# Wellington Electricity

# 10 Year Asset Management Plan

# 1 April 2025 – 31 March 2035

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 (Amended in 2024).

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.

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

# Statement from the Chief Executive Officer

Wellington Electricity (WELL) welcomes the opportunity to submit an updated Asset Management Plan (AMP) for the regulatory period 2025/26 to 2034/35. 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 have included concluding the tender and award of our new Field Service Contract and commencing the transition from Northpower to Omexom who were the successful applicant. The transition is running ahead of schedule and both contractors have a positive working relationship based on their experience of joint services provision on the Auckland network. It is important for WELL to continue to develop contracts which continuously improve the safety, reliability, and affordability of services to our assets and customers.

The 2025 Plan is a contrast from the Climate Change modelling through to 2050 that the 2024 Plan presented, where a net-zero outcome indicated significant network investment to accommodate electrified transport fleets and an exit from gas as a commercial and industrial fuel as well as its current use supplying 65,000 of our 160,000 residential connections.

The Commission engaged on this plan and acknowledged its delivery would be under a different price path, however the DPP4 Determination in November 2024 has provided an uplift in the capex and opex allowances which the 2025 Plan is based on. A business case will still to be required to consider whether a change in Price Path decision is to be taken by the Shareholder.

The 2025 Plan also repositions spend to later in the period as a change in government has seen a number of projects cancelled, reduced in size, or transitions to non-fossil fuel alternatives slowing down, which is in line with a slowing economy and the government reducing public servant positions in order to manage NZ's fiscal recovery. Complicating the pace of change is the winter energy shortages where low hydro storage and depleted gas field volumes have seen a return to thermal generation as renewables are unable to securely and reliably meet demand.

While the period of high inflation has stabilised and is returning to below 3%, the housing market has also cooled with values reducing, and customers are yet to see savings at a household level with lower mortgage rates, so there would be limited support from the community for a frontloaded decarbonisation infrastructure investment program as outlined in the 2024 Plan. In contrast, the 2025 Plan takes the approach for a slower replacement programme to match the economic conditions as there is increasing uncertainty in the pace for change and affordability of greater electrification.

As a lifeline utility, we are proud to continue to deliver our community with a safe, reliable, and secure energy delivery system under a wide range of circumstances. Resilience is a key theme in our Plan, which outlines that a suitable level is in place for our current DPP approach, however, greater investment will be required for a more resilient network as the climate changes. Preparedness for future earthquake events was undertaken in our CPP from 2018 to 2021 as critical spares were purchased and building reinforcement was undertaken as part of a Readiness, Reduction, Response, and Recovery assessment of earthquake events. We completed a new DR Centre (constructed to IL4) last year and are building a new Head Office this year (to be constructed to IL3) to remove the coastal risk from climate events and natural disasters that our current site is exposed to, so we can continue to respond effectively.

WELL continues to proactively engage with WorkSafe, MBIE, the Commission, the Electricity Authority, the Climate Change Commission, and the Infrastructure Commission on improvements in safety and wellbeing performance, price-quality path reopeners, 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.

WELL continues to learn with 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 managing 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 communication of congestion and available capacity of the LV network, and working closely with other industry participants will deliver the best long-term solution for New Zealand.

Modelling of our low voltage network from a sample of purchased smart meter consumption data has allowed a forecast of low voltage constraints as households exit gas and consumers purchase electric vehicles. Different investment scenarios have been developed for various exit and uptake rates. This heat map provides strong guidance for more detailed evaluation than 30min consumption data can provide, and will be targeted in the DPP4 period using INTSA allowances.

A change in Government has seen some transport providers step back and reassess their infrastructure costs, including the procurement of further electric bus fleets. Looking forward we are expecting a revised interisland ferry decision and watching for evidence of EV purchasing rebounding, however the 2025 Plan reflects a slower transition to net carbon zero under a weaker economy.

WELL's Time of Use (ToU) pricing for residential consumers provides retailers with a clear signal to encourage customers to move their usage away from congested peak demand periods. We appreciate the retailers who are reflecting these signals to their customers. In future, more dynamic pricing will be needed to signal to retailers when the network requires more urgent demand reduction to remain in service. This will be a focus of our 2025 Pricing Plan development for 2026. Data access will be a key that unlocks these benefits for customers.

Quality limits will be challenged when large network reinforcement projects place areas of the network on reduced security for the duration of construction, with feeders being required to supply increased numbers of customers at N security as in their N-1 configurations as parts of the network are rebuilt. The Commission is aware of this reality and where WELL will record quality targets for unintended supply consequences while we "rebuild the plane in flight".

We continue to invest in the network assets where they require replacement or maintenance to meet the required asset performance standards, notwithstanding the highlighted risk of lower security levels during large investment projects. 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 have increased on the back of higher supply chain and material costs, and are the reason for the price changes from 1 April and through the DPP4 period for consumers.

Health, safety, and wellbeing remain positive drivers for improved engagement with our own staff and field staff engaged under the outsourced arrangement. Maintaining awareness of hazards ahead of commencing work tasks and ensuring critical controls are exercised as part of our work ensures we have people returning to their families free from harm.

WELL continues to employ a strong team effort across planning, real-time management, 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 and education on their responsibility for responding to cut and trim notices which support proactive vegetation management.

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

We welcome any comments or suggestions regarding this AMP.

Greg Skelton

**Chief Executive Officer**

# Contents

# 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 2025 AMP

This AMP covers the 10-year period commencing 1 April 2025 through to 31 March 2035. It was approved by WELL's Board of Directors on 28 March 2025.

## 1.2 Key Elements of the 2025 AMP

The key element of this AMP is that the balance of New Zealand's energy trilemma has swung towards balancing customer affordability with sustainability. This is reflected in changes in government policy and the intentions of customers for the timing of their major decarbonisation projects, and the impact this has had on WELL's investment forecasts in this Plan relative to the WELL's decarbonisation-focused 2024 AMP.

WELL retains its focus on delivering a safe and reliable electricity supply to its customers, and the 2025 Plan demonstrates WELL's ongoing commitment to investing in the maintenance and condition-based renewal of its assets in order to continue meeting its customers' requirements.

Appendix B provides more detail on the changes made since the 2024 AMP.

## 1.3 The Impact of Changes in Decarbonisation Forecasts

In 2024 WELL modelled the impact of New Zealand's Emissions Reduction Plan (ERP) and incorporated the demand impact and service changes into its 2024 AMP. This was an invaluable exercise to understand how the decarbonisation programme led by the Climate Change Commission would need to be supported by the efficient delivery of additional electricity infrastructure investment for net carbon zero in 2050.

In the 12 months since the publication of the 2024 AMP, changes in economic climate and central government's response to these fiscal conditions has pulled back sustainability as a key driver, and instead tempered infrastructure investment to fit within what the economy dictates as meeting household affordability and the security of supply they are willing to pay for. Central government has also cooled the EV market with the removal of subsidies and implementing an end to a Road User Charge exemption for EV owners, pushing price parity with fossil fuelled vehicles out further.

The impact of this change in decarbonisation intentions is illustrated in Table 1-1, showing the changes in demand forecast based on updated information over the last 12 months. These changes are discussed in detail in Section 9.2.2.

| Demand Type | 2035 MW in 2024 AMP | 2035 MW in 2025 AMP |
|---|---|---|
| Private EV Charging | +55 MW | +28 MW |
| New Commercial EV Charging | +11 MW | +1 MW |
| Process Heat | +60 MW | 0 MW |
| Residential Gas | +68 MW | +13 MW |
| Public Transport Electrification | +63 MW | 0 MW |
| **Decarbonisation Demand** | **+257 MW** | **+42 MW** |

Table 1-1 Changes to Assumptions of Decarbonisation Contribution to Network Maximum Demand

WELL has experienced declining trends in energy volumes and maximum demand through its network, as shown in Figure 1-1. This decline has been particularly pronounced in the Wellington city area, due to a series of milder winters, increased energy efficiency, working from home, business closures, and the Wellington city population having declined since 2020.

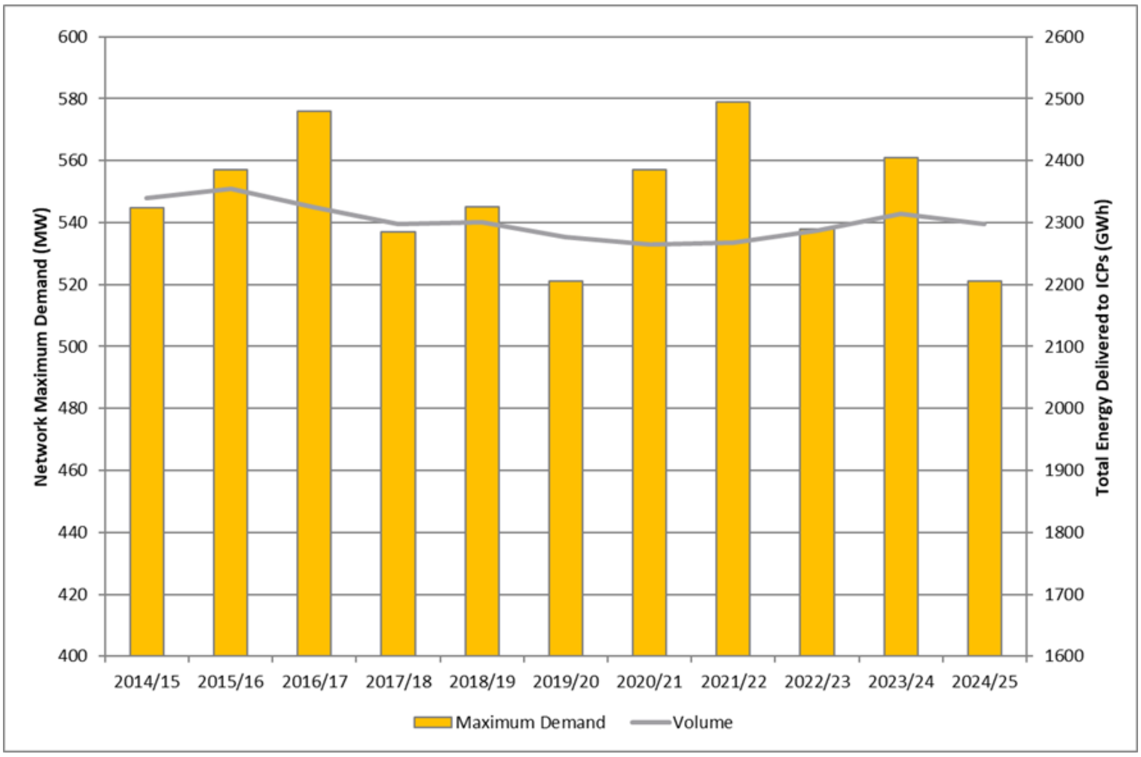



Figure 1-1 Trend in Maximum Demand and Energy Consumption

The number of new dwellings consented annually in the Wellington Region across the four local authorities covered by WELL's network peaked in 2022, with 2023 and 2024 showing a significant reduction, reflecting the change in regional economic conditions. Figure 1-2 shows the number of new dwellings consented over the last seven years.

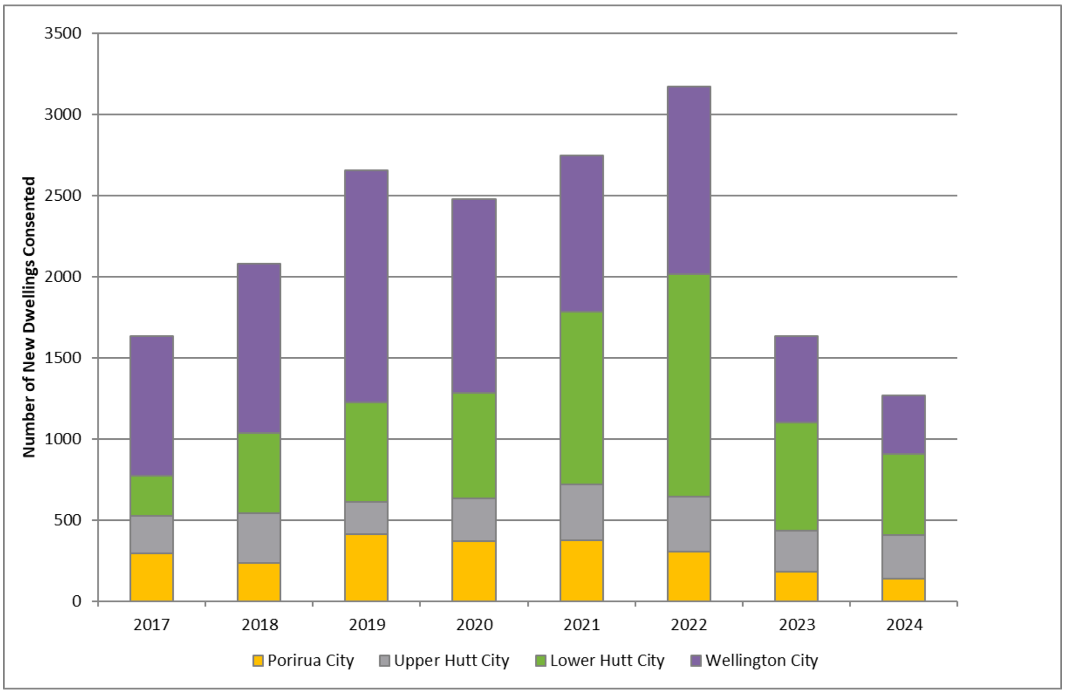



**Figure 1-2 Number of New Dwellings Consented in the Wellington Region**

These are the underlying trends upon which the decarbonisation forecasts summarised in Table 1-1 are superimposed. Figure 1-3 shows the extent to which delayed and cancelled decarbonisation-related electricity load growth, combined with an underlying trend of declining demand, has impacted the forecast demand on WELL's network relative to the forecast in the 2024 AMP.

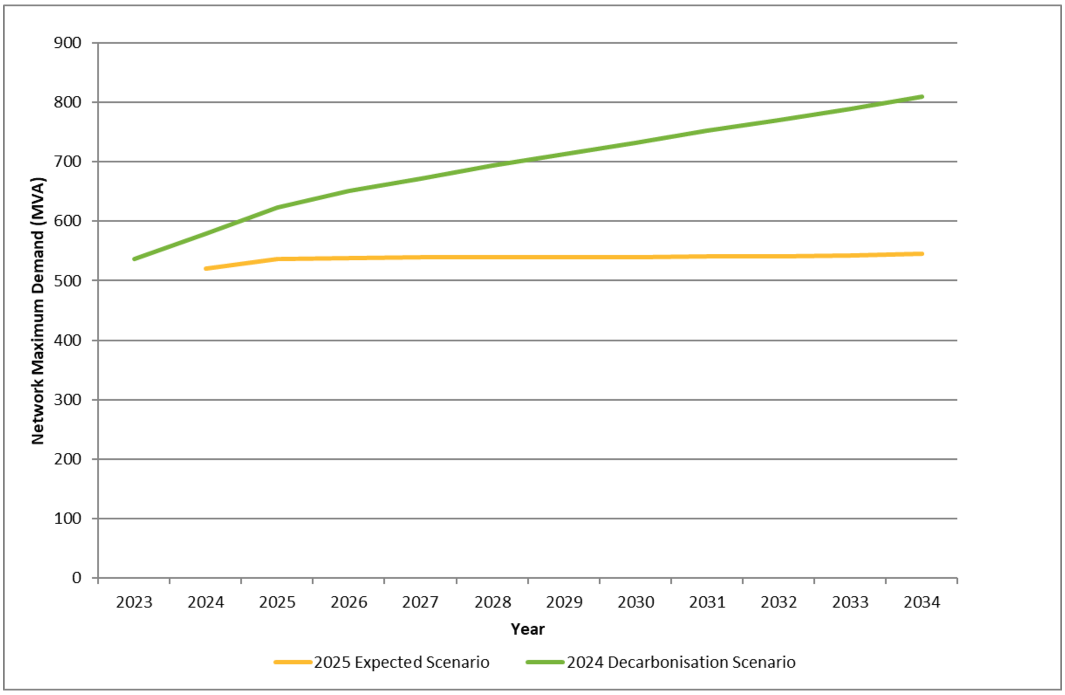



**Figure 1-3 Change in WELL's System Maximum Demand Forecast between 2024 and 2025 AMPs**

WELL has responded to these trends, and the Commission's focus on customer affordability in its DPP4 Determination, with a significant revision of its planned capital investment programme.

In addition to the uncertainty about whether major customer projects will proceed, and their timing and scope if they do, the scale of investment and resources that would be required to support these is significant relative to WELL's default capital expenditure allowances, making them unable to be supported by the Default Price Path. WELL is managing this risk by excluding from this Plan the investment that those customers would drive should they choose to proceed with their projects, with the intention of reopening the Price Path should those projects eventuate.

The reduced demand growth due to delayed decarbonisation, an approach to deliver capacity in multiple smaller incremental stages in order to maintain customer affordability, and ringfencing major customer decarbonisation projects into potential Price Path Reopeners, has produced a lower and sustained level of investment over the next 10 years as compared to the 2024 AMP, as shown in Figure 1-4.

