022/23	$0.1

Project	Description	Constraint Relieved	Target Completion Date (Regulatory year)	Investment Amount (M)
Karori 11 kV feeder reconfiguration	Transfer Karori CB10 feeder cable to the Karori 3/6 feeder ring to improve capacity	Karori 3/6 ring feeder capacity	2023/24	$0.4
University 11 kV bus reconfiguration	Reconfigure then University 11 kV feeders to balance load across the 11 kV bus	University 12 feeder capacity	2024/25	$0.9
Palm Grove 11 kV feeder reconfiguration	New feeder tie between Palm Grove 11 kV feeders 8 and 11.	Palm Grove 8/10/12 ring feeder capacity	2025/26	$1.4
	Enable shifting open points via SCADA on Palm Grove 2/3/6 ring for post contingency load management	Palm Grove 2/3/6 ring feeder capacity	2025/26	$0.8
	Reconfigure and upgrade Palm Grove 2/3/6 ring to transfer some load transfer to Nairn Street 8/12 ring	Palm Grove 2/3/6 ring feeder capacity	2029/30	$2.0

Table 8-25 Southern Area Development Summary

8.5 Northwestern Area NDRP

This section provides a summary of the Northwestern Area NDRP.

8.5.1 GXP Development Plans

The Northwestern Area is supplied from two GXPs, Takapu Road and Pauatahanui. Transpower owns all supply transformers and the switchgear at the GXPs. The transformer capacity and the peak system demand are set out in Table 8-26. The forecast in Table 8-26 considers only committed developments.

GXP	Continuous Capacity (MVA)	Transformer Cyclic Summer / Winter Capacity (MVA)	Peak Demand (MVA)	
			2021	2031
Takapu Road 33 kV	2x90	111 / 116	93	117
Pauatahanui 33 kV	2x20	22 / 24	18	25

Table 8-26 Northwestern Area GXP Capacities

Many of the investment needs identified at Transpower GXPs have been detailed in Transpower's Transmission Planning Report.

The development need at each GXP is discussed further below.

8.5.1.1 Takapu Road

The Takapu Road GXP comprises two parallel 110/33 kV transformers each nominally rated at 90 MVA with a winter N-1 cyclic capacity of 116 MVA. The maximum demand on the Takapu Road GXP in 2021 was 93 MVA. Takapu Road supplies zone substations at Waitangirua, Porirua, Kenepuru, Tawa, Ngauranga and Johnsonville each via double 33 kV circuits.

The Ngauranga subtransmission circuits from Takapu Road GXP are on a 110 kV double circuit tower line. The line is owned and maintained by Transpower. WELL is working with Transpower on long term supply configuration options. Possible options include:

- Maintaining status quo;
- New 33 kV subtransmission assets from either the same supply point or an alternative supply point; and
- Partial decommissioning and reinforcement.

In 2022 WELL will continue this investigation with Transpower and finalise the solution through a more detailed investigation.

The Takapu Road peak demand is forecast to be at the subtransmission N-1 capacity at the end of the next ten-year period with confirmed and highly likely step load growth. WELL will work with Transpower to develop a long-term solution to meet supply requirements.

8.5.1.2 Pauatahanui

The Pauatahanui GXP is supplied from the Takapu Road GXP via two 110 kV circuits. Pauatahanui GXP comprises two parallel 110/33 kV transformers rated at 20 MVA each, with a winter cyclic N-1 capacity of 24 MVA. The Pauatahanui GXP supplies the Mana and Plimmerton zone substations via a single 33 kV overhead circuit connection to each substation. Mana and Plimmerton zone substations are linked at 11 kV providing a degree of redundancy should one of the 33 kV connections be out of service.

Transpower has identified that the Pauatahanui supply transformers are approaching end-of-life and that asset renewal or replacement will be required within the next 5-10 years. Potential housing and small industrial development in Plimmerton (Porirua City's Northern Growth Area) may add up to 7 MVA to the peak demand over a 15 year period, which may cause Pauatahanui GXP loading to exceed the N-1 rating of existing transformers. At the time of replacement a capacity upgrade will be required, with the future ratings still to be determined. WELL is working with Transpower on developing options that provide the most benefits to meet supply requirements.

8.5.2 Subtransmission Network Development Needs

This section describes the identified security of supply constraints and development needs for the Northwestern Area subtransmission and distribution networks.

The Northwestern network consists of 12 subtransmission 33 kV circuits supplying eight zone substations. Each zone substation supplies the respective zone 11 kV distribution network with inter-connectivity via switched open points to adjacent zones. All 11 kV feeders are radial from the zone substations with the exception of the meshed ring feeders supplying the Porirua CBD and the Titahi Bay substation. The load summary of each zone substation is listed in Table 8-27.

Zone Substation	Season	Subtransmission N-1 branch rating (MVA)		Constraining Branch Component	Peak Demand (MVA)		Date Constraints are Binding	ICP Count as at 2021
		Existing	Post - committed network upgrade		2021	2031		
Existing constraints								
Johnsonville	Winter	16.0	N/A	33kV cable	20.6	21.1	Existing	8,876
	Summer	11.0	N/A	33kV cable	13.7	14.9		
Ngauranga	Winter	10.0	N/A	33/11kV transformer	10.7	16.3	Existing (Winter)	4,570
	Summer	10.0	N/A	33/11kV transformer	7.2	13.9		
Mana	Winter	7.0	N/A	11kV MAN-PLI bus-tie	9.1	10.7	Existing (Winter)	4,425
	Summer	7.0	N/A	11kV MAN-PLI bus-tie	5.7	6.0		
Plimmerton	Winter	7.0	N/A	11kV MAN-PLI bus-tie	8.5	14.1	Existing (Winter)	2,390
	Summer	7.0	N/A	11kV MAN-PLI bus-tie	5.4	9.4		
Porirua	Winter	16.0	N/A	33/11kV transformer	21.9	27.3	Existing	7,040
	Summer	14.0	N/A	33kV cable	17.0	21.6		
Forecasted constraints								
Tawa	Winter	16.0	N/A	33/11kV transformer	14.6	16.1	2023	5,392
	Summer	14.4	N/A	33kV cable	10.5	12.0		
Waitangirua	Winter	16.0	N/A	33/11kV transformer	14.7	19.2	2023 (Winter)	6,061
	Summer	15.2	N/A	33kV cable	9.0	11.6		
Not Constrained								
Kenepuru	Winter	18.3	N/A	33/11kV transformer	11.6	12.9	N/A	2,351
	Summer	13.7	N/A	33kV cable	9.2	9.8		

Table 8-27 Northwestern Area Zone Substation Capacities

The development needs for the Northwestern Area at the subtransmission and distribution level are outlined in the following sections.

Subtransmission constraints can be quantified in terms of duration of risk and assessed against the security criteria in Table 8-1, using a load duration curve. Forecasted constraints are quantified in terms of when the risk is likely to occur based on the forecast demand for a given year.

The zone substations that are forecast to be constrained during the planning period are described below.

8.5.2.1 Johnsonville

The peak demand supplied by Johnsonville currently exceeds the N-1 capacity of the subtransmission circuits. Operational risk is currently managed by load control and transfer to HV feeders from other zone substations. Table 8-28 shows the seasonal constraint levels and the minimum off load requirements.

Zone substation	Season	Subtransmission N-1 Constraining N-1 branch rating (MVA)rating (MVA)	Peak Demand @2021 (MVA)	Minimum off load for N-1 @ peak (MVA)
Johnsonville	Winter	16.0	20.6	4.6
	Summer	11.0	13.7	2.7

Table 8-28 Current Johnsonville Subtransmission Constraints

Figure 8-32 shows the load duration curve against the N-1 ratings of Johnsonville subtransmission circuits. The load duration curves show that at present the demand exceeds the N-1 capacity in winter by approximately 16.5% of the time and in summer by approximately 14.4% of the time. This exceeds the network security standard for a mixed commercial and residential zone substation.

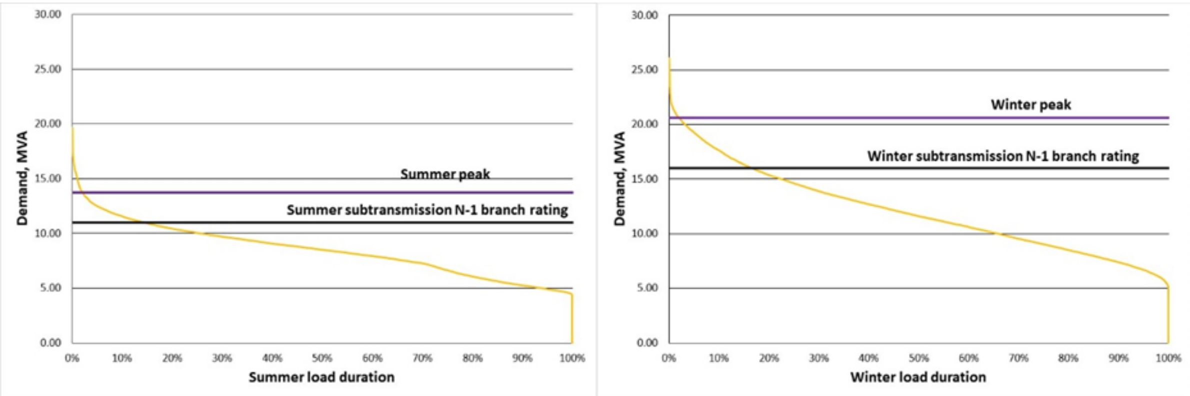


Figure 8-32 Johnsonville Load Duration Curve

Based on the estimated growth scenarios and confirmed step change loaded within the planning period, the load at Johnsonville is forecasted to grow as shown in Figure 8-33.

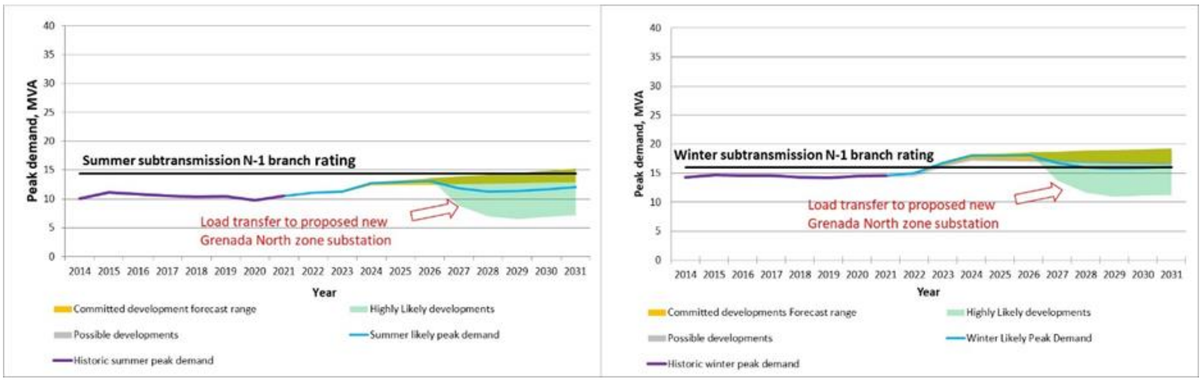


Figure 8-33 Johnsonville Demand Forecast

WELL plans to transfer some load from Johnsonville to a proposed new zone substation at Grenada North and then manage supply security operationally by shifting load to adjacent zone substations to relieve overloads after that.

8.5.2.2 Kenepuru

Maximum demand at Kenepuru is within available N-1 subtransmission capacity. Table 8-29 shows the seasonal constraint levels and the minimum off load requirements.

Circuit	Season	Constraining N-1 branch rating (MVA)	Peak Demand @ 2021 (MVA)	Minimum off load for N-1 @ peak (MVA)
Kenepuru	Winter	18.3	11.6	0
	Summer	13.7	9.2	0

Table 8-29 Current Kenepuru Subtransmission Constraints

Figure 8-34 shows the load duration curve against the N-1 ratings of the Kenepuru subtransmission circuits. The load duration curve shows that at present the demand is below subtransmission N-1 capacity. This is within the network security standard for a mixed commercial and residential zone substation.

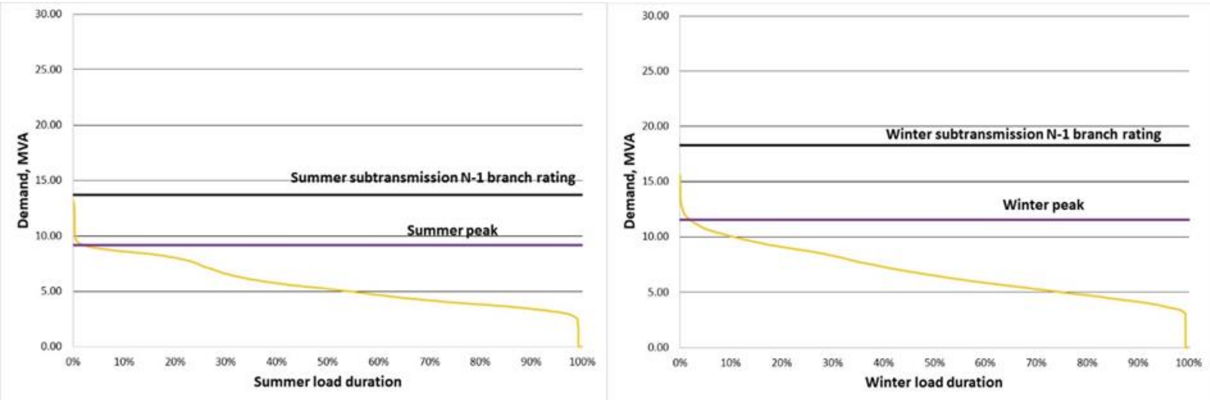


Figure 8-34 Kenepuru Load Duration Curve

Forecasted load growth will come from a new residential sub-division, a retirement village, hospital expansion and industrial load from a factory expanding operations. Figure 8-35 shows the forecast demand for Kenepuru zone substation.

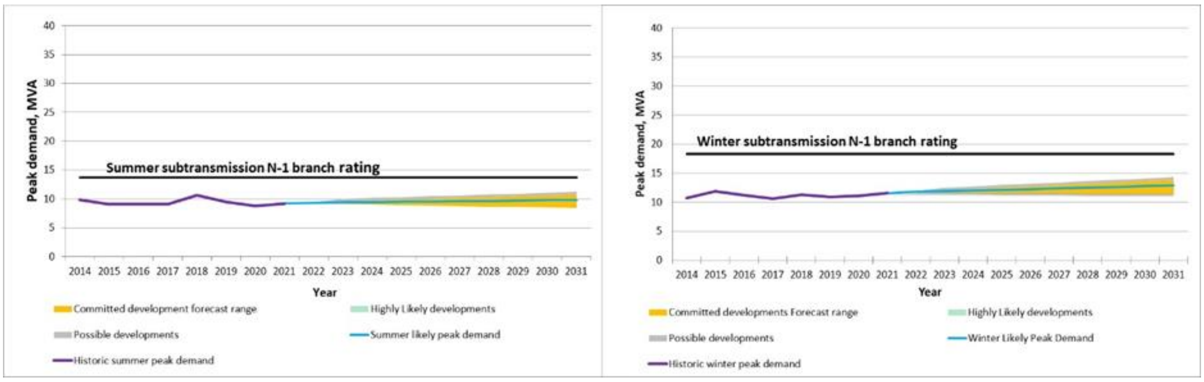


Figure 8-35 Kenepuru Demand Forecast

WELL continues to monitor the load growth and will investigate options to mitigate system constraints as possible step load growth gets confirmed.

8.5.2.3 Ngauranga

The winter peak demand supplied by Ngauranga currently exceeds the N-1 capacity of the subtransmission circuits. Operational risk is currently managed by load control and transfer to HV feeders from other zone substations. Table 8-30 shows the seasonal constraint levels and the minimum off load requirements.

Table 8-30 illustrates the seasonal constraint levels and the minimum off load requirements.

Circuit	Season	Constraining N-1 branch rating (MVA)	Peak Demand @ 2021 (MVA)	Minimum off load for N-1 @ peak (MVA)
Ngauranga	Winter	10.0	10.7	0.7
	Summer	10.0	7.2	0

Table 8-30 Current Ngauranga Subtransmission Constraints

Figure 8-36 shows the load duration curve against the N-1 ratings of the subtransmission circuits for Ngauranga. The load duration curve shows that at present the demand exceeds the N-1 capacity for approximately 5.4% during winter.

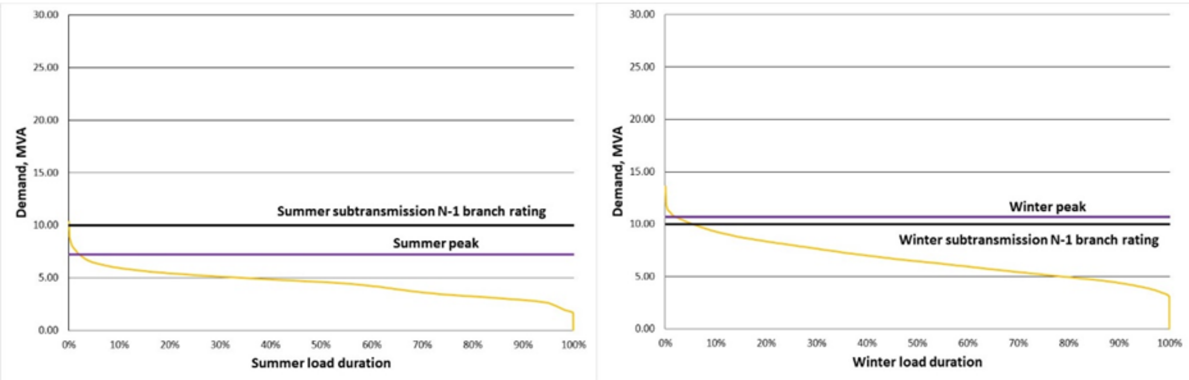


Figure 8-36 Ngauranga Load Duration Curve

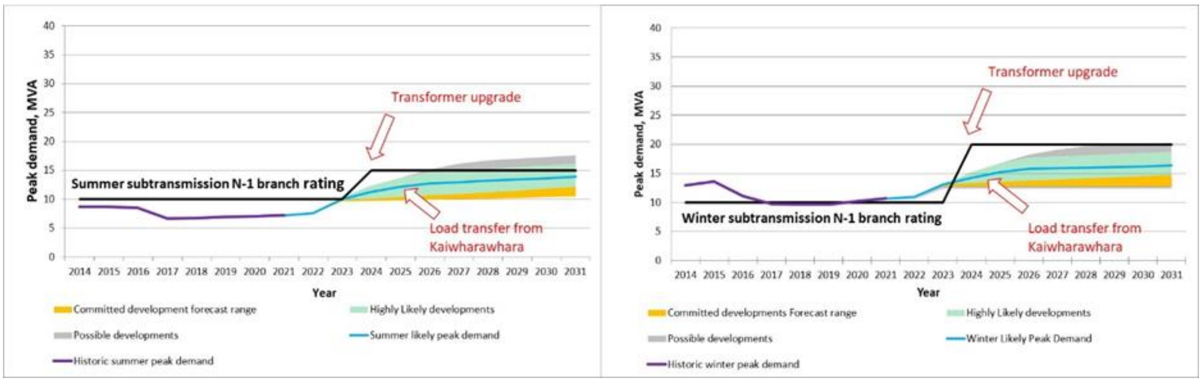


Figure 8-37 shows the forecast demand for Ngauranga zone substation.

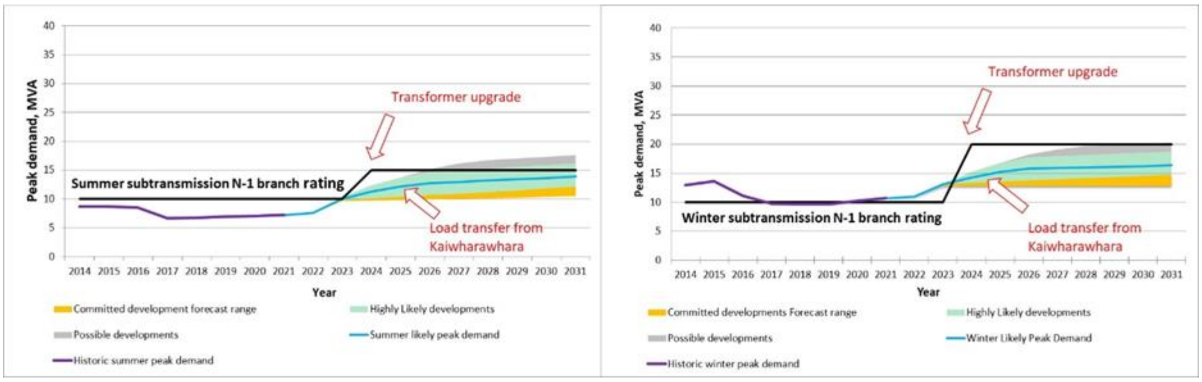


Figure 8-37 Ngauranga Demand Forecast

The peak load at Ngauranga is forecast to exceed the summer and winter N-1 capacity from 2022. In addition, WELL's plans to transfer the primary supply for the abattoir load from Kaiwharawhara to Ngauranga around 2024 is expected to make this situation worse.

WELL plans to resolve these issues by replacing the Ngauranga transformers with higher capacity units. This will provide sufficient capacity for the foreseeable future.

WELL plans to manage supply security operationally by shifting load to adjacent zone substations to relieve overloads until the transformer upgrade.

8.5.2.4 Mana

The Mana zone substation is supplied via a single subtransmission circuit (i.e. a single 33/11 kV transformer and 33kV circuit from Pauatahanui GXP). The Mana zone substation peak demand is below the capacity of this single subtransmission circuit.

The 11 kV buses of the Mana and Plimmerton zone substations are connected via an 11 kV bus tie cable to provide up to 7 MVA backfeed capacity between the two zone substations. When the single 33 kV circuit supplying Mana zone substation is out of service, the amount of load at Mana that can be supplied from the 11 kV bus-tie to Plimmerton zone substation will be limited to the lower of:

- The capacity of the of the 11 kV bus tie cable between Mana and Plimmerton (7 MVA), or
- Ensuring the combined Mana and Plimmerton load does not exceed the capacity of the single subtransmission circuit at Plimmerton (16 MVA).

This may require transferring Mana load to adjacent zone substations, as summarised in Table 8-31.

Circuit	Season	Maximum Mana-Plimmerton Bus-tie capacity (MVA)	Peak Demand @ 2021 (MVA)	Minimum off load for N-1 @ peak (MVA)
Mana	Winter	7.0	9.1	2.1
	Summer	7.0	5.7	0

Table 8-31 Current Mana Subtransmission Constraints

Figure 8-38 shows the load duration curve against the N-1 subtransmission capacity for Mana (with a maximum Mana-Plimmerton bus-tie capacity of 7 MVA). The load duration plot shows the peak demand at

Mana exceeds the available capacity of the bus-tie approximately 15.9% in winter. This load duration curve is based on 30 minute periods and is higher than the peak.

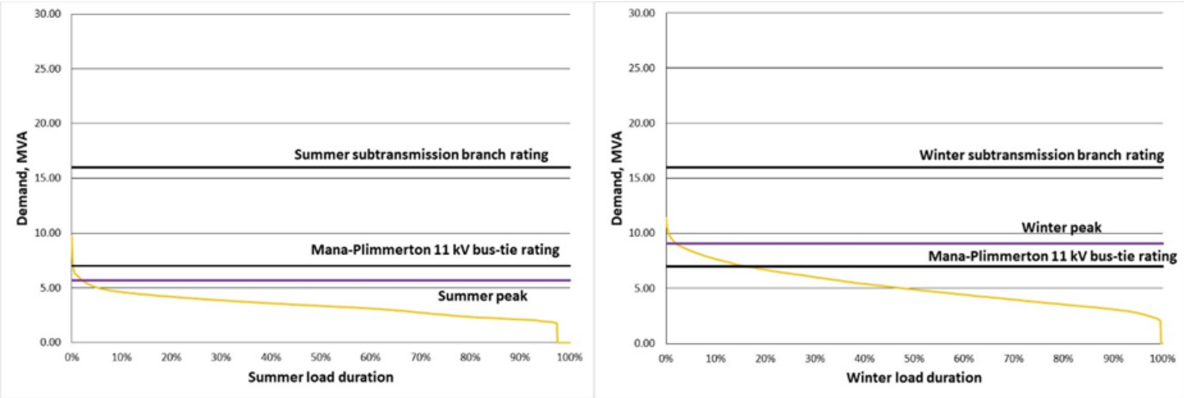


Figure 8-38 Mana Load Duration Curve

Figure 8-39 shows the forecast demand for Mana zone substation based on the estimated growth scenarios and development within the planning period. The subtransmission capacity constraints are plotted for comparison.

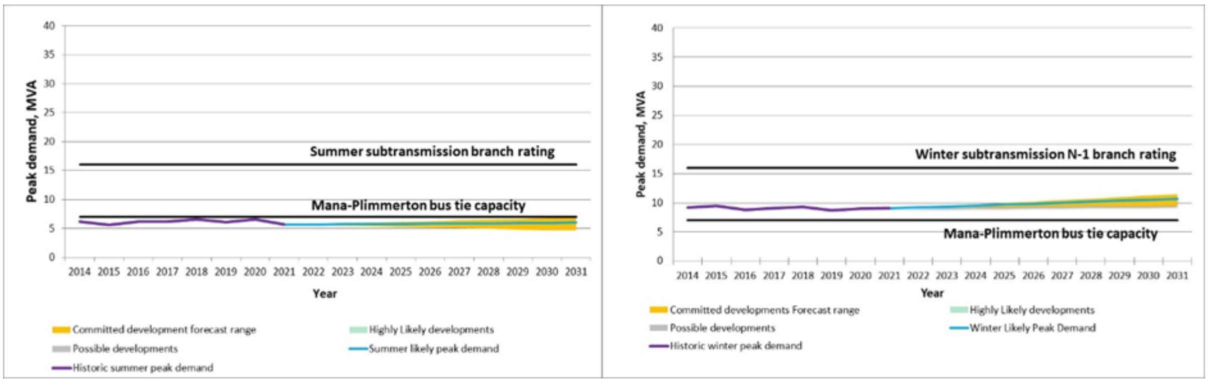


Figure 8-39 Mana Demand Forecast

In the short term, WELL can move load between Mana, Plimmerton and Waitangirua, to manage the capacity within ratings. There is a risk that future step change loading at Mana and Plimmerton will reduce the available transfer capacity and post contingency offload will be less effective.

The new development will also impact the network security and available capacity at Porirua, Waitangirua zone substations and HV feeders in the area.

8.5.2.5 Plimmerton

The Plimmerton zone substation is supplied via a single subtransmission circuit (i.e., a single 33/11 kV transformer and 33 kV circuit from Pauatahanui GXP). The Plimmerton zone substation demand is below the capacity of this single subtransmission circuit.

The 11 kV buses of Mana and Plimmerton zone substations are connected via an 11 kV bus tie cable to provide up to 7 MVA backfeed capacity between the two zone substations. When the single 33 kV circuit supplying Plimmerton zone substation is out of service, the amount of load at Plimmerton zone substation that can be supplied from the 11 kV bus-tie to Mana zone substation will be limited to the lower of:

- The capacity of the of the 11 kV bus tie cable between Mana and Plimmerton (7 MVA), or
- Ensuring the combined Mana and Plimmerton load does not exceed the capacity of the single subtransmission circuit at Mana (16 MVA).

This may require transferring some load to other zone substations, as summarised in Table 8-32.

Circuit	Season	Maximum Mana-Plimmerton Bus-tie capacity (MVA	Peak Demand @ 2021 (MVA)	Minimum off load for N-1 @ peak (MVA)
Plimmerton	Winter	7.0	8.5	1.5
	Summer	7.0	5.4	0

Table 8-32 Current Plimmerton Subtransmission Constraints

Figure 8-40 shows the load duration curve against the N-1 ratings of the Plimmerton subtransmission circuits (with a maximum Mana-Plimmerton bus-tie capacity of 7 MVA). The load duration curve shows that at present the winter peak demand exceeds the firm capacity about 11.4% of the time. This exceeds the network security standard for a mixed commercial and residential zone substation.

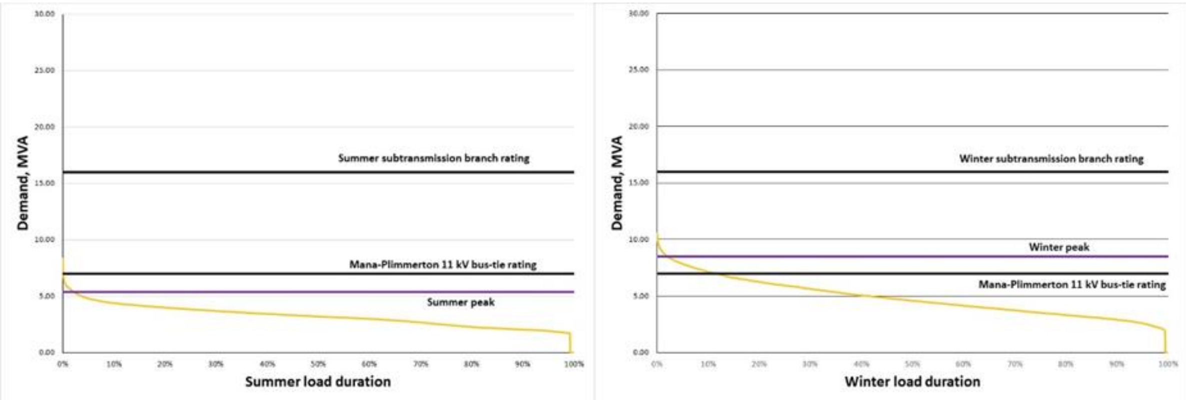


Figure 8-40 Plimmerton Load Duration Curve

Figure 8-41 shows the forecast demand for Plimmerton zone substation based on the estimated growth scenarios and development within the planning period. The subtransmission capacity constraints are plotted for comparison.

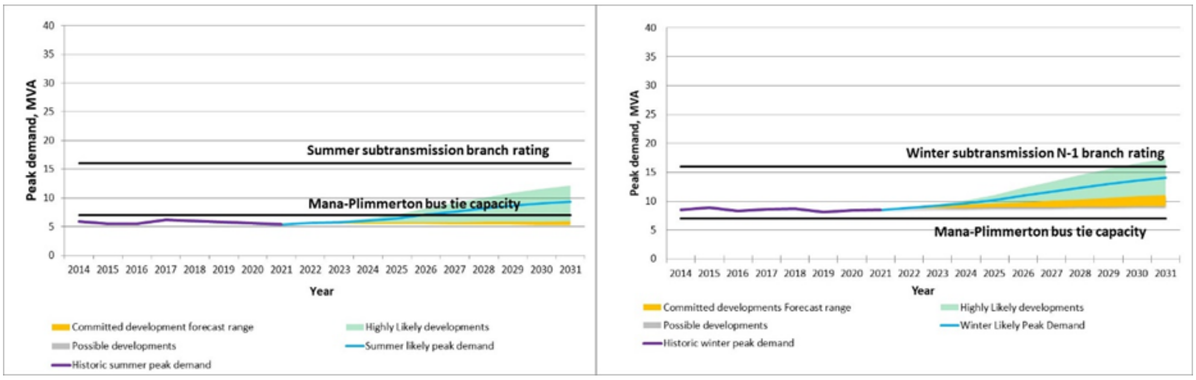


Figure 8-41 Plimmerton Demand Forecast

The load forecast shows that a proportion of load is at risk in the winter periods and a summer constraint may occur if the signalled residential and small industrial development in the Plimmerton proceeds. The new development will also impact the network security and available capacity at Mana zone substations and 11 kV feeders in the area.

8.5.2.6 Porirua

The peak demand supplied at Porirua exceeds the N-1 subtransmission branch ratings for both winter and summer periods. Following a fault on the subtransmission system, load is off-loaded from Porirua to nearby alternative zone substations. Table 8-33 shows the seasonal constraint levels and the minimum off load requirements.

Circuit	Season	Constraining N-1 branch rating (MVA)	Peak Demand @ 2021 (MVA)	Minimum off load for N-1 @ peak (MVA)
Porirua	Winter	16.0	21.9	5.9
	Summer	14.0	17.0	3.0

Table 8-33 Current Porirua Subtransmission Constraints

The risk of increasing these constraints is dependent on planned step change demands due to re-development of the Porirua city centre, continuing residential growth in the Aotea area and the proposed Eastern Porirua Regeneration.

Figure 8-42 shows the load duration curve against the subtransmission N-1 branch ratings.

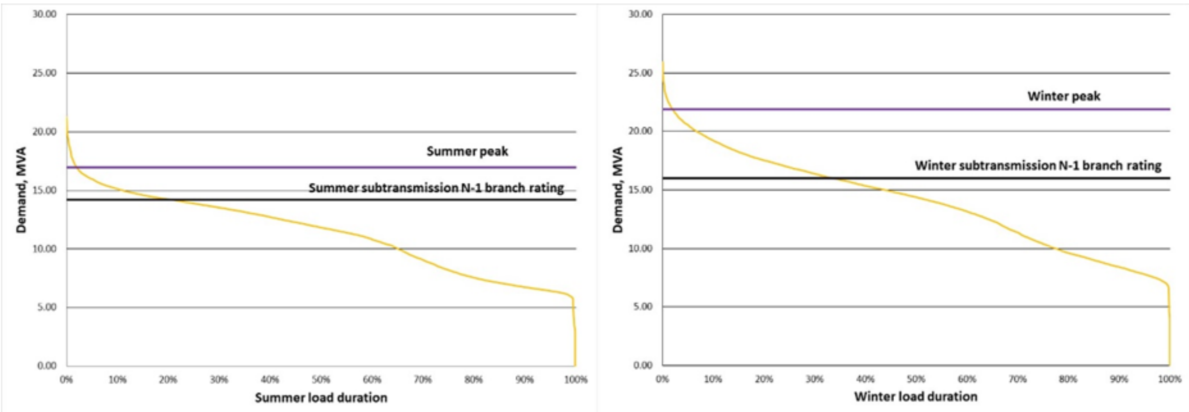


Figure 8-42 Porirua Load Duration Curve

The load duration curve shows that at present, demand exceeds N-1 subtransmission branch rating for approximately 33.4% of the time during winter and 20.3% during summer. Based on the estimated growth scenarios and confirmed step change loads within the planning period, the load at Porirua is forecast to grow as shown in Figure 8-43.

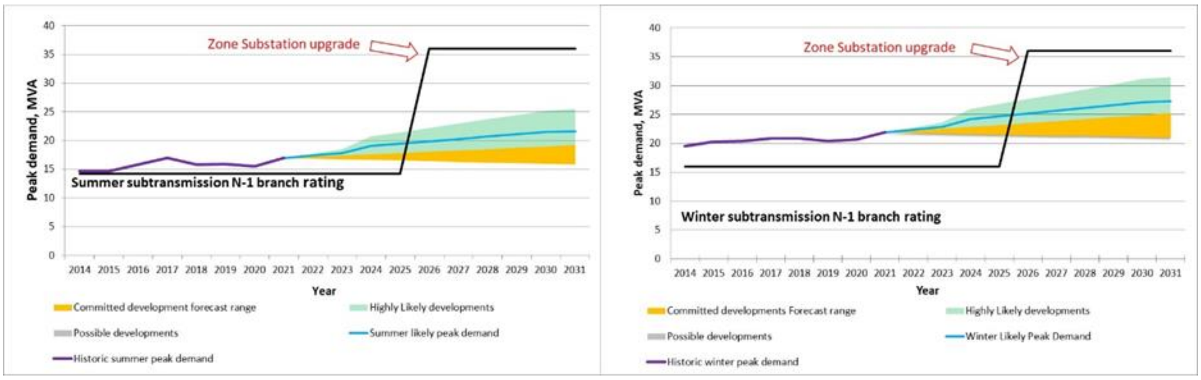


Figure 8-43 Porirua Demand Forecast

WELL plans to upgrade Porirua zone substation, including replacing the transformers with higher capacity units and replacing the sub transmission circuits, to resolve this issue. WELL will manage supply security operationally by shifting load to adjacent zone substations to relieve overloads until the substation upgrade.

8.5.2.7 Tawa

The peak demand supplied at Tawa is currently within the N-1 capacity of the subtransmission circuits. Table 8-34 shows the seasonal constraint levels and the minimum off load requirements.

Circuit	Season	Constraining N-1 branch rating (MVA)	Peak Demand @ 2020 (MVA)	Minimum off load for N-1 @ peak (MVA)
Tawa	Winter	16.0	14.6	0
	Summer	14.4	10.5	0

Table 8-34 Current Tawa Subtransmission Constraints

Figure 8-44 shows the load duration curve against the N-1 subtransmission branch ratings for Tawa.

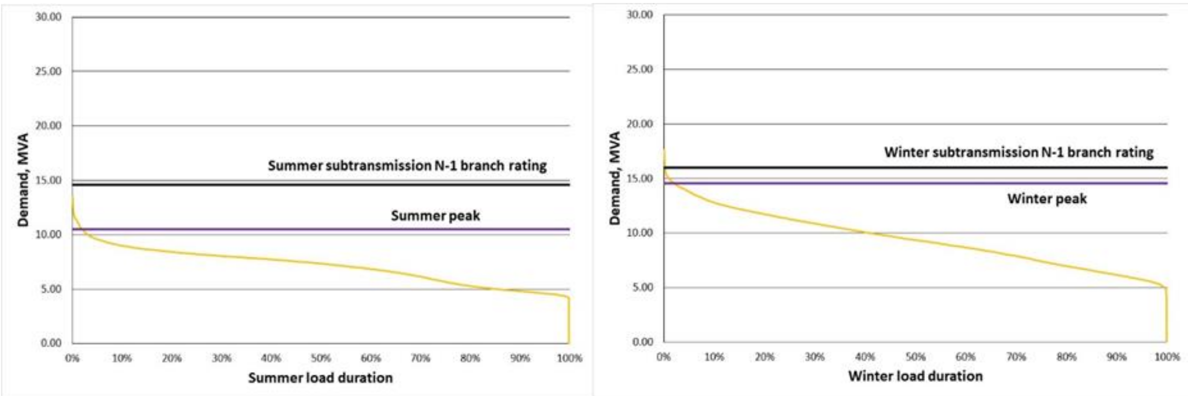


Figure 8-44 Tawa Load Duration Curve

Based on the estimated growth scenarios and confirmed step change loads within the planning period, the load at Tawa is forecast to grow as shown in Figure 8-45. The winter peak demand is forecast to exceed the subtransmission N-1 capacity from 2023. Most of the growth is expected to come from the Grenada North industrial area and new residential developments in Grenada.

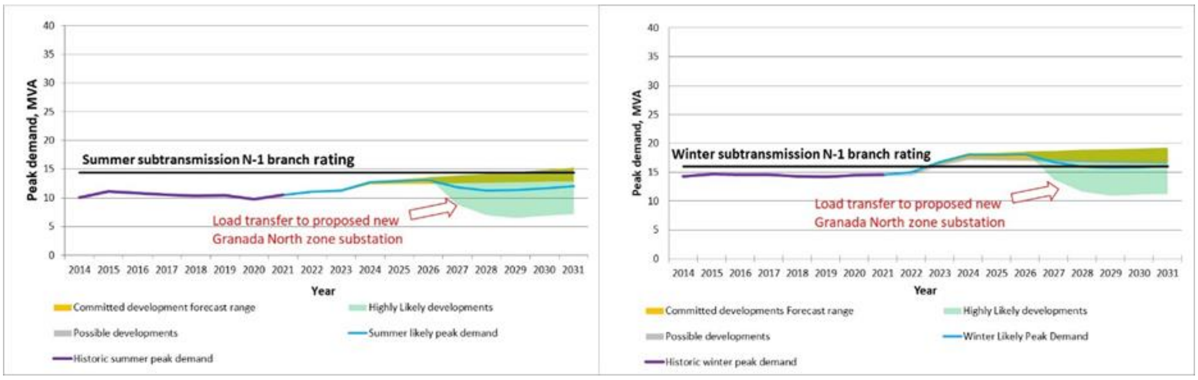


Figure 8-45 Tawa Demand Forecast

WELL plans to shift some load from Tawa to a proposed new zone substation at Grenada North and then manage supply security operationally by shifting load to adjacent zone substations to relieve overloads after that.

8.5.2.8 Waitangirua

The peak demand supplied by Waitangirua is currently within the N-1 branch rating of the subtransmission circuits. Table 8-35 shows the seasonal constraint levels and the minimum off load requirements.

Zone substation	Season	Constraining N-1 branch rating (MVA)	Peak Demand @2020 (MVA)	Minimum off load for N-1 @ peak (MVA)
Waitangirua	Winter	16.0	14.7	0
	Summer	15.2	9.0	0

Table 8-35 Current Waitangirua Subtransmission Constraints

Figure 8-46 shows the load duration curve against the N-1 subtransmission branch ratings for Waitangirua. The load duration curve shows that at present the demand exceeds the N-1 capacity less than 2% of the year. This is within the network security standard for a mixed commercial and residential zone substation.