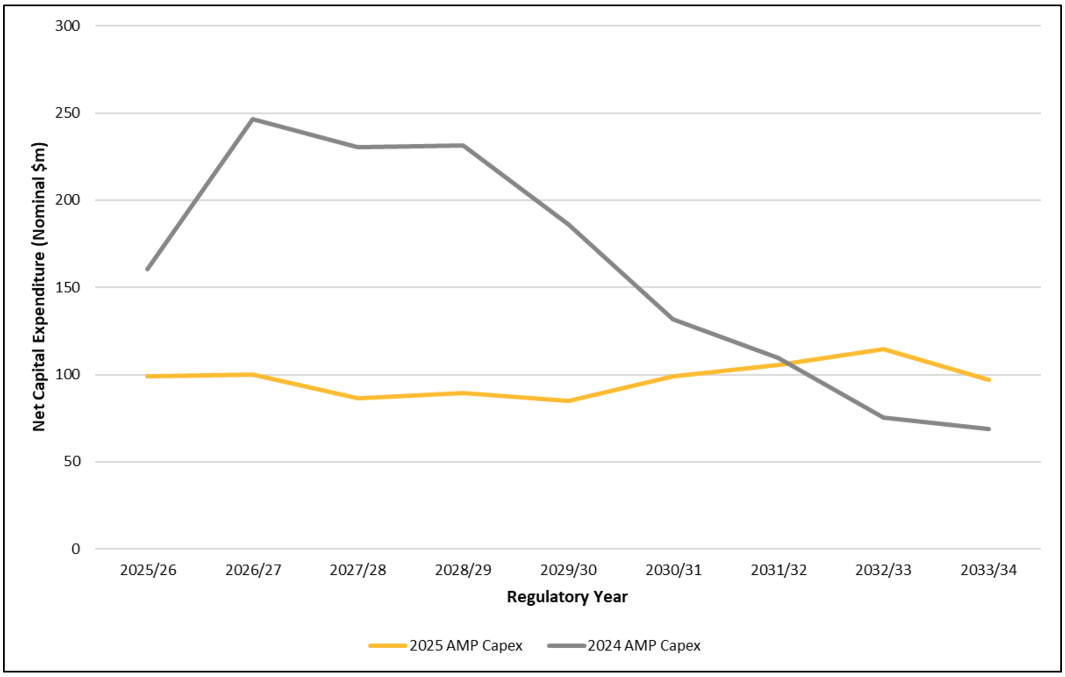



Figure 1-4 Change in WELL's Capital Expenditure Forecast between 2024 and 2025 AMPs

## 1.4 Reliability Performance

The regulatory regime that applies to WELL sets reliability limits for each year that are based on historical performance. Unplanned outage limits are set at two standard deviations above the reference period average, while planned outage limits are set at a multiple of the reference period average. The DPP4 Determination has updated WELL's reliability performance targets and limits for the five year period beginning on 1 April 2025. These regulatory limits for WELL are presented in Table 1-2.

| Regulatory Year | 2021/22-2024/25 | 2025/26-2029/30 |
|---|---|---|
| Annual Unplanned SAIDI Limit | 39.81 | 37.82 |
| Annual Unplanned SAIFI Limit | 0.6135 | 0.5829 |
| Period Planned SAIDI Limit | 55.76 | 76.66 |
| Period Planned SAIFI Limit | 0.4429 | 0.6089 |
| Extreme Event Customer Minutes Limit | 6 million | 6 million |

Table 1-2 WELL Regulatory Reliability Limits

WELL's historic unplanned SAIDI performance against the DPP3 limit is shown in Figure 1-5.

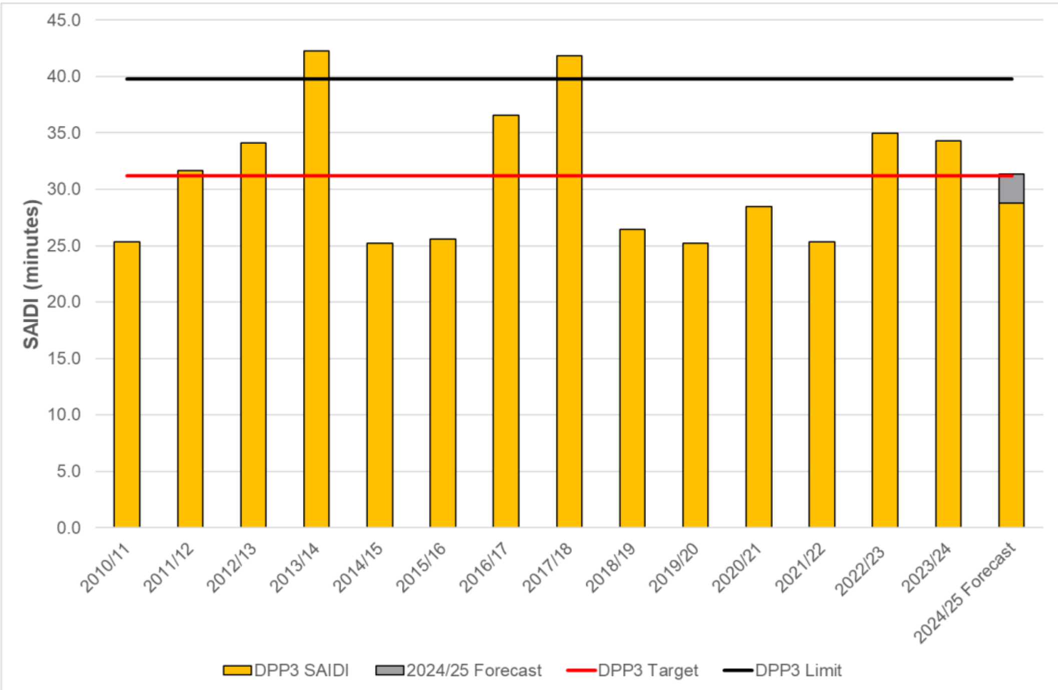



Figure 1-5 WELL's Historical Unplanned SAIDI Performance

WELL's future targets for SAIDI and SAIFI are shown in Table 1-3. These targets assume that SAIDI and SAIFI beyond 2030 will be calculated using the same methodology as the DPP4 Determination, including the mechanism for normalising Major Event Days.

| Regulatory Year | 2025/26 | 2026/27 | 2027/28 | 2028/29 | 2029/30 | 2030/31 | 2031/32 | 2032/33 | 2033/34 | 2034/35 |
|---|---|---|---|---|---|---|---|---|---|---|
| Unplanned SAIDI target | 29.64 | 29.64 | 29.64 | 29.64 | 29.64 | 29.64 | 29.64 | 29.64 | 29.64 | 29.64 |
| Unplanned SAIFI target | 0.457 | 0.457 | 0.457 | 0.457 | 0.457 | 0.457 | 0.457 | 0.457 | 0.457 | 0.457 |
| Planned SAIDI target | 13.77 | 12.75 | 12.30 | 13.23 | 11.36 | 12.71 | 11.51 | 12.36 | 11.26 | 11.26 |
| Planned SAIFI target | 0.078 | 0.072 | 0.070 | 0.075 | 0.064 | 0.072 | 0.065 | 0.070 | 0.064 | 0.064 |

Table 1-3 Network Reliability Performance Targets

While WELL is committed to maintaining its network to ensure that unplanned reliability performance remains in line with the acceptable historical average, planned outage targets over the period scale relative to size of the capital work programme. While most of the increase in expenditure will be related to subtransmission and zone substation reinforcement projects that can usually be completed without any customer outages, there will also be a significant increase in 11 kV reinforcement, which will increase planned outage indices.

## 1.5 Network Expenditure

### 1.5.1 Network Capital Expenditure

WELL separates 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.
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.
4. **Relocation Capital –** expenditure required to relocate assets primarily due to roading projects and where the cost is normally shared with NZ Transport Agency.
5. **Customer Connection –** includes the costs to deliver customer-requested capital projects, such as new subdivisions, customer substations, or connections.

While the level of investment over the next ten years is significantly less than was forecast in the 2024 AMP as discussed in Section 1.3, WELL is still entering a phase of increased investment. This is due to WELL's historic practice of closely matching 33 kV capacity to demand in order to keep costs for customers low, which is now leading to relatively small changes in new demand creating 33 kV constraints that require significant investment to resolve.

WELL's network capital expenditure, both historical and as forecast for the next ten years, is shown in Figure 1-6.

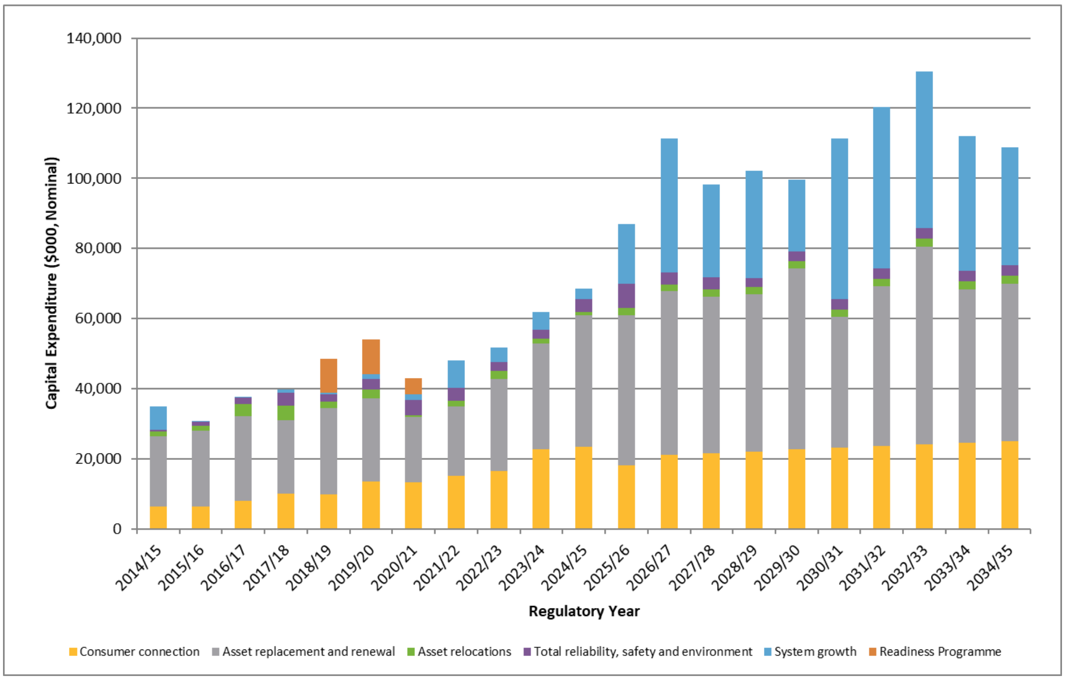



**Figure 1-6 Network Capital Expenditure
($K in Nominal Prices, Gross of Customer Contributions)**

### 1.5.2 Network Operational Expenditure

WELL separates its 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, standover 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 replacements that do not meet the requirements for capitalisation.

The network operational expenditure, both historical and forecast, is shown in Figure 1-7.

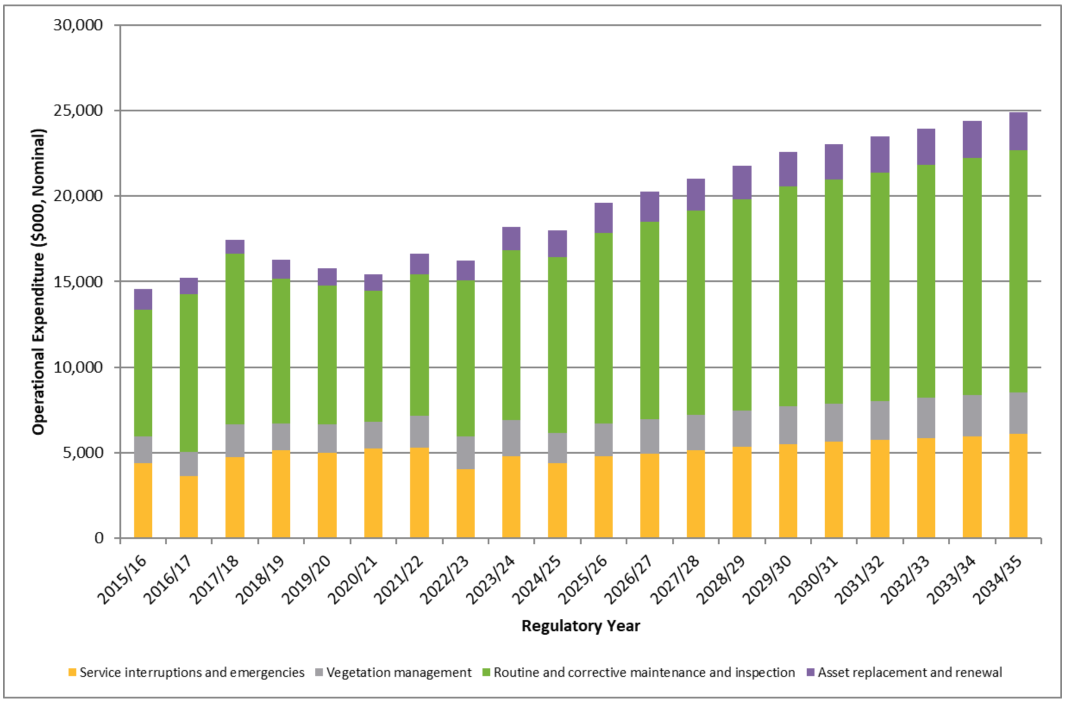



**Figure 1-7 Network Operational Expenditure ($K in Nominal Prices)**

## 1.6 WELL's Capability to Deliver

Delivering the investment path described in this plan requires a step change in resourcing compared to that which has been required during recent years. WELL has met this resourcing challenge by engaging an engineering consultancy to provide a Project Management Office (PMO) function, and greater engagement with specialist civil contractors in addition to the traditional electrical contractors that have operated on the network. Having an external PMO to call on allows WELL to flex its resourcing as required to support large projects.

The New Zealand electricity industry is suffering from an ageing workforce and global competition resulting in a shortage of trained workers. It is essential that the industry invests in attracting, training, and retaining workers, in order to be able to meet these challenges. To this end, WELL is currently training three graduate engineers on a rotation programme that covers all aspects of the business' operation, and three trainee network controllers.

WELL tendered its Field Services Contract in 2024, and selected Omexom as its new Field Service Provider, contracted to perform maintenance and fault response services. This engagement will ensure that WELL continues to provide value for money for its customers, along with the safe and efficient delivery of services throughout the Wellington region.

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.

# 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 (amended in November 2024). It describes WELL's long-term investment plans for the planning period from 1 April 2025 to 31 March 2035.

The document was approved for disclosure by the WELL Board of Directors on 28 March 2025.

## 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.

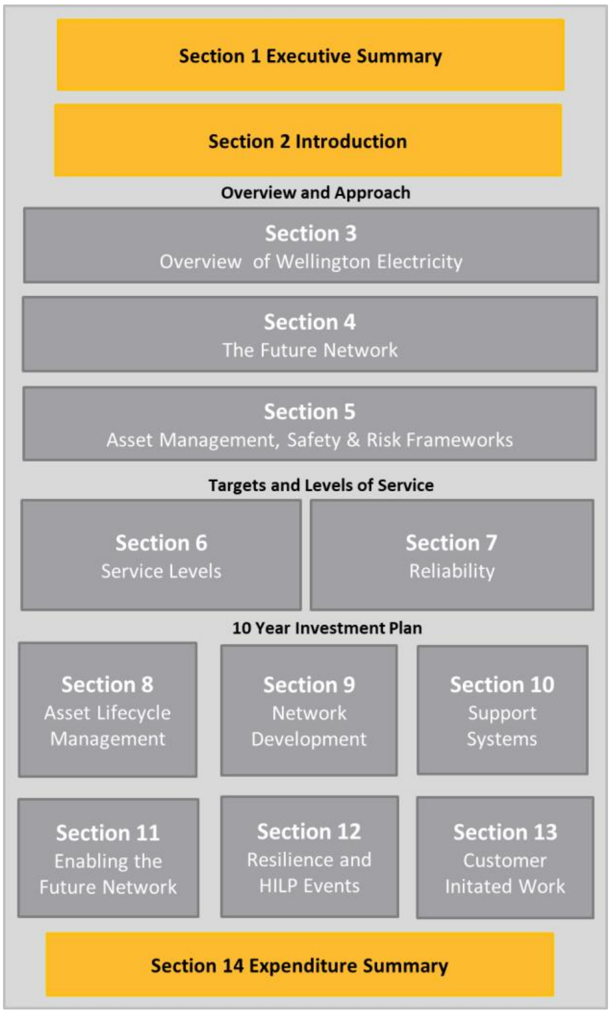



Figure 2-1 Structure of the 2025 AMP

## 2.3 Formats used in this AMP

The following formats are adopted in this AMP:

- Financial values are in constant price 2025 New Zealand dollars, except where otherwise stated;
- Calendar years are referenced as the year e.g. 2025. 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. 2025/26;
- All asset data expressed in figures, tables, and graphs are as at 30 September 2024 unless otherwise stated; and
- All asset quantities or lengths are quoted at the operating voltage rather than at the design voltage. For example, WELL has 8.7 km of 110 kV cable operating at 33 kV. The length of these cables is incorporated into the statistics for 33 kV cable lengths and not as 110 kV 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;
- Changes to business strategy driven by internal and external factors; and
- The impact of the regulatory regime.

Accordingly, specific network-initiated 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. Customer-initiated projects are less predictable, with potential projects being subject to change, delay, or cancellation as customers' priorities change.

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 from 1 April to 31 March.

# 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 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 the current regulatory environment.

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 inform its 2025 Business Plan. It takes into account the interests of customers, stakeholders, and the changing operating environment (discussed in Sections 3.6 and 3.7). Figure 3-1 illustrates this flow from WELL's mission to the Business Plan to the AMP.

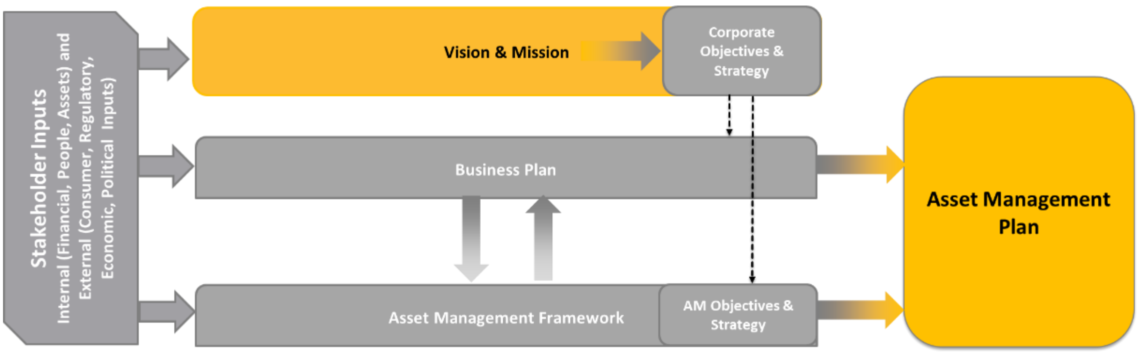



**Figure 3-1 Interrelationship between WELL's Mission, the Business Plan, the Asset Management Framework and the AMP**

The Asset Management Framework utilised by WELL is discussed further in Section 5.

## 3.2 Organisational Structure

### 3.2.1 Ownership

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

The CK Infrastructure Holdings Limited group has established a strong global presence with investments in the 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 and 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[1]), which meets via conference to discuss the latest developments in new technologies from around the globe.

In addition, WELL attends joint Cheung Kong Infrastructure (BVI) Ltd. and Power Assets Holding Ltd. 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. WELL operates an outsourced services model for its field services, contact centre operations, and certain specialist functions. The overall company organisation structure is shown in Figure 3-2.

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

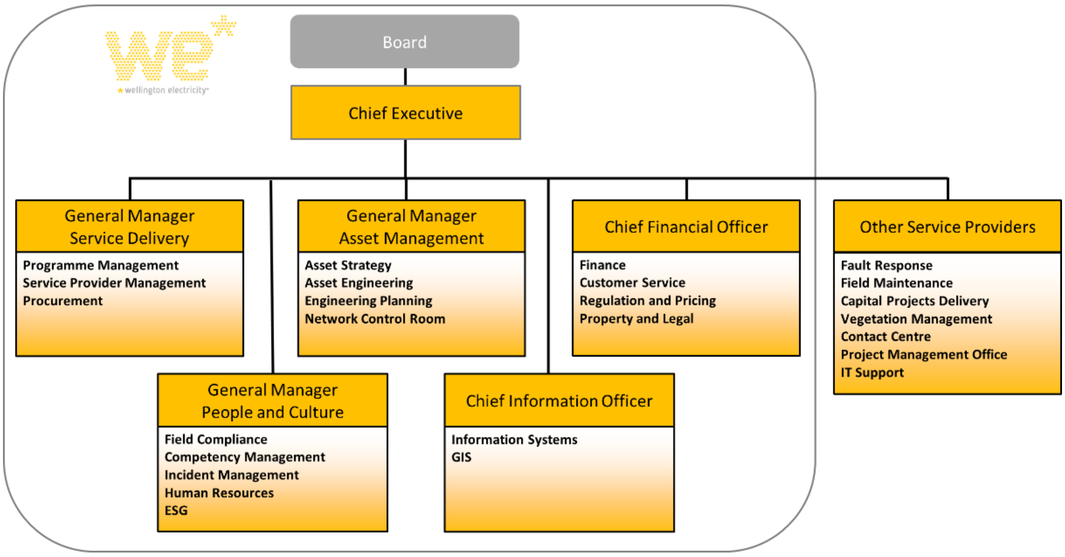



**Figure 3-2 WELL Organisation Structure**

### 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.[2]

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

The scope of the CIC is also to ensure that 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 provides their recommendation for Board review and 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 the 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.

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

The Chief Financial Officer is accountable for finance, customer service, regulatory management, legal and property management, and information technology support.

The General Manager – People and Culture is accountable for human resources, quality and safety processes, and ESG strategies and targets.

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 Group

The Asset Management team's responsibilities are separated into four areas: asset engineering, asset planning, asset strategy, 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<br>• Asset and network management<br>• Condition-based risk management<br>• Reliable service levels for customers<br>• Approval of asset management projects and budgets<br>• Quality performance management<br>• Network policies and standards<br>• Technical engineering support<br>• Development and prioritisation of the 3-12 month combined CAPEX and OPEX work plan<br>• Analysis of asset data to inform decision making |
| Asset Planning | • Safety-by-Design for new builds<br>• Network load forecasting<br>• Reinforcement planning<br>• Review of large customer connection requests |
| Asset Strategy | • Strategic network development planning to a 30-year horizon.<br>• Network resilience initiatives.<br>• Innovation and flexibility workstreams. |
| Network Operations | • Network operations and safety<br>• Outage management<br>• Fault response and management<br>• Control Room<br>• Operationalising new technologies onto the network |

**Table 3-1 Asset Management Team Responsibilities**

#### 3.2.5.2 Service Delivery Group

The Service Delivery team's responsibilities are separated into management of the 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)<br>• Delivery of reactive maintenance and value add services under the FSA |
| Contracts Management | • Management of specialist contracts, for example, vegetation management and the Mill Creek maintenance contract |

**Table 3-2 Service Delivery Team Responsibilities**

### 3.2.5.3 Commercial and Finance Group

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

| Commercial and Finance Team | Asset Management Responsibilities |
|---|---|
| Commercial and Regulatory | • Compliance with regulatory requirements |
| Finance | • Adequate funding of asset management plans |
| Customer Service | • Accountable for customer relations management including cost-quality surveys |
| Property and Legal | • Corporate risk management<br>• Management of property and land |

**Table 3-3 Commercial and Finance Team Responsibilities**

### 3.2.5.4 Information Technology Group

The Information Technology team responsibilities are described in Table 3-4.

| Information Technology Team | Asset Management Responsibilities |
|---|---|
| Information Technology | • Operational system maintenance and upgrades<br>• Business support systems |

**Table 3-4 Information Technology Team Responsibilities**

### 3.2.5.5 People and Culture Group

The People and Culture team's responsibilities are described in Table 3-5.

| People and Culture Team | Asset Management Responsibilities |
|---|---|
| QSE | • Quality processes and procedures in place to manage the delivery of asset management plans<br>• Adherence to Health & Safety and Environmental legislation |
| Human Resources | • The capability of people to deliver Asset Management functions |
| ESG | • Implementation of corporate ESG strategy<br>• Delivery of agreed ESG targets |

**Table 3-5 People and Culture Team Responsibilities**

### 3.2.5.6 Other Service Providers

WELL outsources the majority of its field services tasks and its customer contact centre. WELL maintains the overarching accountability for the 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 – Omexom;
- Contestable capital works – Omexom, 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 services 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 the infrastructure to support the distribution of electricity to approximately 177,000 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.

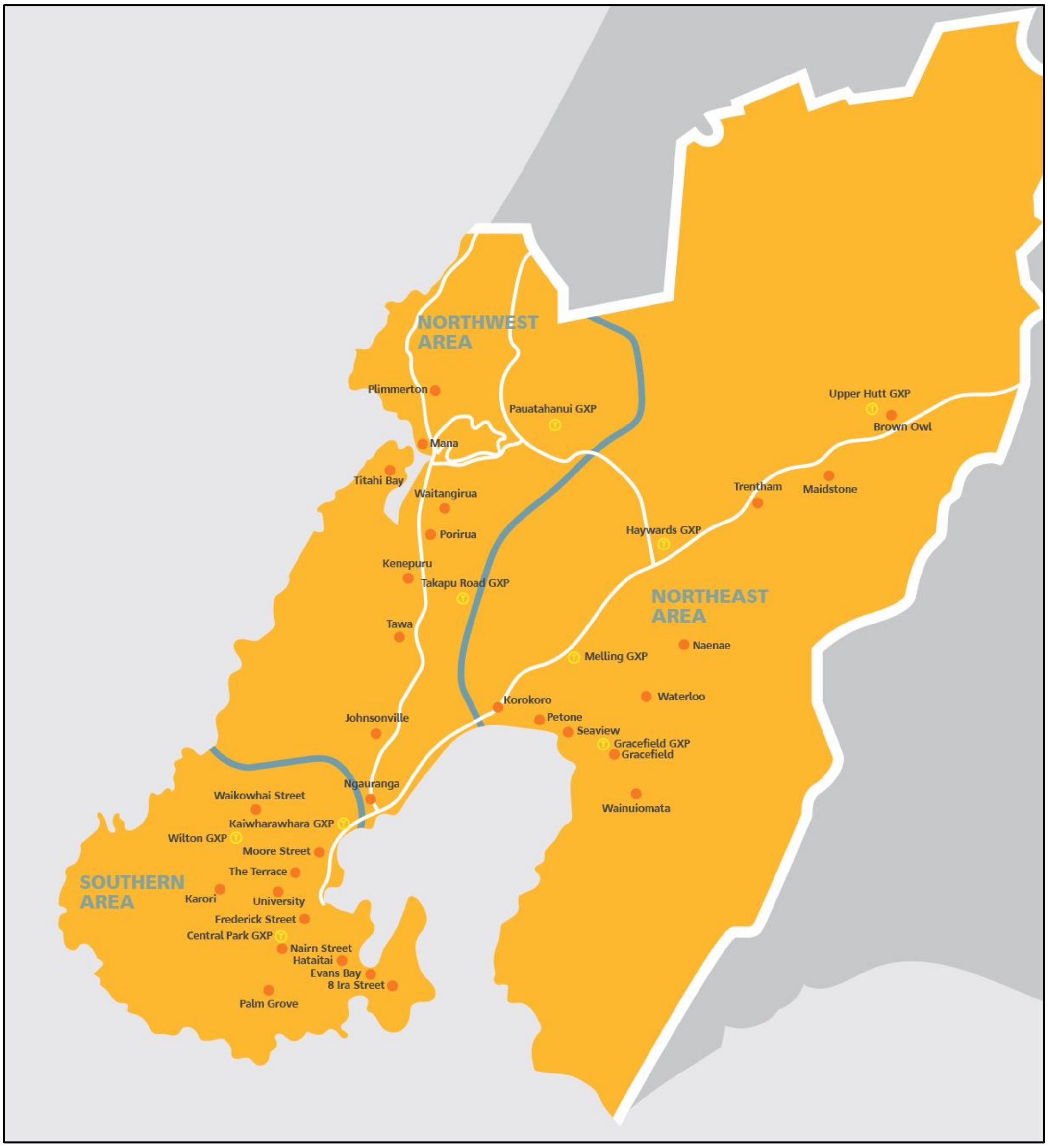



Figure 3-3 WELL Network Area

## 3.4 The Network

The total system length of WELL's network (excluding streetlight circuits) is 4,903 km, 65% 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 Road, 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 the N-1[3] security level. The 33 kV system is generally radial with each circuit supplying its own dedicated power transformer, with the exception of Tawa and Kenepuru where two circuits from the Takapu Road branch to supply four transformers (two at each substation), and Evans Bay where three circuits from Central

[3] 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.

Park are connected to a 33 kV bus that supplies four transformers at Evans Bay and Ira Street. 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 196 km, of which 139 km is underground. A single-line diagram of the subtransmission network is included in Appendix F.[4]

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 a normally closed 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 4,515 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 1,814 km, of which 68% is underground. 71% of the 11 kV feeders in the Wellington CBD[5] 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 2,877 km, of which 63% is underground. An additional 1,977 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.

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

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

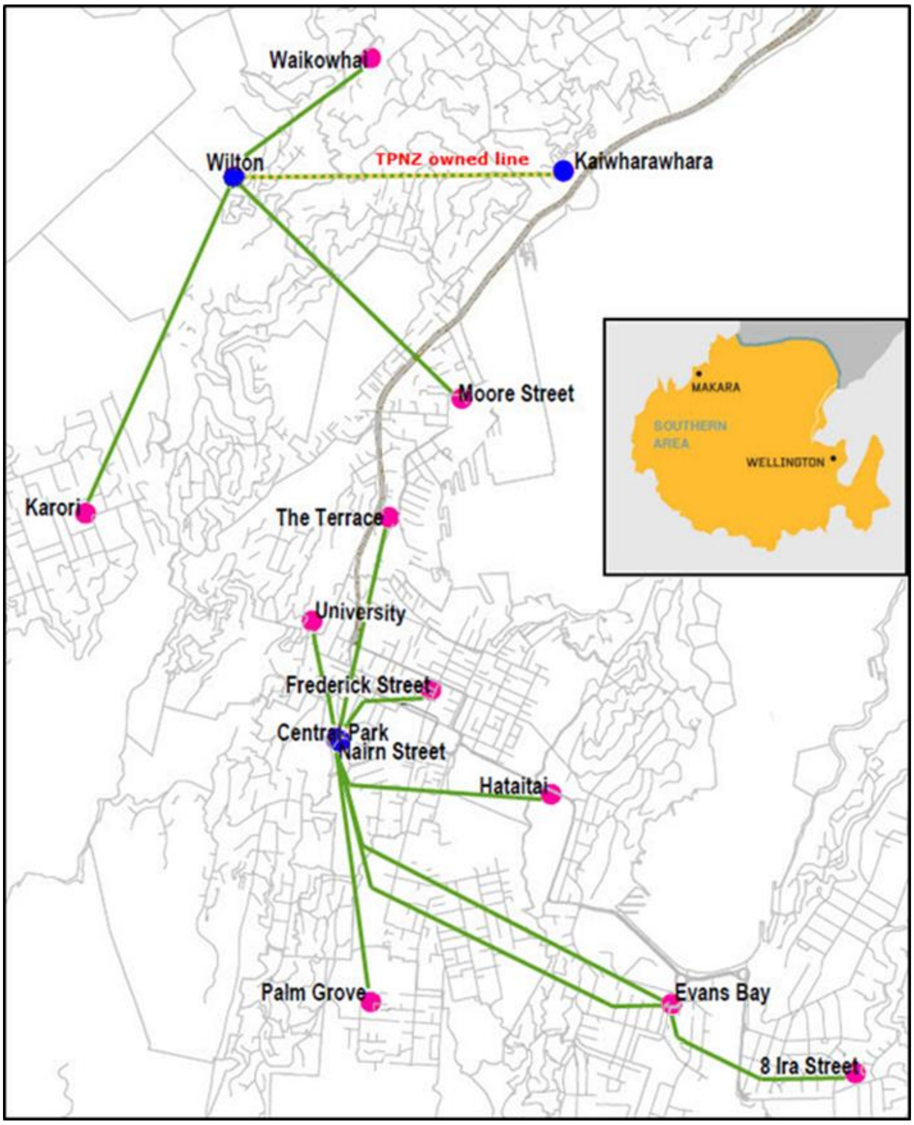



Figure 3-4 Wellington Southern Area Subtransmission Network

### 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 a 33 kV indoor bus. There are also two Transpower-owned 33/11 kV (25 MVA) transformers supplying the station local service and an 11 kV point of supply to WELL's network.

Central Park is supplied at 110 kV by three overhead circuits from Wilton GXP. There is no 110 kV bus at Central Park, 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 zone substation 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 12.

#### 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 an 11 kV supply from Transpower's Kaiwharawhara GXP and distributes this via a WELL-owned switchboard located within the GXP.

#### 3.4.1.4 Southern Area Summary

| Supply Point | Connection Voltage (kV) | Maximum Demand – 2024 (MVA) | Firm Capacity[6] (summer/winter MVA) | Volumes – 2024 (GWh) | ICP Count |
|---|---|---|---|---|---|
| Central Park 33 kV | 33 | 132 | 217/223 | 636 | 42,385 |
| Central Park 11 kV | 11 | 21 | 30/30 | 88 | 7,600 |
| Wilton 33 kV | 33 | 39 | 103/110 | -31[7] | 12,874 |
| Kaiwharawhara 11 kV | 11 | 28 | 38/38 | 133 | 5,596 |
| **Total** | | | | **826** | **68,455** |

**Table 3-6 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.

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

[7] Net of 324 GWh injected by Mill Creek Generation into the GXP.

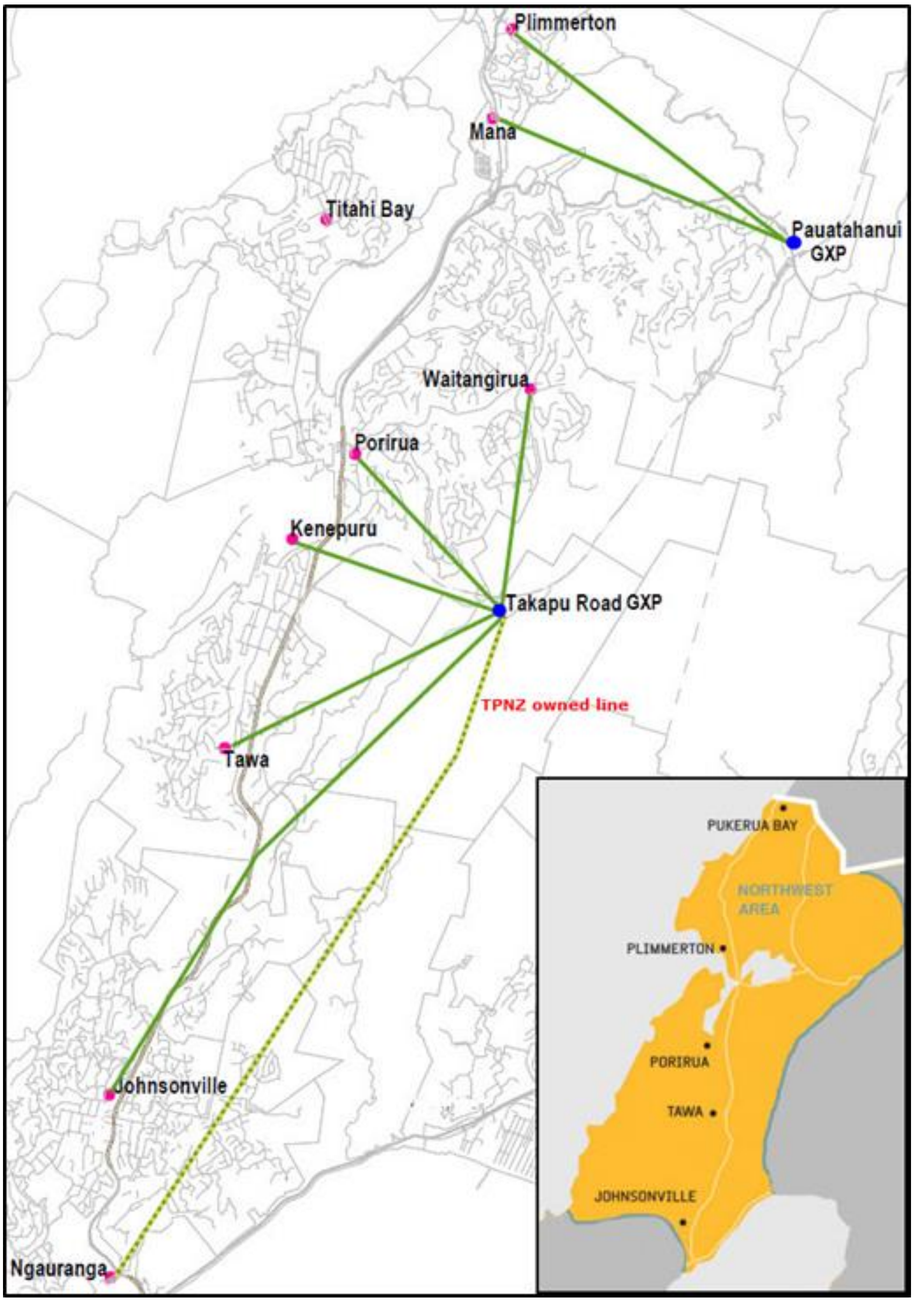



**Figure 3-5 Wellington Northwestern Area Subtransmission Network**

### 3.4.2.1 Pauatahanui

Transpower's Pauatahanui GXP comprises two 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 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. The circuits from Takapu Road to Ngauranga zone substation are Transpower-owned lines rated to 110 kV and operated at 33 kV.