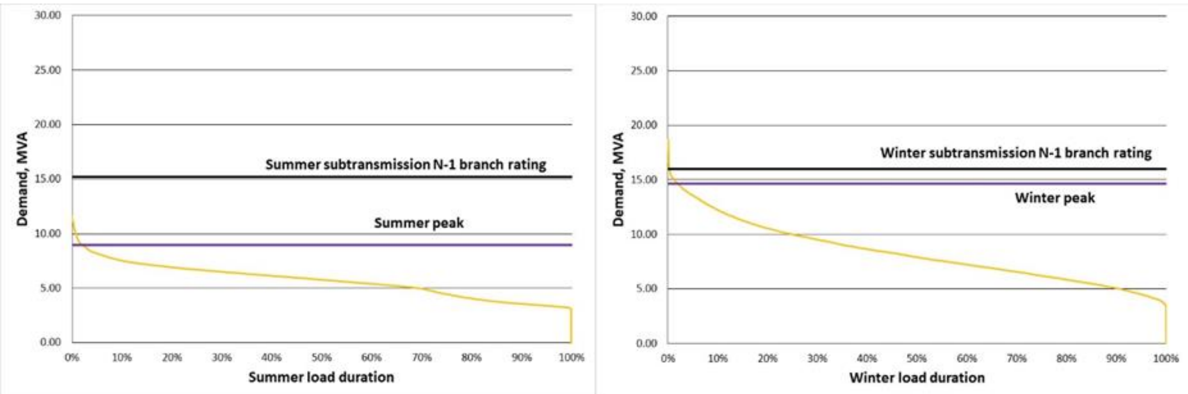


Figure 8-46 Waitangirua Load Duration Curve

Based on the estimated growth scenarios and confirmed step change loaded within the planning period, the load at Waitangirua is forecasted to grow as show in Figure 8-47. Without action, the peak demand will exceed the N-1 subtransmission capacity from 2023. This will also reduce the capacity available to backup adjacent zone substations. Growth in the Waitangirua load is expected to come from residential developments in the Whitby area and the proposed Eastern Porirua Regeneration project.

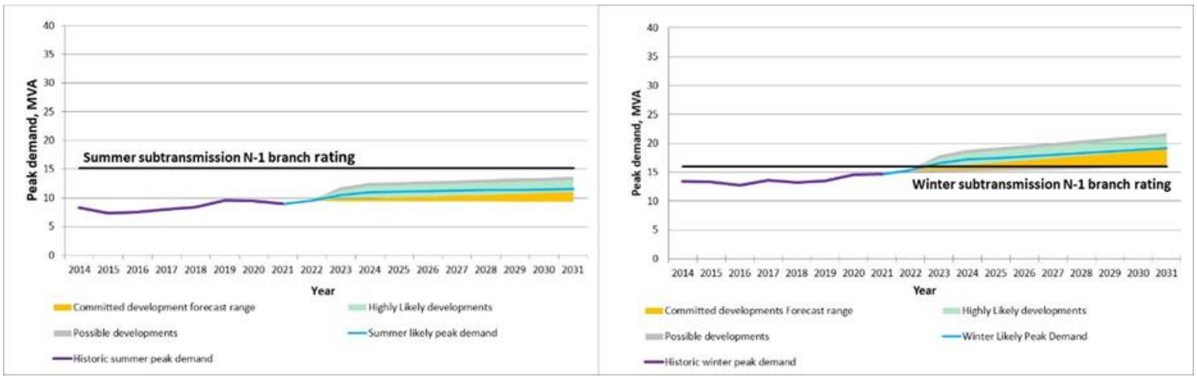


Figure 8-47 Waitangirua Demand Forecast

WELL will continue monitoring load growth and manage the overloading risk through operational control by shifting load to adjacent zone substations to relieve overloads.

8.5.3 Distribution Level Development Needs

The most critical distribution level issues are those associated with:

- Meshed ring feeders supplying a high number of customers; and
- Links between zone substations which can be used for load transfer.

Table 8-36 shows where the applicable security criteria for the feeder configurations are exceeded, based on forecast demand growth and confirmed step load changes, and an estimation of when the constraints bind. This is used to determine whether further contingency analysis of each individual feeder is required. Alongside each feeder is the priority level of the planning and investment requirements.

Feeder	Loading criteria	Zone Substation	Length of section exceeding loading criteria	Present Loading	+5 years	Feeder ICP Count	Priority
Current							
JOH CB6	67%	Johnsonville	998 m	74%	76%	1,769	Medium
JOH CB12	67%	Johnsonville	446 m	69%	71%	1,346	Medium
KEN CB9	67%	Kenepuru	383 m	69%	73%	492	Low
NGA CB4	67%	Ngauranga	1,025 m	70%	74%	1,730	Low
POR CB4/5	50%	Porirua	110 m	64%	67%	376	Low
POR CB06	67%	Porirua	850 m	83%	124%	49	Medium
TAW CB11	67%	Tawa	2,207 m	74%	75%	639	High
WTG CB5	67%	Waitangirua	3,983 m	84%	92%	1,775	High
WTG CB11	67%	Waitangirua	1,937 m	89%	142%	1,727	High

Within Five Years							
KEN CB 4	67%	Kenepuru	493 m	Less than 67%	89%	148	Low
NGA CB1	67%	Ngauranga	70 m	Less than 67%	74%	485	Low
NGA CB9	67%	Ngauranga	2,340 m	Less than 67%	129%	1,063	High
POR CB1/11 (POR-TIT)	50%	Porirua	8,590 m	Less than 50%	74%	3,157	Medium
POR CB 12	67%	Porirua	890 m	Less than 67%	84%	1,045	Low

Table 8-36 Distribution Level Issues

Feeder protection settings are typically set for protection of the feeder breaker and an allowable short time overload of the cables. The sudden loss of a single feeder may result in the transfer of load to the remaining feeders and is designed to avoid a trip of the feeder protection relays at the zone substation.

Table 8-37 shows the results of the contingency analysis performed on the meshed ring feeders in the Northwestern Area which currently exceeds the security criteria. Overloading feeder segments for each contingency scenario are shown as well as the location of worst case loading. The contingency loading calculation is based on the peak demand for each feeder recorded for 2021.

Meshed Ring	Feeder out of service	Overloaded in-service feeder	Length of overloading feeder section	Loading on the in-service feeder sections
Current				
POR CB1/11 (POR-TIT)	POR 01 out	POR 11	4,298 m	94%
	POR 11 out	POR 01	4,291 m	94%
POR CB4/5	POR 04 out	POR 05	591 m	106%

Table 8-37 Meshed Ring Feeder Contingency Analysis

WELL is aware of a number of possible future step load changes identified through customer connection requests, developments detailed in the individual local council District Plans and consultation with city councils, developers, and large customers. A number of property developers and businesses have also flagged developments that may create new loads on the network.

The actual outcome and impact of these possible future step change demands is uncertain, and difficult to estimate, and has not been included in the assessment above. WELL will continue to monitor progress with these possible step change demands and develop timely solutions to resolve any network issues arising from the step change demands as they are confirmed.

8.5.4 Summary of Network Development Plan

This section summarises the options available to meet the development needs described above.

The development options for the Northwestern Area comprise of a combination of the individual solutions required to meet each need. Each individual solution is not mutually exclusive because there are solutions which meet several needs for the same investment.

8.5.4.1 Non-network Solutions

Prior to any investment in any infrastructure being considered, the first step is to implement non-network solutions, discussed in Section 8.1.8, to defer investment.

8.5.4.2 Projects for 2022/23

Projects currently underway or planned to start over the next 12 months are listed in Table 8-38.

Project	Description
11 kV feeder upgrade programme	11 kV feeder upgrades / new feeder cables across the area

Table 8-38 Northwestern Area Projects for 2022/23

8.5.4.3 Development Plan Summary

A summary of the development plan for this area is listed in Table 8-39. This information is an extract from the NDRP, which provides detailed development options and feasibility analysis.

Each constraint is identified as an individual issue, but the overall development plan for the region is optimised through a shortlisting process. The most feasible solution may not be the replacement of the constrained asset itself, for example, many subtransmission constraints can be solved through HV distribution level configuration change or managed operationally by shifting load to adjacent zone substations to relieve overloads.

Detailed project planning and option engineering will be completed at the project scope development and approval stage.

Project	Description	Constraint Relieved	Target Completion (Regulatory year)	Investment Amount (M)
Subtransmission				
Khandallah – Takapu Road 33kV pole line replacement	Explore replacing or upgrading the existing 33 kV overhead line from Takapu Road GXP to Ngauranga zone substation.route	Ngauranga subtransmission future configuration	2024/25	$0.7
Ngauranga transformer upgrade	Upgrade NGA transformer capacity with higher capacity units	Ngauranga 33/11 kV transformer capacity	2025/26	$4.5
Porirua Zone Substation upgrade	1. Upgrade Porirua zone substation 33 kV subtransmission and 33/11 kV transformer capacity to 36 MVA 2. Transfer some Kenepuru zone substaton load to Porirua zone substation after the upgrade	1. Porirua 33kV subtransmisison and 33/11 kV transformer capacity 2. Waitangarua 33 kV subtransmission and 33/11 kV transformer capacity 3. Kenepuru 33kV subtransmission capacity	2027/28	$16.0
Mana 11 kV feeder upgrade	Reinforce 11 kV feeders to enable load transfer from Mana to Porirua and Plimmerton after their upgrade.	Mana zone substation supply capacity	2027/28	$4.0
Grenada North Zone Substation	1. New Grenada North zone substation supplied from first section of the Khandallah – Takapu Road 33 kV line. 2. Develop new 11 kV ties to existing Johnsonville and Tawa feeders	1. Johnsonville 33 kV subtransmission capacity 2. Tawa 33/11 kV transformer capacity	2028/29	$20.0
Plimmerton zone substation upgrade	Install a 33 kV bus, a second 24 MVA transformer and a second 11kV bus section at Plimmerton.	Plimmerton zone substation supply capacity	2029/30	$8.0
Distribution				
Tawa 11 kV feeder reinforcement	New 11 kV feeder and 11 kV feeder reconfiguration	Tawa 11 feeder capacity	2022/23	$1.2
New Waitangarua 11kV feeder	Transfer some Watangarua feeder 5 and 11 load to new feeders	Waitangarua feeder 5 and 11 capacity	2023/24	$1.8
Ngauranga 11 kV feeder upgrade	New 11 kV feeders from Ngauranga Zone Substation	Kaiwharawhara 6/7/9/10 ring feeder capacity	2023/24	$1.7
Ngauranga 11 kV feeder reinforcement	Upgrade 11 kV cable section on Ngauranga 4 feeder approx. 320m	Ngauranga 4 feeder capacity	2024/25	$0.4
Porirua 11 kV feeder capacity upgrade	1. Add a new feeder to Porirua 4/5 feeder ring extend it about 0.9 km to form a three feeder ring. 2. Transfer some of the Porirua feeder 6 load to Kenepuru. 3. After Porirua 4/5 feeder upgrade, install an extra CB at 19 Parumoana to split the existing Porirua feeder 6 into two separate feeders	1. Porirua 4/5 ring feeder capacity 2. Porirua feeder 6 capacity	2025/26 2025/26	$1.4 $0.4

Project	Description	Constraint Relieved	Target Completion (Regulatory year)	Investment Amount (M)
Cross Harbour link from Porirua Zone Substation to Titahi Bay substation	New 11kV cross-harbour cable from Porirua Zone Substation to Titahhi Bay substation	1. Porirua 1/11 (TIT) ring feeder capacity 2. Titahi Bay supply security on non- transferable load	2027/28	$3.0
Kenepuru 11 kV feeder reinforcement	Upgrade 11 kV cable section on Kenepuru 4 feeder approx. 490 m	Kenepuru 4 feeder capacity	2027/28	$0.6

Table 8-39 Northwestern Area Development Summary

8.6 Northeastern Area NDRP

This section provides a summary of the Northeastern Area NDRP.

8.6.1 GXP Development Plan

The Northeastern area is supplied from four GXPs. Gracefield and Upper Hutt provide subtransmission supply at 33 kV, while Melling and Haywards GXPs provide supply at 33 kV and 11 kV. Transpower owns all supply transformers and the switchgear at the GXPs. The transformer capacity and the peak system demand are set out in Table 8-40. The forecast in Table 8-40 considers only committed and highly likely developments.

GXP	Continuous Capacity (MVA)	Transformer Cyclic Summer / Winter Capacity (MVA)	Peak Demand (MVA)	
			2021	2031
Gracefield 33 kV	1x60 + 1x85	76 / 80	62	74
Upper Hutt 33 kV	2x40	51 / 53	30	28
Melling 33 kV	2x 50	64 / 65	31	31
Melling 11 kV	2x 25	32 / 34	24	26
Haywards 33 kV	2 x 25[1]	25 / 25	15	21
Haywards 11 kV	2x 30[1]	30 / 30	17	21

Notes:

1. Haywards 33 kV and 11 kV GXPs are supplied from two 110/33/11 kV, 60/25/30 MVA transformers.

Table 8-40 Northeastern Area GXP Capacities

8.6.1.1 Gracefield

There are no capacity and security constraints at Gracefield as the peak demand at this GXP is below the N-1 supply transformer capacity.

8.6.1.2 Haywards

There are two parallel 110/33/11 kV, three-winding, 60/25/30 MVA transformers at Haywards that provide N-1 supply to:

- Trentham zone substation via two 33 kV circuits, and
- Haywards 11 kV switch board.

The maximum demand on the Haywards 33 kV GXP was 16 MVA and the Haywards 11 kV GXP was 17 MVA in 2021.

The Haywards peak demand is forecast to be within the subtransmission N-1 capacity for the next ten years with confirmed and highly likely step load growth.

8.6.1.3 Upper Hutt

The Upper Hutt GXP comprises two parallel 110/33 kV transformers each nominally rated at 40 MVA with a winter N-1 cyclic capacity of 53 MVA. The maximum demand on the Upper Hutt GXP in 2021 was 30 MVA. Upper Hutt supplies zone substations at Brown Owl and Maidstone each via double 33 kV circuits.

WELL recently installed new RTUs at Brown Owl and Maidstone. An upgrade project on the subtransmission protection system is scheduled in 2022. The new protection equipment will be designed to interface with Transpower equipment at the site.

8.6.1.4 Melling

Melling has a 33 kV GXP and an 11 kV GXP.

The Melling 33 kV GXP comprises two parallel 110/33 kV transformers each nominally rated at 50 MVA with a winter N-1 cyclic capacity of 65 MVA. The maximum demand on the Melling 33 kV GXP in 2021 was 31 MVA. Melling 33kV GXP supplies zone substations at Naenae and Waterloo, each via double 33 kV circuits.

The Melling 11 kV GXP comprises two parallel 110/11 kV transformers each nominally rated at 25 MVA with a winter N-1 cyclic capacity of 34 MVA. The maximum demand on the Melling 11 kV GXP in 2021 was 24 MVA. The Melling 11kV GXP supplies the Melling zone substation directly from the 110/11 kV transformer LV circuit breakers.

The capacity of the 110/11 kV transformers is restricted due to the limit imposed by the protection equipment. Transpower propose to resolve this protection limitation to increase the cyclic capacity of the transformers. In the meantime, WELL will work with Transpower to manage network loading risk using demand side management and operational control by shifting load to adjacent zone substations to relieve overloads.

8.6.2 Subtransmission Network Development Needs

This section describes the identified security of supply constraints and development needs for the Northeastern Area.

The Northeastern network consists of 18 subtransmission 33 kV circuits supplying nine zone substations. Each zone substation supplies the respective 11 kV distribution network with inter-connectivity via switched open points to adjacent zones. The Haywards and Melling GXP 11 kV switchboards directly feed into the distribution network. The characteristics of each zone substation are listed in Table 8-41.

Zone Substation	Season	Subtransmission N-1 branch rating (MVA)		Constraining Branch Component	Peak Demand (MVA)		Date Constraints are Binding	ICP Counts as at 2021
		Existing	Post - committed network upgrade		2021	2031		
Existing constraints								
Korokoro	Winter	15.5	N/A	33kV cable	20.8	23.8	Existing	6,005
	Summer	13.2	N/A	33kV cable	15.6	17.3		
Seaview	Winter	13.8	N/A	33kV cable	14.9	15.6	Existing	3,635
	Summer	10.6	N/A	33kV cable	12.3	12.3		
Wainuiomata	Winter	16.5	N/A	33/11kV transformer	17.6	21.6	Existing (Winter)	7,082
	Summer	16.5	N/A	33/11kV transformer	11.0	13.7		
Maidstone	Winter	17.6	N/A	33kV cable	15.0	21.5	Existing (Summer)	4,799
	Summer	10.2	N/A	33kV cable	10.6	15.3		
Waterloo	Winter	20.1	N/A	33kV cable	16.3	18.6	Existing (Summer)	5,929
	Summer	12.0	N/A	33kV cable	12.1	11.9		
Forecasted constraints								
Trentham	Winter	19.1	N/A	33kV cable	16.3	21.1	2027 (winter) 2028 (summer)	5,379
	Summer	14.7	N/A	33kV cable	10.3	15.5		
Naenae	Winter	18.3	N/A	33kV cable	15.1	18.7	2030	6,292
	Summer	13.9	N/A	33kV cable	10.1	12.1		
Not Constrained								
Brown Owl	Winter	18.4	N/A	33/11kV transformer	15.5	17.2	Not Constrained	6,758
	Summer	12.9	N/A	33kV cable	10.5	11.8		
Gracefield	Winter	16.5	23.0	33/11kV transformer	10.8	16.9	Not Constrained	2,628
	Summer	9.3	23.0	33/11kV transformer	9.3	14.2		

Table 8-41 Northeastern Area Zone Substation Capacities

8.6.2.1 Brown Owl

The peak demand supplied by Brown Owl is currently within the N-1 capacity of the zone substation. Table 8-42 shows the seasonal constraint levels and the minimum off load requirements.

Zone substation	Season	Subtransmission N-1 branch rating (MVA)	Peak Demand @2021 (MVA)	Minimum off load for N-1 @ peak (MVA)
Brown Owl	Winter	18.4	15.5	0
	Summer	12.9	10.5	0

Table 8-42 Current Brown Owl Subtransmission Constraints

Figure 8-48 shows the load duration curve against the N-1 branch ratings of the subtransmission for Brown Owl. The load duration curve shows that at present the demand exceeds the N-1 capacity less than 2% of the year. This is within the network security standard for a mixed commercial and residential zone substation.

WELL will monitor load growth and manage the overloading risk by shifting open points on the HV feeders and through operational control by shifting load to adjacent zone substations to relieve overloads.

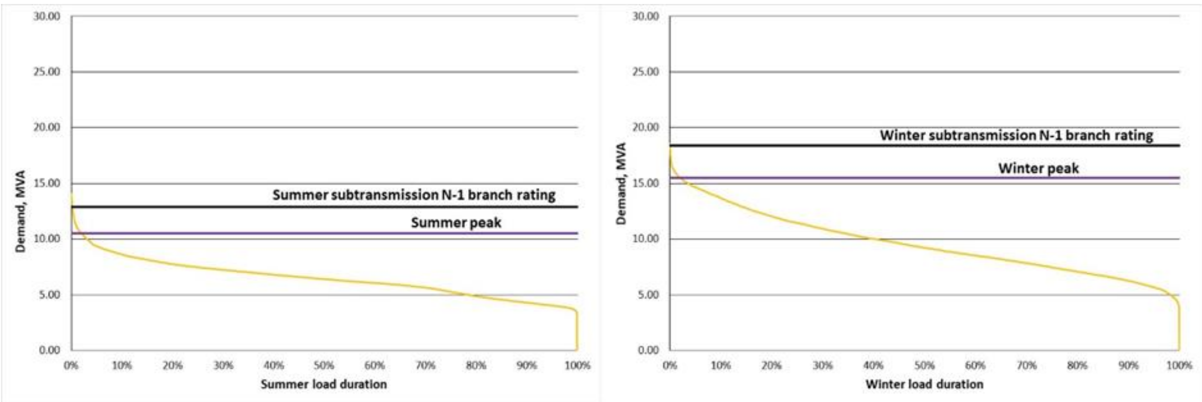


Figure 8-48 Brown Owl Load Duration Curve

Based on the estimated growth scenarios and confirmed step change loaded within the planning period, the load at Brown Owl is forecasted to grow as show in Figure 8-49.

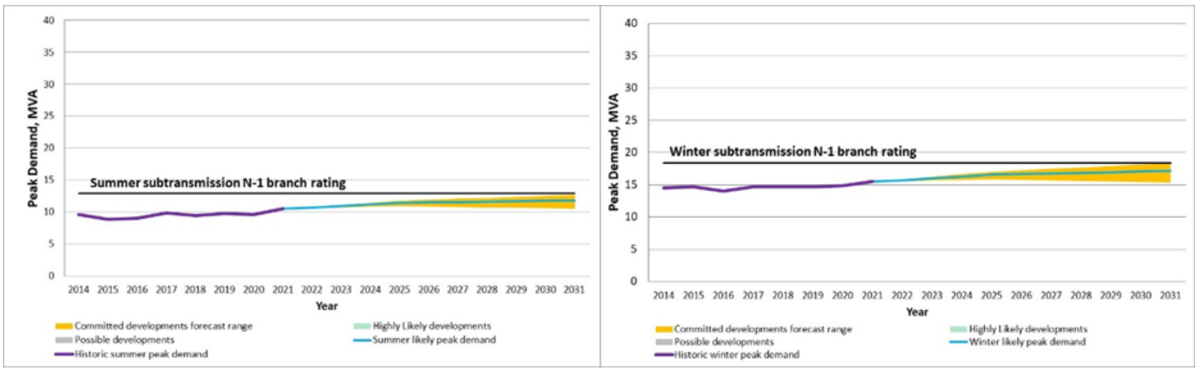


Figure 8-49 Brown Owl Demand Forecast

8.6.2.2 Gracefield

The peak demand supplied by Gracefield is currently within the N-1 capacity of the subtransmission circuits. Table 8-43 shows the seasonal constraint levels and the minimum off load requirements.

Zone substation	Season	Constraining N-1 branch rating (MVA)	Peak Demand @2021 (MVA)	Minimum off load for N-1 @ peak (MVA)
Gracefield	Winter	16.5	10.8	0
	Summer	12.0	9.3	0

Table 8-43 Current Gracefield Subtransmission Constraints

Figure 8-50 shows the load duration curve against the N-1 branch ratings of the subtransmission circuits for Gracefield. The load duration curve shows that at present the demand is below the N-1 capacity at the zone substation.

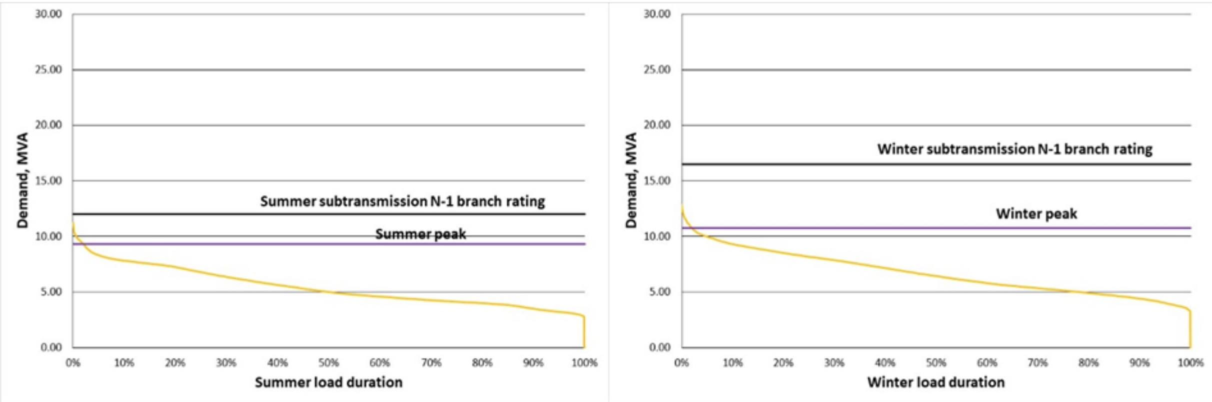


Figure 8-50 Gracefield Load Duration Curve

Based on the estimated growth scenarios and confirmed step change loaded within the planning period, the load at Gracefield is forecasted to grow as show in Figure 8-51. The subtransmission capacity constraints are plotted for comparison.

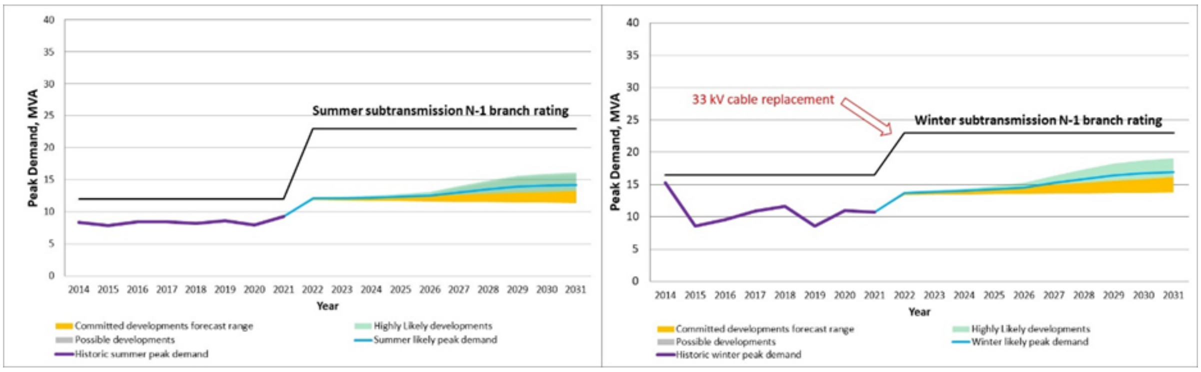


Figure 8-51 Gracefield Demand Forecast

WELL currently has a project to replace the Gracefield zone substation 33 kV subtransmission cables with higher capacity cables in 2022 as part of Transpower's Gracefield GXP 33 kV switchboard replacement project. This will increase the Gracefield zone substation 33 kV subtransmisson summer and winter N-1 capacity to 23 MVA.

8.6.2.3 Haywards

The peak demand supplied by Haywards is currently within the N-1 capacity of subtransmission circuits. Table 8-44 shows the seasonal constraint levels and the minimum off load requirements.

Zone substation	Season	Constraining N-1 branch rating (MVA)	Peak Demand @2021 (MVA)	Minimum off load for N-1 @ peak (MVA)
Haywards	Winter	30.0	17.1	0
	Summer	30.0	11.7	0

Table 8-44 Current Haywards Subtransmission Constraints

Figure 8-52 shows the load duration curve against the N-1 branch ratings of the subtransmission cables for Haywards. The load duration curve shows that at present the demand is below the N-1 capacity at the zone substation. This is within the network security standard for a mixed commercial and residential zone substation.

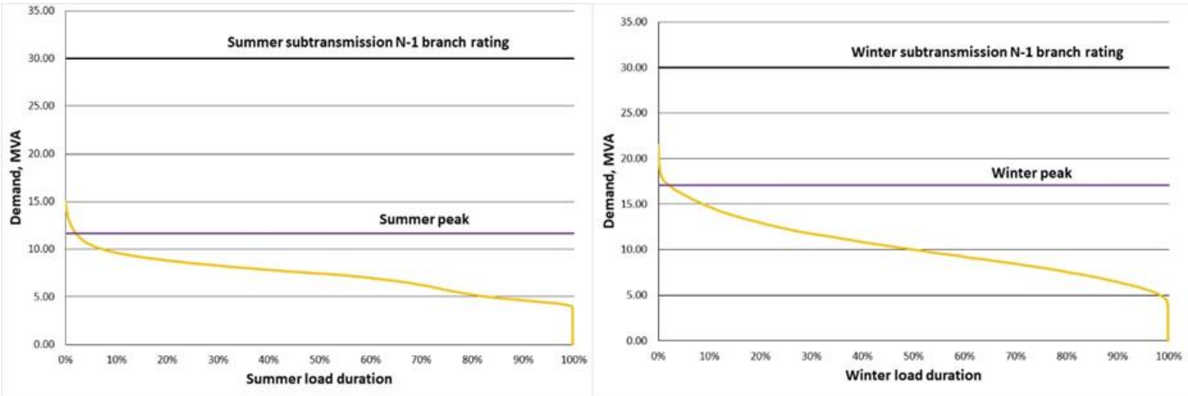


Figure 8-52 Haywards Load Duration Curve

Based on the estimated growth scenarios and confirmed step change loaded within the planning period, the load at Haywards is forecasted to grow as show in Figure 8-53. The subtransmission capacity constraints are plotted for comparison.

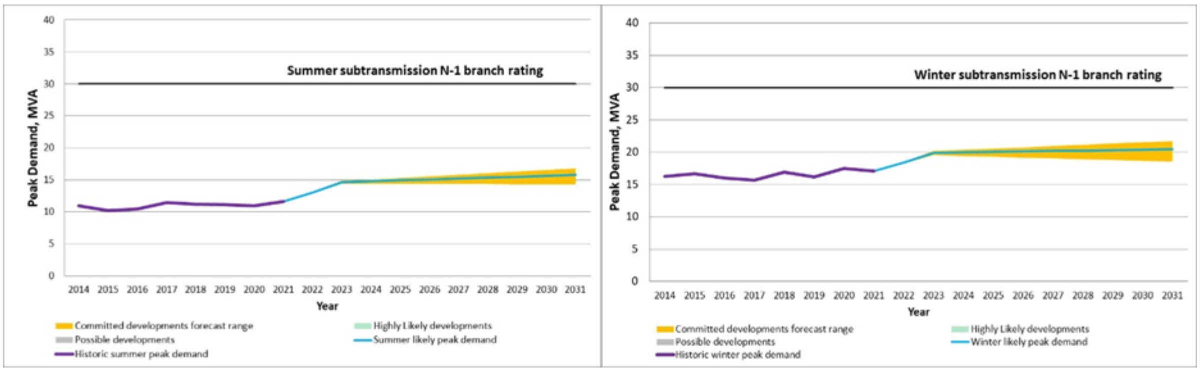


Figure 8-53 Haywards Demand Forecast

8.6.2.4 Korokoro

The peak demand at Korokoro currently exceeds the N-1 capacity of subtransmission circuits. Table 8-45 shows the seasonal constraint levels and the minimum off load requirements on each circuit.

Zone substation	Season	Constraining N-1 branch rating (MVA)	Peak Demand @2021 (MVA)	Minimum off load for N-1 @ peak (MVA)
Korokoro	Winter	15.5	20.8	5.3
	Summer	13.2	15.6	2.4

Table 8-45 Current Korokoro Subtransmission Constraints

Figure 8-54 shows the load duration curve against the N-1 ratings of transformer and subtransmission cables for Korokoro. The load duration curve shows that at present the demand exceeds the summer N-1 capacity by approximately 20.3% of the time and the winter N-1 capacity approximately 35.3% of the time. This analysis uses a load duration curve based on 30-minute periods and is higher than the peak.

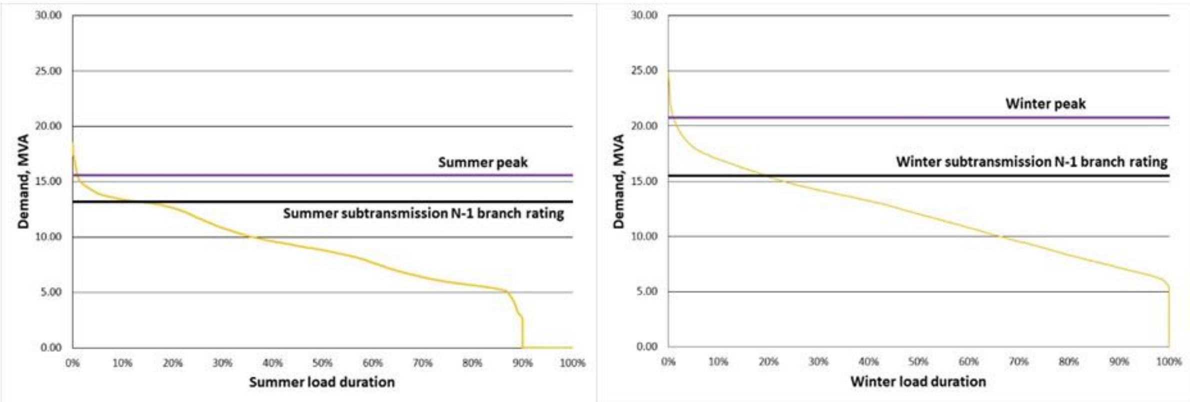


Figure 8-54 Korokoro Load Duration

Based on the estimated growth scenarios and development within the planning period, the peak load at Korokoro is forecasted as shown in Figure 8-55. The subtransmission capacity constraints are plotted for comparison.

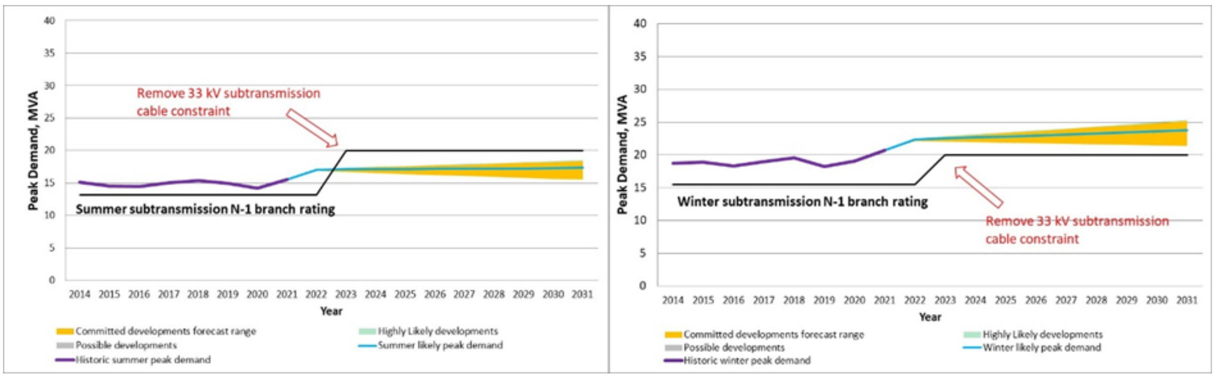


Figure 8-55 Korokoro Load Forecast

The Korokoro 33 kV subtransmission capacity is currently limited by a constraint on the 33kV subtransmission cables. WELL is investigating removing constraints on the 33kV subtransmission cables to increase the Korokoro subtransmisison capacity. WELL will continue monitoring load growth and manage the overloading risk through operational control by shifting load to adjacent zone substations to relieve overloads.

8.6.2.5 Maidstone

The peak demand supplied by Maidstone currently exceeds the N-1 capacity of subtransmission circuits in summer. Table 8-46 shows the seasonal constraint levels and the minimum off load requirements on each circuit.

Zone substation	Season	Constraining N-1 branch rating (MVA)	Peak Demand @2021 (MVA)	Minimum off load for N-1 @ peak (MVA)
Maidstone	Winter	17.6	15.0	0
	Summer	10.2	10.6	0.4

Table 8-46 Current Maidstone Subtransmission Constraints

Figure 8-56 shows the load duration curve against the N-1 branch ratings of the subtransmission circuits for Maidstone. The load duration curve shows that at present the demand exceeds the summer N-1 capacity for approximately 3.5% of the time and the winter N-1 capacity for approximately 0.1% of the time.

WELL will monitor load growth and manage the overloading risk by shifting open points on the HV feeders and through operational control by shifting load to adjacent zone substations to relieve overloads.

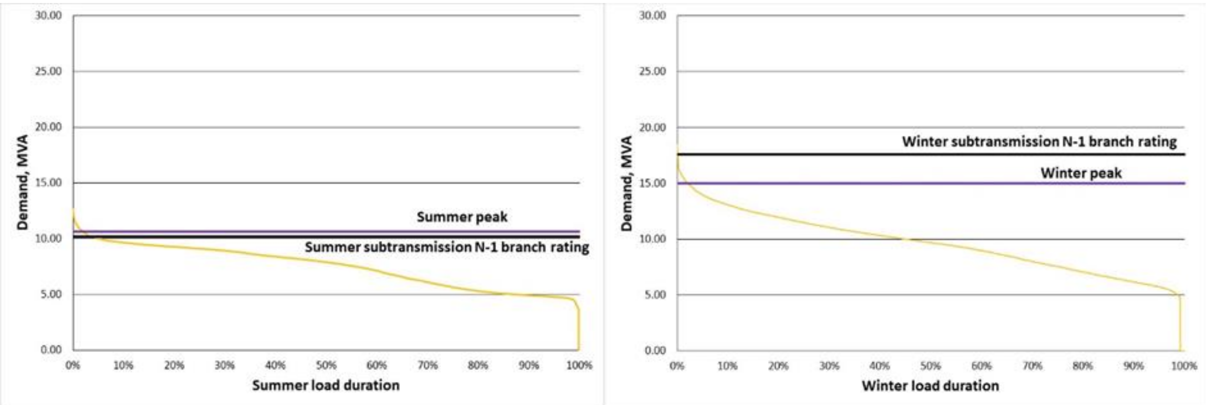


Figure 8-56 Maidstone Load Duration Curve

Based on the estimated growth scenarios and confirmed step change loaded within the planning period, the load at Maidstone is forecasted to grow as show in Figure 8-57.

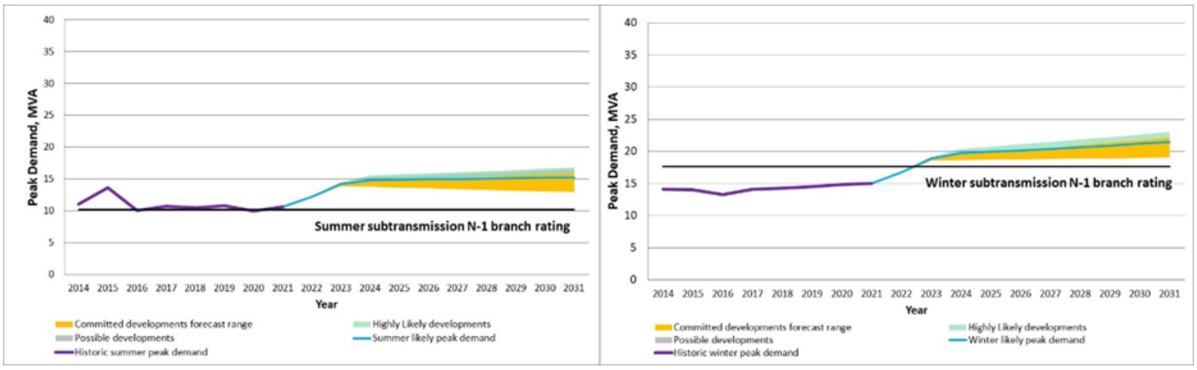


Figure 8-57 Maidstone Demand Forecast

The Maidstone peak demand currently exceeds the summer subtransmission N-1 capacity and is forecast to exceed the winter subtransmission N-1 capacity by 2023. Security of supply will be managed operationally by shifting load to adjacent zone substations to relieve overloads. WELL continues to monitor the load growth and will investigate options to mitigate system constraints as possible step load growth gets confirmed.

8.6.2.6 Melling

The peak demand supplied by Melling is currently within the N-1 capacity of subtransmission circuits. Table 8-47 shows the seasonal constraint levels and the minimum off load requirements on each circuit.

Zone substation	Season	Constraining N-1 branch rating (MVA)	Peak Demand @2021 (MVA)	Minimum off load for N-1 @ peak (MVA)
Melling	Winter	34.0	22.9	0
	Summer	32.0	16.7	0

Table 8-47 Current Melling Subtransmission Constraints

Figure 8-58 shows the load duration curve against the N-1 branch ratings of the subtransmission circuits for Melling. The load duration curve shows that at present the demand exceeds the N-1 capacity less than 2% of the year. This is within the network security standard for a mixed commercial and residential zone substation.

WELL will monitor load growth and manage the overloading risk by shifting open points on the HV feeders and through operational control by shifting load to adjacent zone substations to relieve overloads.

Figure 8-58 Melling Load Duration Curve

Based on the estimated growth scenarios and confirmed step change loaded within the planning period, the load at Melling is forecasted to grow as show in Figure 8-59.

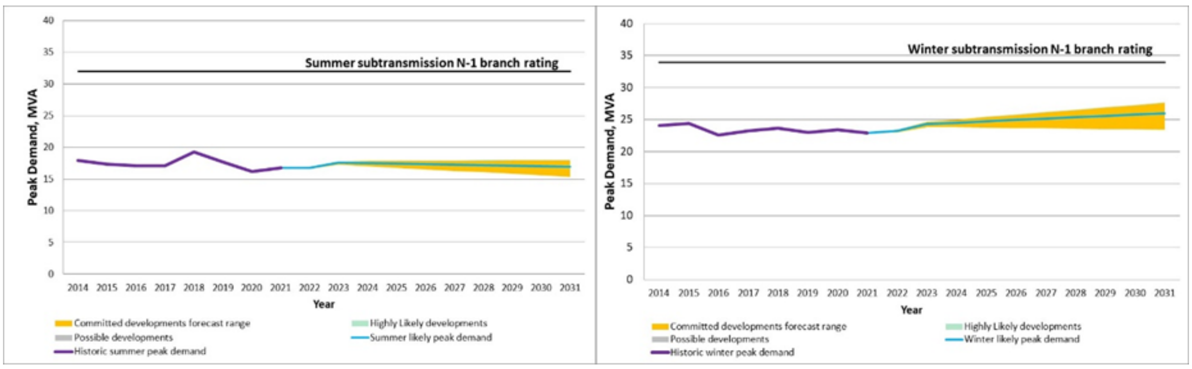


Figure 8-59 Melling Demand Forecast

WELL continues to monitor the load growth and will investigate options to mitigate system constraints as possible step load growth gets confirmed.

8.6.2.7 Naenae

The peak demand supplied by Naenae is currently within the N-1 capacity of the subtransmission circuits. Table 8-48 shows the seasonal constraint levels and the minimum off load requirements.