#### 3.4.2.3 Northwestern Summary

| Supply Point | Connection Voltage (kV) | Maximum Demand – 2024 (MVA) | Firm Capacity (summer/winter MVA) | Volumes – 2024 (GWh) | ICP Count |
|---|---|---|---|---|---|
| Pauatahanui 33 kV | 33 | 18 | 22/24 | 71 | 7,265 |
| Takapu Road 33 kV | 33 | 92 | 111/116 | 425 | 34,820 |
| **Total** | | | | **496** | **42,085** |

Table 3-7 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.

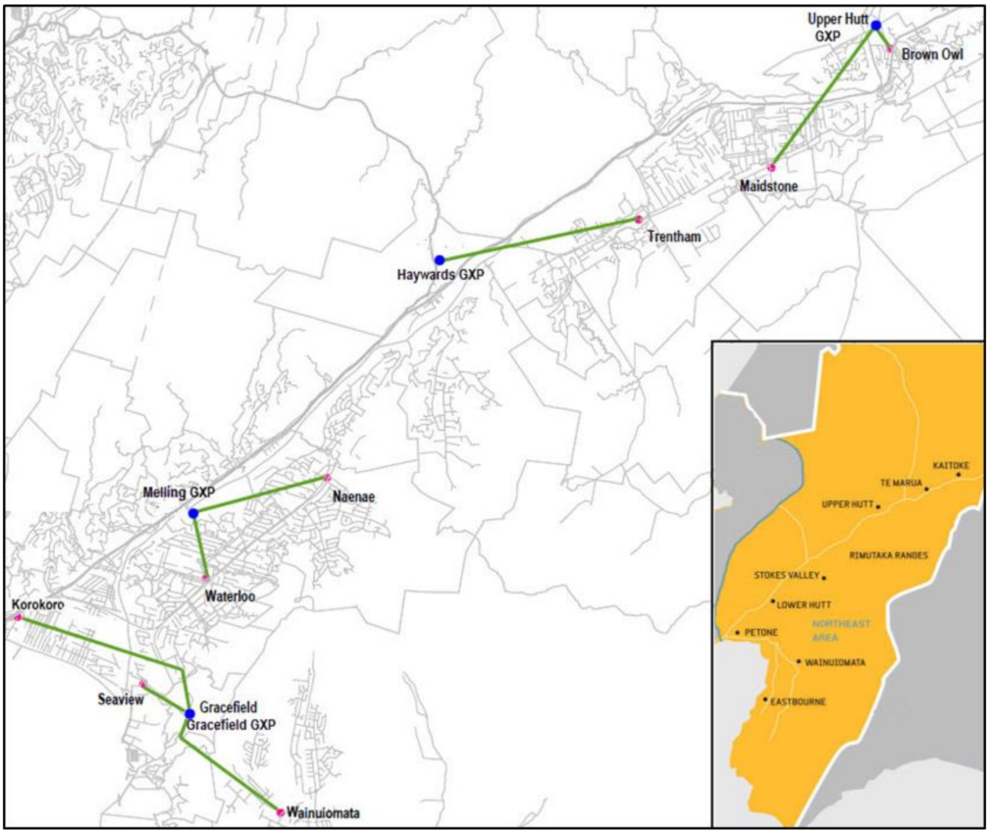



Figure 3-6 Wellington Northeastern Area Subtransmission Network

#### 3.4.3.1 Upper Hutt

Transpower's Upper Hutt GXP comprises two 110/33 kV transformers each nominally rated at 37 MVA supplying a 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 60/24/30 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 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 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 110/33 kV transformers nominally rated at 60 MVA and 85 MVA, supplying a 33 kV indoor bus. In late 2019, one of the two 85 MVA transformers had a winding fault and Transpower temporarily installed a 60 MVA strategic spare. 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 – 2024 (MVA) | Firm Capacity (summer/winter MVA) | Volumes – 2024 (GWh) | ICP Count |
|---|---|---|---|---|---|
| Gracefield 33 kV | 33 | 59 | 76/80 | 277 | 20,208 |
| Haywards 33 kV | 33 | 17 | 24/24 | 75 | 6,357 |
| Melling 33 kV | 33 | 32 | 64/65 | 142 | 12,903 |
| Upper Hutt 33 kV | 33 | 30 | 51/53 | 138 | 11,389 |
| Haywards 11 kV | 11 | 16 | 30/30 | 73[8] | 7,137 |
| Melling 11 kV | 11 | 24 | 32/34 | 142 | 8,110 |
| **Total** | | | | **816** | **66,104** |

**Table 3-8 Summary of Northeastern Area GXPs**

[8] Net of 13 GWh injected by Silverstream Generation into the GXP.

### 3.4.4 Embedded Generation

There is a wide range of embedded generation connected to the network, including 3,328 installations of PV with 15.9 MVA 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. 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 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 2024/25 WELL's network is forecast to deliver 2,297 GWh to customers around the region. The network maximum demand during winter 2024 was 521 MW. Figure 3-7 illustrates the historic trend in volume and maximum demand.

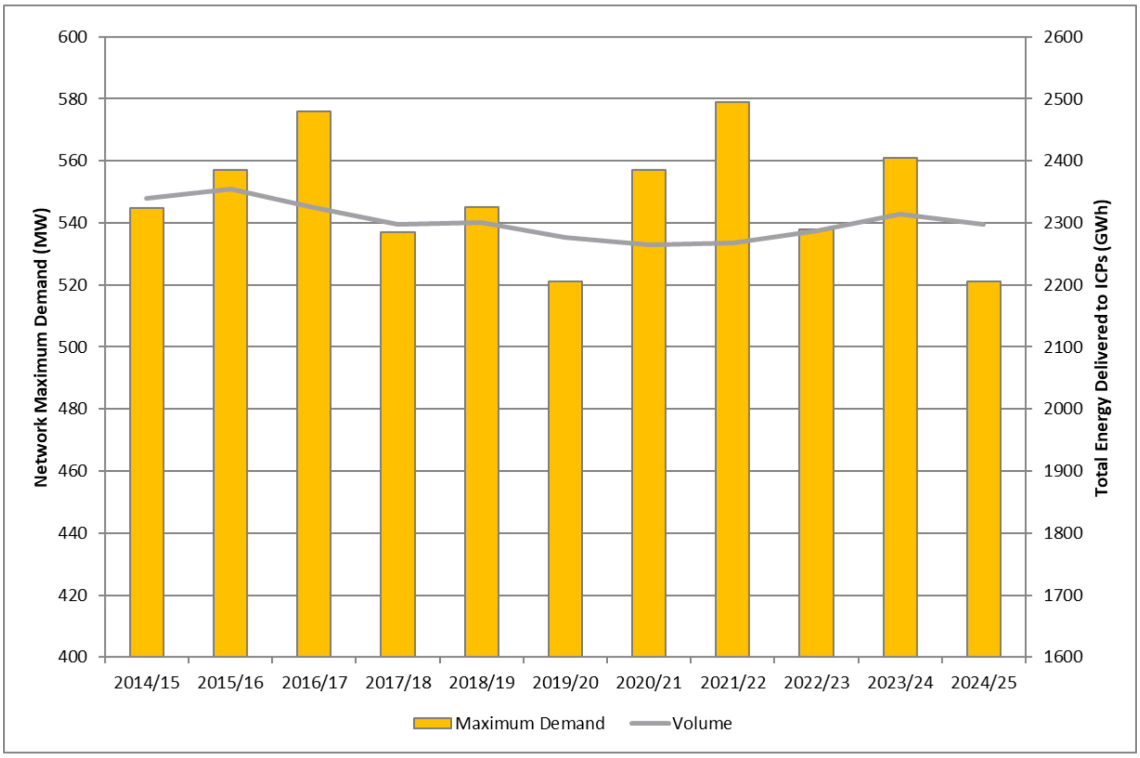



Figure 3-7 Maximum Demand and Energy Injected

On the Wellington network, the period of maximum demand occurs in winter when household heating is at its highest. The maximum demand recorded in any particular year is therefore highly dependent on the nature of the coldest winter weekday – the colder and wetter the day, the higher the maximum demand on the network will be during the evening peak. This dependency on weather creates a significant variation in maximum demand from year to year, around an underlying declining trend of about 0.5% per year, believed to be due to the increasing energy efficiency of the housing stock and residential appliances.

Volume figures are independent of maximum demand figures. Whereas maximum demand is set by the weather on the worst day of the year, volume is driven by whether the year as a whole is milder or colder than average, and prevailing economic conditions.

As shown in Table 3-9, the overall customer mix on the Wellington network consists of approximately 90% residential connections.

| Customer Type | ICP Count |
|---|---|
| Residential | 159,271 |
| Large Commercial | 552 |
| Medium Commercial | 478 |
| Small Commercial | 14,841 |
| Large Industrial | 45 |
| Small Industrial | 606 |
| Unmetered | 848 |
| Individual Contracts | 191 |
| **Total** | **176,832** |

Table 3-9 WELL's Customer Mix as at January 2025

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 Waka Kotahi, Wellington International Airport, and CentrePort;
- Large education institutions such as Victoria University of Wellington, Massey University, Whitireia and WelTec;
- Network security sensitive customers such as the stock exchange, Wētā FX, 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;
- Iwi;
- 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 a variety of media to communicate to and engage with its customers. Community meetings, exhibiting at public events, the WELL website and mobile application, public disclosure documents, newspaper, radio and digital advertising, email, and phone are all media that WELL uses. A focus for the 2025 is exploring a potential expansion into the use of social media as a way of providing more timely and quality engagement with customers.

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. Recent outages and upcoming planned outages are also shown on the website platform. Improving the customer experience by improving the accuracy of published estimated restoration times is a constant focus for WELL and its contractors.

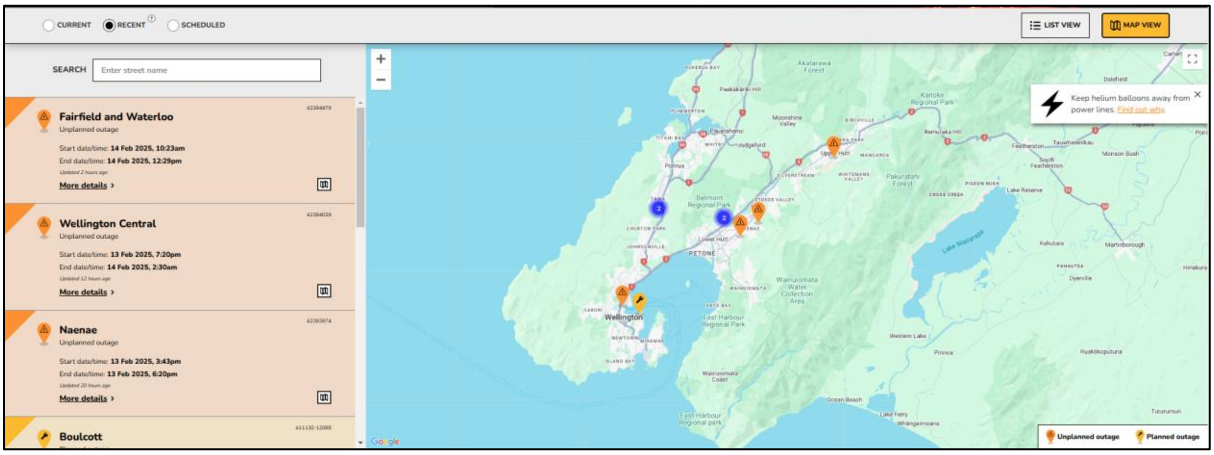



Figure 3-8 WELL's Web-based Outage Reporting Application

### 3.6.1.2 Iwi

WELL is committed to strengthening its relationships with local iwi. WELL is striving to communicate in an open and timely manner and to ensure there is an understanding of each other's priorities and expectations. Early engagement around projects will help provide positive outcomes.

### 3.6.1.3 Retailers

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

Customer quality of supply 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.

### 3.6.1.4 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 the regulatory development process, and preparing information disclosures.

#### 3.6.1.5 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 requires 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 the implementation of operational standards and procedures, appropriate investment in the network, and regular meetings.

#### 3.6.1.6 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.

#### 3.6.1.7 Industry Organisations

The interests of industry organisations such as Engineering New Zealand, Electricity Engineers Association (EEA), and Electricity Networks Aotearoa (ENA) 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 and community engagement strategies with industry frameworks and practices.

As a lifeline utility (an essential service), WELL also works closely with the Wellington Lifelines Group (WeLG). The purpose of WeLG 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 12.

#### 3.6.1.8 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.

#### 3.6.1.9 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.

#### 3.6.1.10 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 Distribution Agreement 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 in the management of the interface boundary with all principals 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. WELL is currently operating on the Default Price Path (DPP).

#### 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 Electricity Distribution Information Disclosure Determination 2012 to ensure that information is accurate and available in the prescribed form.

#### 3.7.1.4 Default Distributor Agreements

Retailers contract with Electricity Distribution Businesses (EDBs) for the supply of 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.[9] 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 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 comments and submissions when required.

#### 3.7.1.7 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.

### 3.7.2 The Changing Technology Environment

There continues to be much interest around customer-owned Consumer Energy Resources (CER) and how these will impact transmission and distribution networks, metering, centralised generation, and retailers. This new technology could also impact customers, with new markets developing for customers if they give permission for their assets to be used for demand management.

The growth of new technologies in the energy storage and market trading environments has a significant effect on the development of smarter electrical networks, and the ability of WELL to influence the timing of energy consumption. 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 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 penetration of EVs in Wellington's vehicle fleet, and the applicability and use of technology for network monitoring, design, and operation. Technology will have an increasingly significant impact on customer behaviour as EVs, PVs, and battery storage become more affordable.

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;
- **Congestion standards:** Introduce standards on how congestion is defined and allow distribution network congestion to be valued and cleared by the market;
- **Low voltage monitoring:** Improve the monitoring of the network, particularly LV with CERs where monitoring has previously not been required and where changes are most likely to be felt;

[9] https://www.welectricity.co.nz/disclosures/pricing/future-pricing

- **Support with efficient prices:** Introduce efficient price signals that reflect the benefits new technology can provide, while ensuring that this does not result in cross-subsidisation from customers who are unable to install their own CER;

- **Consumption and power quality data:** Consumption and power quality data are needed to support the operation of the low voltage network with an increasing prevalence of CER. The industry needs to decide what data is needed, at what standard of quality, and how to collect, store, protect, and utilise the information; and

- **Regulatory support:** Ensure the regulatory framework provides industry participants the tools needed to develop and implement these changes, including appropriate regulatory allowances for price-quality regulated businesses.

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 managing the uncertainty associated with new and emerging technology, while avoiding the risk of overbuild in the short term. It is WELL's view that the prudent use of new technology will enable the efficient 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, technology providers, and other industry participants, to draw on New Zealand-specific experience with CER integration.

#### 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 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 ran EV Connect, 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 distribution networks to accommodate the uptake of EVs.[10]

[10] https://www.welectricity.co.nz/major-projects/innovation-projects/ev-connect

### 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.

WELL regularly reviews which regulatory model is most appropriate for meeting its customers' needs, balancing the low-cost simplicity of the DPP against the ability to fund large capital programmes under alternative prices paths such as a CPP.

Funding for innovation projects has been available from Government initiatives such as the Low Emission Transport Fund (LETF). There is also an allowance of 0.8% of allowable revenue included in DPP4 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 Clause 54Q of Part 4 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.

# 4 The Future Network

In 2024 WELL modelled the impact of New Zealand's Emissions Reduction Plan (ERP) and incorporated the demand impact and service changes into its submitted AMP. This was an invaluable exercise to understand how the decarbonisation programme led by the Climate Change Commission would need to be supported by the efficient delivery of additional electricity infrastructure investment for net carbon zero in 2050.

The Commerce Commission has since determined the DPP4 Price-Quality Path for the period from 2025 to 2030, which has approved 40% of the capital allowances from WELL's 2024 AMP and maintained no substantial change to its current operational allowances.

This underlines a clear position by the Price-Quality regulator that uncertainty since March 2024 due to changes in economic climate and central government's response to these fiscal conditions has pulled back sustainability as the primary driver, and instead tempered infrastructure investment to fit within what the economy dictates as meeting household affordability and the security of supply they are willing to pay for.

Central government has cooled the EV market with removal of subsidies and implementing an end to a Road User Charge exemption for EV owners, pushing price parity with fossil fuelled vehicles out further.

The well-signalled energy risk headwinds for winter 2024 arrived and the interplay of low hydro storage levels and a 20% reduction in gas supplies doubled the winter price for the wholesale energy market, sending some industrial customers into closure. This prompted the Minister of Energy to issue a Government Policy Statement (GPS) in October 2024, directing the Electricity Authority to ensure that the energy market favours the cheapest fuels, even if this means that they are not renewable, so that wholesale electricity prices remain internationally competitive.

WELL's 2025 AMP picks up on this theme of cutting our cloth to what our customers expect, with a more balanced plan across the energy tensions between sustainability, affordability, and security of supply.

WELL's gas transition and electrified transport fleet assumptions are still set to a 2050 net zero goal, based on central government's ongoing commitment to this long-term target, however the rate of change in demand over the next 10 years has slowed, and the delivery strategy is focused on delivering capacity in smaller increments based on the allowances provided by the Commission. The future network will be slower to grow as WELL shifts its focus to a slower infrastructure investment path that meets security and reliability standards for its customers as determined on their behalf by the Commission.