Zone substation	Season	Constraining N-1 branch rating (MVA)	Peak Demand @2021 (MVA)	Minimum off load for N-1 @ peak (MVA)
Naenae	Winter	18.3	15.1	0
	Summer	13.9	10.1	0

Table 8-48 Current Naenae Subtransmission Constraints

Figure 8-60 shows the load duration curve against the N-1 branch ratings of the subtransmission circuits for Naenae. The load duration curve shows that at present the demand exceeds the N-1 capacity less than 2% of the year. This is within the network security standard for a mixed commercial and residential zone substation.

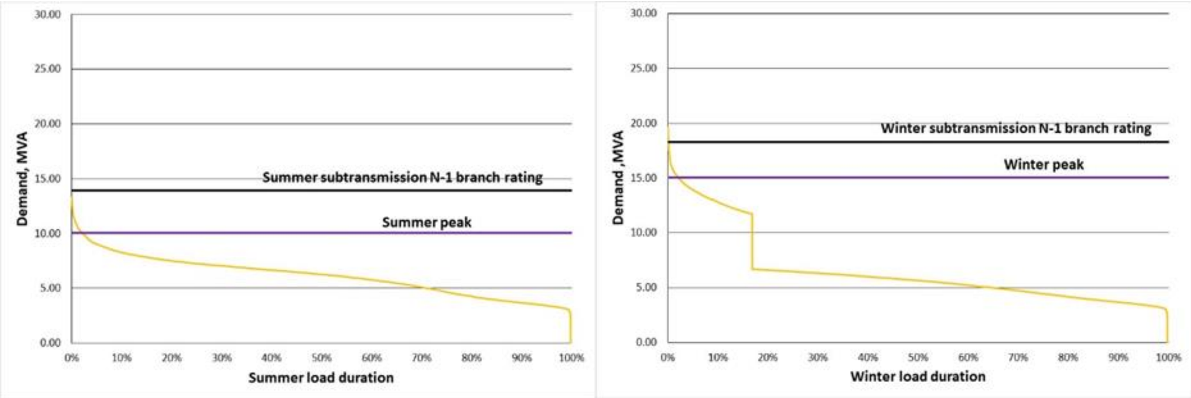


Figure 8-60 Naenae Load Duration Curve

WELL will monitor load growth and manage the overloading risk by shifting open points on the HV feeders and through operational control by shifting load to adjacent zone substations to relieve overloads.

Based on the estimated growth scenarios and confirmed step change loaded within the planning period, the load at Naenae is forecasted to grow as show in Figure 8-61. Without action, the winter peak load is forecast to exceed the N-1 subtransmission capacity from 2030.

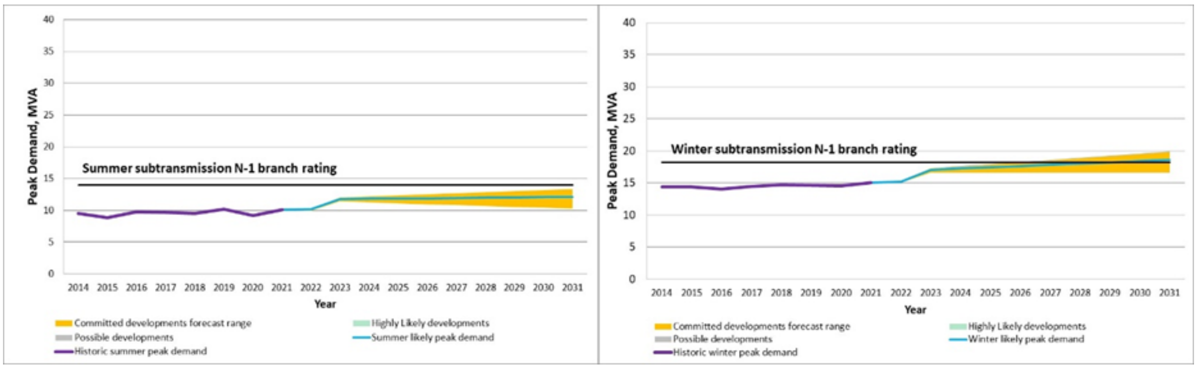


Figure 8-61 Naenae Demand Forecast

8.6.2.8 Seaview

The peak demand supplied by Seaview currently exceeds the summer and winter N-1 capacity of the subtransmission circuits. Table 8-49 shows the seasonal constraint levels and the minimum off load requirements.

Zone substation	Season	Constraining N-1 branch rating (MVA)	Peak Demand @2021 (MVA)	Minimum off load for N-1 @ peak (MVA)
Seaview	Winter	13.8	14.9	1.1
	Summer	10.6	12.3	1.7

Table 8-49 Current Seaview Subtransmission Constraints

Figure 8-62 shows the load duration curve against the N-1 branch ratings of the subtransmission circuits for Seaview. The load duration curve shows that at present the demand exceeds the summer N-1 capacity by approximately 15.4% of the time and winter N-1 capacity by approximately 6.6% of the of the time.

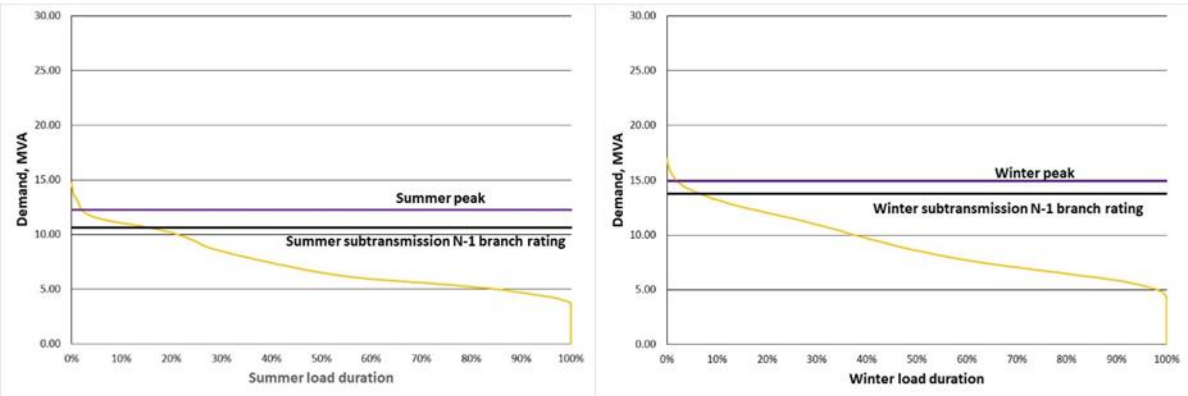


Figure 8-62 Seaview Load Duration Curve

Based on the estimated growth scenarios and confirmed step change loaded within the planning period, the load at Seaview is forecasted to grow as show in Figure 8-63.

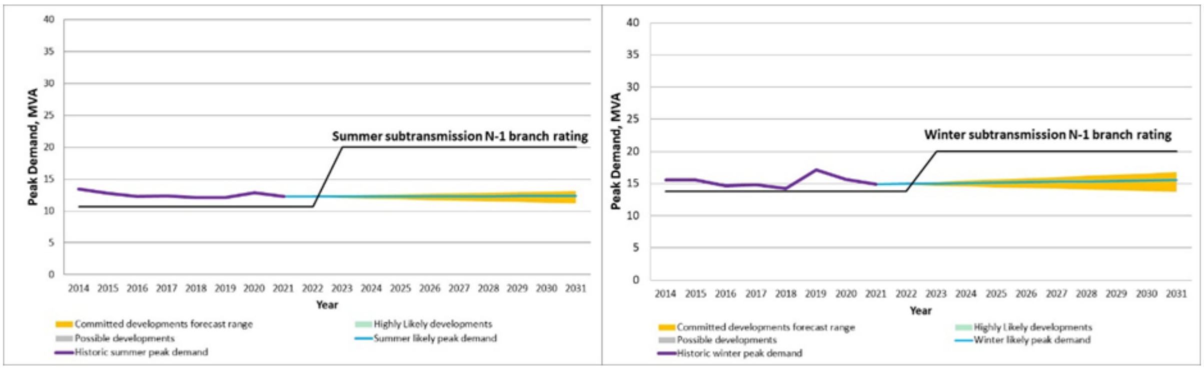


Figure 8-63 Seaview Demand Forecast

WELL plans to remove capacity constraints on the Seaview 33kV cables in 2023. In the meantime, WELL will monitor load growth and manage the overloading risk by shifting open points on the 11 kV feeders and through operational control by shifting load to adjacent zone substations to relieve overloads.

8.6.2.9 Trentham

The peak demand supplied by Trentham is currently within the N-1 capacity of the subtransmission circuits. Table 8-50 shows the seasonal constraint levels and the minimum off load requirements.

Zone substation	Season	Constraining N-1 branch rating (MVA)	Peak Demand @2021 (MVA)	Minimum off load for N-1 @ peak (MVA)
Trentham	Winter	19.1	15.0	0
	Summer	14.7	10.3	0

Table 8-50 Current Trentham Subtransmission Constraints

Figure 8-64 shows the load duration curve against the N-1 branch ratings of the subtransmission circuits for Trentham. The load duration curve shows that at present the demand is below the N-1 capacity at the zone substation. This is within the network security standard for a mixed commercial and residential zone substation.

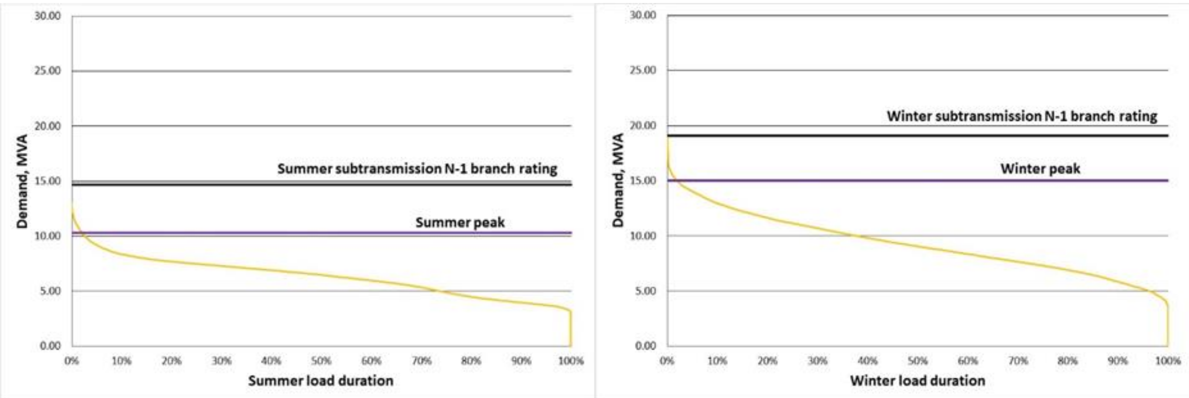


Figure 8-64 Trentham Load Duration Curve

Based on the estimated growth scenarios and confirmed step change loaded within the planning period, the load at Trentham is forecasted to grow as show in Figure 8-65. The forecast load growth could come from proposed residential sub-divisions and commercial developments in the area.

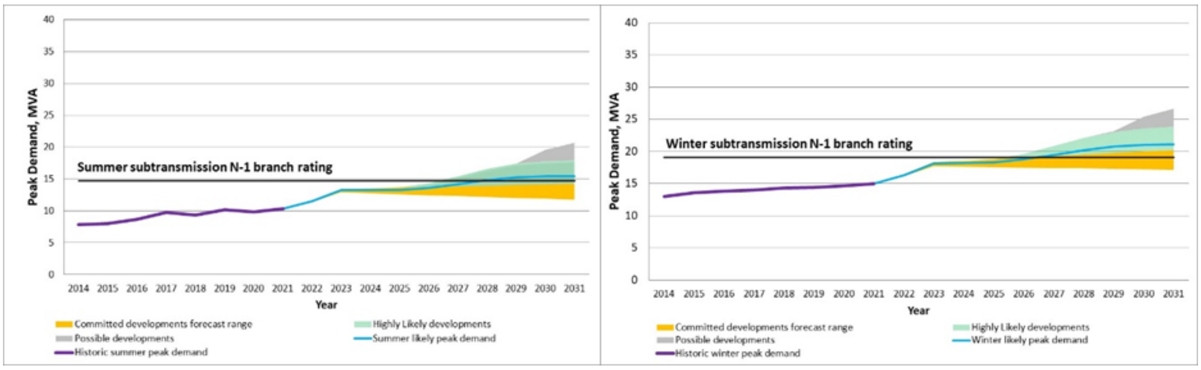


Figure 8-65 Trentham Demand Forecast

The Trentham winter peak demand is forecast to exceed the subtransmission winter N-1 capacity from 2027 and the summer N-1 capacity from 2028.

WELL continues to monitor the load growth and will investigate options to mitigate system constraints as possible step load growth gets confirmed.

8.6.2.10 Wainuiomata

The peak demand supplied by Wainuiomata currently exceeds the winter N-1 capacity of the subtransmission circuits. Table 8-51 shows the seasonal constraint levels and the minimum off load requirements.

Zone substation	Season	Constraining N-1 branch rating (MVA)	Peak Demand @2021 (MVA)	Minimum off load for N-1 @ peak (MVA)
Wainuiomata	Winter	16.5	17.6	1.1
	Summer	16.5	11.0	0

Table 8-51 Current Wainuiomata Subtransmission Constraints

Figure 8-66 shows the load duration curve against the N-1 branch ratings of the subtransmission circuits for Wainuiomata. The load duration curve shows that at present, the demand exceeds the winter N-1 capacity for approximately 4.4% of the time.

WELL will monitor load growth and manage the overloading risk by shifting open points on the HV feeders and through operational control by shifting load to adjacent zone substations to relieve overloads.

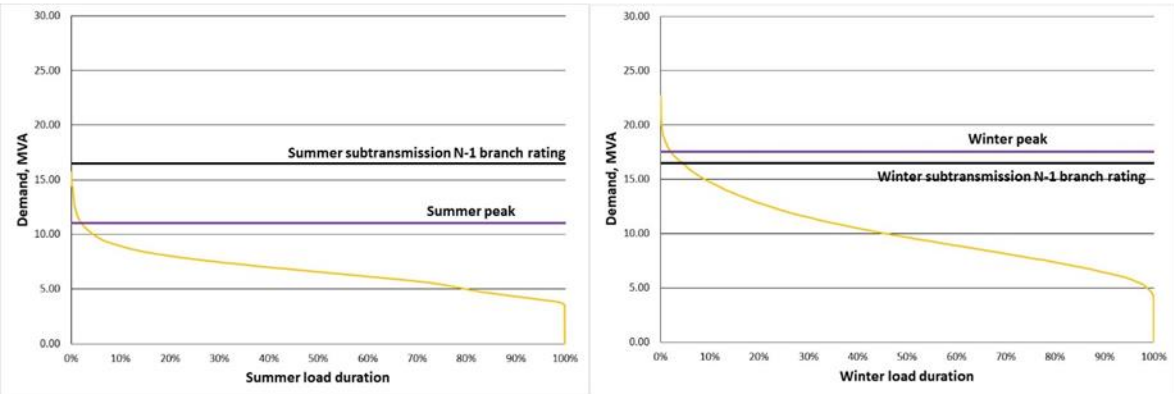


Figure 8-66 Wainuiomata Load Duration Curve

Based on the estimated growth scenarios and confirmed step change loaded within the planning period, the load at Wainuiomata is forecasted to grow as show in Figure 8-67. The forecast load growth could come from proposed residential sub-divisions and commercial developments in the area.

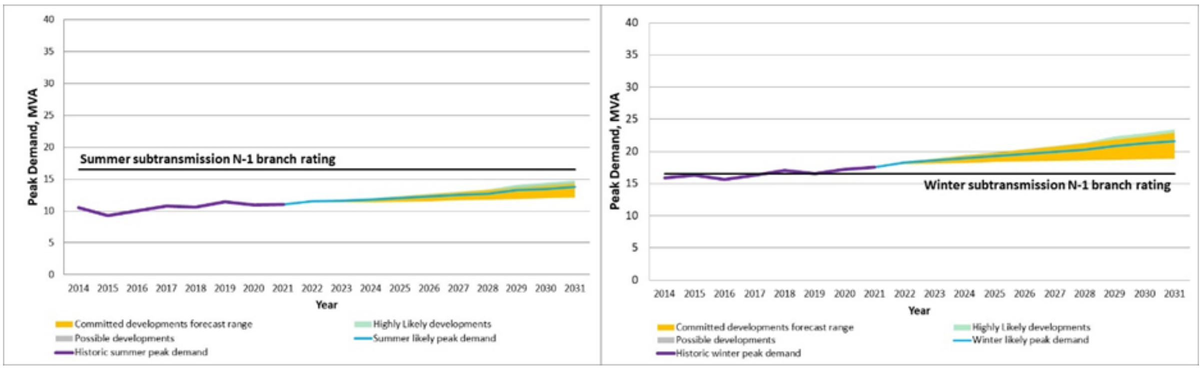


Figure 8-67 Wainuiomata Demand Forecast

The limiting component is the cable section at Gracefield GXP which is relatively simple to fix due to the short cable lengths. The next constraint after the cable constraint at Gracefield is fixed is the 33/11 kV transformer N-1 limit at Wainuiomata at 16.5 MVA.

WELL recently replaced the existing cable section at Gracefield GXP with higher capacity cables as part of Transpower's 33 kV switchgear replacement project at Gracefield GXP. This increased the Wainuiomata 33 kV subtransmission N-1 capacity to 16.5 MVA.

In the short-term security of supply will be managed operationally by shifting load to adjacent zone substations to relieve overloads and through the use of a mobile substation. WELL will investigate options for a permanent long-term solution for managing Wainuiomata zone substation capacity.

8.6.2.11 Waterloo

The peak demand supplied by Waterloo is currently within the N-1 capacity of the subtransmission. Table 8-52 shows the seasonal constraint levels and the minimum off load requirements.

Zone substation	Season	Constraining N-1 branch rating (MVA)	Peak Demand @2020 (MVA)	Minimum off load for N-1 @ peak (MVA)
Waterloo	Winter	20.1	16.3	0
	Summer	12.0	12.1	0.1

Table 8-52 Current Waterloo Subtransmission Constraints

Figure 8-68 shows the load duration curve against the N-1 branch ratings of the subtransmission circuits for Waterloo. The load duration curve shows that at present the demand exceeds the summer N-1 capacity for approximately 2.4 % of the time.

WELL will monitor load growth and manage the overloading risk by shifting open points on the HV feeders and through operational control by shifting load to adjacent zone substations to relieve overloads.

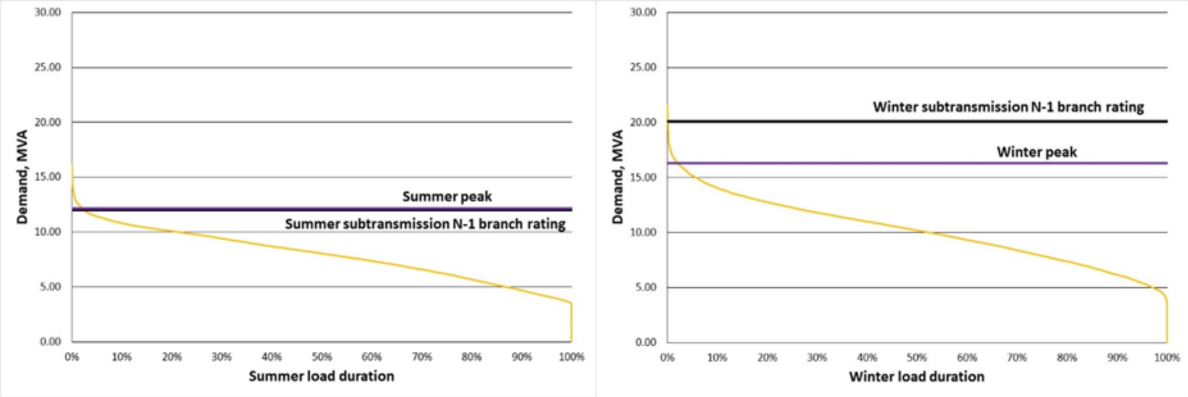


Figure 8-68 Waterloo Load Duration Curve

Based on the estimated growth scenarios and confirmed step change loaded within the planning period, the load at Waterloo is forecasted to grow as show in Figure 8-69.

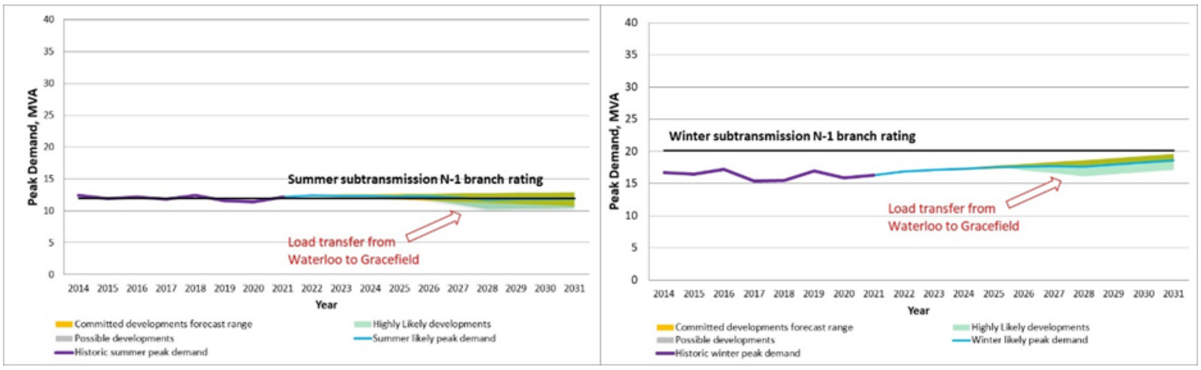


Figure 8-69 Waterloo Demand Forecast

WELL plans to shift some load from Waterloo to Gracefield from approximately 2026 and will continue to monitor the load growth at Waterloo zone substation. WELL will investigate options to mitigate system constraints as possible step load growth gets confirmed.

8.6.3 Distribution Level Development Needs

The most critical distribution level issues are those associated with:

- Meshed ring feeders supplying a high number of customers; and
- Links between zone substations which can be used for load transfer.

Table 8-53 shows where the applicable security criteria for the feeder configurations are exceeded, based on forecast demand growth and confirmed step load changes, and an estimation of when the constraints bind. This is used to determine whether further contingency analysis of each individual feeder is required. Alongside each feeder is the priority level of the planning and investment requirements. There are no meshed feeders in this region.

Feeder	Loading criteria	Zone Substation	Length of section exceeding loading criteria	Present Loading	+5 years	Feeder ICP Count	Priority
Current							
BRO CB2	67%	Brown Owl	90 m	68%	76%	1,179	Low
BRO CB 8	67%	Brown Owl	750 m	87%	98%	1,747	High
GRA CB7	67%	Gracefield	248 m	88%	147%	27	Medium
HAY CB2822	67%	Haywards (GXP)	68 m	67%	73%	1,364	Medium
HAY CB2862	67%	Haywards (GXP)	2,534 m	75%	84%	861	Medium
HAY CB2722	67%	Haywards (GXP)	3,342 m	76%	85%	1,517	Medium
MAI CB6	67%	Maidstone	430 m	Less than 67%	83%	1,044	Low
MAI 11	67%	Maidstone	152 m	72%	81%	1,303	Low
WAT CB5	67%	Waterloo	637 m	79%	80%	1,712	Medium
Within 5 Years							
BRO CB2	67%	Upper Hutt	1,470 m	Less than 67%	73%	1,179	Low
GRA CB9	67%	Gracefield	529 m	Less than 67%	68%	1,055	Low
MAI CB6	67%	Maidstone	360 m	Less than 67%	69%	1,044	Low
WAT CB5	67%	Waterloo	705 m	Less than 67%	68%	1,712	Low
WAT CB6	67%	Waterloo	270 m	Less than 67%	68%	946	Low
WAT CB9	67%	Waterloo	321 m	Less than 67%	70%	308	Low
WNU CB13	67%	Wainuiomata	608 m	Less than 67%	73%	1,074	Medium

Table 8-53 Distribution Level Issues

The identified highly loaded feeders supplied from Maidstone, Waterloo and Haywards are forecast to decline in load over the planning period and may not require mitigation.

There is no contingency analysis is this region as there are no ring feeders.

WELL is aware of a number of possible future step load changes identified through customer connection requests, developments detailed in the local council District Plans and consultation with City Councils, developers, and large customers. A number of property developers and businesses have also flagged developments that may create new loads on the network.

The actual outcome and impact of these possible future step load change demands is uncertain, and difficult to estimate, and has not been included in the assessment above. WELL will continue to monitor progress with these possible step change demands and develop timely solutions to resolve any network issues arising from the step change demands as they are confirmed.

8.6.4 Summary of Network Development Plan

This section summarises the options available to meet the development needs described above.

The development options for the Northeastern Area are comprised of a combination of the individual solutions required to meet each need. Each individual solution is not mutually exclusive because there are solutions which meet several needs for the same investment.

8.6.4.1 Non-network Solutions

Prior to any investment in any infrastructure being considered, the first step is to implement non-network solutions, discussed in Chapter 8.1.8, to defer investment.

8.6.4.2 Projects for 2022/23

Projects currently underway or planned to start over the next 12 months are listed in Table 8-54.

Project	Description
Korokoro subtransmission capacity upgrade	Remove constraints on the Korokoro 33 kV incomer cables to increase subtransmission capacity.
Gracefield subtransmission cable replacement	Replace existing 33 kV subtransmission cable sections outside Gracefield Grid Exit Point. The 33 kV cables on the Gracefield to Wainuiomata circuits have already been replaced. The remainder of the 33 kV cables to Gracefield, Korokoro and Seaview zone substations are scheduled to be replaced early to mid 2022.

Table 8-54 Northeastern Area Projects for 2022/23

8.6.4.3 Development Plan Summary

A summary of the development plan for this area is listed in Table 8-55. This information is an extraction from the NDRP, which provides detailed development options and feasibility analysis.

Each constraint is identified as an individual issue, but the overall development plan for the region is optimised through a shortlisting process. The most feasible solution may not be the replacement of the constrained asset itself, for example, many subtransmission constraints can be solved through HV distribution level configuration change and/or managed operationally by shifting load to adjacent zone substations to relieve overloads.

Detailed project planning and option engineering will be completed at the project scope development and approval stage.

Project	Description	Constraint Relieved	Target Completion (Regulatory Year)	Investment Amount (M)
Subtransmission				
Remove Korokoro 33kV subtransmisison constraints	Remove Korokoro 33kV subtransmisison cable capacity constraints outside Seaview zone substation	1. Korokoro 33 kV subtransmission capacity 2. Korokoro 33 kV transformer capacity 3. Seaview 33 kV subtransmission constraints	2023/24	$0.6
Remove Seaview 33kV subtransmisison cable constraints	Rebalance the load between Seaview and Gracefield zone substations	Seaview 33 kV subtransmission cable capacity	2022/23	$0.1
Distribution				
Waterloo 11 kV bus reconfiguration	Split Waterloo feeder 5 into two separate feeders and reconfigure and rebalance load across the Waterloo 11kV feeders	Waterloo feeder 5 capacity	2025/26	$0.5
Haywards 11 kV feeder reconfiguration	Upgrade Haywards 2862 cable section approx. 100 m Upgrade Haywards 2822 cable section approx. 468 m	Haywards feeder 2862 (Stokes Valley B) capacity Haywards feeder 2822 (Manor Park) capacity	2026/27 2027/28	$0.2 $0.6
Maidstone 11 kV feeder reconfiguration	Establish an 11 kV feeder tie between Brown Owl and Maidstone zone substations	Maidstone feeder 6 capacity	2027/28	$0.5
Seaview 11 kV feeder reinforcement	Upgrade Seaview 11 cable section approx. 389 m	Seaview feeder 11 capacity	2026/27	$0.5
Waterloo 11 kV feeder 9 reconfiguration	Transfer the Griffins load from Waterloo zone substation to Gracefield zone substation	Waterloo feeder 9 capacity	2026/27	$0.1
Gracefield 11 kV feeder 9 upgrade	Upgrade limiting cable section of Gracefield feeder 9 with higher capacity cable	Gracefield feeder 9 capacity	2028/29	$3.0

Table 8-55 Northeastern Area Development Summary

8.7 System Growth and Reinforcement Summary for 2022-2032

From the details in the sections above, WELL's network development and growth capital expenditure forecast by region is summarised in Table 8-56.

Category	2022/23	2023/24	2024/25	2025/26	2026/27	2027/28	2028/29	2029/30	2030/31	2031/32
Primary - Southern	5,465	1,149	1,551	5,346	-	-	6,650	8,200	10,150	8,500
Primary - Western	2,315	2,485	3,839	9,260	9,876	18,190	14,500	4,500	800	3,350
Primary - Eastern	310	1,021	200	1,300	1,500	2,900	2,500	800	820	800
Secondary Assets	275	366	300	300	300	600	600	600	800	800
System Growth Total	**8,365**	**5,021**	**5,890**	**16,206**	**11,676**	**21,690**	**24,250**	**14,100**	**12,570**	**13,450**

Table 8-56 Capital Expenditure Forecasts by Region
($K in constant prices)

The total forecast capital expenditure for system growth and security of supply for 2021 to 2031 by asset category is summarised in Table 8-57.

Asset Category	2022/23	2023/24	2024/25	2025/26	2026/27	2027/28	2028/29	2029/30	2030/31	2031/32
Subtransmission	638	-	-	1,800	5,900	8,800	13,450	7,000	10,950	9,300
Zone Substations	4,872	399	3,171	8,106	3,276	5,240	8,500	4,000	-	-
Distribution Poles and Lines	-	350	700	2,300	1,900	2,350	1,600	500	800	3,350
Distribution Cables	2,565	3,485	1,300	3,700	300	4,700	100	2,000	20	-
Distribution Substations	15	421	419	-	-	-	-	-	-	-
Distribution Switchgear	-	-	-	-	-	-	-	-	-	-
Other Network Assets[37]	275	366	300	300	300	600	600	600	800	800
Total	**8,365**	**5,021**	**5,890**	**16,206**	**11,676**	**21,690**	**24,250**	**14,100**	**12,570**	**13,450**

Table 8-57 Capital Expenditure Forecast by Asset Type
($K in constant prices)

[37] Other Network Assets excludes the capital expenditure required for emerging technologies which is included in Section 9.

Section 9

The Future Network

9 The Future Network

This section looks ahead of the business as usual investment covered in the AMP to discuss additional investment in the network needed to meet anticipated increase in demand. Details of programme and project case studies are provided to illustrate specific examples of WELL's future-focused initiatives.

Wellington has been a low growth network where, for the past decade, there has been modest growth which has allowed the life of assets to be maximised. This has meant a low cost, secure and affordable network service to customers who have largely seen a flat distribution price for the last decade.

The recent period of low interest rates, combined with a housing shortage, has seen developers increase their activity in providing more housing stock. While this activity has been tempered by the impact of COVID-19 and affected building material supply chains, it has taken up some of the capacity headroom which the network assets have had available.

At a government policy level, the Climate Change Commission (CCC) has updated its advice report which makes recommendations on actions for New Zealand to achieve its climate change goals of reducing carbon emissions.[38] The Emissions Reduction Plan is due for publication in May 2022 and is expected to recommend decarbonisation programmes to electrify transportation, transition from gas to electricity, and to electrify manufacturing process heat. These changes will increase electricity consumption and New Zealand's reliance of electricity, and could also significantly impact the loading and operation of WELL's electricity distribution network. In anticipation, WELL is developing the technology, equipment, and resources to ensure the Wellington network has the capacity and capability to deliver these decarbonisation programmes. By collaborating with other industry stakeholders WELL can support the programmes at an optimal cost, while maintaining a safe, secure, and reliable distribution network for all customers.

WELL is running a series of workstreams to trial new technology and to develop the tools, resources, and network designs that will best deliver these future energy requirements. For example, WELL is running the EV Connect programme to support the uptake of EVs, while also addressing their impact on security and supply quality, such as by shifting charging outside of maximum demand periods.

Funding for new technology trials that will help plan WELL's long term investment requirements are included in this AMP, with an initial $0.4 million per annum over the first five years rising to around $3 million at the end of the planning period. The results of these technology trials will be used to develop and refine the business case for further investment. The business case will:

- Demonstrate how WELL will meet New Zealand decarbonisation targets on the Wellington distribution network;
- Provide a long term (30 years) work programme and funding required to deliver New Zealand's decarbonisation initiatives;
- Provide a consumer cost benefits analysis that will be used to facilitate future customer engagement;
- Provide an Industry Roadmap which will highlight the legislative, policy and regulatory changes needed to support the implementation of the works programme;

[38] https://ccc-production-media.s3.ap-southeast-2.amazonaws.com/public/evidence/advice-report-DRAFT-1ST-FEB/ADVICE/CCC-ADVICE-TO-GOVT-31-JAN-2021-pdf.pdf, accessed 15 February 2020

- Provide an initial view on the regulatory funding model that maybe required, i.e. whether the programme could be delivered under the DPP framework or whether a different price path would be needed; and
- Recommended a customer consultation programme.

Progress on the business case will be provided in future iterations of the AMP. At the time of updating this AMP, work has progressed on a draft 30-year funding model which will be further refined and shared with the Commission as part of the Input Methodology (IM) consultation.

The Commission has stated in their IM Review Notice of Intention cover letter of 23 February 2022[39] that:

> *A key part of the review will be working closely with industry and other government agencies to understand the issues as a whole and the role that our regulatory settings can play in helping regulated entities deliver the right outcomes for Aotearoa New Zealand,"*
>
> and
>
> *"Our rules may need to be more flexible to help keep up with the pace of change, but we'll need to balance this flexibility with the benefits of certainty that input methodologies are designed to provide to regulated parties as well as other stakeholders."*

It is pleasing to see the Commission recognise that change in regulation will be required as part of the upcoming IM and Information Disclosure (ID) reviews. This will ensure that Part 4 of the Commerce Act, which largely targets business as usual, is changed to become fit for purpose to provide shareholders the confidence to continue to invest in new infrastructure to meet greater network demand.

9.1 Emerging Technology Investment Plan

This section summarise work completed and planned in eight areas:

- Electrifying Transport
- Distributed Generation
- Energy Storage
- Advanced Network
- Energy Efficiency
- Real Time Technology
- Digitisation
- Transformation to DSO

9.1.1 Electrifying Transport

Electrification of the transport fleet is a key focus for New Zealand to achieve the Government's decarbonisation targets, and has the potential to grow exponentially over the next decade. EVs and other forms of electrified transportation will increase energy demand across the network when they plug in to charge.

[39] https://comcom.govt.nz/__data/assets/pdf_file/0033/277386/IM-review-notice-of-intention-Cover-letter-23-February.pdf

The actual impact of these EVs connecting to the network at the same time for battery charging depends on charger types, duration and connection capacity, but could be adding more than 150 MW (~25%) to the peak demand if not managed carefully. This will lead to a significant change in WELL's asset planning requirements and investment.

To support the swift adoption of EV's, WELL has a number of EV specific workstreams.

9.1.1.1 EV Charging Trial

In late 2017 WELL conducted a trial to better understand the home charging behaviours of EV owners and how they could potentially affect the demand for electricity. The results of the trial have helped influence the design of EV ToU pricing and allowed WELL to gain an insight into customers' preferences for future EV charging services.

WELL identified that transport would become an obvious choice for electrification. Despite using more electricity to charge a vehicle battery, significantly reducing household reliance on petrol results in a marked reduction in overall home energy costs. This is illustrated in Figure 9-1.

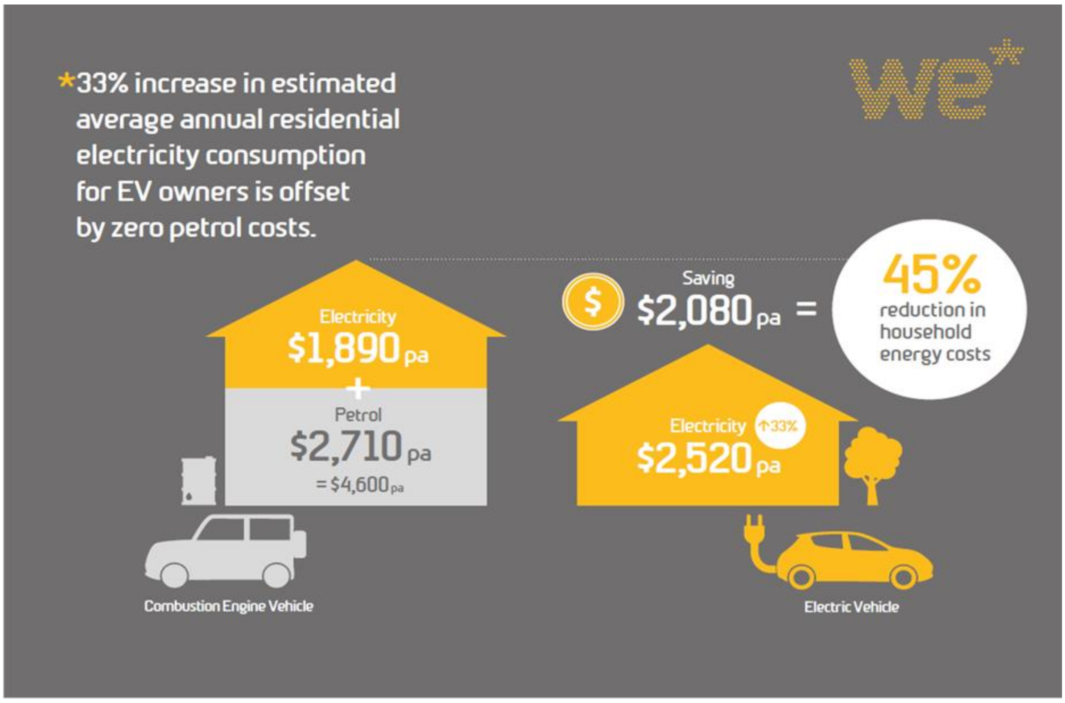


Figure 9-1 Household Financial Benefit of Electric Vehicles (Based on 2017 pricing)

9.1.1.2 Time of Use Prices

WELL has introduced ToU prices which encourage EV users to charge their vehicles during less congested periods. Charging during less congested periods on the network means a larger network does not need to be built to cater for the expected increase in EVs. Avoiding having to build a larger network means that prices can be kept low.

In 2017 WELL engaged with customers about the risk the network faced of having more electricity demand appear in the evening peak period. The engagement was undertaken through the retailers of 92 EV owners and a control group on non-EV owners. Customers were surveyed on their understanding of network investment driving costs and considering what cost-reflective tariff would influence charging behaviour through a price signal.

The response was positive in that it answered some key questions around customers' knowledge of shifting demand, the willingness to consider that demand shifting could be a service provided by a retailer or distributor, and an initial understanding that an EV battery at the customer's house could potentially be an energy source to support the future network via Vehicle to Grid. Summaries of customer responses on these areas are presented in Figures 9-2 to 9-4.