However, WELL will need to reopen its Price Path based on a recent announcement that the Wellington Metro Rail network has been granted $137m to upgrade the rail network, and with WELL's contribution to building capacity for that project, signalled in the 2024 Plan, having been removed by the Commission's decision to limit capex to 40% of the submitted plan.

While this chapter traditionally has provided WELL's thoughts on how we expect our 30-year view aligns with the ERP delivery timetable, and of the Wellington network's resultant future demand and investment profiles, this is unable to be funded at the rate set out in our previous plan. The purpose of this chapter has now changed to providing context to the more detailed 10-year AMP planning window, outlining the overarching drivers and reasons behind the changes to this year's AMP disclosures.

## 4.1 Changes from the 2024 Asset Management Plan

WELL's 2024 AMP presented the required investment to support full decarbonisation by 2050, based on the information available at the time, focused on the cost-efficient delivery of capacity increases by sizing new assets (with expected lives of greater than 45 years) for the expected 30-year demand increases due to decarbonisation.

Since last year, deteriorating regional economic conditions, significant delays in major customers' decarbonisation programmes, and changes in government policy have reduced the expected rate of electrification in the Wellington region. This is reflective of the wider trend across New Zealand, with the top three concerns for businesses being the economic downturn, inflation, and labour shortages.[11] WELL's 2025 AMP is based on these revised forecasts. The end target of decarbonisation by 2050 remains, however, the lower rate of decarbonisation in the early part of the 30 years has resulted in a delay in some system reinforcement expenditure, pushing a proportion of that planned expenditure outside of the 10-year AMP horizon. Figure 4-1 shows the change in demand forecasts between the 2024 and 2025 AMPs.

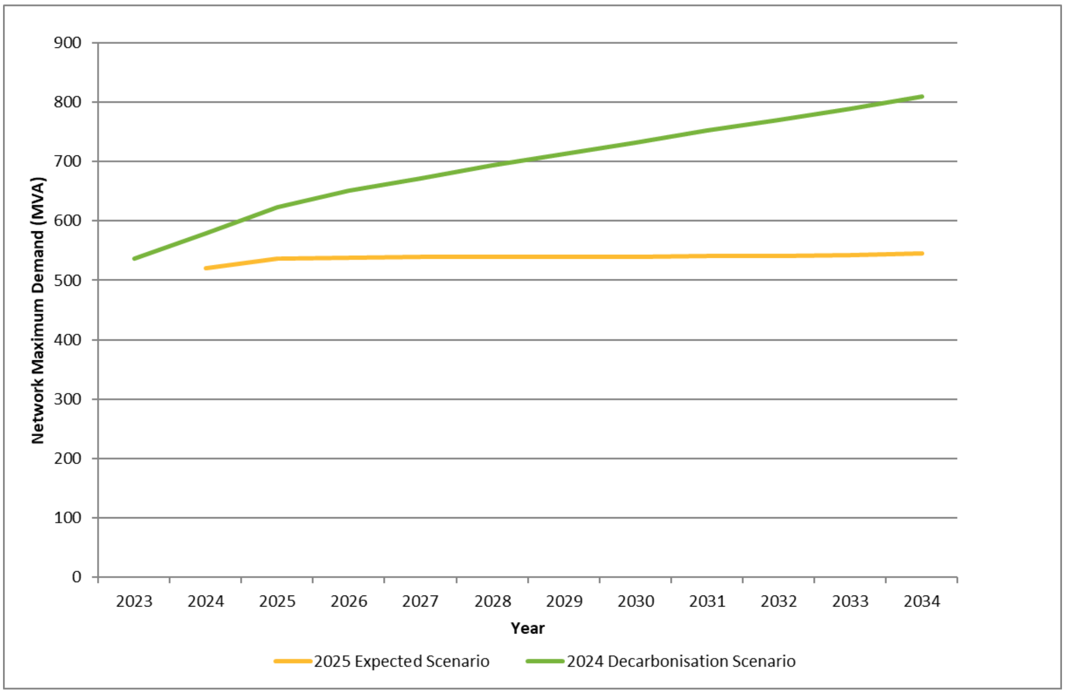



**Figure 4-1 Change in WELL's System Demand Forecast between 2024 and 2025 AMPs**

In November 2024, the Commission published its final decision on the DPP4 Price-Quality Path for 2025-2030. This decision awarded WELL a CAPEX allowance for the period representing 40% of the work programme signalled in WELL's 2024 AMP. WELL has reassessed its network reinforcement programme to identify smaller incremental capacity increases that can meet the forecast short-term load growth while delaying the larger investments that would have otherwise met both short- and long-term needs with a single project. Major customer-initiated projects will need to be funded using Price Path Reopeners, in order to manage the impact of the uncertain timeframes of these projects, and as funding these from the DPP4 allowances would require WELL to divert significant investment away from critical asset renewal and quality of supply programmes.

[11] World Economic Forum Global Risks Report 2025

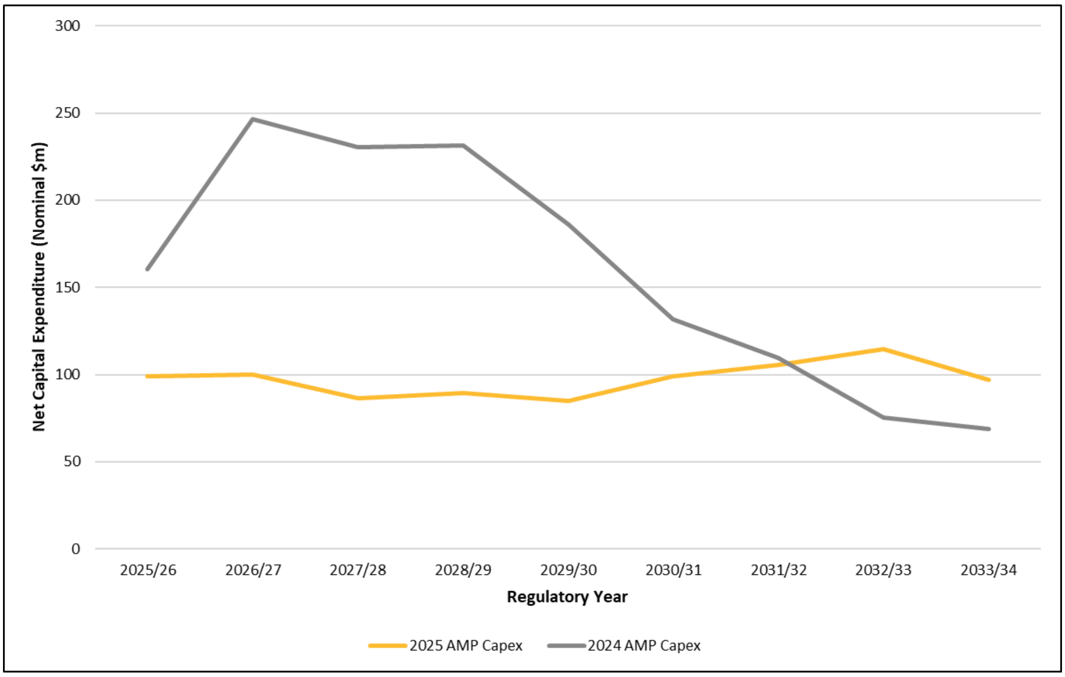



**Figure 4-2 Change in WELL's Capex Forecast between 2024 and 2025 AMPs (Net of Customer Contributions and Excluding Potential Customer-initiated Reopeners)**

The result is that in order to align with customer affordability expectations as set by the regulatory regime, WELL must implement an overall more expensive programme over the next 30 years than if WELL had been able to undertake the more efficient programme that was proposed in the 2024 AMP. This is because some capacity will need to be incremented twice during the asset lifetime instead of once, and there is a reduction in WELL's ability to coordinate projects into efficient larger packages of work. The details of these changes are provided in Appendix B.

### 4.1.1 On-going Development and Refinement of the AMP

WELL is making good progress on defining the investment requirements that will be needed to develop the capability and capacity to meet future demand. WELL's forecast models are being refined and updated as thinking is developed and new experience from innovation projects (discussed in Section 11) is incorporated, and as new information about the demand growth that will drive the timing of those needs becomes available.

Readers of AMPs can expect the forecast disclosures to change from year to year as AMP processes and forecasts are developed, refined, and adjusted. Unlike in the past 'business as usual' operating environment, EDBs will have to keep adjusting their investment plans to manage uncertainty in changes in demand, to reflect their own evolving understanding of how the services being delivered over their networks are changing, and what new capability is required.

## 4.2 The Drivers of Change

For the last decade, the Wellington distribution network has operated under a 'business as usual' operating environment with modest new connections growth and a steady asset replacement programme. Previous AMPs have focused on asset health, maintaining the existing asset fleets, and preserving the existing quality of supply levels. The majority of investments made have been to replace ageing assets as they reach the end of their useful lives. Similarly, the supporting regulatory model has been focused on efficiency, incentivising networks to provide the same level of service at a more efficient price, setting allowances and quality targets based on historic performance, and rewarding cost savings.

In response to modest historic long-term population growth in Wellington of less than 1% per year, and declining electricity use per household due to increasing energy efficiency, WELL developed demand management tools to deliver new growth using the existing network. Demand management tools are used to manage congestion by redistributing electricity usage across Wellington's meshed 11 kV network[12] or to shift electricity use to less congested times using ripple control and time of use prices. This has allowed WELL to meet new growth without needing to build expensive new network capacity, minimising the cost to customers.

The focus on efficiency has meant customers on the Wellington network have benefited from low prices and good quality of supply. The benchmarking analysis in Figure 4-3 shows that Wellington customers enjoy one of the lowest distribution prices in New Zealand while receiving one of the most reliable services. In the chart, WELL is the yellow diamond located in the low SAIDI/low-cost quadrant of the chart, with the other EDBs displayed as grey diamonds.

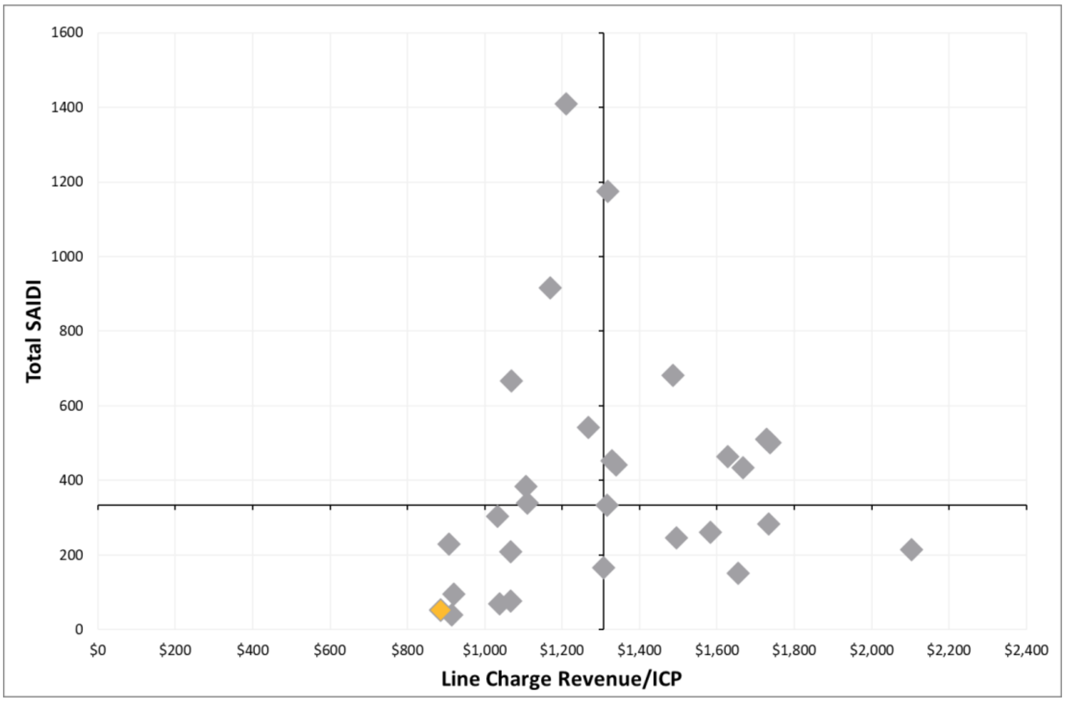



**Figure 4-3 Quality vs Price Benchmarking Analysis (2022-2024)[13]**

[12] Parts of Wellington's 11 kV network are designed in a mesh pattern which allows the supply of electricity to be redistributed to where it is needed. If a part of the networks is congested, electricity can be supplied from another direction to relieve the congestion.

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

### 4.2.1 Electrification Trends

The primary uncertainties around demand growth on WELL's network are due to the electrification of transport, both private EVs and public transport, and the future of fossil gas as a residential fuel.

#### 4.2.1.1 EV Growth

Wellington has seen a rapid uptake in electric vehicles. As of 31 December 2024, the WELL network area is home to approximately 261,000 light passenger vehicles, with 13,000 of these being electric or plug-in hybrids.[14] The growth of the electric light passenger vehicle fleet was relatively steady until the introduction of the Government's Clean Car Discount programme from 2021 to 2023, which drove a significant increase in the rate of EV registrations until its expiry at the end of 2023. The rate of EV uptake during 2024 was significantly lower. The trend in the number of EVs as a proportion of the total light passenger vehicle fleet in WELL's network area is shown in Figure 4-4.

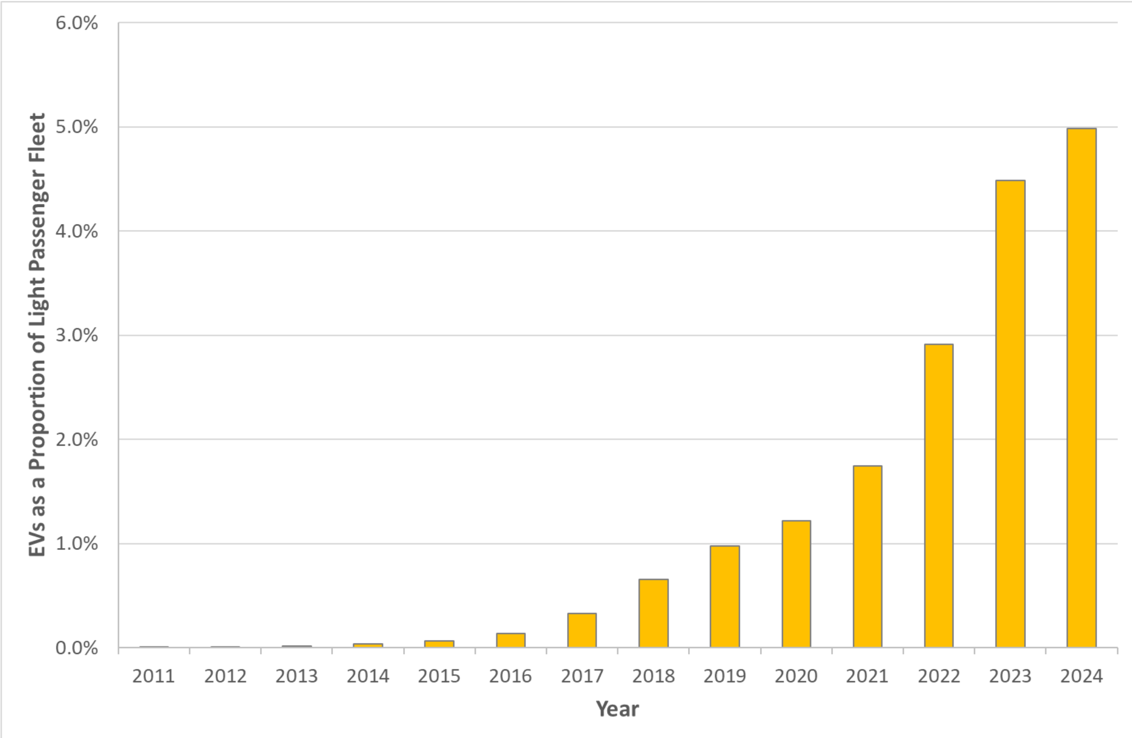



Figure 4-4 EVs as a Proportion of the Light Passenger Fleet in WELL Network Area

The Government's Clean Car Subsidy helped close the price gap between fossil fuel vehicles and EVs, leading to a surge in EV registrations from July 2021, followed by a large drop when the incentive was removed at the end of 2023, shown in Figure 4-21.

[14] Waka Kotahi Open Data Portal

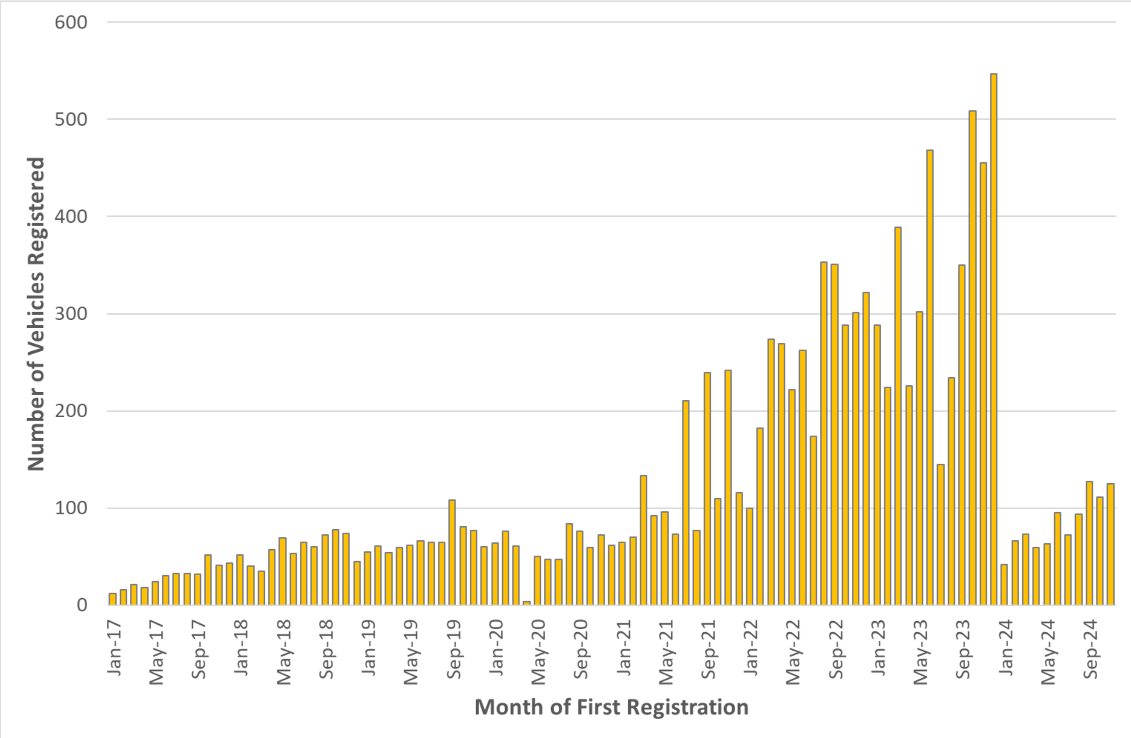



Figure 4-5 Monthly Registrations of EVs and PHEVs in the WELL Network Area

The influences of government subsidies, supply restrictions, the speed of technology improvements, customer choice, and customer charging habits, all make it difficult to forecast EV uptake and the associated impact on electricity demand.