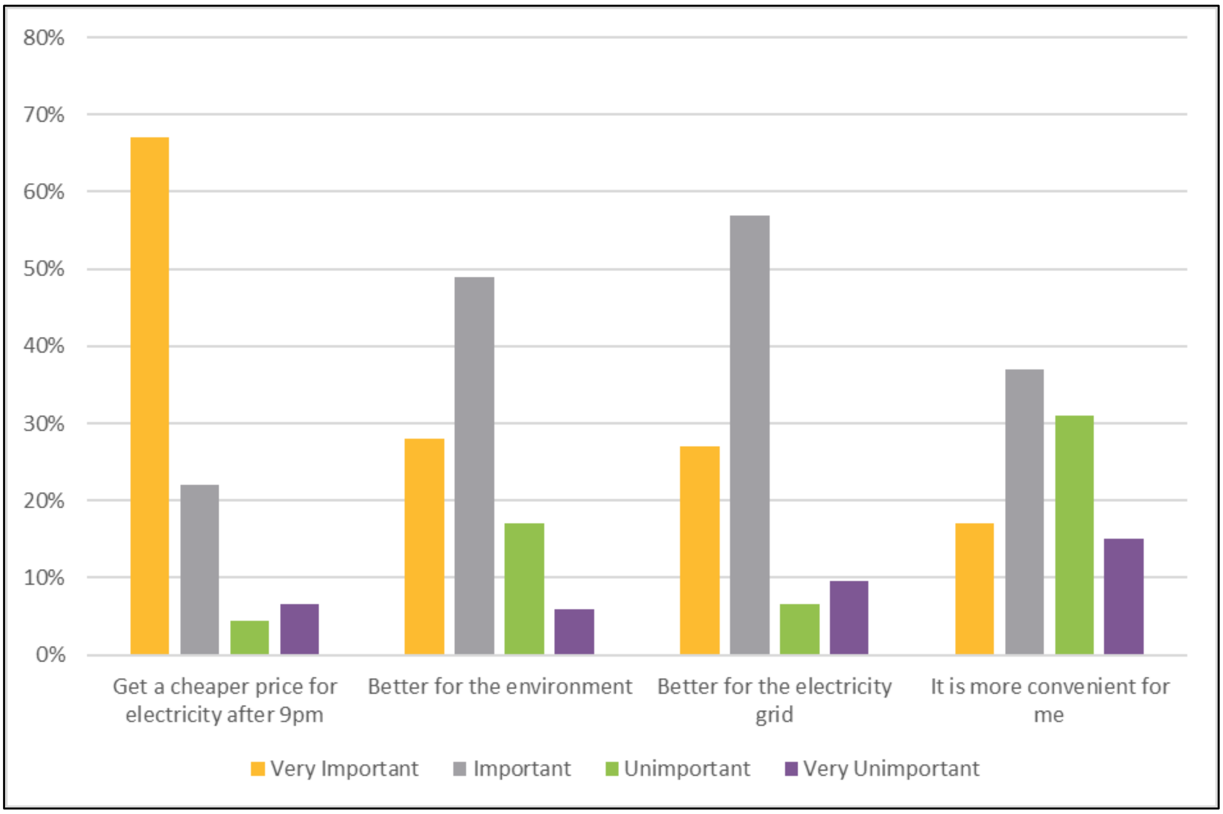


Figure 9-2 Reasons for Charging after 9pm

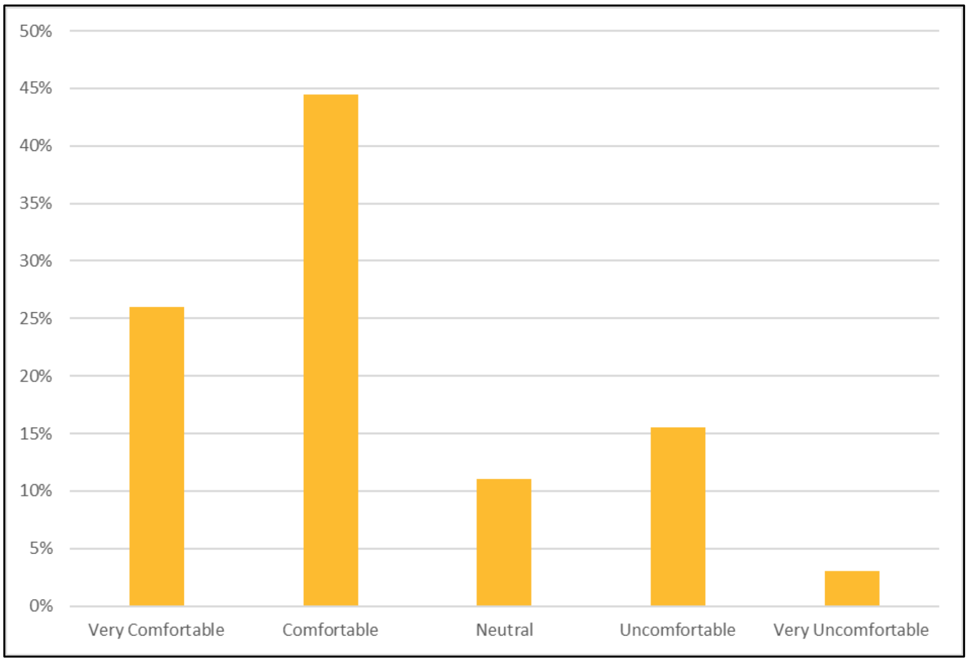


Figure 9-3 Willingness to Consider Demand Shifting

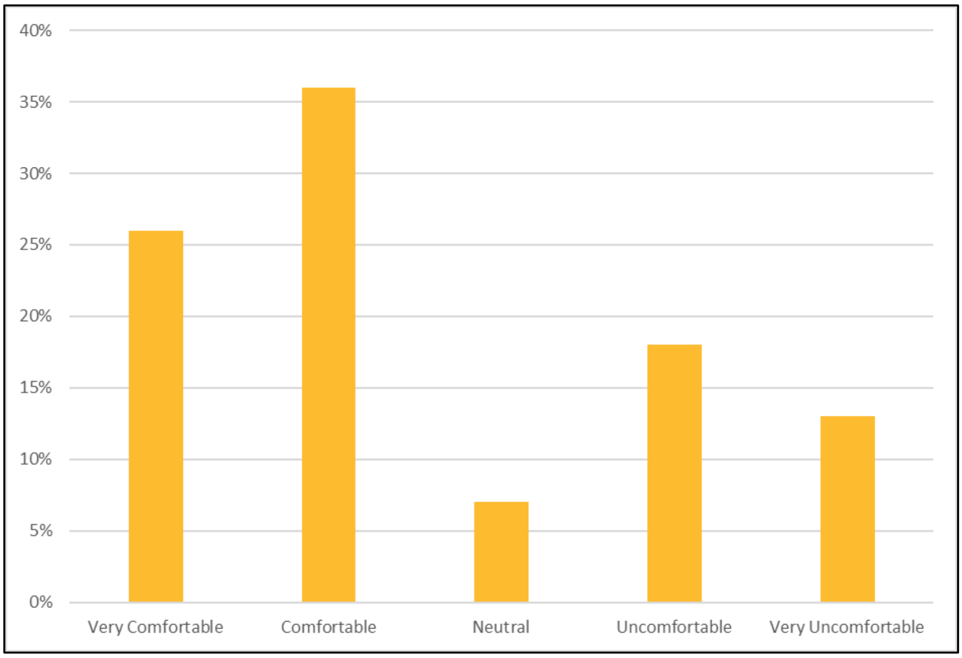


Figure 9-4 Level of Comfort with Vehicle to Grid Energy Source

WELL is expecting a step change in both the amount of electricity used and the times this will required. There are clear signs from earlier trials looking at adoption of EVs in the Wellington region that customers knew it was more sustainable to charge their vehicles outside of the evening peak period. This was largely learned from the longstanding practice of using ripple control for managing hot water heating. It appears that once an advantage or benefit is provided which is then automated, customers are relaxed in allowing this control service to prevail.

WELL is working with retailers to continue providing incentives for customers to move their electricity use away from peak demand periods.

9.1.1.3 EV Connect

EV Connect is an industry wide work programme that focuses on how more energy can be delivered through the existing network. This is part of an Energy Efficiency & Conservation Authority (EECA) LEVCF project. The purpose of EV Connect is to support EV adoption while maintaining network security.

WELL has collaborated with its technology partner GreenSync to develop a roadmap of the industry changes needed to support the introduction of EVs and to offer managed EV charging flexibility services. Changes outlined in the EV Connect Roadmap include ensuring regulation and policy supports the action needed to connect EVs and that networks operators are appropriately funded. The Electricity Code provides rules to ensure consumers can safely connect EVs in their homes. The Roadmap highlights the need for flexible regulation that allows stakeholders to test and develop new services without creating barriers that restrict or slow progress. For example, regulation is needed to ensure customer devices have the right technical specification to participate in the future flexibility services.

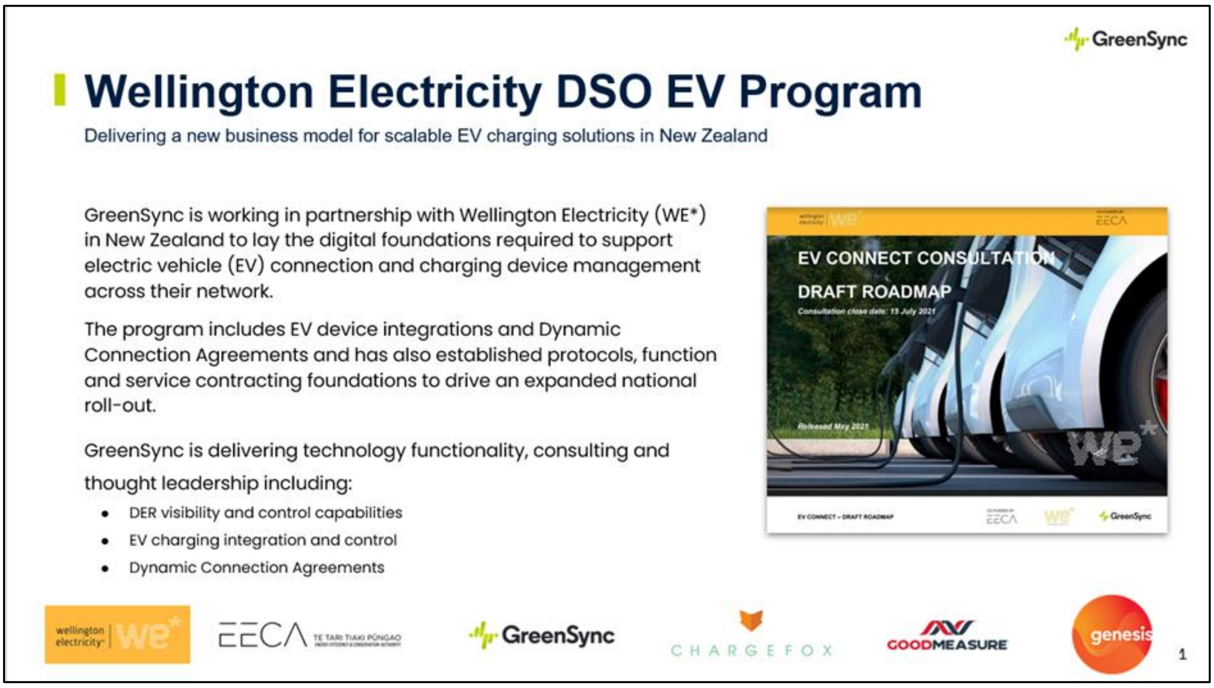


Figure 9-5 EV Connect Summary

The EV Connect Roadmap was developed with the input of 50 key stakeholders provided via workshops and consultations. Stakeholders included policy advisors from the Ministry of Business, Innovation and Employment (MBIE), other EDBs, Transpower as the national grid operator, regulators (the Commission and EA), electricity retailers, consumer advocates and EV user groups.

The EV Connect Roadmap identified eight ‘least regret’ decisions which can be readily implemented:

1. **Establish an industry leadership group to implement the changes outlined in the Roadmap**: A joint leadership group with government authority and industry representation would drive objectives, set outcomes and report annually on progress.
2. **Shared and easy access to consumption data**: Consumption data is an essential input into network planning and management but is not easily accessed. Changes are needed to provide all stakeholders with the information needed to develop customer services to shift peak demand and for network operators to build the capacity and capability.
3. **Central EV register:** Currently networks do not know the location of new EVs. The location and operating characteristics of the EV fleet is needed so networks can plan for the additional demand and placement of large EV chargers.
4. **Funding to trial and purchase flexibility services:** Currently networks do not have the funding to develop the services to shift demand away from peak congestion period on the network or to purchase these new services in the future.
5. **Understand customer preferences for flexibility services (high participation):** For flexibility services to be a viable alternative to traditional wire solutions, they must have high customer participation to provide the scale needed. Flexibility services must be offered in a form that customers want to participate in.
6. **Mandate smart chargers**: To participate in flexibility services, EV chargers must be able to communicate with flexibility providers and their use must be able to be controlled. Smart chargers need to be a pre-requisite for electric vehicles requiring above 2.5 kW of charging capacity. This will allow the demand from large chargers to be managed so they do not impact the quality of supply.
7. **Tools to provide an aggregated demand response**: Development of the tools to directly control smart chargers and to aggregate the response for all customer participating in flexibility services.
8. **Tools to forecast future network congestion**: Network operators need to develop the tools to model and forecast future congestion on their networks to a level of accuracy that will allow them to co-ordinate where and when to call on customers to shift their energy use.

The EV Connect Roadmap can be found on WELL’s website at https://www.welectricity.co.nz/about-us/major-projects/ev-connect/. WELL is focused on implementing the roadmap actions, starting with setting up the leadership group and looking to partner with flexibility providers to trail EV charging flexibility services.

9.1.1.4 Public Bus Services

The Wellington trolley bus system has recently been decommissioned. It is being replaced by a new electric bus fleet which will have on-board batteries designed to be charged at designated locations. The Wellington Reef Street Bus Charger project involved working with one of the bus service providers in Wellington and to study the impact of adopting EV transportation on the network. WELL has also been working with the bus service operators and Greater Wellington Regional Council on more dedicated chargers at several other locations which were installed in 2021 and include both a combination of fast and overnight slow charging.

On the Buses - Electrifying Public Transport

With the decommissioning of the trolley bus system in Wellington, new contracts were assigned by Greater Wellington Regional Council which saw the advent of EBus technology onto the network. Initial discussions with the three providers required depots to be upgraded with an additional 2 MW of capacity to facilitate overnight bus charging. These depots are in locations not linked with the trolley bus demand areas, and have contributed to a number of 11 kV feeders being pushed to their capacity limits.

There is also the added problem of losing the diversity a network provides as the trolley bus system was distributed, whereas the charging supply to a depot is a point load on a single feeder where industrial land is located at the edge of a developed area.

Initial requests for on-route charging were chosen for bus operation requirements, located at the end of a bus route, which coincidentally was the end of the network feeder. As WELL discussed the energy requirements, providing 470 kW of charging load would have required a $1 million network investment to meet the bus timetable requirements.

The solution was taking a price-quality approach to enable a more dynamic network supply position which avoided network investment in return for the bus charging capacity being flexibly managed dependant on the existing network headroom. It became an opportunity charger, and a dynamic connection agreement was entered into to meet the requirements of both parties.

Further bus operators are engaging in more diverse solutions around how security of their depots' demand could become more distributed or where their storage can be shared for network requirements.

The lessons from early EBus connections are likely to be considered in further electric transport connections where price, security & flexibility are key considerations in delivering a secure, affordable

9.1.1.5 Ferry Services

WELL is working with ferry service providers in the region on electrification of their new passenger ferry fleets. This will further reduce the overall carbon footprint from public transportation in the region. The first solution was implemented in early 2022, with other larger projects planned for 2024.

9.1.2 Distributed Generation

While PV installations are the most common form of small-scale distributed generation (DG), they currently have minimal impact on the network and demand profile. However, learnings from other countries with much higher adoption rates have indicated the importance of managing PV maximum export level, power quality mode settings, and disturbance ride through capability. A critical issue for such DG on the WELL network is that the PV maximum output is not coincident with the network maximum demand periods which are during winter nights.

There are approximately 2,000 PV systems with a total output of 8.7 MW connected to the WELL network, and approximately 5,700 EV registrations in the region which would be expected to be consuming 2,000 kWh per annum on average. The annual historical increases in the number of these systems are shown in Figure 9-6.

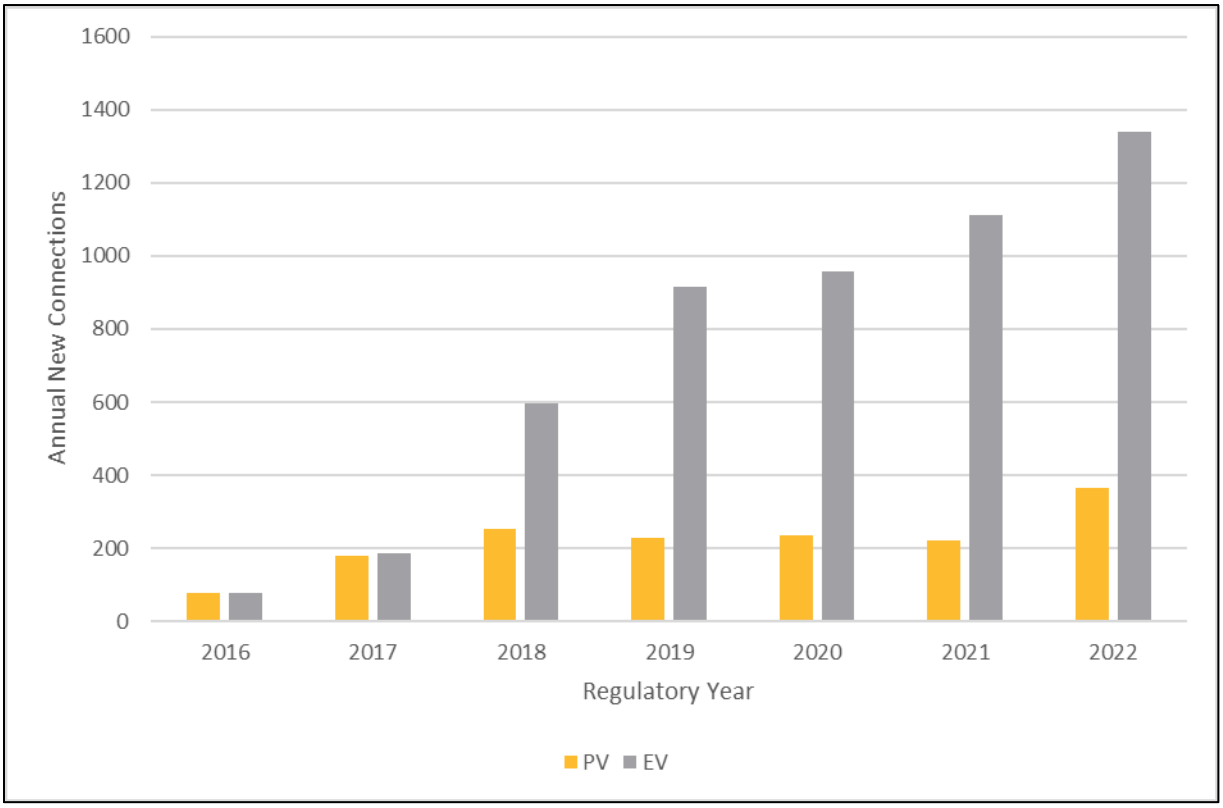


Figure 9-6 Annual New PV and EV Connections to the WELL Network

The improving economics and choices of emerging technologies such as EVs provides opportunities for customers to reduce electricity consumption from the network. WELL will incorporate this small-scale DG into wider network and industry DG developments.

WELL released an updated version of its Distribution Code and Network Connection Standard in December 2020. The updated document details the requirement for gaining visibility and controllability of the customer DG devices.

WELL has run a DG technical workshop with their sister company (SA Power Networks) in South Australia to discuss the technical and commercial issues with DG connections and the guidelines and standards that had been put in place there. Guidelines and standards are especially important for larger sites that could island within the network and create a safety risk.

Development of the demand response market by Transpower provides incentives to building owners with standby generation to respond to signals from the System Operator. As DG market activity increases, it is expected that the demand profile may be distorted which could impact supply quality to end consumers. WELL is concerned that this system does not adequately account for this supply quality which is currently the responsibility of the EDBs.

9.1.3 Energy Storage

Energy storage mechanisms include batteries, compressed air, pumped water, and various forms of heat storage including hot water. These mostly have the ability to increase the flexibility of a power system because they can store and release energy on demand.

WELL has partnered with Wellington City Council (WCC) and Contact Energy (Contact) to trial rooftop solar power systems coupled with battery storage. One objective of the trial was to investigate whether enabling customers to run a micro grid that is islanded from the network makes Wellington more resilient.

The trial enabled Contact and WELL to control the batteries and view the meter data captured. This data included the solar output, battery state of charge, and household usage. The batteries could be activated during a fault or peak demand periods to reduce loading on the network. Results from the trial confirm the effectiveness of battery storage for the targeted objectives. Other findings are that coordinated charging and discharging can benefit the network by reducing peak demand and avoid large output variations from distributed generation.

The rate of installation of batteries for energy storage in Wellington is expected to rise as the unit cost for batteries falls. Installation rates will also be influenced by the results of research to improve battery capacity and capability, and as tariffs (feed-in and time-of-use charges) are refined.

While solar and battery systems cost $10k-$20k, they typically provide only 5 kW of the 20 kW most homes use in a 24-hour period. This means that new technology must work in concert with the network, so there needs to be greater orchestration to enable a return on customers' capital as well as return on shareholder capital where both investments are operating collaboratively.

Residential and commercial hot water storage systems are forms of energy storage that can be controlled via the existing ripple control system. The CCC programmes will increase hot water heating load by reducing gas consumption. WELL has been using ripple control technology for a long time and should be able to move most of this load out of peak times.

Hydrogen technology is still at the early stages but offers some unique advantages in comparison with electrochemical based storage like batteries. WELL's sister companies in Australia and the UK are currently running projects, with the most advanced in Leeds now supplying homes with hydrogen.

9.1.4 Advanced Network

Advanced network elements are able to adjust local load and effect network reconfiguration in response to network conditions and needs. This capability can be used to monitor and then isolate faulted network sections or implement demand response.

Most of the investment in developing advanced networks will be on the LV circuits as traditionally EDBs do not monitor LV status in real time in the same way as they do for 11 kV and above. The benefits of monitoring LV have traditionally not justified the costs of doing so. The accepted industry practice for LV monitoring is to investigate consumer complaints on power quality or interruptions when they occur. With an increasing number of emerging technology devices connecting to the network this approach may not be sufficient.[40]

While current LV asset loading information is limited to the peak loading, LV monitoring makes daily asset loading patterns visible, enabling operations and planning to optimise asset utilisation.

Full visibility requires free and unobstructed access to historical and real time data. Changes to the Electricity Code has provided a framework for distributors and retailers to exchange meter data. New distributed energy

[40] SCADA is mostly an HV toolset (justified by the proportion of system cost compared the primary assets value) while smart metering is primarily an energy consumption device (with some in-built tools that monitor local network parameters). LV monitoring fills in the 'data vacuum' that currently exists between the SCADA and smart metering.

resources, like electric vehicles and household batteries, can now provide consumption data via the web. Aggregators of these distributed energy resources could provide an important source of future consumption data.

WELL continues to trial LV monitoring products as they become available and are still developing a long term strategy where and when to install LV monitoring. This work programme will also decide the best source of consumption data and how to store and analysis the information.

With advanced networks, assets can be designed and operated on the basis that outages will not interrupt supply if services can be restored before batteries are depleted. This supports a change in priorities from planning for redundancy and achieving very low failure rates in our network to ensuring more rapid supply restoration; shifting the emphasis from reliability to resilience.

The advanced networks development plan includes the use of the SCADA system in 2022 to automatically switch 11kV network components following a network outage. The learnings from this work will then be used as a base for the LV network.

Finding the Best Way to Shift Peak Demand

WELL is part of a Concept Consulting EV Study work programme. A key deliverable of the programme is to establish what load can be shifted to a less congested period. This will allow WELL to focus on the development of flexibility services for customer DER that can be practically moved.

The study found that management of EV chargers and hot water heating provides the best opportunity for shifting peak residential demand. Of new demand, management of EV chargers has the largest influence on peak demand, which is why WELL's work programme has focused on EV chargers. WELL's work programme in the future will consider hot water heating and how the current control capability can be maintained and expanded, particularly as gas hot water heating systems are electrified.

The Concept Consulting EV study analysed two points in time:

1. 'Today', being a breakdown of electricity consumption between end-uses as per EECA's Energy End-Use Database; and
2. 'Electric 2050', being the increase in average per household electricity consumption by 2050 assuming the degree of electrification proposed by the CCC in its draft advice.

Prior to any demand management, the biggest driver of today's average uncontrolled household contribution to system peak is space heating, followed by water heating, then cooking, with other appliances driving the remaining 30% of peak demand. By 2050, if households have no incentives to manage when they charge their EVs, un-managed peak per household demand will increase by 45% - largely from EVs, with some increased contribution from water heating (due to gas being removed) and small offsets from other uses. In total, EVs would represent 30% of un-managed peak demand per household, as shown in Figure 9-7.

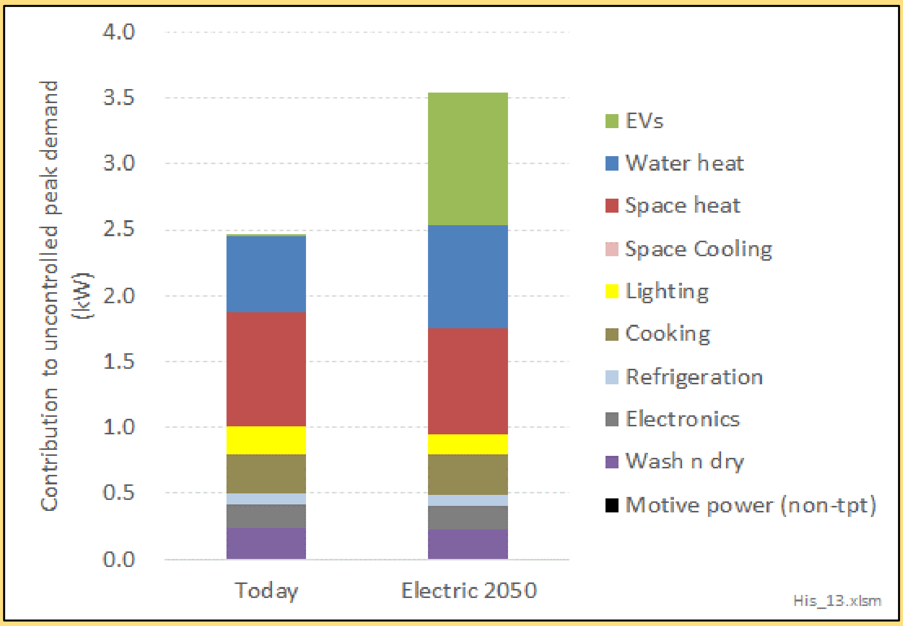


Figure 9-7 Average Contribution to Peak Demand Prior to Demand Management

The study looked at what appliances have the most potential for demand management. Figure 9-8 shows an estimated breakdown of the potential for appliance demand management per household. The key takeaway is that EV charging and water heating have the largest potential for load management.

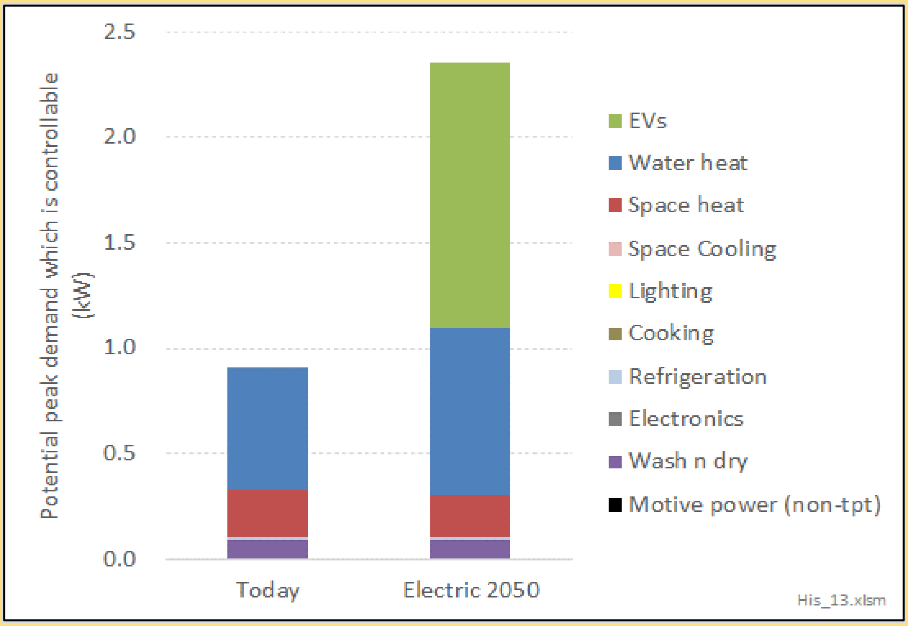


Figure 9-8 Potential for Appliance Demand Management During Peak Demand

While the study is based on national data, WELL's network has the highest proportion of gas space heating in New Zealand, and its urban environment is better suited to EVs than many other networks. Therefore the potential for controlling peak demand is even higher in the Wellington region. This may also mean that areas on WELL's network already seeing demand growth require investment earlier than expected.

9.1.5 Energy Efficiency

Initiatives undertaken by the EECA are raising the awareness of consumers about improvements in energy efficiency. The past four years have seen stable volumes overall on the network. Although ICP numbers have increased the overall volumes have not increased due partly to energy efficiency improvements. Energy efficiency improvements can also offset increases in electricity required by the CCC programmes.

WELL has applied for funding for a trial programme to reduce power bills for those in energy hardship. The programme is being implemented in Porirua and will reduce household power bill by:

- Providing energy saving light bulbs;
- Providing advise on how to save money using WELL's ToU prices;
- Providing various simple changes households can make that save them electricity for no or little cost; and
- Provide Powerswitch assessments to check if another retail plan will save a household money and assist (as required) in making the change.

9.1.6 Master Station and Real-time Technology

Network real-time technology refers to secondary systems that enable a network operator to view the network from a central point and automate protection, control and communications functions, i.e. collect information on system state and execute operational actions (switching or changing set points) at the instance the decision point is reached (real-time). The master station is a core component of real-time technology that is in a centralised location and providing interface to a smart network.

The objectives of network real-time technology include safe network operation, increased reliability and improved asset utilisation. The technologies include Supervisory Control and Data Acquisition (SCADA), Distribution Management System (DMS), Outage Management System (OMS), Work Order Management (WOM), Field Mobility Dispatcher (mobile switching), Energy Management System (EMS), and Power Control System (PCS). An advanced distribution management system (ADMS) integrates these features into a single solution.

The network real-time technologies function over a communications platform that may be one, or a hybrid, of traditional RTU driven point-to-point systems, multi-cast radio and/or segregated secure tunnel via public wireless data network. WELL needs to update its load management Master Station in 2024 that controls the ripple control system and this project will consider the wider system requirements.

9.1.7 Digitisation and Data Transformation

WELL's existing asset base is made up of a combination of legacy assets from the pre-digital age and recent additions to the network that are digitally enabled (for example, switchgear with digital interfaces, numeric protection relays, and IP based communication links to key sites). With current levels of digitisation WELL can only exploit a limited proportion of the device capabilities until full digital integration can be realised.

Data collection and exchange is growing rapidly, creating both digital threats and opportunities. Digitisation alters the capabilities and tools that a network operator needs to succeed. It greatly lowers barriers to market entry for competitors that do not traditionally participate in the electricity market, and is also a catalyst for raising customer expectations around products and services not previously offered by utility companies.

WELL is investigating the optimal approach to managing technology changes in data management. This includes the option of receiving services from data storage vendors (Metering Service Provider) to provide reports of key information as an alternative to the investment (and associated cyber security requirements) to run duplicate data storage in-house.

Leveraging Meter Data

An example of using data from a Metering Service Provider (MSP) to assist with managing the network is where voltage information received by Smart Meter can be interpreted as a failing neutral connection on the LV network. The connection failure can be identified from the MSP's data source and alerted to the EDB, as illustrated in Figure 9-9. This type of leveraging of meter data is a project that WELL is currently investigating with a MSP.

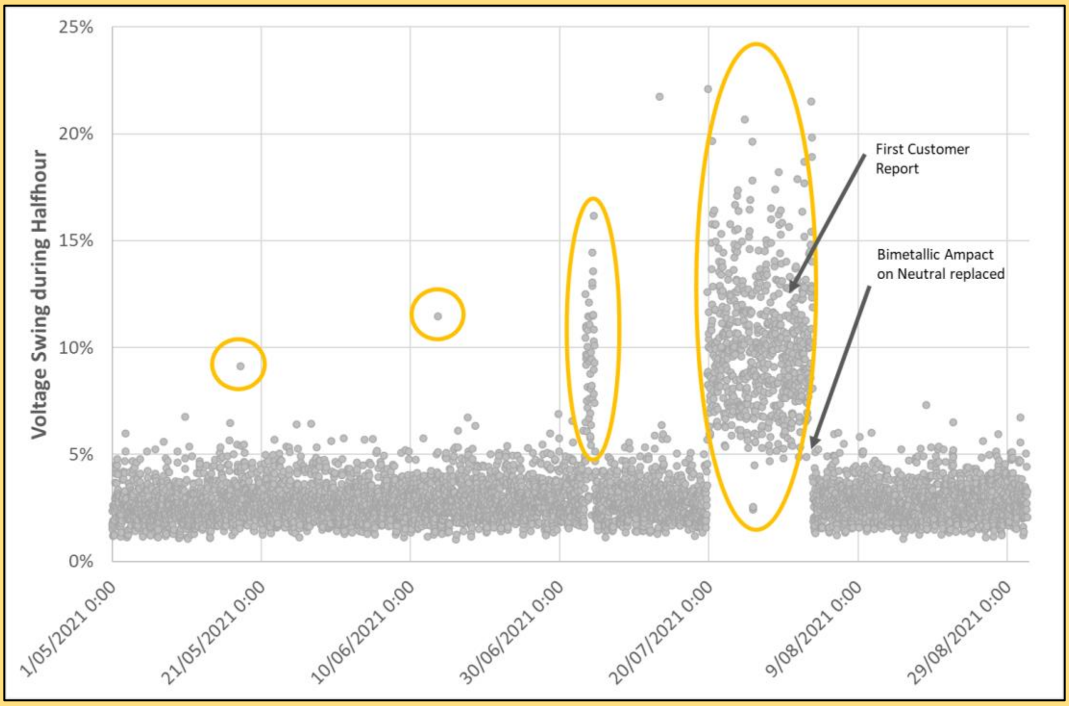


Figure 9-9 Voltage Swing Recorded by Smart Meter During Neutral Connection Failure

9.1.8 Transformation to a Distribution System Operator

With the increase in emerging technology, the Distribution Network Operators (DNOs) will need to manage the LV network so it stays in balance and remains a secure system. A Distribution System Operator (DSO) platform is expected to be needed to provide the tools and processes to manage and coordinate the network so that their demand requirements can be manage congestion within reliability and quality limits and within network constraints.

EDBs are responsible for maintaining power quality as required by the Electricity (Safety) Regulations 2010. While EDBs may not be the only candidate to be the DSO provider, they are best placed to understand and manage local technical electricity supply issues and set technical standards governing emerging technology to network connections.

The path to become a full DSO is complex, and WELL is learning from the EV Connect project to better understand the tools, process, partnerships, and skills requirement to deliver the DSO function.

9.2 Developing a Business Case for New Technology

WELL's initial analysis shows that managing congestion using distributed energy resources will allow WELL to avoid increasing the capacity of the existing network to meet the expected exponential increase in energy demand from the uptake of EVs. WELL expects the savings to customers from managing congestion using DER could be significant.

- **The size of the increase in demand:** Electrification to reduce fossil fuel use creates a step change in energy choice for households, away from gas cooking, space and water heating (impacting electricity demand in 55,000 of WELL's 172,000 network connections). Visibility of changes in customer behaviour is a useful input into how fast the network must grow to keep up with demand. Extrapolating population and housing growth with a reduction in fossil fuel use out to 2050, it is easy to contemplate a 3-4 kW home having an additional 2 kW of EV charging and 2 kW of gas fuel now being electrified. This effectively doubles the demand on the current network. Other sources (for example Transpower's Te Mauri Hiko[41]) have indicated similar increases from electrification to meet climate change initiatives.

- **Cumulative effect from uptake of electric vehicles:** The uptake of EVs is a cornerstone of the climate change actions to reduce carbon emissions. The cheaper price of electricity compared to the cost of petrol is seen as a key factor in the increasing number of EVs in New Zealand. Government subsidies for purchasing EVs as well as larger batteries improving driving range further support EV uptake. This may see home charging demand at 7.5 kW (32A) rather than the 2 kW expected. Time of charging will be critical for the quality and security of the network during traditional peak demand times. Locational visibility and management of charging times and rates are key tools for this purpose. Some of these will be services offered to the market with distributers requesting demand reduction for security and supply quality requirements, similar to the Warning Notice (WRN) and Grid Emergency Notice (GEN) mechanisms in the DDA. Gaining visibility of where EVs are charging overnight assists planning of targeted upgrades of managed charging rates at peak demand periods. Similar to the United Kingdom, once EV penetration reaches a threshold, the upgrade allowance is released to support network investment.

- **New technology:** New customer products will allow homes to generate, store and export energy from behind the meter. The new technology will provide consumers with the opportunity to participate in flexibility services to support network security and reliability.

- **Cost impact:** Building a larger network commits the distributor to long life assets which are expensive to install and manage through their lifecycle. While solar and battery systems cost $10-20k, they typically provide only 5kW of the 20kW most homes use in a 24-hour period. Investing in new technology needs to enable a return on customers' capital as well as a return on shareholder capital where both investments are operating collaboratively. For example, finding the point of balance which defers EV charging to allow deferral of network investment will alleviate peak demand by over 90%.

[41] https://www.transpower.co.nz/resources/te-mauri-hiko-energy-futures

- **Time and resources needed to increase the capacity of the network:** The significant increase in network investment will come at a time when other distribution networks, the transmission grid and other utility industries like water and transportation will also be replacing, developing and growing their infrastructure. A finite pool of skilled resource in New Zealand (and potentially globally as other countries reduce carbon emissions) could make this level of growth particularly challenging to deliver.

- **Customer affordability:** While WELL can manage demand to provide a secure network for meeting climate change initiatives, WELL also needs to ensure this remains affordable for consumers.

Traditional methods of responding to increases in demand are unlikely to work by themselves. A new approach to delivering future capacity with flexibility services needs to be developed ahead of more traditional capacity investment.

WELL's EV Connect programme has shown that industry stakeholders have common views about the changes needed to realise these savings. Stakeholders agree that a co-lead (government and industry), coordinated approach is needed to develop the strategies and frameworks needed to accommodate EVs and distributed energy resources into the New Zealand electricity system. The EV Connect programme highlights legislative, policy and regulatory changes needed to support the uptake of EVs.

At a network level, WELL is running a series of work streams to trial new technology and to develop the tools, resources and network designs that will best deliver future energy requirements. The industry Roadmap developed as part of the EV Connect programme will be combined with the network level work programmes to develop a business case for the accommodation of EV's and other DER's on the Wellington Network. The business case will:

- Demonstrate how WELL will meet New Zealand decarbonisation targets on the Wellington distribution network;

- Provide a long term (30 years) work programme and funding required to deliver New Zealand's decarbonisation initiatives;

- Provide a consumer cost benefits analysis that will be used to facilitate future customer engagement;

- Provide an Industry Roadmap which will highlight the legislative, policy and regulatory changes needed to support the implementation of the works programme;

- Provide an initial view on the regulatory funding model that maybe required i.e. whether the programme could be delivered under the default price path framework or whether a different price path would be needed; and

- Recommended a consumer consultation programme.

9.2.1 Demand Growth Projections

WELL's early projections (through to 2050) of housing and ICP growth include an EV uptake of 2 kW and a reduction in gas use across 55,000 current connections. Adding a further 2 kW has a large effect on what demand increase the network of the future may be required to support. This is set out in Table 9-1.

Growth		Driver	Peak Demand 2050 (MW)	Total Change 2050 (%)	Annual Change (%)
Current demand (2021)			**580**	**n/a**	**n/a**
Growth	Population Growth	Population growth and housing shortage	103	18%	0.6%
	Transport electrification	Climate change programme	390	67%	2.2%
	Transition from gas	Climate change programme	273	47%	1.6%
New Growth			**766**	**n/a**	**n/a**
Total new growth (2050) – uncontrolled			**1,349**	**132%**	**4.4%**
Load Control		Introduction of flexibility services	-224	-39%	-1.3%
Total new growth (2050) – controlled			**1,122**	**93%**	**3.1%**

Table 9-1 Projected New Demand Growth on the WELL Network to 2050

The key to supporting investment from a climate change and sustainability perspective is to ensure the network remains secure and the price to customers remains affordable. The ability to shift demand through the digitalisation and management of DER will help to achieve all three requirements of having a secure, affordable, and sustainable electricity distribution system.

9.3 Funding Assumptions

WELL is currently funded through the Default Price Path (DPP3) which expires in 2025. This funding model uses the 2020 AMP as the basis for capital funding allocations for asset renewals and system growth.

The funding for the trials has been included in this AMP and the DPP3 allowances, with an initial cost of around $0.4 million per annum over the first five years and rising to around $3 million at the end of the planning period.

The business case for delivering the CCC decarbonisation targets and accommodating EVs on the WELL Network is being developed. A key business case deliverable will be an initial view on the regulatory funding model that maybe required, i.e. whether the programme could be delivered under the DPP4 framework or whether a different price path would be needed.

Early modelling shows that the investment is likely to be significant and is unlikely to fit within the DPP capital expenditure limits which caps capital allowances at 120% of historic average expenditure. If WELL cannot fund the business case within the DPP, then under the current regulatory framework, it will have to consider a CPP.

9.3.1 Changes Needed to the Regulatory Framework

It is important that a responsive regulatory system is evolved to allow EDBs to make the investment needed to deliver their decarbonisation targets. If EDBs cannot fund the development and implementation of tools to accommodate an electrified transport fleet, the transition from gas to electricity and the electrification of manufacturing process heat, the electricity supply is likely to be disrupted by an unmanaged increase in load. New Zealand will not achieve its 2050 carbon neutral targets.

The current regulatory framework of providing a DPP for business as usual levels of investment and a CPP for a step change in business activities, works well for the operation of a traditional network with modest increases in demand. The funding for network growth and regular fleet replacements can be carefully and precisely managed to meet known growth rates and well-understood asset performance profiles. The traditional and predictable investment profiles can be forecast well in advance of actual expenditure and can be managed using long five yearly regulatory periods.

The significant increase in demand from the decarbonisation programmes and the change from the traditional response of building a larger network to using new technology to increase utilisation of the existing network, means that there will not be the predictability and certainty the existing regulatory framework relies on. Specifically:

- The rate of the increase in demand is uncertain and networks will need to flex their investment programmes to meet that demand within a 5-year regulatory window. For example, the size of government subsidies for purchasing EVs, timing of restrictions on petrol and diesel engines, the speed of transition from gas, and the development of an EV charging network will all influence the speed of change in electricity demand.

- The types of services that consumers want will change rapidly – how and when consumers choose to charge their cars, whether they install solar and how they discharge household batteries are likely to change the networks demand characteristic. Investment in demand management and network re-enforcement will have to quickly adjust.

- The technology to improve the utilisation of the existing networks is new and is developing rapidly. EDBs will not be able to accurately predict cost and capabilities five years in the future – EDBs will need the ability to adapt their allowances to reflect quickly changing demand management solutions.

The current regulatory model is a barrier to EDBs delivering their decarbonisation initiatives. The DPP framework does not provide the funding capacity needed, while the CPP is slow and expensive to apply and its application is too uncertain for an EDBs to be confident that they will be made whole for their investment. Specific concerns around the CPP include:

- The DPP framework is backwards looking for the calculation of its operating cost allowances and for the gating and restricting the size of its capital programme. New types of costs will not be captured;

- The increase in energy demand from EVs will be nation-wide and is likely to impact most EDBs. The speed of EV uptake will also differ between EDBs, with urban networks likely to see faster EV growth than rural networks. New Zealand decarbonisation initiatives will mean there is no 'business as usual' scenarios that suit the DPP and the higher levels of funding are likely to become the norm, rather than the exceptional circumstance a CPP regime was designed for;

- The unrecoverable CPP application costs means that an EDB is unlikely to make a real return on a medium size investment programmes; and

- For many networks the investment to meet the decarbonisation targets will be modest but too large to be captured by the business as usual DPP framework and are not a large enough to represent an operational change or investment to require a CPP application. Applying for a CPP is an expensive, complex, whole of business process.

While there is uncertainty in the rate of adoption, EDBs will be able to look at heat maps of their network as the visibility of solar and EV penetrations becomes known (EV locations remain invisible at the moment). This will allow a threshold to be established which will then require demand response (flexibility) services to be developed or failing that, the need for network investment. If the growth rate and thresholds are pre-agreed as part of the IM's then the reopener criteria may be an efficient mechanism for investment. This investment would be supported by a price increase to customers in a sequenced manner within a regulatory reset period, avoiding the delays of delaying connection until allowances align with infrastructure provision.

There are two projects which will be directed through the DPP reopening process in 2022 which involve capital investments of $20 million and $5 million for two customers. The first project is related to increasing the customers' transport capacity and speed of service with the second looking for increased service and change from gas to electricity for heating. The reopener process appears to be a useful tool to assist customers who have not had their developments included in the current 5-year allowances, and are too small or time bound (both projects require delivery before 2025, the end of the current reset period) to warrant a CPP application.

WELL supports refining the current regulatory framework to provide EDBs with a price path which has the flexibility to meet changing demand, changing customer services and new delivery solutions.

Options to provide regulatory flexibility could include:

- Introducing more re-openers to provided networks with the flexibility needed to response to rapid changes in growth. This could include both Opex re-openers to support flexibility services and Capex reopeners to support growth from many small customers (like growth that would come from EV uptake).

- An individual price path using consistent and repeatable review processes. It is likely that networks will need to invest over multiple regulatory periods. An individual price path with consistent and repeatable review process will allow an EDB to adjust their expenditure levels at a lower administration cost than a CPP.

- Refining the DPP framework to keep regulatory compliance costs as low as possible and allow one-off projects outside of the capex gating with additional scrutiny. The calculation of operating costs under the DPP model should also be adjusted to include new costs and cost increases unique to a specific network. A successful example of this model was the 'streamline' CPP used for WELL's earthquake readiness programme. WELL essentially remained on the DPP for its business-as-usual operations and applied a higher level of CPP scrutiny to the specific $32m, three-year earthquake readiness investment programme which concluded in March 2021 in response to the 2016 Kaikoura Earthquakes.

- Removing penalties on exceeding capital expenditure on new customer connections and network re-enforcement to allow networks to deliver faster than expected customer growth. This would allow networks to meet rapid uptakes in new customer connections and climate change growth, without being penalised.

Some flexibility was added during the DPP3 reset – the reopener for new customer growth provides EDBs with an important ability to re-open the price path for unexpected growth. The upcoming Input Methodology review provides another opportunity to add further flexibility.

The DPP3 reset also included the introduction of an innovation project allowance for up to 50% of the total cost of approved innovative projects in the assessment period, but not exceeding 0.1% of the total allowance in the regulatory period. While this innovative fund is in line with Part 4 of the Commerce Act to promote the long term benefit of consumers, the actual allowance amount is insufficient for EBDs to deliver the innovation projects that are needed to deliver the zero carbon targets. The upcoming Input Methodology review provides an important opportunity to align the innovation incentives with the size of the upcoming development programmes.

9.4 Summary of Emerging Technology Investment Plan

The AMP over the next 2–3 years has a strong focus on research and development to test new technology and to develop a business plan of the future DSO. The following 5–10 year period will then begin to deliver that business plan. WELL will collaborate with other stakeholders and identify innovation partners and work with them to develop the proof of concepts and actively participate in industry forums to share what we have learned.

The total capital expenditure forecast for the emerging technology related development plan over the next 10 years is shown in Table 9-2.

Expenditure Type	2022/23	2023/24	2024/25	2025/26	2026/27	2027/28	2028/29	2029/30	2030/31	2031/32
Electric Transportation	350	350	350	1,550	1,550	1,550	1,550	1,550	1,550	1,550
Other Emerging Technology Projects	180	224	370	945	1,195	1,345	1,345	1,505	1,505	1,505
Capital Expenditure Total	**530**	**574**	**720**	**2,495**	**2,745**	**2,895**	**2,895**	**3,055**	**3,055**	**3,055**

**Table 9-2 Future Network Capex Forecast Summary
($K in constant prices)**

Section 10

Support System

10 Support Systems

WELL invests in non-network assets to support the distribution of electricity to customers. These assets include information systems, plant and machinery, and land and buildings. This section describes the approach taken and the investment requirements for these systems over the planning period.

10.1 WELL Information Systems

The following information describes the key repositories of asset data used in the asset management process, the type of data held, 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.

Table 10-1 shows where asset information is stored within WELL's systems.

	Physical Assets	Equipment Ratings	Asset Condition	Connectivity	Customer Service	Financial Management
Supervisory Control & Data Acquisition (SCADA)		✓		✓	✓	
Geographical Information Systems (GIS)	✓	✓		✓	✓	
Drawing Management System	✓	✓			✓	
Power Systems Modelling		✓		✓		
Protection Relay Configuration Management System	✓	✓				
Maintenance Management System	✓		✓		✓	✓
Billing System				✓	✓	
Financial System						✓

Table 10-1 Asset Data Repositories

10.1.1 Asset Information and Operational Systems

The information systems WELL uses to manage its asset information are described below.

10.1.1.1 SCADA

A GE PowerOn Fusion Supervisory Control and Data Acquisition (SCADA) system is used for real time operational management of the WELL network. The SCADA system provides operation, monitoring and control of the network at 33 kV and 11 kV. WELL does not have any telemetry feeding the SCADA system for the low voltage (LV) network (400 volts or below) but is investigating how this could be implemented as distribution substations are upgraded or replaced. In addition to this, with advances in GIS technology investigations are underway to identify how to develop LV switching schematics from the GIS. Outage reports are recorded by the GE PowerOn Fusion Calltaker system utilised by the Outage Manager at the WELL Contact Centre. The Calltaker system electronically interfaces with the field service provider's dispatch systems to dispatch field staff for fault response. Closed jobs are also fed back electronically to the Calltaker system. The WELL Contact Centre also updates outage information for publication on the WELL website and outage application.

In 2022 WELL will upgrade its SCADA from PowerOn Fusion to GE's PowerOn Advantage product, which will enable:

- A more flexible and resilient IT architecture utilising virtual machines;
- Future integration with GIS via common information model adaptor so that LV models can be imported; and
- An upgrade of workstation and server hardware to latest supported hardware and operating systems.

In addition, during 2022 WELL will commence the replacement of its standalone Load Management Master Station.

WELL is also currently investigating options for an updated historian system. WELL currently uses TrendSCADA which is a proprietary data historian tool interfaced with the GE PowerOn Fusion system, for network operations and 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, and a limited suite of analysis tools. The investigation will consider alternative products used by other EDBs which may offer greater benefits to the business and improve user-friendliness.

10.1.1.2 Geographic Information System (GIS)

The GIS provides a representation of the system's fixed assets overlaid on a map of the supply area. WELL uses the GE Smallworld GIS application for planning, designing and operating the distribution system and this is the primary repository of network asset information.

The GIS interfaces to WELL's maintenance management system (SAP PM), the billing system (Gentrack), and the field service provider's works management system.

WELL is currently replacing the existing GIS with the GE Electric Office suite, which provides better system performance, data quality assurance tools, and improved user functionality. Electric Office provides a long term technology fit for WELL, with integration with GIS and SCADA in future.

10.1.1.3 Drawing Management System

WELL stores all GXP, substation, system drawings, and historic asset information diagrams in ProjectWise in PDF and CAD format.

10.1.1.4 Power System Modelling

The DigSILENT PowerFactory is used to model and simulate the electrical distribution network and analyse load flows for development planning, contingency planning, and protection studies. The PowerFactory database contains detailed connectivity and asset rating information. To ensure ongoing accuracy, the model is manually updated every quarter to include recently commissioned network assets and augmentations. Model updates are regularly distributed to design consultants to ensure consistency for commissioned studies.

10.1.1.5 Cable Rating Modelling

CYMCAP (cable ampacity and simulation tool) is used to model the ratings of underground cables at all voltages for existing cables in service and new developments.

10.1.1.6 LV Voltage Drop Modelling

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

10.1.1.7 Protection Relay Configuration Management Database

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

10.1.1.8 Maintenance Management System

WELL uses the SAP Plant Maintenance (SAP PM) module to plan its maintenance activities and capture asset condition data for both preventative and corrective works. This system allows WELL to issue maintenance workpacks to service providers electronically. Maintenance results are returned electronically via either an integration module (for high volume tasks), or a web interface (for low volume tasks). Asset data is synchronised with GIS, which allows maintenance tasks to be grouped spatially to increase efficiency.

SAP PM is currently hosted in Melbourne by WELL's sister company Powercor. Powercor's plans to upgrade the SAP system have triggered WELL to explore replacement options for SAP PM. This will include the SAP Portal which is also used as a customer and contractor-facing system. In addition, the SAP Portal has limited functionality which adds weight to the need to seek a replacement.

10.1.2 Billing System

Gentrack is used to manage ICP and revenue data as well as the architecture of the network model of ICP's against feeders and GXP reconciliation to deliver billing and connection services. Gentrack is populated and synchronised with the central National ICP registry. It interfaces with the GIS and PowerOn Fusion systems to provide visibility of customers affected by planned and unplanned network outages. Gentrack also interfaces with the SAP financial system for billing purposes.

The current Gentrack system is hosted in Melbourne by WELL's sister company Powercor. The system will be relocated to WELL's datacentres in New Zealand in 2022.

10.1.3 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.

SAP is currently hosted in Melbourne by WELL's sister company Powercor and is an aged version. WELL is reviewing whether SAP Financial is the best platform for financial management in the future. Powercor's plans to upgrade the SAP system have triggered WELL to explore options to replace SAP with a system that might be better suited to a medium sized New Zealand distribution utility.

10.1.4 Cyber Security

WELL is facing increased cyber security threats in the same manner as all critical infrastructure providers. The energy sector is highlighted as a cyber security target and this threat is only going to increase given the ongoing digitisation of the power utility applications. A cyber security attack on a power utility can have severe consequences affecting the physical network, such as overloading of power systems or erroneous power system operation. WELL is working closely with the National Cyber Security Centre (NCSC) to ensure that its IT systems, especially those relating to the direct control of the electricity network, are as secure as possible. This increased cyber risk means that WELL needs to invest more heavily in training, systems and processes that enhance cyber security monitoring and protection.

10.2 Identifying Asset Management Data Requirements

Asset management data requirements are defined in WELL's asset maintenance standards. The asset management data requirements are updated when 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 who input asset information into the GIS and SAP PM information systems.

10.3 Data Quality

Robust and timely asset information is needed to drive asset management activities such as development, maintenance, refurbishment and replacement. As the GIS system is the central repository for WELL's network asset information, it needs to be complete, accurate, and up to date to make good asset management decisions.

Initially asset data is entered into the relevant information systems at the time the asset is created. The asset data will be updated, as required, throughout the life of the asset. Processes are in place to establish 'one source of truth' for each category of information and synchronisation of data between the various information systems.

To ensure data quality, WELL continually:

- Updates data on missing or discovered assets and nameplate information stored in GIS;
- Identifies and fixes network connectivity in GIS; and
- Implements measures to improve the quality of the maintenance data reported from the field.

Data quality is managed by implementing controls such as mandatory fields, fixed selection lists when inputting data, and continually checking and verifying the data in the major systems (GIS, SAP PM). User training is provided to ensure users understand what information is required, why particular information is captured and its use within the overall asset management process. Table 10-2 lists areas where risks have been identified due to gaps in the availability or completeness of asset data.

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 the GIS updating process to correct gaps on inspected equipment.
	LV connectivity is incomplete in some places	Project to continually improve LV connectivity and create accurate representation of LV feeders and open points.
GIS/Gentrack	ICP connections to transformers	Historically some ICPs were not connected to the correct transformers in GIS and there is a mismatch between the Gentrack system and GIS. This is progressively being corrected and new processes are in place to ensure new ICPs are connected to the correct transformer (physical connection in the field is correct).
SAP PM	Some required data not collected for early records	Data entry into SAP PM now has mandatory fields to ensure all relevant data is captured at the time of entry into the system. Historic entries are being reviewed to fill in gaps.
	Condition Assessment (CA) scores incorrect for early inspections.	Standardised CA scoring and field training is in place. Annual re-inspection will provide correct information from second pass.
PowerFactory	Historical network augmentations or customer connections may not be captured in the model	Engineering Planning team updates the model to reflect new and updated system components on project completion. Project Managers are required to submit relevant information in a timely manner at the completion of projects to allow the models to be updated to reflect actual state.
StationWare	Not all station protection relay settings have been captured.	Settings are updated at the time of projects being undertaken, or audited as required to undertake protection and network studies.
PowerOn Fusion	Not all network branches have ratings assigned to them in PowerOn Fusion.	The NCR utilises a spreadsheet of ratings based on operational scenarios. Alarm limits based on these ratings are assigned as required.

Table 10-2 Overview of Asset Data Gaps and Improvements

Data management and governance is becoming more critical for WELL as the distribution network business evolves. WELL has completed a review of its data management and is working on a plan to implement the most important findings of this review and include them in any future system replacements.

10.4 Plant and Machinery Assets

Vehicles are typically replaced every three years in accordance with WELL's Motor Vehicle Policy. Other test equipment and tools are replaced as required, for example power quality measurement devices and partial discharge test sets. There are no other material investments planned for non-network plant and machinery.

10.5 Land and Building Assets

WELL 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.

The capitalised lease capex item relates to the new accounting standard that now treats operating leases as a capital item. The capitalised lease items mainly relate to leased vehicles.

10.6 Non-Network Asset Expenditure Forecast

From the details in the sections above, WELL's non-network expenditure forecast is summarised in Table 10-3.

Expenditure Type	2022/23	2023/24	2024/25	2025/26	2026/27	2027/28	2028/29	2029/30	2030/31	2031/32
GIS	200	50	50	50	50	50	50	50	50	50
SCADA	721	455	-	-	-	-	2,000	-	-	-
Load Management	350	-	-	-	-	250	-	-	-	-
Operational IT Infrastructure	50	-	-	-	-	750	-	-	-	-
Historian	-	600	100	100	100	100	100	100	100	100
Mobile Operations Tools	-	200	-	100	-	100	-	100	-	100
Outage Management	120	60	-	-	-	-	-	-	-	-
Asset Management	-	350	400	125	125	-	-	-	-	-
Engineering Tools	-	20	-	20	100	20	-	20	-	20
Other Systems (e.g. Billing, Financial, Website)	504	740	345	240	95	620	95	370	670	120
IT Infrastructure	293	1,040	775	1,675	865	525	825	525	1,725	525
Capitalised Leases	-	-	-	-	2,705	-	-	-	-	-
Total Non-network Capital Expenditure	**2,238**	**3,515**	**1,670**	**2,310**	**4,040**	**2,415**	**3,070**	**1,165**	**2,545**	**915**
System Operations and Network Support	6,170	6,136	6,144	6,151	6,158	6,165	6,172	6,179	6,186	6,186
Business Support	13,464	13,160	13,025	13,535	13,360	13,355	13,351	13,346	13,342	13,342
Total Non-network Operational Expenditure	**19,634**	**19,296**	**19,169**	**19,686**	**19,518**	**19,520**	**19,523**	**19,525**	**19,528**	**19,528**

Table 10-3 Non-Network Expenditure Forecast
($K in constant prices)

Section 11
Resilience

11 Resilience

11.1 WELL's Resilience Framework

This section describes WELL's approach and investment plan relating to resilience and focuses on managing and mitigating events beyond normal circumstances and under emergency situations.

As a lifeline utility in accordance with the CDEM Act, WELL must ensure that it is able to function to the fullest possible extent during and after an emergency, even though this may be at a reduced capacity. This can include one-off events such as a storm, earthquake, or equipment failure. A concern for WELL is that currently the existing avenue of funding via the DPP allowances does not fully cater for resilience funding. This was shown by WELL needing to make a CPP application to address earthquake readiness following the 2016 Kaikoura earthquake. This was in response to the Government Policy Statement of 21 September 2017, and was approved by the Commission in March 2018.

The WELL resilience framework has been sectionalised in this plan per the following structure:

- Climate change;
- Emergency response and contingency planning;
- High impact low probability (HILP) events;
- Future resilience work – WeLG Regional Resilience Project; and
- The EEA Resilience Guide and Self-Assessment.

A significant amount of work has been undertaken to improve earthquake readiness under WELL's CPP. Delivery of the CPP is complete and has greatly improved WELL's ability to respond in an emergency. It is important to note that the focus of the CPP programme was the readiness area of the 4Rs resilience model, and while this does improve resilience, further work is needed to increase the network's ability to withstand a major earthquake. Section 11.5 discusses additional work that needs to be delivered to further improve resiliency, including improving the single point of failure risk at Transpower's Central Park substation and accelerating the replacement of fluid and gas-filled subtransmission cables.

11.2 Climate Change

Climate change is expected to cause a rise in sea levels as well as changing weather patterns which are expected to result in more frequent and severe storms than have previously been experienced. This will impact temperature, rainfall and wind within the region as well as the frequency and intensity of storms.

The average temperature in the region is expected to increase by 0.7-1.1°C by 2040 and could increase by up to 3°C by 2090.[42] Rainfall is expected to vary locally within the region as well as seasonally. Latest projections do not show an increase in the frequency of storms greater than the current inter-annual variation, however the intensity of these storms may increase. It is expected that more high wind days will be experienced which will require continuing efforts to manage the reliability of overhead lines and vegetation.

[42] "Wellington Region climate change projections and impacts" NIWA, June 2017.

Wellington already has one of the highest wind zones in the county due to its position at the bottom of the North Island on Cook Strait and between mountain ranges of the two islands.

Rising sea levels present a risk in central Wellington where a large number of substations in the CBD are in the basements of buildings. The sea level at Wellington rose at an average of 2.79 mm per year from 1961 to 2018, through a combination of climate factors and seismic subsidence, with the rate of rise continuing to accelerate.[43]

Sea level rise is a long term problem, with significant variations in possible scenarios, and effects becoming significant towards the end of the century.[44] Issues could occur sooner with stronger storms due to warmer seas creating larger storm surges on top of rising sea levels, such as was witnessed during Hurricane Sandy in 2012, Cyclones Fehi and Gita in 2018, and the large storm surges that caused damage on the south coast of Wellington in April 2020 and June 2021.

Figure 11-1 Storm Surge in Owhiro Bay

A co-ordinated response between local authorities and utilities is required to prepare the region for the impacts of climate change. WELL is making changes to policies and standards to better protect the network from these risks. For example, a storm inundation policy has been written that over time will help WELL to better protect assets at risk of storm inundation. To be effective, these changes in standards cannot be made in isolation. Further work with local authorities is required to understand their defence strategies, and to influence District Plan updates, to ensure that WELL's policies and standards are tightly aligned to a coherent plan across the Lifelines Group.

[43] "Update to 2018 of the annual MSL series and trends around New Zealand" NIWA, November 2018.

[44] "Sea Level Rise Options Analysis" Tonkin & Taylor, June 2013.

11.3 Emergency Response and Contingency Planning

WELL follows the 4Rs approach to hazard management, as outlined by the National Emergency Management Agency (NEMA).[45] The 4Rs are described in the context of EDBs in the EEA resilience guide as follows:

- **Reduction** – Identify and mitigate network vulnerability risks;
- **Readiness** – Pre-event contingency planning and training;
- **Response** – Immediate actions following an event; and
- **Recovery** – Long term reinstatement of the network.

The mitigation of potential emergency events is supported by a number of plans and initiatives across the business described in the following sections.

11.3.1 Civil Defence

The National Emergency Management Agency (NEMA) is responsible for emergency management on a national scale. Emergency management is governed through the Civil Defence Emergency Management (CDEM) Act 2002 which sets out the requirements for each resilience group, including local Emergency Management groups, Lifeline Utilities and Emergency Services as well as producing and maintaining the national components of the emergency management framework.

11.3.2 Wellington Regional Emergency Management Office (WREMO)

The Wellington Regional Emergency Management Office (WREMO) was formed in 2012 and is a semi-autonomous organisation that coordinates civil defence and emergency management services on behalf of the councils in the Wellington region. While there is not an emergency response the emergency management office concentrates on identifying potential local hazards and implementing measures to reduce risks as well as promoting awareness of these risks and assisting other regional groups when this is requested.

11.3.3 Wellington Lifelines Group (WeLG)

The Wellington Lifelines Group is a working group comprised of the lifeline utilities operating within the region and representatives from local and regional government. Lifeline utilities are defined by the CDEM Act as businesses providing essential services to the community including:

- Transport infrastructure (road, sea and air);
- Water supply and reticulation systems;
- Sewerage and storm water drainage systems;
- Electricity transmission, generation and distribution networks; and
- Telecommunications network providers.

WELL is classified as a Lifeline Utility under the CDEM Act and as such has the following responsibilities:

[45] https://www.civildefence.govt.nz/cdem-sector/the-4rs/

- Ensuring it is able to function to the fullest possible extent even though this may be at a reduced level during and after an emergency;
- Having a plan for functioning during and after an emergency;
- Participation in CDEM strategic planning; and
- Providing technical advice on CDEM where required.

The CDEM Amendment Act 2016 places additional emphasis on ensuring that lifeline utilities provide continuity of operation where their service supports essential emergency response activities.

In November 2012 WeLG published a report on the likely restoration times for lifeline utilities based on the scenario of a magnitude 7.5 earthquake on the Wellington fault, centred in the harbour area. This report was partly in response to questions arising after the Christchurch earthquakes as to how Wellington would fare in a similar event. The report set out the time required after an event for each lifeline utility to restore services to a defined level in different areas around the region. Dependencies between utilities were not accounted for but these were often mentioned among the assumptions. A key difference identified in the report between the Canterbury and Wellington regions was the number and vulnerability of transport access routes in the Wellington region and the extensive recovery times anticipated. It is expected that some of this will be alleviated by the Transmission Gully route which is currently under construction.

Through 2018 and 2019 WeLG conducted a project on regional disaster response and recovery, as discussed in Section 11.5. A key component of this project was consideration of the interdependencies between lifeline utilities and how these are likely to affect the restoration process. This project involved detailed modelling of the likely damage to each lifeline utility network based on GNS modelling of the Wellington fault and regional geography as well as the economic impact on the region that such an earthquake would have.

11.3.4 WELL Contingency Plans

To comply with the responsibilities as a lifeline utility as set out in the CDEM Act, WELL has created a number of plans detailing the actions to be taken in a range of situations.

11.3.4.1 Emergency Response Plans (ERPs)

As part of the Business Continuity Framework Policy, WELL has a number of ERPs to cover emergency and high business impact situations. The ERPs require simulation exercises to test the plans and procedures and provide feedback on potential areas of improvement. All ERPs are periodically reviewed and revised. Learnings from natural disasters in New Zealand such as the Christchurch earthquakes and the Wellington June 2013 storm have been incorporated into these plans.

11.3.4.2 Civil Defence and Emergency Management (CDEM) Plan

WELL 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 supply.

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

11.3.4.3 Crisis Management Plan (CMP)

The CMP defines the structure of the Crisis Management team and the roles and responsibilities of staff during a crisis. The CMP contains detailed contact lists of all key stakeholders who may contribute to, or be affected by, the crisis.

11.3.4.4 Major Event Management Plan (MEMP)

The MEMP defines a major event and describes the actions required and the roles and responsibilities of staff during a major event. A focus of the MEMP is how the internal and external communications are managed. It contains detailed contact lists of all key stakeholders who may contribute to, or be affected by, the major event. Should the event escalate to a crisis, it is then managed in accordance with the CMP.

11.3.4.5 Business Recovery Management Plan (BRMP)

The BRMP covers, any event that interrupts the occupancy of WELL's 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 WELL disaster recovery site at Haywards. 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.

This plan was put into practice after the November 2016 earthquake which rendered the corporate office in Petone unsafe to conduct business from, and required all corporate business functions to relocate to Haywards substation and operate from there until the end of January 2017.

11.3.4.6 Information Technology Recovery Plan (ITRP)

The ITRP is in place so that WELL's IT systems can be restored quickly following a major business interruption affecting these systems. The level of recovery has been determined based on the business requirements.

11.3.4.7 Major Event Field Response Plan (MEFRP)

The MEFRP covers WELL's field contractors so they are prepared for, and can respond appropriately to, a HILP event. The MEFRP designates actions required and responsibilities of WELL and field contractor coordination during an event. It focuses on systems and communications (internal and external) to restore supply. A major event field response can escalate to the MEMP if required.

11.3.4.8 Emergency Evacuation Plan (EEP)

The purpose of the EEP is to ensure that the Network Control Room (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. This plan was also utilised after the November 2016 earthquake which rendered the corporate office in Petone unsafe and required all corporate business functions to relocate to Haywards.

11.3.4.9 Earthquake Response Plan

The purpose of the Earthquake Response Plan is to ensure that WELL is prepared to respond safely and effectively to an earthquake that impacts the electricity network, with consideration for the probable isolation between different network areas. This involves direction on how and when to activate other associated event management plans as well as directions for use of the DR sites and access to earthquake specific equipment and systems including:

- P-Alert warning system and shakemap;
- Safe building entry;
- Emergency spares locations and access; and
- Mobile substations and data centres.

11.3.4.10 Pandemic Preparedness Plan

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

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

The Pandemic Preparedness Plan was updated in early 2020 as it became apparent that COVID-19 was going to have a major impact on the operation of the business. The Plan has been regularly updated throughout the pandemic as government guidance has evolved, and to incorporate best practice learned from WELL's sister companies overseas. This has enabled the control room to operate with a minimum degree of risk through all stages of the pandemic response by utilising the disaster recovery site in addition to the primary offices. The Plan also describes working arrangements for each alert level, with staff being split across two sites and working remotely at higher alert levels.

11.3.4.11 Other Emergency Response Plans

WELL has other emergency response plans including:

- Priority notification procedures to key staff and contractors;
- Total Loss of a Zone Substation Plan;
- Network Spares Management Policy
- 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.

11.4 High Impact Low Probability (HILP) Events

The WELL network is designed with a certain amount of security and reliability built into it to account for isolated equipment failures and regularly occurring adverse events. However, as with all infrastructure, the network is susceptible to potential HILP events which could cause a major unplanned outage for a prolonged period.

Due to the geography of the region and weather patterns, the Wellington region is at risk from both earthquakes and severe storms, with earthquakes having the most potential to cause widespread damage throughout the region. Other possible HILP events include an upstream supply failure, communications failure, cyber security breach or information security breach or loss. This is managed through IT security policies.

WELL is working closely with the National Cyber Security Centre (NCSC) to ensure that its IT systems, especially those relating to the direct control of the electricity network, are as secure as possible. The increase in cyber risk means that WELL needs to invest in training, systems and processes that enhance cyber security monitoring and protection.

HILP events are unpredictable, generally uncontrollable and prohibitively expensive to avoid, if at all possible. WELL's design standards align with industry best practice and take the weather and seismic environment of the region into account. These design standards do not however cater for weather conditions or seismic events that are beyond what is deemed 'normal' for the region.

WELL's management of unforeseen events is split into two areas, mitigation of the risk through network planning, design and asset maintenance and then response during and after an event to restore power quickly without compromising contractor or public safety.

11.4.1 Identification and Planning for HILP Events

Some of the methods used by WELL to identify HILP events are:

- **Transmission risk reviews** – participation in the Connection Asset Risk Review projects undertaken with Transpower every 3-4 years to identify risks on the transmission circuits and substations, and to develop mitigation measures;

- **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, or the destruction of a zone substation. Contingency response plans have been drawn up to mitigate impacts from such events; and

- **Environmental risk reviews** – understanding and identification of the risk posed by natural disasters such as earthquake and tsunami. Studies have been undertaken on behalf of WELL by GNS and other external providers have supported the development of WELL's Storm Inundation Policy.

11.4.2 Strategies to Mitigate the Impact of HILP Events

A discussion on the following HILP events is covered below:

- Pandemic

- Major storm events;

- High impact asset failure;
- Upstream supply failure; and
- Major earthquake.

11.4.2.1 Pandemic

The ongoing COVID-19 pandemic has caused major disruption to all aspects of life. As a lifeline utility it is WELL's responsibility to ensure that it is able to operate to the fullest possible level in such situations.

WELL has been operating with two control rooms in separate locations, alternating shifts between the main control room and DR site to minimise the crossover of controllers. During elevated COVID-19 alert levels WELL has transitioned to staff largely working from home, with only the network control room and some senior management working from the two operational sites.

11.4.2.2 Major Storm Events

The Wellington region is very susceptible to high winds and severe storms, which have the potential to cause a significant amount of widespread damage to the overhead network. For this reason WELL uses a relatively high wind loading when designing overhead lines when compared with other network companies. This susceptibility is also a factor in the high proportion of the Wellington network that has been constructed with underground cables.

A major risk of potential outages on overhead sections of the WELL network is lines being struck by vegetation and windblown debris. This is currently managed via the WELL vegetation programme which, as discussed in Section 6.5, has been successful in maintaining the reliability of the network. It can be difficult to protect against strong wind gusts causing vegetation to contact lines that do not normally get close to a line, or where debris has been blown clear of the line before a patrol can be completed.

In June 2013, Wellington experienced a severe storm of a magnitude similar to the "Wahine" storm of 1968. Wind gust speed remained above 100km/h for approximately 24 hours, peaking at over 200km/h. The storm caused significant damage to the WELL network and at its peak resulted in 30,000 homes and businesses being without power. Damage to network assets affected customers in both rural and urban areas with wind gusts uprooting trees and carrying debris into overhead lines, damaging poles and conductors.

The affected areas were widespread and outages were prolonged as the conditions made it difficult to patrol and repair lines. Blocked roads and traffic congestion resulted in travel time delays. To address the significant workload, 150 additional staff from other regions were brought in to assist with the restoration efforts. Since then, improvements have been made to vegetation management, SCADA system capacity and capacity to scale-up emergency staff in an event.

In addition to causing widespread damage in the overhead network, major storms can result in flooding in parts of the region. While this does not cause the same widespread network damage it does have an effect on the response times as roads become blocked, making access to some areas difficult or impossible.

11.4.2.3 High Impact Asset Failure

WELL network's system security standard is designed to provide a security of N-1 at zone substation level, meaning that each zone can operate at full capacity after the failure of a single asset. This is generally achieved by having dual subtransmission circuits and power transformers. Resilience within the 11 kV network is provided by the use of meshed rings or tie points between radial feeders to minimise the effect of equipment failure and improve the restoration after an event.

Due to the constrained nature of many WELL sites and the subtransmission routes that have been constructed sharing the same route, an event affecting one component has the potential to affect the other and lead to a total outage at that site. This is mitigated through different means depending on the type of asset, such as physical barriers between transformers at most sites, or separation between overhead lines where space allows. Cable route resilience is considered as part of the route selection process for new subtransmission cables.

Where an event leads to a total loss of supply at a zone substation it is generally possible to restore the majority of the load through network switching to supply the area from a different zone substation, though this does not consider potential damage to the distribution network or adjacent zone substations in a major event. The total resupply of a zone substation from a neighbouring zone is not possible for all substations or at all times in the year, as higher loadings, or substations located at the extremities of the network and without strong ties to other zones, result in areas that are unable to be supplied in the event of a total zone substation outage.

Areas that are unable to be supplied in the event of a zone substation outage are mostly at the extreme ends of the network with Wainuiomata, Karori, Mana-Plimmerton and north of Upper Hutt being the most obvious examples. Two of these substations also supply two of the main water treatment plants providing potable water to the region at Te Marua and Wainuiomata treatment and pumping stations. Both plants have backup power supplies that can cover their emergency requirements but require network supply to operate at full capacity.

11.4.2.4 Upstream Supply Failure

WELL takes supply from Transpower at Grid Exit Point (GXP) substations. There are nine GXPs in the Wellington region supplying WELL at either 33 kV or 11 kV, with some GXPs supplying at both voltages. While the loss of any of these substations will result in the loss of supply to one or more zone substations and a significant number of customers, Central Park substation is the most significant. Central Park is a highly loaded substation and would have the largest impact in terms of both load lost and customers without supply.

Central Park substation supplies seven zone substations with over 42,000 customer connections and a maximum demand of approximately 190 MVA. There is very limited capacity for the shifting of load onto the Wilton GXP with approximately 17 MVA able to be transferred to Moore Street, Kaiwharawhara and Karori substations. The area supplied by Central Park contains the majority of the Wellington CBD and includes a number of high priority and regionally critical sites.

The Central Park site, shown in Figure 11-2, is constrained by the limited available space as well as the construction standards at the time of construction which increases the likelihood of a failure in one area spreading to adjacent areas or equipment. Large Transpower sites such as Penrose or Haywards are often 300-400m across while Central Park is barely over 50m with no fire separation between two of the transformers or between bus sections in the 33 kV switchroom.

Figure 11-2 Central Park Substation

This site supplies the majority of the CBD load in the national capital city and there is no alternate supply in the event of a failure of the site. The potential loss of the majority of Wellington city load is an unacceptable risk and there is ongoing work between WELL and Transpower looking at potential solutions to improve the resilience of the site. This is discussed further in Section 11.5.1.

11.4.2.5 Major Earthquake

The Wellington Region contains numerous known fault lines with the potential to cause a severe shaking event. The three most well studied fault lines in the region are the Wellington, Ohariu, and Wairarapa fault lines. These are shown in Figure 11-3, a map of the region created by GNS science.

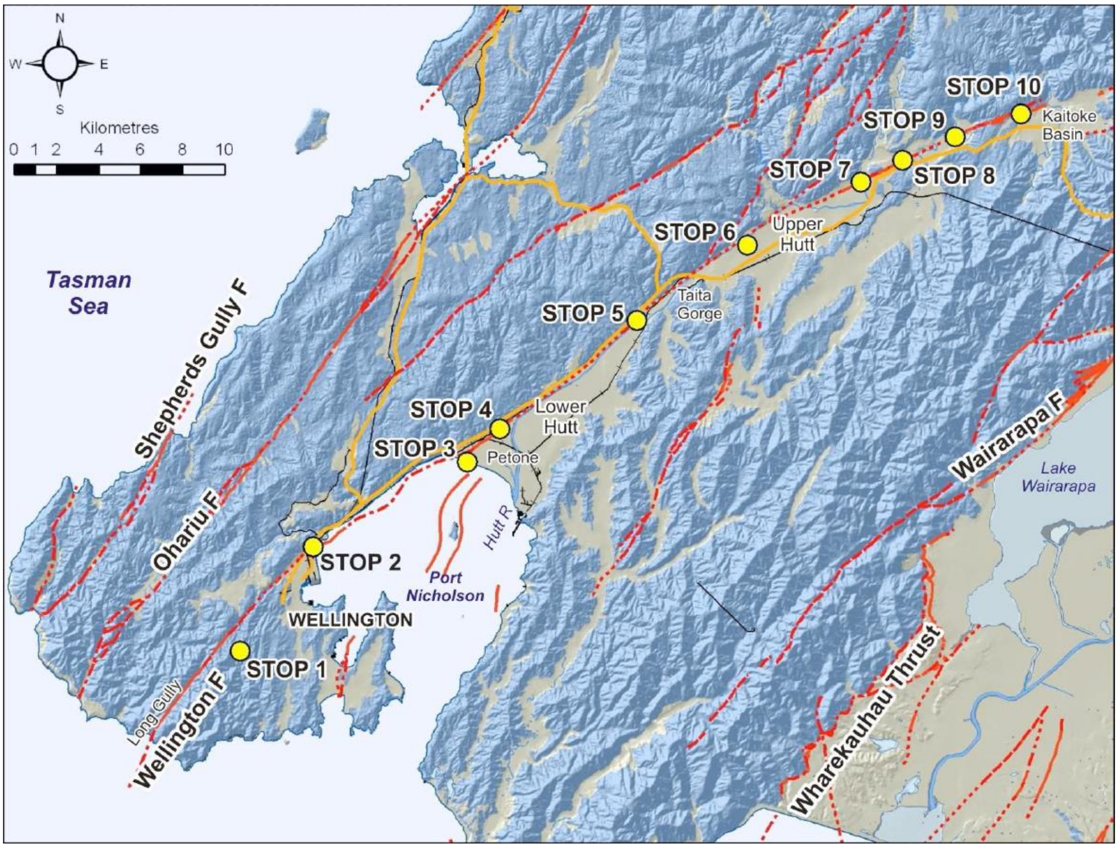


Figure 11-3 Wellington Region Fault Lines[46]

The Wellington fault line runs from Long Gully through Thorndon, along the edge of Wellington Harbour and roughly along State Highway 2 to Kaitoke. The Ohariu fault runs up the Ohariu valley, through Porirua and past Mana along the northern edge of the Pauatahanui inlet. The Wairarapa fault runs along the Rimutaka ranges and ruptured in 1855 resulting in an earthquake with a magnitude of 8.2, making it the most powerful earthquake recorded in New Zealand.

A rupture of any of these faults would lead to a severe earthquake in the region with a level of damage expected to be similar to or exceeding that of the February 2011 Christchurch earthquake. It is expected that large sections of the network will be without power immediately after a major event but that the majority of this will be able to be restored once equipment inspections and line patrols have been completed. After the initial restoration work, fault finding and repair work will have to be carried out on the remaining damaged areas of the network.

To identify potential resilience improvements, WELL has estimated damage that would be caused to the network by a major earthquake in the Wellington region. In normal service, when there is an outage due to equipment failure, the area that has lost supply is usually able to be supplied from an adjacent feeder or zone. These damage estimates indicate that supply from adjacent feeders would not be possible following a major earthquake. As a result there would be extended outages in much of the network and restoration would be slowed by difficulties with transport into and within the region.

[46] Field Trip 1; Wellington Fault: Neotectonics and Earthquake Geology of the Wellington-Hutt Valley Segment. GNS Science (the stops on the picture refer to the stops made during the field trip).

Restoration time estimates were separated into the time for transport into the area to be available and the time to repair damage. These outage durations are consistent with previous estimates which identified that restoration could take in excess of 90 days.

The 2016 Kaikoura Earthquake reinforced that a major earthquake within the region would cause major disruption to the electricity network, and power outages that would last longer than is acceptable even in an extreme event. To enable mitigation work WELL applied for a CPP targeting improving readiness, which was approved in 2018.

The CPP was split into five workstreams with each delivered as a separate project:

1. Spares - The spares workstream was split into three projects with overhead line spares, cable and joint spares, and the procurement of a mobile 11 kV switchboard. The spares workstream also included the setup of stores locations throughout the network.

2. Data Centres - Three data centres have been constructed and installed within the network to provide access to critical operating software and data in the event that communications to the Network Control Room are cut off.

3. Mobile Substations - Two mobile 33 kV/11 kV substations have been constructed to restore supply where a substation is so damaged that the transformers and/or switchboard are unable to be used. The substations have been constructed in a modular manner with the transformer and switchgear/controls units separately transportable. The transformer is mounted on a trailer with the switchgear/control module fitting the dimensions of a standard 20ft shipping container. This arrangement is due to transport considerations. With road access being potentially affected, a smaller trailer and container are more easily transported from the storage location to a damaged substation. This arrangement also provides more flexibility in connection and the physical layout on site.

4. Radio and Phones - A modern digital radio system has been installed to improve connectivity and coverage while reducing reliance on cellular networks, which may not be functional following a major event. A VoIP telephone system has been installed to provide improved connection functionality between the network control room and zone substations.

5. Seismic Reinforcement – WELL has had an ongoing programme of work to reinforce buildings constructed before 1976 that have been identified as having a strength of less than 34% of New Building Standard (NBS). As a part of the CPP, this programme was expanded to include the strengthening 91 significant substations to a minimum of 66% of NBS.

11.5 Wellington Lifelines Regional Resilience Project

The Wellington Lifelines Regional Resilience Project (WeLG RRP) was initiated by WeLG in the aftermath of the 2016 Kaikoura Earthquake, to assess the resilience of lifeline services and to compile a coordinated business case for resilience expenditure. The project published its report in October 2019, which can be found at https://wremo.nz/about-us/lifeline-utilities/.

The economic modelling indicated that a single 7.5 magnitude event on the Wellington fault line could adversely impact the national GDP by $16.7 billion over a five year period. Hazard and damage state modelling was done through RiskScape, a multi-hazard risk assessment tool developed by GNS and NIWA. Lifeline industries were engaged to assist with fragility curves and damage restoration time frames. Economic impact was assessed using MERIT (Modelling the Economics of Resilient Infrastructure Tool) which assesses not only the immediate damage but longer term economic impacts as well.