WELL procured EV registration location data from NZTA in early 2024. This was supplied at Statistical Area (SA2) level, which breaks the Greater Wellington region up into 174 areas with an average of 1,000 residential dwellings per area. This data was then used to produce a heat map of EV registrations per 100 ICPs, which is presented in Figure 4-6. This shows the wide range of uptake rates across the region, from 0.5% of ICPs having an EV in areas of high deprivation to 20% of ICPs in some rural lifestyle suburbs.

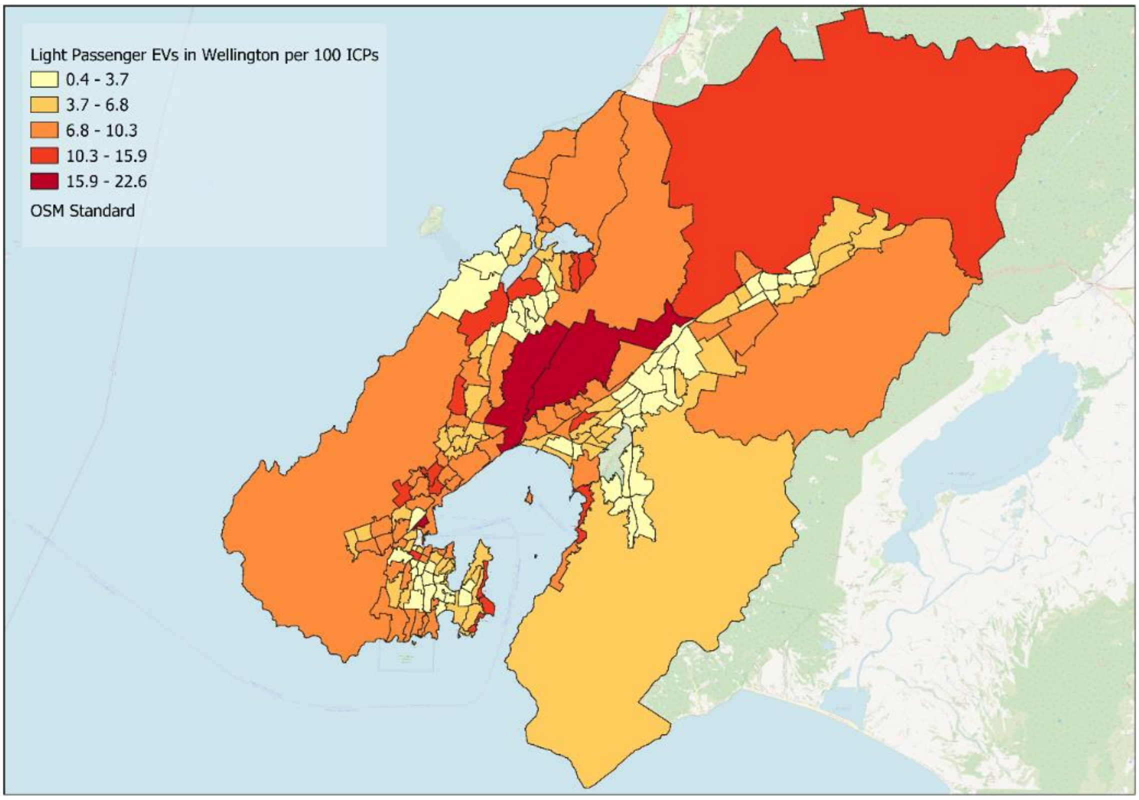



**Figure 4-6 Estimated EV Uptake per ICP by Statistical Area as of February 2024**

Registration data can be used to approximate the impact of EVs on the network, but it does not provide information about where the EVs are being charged. EDBs are currently unable to access information about private EV charging locations. Networks need this information to forecast and manage congestion on the LV networks that EV chargers are connected to.

#### 4.2.1.2 Electrified Public Transport

WELL's demand forecast in the 2024 Plan included an increase in the capacity of Wellington's electric rail services, electrifying the regional bus fleets and the electrification of air transport, as WELL had been in discussions with transport operators about supporting their decarbonisation projects.

Public transport operators have scaled back, delayed, or cancelled these decarbonisation projects over the last 12 months. WELL cannot predict whether these projects will eventuate and, if they do, when they will impact maximum demand on the network. Table 4-1 provides a summary of the changes to WELL's forecasts of public transport electrification's contribution to network maximum demand, between the 2024 and 2025 AMPs.

| Transport Type | 2024 AMP Forecast | 2025 AMP Forecast | Change in Forecast |
|---|---|---|---|
| Rail Network Upgrades | 25 MW | 8.5 MW | -16.5 MW |
| Bus Fleet Electrification | 15.5 MW | 3 MW | -12.5 MW |
| Port Operation Electrification | 20 MW | 0 MW | -20 MW |
| Air Transport Electrification | 2 MW | 0 MW | -2 MW |
| **Total** | **62.5 MW** | **11.5 MW** | **-51 MW** |

**Table 4-1 Changes in Major Transport Electrification Projects in the WELL Network Area**

#### 4.2.1.3 The Impact of Shifting Reticulated Gas Use to Electricity

Under the ERP the government is expected to develop a transition plan for natural gas. Until this plan is published, it is not known what impact it will have on the demand on WELL's network. Fossil gas use could transition to a biogas substitute, hydrogen, the electricity network, or a combination of the three.

The potential transition to electricity would have a significant impact on the demand on WELL's network. Approximately 65,000 properties have a reticulated natural gas connection,[15] used for water heating, space heating, and cooking, which represents 40% of WELL's residential customers. WELL's network has been historically designed and operated in a manner that reflects this prevalence of gas as a residential fuel, due to gas-heated houses typically having a very low after-diversity maximum demand (ADMD).

It is likely that some customers will choose to transition their own gas use, regardless of government policy. This will be driven by cost increases due to worsening gas shortages[16] and the accelerated depreciation of gas networks that has been permitted by the Commission being reflected in rapidly increasing fixed daily charges for gas connections. The speed of this self-transition will be limited only by customers' ability and willingness to invest in replacing their gas appliances.

The gas transition will inevitably increase WELL's winter peak demand. An increase in electric water heating can be managed through an extension of EDBs' ripple control capabilities (see Section 4.2.2.1), however cooking and heating load will be non-discretionary, and add directly to the evening peak. WELL's future load growth, and hence any network constraints and reinforcement required, will remain highly uncertain.

[15] PowerCo 2023 Gas Asset Management Plan, Appendix 6.

[16] https://www.mbie.govt.nz/about/news/gas-production-forecast-to-fall-below-demand

**Case Study 1 – The Impact of EVs and the Gas Transition on the Low Voltage Network**

The transition to electric vehicles and from gas use to electricity for residential space and water heating will have a large impact on the low voltage network, increasing the demand from existing connections. To better understand the impact on the LV network, WELL commissioned ANSA to develop an LV CAPEX forecasting tool to assess the impact on its low voltage networks located in residential areas.

The desired outcome was to determine the proportion of assets that were likely to become constrained and require upgrade for each LV network, across a range of different future EV uptake and gas-to-electricity transition scenarios. In turn, given the upgrade costs of each asset type (distribution transformer, LV cable, and LV overhead line), this information has been used to calculate the capex requirement by regulatory period for a given constraint risk threshold and decarbonisation scenario.

This capex forecast is shown in Table 4-2. The figure compares the cumulative LV reinforcement capex (the capex required to solve LV constraints) to 2050 under some of the growth scenarios that have been modelled, with combinations of EV uptake and gas transition rates, including a scenario where rapid EV uptake is coupled with widespread demand-side flexibility that ensures that the majority of EV charging occurs outside of the evening peak demand period.

| | | EV Uptake Rate | | |
|---|---|---|---|---|
| | | Slow | Rapid | Rapid with Flex |
| Gas Transition | None | $161m | $336m | $145m |
| | Rapid | $185m | $368m | $147m |

Table 4-2 Cumulative LV Reinforcement CAPEX to 2050 by Growth Scenario

The results provide important insights into the future capex required to mitigate network congestion on the LV network, the magnitude of the cost reduction for customers that can be realised through incentivising moving discretionary demand off-peak through the cost-reflective pricing of congestion, and how flexibility in one type of demand can create capacity headroom that reduces the cost impact of another type of demand.

The ANSA study is discussed in more detail in Section 9.7.

As well as a high prevalence of gas as a residential fuel, there are a number of large commercial and business users of gas on the Wellington network. DETA has surveyed large gas users in Wellington to assist in the planning of the transition to alternative energy sources like electricity. The survey indicated that the businesses that responded have 90 MW of gas load that could transition to up to 40 MW of additional electricity use. WELL is supporting further work being undertaken in this area by EECA’s Regional Energy Transition Accelerator (RETA) programme to understand gas users’ transition costs, however such analysis must be approached with care as a superficial review by external parties may not recognise the need for networks to retain spare capacity in their networks to support operational contingency plans, and therefore understate the network investment required to support the transition.

WELL supports the continued use of gas as a transition fuel. Continued use of the existing gas transmission and distribution networks maximises the value to the community of those existing assets while delaying some of the capital expenditure required to reinforce the electricity distribution network to support the electrification of heating for a significant proportion of WELL's customers.

### 4.2.2 CER and Flexibility Services

A significant proportion of future network use will be related to Consumer Energy Resources (CER): customer-owned devices that can be used to generate, store, or manage electricity. These devices are purchased by customers and connected in their homes and businesses. An example of CER is smart, web-enabled EV chargers. The battery charging can be contracted to be remotely managed for the benefit of the customer, delaying the charging until periods when electricity prices are lower without requiring any active participation by the customer.

The Electricity Sector has identified the development of flexibility services as being a key to enabling the delivery of New Zealand's Emissions reduction targets. The October 2024 Government Policy Statement on Electricity, Ministry for the Environment's '*Second Emission Reduction Plan',* the Authority's '*Updating the Regulatory Settings for Distribution Networks'* consultation, Transpower's '*Whakamana i Te Mauri Hiko',* and Boston Consulting Group's *'The Future is Electric'* all highlight the central roles flexibility services can have in managing demand and supply uncertainty and helping to manage the size of customer bill increases.

Flexibility services for new smart connected managed CER are in their infancy and still need to be developed into an industry-wide solution in order to provide the scale needed. There is uncertainty about how dependable these services will be as an alternative to building traditional capacity, how quickly they will grow to the scale required, and whether they will be available every time a network needs them. While the industry recognises the potential value, the capability still needs development to be able to confirm whether the expected benefits will be realised, and this will take time.

Early progress has been made by retailers, but typically this is smaller retailers who lack the geographic concentration necessary to help EDBs manage network constraints. As flexibility services are the aggregation of customer-owned assets, the speed with which flexible demand can scale to the level required is totally dependent on customer investment and participation decisions. The recent slowdown in uptake trends of EVs and DG connections is a warning to EDBs that it cannot be taken for granted that flexibility services will be available to provide a solution to network constraints.

**Case Study 2 – Managing Aggregated Demand**

Figure 4-7 provides a simplified example to illustrate why the use of large CER needs to be coordinated. The example uses a sample LV network with a 300 kVA transformer and assumes 30% of households have a large EV charger. If all large EV chargers connected to an LV network charge at the same time when the network is already busy, the network operating limits will be exceeded, potentially resulting in outages or unacceptably low voltage for customers, which would need to be resolved by the EDB investing in installing a larger transformer.

However, if large EV chargers are smart and able to be coordinated, their combined use can remain within the transformer's physical current and voltage limits. Doing this ensures that EVs are charged and ready to be used when their owners want, utilising spare capacity on the existing assets, without their use impacting the supply of electricity to other users of the network, and delaying the need for the EDB to invest in upgrading the transformer. This creates a financial benefit that is shared among all customers.


**Figure 4-7 Example Impact of Large EV Charger Management on LV Network Capacity Without Charger Coordination (Left) and With Charger Coordination (Right)**

The caveat is that this coordination of aggregated demand needs to be completely successful at keeping demand within the network limits, for every single peak demand period for the remaining life of the existing assets. Any failure of the coordination resulting in aggregated demand exceeding the network limits can cause outages due to thermal constraints being exceeded, or asset failure due to premature aging. An EDB relying on third party control to keep demand within the capacity of its assets may face consequences for a reduction in power quality, unexpected costs, and potential liabilities under legislation, caused by its reliance on the actions of third parties outside of the EDB's direct control. EDBs will therefore need to have a very high level of confidence in the predictability and reliability of third-party control measures before they will be able to rely on them as an alternative to traditional investments in increased asset capacity.

#### 4.2.2.1 Extending Hot Water Ripple Control

Wellington has 65,000 gas connections, providing hot water heating, space heating, and cooking for residential customers. The potential conversion of gas usage to electricity would represent a significant increase in peak demand. EDBs will need to extend their existing hot water ripple control systems to capture the transition of gas to electricity and provide rapid, coordinated, and cost-effective management of this new load. This will require:

- Funding to extend the capacity of EDBs' ripple plants,
- EDBs having priority access to ensure that meter-controlled hot water is available for system security purposes, for example as load shedding in response to a Network Emergency declared by the EDB, or Grid Emergency declared by the System Operator, and
- Policy changes to support the transition of new electric hot water heating load onto ripple control, due to ripple control being the fastest, most resilient, and most reliable technology for the rapid shedding of hot water load in an emergency.

Without extending this capability, networks may not be able to maintain a stable network for the period until they have the time and allowances to build new capacity. It is not yet clear whether the decentralised control of hot water by retailers will be able to deliver the coordinated and equitable response needed to avoid exceeding the network's physical voltage and current limits, with enough consistency to allow EDBs to be confident to rely on them as an alternative to ripple control for deferring network reinforcement expenditure. With EDBs being accountable for power quality under the Commerce Act, Consumer Guarantees Act, and Electricity (Safety) Regulations, while lacking the protections provided to the transmission grid under the Code, EDBs retaining direct control of hot water through their ripple control systems during peak demand periods is likely to remain essential for continuing to meet their regulatory responsibilities.

#### 4.2.2.2 Supporting Regulatory Framework and Hierarchy of Needs

Careful planning is needed to design a regulatory framework to ensure flexibility services are available whenever they are needed by networks (both EDBs and the System Operator) to maintain network security. Flexibility services first need to be available in emergencies – when direct intervention is needed to 'keep the lights on' – and then once the distribution network and grid are operating stably, to be available wherever they provide the most value to customers, subject to limits to ensure that they do not adversely affect other customers' power quality.

Practically this will mean the development of a flexibility market which assigns flexibility services to where they provide the most value (i.e. who will pay the most to buy the services), with guardrails set according to the laws of physics that govern current and voltage on the distribution network, and will have a set of prioritising rules that provides networks with emergency access to all services. The regulatory framework setting the terms and conditions for services between EDBs and retailers provides an example of how this could work in practice. The Default Distribution Agreement (DDA) outlines that parties other than EDBs can provide load control services on the distribution network but must provide EDBs and the System Operator access to those services in emergencies. Similar rules should be expanded to include flexibility service providers that are not retailers.

The market rules for the operation of the New Zealand transmission grid can provide a template for the framework that flexibility services can operate within. With the EDB assigning value to constraints on the distribution network (e.g. through operating envelopes or capacity pricing bands), Retailers can optimise their position by balancing load, generation, and storage to clear the constraint at the most favourable cost for customers. This framework would provide a clear signal to the EDB of the economic case for network investment to resolve the constraint.

Flexibility services using customer-owned devices connected to distribution networks could also be dispatched by parties outside of the distribution network, for example the System Operator dispatching devices to manage grid-level security. In doing this, the System Operator will need to be mindful of the interaction between services that it procures that are embedded within distribution networks, and the services required to be provided by EDBs under the Code. An example is Automatic Under Frequency Load Shedding (AUFLS), where the automatic disconnection of distribution load to support system frequency can disconnect Virtual Power Plants (VPP) or demand-side management that the SO has contracted.

EDBs will need the ability to ensure that the operation of CER by third parties remains within the network's operating limits. EDBs are responsible for distribution network quality and face fines under the Commerce Act of up to $5m per quality breach for non-compliance, and are liable under the Consumer Guarantees Act for damage to customer appliances. Therefore, EDBs must have oversight of how these devices are being used, and the ability to apply penalties to third parties whose actions have been identified as having had a detrimental effect on the safe operation of the network, so that they can continue to meet their regulatory obligations.