A range of options of varying expenditure were identified and passed through the same modelling process to identify the overall benefit, recommending an investment of $3.9 billion which could reduce the GDP impact of a major earthquake by $6.16 billion.

The preferred option included a $205 million investment in the regional electricity infrastructure, as shown in Figure 11-4.

Lifeline Infrastructure	Preferred Investment Programme		
	Initiative Name	Owner	Indicative Cost
Electricity	Central Park Substation improved resilience	Transpower, WE*	$40M
	Seismic upgrade of cables and creation of 33kV Rings	WE*	$160M
	Central Park to Frederick St cables replacement	WE*	$5M

Figure 11-4 Electricity Expenditure for Preferred Regional Resilience Investment Option
Source: Wellington Lifelines Project Report, 2019

The preferred option involves three initiatives to improve the resilience of the electrical networks in the Wellington region. The most vulnerable assets in the region are the fluid and gas-filled subtransmission cables, which could be mitigated by cable replacement in a more resilient ring configuration. Another major risk is the single point of failure at Central Park Substation, with this substation being the main supply point for most of Wellington City. The third initiative is the replacement of the Central Park to Frederick Street cable, which was separated from the main seismic upgrade of cables because the cable is currently being replaced for loading reasons.

These resilience initiatives were not included within the CPP application as this was focussed on readiness initiatives and not resilience. As such these works were outside the scope of the CPP and the level of investment required is beyond what can be funded within the DPP allowances. While the items planned as part of the CPP programme will provide an improvement to restoration times, there may still be significant outages in many areas of the network depending on the scale of any earthquake occurring, hence the potential need for this extra work.

11.5.1 Central Park

There is a significant risk posed by a potential loss of supply at Central Park GXP, and WELL and Transpower have been investigating options to improve its supply resilience. The most effective means of reducing this risk is the construction of a smaller "Central Park II" substation which will replicate a portion of the existing site at a nearby location. The Central Park II substation construction will coincide with the decommissioning of one transformer bank at the current site. This transformer would be replaced with a transformer at the new site. The new site would also contain a 33 kV bus section with one supply to each of the connected WELL zone substations. This substation will be operated as an extension of the existing GXP, although physically separated. The work will be funded under a new customer connection contract with Transpower and recovered as a pass through cost to end customers.

WELL has asked Transpower to proceed with the project based on a Value of Lost Load (VoLL) figure of $23.5k/MWhr, which was approved by the Electricity Authority in 2021. Transpower is now establishing a project team to deliver the project, with a schedule for the delivery shown in Table 5-5.

Project Activity	Timeframe
Land acquisition and consenting	Q4 2021 to Q4 2023
Detailed investigation	Q1 2023 to Q1 2024
Design	Q3 2023 to Q1 2025
Construction	Q3 2024 to Q3 2026

Table 11-1 Timeframe for Construction of Central Park II

11.5.2 Subtransmission Fluid Filled Cables

The majority of the subtransmission cable in the WELL network is fluid pressurised cable, installed between 1960 and 1980. Fluid filled cables are particularly prone to damage in an earthquake as well as being expensive and time consuming to repair, requiring skills that are not readily available within the region.

The condition of these cables is individually monitored and assessed against asset health and criticality criteria. These cables have historically given a high level of reliability and are manageable from an operational point of view for the planning period as described in Section 7.5.1.

A significant earthquake could result in cable damage that does not immediately cause a fault, such as fluid leaks or sheath damage, but which would have a negative impact on the reliability of the network. Repairing a fluid leak is a difficult task as the means of locating the leak can take time when there is no associated cable fault, resulting in leaks having a high cost to locate and repair, as well as ongoing costs while fluid is being lost. Once the damage is located, repair work can also be time consuming and requires a specialised skill set to be brought in from outside the region. Due to these repair difficulties and the high likelihood of a fault causing damage in an earthquake, repair of these cables may not be a viable solution. The CPP spares project provided equipment for the construction of temporary overhead lines in the worst affected areas following an earthquake.

Modern cables installed within ducts are less likely to sustain this type of damage and do not have the labour resourcing issues associated with fluid filled cables. Resilience can also be improved by diversifying the cable routes to substations and providing greater interconnection between Transpower GXPs. Diversified cable routes will mean that localised cable damage is less likely to cause an outage at any site compared with the current network layout where both circuits to a substation are typically run alongside each other.

The WeLG RRP Programme Business Case (PBC) analysed the effect of subtransmission upgrades on the potential restoration times, based on damage modelling work carried out by GNS Science. The construction of rings was grouped into three separate projects for the purpose of this analysis:

- A subtransmission ring through the eastern suburbs of Wellington;
- A subtransmission ring in Lower Hutt; and
- The seismic upgrade of other fluid filled cables.

The damage modelling has identified the construction of two subtransmission rings as the preferred option for improving the resilience of electricity distribution in the Wellington region.

Under 'business as usual', some of this work is likely to be completed as 33 kV circuits are replaced due to condition or capacity. The gas-filled subtransmission cables are planned for replacement over a 15 year timeframe as outlined in Table 11-2.

Subtransmission Circuits	Cable Type	Project Completion	Project Driver
University	Gas	2026	Condition
Karori	Gas	2029	Condition
Maidstone	Gas	2032	Condition
Ira Street	Gas	2033	Capacity
Hataitai	Gas	2035	Capacity
Waikowhai	Gas	2037	Condition

Table 11-2 Timeframe for Gas Filled Cable Replacement under BAU

Subtransmission rings would allow for greater load transfer between zone substation and GXPs and the associated cable replacement would enable diversification of cable routes. The predicted earthquake performance along proposed cable routes would be considered when selecting the route for any new cables.

11.6 Wellington Electricity Resilience Self-Assessment

During 2019 and 2020, the EEA produced a resilience guide aimed at the distribution industry. A major part of this guide is a self-assessment tool which has been based on the AMMAT. This Resilience Maturity Measurement Tool (RMMAT) is intended to help EDBs identify where there are areas for improvement in the resilience of the network or organisation. There are four assessment areas:

- Reduction;
- Readiness;
- Response; and
- Recovery.

An assessment of WELL's resilience has been undertaken using the RMMAT to identify where opportunities for further improvement could be found, with the results summarised in Figure 11-5 which shows the average score for each of the 4Rs.

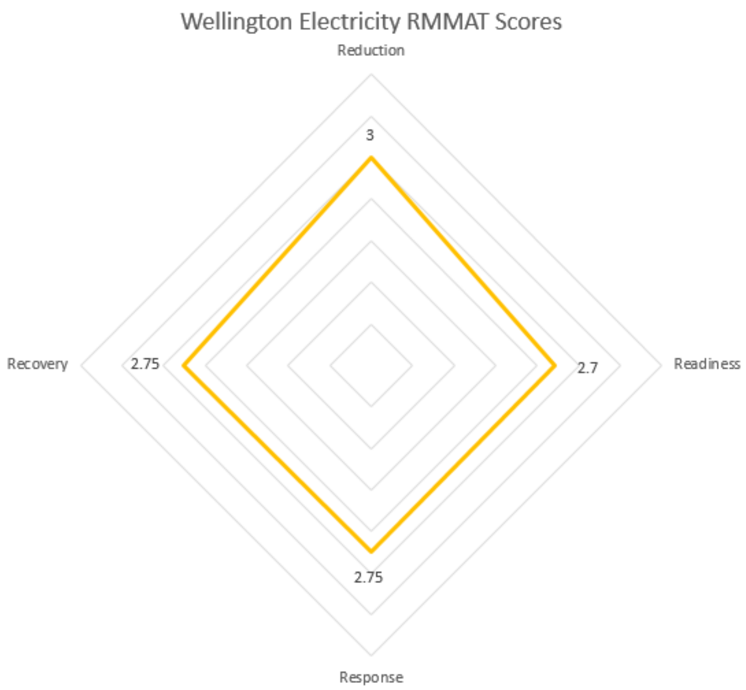


Figure 11-5 Summary of the Resilience Self-Assessment 2021

11.6.1 Areas for Improvement

An earthquake is the biggest event that is likely to occur in this region, and in that event the main risks affecting the response are transport links being broken and limited fuel supplies into the region. Both of these are out of WELL's direct control.

The main issue in the response area is staffing of the control room, with the possibility of needing to run up to three independent control rooms based in the data centres, each responsible for an area of the network. WELL's control room is staffed to safely respond to major events from a central location, however if WELL needed to maintain decentralised operation across multiple control rooms for an extended period, fatigue management of local staff will become a concern. In this case WELL would need to seek additional controllers from other EDBs through mutual aid agreements. A number of other EDBs use the GE SCADA systems which will allow controllers to be brought in that are familiar with the software being used by WELL.

Section 12
Customer Initiated Projects and Relocation

12 Customer Initiated Projects and Relocations

This section provides information on customer initiated projects and relocations on WELL's network over the next 10 years. New connections or the changing of existing connections initiated by customer projects have an impact on WELL's long term network planning and development strategy. The introduction of modern technologies (e.g. energy storage system, demand response programmes etc) will also affect WELL's ability to maintain supply quality and network capacity.

Expenditure for customer initiated projects and relocations have been aggregated in the budget in accordance with the categories discussed below.

12.1 New Connection Application Process

New connection applications are made through WELL's website, allowing customers to register their request for a new connection (https://www.welectricity.co.nz/getting-connected/new-online-forms-holder/get-connected/). These are broadly categorised into either residential or business connections, and into fuse sizing requirements of 60A, 100A or greater than 100A rating requests.

Simple new connections (typically residential customers) can be made quickly (usually within three months) using standard designs and pricing. In 2022 WELL is introducing fixed pricing for the majority of residential connections which will make the process even easier for customers.

Where new connections are identified as complex, the Service Delivery team evaluate the customer's requirements, collect information for these applications, construct a brief project scope with material requirements, and compile a Technical Approval (TA) form for submission to the Asset Management team who consider and approve the connection.

Upon receipt of this TA request, the Engineering Planning team reviews and further defines the project as either minor or major, and completes the approval process accordingly. For complex–minor projects, basic checks include system capacity analysis, contingency analysis, equipment type review, and secondary asset review. After completing assessments, the TA is returned to Service Delivery for tendering. Once the competitive tender process is complete, a tender evaluation is undertaken which will determine pricing to enable a quotation. This is then structured into a formal offer and presented to the customer.

Applications classified as complex–major require more in-depth analysis. Applications such as these may trigger a High Level Response (HLR) query. A study is conducted illustrating the load flow analysis and network constraints. Several viable options for delivering the required supply capacity are detailed inclusive of project durations and cost estimates. This HLR is then presented to the customer to enable them to select an option that best matches their requirements.

A Detailed Solution Development (DSD) study may be initiated to further refine the project requirements and estimates. This is completed by an independent consultant. One of the primary objectives of this exercise is to validate the selected option and refine the estimate.

Upon completion of the DSD process the customer may opt to pursue the selected option. Where the level of complexity of the planned installation is high, then an independent design consultant may be engaged for the detailed design. The detailed design is integral for the construction tender process to enable pricing from the installation contractors. On completion of the tender evaluation and internal approval processes, Service

Delivery will begin to make a formal connection offer to the customer based on the requirements specified in the development process.

12.2 New Connections and ICPs

For several years the number of new dwellings consented annually in the Wellington region across the four local authorities has been increasing, driven by the growth in apartments within the Wellington CBD and subdivision growth along the northern belt. Figure 12-1 shows the number of new dwellings consented over the last seven years.[47]

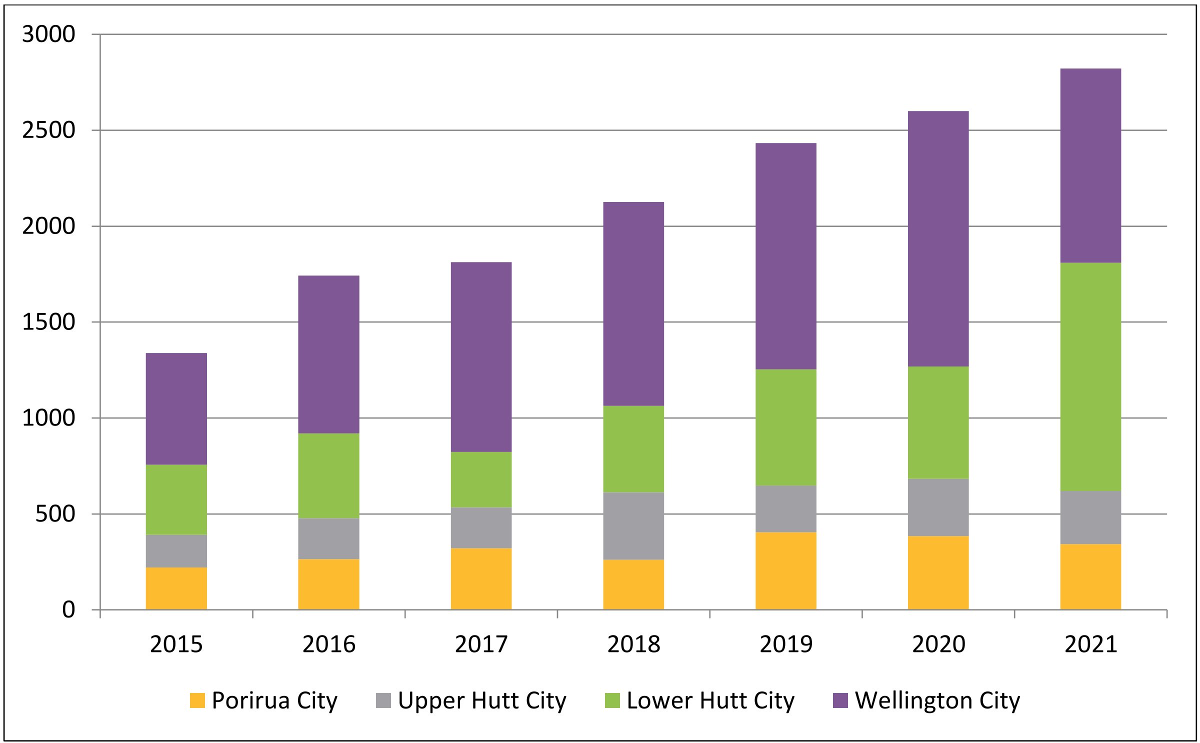


Figure 12-1 Number of New Dwellings Consented in the Wellington Region

Figure 12-2 shows the number of new connections added to the Wellington network since 2018[48] and the expected new connections for the next five years. The number of new ICP connections does not align exactly to building consents due to the lag between consent approval and connecting to the network (which can be between one and five years) and because multiple apartments with a building consent each can be serviced by a single ICP connection.

[47] These figures differ from past AMPs as they now include all new connections (previously it only included a set of residential connections).

[48] The 2022 year includes an estimate for March 2022 as this was not finalised in time to include in the AMP.

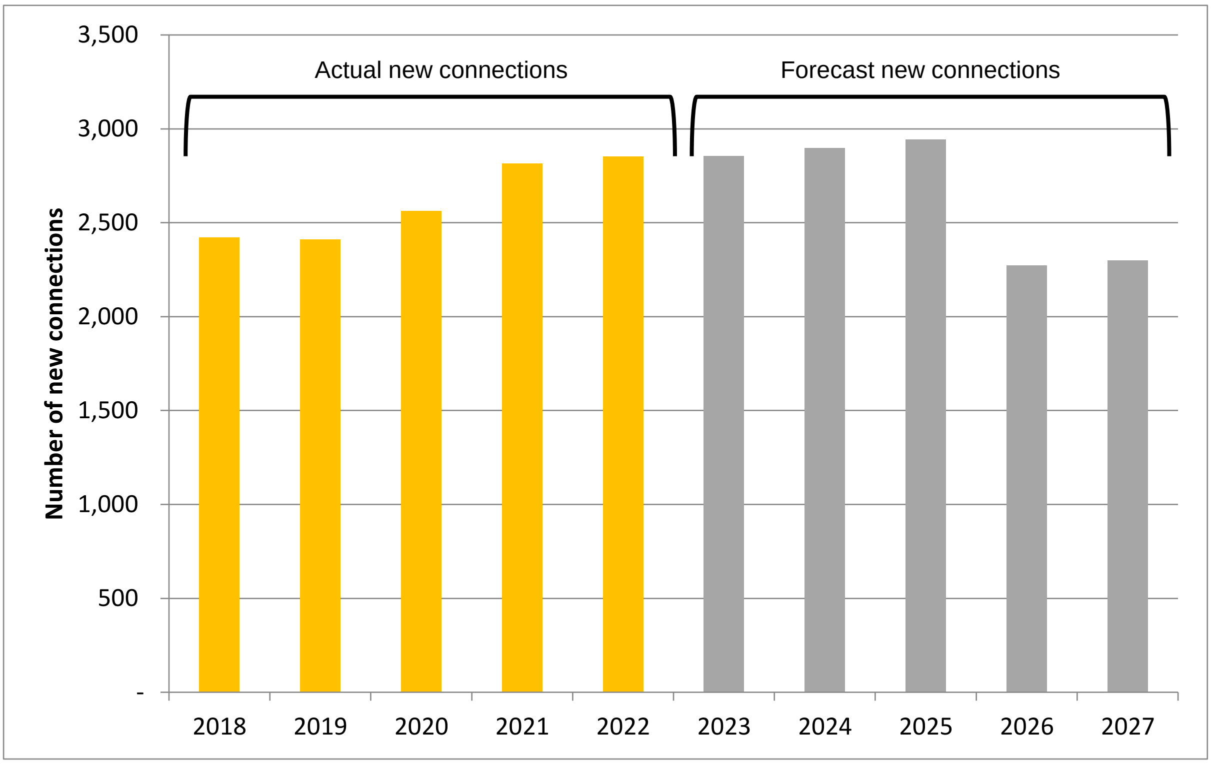


Figure 12-2 New Connections in the Wellington Region

WELL expects the current levels of new connections to continue for another three years. This is based on building consents and WELL's forward work programme indicating that the current high growth of new buildings is expected to continue for the next few years. The volume of new connections is expected to decline in the medium term as the number of new connections returns back in line with Wellington's population growth as housing construction catches up with demand.

12.3 Substations

These projects include new substations and HV connections, often for the increased capacity requirements of new businesses in either new or repurposed industrial sites. The requests for large substation connections have been consistent for several years. The forecast is set conservatively to reflect the uncertainty about whether individual projects will go ahead, however a number of large customer projects requiring additional capacity in Wellington and Porirua districts are proposed which could significantly increase expenditure if the customers decide to proceed in 2022.

12.4 Subdivisions

Small and infill subdivisions have been increasing over the last a couple of years. Developers continue a trend where appetite for large scale residential (>100 lots) subdivisions is still increasing, particularly in the northern areas of Wellington and Porirua cities. Additionally, industrial type subdivision requests have been received to cater for smaller commercial and manufacturing businesses.

12.5 Capacity Changes

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

12.6 Relocations

Primarily these projects are initiated by NZTA or local authorities, but can also be private customer initiated relocations. State Highways and local authority road safety improvements are critical projects in this category.

12.7 Reopeners for Large New Connections

The DPP regulatory framework allows network operators to apply for reopeners to provide additional allowances for large new customer connections that were not included in the regulatory allowance calculation set every five years. The Commission added this new feature to the regulatory allowance calculation, in recognition of the changes in the electricity sector which are driving increased uncertainty in the level of electricity demand, new connections, and the way distribution networks will need to be managed.

WELL is receiving applications for large new connections for the Wellington network relating to the Government's climate change initiatives – the electrification of public transport and the transition away from fossil fuel to electricity for business and commercial energy use. These new connections are not included in current allowances, and WELL expects to be making several applications to the Commission for additional allowances using the reopener for large new connections.

The reopener application process is designed to ensure that the cost of the new connections is funded by the party connecting and not by existing customers. However, some projects may require reinforcement of the wider network to provide the additional capacity. This may provide opportunities to bring forward future investment for a cost less than if the future project was implemented in isolation – i.e., combining projects can save costs by sharing the trenching and civil works costs and by ensuring cables installed have enough capacity for future requirements. In these situations, the cost will be shared with existing network customers.

12.8 Customer Connections Summary for 2022-2032

The total forecast customer connection capital expenditure for 2022 to 2032 is presented in Table 12-1.

Customer Type	2022/23	2023/24	2024/25	2025/26	2026/27	2027/28	2028/29	2029/30	2030/31	2031/32
Substation	4,464	3,661	3,614	3,484	3,496	3,508	3,520	3,526	3,526	3,526
Subdivision	6,062	5,757	5,575	5,595	5,613	5,632	5,653	5,663	5,663	5,663
High Voltage Connection	-	-	-	-	-	-	-	-	-	-
Residential Customers	3,070	2,725	2,557	2,564	2,574	2,583	2,592	2,596	2,596	2,596
Public Lighting	78	78	78	79	79	79	79	80	80	80
Total Gross	**13,674**	**12,221**	**11,824**	**11,722**	**11,762**	**11,802**	**11,844**	**11,865**	**11,865**	**11,865**

Table 12-1 Customer Connection Capital Expenditure Forecast ($K in constant prices)

12.9 Asset Relocations Summary for 2022-2032

The forecast asset relocation capital expenditure, which is primarily related to either roading projects or the undergrounding of existing overhead network for subdivision development, is presented in Table 12-2.

Programme	2022/23	2023/24	2024/25	2025/26	2026/27	2027/28	2028/29	2029/30	2030/31	2031/32
Asset Relocations	714	714	714	714	714	714	714	714	714	714
Total Gross	**714**	**714**	**714**	**714**	**714**	**714**	**714**	**714**	**714**	**714**

Table 12-2 Asset Relocation Capital Expenditure Forecast ($K in constant prices)

Section 13

Expenditure Summary

13 Expenditure Summary

This section provides an overview of WELL's forecast capital and operational expenditure over the planning period in order to implement this AMP.

13.1 Capital Expenditure 2022-2032

13.1.1 Customer Connections

The total forecast customer connection capital expenditure for 2022 to 2032, as discussed in Section 12.1.7, is presented in Table 13-1.

Customer Type	2022/23	2023/24	2024/25	2025/26	2026/27	2027/28	2028/29	2029/30	2030/31	2031/32
Substation	4,464	3,661	3,614	3,484	3,496	3,508	3,520	3,526	3,526	3,526
Subdivision	6,062	5,757	5,575	5,595	5,613	5,632	5,653	5,663	5,663	5,663
High Voltage Connection	-	-	-	-	-	-	-	-	-	-
Residential Customers	3,070	2,725	2,557	2,564	2,574	2,583	2,592	2,596	2,596	2,596
Public Lighting	78	78	78	79	79	79	79	80	80	80
Total	**13,674**	**12,221**	**11,824**	**11,722**	**11,762**	**11,802**	**11,844**	**11,865**	**11,865**	**11,865**

Table 13-1 Customer Connection Capital Expenditure Forecast ($K in constant prices)

13.1.2 System Growth

The total forecast capital expenditure for system growth and security of supply for 2022 to 2032, is presented in Table 13-2. In addition to system growth expenditure discussed in Section 8, this includes network capital expenditure on the emerging technology related development plan as discussed in Section 9.

Asset Category	2022/23	2023/24	2024/25	2025/26	2026/27	2027/28	2028/29	2029/30	2030/31	2031/32
Subtransmission	638	-	-	1,800	5,900	8,800	13,450	7,000	10,950	9,300
Zone Substations	4,872	399	3,171	8,106	3,276	5,240	8,500	4,000	-	-
Distribution Poles and Lines	-	350	700	2,300	1,900	2,350	1,600	500	800	3,350
Distribution Cables	2,565	3,485	1,300	3,700	300	4,700	100	2,000	20	-
Distribution Substations	15	421	419	-	-	-	-	-	-	-
Distribution Switchgear	-	-	-	-	-	-	-	-	-	-
Other Network Assets[49]	805	940	1,020	2,795	3,045	3,495	3,495	3,655	3,855	3,855
Total	**8,895**	**5,595**	**6,610**	**18,701**	**14,421**	**24,585**	**27,145**	**17,155**	**15,625**	**16,505**

Table 13-2 System Growth Capital Expenditure Forecast
($K in constant prices)

13.1.3 Asset Replacement and Renewal

The total forecast capital expenditure for asset replacement and renewal for 2022 to 2032 as discussed in Section 7 is presented in Table 13-3. This includes provision for replacements that arise from condition assessment programmes during the year.

Asset Category	2022/23	2023/24	2024/25	2025/26	2026/27	2027/28	2028/29	2029/30	2030/31	2031/32
Subtransmission	-	500	1,700	3,200	-	4,000	8,000	-	8,700	8,700
Zone Substations	2,685	200	200	200	200	200	200	200	2,700	4,200
Distribution Poles and Lines	6,873	7,330	7,030	6,789	7,116	7,102	6,954	6,819	6,776	6,752
Distribution Cables	2,550	2,550	2,550	2,550	2,550	3,050	3,050	3,050	3,050	3,050
Distribution Substations	4,269	4,577	4,720	4,601	4,830	5,042	5,372	5,288	5,425	4,421
Distribution Switchgear	4,462	5,460	5,410	5,414	5,590	6,467	5,735	5,740	5,771	5,772
Other Network Assets	3,095	4,715	3,015	3,515	3,315	3,410	2,910	3,010	3,010	3,010
Total	**23,934**	**25,332**	**24,625**	**26,269**	**23,601**	**29,271**	**32,221**	**24,107**	**35,432**	**35,905**

Table 13-3 System Asset Replacement and Renewal Capital Expenditure Forecast
($K in constant prices)

[49] Other Network Assets includes the capital expenditure required for emerging technologies.

13.1.4 Asset Relocations

The forecast asset relocation capital expenditure, primarily related to roading projects, is presented in Table 13-4.

Programme	2022/23	2023/24	2024/25	2025/26	2026/27	2027/28	2028/29	2029/30	2030/31	2031/32
Roading Relocations	714	714	714	714	714	714	714	714	714	714
Total	**714**	**714**	**714**	**714**	**714**	**714**	**714**	**714**	**714**	**714**

Table 13-4 Asset Relocation Capital Expenditure Forecast ($K in constant prices)

13.1.5 Reliability, Safety and Environment

Asset management expenditure that is not directly the result of asset health drivers is categorised into quality of supply and other reliability, safety and environmental expenditure. Quality of supply projects target poorly performing feeders. Other reliability, safety and environmental projects include the seismic programme and other resilience work. The total forecast capital expenditure for these categories is presented in Table 13-5.

Programme	2022/23	2023/24	2024/25	2025/26	2026/27	2027/28	2028/29	2029/30	2030/31	2031/32
Feeder Reliability Projects	2,097	2,094	2,094	2,242	2,288	2,334	2,382	2,497	2,713	2,854
Total Quality of Supply	**2,097**	**2,094**	**2,094**	**2,242**	**2,288**	**2,334**	**2,382**	**2,497**	**2,713**	**2,854**
Seismic Programme	458	676	-	-	-	-	-	-	-	-
Total Other Reliability, Safety and Environment	**458**	**676**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**

Table 13-5 Reliability, Safety and Environmental Capital Expenditure ($K in constant prices)

13.1.6 Non-network Assets

The forecast capital expenditure for non-network assets is presented in Table 13-6.

Routine Expenditure	2022/23	2023/24	2024/25	2025/26	2026/27	2027/28	2028/29	2029/30	2030/31	2031/32
Software and Licenses	1,945	2,475	895	635	470	1,890	2,245	640	820	390
IT Infrastructure	293	1,040	775	1,675	865	525	825	525	1,725	525
Capitalised Leases	-	-	-	-	2,705	-	-	-	-	-
Total Non-network Assets	**2,238**	**3,515**	**1,670**	**2,310**	**4,040**	**2,415**	**3,070**	**1,165**	**2,545**	**915**

Table 13-6 Non-Network Asset Capital Expenditure Forecast
($K in constant prices)

13.1.7 Capital Expenditure Summary

The total combined capital expenditure on assets is presented in Table 13-7.

Category	2022/23	2023/24	2024/25	2025/26	2026/27	2027/28	2028/29	2029/30	2030/31	2031/32
Customer Connection	13,674	12,221	11,824	11,722	11,762	11,802	11,844	11,865	11,865	11,865
System Growth	8,895	5,595	6,610	18,701	14,421	24,585	27,145	17,155	15,625	16,505
Asset Replacement & Renewal	23,934	25,332	24,625	26,269	23,601	29,271	32,221	24,107	35,432	35,905
Asset Relocations	714	714	714	714	714	714	714	714	714	714
Quality of Supply	2,097	2,094	2,094	2,242	2,288	2,334	2,382	2,497	2,713	2,854
Other Reliability, Safety & Environment	458	676	-	-	-	-	-	-	-	-
Subtotal – Network Capital Expenditure	**49,772**	**46,632**	**45,867**	**59,648**	**52,786**	**68,706**	**74,306**	**56,338**	**66,349**	**67,843**
Non-Network Assets	2,238	3,515	1,670	2,310	4,040	2,415	3,070	1,165	2,545	915
Subtotal – Non-network Capital Expenditure	**2,238**	**3,515**	**1,670**	**2,310**	**4,040**	**2,415**	**3,070**	**1,165**	**2,545**	**915**
Total – Capital Expenditure on Assets	**52,010**	**50,147**	**47,537**	**61,958**	**56,826**	**71,121**	**77,376**	**57,503**	**68,894**	**68,758**

Table 13-7 Capital Expenditure Forecast
($K in constant prices)

13.2 Operational Expenditure 2022-2032

The total forecast operational expenditure for 2022 to 2032 is shown in Table 13-8.

Category	2022/23	2023/24	2024/25	2025/26	2026/27	2027/28	2028/29	2029/30	2030/31	2031/32
Service interruptions & emergencies maintenance	4,754	4,741	4,744	4,733	4,737	4,737	4,737	4,737	4,737	4,737
Vegetation management	1,764	1,757	1,757	1,757	1,757	1,757	1,757	1,757	1,757	1,757
Routine & corrective maintenance and inspection	8,642	8,607	8,606	8,601	8,600	8,599	8,597	8,595	8,594	8,594
Asset replacement & renewal maintenance	990	979	975	990	985	985	985	985	985	985
Subtotal – Network Operational Expenditure	**16,150**	**16,084**	**16,082**	**16,081**	**16,079**	**16,078**	**16,076**	**16,074**	**16,073**	**16,073**
System Operations and Network Support	6,170	6,136	6,144	6,151	6,158	6,165	6,172	6,179	6,186	6,186
Business Support	13,464	13,160	13,025	13,535	13,360	13,355	13,351	13,346	13,342	13,342
Subtotal – Non-network Operational Expenditure	**19,634**	**19,296**	**19,169**	**19,686**	**19,518**	**19,520**	**19,523**	**19,525**	**19,528**	**19,528**
Total – Operational Expenditure	**35,784**	**35,380**	**35,251**	**35,767**	**35,597**	**35,598**	**35,599**	**35,599**	**35,601**	**35,601**

Table 13-8 Operational Expenditure Forecast
($K in constant prices)

Appendices

Appendix A 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.	Growth in peak demand will continue to be lower than the national average and will remain steady through the forecast period. Overall consumption of electricity (kWh volume) is forecast to increase steadily.	Measured system loadings and load analysis indicate maximum demand growth in some areas but energy volumes stable across the network as a whole. Moderate levels of growth in the housing sector. Further load growth due to possible decarbonisation policies is being assessed.
Capital Expenditure - Resilience	Investment levels may change in response to legislative changes.	The current regulatory environment does not allow for resilience spend, and this position is assumed to continue for the duration of the plan.	Correspondence from the Commission indicates that they will not consider a single-issue CPP for Resilience.
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 steady though building consents do show an increase. 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 well known, steady and no "step change" in expenditure is expected.
Operational Expenditure - Routine Inspection and Maintenance	Any material change to the annual maintenance programme or costs associated with them may lead to an increase, or decrease in the Opex costs associated with inspection and maintenance.	The inspection and maintenance expenditure proposed will broadly remain within forecast levels for the next four years.	The inspection programme is defined by comprehensive maintenance standards covering all asset classes. Managing mature network assets, the routine of inspection and servicing is not likely to change significantly.

Area	Possible impact and variation to plan	Assumption	Reason for assumption
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 year. Aging assets may lead to higher levels of reactive maintenance required longer term and a change of the FSA may result in changes to the associated reactive maintenance expenditure.	Reactive maintenance rates defined in FSA, which are expected to be maintained at similar levels.
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 are detailed in Schedule 14a.	The rates used for the expenditure forecast are based on the midpoint of the RBNZ's target inflation range.
Quality targets	Any increase in quality targets, or alteration in the assessment method, may lead to increased level of investment to maintain network performance.	Network reliability performance targets for 2020-2025 were set by the Commission's 2019 DPP Determination. It is assumed that the targets will remain constant for 2025-2030.	The targets adopted in this plan align with the Commission's 2019 determination for 2022-2032. This reflects WELL's intention to maintain network reliability at current levels.
Regulatory environment	A change to the regulatory environment may lead to increased or decreased ability to recover on investments.	The regulatory environment will continue to incentivise shareholders to invest in the network to ensure a sustainably profitable business.	The expected impact of the 2019 DPP reset has been assessed, providing stability through to 2025.
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 changes to the grid that will significantly impact WELL during the planning period, other than those identified in Section 8 and the Section 11.

Area	Possible impact and variation to plan	Assumption	Reason for assumption
Transmission Pricing	Changes to the methods of transmission pass-through pricing may lead to increased expenditure as grid alternative options become more attractive in a non-pass-through environment.	The transmission pricing methodologies will remain largely unchanged and the transmission pass-through pricing will remain in place.	Transmission pricing is regulated as a pass-through cost and our expectation that this will remain as a pass-through cost with the net effect to the business remaining the same.
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 WELL is likely to be modest for the foreseeable future.	Assumptions of regional GDP growth are supported by observations of demand on the network and local business activities.
Business cycle	The evolution of a business and its operating environment can impact on strategic decision making and overall approach.	The business cycle is expected to change due to the introduction of new technologies and appropriate investment forecasts have been included into this plan.	The changes to customer behaviour due to the penetration of new technologies have been based on the worldwide trend of lower costs associated with such technologies making them more accessible.
Technology	Increased levels of network reinforcement may be required to accommodate sudden load increases at customer premises resulting from demand side technologies, or significantly reduced loads may be seen that could defer investment if load reduction technologies are introduced by customers.	There will be changes that will result in a rapid uptake of new technology by customers which could result in higher expenditure on network reinforcement. This reinforcement will be deferred by enabling new technologies on the network and by moving towards becoming a Distribution System Operator.	At demand side, displacement or disruptive technologies such as electric vehicles, vehicle-to-grid and distributed generation will begin to gain penetration into Wellington. Trends in the area of disruptive technology are being closely monitored and plans forecast to prepare for these changes are in Section 9.
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.	Compliance with requirements for public safety management will not adversely impact upon the existing network assets located in the public domain.	Implementation of a public safety management system in the business, including compliance with NZS 7901 and promoting a culture of incident reporting and safety awareness.

Appendix B Update from 2021 Plan

During the past year, WELL has continued the review of its asset management strategy and practices. Progress against the gaps identified in the 2021 AMP, along with material changes to network development and lifecycle asset management plans, is shown in the Table B-1.

2021 AMP Section	Item	Description
3.6.1.1	Publication of planned outages to the WELL website	**2021 AMP:** In 2021 WELL will add planned outages to its web and mobile platforms.
		Update: WELL is currently trialling publishing planned outages on its web and mobile platforms.
3.6.1.1	Community engagement	**2021 AMP:** During 2021 WELL will resume its community engagement programme, prioritising those communities who have been most impacted by unplanned outages.
		Update: The restrictions imposed by the government's response to COVID-19 impacted WELL's community engagement programme in 2020 and 2021. WELL will resume its community engagement programme once it is able to, prioritising those communities who have been most impacted by unplanned outages.
5.5	Customer Experience Improvement Programmes	**2021 AMP:** During 2021 the connections request functionality of the WELL website will be enhanced to further improve the experience for those customers
		Update: These changes have been developed and will be released in the first half of 2022.
9	Long term funding	**2021 AMP:** Work has started on developing a 30 year long term funding model.
		Update: Work has progressed on a draft 30 year model which will be further refined and shared with the Commission as part of the Input Methodology consultation.
9.1.1	EV Connect Roadmap	**2021 AMP:** One of the outcomes of the EV Connect programme is, by April 2021, to deliver an industry roadmap of the actions needed for distributions networks to accommodate the uptake of EVs.
		Update: The EV Connect roadmap was published in June 2021

2021 AMP Section	Item	Description
10.1.1.1	SCADA Historian	**2021 AMP:** The system is expected to be replaced in 2024 following the SCADA system upgrade.
		Update: The system is planned for replacement in 2023 in conjunction with the SCADA system upgrade.
10.1.1.1	Load Management System	**2021 AMP:** The system is due for replacement in 2024.
		Update: The system is planned for replacement in 2023 in conjunction with the SCADA system upgrade.
10.1.2	Billing System	**2021 AMP:** It is planned to relocate the billing system to WELL's datacentres in New Zealand in 2021.
		Update: This work is now planned to occur in 2022.
11.6.1	Central Park GXP	**2021 AMP:** The project is currently being discussed with the EA to finalise the approval process required for this work to proceed.
		Update: Transpower is establishing a project team to deliver the project for Q3 2026.

Table B-1 Progress against Actions Identified in 2021 AMP

Comparisons between forecast expenditure from the 2021 AMP and the actual expenditure for the 2021/22 regulatory year are shown below in Table B-2 for operational expenditure and Table B-3 for capital expenditure.

Expenditure Category	2021/22 Forecast from 2021 AMP	2021/22 Actuals	Variation
Service Interruptions and Emergencies	4,738	5,278	540
Vegetation Management	1,765	1,876	111
Routine and Corrective Maintenance and Inspection	8,308	8,282	26
Asset Replacement and Renewal	942	1,219	277
System Operations and Network Support	5,887	6,024	136
Business Support	12,424	12,840	416
Operational expenditure	**34,065**	**35,519**	**1,454**

Table B-2 Comparison of Operational Expenditure against 2021 AMP Forecasts
($K, forecast in nominal dollars)

Operating expenditure was approximately 4% higher than forecast, with variances primarily due to Service Interruptions and Emergencies costs being greater than the forecast due to more complex faults, and an increase in Business Support costs due to increases in IT software costs.

Expenditure Category	2021/22 Forecast from 2021 AMP	2021/22 Actuals	Variation
Customer Connection	11,636	15,925	4,289
System Growth	9,122	7,987	(1,135)
Asset Replacement and Renewal	20,413	19,346	(1,067)
Asset Relocations	714	1,903	1,189
Reliability, Safety and Environment	2,905	4,020	1,115
Expenditure on Non-network Assets	1,805	1,889	83
Capital Expenditure	**46,596**	**51,070**	**4,474**

Table B-3 Comparison of Capital Expenditure against 2021 AMP Forecasts ($K, forecast in nominal dollars)

Capital expenditure was approximately 10% higher than forecast, with variances primarily due to Customer Connection and Asset Relocation spend being significantly higher than the forecast. This was due to a large number of customer-initiated projects occurring during the year. Customer contribution revenue also increased in line with the increases in Customer Connection and Asset Relocation capital expenditure. Differences to the system growth and asset replacement and renewal programmes were due to changes in refinements in the project plans.

Appendix C Schedules

		Company Name	Wellington Electricity
		AMP Planning Period	1 April 2022 – 31 March 2032

SCHEDULE 11a: REPORT ON FORECAST CAPITAL EXPENDITURE

This schedule requires a breakdown of forecast expenditure on assets for the current disclosure year and a 10 year planning period. The forecasts should be consistent with the supporting information set out in the AMP. The forecast is to be expressed in both constant price and nominal dollar terms. Also required is a forecast of the value of commissioned assets (i.e., the value of RAB additions)

EDBs must provide explanatory comment on the difference between constant price and nominal dollar forecasts of expenditure on assets in Schedule 14a (Mandatory Explanatory Notes).