### 4.2.3 Changing Customer Expectations

New technologies are offering customers new benefits and opportunities and are changing how they use electricity. Table 4-3 summarises the changing customer requirements and the resulting impact on the distribution network.

| New Customer Requirement | Impact on Network | Potential Network Investment |
|---|---|---|
| New large appliances like EV chargers. | Residential ADMD increasing beyond what the low-voltage network was designed for. | Reinforcement of the LV network.<br>Increasing distribution transformer sizes.<br>The need for flexibility services to manage the uptake of large CER |
| Increased reliance on electricity as the sole household energy source. | Expectation of higher service quality and fewer outages. | Increasing network resilience. |
| Increasing use of flexible working arrangements, such as working from home. | Less tolerance for planned outages for maintenance in residential areas. | Deployment of mobile batteries (in place of diesel generators) to maintain supply to customers during maintenance activities. |
| Customers wanting to share spare electricity they have stored or generated. | Two-way power flows on the LV network.<br>Voltage profiles becoming less predictable. | Increased visibility and control of the LV network. |

Table 4-3 Summary of Changing Customer Requirements and Network Impacts

### 4.2.4 Asset Replacement Programme

Several of WELL's largest asset fleets are coming to the end of their useful lives. Specifically, the replacement of underground cables and power transformers has started and will continue over the next 25 years. The replacement of these two asset fleets is a step change in the replacement programme.

There are strong synergies between this renewal and the network reinforcement programme, as the major assets approaching end of life may also require capacity upgrades. In the 2024 AMP, the need for more capacity was usually the first investment trigger, resulting in asset replacements being brought forward to align with the need to support ERP-related growth. The revised forecasts in this AMP have resulted in many of those capacity trigger points being reached later. Synergies will still be achieved, however, in some cases, the trigger point for investment will now be the asset reaching end of life, rather than the need for capacity.

## 4.3 WELL’s Long-Term Investment Programme

WELL’s 30-year combined capital expenditure programme rationalises the investment programme so that new assets have both the capacity needed to meet future growth expectations and are replaced before they adversely impact quality. Where an asset is required to be included in both the replacement and network growth programmes, the asset replacement will be scheduled to meet the earliest of the asset replacement date or when the new capacity is required.

### 4.3.1 WELL’s Consolidated 10-year Subtransmission Investment Programme

The 33 kV network of subtransmission assets and zone substations is a key component of WELL’s ability to meet its customers’ future needs. WELL’s programme of investment in its zone substations and 33 kV network over the next ten years is the consolidation of multiple workstreams into a single coordinated programme. This programme aims to:

- Ensure the ongoing safety of network assets for the public and workers.
- Increment network capacity as needed to support growth and decarbonisation, at a rate that remains affordable for customers.
- Maintain network quality at a level that customers are willing to pay for.
- Reduce resilience risks relating to earthquakes and the changing climate.

Figure 4-8 shows a summary view of WELL’s zone substations and 33 kV network, highlighting which aspects of capacity, asset condition, resilience, and criticality are driving investment in the assets over the next 10 years. Table 4-4 provides the definitions for the site ratings displayed in Figure 4-8.

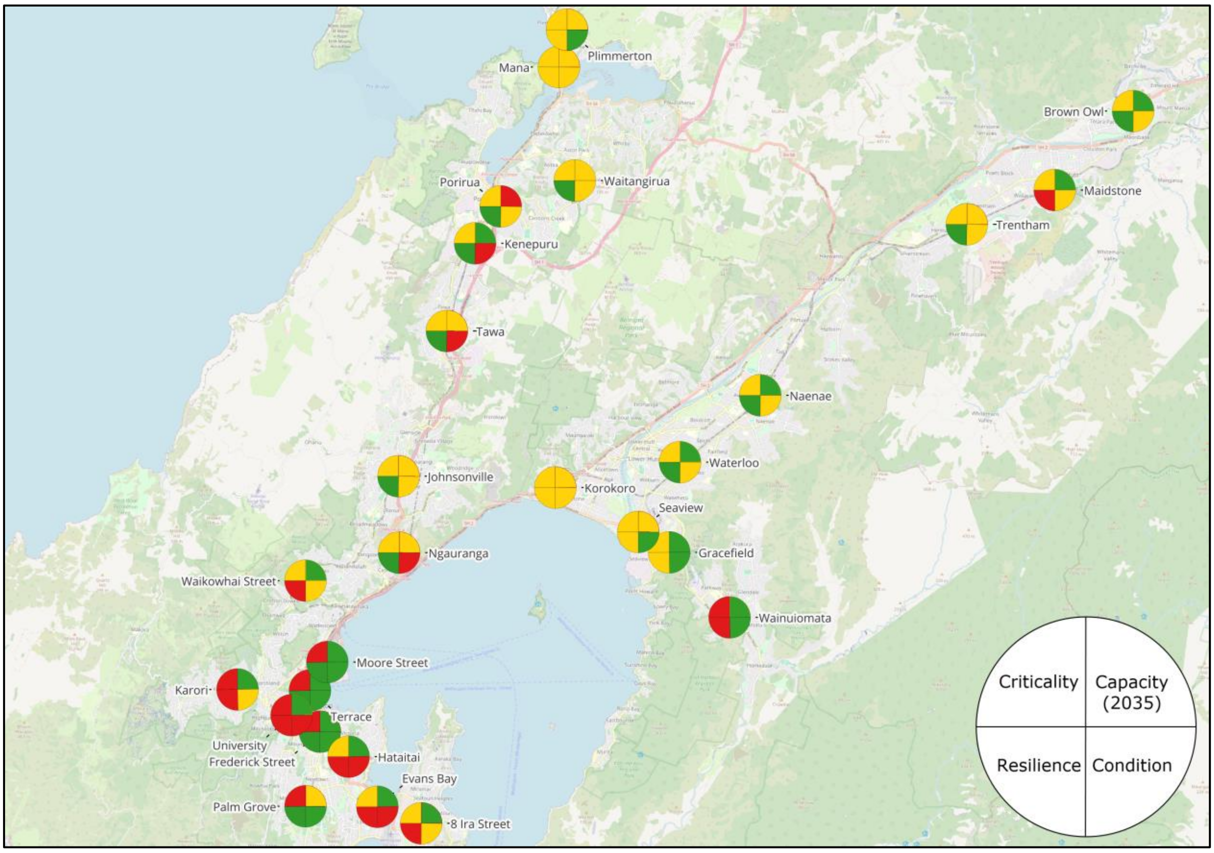



Figure 4-8 WELL's Subtransmission and Zone Substation Planning Statuses

| Aspect | Red Rating | Orange Rating | Green Rating |
|---|---|---|---|
| Capacity (Section 9.2) | 2035 Maximum Demand exceeding present N-1 capacity and outside capability of existing operational measures. | 2035 Maximum Demand exceeding present N-1 capacity, with risk controllable through existing operational measures. | 2035 Maximum Demand less than present N-1 capacity. |
| Condition (Section 8.3) | 33kV cable or power transformer Asset Health Index 2 or less. | 33kV cable or power transformer AHI between 2 and 3.[17] | 33kV cable or power transformer AHI 3 or greater. |
| Resilience (Section 12) | Gas-filled 33kV cables (Section 12.5.2).<br>Located at network edge with limited 11kV interconnectivity. | Located within a tsunami evacuation zone. | All other zone substations. |
| Criticality (Section 8.3) | Supplying a major hospital.<br>Supplying Wellington CBD.<br>Potential N-2 Extreme Outage (Section 7.1.1). | All other zone substations. | - |

Table 4-4 Ratings for Consolidated View

The issues identified in Figure 4-8, their solutions, and references to discussion of these issues in this Plan are presented in Table 4-5.

[17] The highest possible AHI for a fluid- or gas-filled cable is 2.9 due to type factors in the EEA health model.

| Zone Substation | Rating | Key Issues | 10-year Plan | Timeframe | 2025 AMP Reference |
|---|---|---|---|---|---|
| 8 Ira Street | | Resilience (Gas Cables) | Replacement of 33kV gas cable sections between Evans Bay 33kV bus and Ira Street | 2031 | 9.4.2.1<br>12.5.2 |
| Brown Owl | | 33kV Fluid Cables | - | - | 9.6.2.1 |
| Evans Bay | | 33kV Cable Condition<br>Resilience (Gas Cables) | Replacement of 33kV gas cable sections between Hataitai 33kV bus and Evans Bay | 2030 | 9.4.2.2<br>12.5.2 |
| Frederick Street | | Criticality (CBD) | Improved 11kV ties to allow offload to adjacent zone substations | 2029 | 9.4.2.4 |
| Gracefield | | Resilience (Tsunami Zone) | - | - | 12.4.2.4 |
| Hataitai | | 33kV Cable Condition<br>Resilience (Gas Cables) | Repaired and being monitored<br>New 33kV bus at Hataitai.<br>Replacement of 33kV cables between Central Park and Hataitai, aligned with SH1 projects | 2030<br>2032 | 8.5.1<br>9.4.2.5<br>12.5.2 |
| Johnsonville | | 33kV Fluid Cables<br>Capacity | Develop new zone substation in Grenada to offload Johnsonville and Ngauranga | 2028 | 9.5.2.1 |
| Karori | | Resilience (Gas Cables, Network Edge) | Reinforce 11kV ties between University and Karori<br>Replace 33kV gas cables | 2027<br>2033 | 8.5.1<br>9.4.2.6<br>12.5.2 |
| Kenepuru | | Transformer Condition | Replace power transformers | 2028 | 8.5.2.1 |
| Korokoro | | Resilience (Tsunami Zone) | - | - | 12.4.2.4 |
| Maidstone | | Gas Cable Condition<br>Resilience (Gas Cables) | Replace 33kV gas cables | 2030 | 8.5.1<br>12.5.2 |
| Mana | | Capacity<br>Resilience (Tsunami Zone)<br>Transformer Condition | Reinforce 11kV ties south of Mana<br>Replace power transformer | 2027<br>2030 | 9.5.2.4<br>8.5.2.1 |
| Moore Street | | Criticality (CBD) | Ongoing demand and asset condition monitoring | - | 9.4.2.7 |
| Naenae | | 33kV Fluid Cables | Reinforce 11kV ties to adjacent substations | 2027 | 9.6.4 |
| Ngauranga | | Capacity<br>Transformer Condition | Replace power transformers | 2028 | 9.5.2.3<br>8.5.2.1 |
| Palm Grove | | Capacity<br>Criticality (Hospitals) | Solution pending customer decision. Ongoing demand and asset condition monitoring | - | 9.4.2.8 |
| Plimmerton | | Resilience (Tsunami Zone) | - | - | 12.4.2.4 |
| Porirua | | Capacity | New 11kV feeders from Kenepuru to increase transfer to Kenepuru<br>Replace 33kV fluid cables, power transformers and 11kV switchgear | 2026<br>2030 | 9.5.2.6 |
| Seaview | | Resilience (Tsunami Zone) | - | - | 12.4.2.4 |
| Tawa | | 33kV Cable Condition | Repaired and being monitored | - | 8.5.1<br>9.5.2.7 |

| Zone Substation | Rating | Key Issues | 10-year Plan | Timeframe | 2025 AMP Reference |
|---|---|---|---|---|---|
| The Terrace | | Criticality (CBD) | Ongoing demand and asset condition monitoring | - | 9.4.2.10 |
| Trentham | | Capacity | Replace 33kV fluid cables | 2027 | 9.6.2.9 |
| University | | 33kV Cable Condition<br>Resilience (Gas Cables)<br>Criticality (CBD) | Replace 33kV cables<br>Reinforce 11kV ties between University and Karori | 2027<br>2032 | 8.5.1<br>9.4.2.11<br>12.5.2 |
| Waikowhai | | Resilience (Gas Cables) | Replace 33kV gas cables | 2037 | 12.5.2 |
| Wainuiomata | | Resilience (Network Edge) | Reinforcement of 11kV feeders from Gracefield to increase transfer to Wainuiomata | 2031 | 9.6.2.10 |
| Waitangirua | | Capacity | Reinforcement of 11kV feeders to increase transfer to Porirua and Mana | 2027 | 9.5.2.8 |
| Waterloo | | Fluid Cable Condition | Reinforce 11kV ties to adjacent substations<br>Replace 33kV fluid cables | 2027<br>2035 | 9.6.4<br>8.5.1 |

Table 4-5 10-year Subtransmission and Zone Substation Work Programme

The following sections discuss the external factors that could impact on the delivery of this programme.

### 4.3.2 Demand Uncertainty

EDBs will have to build new capacity to meet the 2050 emissions reduction targets. However, there is uncertainty around the rate of the demand increase and in what sequence that new capacity will be needed. Demand is the primary driver of the timing of network reinforcement investment programmes, and uncertain demand will result in networks having to adjust the order of the work programmes.

Specific drivers of demand uncertainty and work programme resequencing are:

- How fast will customers transition from fossil gas? The electricity system is expected to provide some or all of the energy use currently provided by natural gas.
- How quickly will flexibility services be developed to the scale and reliability needed to better utilise the existing distribution network? If these services are not successfully developed, networks will have to build more capacity.
- What will the speed of EV uptake be? EV uptake rates have exceeded that provided in the 2022 ERP, however demand has cooled significantly following government policy changes. Case Study 3 looks at the uncertainty in EV uptake forecasts.
- Where will the growth be? Many EDBs have no visibility of demand on their LV networks and where customers are charging EVs or replacing gas appliances. While distribution connection standards say that customers must apply to an EDB before connecting DG, there is no requirement for customers to tell the network that they are connecting a large EV chargers or household batteries.

**Case Study 3 – The Uncertainty in EV Uptake Forecasts**

EV uptake rates have been shown to be dependent on a range of drivers like the level of government subsidies, the resulting affordability of those vehicles, and suppliers' ability to keep up with the resulting demand.

EECA's 2019 electric vehicle growth scenarios[18] varied based on how fast the price of EVs reach price parity with internal combustion engine vehicles. The speed at which this occurs will be influenced by factors like production/technology costs, government subsidies, and other incentives. The EECA scenarios are shown in Figure 4-9, overlaid with the actual fleet size for 2021 to 2024 to illustrate the current situation.

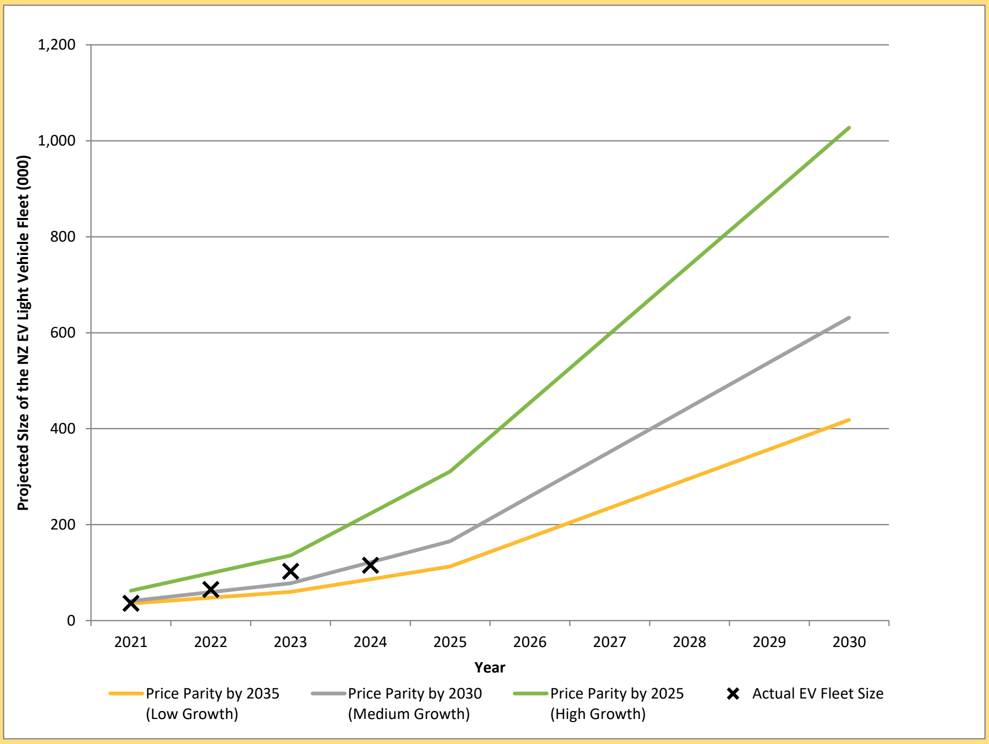



Figure 4-9 EECA's New Zealand EV Uptake Scenarios (2019) [18]

### 4.3.2.1 The Impact of Demand Uncertainty

Forecast demand drives when new network capacity is needed. Fast demand growth means that EDBs will need to bring forward a work programme. Lower demand means networks can push back when they need to build new capacity.

The judgement of when and what new capacity is needed will become more difficult. EDBs will not be able to precisely match demand and capacity as they have in the past. Some of the drivers of demand growth could result in rapid changes that may require networks to quickly change their investment forecasts. For example, an exponential gas exit by customers could quickly add unexpected new load within a regulatory

[18] https://www.eeca.govt.nz/assets/EECA-Resources/Research-papers-guides/EV-Charging-NZ.pdf

period before regulatory allowances are able to respond. Other changes may be slower and the ability to change investment profiles within a regulatory period may not be as important.

EDBs will need the ability to adjust the sequence of their work programmes in response to changes in demand growth rates. Networks will need to continue to refine their demand growth models and develop flexible planning processes that will ensure that new capacity is built before demand exceeds capacity and a secure electricity supply continues to be provided. EDB work programme sequencing, in response to volatile and potentially rapid demand growth, will need to consider:

- Large subtransmission projects have long (up to three years) lead times. The work programme must consider faster-than-expected growth rates within the build window. Practically this means including a buffer that will ensure capacity is available before the fastest growth scenario within the build window.

- An EDB may have to adjust when it builds capacity to match the availability of resources. If other EDBs and infrastructure providers, both locally and internationally, are also investing in their networks, there is likely to be a worsening resource shortage. Not only will networks need the ability to adjust their investments to match demand, but they will also need to consider the availability of resources as part of this investment forecasting.

Networks will need flexible regulatory mechanisms that allow regulatory allowances to be shifted to when the investment is needed. The current regulatory model provides allowances in five-year investment blocks, built on an assumption that demand growth is well-understood and predictable. The model also provides some flexibility with the ability to request additional allowances for unforeseen large customer projects if specific criteria are met and the investment is approved by the Commission. However, the ability to access new allowances is limited and the application process is slow.

WELL believes that regulatory flexibility is necessary for re-sequencing programmes between regulatory periods. Given that large subtransmission upgrades have 3-4 year design and build cycles, relatively short and rigid five-year regulatory funding periods may no longer be fit for purpose, with longer planning cycles or the ability to re-order work programmes between regulatory periods being needed to allow networks to efficiently match funding with expenditure. It may be that an ongoing Individual Price Path (IPP) regulatory framework is needed to allow networks to manage the transition of work programmes between regulatory periods.