This information is not part of audited disclosure information.

sch ref			Current Year CY	CY+1	CY+2	CY+3	CY+4	CY+5	CY+6	CY+7	CY+8	CY+9	CY+10
8		for year ended	31 Mar 22	31 Mar 23	31 Mar 24	31 Mar 25	31 Mar 26	31 Mar 27	31 Mar 28	31 Mar 29	31 Mar 30	31 Mar 31	31 Mar 32
9	**11a(i): Expenditure on Assets Forecast**		$000 (in nominal dollars)										
10		Consumer connection	15,925	13,947	12,715	12,548	12,688	12,986	13,291	13,605	13,902	14,180	14,463
11		System growth	7,987	9,073	5,821	7,015	20,243	15,922	27,687	31,181	20,100	18,673	20,120
12		Asset replacement and renewal	19,346	24,413	26,355	26,132	28,434	26,057	32,964	37,012	28,245	42,345	43,768
13		Asset relocations	1,903	728	743	758	773	788	804	820	837	853	870
14		Reliability, safety and environment:											
15		Quality of supply	1,123	2,139	2,179	2,222	2,427	2,526	2,628	2,736	2,926	3,242	3,479
16		Legislative and regulatory	-	-	-	-	-	-	-	-	-	-	-
17		Other reliability, safety and environment	2,898	467	703	-	-	-	-	-	-	-	-
18		**Total reliability, safety and environment**	4,020	2,606	2,882	2,222	2,427	2,526	2,628	2,736	2,926	3,242	3,479
19		**Expenditure on network assets**	49,181	50,767	48,516	48,674	64,565	58,280	77,374	85,354	66,009	79,293	82,700
20		Expenditure on non-network assets	1,889	2,283	3,657	1,772	2,500	4,460	2,720	3,526	1,365	3,042	1,115
21		**Expenditure on assets**	51,070	53,050	52,173	50,447	67,065	62,740	80,094	88,881	67,374	82,335	83,816
22													
23	*plus*	Cost of financing	274	179	177	203	224	229	231	234	238	243	248
24	*less*	Value of capital contributions	14,084	9,356	9,833	9,879	9,961	10,040	10,222	10,455	10,679	10,893	11,110
25	*plus*	Value of vested assets	-	-	-	-	-	-	-	-	-	-	-
26									-	-			
27		**Capital expenditure forecast**	37,260	43,873	42,517	40,771	57,329	52,930	70,103	78,659	56,933	71,685	72,953
28													
29		Assets commissioned	39,606	44,827	43,597	40,771	57,329	52,930	70,103	78,659	56,933	71,685	72,953
30			Current Year CY	CY+1	CY+2	CY+3	CY+4	CY+5	CY+6	CY+7	CY+8	CY+9	CY+10
31		for year ended	31 Mar 22	31 Mar 23	31 Mar 24	31 Mar 25	31 Mar 26	31 Mar 27	31 Mar 28	31 Mar 29	31 Mar 30	31 Mar 31	31 Mar 32
32			$000 (in constant prices)										
33		Consumer connection	15,925	13,674	12,221	11,824	11,722	11,762	11,802	11,844	11,865	11,865	11,865
34		System growth	7,987	8,895	5,595	6,610	18,701	14,421	24,585	27,145	17,155	15,625	16,505
35		Asset replacement and renewal	19,346	23,934	25,332	24,625	26,269	23,601	29,271	32,221	24,107	35,432	35,905
36		Asset relocations	1,903	714	714	714	714	714	714	714	714	714	714
37		Reliability, safety and environment:											
38		Quality of supply	1,123	2,097	2,094	2,094	2,242	2,288	2,334	2,382	2,497	2,713	2,854
39		Legislative and regulatory	-	-	-	-	-	-	-	-	-	-	-
40		Other reliability, safety and environment	2,898	458	676	-	-	-	-	-	-	-	-
41		**Total reliability, safety and environment**	4,020	2,555	2,770	2,094	2,242	2,288	2,334	2,382	2,497	2,713	2,854
42		**Expenditure on network assets**	49,181	49,772	46,632	45,867	59,648	52,786	68,706	74,306	56,338	66,349	67,843
43		Expenditure on non-network assets	1,889	2,238	3,515	1,670	2,310	4,040	2,415	3,070	1,165	2,545	915
44		**Expenditure on assets**	51,070	52,010	50,147	47,537	61,958	56,826	71,121	77,376	57,503	68,894	68,758
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											
50													

		Current Year CY	CY+1	CY+2	CY+3	CY+4	CY+5	CY+6	CY+7	CY+8	CY+9	CY+10
52	for year ended	31 Mar 22	31 Mar 23	31 Mar 24	31 Mar 25	31 Mar 26	31 Mar 27	31 Mar 28	31 Mar 29	31 Mar 30	31 Mar 31	31 Mar 32
53	**Difference between nominal and constant price forecasts**	$000										
54	Consumer connection	-	273	494	724	966	1,224	1,489	1,761	2,037	2,315	2,598
55	System growth	-	178	226	405	1,542	1,501	3,102	4,036	2,945	3,048	3,615
56	Asset replacement and renewal	-	479	1,023	1,507	2,165	2,456	3,693	4,791	4,138	6,913	7,863
57	Asset relocations	-	14	29	44	59	74	90	106	123	139	156
58	Reliability, safety and environment:											
59	Quality of supply	-	42	85	128	185	238	294	354	429	529	625
60	Legislative and regulatory	-	-	-	-	-	-	-	-	-	-	-
61	Other reliability, safety and environment	-	9	27	-	-	-	-	-	-	-	-
62	**Total reliability, safety and environment**	-	51	112	128	185	238	294	354	429	529	625
63	**Expenditure on network assets**	-	995	1,884	2,807	4,917	5,494	8,668	11,048	9,671	12,944	14,857
64	Expenditure on non-network assets	-	45	142	102	190	420	305	456	200	497	200
65	**Expenditure on assets**	-	1,040	2,026	2,910	5,107	5,914	8,973	11,505	9,871	13,441	15,058

67		Current Year CY	CY+1	CY+2	CY+3	CY+4	CY+5
	for year ended	31 Mar 22	31 Mar 23	31 Mar 24	31 Mar 25	31 Mar 26	31 Mar 27
68	**11a(ii): Consumer Connection**						
69	*Consumer types defined by EDB**	$000 (in constant prices)					
70	Substation	8,089	4,464	3,661	3,614	3,484	3,496
71	Subdivision	4,474	6,062	5,757	5,575	5,595	5,613
72	High Voltage Connection	508	-	-	-	-	-
73	Residential Consumers	2,853	3,070	2,725	2,557	2,564	2,574
74	Public Lighting	-	78	78	78	79	79
75	**include additional rows if needed*						
76	**Consumer connection expenditure**	15,925	13,674	12,221	11,824	11,722	11,762
77	*less* Capital contributions funding consumer connection	12,581	8,717	8,929	8,779	8,674	8,573
78	**Consumer connection less capital contributions**	3,344	4,957	3,292	3,045	3,048	3,189
79	**11a(iii): System Growth**						
80	Subtransmission	6,865	638	-	-	1,800	5,900
81	Zone substations	365	4,872	399	3,171	8,106	3,276
82	Distribution and LV lines	207	-	350	700	2,300	1,900
83	Distribution and LV cables	-	2,565	3,485	1,300	3,700	300
84	Distribution substations and transformers	354	15	421	419	-	-
85	Distribution switchgear	41	-	-	-	-	-
86	Other network assets	155	805	940	1,020	2,795	3,045
87	**System growth expenditure**	7,987	8,895	5,595	6,610	18,701	14,421
88	*less* Capital contributions funding system growth	-	-	-	-	-	-
89	**System growth less capital contributions**	7,987	8,895	5,595	6,610	18,701	14,421

11a(iv): Asset Replacement and Renewal

	Current Year CY	CY+1	CY+2	CY+3	CY+4	CY+5
for year ended	31 Mar 22	31 Mar 23	31 Mar 24	31 Mar 25	31 Mar 26	31 Mar 27
	$000 (in constant prices)					
Subtransmission	-	-	500	1,700	3,200	-
Zone substations	1,718	2,685	200	200	200	200
Distribution and LV lines	7,609	6,873	7,330	7,030	6,789	7,116
Distribution and LV cables	104	2,550	2,550	2,550	2,550	2,550
Distribution substations and transformers	2,127	4,269	4,577	4,720	4,601	4,830
Distribution switchgear	2,510	4,462	5,460	5,410	5,414	5,590
Other network assets	5,279	3,095	4,715	3,015	3,515	3,315
Asset replacement and renewal expenditure	19,346	23,934	25,332	24,625	26,269	23,601
less Capital contributions funding asset replacement and renewal	-	-	-	-	-	-
Asset replacement and renewal less capital contributions	19,346	23,934	25,332	24,625	26,269	23,601

11a(v): Asset Relocations

	Current Year CY	CY+1	CY+2	CY+3	CY+4	CY+5
for year ended	31 Mar 22	31 Mar 23	31 Mar 24	31 Mar 25	31 Mar 26	31 Mar 27
*Project or programme**	**$000 (in constant prices)**					
Roading Relocations	1,903	714	714	714	714	714
[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 project or programmes - asset relocations	-	-	-	-	-	-
Asset relocations expenditure	1,903	714	714	714	714	714
less Capital contributions funding asset relocations	1,503	455	522	530	528	520
Asset relocations less capital contributions	400	259	192	184	186	194

11a(vi): Quality of Supply

	Current Year CY	CY+1	CY+2	CY+3	CY+4	CY+5
for year ended	31 Mar 22	31 Mar 23	31 Mar 24	31 Mar 25	31 Mar 26	31 Mar 27
*Project or programme**	**$000 (in constant prices)**					
Feeder Reliability Improvement	1,123	2,097	2,094	2,094	2,242	2,288
[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 projects or programmes - quality of supply	-	-	-	-	-	-
Quality of supply expenditure	1,123	2,097	2,094	2,094	2,242	2,288
less Capital contributions funding quality of supply	-	-	-	-	-	-
Quality of supply less capital contributions	1,123	2,097	2,094	2,094	2,242	2,288

11a(vii): Legislative and Regulatory

	Current Year CY	CY+1	CY+2	CY+3	CY+4	CY+5
for year ended	31 Mar 22	31 Mar 23	31 Mar 24	31 Mar 25	31 Mar 26	31 Mar 27
*Project or programme**	$000 (in constant prices)					
[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 projects or programmes - legislative and regulatory	-	-	-	-	-	-
Legislative and regulatory expenditure	-	-	-	-	-	-
less Capital contributions funding legislative and regulatory	-	-	-	-	-	-
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 22	31 Mar 23	31 Mar 24	31 Mar 25	31 Mar 26	31 Mar 27
*Project or programme**	$000 (in constant prices)					
BAU Seismic Strengthening	669	458	676	-	-	-
[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 projects or programmes - other reliability, safety and environment	2,228	-	-	-	-	-
Other reliability, safety and environment expenditure	2,898	458	676	-	-	-
less Capital contributions funding other reliability, safety and environment	-	-	-	-	-	-
Other reliability, safety and environment less capital contributions	2,898	458	676	-	-	-

11a(ix): Non-Network Assets

	Current Year CY	CY+1	CY+2	CY+3	CY+4	CY+5
for year ended	31 Mar 22	31 Mar 23	31 Mar 24	31 Mar 25	31 Mar 26	31 Mar 27
Routine expenditure						
*Project or programme**	$000 (in constant prices)					
Software and Licenses	971	1,945	2,475	895	635	470
IT Infrastructure	879	293	1,040	775	1,675	865
[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 projects or programmes - routine expenditure	40	-	-	-	-	-
Routine expenditure	1,889	2,238	3,515	1,670	2,310	1,335
Atypical expenditure						
*Project or programme**						
Capitalised operating leases	-	-	-	-	-	2,705
[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 projects or programmes - atypical expenditure	-	-	-	-	-	-
Atypical expenditure	-	-	-	-	-	2,705
Expenditure on non-network assets	1,889	2,238	3,515	1,670	2,310	4,040

Company Name: **Wellington Electricity**
AMP Planning Period: **1 April 2022 – 31 March 2032**

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 22	31 Mar 23	31 Mar 24	31 Mar 25	31 Mar 26	31 Mar 27	31 Mar 28	31 Mar 29	31 Mar 30	31 Mar 31	31 Mar 32
9	**Operational Expenditure Forecast**	**$000 (in nominal dollars)**										
10	Service interruptions and emergencies	5,278	4,849	4,933	5,034	5,123	5,230	5,334	5,441	5,550	5,661	5,774
11	Vegetation management	1,876	1,799	1,828	1,865	1,902	1,940	1,979	2,019	2,059	2,100	2,142
12	Routine and corrective maintenance and inspection	8,282	8,815	8,955	9,133	9,310	9,496	9,684	9,875	10,071	10,270	10,475
13	Asset replacement and renewal	1,219	1,010	1,018	1,035	1,071	1,087	1,109	1,131	1,154	1,177	1,201
14	**Network Opex**	16,655	16,473	16,735	17,068	17,407	17,753	18,106	18,466	18,834	19,208	19,592
15	System operations and network support	6,024	6,294	6,384	6,520	6,658	6,799	6,943	7,090	7,240	7,393	7,540
16	Business support	12,840	13,733	13,692	13,822	14,651	14,750	15,040	15,336	15,637	15,945	16,263
17	**Non-network opex**	18,864	20,027	20,076	20,341	21,309	21,549	21,983	22,426	22,877	23,337	23,804
18	**Operational expenditure**	35,519	36,500	36,811	37,409	38,716	39,302	40,089	40,892	41,710	42,545	43,396

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
20	for year ended	31 Mar 22	31 Mar 23	31 Mar 24	31 Mar 25	31 Mar 26	31 Mar 27	31 Mar 28	31 Mar 29	31 Mar 30	31 Mar 31	31 Mar 32
21		**$000 (in constant prices)**										
22	Service interruptions and emergencies	5,278	4,754	4,741	4,744	4,733	4,737	4,737	4,737	4,737	4,737	4,737
23	Vegetation management	1,876	1,764	1,757	1,757	1,757	1,757	1,757	1,757	1,757	1,757	1,757
24	Routine and corrective maintenance and inspection	8,282	8,642	8,607	8,606	8,601	8,600	8,599	8,597	8,595	8,594	8,594
25	Asset replacement and renewal	1,219	990	979	975	990	985	985	985	985	985	985
26	**Network Opex**	16,655	16,150	16,084	16,082	16,081	16,079	16,078	16,076	16,074	16,073	16,073
27	System operations and network support	6,024	6,170	6,136	6,144	6,151	6,158	6,165	6,172	6,179	6,186	6,186
28	Business support	12,840	13,464	13,160	13,025	13,535	13,360	13,355	13,351	13,346	13,342	13,342
29	**Non-network opex**	18,864	19,634	19,296	19,169	19,686	19,518	19,520	19,523	19,525	19,528	19,528
30	**Operational expenditure**	35,519	35,784	35,380	35,251	35,767	35,597	35,598	35,599	35,599	35,601	35,601
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	2,166	2,326	2,475	2,528	2,523	2,518	2,513	2,509	2,504	2,500	2,500

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

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
40	for year ended	31 Mar 22	31 Mar 23	31 Mar 24	31 Mar 25	31 Mar 26	31 Mar 27	31 Mar 28	31 Mar 29	31 Mar 30	31 Mar 31	31 Mar 32
41	**Difference between nominal and real forecasts**	**$000**										
42	Service interruptions and emergencies	-	95	192	290	390	493	597	704	813	924	1,037
43	Vegetation management	-	35	71	108	145	183	222	262	302	343	385
44	Routine and corrective maintenance and inspection	-	173	348	527	709	896	1,085	1,278	1,476	1,676	1,881
45	Asset replacement and renewal	-	20	39	60	81	102	124	146	169	192	216
46	**Network Opex**	-	323	651	986	1,326	1,674	2,028	2,390	2,760	3,135	3,519
47	System operations and network support	-	124	248	376	507	641	778	918	1,061	1,207	1,354
48	Business support	-	269	532	797	1,116	1,390	1,685	1,985	2,291	2,603	2,921
49	**Non-network opex**	-	393	780	1,172	1,623	2,031	2,463	2,903	3,352	3,809	4,276
50	**Operational expenditure**	-	716	1,431	2,158	2,949	3,705	4,491	5,293	6,111	6,944	7,795

Company Name	**Wellington Electricity**
AMP Planning Period	**1 April 2022 – 31 March 2032**

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**	**H1**	**H2**	**H3**	**H4**	**H5**	**Grade unknown**	**Data accuracy (1–4)**	**% of asset forecast to be replaced in next 5 years**
9												
10	All	Overhead Line	Concrete poles / steel structure	No.	0.27%	0.81%	27.99%	31.87%	39.07%	0.75%	3	1.08%
11	All	Overhead Line	Wood poles	No.	0.86%	7.36%	64.37%	19.47%	7.94%	3.30%	3	8.22%
12	All	Overhead Line	Other pole types	No.			1.12%	1.12%	97.76%		4	-
13	HV	Subtransmission Line	Subtransmission OH up to 66kV conductor	km		13.83%	79.63%	1.11%	5.43%		3	-
14	HV	Subtransmission Line	Subtransmission OH 110kV+ conductor	km							N/A	
15	HV	Subtransmission Cable	Subtransmission UG up to 66kV (XLPE)	km			9.25%	5.41%	85.34%		4	-
16	HV	Subtransmission Cable	Subtransmission UG up to 66kV (Oil pressurised)	km		35.30%	64.70%				3	-
17	HV	Subtransmission Cable	Subtransmission UG up to 66kV (Gas pressurised)	km	2.15%	16.99%	80.86%				3	8.79%
18	HV	Subtransmission Cable	Subtransmission UG up to 66kV (PILC)	km		26.88%	73.12%				3	-
19	HV	Subtransmission Cable	Subtransmission UG 110kV+ (XLPE)	km							N/A	
20	HV	Subtransmission Cable	Subtransmission UG 110kV+ (Oil pressurised)	km							N/A	
21	HV	Subtransmission Cable	Subtransmission UG 110kV+ (Gas Pressurised)	km							N/A	
22	HV	Subtransmission Cable	Subtransmission UG 110kV+ (PILC)	km							N/A	
23	HV	Subtransmission Cable	Subtransmission submarine cable	km							N/A	
24	HV	Zone substation Buildings	Zone substations up to 66kV	No.			100.00%				4	-
25	HV	Zone substation Buildings	Zone substations 110kV+	No.							N/A	
26	HV	Zone substation switchgear	22/33kV CB (Indoor)	No.		100.00%					4	100.00%
27	HV	Zone substation switchgear	22/33kV CB (Outdoor)	No.							N/A	
28	HV	Zone substation switchgear	33kV Switch (Ground Mounted)	No.							N/A	
29	HV	Zone substation switchgear	33kV Switch (Pole Mounted)	No.			100.00%				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.		2.19%	69.13%	14.47%	14.21%		3	2.19%
34	HV	Zone substation switchgear	3.3/6.6/11/22kV CB (pole mounted)	No.							N/A	
35												

	Voltage	Asset category	Asset class	Units	H1	H2	H3	H4	H5	Grade unknown	Data accuracy (1–4)	% of asset forecast to be replaced in next 5 years
36					Asset condition at start of planning period (percentage of units by grade)							
37												
38												
39	HV	Zone Substation Transformer	Zone Substation Transformers	No.	3.85%	23.08%	73.07%				3	3.85%
40	HV	Distribution Line	Distribution OH Open Wire Conductor	km	0.32%	16.30%	68.05%	7.52%	7.81%		3	1.95%
41	HV	Distribution Line	Distribution OH Aerial Cable Conductor	km		53.11%	46.79%	0.10%			3	1.00%
42	HV	Distribution Line	SWER conductor	km							N/A	
43	HV	Distribution Cable	Distribution UG XLPE or PVC	km		0.45%	0.88%	38.91%	59.76%		3	1.00%
44	HV	Distribution Cable	Distribution UG PILC	km	0.03%	4.01%	73.12%	22.72%	0.12%		3	1.00%
45	HV	Distribution Cable	Distribution Submarine Cable	km			100.00%				4	
46	HV	Distribution switchgear	3.3/6.6/11/22kV CB (pole mounted) - reclosers and sectionalisers	No.		3.57%	25.00%	32.14%	39.29%		3	3.57%
47	HV	Distribution switchgear	3.3/6.6/11/22kV CB (Indoor)	No.	1.88%	2.04%	59.98%	20.67%	15.43%		3	3.92%
48	HV	Distribution switchgear	3.3/6.6/11/22kV Switches and fuses (pole mounted)	No.	-	0.27%	66.03%	20.30%	13.40%		3	6.87%
49	HV	Distribution switchgear	3.3/6.6/11/22kV Switch (ground mounted) - except RMU	No.	9.03%	22.58%	60.32%	2.90%	5.16%		3	13.55%
50	HV	Distribution switchgear	3.3/6.6/11/22kV RMU	No.	0.05%	0.60%	84.14%	11.21%	4.00%		3	2.00%
51	HV	Distribution Transformer	Pole Mounted Transformer	No.	0.65%	2.61%	15.03%	14.38%	67.32%		3	6.15%
52	HV	Distribution Transformer	Ground Mounted Transformer	No.	0.31%	1.45%	52.75%	20.90%	24.60%		3	4.39%
53	HV	Distribution Transformer	Voltage regulators	No.							N/A	
54	HV	Distribution Substations	Ground Mounted Substation Housing	No.	0.66%	1.48%	50.74%	22.64%	24.48%		3	3.24%
55	LV	LV Line	LV OH Conductor	km	0.16%	14.15%	79.35%	5.36%	0.98%		2	1.00%
56	LV	LV Cable	LV UG Cable	km	0.05%	2.64%	74.95%	14.33%	8.03%		2	2.00%
57	LV	LV Streetlighting	LV OH/UG Streetlight circuit	km	0.06%	6.92%	79.17%	10.29%	3.57%		1	1.00%
58	LV	Connections	OH/UG consumer service connections	No.		0.06%	96.00%	3.67%	0.27%		1	2.00%
59	All	Protection	Protection relays (electromechanical, solid state and numeric)	No.	0.70%	4.90%	76.50%	9.37%	8.53%		3	8.26%
60	All	SCADA and communications	SCADA and communications equipment operating as a single system	Lot	6.82%	34.09%	22.73%	20.45%	15.91%		3	8.52%
61	All	Capacitor Banks	Capacitors including controls	No.							N/A	
62	All	Load Control	Centralised plant	Lot		8.00%	76.00%	4.00%	12.00%		3	8.00%
63	All	Load Control	Relays	No.							N/A	
64	All	Civils	Cable Tunnels	km			100.00%				3	-

Company Name **Wellington Electricity**
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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 Street -	16	20	N-1	10	80%	20	91%	No constraint within +5 years	
10	Brown Owl -	16	18	N-1	7	87%	18	91%	No constraint within +5 years	
11	Evans Bay -	12	19	N-1	9	63%	24	80%	No constraint within +5 years	New 33kV bus and transformer replacement in 2023
12	Frederick Street -	28	23	N-1	13	122%	30	103%	Transformer	33 kV subtransmisison cable replacement in 2022
13	Gracefield -	11	23	N-1	13	48%	23	63%	No constraint within +5 years	33 kV cables replaced with higher capacity cables 1st quarter of 2022.
14	Hataitai -	18	22	N-1	11	82%	22	88%	No constraint within +5 years	
15	Johnsonville -	21	16	N-1	8	131%	16	133%	Subtransmission circuit	Peak load control until load can be transferred to proposed new Grenada North ZS
16	Karori -	15	20	N-1	6	75%	20	91%	No constraint within +5 years	
17	Kenepuru -	12	18	N-1	8	67%	18	67%	No constraint within +5 years	
18	Korokoro -	21	16	N-1	17	135%	20	115%	Subtransmission circuit	Remove 33 kV subtransmisison cable and transformer costraint
19	Maidstone -	15	18	N-1	12	85%	18	115%	Subtransmission circuit	
20	Mana -	9	7	N-1	12	129%	7	141%	Other	Low capacity Mana-Plimmerton bus tie
21	Moore Street -	21	30	N-1	14	70%	30	77%	No constraint within +5 years	
22	Naenae	15	18	N-1	11	82%	18	97%	No constraint within +5 years	
23	Nairn Street -	22	22	N-1	16	100%	22	111%	Subtransmission circuit	
24	Ngauranga -	11	10	N-1	10	110%	24	66%	No constraint within +5 years	Transformer upgrade planned for 2025
25	Palm Grove -	25	20	N-1	11	125%	34	87%	No constraint within +5 years	Transformer upgrade planned for 2025
26	Plimmerton -	8	7	N-1	12	114%	7	157%	Other	Low capacity Mana-Plimmerton bus tie
27	Porirua -	22	16	N-1	13	138%	36	70%	No constraint within +5 years	Upgrade 33 kV subtransmission cables, 33/11kV transformers and 11kV bus planned for 2025
28	Seaview -	15	14	N-1	12	109%	20	76%	No constraint within +5 years	Remove 33 kV subtransmisison cable costraint
29	Tawa -	15	16	N-1	16	94%	16	113%	Transformer	Peak load control until load can be transferred to proposed new Grenada North ZS
30	The Terrace -	24	30	N-1	20	80%	30	87%	No constraint within +5 years	
31	Trentham -	15	19	N-1	10	79%	19	98%	No constraint within +5 years	
32	University -	18	20	N-1	21	90%	20	99%	No constraint within +5 years	
33	Waikowhai Street -	14	15	N-1	10	93%	15	98%	No constraint within +5 years	
34	Wainuiomata	18	17	N-1	3	109%	17	119%	Transformer	33 kV cables at Gracefield replaced with higher capacity cables 1st quarter of 2022.
35	Waitangirua -	15	16	N-1	11	94%	16	111%	Transformer	Transfer load to Porirua following planned Porirua upgrade
36	Waterloo	16	20	N-1	14	80%	20	88%	No constraint within +5 years	

37 [1] *Extend forecast capacity table as necessary to disclose all capacity by each zone substation*

Company Name: **Wellington Electricity**
AMP Planning Period: **1 April 2022 – 31 March 2032**

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**							
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 22**	**31 Mar 23**	**31 Mar 24**	**31 Mar 25**	**31 Mar 26**	**31 Mar 27**
11	*Consumer types defined by EDB**							
12	Domestic		2,050	2,084	2,116	2,149	1,659	1,678
13	Small Commercial		14	14	15	15	11	12
14	Medium Commercial		1	1	1	1	1	1
15	Large Commercial		16	17	17	17	13	13
16	Small Industrial		719	731	742	754	582	588
17	Large Industrial		8	8	8	8	6	6
18	Unmetered		46	-	-	-	-	-
19	**Connections total**		2,854	2,855	2,899	2,944	2,272	2,299
20	**include additional rows if needed*							
21	**Distributed generation**							
22	Number of connections		365	365	365	365	365	365
23	Capacity of distributed generation installed in year (MVA)		2	2	2	2	2	2
24	**12c(ii) System Demand**							
25			*Current Year CY*	*CY+1*	*CY+2*	*CY+3*	*CY+4*	*CY+5*
26	**Maximum coincident system demand (MW)**	for year ended	**31 Mar 22**	**31 Mar 23**	**31 Mar 24**	**31 Mar 25**	**31 Mar 26**	**31 Mar 27**
27	GXP demand		530	542	549	556	563	570
28	*plus* Distributed generation output at HV and above		49	49	49	49	49	49
29	**Maximum coincident system demand**		579	591	598	605	612	619
30	*less* Net transfers to (from) other EDBs at HV and above		-	-	-	-	-	-
31	**Demand on system for supply to consumers' connection points**		579	591	598	605	612	619
32	**Electricity volumes carried (GWh)**							
33	Electricity supplied from GXPs		2,145	2,190	2,214	2,240	2,266	2,293
34	*less* Electricity exports to GXPs		-	-	-	-	-	-
35	*plus* Electricity supplied from distributed generation		259	259	259	259	259	259
36	*less* Net electricity supplied to (from) other EDBs		-					
37	**Electricity entering system for supply to ICPs**		2,404	2,449	2,473	2,499	2,525	2,552
38	*less* Total energy delivered to ICPs		2,234	2,281	2,306	2,333	2,360	2,388
39	**Losses**		170	168	167	166	165	164
40								
41	**Load factor**		47%	47%	47%	47%	47%	47%
42	**Loss ratio**		7.1%	6.9%	6.8%	6.6%	6.5%	6.4%

Company Name	**Wellington Electricity**
AMP Planning Period	**1 April 2022 – 31 March 2032**
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								
8			*Current Year CY*	*CY+1*	*CY+2*	*CY+3*	*CY+4*	*CY+5*
9		for year ended	**31 Mar 22**	**31 Mar 23**	**31 Mar 24**	**31 Mar 25**	**31 Mar 26**	**31 Mar 27**
10	**SAIDI**							
11	Class B (planned interruptions on the network)		9.8	10.0	10.0	10.0	10.0	10.0
12	Class C (unplanned interruptions on the network)		27.5	31.2	31.2	31.2	31.2	31.2
13	**SAIFI**							
14	Class B (planned interruptions on the network)		0.06	0.07	0.07	0.07	0.07	0.07
15	Class C (unplanned interruptions on the network)		0.42	0.48	0.48	0.48	0.48	0.48

Company Name	**Wellington Electricity**
AMP Planning Period	**1 April 2022 – 31 March 2032**
Asset Management Standard Applied	

SCHEDULE 13: REPORT ON ASSET MANAGEMENT MATURITY

This schedule requires information on the EDB'S self-assessment of the maturity of its asset management practices .

Question No.	Function	Question	Score	Evidence—Summary	User Guidance	Why	Who	Record/documented Information
3	Asset management policy	To what extent has an asset management policy been documented, authorised and communicated?	3	WELL has an Asset Management Policy which is derived from the organisational vision and linked to the organisational strategies, objectives and targets. WELL has also published an Asset Management Strategy (AM Strategy) and associated Fleet Strategies for discreet assets.		Widely used AM practice standards require an organisation to document, authorise and communicate its asset management policy (eg, as required in PAS 55 para 4.2 i). A key pre-requisite of any robust policy is that the organisation's top management must be seen to endorse and fully support it. Also vital to the effective implementation of the policy, is to tell the appropriate people of its content and their obligations under it. Where an organisation outsources some of its asset-related activities, then these people and their organisations must equally be made aware of the policy's content. Also, there may be other stakeholders, such as regulatory authorities and shareholders who should be made aware of it.	Top management. The management team that has overall responsibility for asset management.	The organisation's asset management policy, its organisational strategic plan, documents indicating how the asset management policy was based upon the needs of the organisation and evidence of communication.
10	Asset management strategy	What has the organisation done to ensure that its asset management strategy is consistent with other appropriate organisational policies and strategies, and the needs of stakeholders?	3	All key components of WELL's AM Strategy are covered in the AMP. Development of Fleet Strategies as well as the overarching AM Strategy has taken into consideration alignment with other organistaional policies and key stakeholders and has had peer review undertaken by industry experts.		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?	3	An Asset Management Strategy has been published to cover the total management of assets. Lifecycle Strategies have been developed for primary 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?	3	Flowing on from the abovementioned Asset Fleet Strategies, WELL has put in place comprehensive asset management plans (fleet strategies) that cover all lifecycle activities of the key asset classes, aligned to asset management objectives and strategies.		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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AMP Planning Period	**1 April 2022 – 31 March 2032**
Asset Management Standard Applied	

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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AMP Planning Period	1 April 2022 – 31 March 2032
Asset Management Standard Applied	

SCHEDULE 13: REPORT ON ASSET MANAGEMENT MATURITY (cont)

Question No.	Function	Question	Score	Evidence—Summary	User Guidance	Why	Who	Record/documented Information
27	Asset management plan(s)	How has the organisation communicated its plan(s) to all relevant parties to a level of detail appropriate to the receiver's role in their delivery?	3	The plan is communicated to all relevant employees, stakeholders, and contracted service providers to a level of detail appropriate to their participation or business interests in the delivery of the plan, and there is confirmation that they are being used effectively. All asset strategies are published as controlled documents.		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 documents responsibilities for the delivery actions, and appropriate detail is provided to enable delivery of these actions. Roles and responsibilities of individuals and organisational departments are defined.		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	WELL's plans are realistic in terms of the resources required and achievable timescales. They capture any changes required to policies, strategies, standards, processes and information systems.		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	WELL has a suite of appropriate Emergency Response Procedures and Contingency Plans in place to mitigate and manage the impact of potential High Impact Low Probability events. These are listed and described in Section 11 of this AMP. These plans get tested in simulated major event situations.		Widely used AM practice standards require that an organisation has plan(s) to identify and respond to emergency situations. Emergency plan(s) should outline the actions to be taken to respond to specified emergency situations and ensure continuity of critical asset management activities including the communication to, and involvement of, external agencies. This question assesses if, and how well, these plan(s) triggered, implemented and resolved in the event of an incident. The plan(s) should be appropriate to the level of risk as determined by the organisation's risk assessment methodology. It is also a requirement that relevant personnel are competent and trained.	The manager with responsibility for developing emergency plan(s). The organisation's risk assessment team. People with designated duties within the plan(s) and procedure(s) for dealing with incidents and emergency situations.	The organisation's plan(s) and procedure(s) for dealing with emergencies. The organisation's risk assessments and risk registers.

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AMP Planning Period	1 April 2022 – 31 March 2032
Asset Management Standard Applied	

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	Accountability for asset management responsibility flows from the CEO through the GM Asset Management, to the functional Line Managers.		In order to ensure that the organisation's assets and asset systems deliver the requirements of the asset management policy, strategy and objectives responsibilities need to be allocated to appropriate people who have the necessary authority to fulfil their responsibilities. (This question, relates to the organisation's assets eg, para b), s 4.4.1 of PAS 55, making it therefore distinct from the requirement contained in para a), s 4.4.1 of PAS 55).	Top management. People with management responsibility for the delivery of asset management policy, strategy, objectives and plan(s). People working on asset-related activities.	Evidence that managers with responsibility for the delivery of asset management policy, strategy, objectives and plan(s) have been appointed and have assumed their responsibilities. Evidence may include the organisation's documents relating to its asset management system, organisational charts, job descriptions of post-holders, annual targets/objectives and personal development plan(s) of post-holders as appropriate.
40	Structure, authority and responsibilities	What evidence can the organisation's top management provide to demonstrate that sufficient resources are available for asset management?	3	WELL has a suite of appropriate Emergency Response Procedures and Contingency Plans in place to mitigate and manage the impact of potential High Impact Low Probability events. These are listed and described in Section 11 of this AMP. These plans get tested in simulated major event situations.		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 the annual AMP disclosures, and through weekly and monthly meetings with management teams and service providers.		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?	3	WELL outsources a number of asset management activities, particularly with Service Delivery responsibilities. These are described in Section 4 of this AMP. Comprehensive contracts and performance measures are in place to ensure efficient and cost-effective delivery of these activities.		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	WELL can demonstrate that role descriptions are in place for all staff required to conduct asset management functions, and that these roles are filled with appropriately qualified personnel.		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	Position descriptions are in place for all staff required to conduct asset management functions. Staff undertake training and development where required to ensure they can deliver on the requirements of the AMP. Work competencies are listed for all main contracting activities, and WELL monitors and ensures that the Contractors' staff have, and maintain their competencies.		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	Training requirements are identified at the start of the year, and reviewed every six months during staff performance reviews. Work competencies are listed for all main contracting activities, and WELL monitors and ensures that the Contractors' staff have, and maintain their competencies.		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, Asset Management and Service Delivery Managers and the respective service providers. In addition specific asset management is communicated between employees and contractors through safety alerts, technical alerts, network instructions, and at technical forums.		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?	3	Asset Management documentation and control is in place, and is described in Section 4 of the AMP.		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	Asset Management information systems are in place, and these are listed and described in Section 10 of this AMP. They include SCADA, GIS and SAP. Support for these systems is provided by CHED Services.		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	Contols are are place in the form of data quality standards to manage the quality and accuracy of the data entered into the asset management information systems. Processes for QA and audit of data are in place.		The response to the questions is progressive. A higher scale cannot be awarded without achieving the requirements of the lower scale. This question explores how the organisation ensures that information management meets widely used AM practice requirements (eg, s 4.4.6 (a), (c) and (d) of PAS 55).	The management team that has overall responsibility for asset management. Users of the organisational information systems.	The asset management information system, together with the policies, procedure(s), improvement initiatives and audits regarding information controls.

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SCHEDULE 13: REPORT ON ASSET MANAGEMENT MATURITY (cont)

Question No.	Function	Question	Maturity Level 0	Maturity Level 1	Maturity Level 2	Maturity Level 3	Maturity Level 4
53	Communication, participation and consultation	How does the organisation ensure that pertinent asset management information is effectively communicated to and from employees and other stakeholders, including contracted service providers?	The organisation has not recognised the need to formally communicate any asset management information.	There is evidence that the pertinent asset management information to be shared along with those to share it with is being determined.	The organisation has determined pertinent information and relevant parties. Some effective two way communication is in place but as yet not all relevant parties are clear on their roles and responsibilities with respect to asset management information.	Two way communication is in place between all relevant parties, ensuring that information is effectively communicated to match the requirements of asset management strategy, plan(s) and process(es). Pertinent asset information requirements are regularly reviewed.	The organisation's process(es) surpass the standard required to comply with requirements set out in a recognised standard. The assessor is advised to note in the Evidence section why this is the case and the evidence seen.
59	Asset Management System documentation	What documentation has the organisation established to describe the main elements of its asset management system and interactions between them?	The organisation has not established documentation that describes the main elements of the asset management system.	The organisation is aware of the need to put documentation in place and is in the process of determining how to document the main elements of its asset management system.	The organisation in the process of documenting its asset management system and has documentation in place that describes some, but not all, of the main elements of its asset management system and their interaction.	The organisation has established documentation that comprehensively describes all the main elements of its asset management system and the interactions between them. The documentation is kept up to date.	The organisation's process(es) surpass the standard required to comply with requirements set out in a recognised standard. The assessor is advised to note in the Evidence section why this is the case and the evidence seen.
62	Information management	What has the organisation done to determine what its asset management information system(s) should contain in order to support its asset management system?	The organisation has not considered what asset management information is required.	The organisation is aware of the need to determine in a structured manner what its asset information system should contain in order to support its asset management system and is in the process of deciding how to do this.	The organisation has developed a structured process to determine what its asset information system should contain in order to support its asset management system and has commenced implementation of the process.	The organisation has determined what its asset information system should contain in order to support its asset management system. The requirements relate to the whole life cycle and cover information originating from both internal and external sources.	The organisation's process(es) surpass the standard required to comply with requirements set out in a recognised standard. The assessor is advised to note in the Evidence section why this is the case and the evidence seen.
63	Information management	How does the organisation maintain its asset management information system(s) and ensure that the data held within it (them) is of the requisite quality and accuracy and is consistent?	There are no formal controls in place or controls are extremely limited in scope and/or effectiveness.	The organisation is aware of the need for effective controls and is in the process of developing an appropriate control process(es).	The organisation has developed a controls that will ensure the data held is of the requisite quality and accuracy and is consistent and is in the process of implementing them.	The organisation has effective controls in place that ensure the data held is of the requisite quality and accuracy and is consistent. The controls are regularly reviewed and improved where necessary.	The organisation's process(es) surpass the standard required to comply with requirements set out in a recognised standard. The assessor is advised to note in the Evidence section why this is the case and the evidence seen.

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SCHEDULE 13: REPORT ON ASSET MANAGEMENT MATURITY (cont)

Question No.	Function	Question	Score	Evidence—Summary	User Guidance	Why	Who	Record/documented Information
64	Information management	How has the organisation's ensured its asset management information system is relevant to its needs?	3	Asset Management requirements were fully reviewed during development of the business case to implement SAP-PM, and to upgrade GIS ensuring that they meet Asset Management needs. The systems have been reviewed at various times by CHED auditors, Jacobs, PwC, and other external specialists.		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?	3	In January 2016, WELL aligned its risk approach with that of CKI by adopting the Enterprise Risk Management (ERM) – Integrated Framework Risk Management Principles and Guidelines Standard. This provides a structured and robust framework to managing risk, which is applied to all business activities.		Risk management is an important foundation for proactive asset management. Its overall purpose is to understand the cause, effect and likelihood of adverse events occurring, to optimally manage such risks to an acceptable level, and to provide an audit trail for the management of risks. Widely used standards require the organisation to have process(es) and/or procedure(s) in place that set out how the organisation identifies and assesses asset and asset management related risks. The risks have to be considered across the four phases of the asset lifecycle (eg, para 4.3.3 of PAS 55).	The top management team in conjunction with the organisation's senior risk management representatives. There may also be input from the organisation's Safety, Health and Environment team. Staff who carry out risk identification and assessment.	The organisation's risk management framework and/or evidence of specific process(es) and/ or procedure(s) that deal with risk control mechanisms. Evidence that the process(es) and/or procedure(s) are implemented across the business and maintained. Evidence of agendas and minutes from risk management meetings. Evidence of feedback in to process(es) and/or procedure(s) as a result of incident investigation(s). Risk registers and assessments.
79	Use and maintenance of asset risk information	How does the organisation ensure that the results of risk assessments provide input into the identification of adequate resources and training and competency needs?	3	Outputs from risk assessments are fed back into standards, procedures and training through the actions resulting from various meetings and other communications.		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	WELL has staff in its office that are responsible for Legal, Regulatory, Statutory and other asset management requirements.		In order for an organisation to comply with its legal, regulatory, statutory and other asset management requirements, the organisation first needs to ensure that it knows what they are (eg, PAS 55 specifies this in s 4.4.8). It is necessary to have systematic and auditable mechanisms in place to identify new and changing requirements. Widely used AM standards also require that requirements are incorporated into the asset management system (e.g. procedure(s) and process(es))	Top management. The organisations regulatory team. The organisation's legal team or advisors. The management team with overall responsibility for the asset management system. The organisation's health and safety team or advisors. The organisation's policy making team.	The organisational processes and procedures for ensuring information of this type is identified, made accessible to those requiring the information and is incorporated into asset management strategy and objectives

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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?	3	Consultants are often used to assist during the design stage. Scope of work is clearly defined and controlled through a Short Form Agreement. Procurement is controlled through an approved materials standard. Construction and commissioning activities are outsourced, and these are carefully controlled through contracts with the service providers.		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 an inspection and maintenance plan in place with remedial actions derived from the prioritisation of critical defects. Ongoing training is carried out to standardise the level of consistency across the inspection and condition assessment process, and how the results are then optimised within the maintenance planning function. These plans are reviewed and optimised on an annual basis.		Having documented process(es) which ensure the asset management plan(s) are implemented in accordance with any specified conditions, in a manner consistent with the asset management policy, strategy and objectives and in such a way that cost, risk and asset system performance are appropriately controlled is critical. They are an essential part of turning intention into action (eg, as required by PAS 55 s 4.5.1).	Asset managers, operations managers, maintenance managers and project managers from other impacted areas of the business	Documented procedure for review. Documented procedure for audit of process delivery. Records of previous audits, improvement actions and documented confirmation that actions have been carried out.
95	Performance and condition monitoring	How does the organisation measure the performance and condition of its assets?	3	WELL annually rates all assets against Asset Health Indicators that is based on the AHI's guideline published by the EEA. In addition WELL has developed Criticality indices to further inform the risks of each asset. This is used to measure the performance and condition of its assets. This is informed by the results of the inspection and maintenance programme conducted by its maintenance service provider at frequencies and according to procedures detailed in maintenance standards. The AHI & ACI analysis in turn assists with the update of the Fleet Strategies and replacement programmes.		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	WELL has procedures which clearly outline the roles and responsibilities for managing major incidents and emergency situations. The Asset Failure investigation standard describes the process and responsibilities for investigating asset-related failures.		Widely used AM standards require that the organisation establishes implements and maintains process(es) for the handling and investigation of failures incidents and non-conformities for assets and sets down a number of expectations. Specifically this question examines the requirement to define clearly responsibilities and authorities for these activities, and communicate these unambiguously to relevant people including external stakeholders if appropriate.	The organisation's safety and environment management team. The team with overall responsibility for the management of the assets. People who have appointed roles within the asset-related investigation procedure, from those who carry out the investigations to senior management who review the recommendations. Operational controllers responsible for managing the asset base under fault conditions and maintaining services to consumers. Contractors and other third parties as appropriate.	Process(es) and procedure(s) for the handling, investigation and mitigation of asset-related failures, incidents and emergency situations and non conformances. Documentation of assigned responsibilities and authority to employees. Job Descriptions, Audit reports. Common communication systems i.e. all Job Descriptions on Internet etc.

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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))?	3	CKI has internal auditors in CHED Services in Melbourne that select two areas to do comprehensive audits on each year. Further to this WELL has had its Asset Management activities and processes reviewed by Jacobs with a positive outcome and report.		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	Incident and root cause analysis investigations and corrective actions involve both WELL and its service providers, and are logged, reviewed and discussed at weekly & bi-weekly meetings. A package called 1Fics is used to track and keep information relating to all incidents and corrective actions until they have been completed and the incident closed out.		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?	3	The Asset Fleet Strategies detail asset-specific strategies for meeting the asset management objectives. These documents analyse the performance, and condition of assets across the whole life cycle, as well as maintenance and replacement costs, and any associated asset-related risks. They are controlled documents on an annual review cycle, with this update process ensuring that continual improvement in the management of asset performance, condition, costs, and risks.		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, WELL places a high level of importance on learnings that can be made from its sister companies within the group, and from within the industry in New Zealand. There are video conferences held between sister companies to discuss the latest in AM practices from across the world.		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.

Schedule 14a: Mandatory Explanatory Notes on Forecast Information

(In this Schedule, clause references are to the Electricity Distribution Information Disclosure Determination 2012 – as amended and consolidated 3 April 2018)

This Schedule provides for EDBs to provide explanatory notes to reports prepared in accordance with clause 2.6.6.

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

There is no difference between constant and nominal values in the current disclosure year ended 31 March 2022.

The difference from 2022/23 to 2031/32 represents inflation and is 2.0% per annum across the planning period.

The rates are based on the midpoint of the RBNZ's target inflation range.

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

There is no difference between constant and nominal values in the current disclosure year ended 31 March 2022.

The difference from 2022/23 to 2031/32 represents inflation and is 2.0% per annum across the planning period.

The rates are based on the midpoint of the RBNZ's target inflation range.

Appendix D Network Development Options

This section summarises the options considered for the major network constraints identified in Section 8.4-8.6.

Southern Area

Karori – 3/6 ring feeder capacity

The following options are being considered to resolve the expected future subtransmission constraint at Karori detailed in Section 8.4.3.

Option ID	Option Description	Cost ($M)	Complexity	Pros	Cons
A1I6-1	Upgrade approximately 2,137 m of cable	5.0	High	New cable sized for the existing and forecast load	High cost
A1I6-2	Transfer load to adjacent feeders. Allow for 200m 11 kV feeder changes and one new switching station	0.2	Moderate	Low cost balancing between feeders	
A1I6-3	Add a new feeder CB at the zone substation and install a new cable to connect to existing ring.	2.2	Moderate	A three feeder ring allows pre-contingency feeder loading to 67%, which improves available capacity and asset utilisation.	Higher cost compared to Option A1I6-4.
A1I6-4	Transfer Karori CB10 feeder cable to the Karori 3/6 feeder ring to improve capacity	0.4	Moderate	A three feeder ring allows pre-contingency feeder loading to 67%, which improves available capacity and asset utilisation.	Reduces Karori 8/10 feeder cable ring to a radial feeder supplied from Karori CB8

Palm Grove – 33/11 kV transformer capacity

The following options are being considered to resolve the 33/111 kV transformer constrain t at Palm Grove detailed in Section 8.4.2.8.

Option ID	Option Description	Cost ($M)	Complexity	Pros	Cons
A2I3-1	Upgrade PAL transformer capacity - replace existing with 36 MVA units.	4.5	Moderate	Lift Palm Grove transformer constraints, improve branch rating to 36 MVA, resolve acoustic issues at site.	
A2I3-2	Transfer some Palm Grove load to Hataitai through a new tie point at hospital	0.6	Moderate	Opportunity to coordinate with customer projects - Wellington hospital expansion	Customer has signalled in 2019 that we have funding issues to improve capacity or security, it is likely to be within the same timeline
A2I3-3	Battery Storage	4.0	Moderate	Resiliency improvement if installed at a remote location	High cost and limited lifetime

Palm Grove – 8/10/12 ring feeder capacity

The following option is being considered to resolve the existing Palm Grove 8/10/12 distribution ring feeder constraint detailed in Section 8.4.3.

Option ID	Option Description	Cost ($M)	Complexity	Pros	Cons
A2I4-1	New feeder tie between Palm Grove 11 kV feeders 8 and 11.	1.4	Moderate	Coordinate reinforcement with customer developments	

Palm Grove – 2/3/6 ring feeder capacity

The following option is being considered to resolve the existing Palm Grove 8/10/12 distribution ring feeder constraint detailed in Section 8.4.3.

Option ID	Option Description	Cost ($M)	Complexity	Pros	Cons
A2I9-1	Enable shifting open points via SCADA on Palm Grove 2/3/6 ring for post contingency load management	0.8	Moderate	Interim low cost solution to defer major investment	
A2I9-2	Reconfigure and upgrade Palm Grove 2/3/6 ring to transfer some load transfer to Nairn Street 8/12 ring	2.0	Low	Longer term solution to balance load between zone substations	

University – feeder CB12 capacity

The following options are being considered to resolve the expected future University distribution feeder CB12 constraint detailed in Section 8.4.3.

Option ID	Option Description	Cost ($M)	Complexity	Pros	Cons
A1I10-1	Upgrade constraining cable section	0.5	Moderate	New cable sized for the existing and forecast load	
A1I10-2	Reconfigure the University 11 kV feeders to balance load across the 11 kV bus	0.9	Low	Utilise existing assets to balance load across the 11 kV bus	

Northwestern Area

Johnsonville – 33 kV subtransmission and 33/11 kV transformer capacity

The following options are being considered to resolve the 33 kV subtransmission and 33/11 kV transformer constraints at Johnsonville detailed in Section 8.5.2.1.

Option ID	Option Description	Cost ($M)	Complexity	Pros	Cons
B1I2-1	Upgrade Johnsonville transformer capacity - replace existing transformers with 36 MVA units.	5.0	Moderate		Leads to a high-capacity JOH substation that is difficult to back up.
B1I3-1	Replace existing JOH 33 kV cable with 1000mm^2 Al XLPE cables, approximately 5km while retaining the existing subtransmission circuit configuration.	8.0	Moderate		
B1I2-2	Upgrade Ngauranga transformer capacity – Option B1I7-2	2.0	Moderate	The option resolves and/or delays a number of issues: - NGA transformer capacity issue, - NGA transformer condition issue, - JOH 6 capacity issue, - KAI 6/7/9/10 ring feeder capacity, - delay JOH transformer capacity issue, - delay KAI GXP transformer capacity issue, and - provides more capacity to back up JOH	

Option ID	Option Description	Cost ($M)	Complexity	Pros	Cons
B1I2-3	Develop Grenada North zone substation supplied from first TKR-KDH line section. Upgrade 11kV ties to supply Ngauranga and Johnsonville from Grenada.	20.0	High	Avoids the high maintenance cost and safety risks associated with the existing TKR-KDH tower line. It improves reliability and utilisation of the subtransmission circuits into the subregion. The option improves reliability by addressing the existing condition and capacity issues of the JOH cables, the 33/11 kV transformers in the subregion. The option can be delivered in stages therefore delays need for immediate upgrade of Tawa ZS and re-establishment of Ngauranga ZS. Provide capacity for the Churton Park and Grenada North growth areas between Tawa and JOH currently served by a rural feeder that is already at capacity while improving reliability by providing better transfer capability between zone substations.	Still need a zone substation at Ngauranga to back up Johnsonville and to limit the size of Johnsonville zone substation. Difficult cable routes including crossing SH1.
B1I3-3	New GRE - JOH Cable instead of TKR - JOH, terminate one of the existing 33kV circuits to GRE bus.	8.0	Moderate		Reduced redundancy

Kenepuru – 33 kV subtransmission capacity

The following options are being considered to resolve the forecast 33 kV subtransmission constraint at Kenepuru detailed in Section 8.5.2.2.

Option ID	Option Description	Cost ($M)	Complexity	Pros	Cons
B2I1-1	Transfer load to adjacent Porirua zone substation after more capacity is created at Porirua	0.1	High	Minimise the impact at Kenepuru Use additional capacity introduced by Porirua which is a centralised solution for the area	No capacity margin at the adjacent zone sub
B2I1-2	Resolve pinch point along the cable route to resolve summer constraints	1.5	Moderate		
B2I1-3	Replace existing 240mm^2 Kenepuru 33kV cable with 1000mm^2 Al XLPE cables, approx. 770m.	2.5	Moderate		SH1 crossing

Ngauranga – 33 kV subtransmission and 33/11 kV transformer capacity

The following options are being considered to resolve the expected 33 kV subtransmission and 33/11 kV transformer constraints at Ngauranga detailed in Section 8.5.2.3.

Option ID	Option Description	Cost ($M)	Complexity	Pros	Cons
B1I1-1	Replace the existing TKR-KDH line supplying Ngauranga with a 33kV pole line following the same route. This project would be a Transpower project but WELL would still need to allocate cost for secondary assets replacement and rectify the limitations on the current one way inter-trippng scheme. 33kV CBs will be decommissioned after project completion	0.7	High	This option retains Ngauranga zone substation which will provide backup to Johnsonville, pick up some of Kaiwharawhara load off Station Road (Abattoirs) and continue supplying existing Ngauranga load. The new pole line avoids the high maintenance cost associated with the existing tower line. The new line will be appropriately rated to serve existing and forecast load; and can also be used to supply Grenada North in the future.	Retains the entire load for the subregion at Takapu Road GXP and the radial 33kV subtransmission circuits. Future load growth is forecast towards the north and this option reinforces capacity away from the centre of load growth requiring significant reinforcement of 11 kV feeders to supply the growth areas.
B1I1-2	Convert Ngauranga to an 11kV switching station supplied from Johnsonville. Upgrade the TKR-JOH cable and 33/11 kV transformers; and upgrade 11kV ties to supply NGA from JOH.		High	Low initial cost	Still need a zone substation at Ngauranga to back up, and limit the size of, Johnsonville zone substation. Increases the criticality of Johnsonville zone substation.
B1I1-3	Build a 33kV bus at Johnsonville to supply both Johnsonville and Ngauranga, bring forward TKR-JOH cable replacement and develop new 33 kV JOH-NGA circuits.		High	Avoids the high maintenance cost associated with the existing tower line. The option improves reliability by addressing the existing capacity and improves utilisation of TKR-JOH overhead circuits. The option also addresses the capacity and condition of the 33/11 kV transformers in the subregion.	Retains the entire load for the area at Takapu Road GXP and it is not easy to build on this option to cater for future growth. Load growth may lead to reliance on two 33 kV subtransmission circuits to carry more than 60 MVA of load leading to high consequence of failure.
B1I1-4	Supply Ngauranga from Kaiwharawhara at 33 kV – Replace existing Kaiwharawhara transformers with 110/33/11kV units and install 33 kV cables to NGA.		High	Avoids the high maintenance cost associated with the existing TKR-KDH tower line. The option improves reliability by addressing the existing capacity issues of the Johnsonville cables and the 33/11 kV transformers in the area It diversifies the GXPs supplying the area by shifting load away from Takapu Road.	Reinforces capacity away from the centre of the load growth area. It will be difficult to obtain access to the line corridor currently used for the TKR-KDH line once it has been relinquished. Load growth may lead to need for significant reinforcement of 11 kV feeders to supply the Grenada North and Churton Park growth areas.

Option ID	Option Description	Cost ($M)	Complexity	Pros	Cons
B1I1-5	Develop Grenada zone substation supplied from first TKR-KDH line section. Upgrade 11kV ties to supply Ngauranga and Johnsonville from Grenada. This is linked to the Johnsonville 33kV cable upgrade, which would provide a bus and 11kV feeders along a new 33kV cable route	20.0	High	Avoids the high maintenance cost associated with the existing TKR-KDH tower line. The option improves reliability by addressing the existing capacity issues of the Johnsonville cables and the 33/11 kV transformers in the area. The option can be delivered in stages therefore delays need for immediate upgrade of Tawa ZS and re-establishment of Ngauranga ZS. Provide capacity for the Churton Park and Grenada North growth areas between Tawa and Johnsonville currently served by a rural feeder that is already at capacity while improving reliability by providing better transfer capability between zone substations.	Still need a zone substation at Ngauranga to back up, and limit the size of, Johnsonville zone substation. Difficult cable routes including crossing SH1.
B1I1-5	Upgrade NGA transformer capacity - replace existing with 24MVA units.	4.5	Moderate	Addresses issue and caters for load growth	

Ngauranga – 11 kV feeder capacity

The following option is being considered to resolve the expected future Ngauranga 11 kV distribution feeder constraint detailed in Section 8.5.3.

Option ID	Option Description	Cost ($M)	Complexity	Pros	Cons
B1I19-1	New 11 kV feeders from Ngauranga Zone Substation	1.7	Moderate	Addresses issue and caters for load growth	
B1I19-2	Upgrade 11 kV cable section on Ngauranga 4 feeder approx. 320m	0.4	Moderate	Addresses issue and caters for load growth	

Mana – Zone Substation supply capacity

The following options are being considered to resolve the 11 kV bus tie constraint at Mana detailed in Section 8.5.2.4.

Option ID	Option Description	Cost ($M)	Complexity	Pros	Cons
B3I3-1	Install a second transformer and 11 kV bus section at Mana, 33 kV bus Plimmerton and a new 33 kV circuit from Plimmerton to Mana.	12.0	Moderate		Limited space on the site, high cost.
B3I3-2	Upgrade the Mana-Plimmerton 11 kV bus-tie: install a second cable in parallel with the existing after Plimmerton has a second TX. This will ensure spare Subtransmission is available from Plimmerton	4.5	High	Increase the N-1 Mana capacity to 14 MVA or the remaining capacity at Plimmerton, whichever is lower	Only can build on top of the Plimmerton second transformer solution
B3I3-3	Establish new 11 kV GXP at Pauatahanui and transfer some of Mana load to Pauatahanui - replace existing PNI supply transformers with 2 x 110/33/11 kV transformers and build 11kV ties to connect existing MAN 2 feeder (approximately 2 km of 11 kV cable).	2.8 + 8.0 TP pass through	Moderate		Depends on Transpower plans to be viable
B3I3-4	Reinforce 11 kV feeders to enable load transfer from Mana to Porirua and Plimmerton after their upgrade. Mana will be used to supply the remaining load and pick up more load from Titahi Bay	4.0	Moderate	Reduce Mana load and improve connectivity on all nearby subs	Depends on other zone substation upgrades
B3I3-5	Install a new 11 kV feeder from Porirua - Mana and a 33 kV ring from Porirua to Plimmerton	8.0	High	Reliability and also reduce loading on MAN bus	Cost and complexity

Plimmerton – Zone Substation supply capacity

The following options are being considered to resolve the 11 kV bus tie constraint at Plimmerton detailed in Section 8.5.2.5.

Option ID	Option Description	Cost ($M)	Complexity	Pros	Cons
B3I2-1	Install a 33 kV bus, a second 24 MVA transformer and a second 11kV bus section at PLI. This will introduce a N-1 firm rating of 16 MVA at PLI and ensures spare capacity is available to MAN during a TX outage at MAN	8	High	A 33 kV bus will further increase the ability to supply the new load around PLI farm and northern areas. This can be triggered by the customer project development	
B3I2-2	Upgrade the MAN-PLI 11 kV bus-tie: install a second cable in parallel with the existing.	4.5	High	Increase the bus tie cable to 14 MVA	The actual available capacity from MAN is still limited to 16 MVA less the MAN load, which is only around 7 MVA
B3I2-3	Establish new 11 kV GXP at PNI and transfer some of PLI load to PNI - replace existing PNI 2winding supply transformers with 2 x 110/33/11 kV three winding transformers and build 11 kV ties to connect existing PLI11 feeder (approximately 50m of 11kV cable).	2.8 + 8.0 TP pass through	High		Depends on Transpower plans to be viable

Porirua – 33 kV subtransmission and 33/11 kV transformer capacity

The following options are being considered to resolve the 33 kV subtransmission and 33/11 kV transformer constraints at Porirua detailed in Section 8.5.2.6.

Option ID	Option Description	Cost ($M)	Complexity	Pros	Cons
B2I2-1	A complete upgrade of the Porirua 33kV cable, transformers, and switchboard, for a site N-1 capacity of 36MVA	16.0	High	Provides capacity for the existing and future load at Porirua. The upgraded zone substation improves supply security by providing improved offload options for adjacent ZS.	Complex project co-ordination and risk control in project delivery when working on existing assets. Reduced supply security during changeover. The option increases criticality of the ZS assets.
B2I2-2	Transfer load to adjacent ZS (WTG, KEN)	0.1	Moderate	Low cost	No capacity margin at the adjacent ZS
B2I2-3	Develop new ZS with 33kV bus at Cannons Creek and supply some of POR load to avoid need for upgrade at POR	23.0	High	Addresses existing capacity issues at POR– reduces loading on the 33kV cables and transformers and releases capacity for growth	A new ZS dependent on land availability in the preferred location (discuss opportunity with HNZ as they may be able to help in securing land for the ZS)

Porirua – Titahi Bay 11 kV ring feeder capacity

The following options are being considered to resolve the Porirua – Titahi Bay 11 kV ring feeder constraint detailed in Section 8.5.3.

Option ID	Option Description	Cost ($M)	Complexity	Pros	Cons
B2I6-1	New 11kV cross-harbour cable from Porirua Zone Substation to Titahhi Bay substation	3.0	High	Opportunity to coordinate with council and utilities who also need to bring infrastructure to TIT.	Complex project scope and onerous consenting process.
B2I6-2	Replace existing TIT SubT 33kV oil filled cables with 2x 800mm2 AL XLPE, approx. 5km	8.0	Moderate	Removes oil filled cable condition risk	High cost
B2I6-3	Install a new 33 kV zone substation at Titahi Bay with 33 kV subtransmission connection from Porirua zone substation 33 kV bus at Porirua	15.0	High	Reduces loading at Porirua zone substation	High cost
B2I6-4	Install an 1MW Gen or a battery storage in TIT bay to provide extra capacity	4.0	Moderate	Increased reliability and reduces loading at Porirua zone substation	New technology, noise from generator and lifetime of battery

Porirua – 11 kV distribution feeder capacity

The following options are being considered to resolve the Porirua 11 kV distribution feeder constraint detailed in Section 8.5.3.

Option ID	Option Description	Cost ($M)	Complexity	Pros	Cons
B2I4-1	Upgrade constrained 11 kV feeder cable sections on the Porirua 4/5 ring feeder	2.0	Moderate		
B2I4-2	Add a new feeder to Porirua 4/5 feeder ring extend it about 0.9 km to form a three-feeder ring	1.4	Moderate	Provides additional feeder capacity and allows better utilisation of the assets as this raises security limit for the ring to 67% pre-contingency loading.	Rail corridor crossing
B2I4-3	Load balance between Porirua 11 kV distribution feeders	0.0	Low		No capacity margin at the adjacent feeders.
B2I5-1	Upgrade constrained 11 kV feeder cable sections on the Porirua CB6 feeder	1.7	Moderate		

Option ID	Option Description	Cost ($M)	Complexity	Pros	Cons
B2I5-2	Install an extra CB at 19 Parumoana to split the existing Porirua feeder 6 into two separate feeders	0.4	High	Utilises the extra capacity on POR 4/5 after upgrade	
B2I5-3	Transfer some of the Porirua feeder 6 load to Kenepuru.	0.1	Low	The option allows higher utilisation of the existing feeders.	Retrofitting differential protection to POR 6 will be complex and expensive

Tawa – 33/11 kV transformer capacity

The following options are being considered to resolve the forecast 33/11 kV transformer constraint at Tawa detailed in Section 8.5.2.7.

Option ID	Option Description	Cost ($M)	Complexity	Pros	Cons
B1I5-1	Same as B1I1-5 – Grenada Zone Substation				
B1I5-2	Upgrade TAW transformer capacity to 2x 24 MVA units.	4.5	Moderate	Addresses existing issue and caters for load growth	

Tawa –11 kV distribution feeder capacity

The following options are being considered to resolve the existing Tawa 11 kV distribution feeder constraint detailed in Section 8.5.3.

Option ID	Option Description	Cost ($M)	Complexity	Pros	Cons
B1I6-1	New 11 kV feeder and 11 kV feeder reconfiguration	1.2	Moderate	Addresses existing issue and caters for load growth	
B1I6-2	Upgrade constraining cable section	1.0	Moderate	Defers need for feeder upgrade	Insufficient capacity for future load growth
B1I6-3	Balance load between Tawa distribution feeders	0.1	Low		

Waitangirua – 33 kV subtransmission and 33/11 kV transformer capacity

The following options are being considered to resolve the forecast future 33 kV subtransmission and 33/11 kV transformer constraints at Waitangirua detailed in Section 8.5.2.8.

Option ID	Option Description	Cost ($M)	Complexity	Pros	Cons
B2I7-1	Upgrade Waitangirua transformer capacity to 2 x 30 MVA units	4.0	Moderate		
B2I8-1	Upgrade Waitangirua subtransmission capacity - replace cable with 1000mm^2 Al XLPE, approx. 1.4 km	4.0	Moderate		
B2I7-2/ B2I8-2	B2I2-1 - complete upgrade of the Porirua zone substation	16.0	High	Avoids upgrade of Waitangirua.	
B2I7-3/ B2I8-3	Establish new 11 kV GXP at Pauatahanui and transfer some of Waitangirua load to new sub	2.0 + 8.0 pass through	Moderate	Avoids upgrade of Waitangirua and release capacity at Waitangirua to back up Porirua.	Pauatahanui is located further east of the load centre than would be optimal.

Waitangirua –11 kV distribution feeder capacity

The following options are being considered to resolve the existing Waitangirua 11 kV distribution feeder constraint detailed in Section 8.5.3.

Option ID	Option Description	Cost ($M)	Complexity	Pros	Cons
B1I9-1	Upgrade constraining cable section	4.0	Moderate	Addresses existing issue	Keep all load growth in the Whitby area on Waitangirua, which will result in need for upgrade of upstream circuits.
B1I9-2	Balance load between Waitangirua distribution feeders	0.1	Low	Defers need for feeder upgrade	Insufficient capacity for future load growth
B1I9-3	Transfer some Waitangirua feeder 5 and 11 load to new feeders	1.8	Moderate	Addresses existing issue and caters for future load	

Northeastern Area

Korokoro – 33 kV subtransmission and 33/11 kV transformer capacity

The following options are being considered to resolve the 33 kV subtransmission and 33/11 kV transformer constraints at Korokoro detailed in Section 8.6.2.4.

Option ID	Option Description	Cost ($M)	Complexity	Pros	Cons
C1I1-1	Transfer some of Petone load away to Melling using the deenergised Petone 33 kV cable at 11 kV. Split the Petone 11 kV bus with one half supplied from Korokoro and the other from Melling.	1.2	Moderate	Delays need for upgrading the Korokoro subtransmission cables, enable about 4.5 MVA of load transferable between GFD GXP and MLG GXP	Reuse the 33 kV gas filled cable and relying on a solution that is prone to aging failure
C1I1-2	Replace Korokoro subtransmission cables, approx. 5.2km	8.0	Moderate	New cables and the supply can come from MLG instead of GRA.	High Cost, cable route follows The Esplanade.
C1I1-3	Re-establish Petone 33 kV zone substation, new 33 kV transformers, cables and pick up some of Korokoro load	15	Moderate	Avoids need to upgrade Korokoro subtransmission cables	High cost, requires replacing the Petone 33 kV cables and re-establishing two previously relinquished 33 kV connections at Melling.
C1I1-4	Remove 33 kV subtransmission cable capacity constraints outside Seaview zone substation	0.6	Low	Delays need for upgrading the Korokoro subtransmission cables	
C1I2-1	Upgrade Korokoro transformers - replace existing with 36 MVA units. Also need to replace 11kV board with 2000 A incomers	7.0	Moderate	Introduce new capacity to the Korokoro area	High Cost

Gracefield –11 kV distribution feeder CB9 capacity

The following options are being considered to resolve the future Gracefield 11 kV distribution feeder CB9 constraint detailed in Section 8.5.3.

Option ID	Option Description	Cost ($M)	Complexity	Pros	Cons
C2I8-1	Upgrade limiting cable section of Gracefield feeder 9 with higher capacity cable	3.0	Medium	Addresses existing issue and caters for future load	

Seaview – 33 kV subtransmission and 33/11 kV transformer capacity

The following options are being considered to resolve the 33 kV subtransmission constraint at Seaview detailed in Section 8.6.2.8.

Option ID	Option Description	Cost ($M)	Complexity	Pros	Cons
C1I8-1	Rebalance load between Seaview and Gracefield.	0.1	Low	Low cost balancing between zones.	Does not increase capacity in the area.
C1I8-2	Replace Seaview 33 kV PILC cables, 1.5km	3.0	Moderate	Release existing transformer capacity.	Cables in good condition.
C1I8-3	C1I1-4 - Remove 33kV subtransmisison cable capacity constraints outside Seaview zone substation	0.6	Low	Delays need for upgrading the Seaview subtransmission cables	

Appendix E Summary of AMP Coverage of Information Disclosure Requirements

Information Disclosure Requirements 2012 clause	AMP section
3.1 A summary that provides a brief overview of the contents and highlights information that the **EDB** considers significant	1
3.2 Details of the background and objectives of the **EDB**'s asset management and planning processes	4.1, 4.2
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	2.1
3.3.2 states the corporate mission or vision as it relates to asset management	3.1
3.3.3 identifies the documented plans produced as outputs of the annual business planning process adopted by the **EDB**	4.1
3.3.4 states how the different documented plans relate to one another, with particular reference to any plans specifically dealing with asset management	4.1
3.3.5 includes a description of the interaction between the objectives of the **AMP** and other corporate goals, business planning processes, and plans	3.1
3.4 Details of the **AMP planning period**, which must cover at least a projected period of 10 years commencing with the **disclosure year** following the date on which the **AMP** is disclosed	2
3.5 The date that it was approved by the **directors**	2
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	3.6.1
3.6.2 what these interests are	3.6.1
3.6.3 how these interests are accommodated in asset management practices	3.6.1
3.6.4 how conflicting interests are managed	3.6.2

Information Disclosure Requirements 2012 clause	AMP section
3.7 A description of the accountabilities and responsibilities for asset management on at least 3 levels, including-	
3.7.1 governance—a description of the extent of **director** approval required for key asset management decisions and the extent to which asset management outcomes are regularly reported to **directors**	3.2.2, 3.2.4.1
3.7.2 executive—an indication of how the in-house asset management and planning organisation is structured	3.2.3 & 3.2.5
3.7.3 field operations—an overview of how field operations are managed, including a description of the extent to which field work is undertaken in-house and the areas where outsourced contractors are used	3.2.5 & 4.3.1
3.8 All significant assumptions:	
3.8.1 quantified where possible	Appendix A
3.8.2 clearly identified in a manner that makes their significance understandable to interested persons, including	Appendix A
3.8.3 a description of changes proposed where the information is not based on the **EDB**'s existing business	Appendix A
3.8.4 the sources of uncertainty and the potential effect of the uncertainty on the prospective information	Appendix A
3.8.5 the price inflator assumptions used to prepare the financial information disclosed in **nominal New Zealand dollars** in the Report on Forecast Capital Expenditure set out in Schedule 11a and the Report on Forecast Operational Expenditure set out in Schedule 11b.	Schedule 14a
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	1.3-1.4, 9.4, 9.6 & Appendix A
3.10 An overview of asset management strategy and delivery	4.1, 4.3
3.11 An overview of systems and information management data	10.1
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	10.3

Information Disclosure Requirements 2012 clause	AMP section
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.	 7.4, 10.1.1.8 8.2 5.2.2
3.14 An overview of asset management documentation, controls and review processes	4.4
3.15 An overview of communication and participation processes	3.6, 5.4.1
3.16 The **AMP** must present all financial values in **constant price New Zealand dollars** except where specified otherwise;	2.4
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.	5.2, 4.2, 7 & 8
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.	 3.3 3.4 3.5 3.5 & 8.2 3.5

Information Disclosure Requirements 2012 clause	AMP section
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;	3.4
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;	3.4, 8.4–8.6
4.2.3 a description of the distribution system, including the extent to which it is underground;	3.4, 7.5.4
4.2.4 a brief description of the **network**'s distribution substation arrangements;	3.4, 7.5.5
4.2.5 a description of the **low voltage network** including the extent to which it is underground; and	3.4, 7.5.4
4.2.6 an overview of secondary assets such as protection relays, ripple injection systems, SCADA and telecommunications systems.	7.5.8
4.3 If **sub-networks** exist, the **network** configuration information referred to in subclause 4.2 above must be disclosed for each **sub-network**.	N/A
Network assets by category	
4.4 The **AMP** must describe the **network** assets by providing the following information for each asset category-	
4.4.1 voltage levels;	3.4, 7.5
4.4.2 description and quantity of assets;	7.1
4.4.3 age profiles; and	7.5
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.	7.5

Information Disclosure Requirements 2012 clause	AMP section
4.5 The asset categories discussed in subclause 4.4 above should include at least the following-	
4.5.1 Subtransmission	7.5.1
4.5.2 Zone substations	7.5.2
4.5.3 Distribution and LV lines	7.5.3
4.5.4 Distribution and LV cables	7.5.4
4.5.5 Distribution substations and transformers	7.5.5
4.5.6 Distribution switchgear	7.5.6, 7.5.7
4.5.7 Other system fixed assets	7.5.8
4.5.8 Other assets;	7.5.9
4.5.9 assets owned by the **EDB** but installed at bulk electricity supply points owned by others;	7.5.10
4.5.10 **EDB** owned mobile substations and generators whose function is to increase supply reliability or reduce peak demand; and	7.5.9.2
4.5.11 other generation plant owned by the **EDB**.	7.5.9.2
Service Levels 5. The **AMP** must clearly identify or define a set of performance indicators for which annual performance targets have been defined. The annual performance targets must be consistent with business strategies and asset management objectives and be provided for each year of the **AMP planning period**. The targets should reflect what is practically achievable given the current **network** configuration, condition and planned expenditure levels. The targets should be disclosed for each year of the **AMP planning period**.	5
6. Performance indicators for which targets have been defined in clause 5 above must include **SAIDI** and **SAIFI** values for the next 5 **disclosure years**.	6.1
7. Performance indicators for which targets have been defined in clause 5 above should also include-	
7.1 **Consumer** oriented indicators that preferably differentiate between different consumer types;	5.5
7.2 Indicators of asset performance, asset efficiency and effectiveness, and service efficiency, such as technical and financial performance indicators related to the efficiency of asset utilisation and operation.	5.4, 7.5
8. The **AMP** must describe the basis on which the target level for each performance indicator was determined. Justification for target levels of service includes **consumer** expectations or demands, legislative, regulatory, and other stakeholders' requirements or considerations. The **AMP** should demonstrate how stakeholder needs were ascertained and translated into service level targets.	5, 6.1

Information Disclosure Requirements 2012 clause	AMP section
9. Targets should be compared to historic values where available to provide context and scale to the reader.	5
10. Where forecast expenditure is expected to materially affect performance against a target defined in clause 5 above, the target should be consistent with the expected change in the level of performance.	6
<u>**Network Development Planning**</u> 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;	8.1,8.2
11.2 Planning criteria for network developments should be described logically and succinctly. Where probabilistic or scenario-based planning techniques are used, this should be indicated and the methodology briefly described;	8.1, 8.2
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;	8.1.6
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.	 7.2 & 8.1.6 7.2 & 8.1.6
11.5 A description of strategies or processes (if any) used by the **EDB** that promote the energy efficient operation of the **network**.	8.1.7
11.6 A description of the criteria used to determine the capacity of equipment for different types of assets or different parts of the **network**.	8.1.10
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.	4.2

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;	8.2.1
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;	8.4-8.6
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	8.4-8.6
11.8.4 discuss the impact on the load forecasts of any anticipated levels of **distributed generation** in a **network**, and the projected impact of any demand management initiatives.	8.1.9
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.	Appendix D
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;	8.4-8.7
11.10.2 a summary description of the programmes and projects planned for the following four years (where known); and	8.4-8.7
11.10.3 an overview of the material projects being considered for the remainder of the **AMP planning period**.	8.4-8.7
11.11 A description of the **EDB**'s policies on **distributed generation**, including the policies for connecting **distributed generation**. The impact of such generation on network development plans must also be stated.	8.1.9
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	8.1.8
11.12.2 the potential for non-network solutions to address **network** problems or constraints.	8.1.8

Information Disclosure Requirements 2012 clause	AMP section
<u>Lifecycle Asset Management Planning (Maintenance and Renewal)</u>	
12. The **AMP** must provide a detailed description of the lifecycle asset management processes, including—	
12.1 The key drivers for maintenance planning and assumptions;	7.4 & 7.5
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;	7.5
12.2.2 any systemic problems identified with any particular asset types and the proposed actions to address these problems; and	7.5
12.2.3 budgets for maintenance activities broken down by asset category for the **AMP planning period**.	7.6
12.3 Identification of **asset replacement and renewal** policies and programmes and actions to be taken for each asset category, including associated expenditure projections. This must include-	
12.3.1 the processes used to decide when and whether an asset is replaced or refurbished, including a description of the factors on which decisions are based, and consideration of future demands on the network and the optimum use of existing network assets;	7.2, 7.5
12.3.2 a description of innovations made that have deferred asset replacement;	7.5
12.3.3 a description of the projects currently underway or planned for the next 12 months;	7.5
12.3.4 a summary of the projects planned for the following four years (where known); and	7.5
12.3.5 an overview of other work being considered for the remainder of the **AMP planning period**.	7.5–7.6
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.	Yes
<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;	10.1-10.6
13.2 development, maintenance and renewal policies that cover them;	10.4–10.6
13.3 a description of material capital expenditure projects (where known) planned for the next five years;	10.4
13.4 a description of material maintenance and renewal projects (where known) planned for the next five years.	10.7

Information Disclosure Requirements 2012 clause	AMP section
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; 14.3 A description of the policies to mitigate or manage the risks of events identified in sub clause 14.2; 14.4 Details of emergency response and contingency plans.	4.7 11.4 4.7.3, 11.4 11.3
15. AMPs must provide details of performance measurement, evaluation, and improvement, including— 15.1 A review of progress against plan, both physical and financial;	Appendix B
15.2 An evaluation and comparison of actual service level performance against targeted performance;	5
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.	4.5
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.	4.5
Capability to Deliver 16. **AMPs** must describe the processes used by the **EDB** to ensure that- 16.1 The AMP is realistic and the objectives set out in the plan can be achieved; 16.2 The organisation structure and the processes for authorisation and business capabilities will support the implementation of the AMP plans.	1.7 3.2

Appendix F Glossary of Abbreviations

AAC	All Aluminium Conductor
AAAC	All Aluminium Alloy Conductor
ABS	Air Break Switch
ACSR	Aluminium Conductor Steel Reinforced
ADMS	Advanced Distribution Management System
ADSS	All Dielectric Self Supporting
ACI	Asset Criticality Indicator
AHI	Asset Health Indicator
AMI	Advanced Metering Infrastructure
ANM	Advanced Network Management
BRMP	Business Recovery Management Plan
Capex	Capital Expenditure
CB	Circuit Breaker
CBD	Central Business District
CCT	Covered Conductor Thick
CDEMA	Civil Defence and Emergency Management Amendment Act (2016)
CEO	Chief Executive Officer
CIA	Cyber Security and Data Confidentiality, Integrity and Availability
CIC	Capital Investment Committee
CKI	CK Infrastructure Holdings Limited
CMP	Crisis Management Plan
CPI	Consumer Price Index
CPP	Customised Price Path
CPRG	Constant Price Revenue Growth
CT	Current Transformer
Cu	Copper
DC	Direct Current
DER	Distributed Energy Resources
DG	Distributed Generation
DGA	Dissolved Gas Analysis
DMS	Distribution Management System
DNO	Distribution Network Operator
DP	Degree of Polymerisation
DPP	Default Price-quality Path
DR	Demand Response
DSA	Detailed Seismic Assessment
DSO	Distribution System Operator
DTS	Distributed Temperature Sensing
EDB	Electricity Distribution Business

EDO	Expulsion Drop-out Fuse
EEA	Electricity Engineers Association
EECA	Energy Efficiency and Conservation Authority
EEP	Emergency Evacuation Plan
EIPC	Electricity Industry Participation Code
EMS	Energy Management System
ENA	Electricity Network Association
ENMAC	Electricity Network Management and Control
ERP	Emergency Response Plan
ESO	Energy System Operator
ETR	Estimated Time of Restoration
EV	Electric Vehicle
FDIR	Fault Detection, Isolation and Restoration
FPI	Fault Passage Indicators
GWh	Gigawatt Hour
GIS	Geographical Information System
GXP	Grid Exit Point
HCC	Hutt City Council
HILP	High Impact Low Probability
HLR	High Level Request/Response
HSE	Health, Safety and Environmental
HSW	Health and Safety Work Act (2015)
HV	High Voltage
ICP	Installation Control Point
IEEE	Institute of Electrical and Electronic Engineers
IISC	International Infrastructure Services Company (NZ Branch)
IEP	Initial Evaluation Procedure of Seismic Assessment
IPS	Intruder Prevention System
ISO	International Standards Organisation
IoT	Internet of Things
IIoT	Industrial Internet of Things
IT	Information Technology
ITRP	Information Technology Recovery Plan
km	Kilometre
KPI	Key Performance Indicator
kV	Kilovolt
kVA	Kilovolt Ampere
kW	Kilowatt
kWh	Kilowatt hour
LED	Light Emitting Diode
LEVCF	EECA's Low Emission Vehicle Contestable Fund

LTI	Lost time injury
LTIFR	Lost time injuries per 1,000,000 hours worked
LV	Low Voltage
LVABC	Low Voltage Aerial Bundled Conductor
MAR	Maximum Allowable Revenue
MBIE	Ministry of Business Innovation and Employment
MEMP	Major Event Management Plan
MEFRP	Major Event Field Response Plan
MEUG	Major Electricity Users Group
MUoSA	Model Use of System Agreement
MW	Megawatt
MWFM	Mobile Workforce Management
MVA	Megavolt Ampere
NBS	New Building Standard
NCR	Network Control Room
NDP	Network Development Plan
NICAD	Nickel Cadmium Battery
NIWA	National Institute of Water and Atmospheric Research
NPV	Net Present Value
NZTA	New Zealand Transport Agency
OCB	Oil Circuit Breaker
OD-ID	Outdoor to Indoor conversion
ODV	Optimised Deprival Value/Valuation
O&M	Operating and Maintenance
OLTC	On Load Tap Changer
OMS	Outage Management System
Opex	Operational Expenditure
OT	Operational Technology
PAHL	Power Asset Holdings Limited
PCC	Porirua City Council
PCS	Power Control System
PDC	Polarisation Depolarisation Current
PIAS	Paper Insulated Aluminium Sheath Cable
PILC	Paper Insulated Lead Cable
PLC	Programmable Logic Controller
PM	Preventative Maintenance
PV	Photovoltaic Generation
PVC	Polyvinyl Chloride
RMU	Ring Main Unit
RTU	Remote Terminal Unit
RY	Regulatory Year (1 April – 31 March)

SAIDI	System Average Interruption Duration Index
SAIFI	System Average Interruption Frequency Index
SAP	Systems Applications and Processes
SCADA	Supervisory Control and Data Acquisition System
SCPP	Streamlined Customised Price Path
SF6	Sulphur Hexafluoride
SPS	Special Protection Scheme
TASA	Tap Changer Activity Signature Analysis
TCA	Transformer Condition Assessment
TNIFR	Total notifiable injuries per 1,000,000 hours worked
TNO	Transmission Network Operator
UFB	Ultrafast Broadband
URM	Unreinforced Masonry
UHCC	Upper Hutt City Council
VRLA	Valve Regulated Lead Acid Battery
VT	Voltage Transformer
WCC	Wellington City Council
WELL	Wellington Electricity Lines Limited
WeLG	Wellington Lifelines Group
WOM	Work Order Management
W/S	Winter / Summer
XLPE	Cross Linked Polyethylene insulation

Appendix G Single Line Diagram