### 4.3.3 Increasing Costs

WELL has experienced higher cost inflation than the general national inflation and expects the electricity industry will continue to see higher cost inflation as work programmes increase and equipment and labour become even more scarce and constrained. At the same time, water networks are expected to start replacing New Zealand's ageing water infrastructure, which will place further pressure on the availability of civil contractors. Figure 4-10 provides examples of changes in electricity industry costs since 2013 relative to CPI.

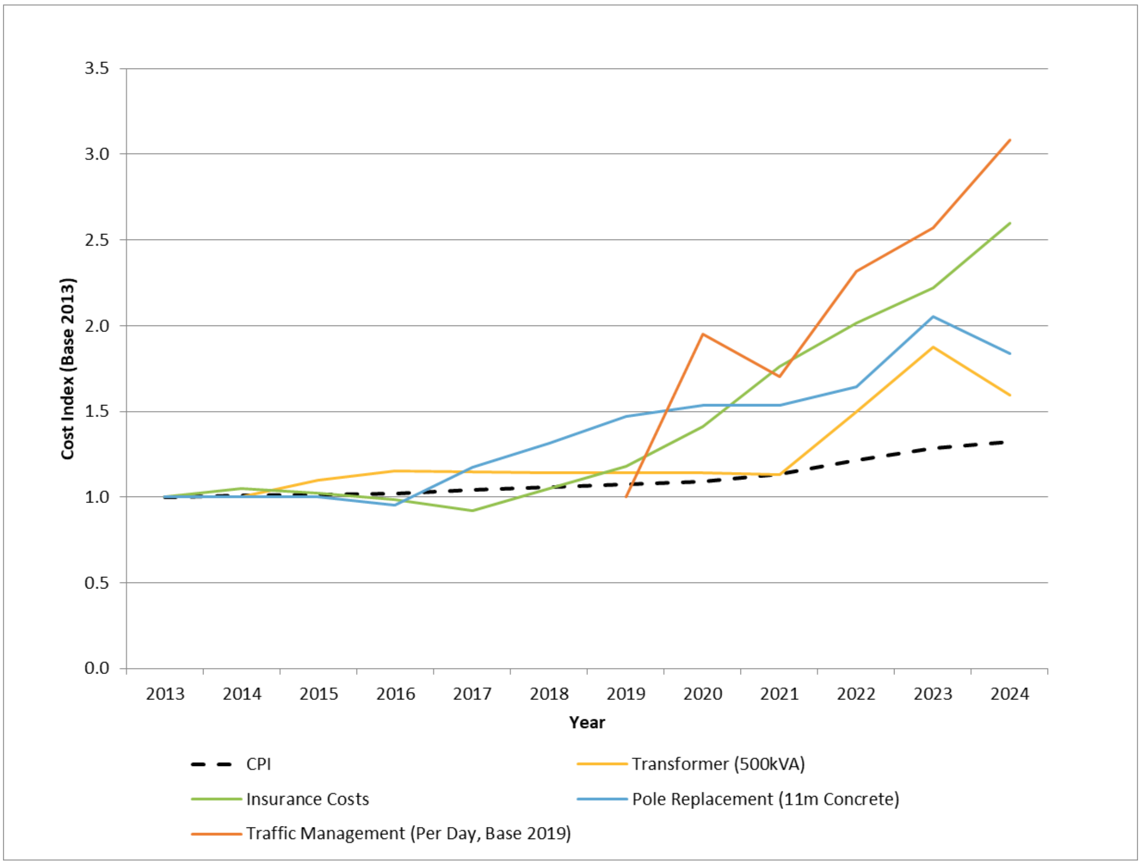



Figure 4-10 Examples of Cost Escalations Relative to CPI

### 4.3.4 Resource and Materials Scarcity

The Boston Consulting Group's *'The Future is Electric'* estimates that networks (grid and distribution) will need to invest $100b to provide New Zealand access to the renewable energy it needs to decarbonise. This investment will be at the same time as other countries are also decarbonising and other ageing infrastructure in New Zealand (like water) is replaced.

This step change in work programmes will lead to resource scarcity – both materials and labour. The COVID-19-driven labour shortages highlighted the impact that labour shortages can have on a business' ability to deliver, but also on labour cost.

Careful planning will be needed to ensure the industry has the labour, expertise, and materials available when they are needed to deliver the required work programmes. EDBs will need to clearly signal their forward work programmes to contractors, both electrical and civil, to give those businesses confidence to engage the necessary resources to do the work across multiple years.

### 4.3.5 Coordination with Other Infrastructure Programmes

60% of WELL's network is underground and is often located in the same corridor as other infrastructure assets like potable water, stormwater, and wastewater pipes. Electricity assets sometimes need to be relocated when water assets are replaced, maintained, or repaired. While the current regulatory framework allows the cost of relocating assets to be recovered from water companies, the relocation will still use scarce contracting resources which are needed for the asset replacement and reinforcement programmes.

The water programmes provide opportunities to share underground civil works costs when electricity services and water assets are in the same corridor. An EDB can lay ducts at the same time as water assets are being upgraded, avoiding having to repeat expensive reinstatement works when the electrical assets need replacing or reinforcement.

**Case Study 4 – Coordinating Work with Other Infrastructure Providers**

In 2023 Wellington Electricity embarked on a project to reinforce the electricity supply in Waitangirua to enable the development of housing in the area. With WELL's zone substation being located on the western side of Waitangirua, and the new subdivision growth occurring in the east towards Transmission Gully, the Waitangirua Link Road was an obvious route for extending WELL's network from source to demand.

In WELL's early discussions with Porirua City Council, it was identified that Wellington Water (WWL) also needed to run water infrastructure along the same route to meet development demands. All three organisations were keenly aware that the community needed them to deliver all the services in an efficient and timely way, and were keen to demonstrate that this collaboration could be achieved.

There were a number of significant issues to resolve including:

- Timing. WELL needed to increase supply by 2025 and WWL sometime after. Could both utilities adjust their plans to meet a common timeframe?
- Each utility going alone would be problematic for the second mover due to limited berm space, increased risk working around live assets, cost inefficiencies, and greater disruption for road users.
- Different regulatory and funding years for the organisations meant complex reshuffling of funding streams.
- Agreement of commercial terms and warranties between the stakeholders.
- Asset owners' requirements across all utilities needing to be set up-front and to be met through the design, installation, and QA process.

Significant effort was put into resolving these issues and arriving at a design and commercial agreement that demonstrated savings for all parties. Construction is currently underway on a single coordinated project that is significantly cheaper than two individual projects would have been, both in terms of financial cost and disruption to the community.

Just as important as the success of this project, however, is the framework, relationships, and precedent that has been established, and the lessons learned by all parties, which will be invaluable for facilitating further collaborative projects in future.

### 4.3.6 Delivery Strategy

WELL's delivery strategy for its future work programme is based on three components:

- A Field Services Contract that delivers the maintenance programmes necessary for maintaining safety and quality of the network.
- Competitive tendering for routine network-initiated asset replacement projects.
- A Project Management Office (PMO) focused on managing the outsourced delivery of large design and build work packages, often triggered by customer-initiated projects.

The outsourcing of large customer projects through the PMO insulates WELL's BAU functions from the impact of changing customer requirements and timeframes, ensuring that these do not distract from WELL's core mission of maintaining the safety and quality of the network. It also establishes visibility to contractors of the pipeline of future work, increasing cost efficiency through large multi-year packages of work, and giving contractors confidence to invest in resourcing their Wellington operations to deliver the work.

# 5 Asset Management, Safety and Risk Frameworks

This section describes WELL's asset management frameworks, its approach to health, safety and quality, and its risk management processes and governance.

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 55001. The key components of the framework are shown in Figure 5-1.

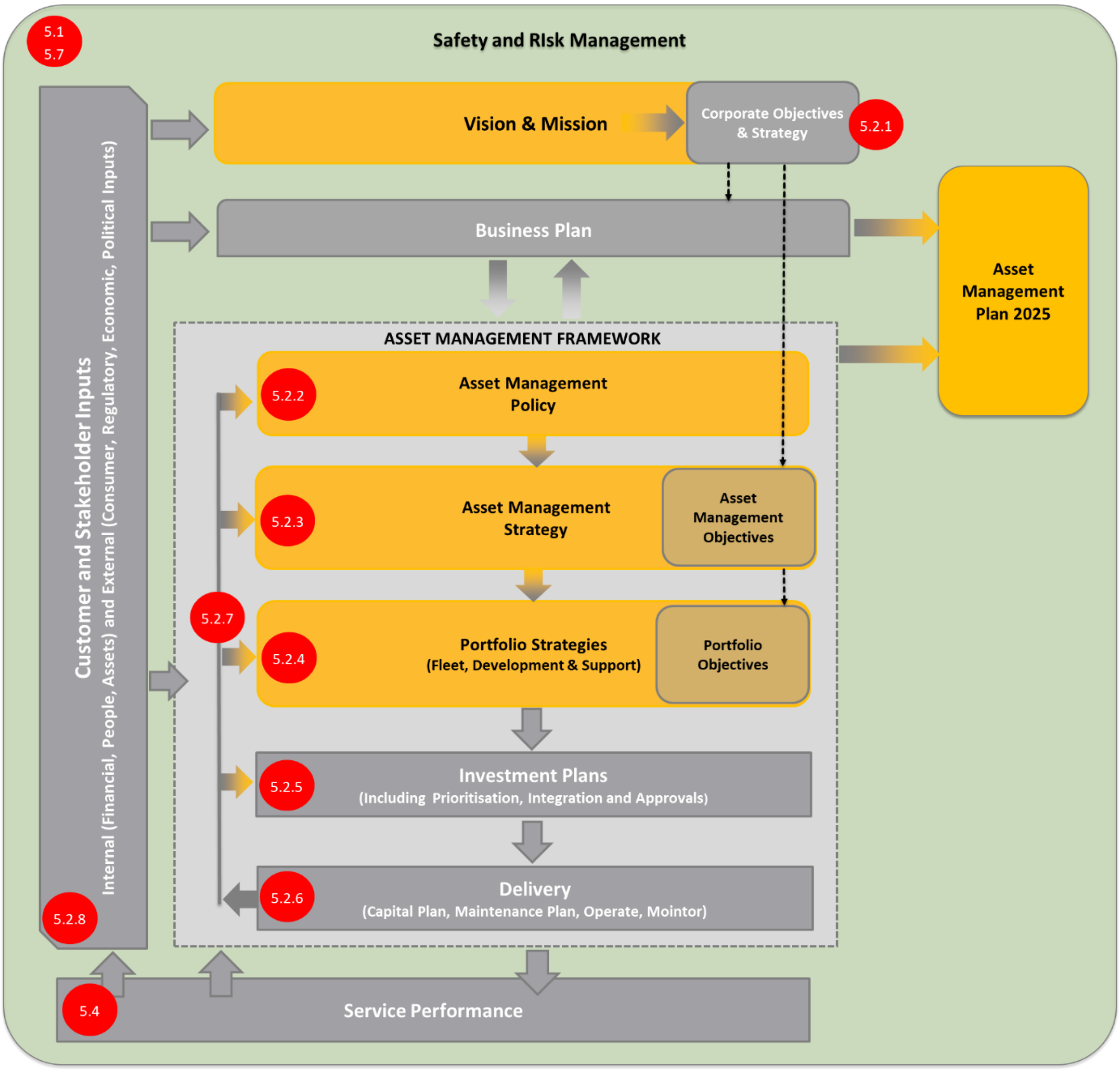



Figure 5-1 Asset Management Framework

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 as referenced in the figure above.

In summary the section covers:

- Quality, safety and the environment (QSE);
- 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); and
- Risk management.

## 5.1 Quality, Safety, and the Environment (QSE)

WELL is committed to providing excellence in QSE outcomes through the 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 on 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 5-2, a formalised safety leadership structure is in place to help ensure that health and safety leadership is provided throughout the business.

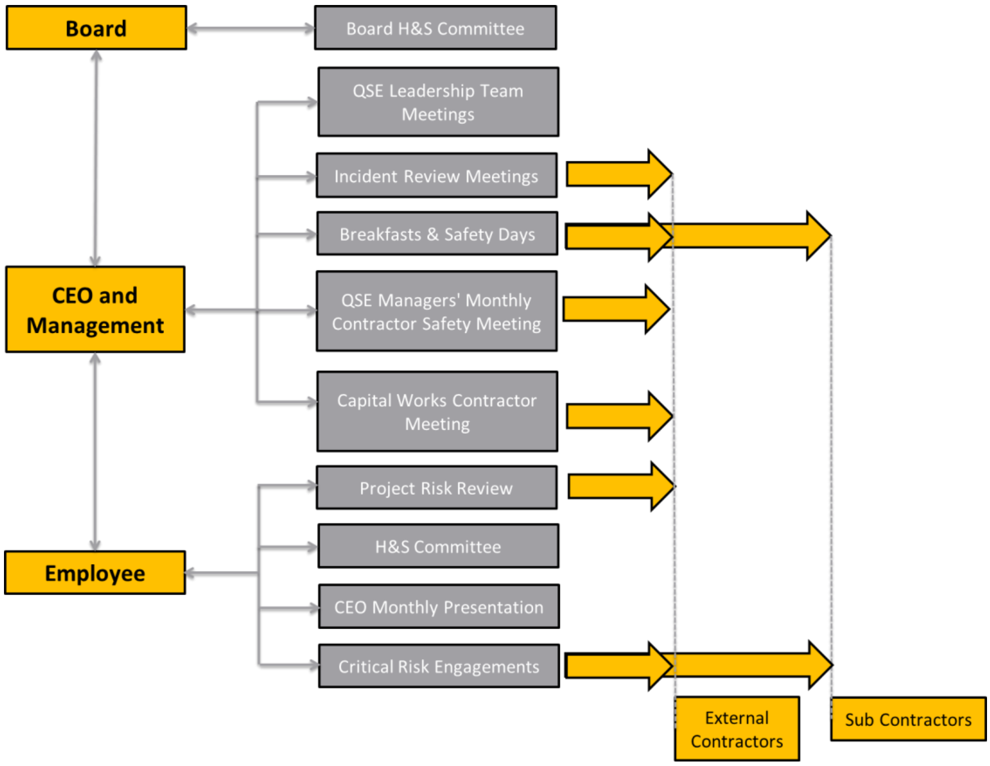



Figure 5-2 WELL's Safety Leadership Structure

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, cooperation 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.

Similarly, quality and environmental outcomes are managed by WELL via consultation, cooperation and coordination. 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 6.1.

### 5.1.1 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 with 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, cooperation, and coordination in relation to health and safety duties and issues. This brought about several 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 purpose 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.

### 5.1.2 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 Electricity and Gas Industries - Safety Management Systems for Public Safety. The certification body Telarc last recertified WELL against the requirements of NZS 7901 in 2024 and confirmed that WELL was compliant with regulatory requirements. The next recertification audit is scheduled for 2027. Annual surveillance audits are conducted by Telarc between recertification audits.

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.

#### 5.1.2.1 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 is 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.

#### 5.1.2.2 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 2024 relating to vegetation management, major event preparedness, and safety in lines down situations.

#### 5.1.2.3 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.

#### 5.1.2.4 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 mailouts to various contracting sectors that interface with the network.

#### 5.1.2.5 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[19]
- Close Approach requests
- Standovers
- High Load Permits
- High Load Escorts

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

### 5.1.3 Workplace Safety and Initiatives

WELL has the following workplace safety initiatives in place.

#### 5.1.3.1 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.

#### 5.1.3.2 Safety Breakfasts

WELL regularly arranges safety breakfasts for all its external contractors. These breakfasts aim 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.

#### 5.1.3.3 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. These seminars aim to reinforce WELL's desired behaviours through direct interface with keynote speakers and other subject matter experts.

#### 5.1.3.4 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.

#### 5.1.3.5 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 by providing, for example:

- CPR/First Aid refresher sessions every six months;
- Work Type Competency training;
- Restricted area access training;
- Defensive driving training; and
- Basic traffic control management training.

#### 5.1.3.6 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 from occurring or reoccurring, and to use lessons learnt for continuous improvement.

#### 5.1.3.7 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.

### 5.1.4 Environmental, Social, and Governance (ESG)

WELL's Board of Directors established an ESG Committee in 2022 that aims to assist the Board in fulfilling its oversight responsibilities with respect to:

- WELL's strategy in relation to ESG, including the future development of policy, objectives, and strategy as the external ESG business environment continues to evolve;
- Ensuring that WELL has appropriate targets and resources in place to ensure effective delivery of key ESG-based commitments;
- Oversight of the reporting and any assurance of performance against ESG targets on a consolidated basis; and
- Oversight of governance as it relates to WELL's strategy in relation to Environmental and Social policy and performance.

WELL's first ESG Strategy was approved by the Board in February 2023. WELL aims to integrate sustainability into how it manages its impact on the economy, environment, and people, and has set an overarching goal of *"Empowering a resilient and sustainable future for Wellington."* To reach this goal WELL has set targets in emissions reductions, gender diversity, waste minimisation, community and staff ESG education, and leading initiatives to support the intensification of renewable energy.

## 5.2 Asset Management Framework

### 5.2.1 Corporate Objectives

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

### 5.2.2 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.

### 5.2.3 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, the 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 6 to 8 provide more detail on specific asset management objectives and strategies associated with these priority areas.

### 5.2.4 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, support systems, emerging technology, resilience, and customer-initiated projects and relocations, which are discussed in Sections 8 to 13 respectively. Each strategy is used to develop Network Standards, and work plans and programmes which include the activities and budgets presented in the 10-year AMP and five-year business plan.

### 5.2.5 Investment Planning

WELL’s investment plans are developed from the portfolio strategies. Investment planning includes integration, prioritisation and approval processes to ensure prudent financial investment. Investment planning is discussed further in Section 5.3.

### 5.2.6 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 5.3.

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.

### 5.2.7 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.

### 5.2.8 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 about 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.

## 5.3 The Investment Selection Process

The investment selection process has five generalised stages, as illustrated in Figure 5-3.

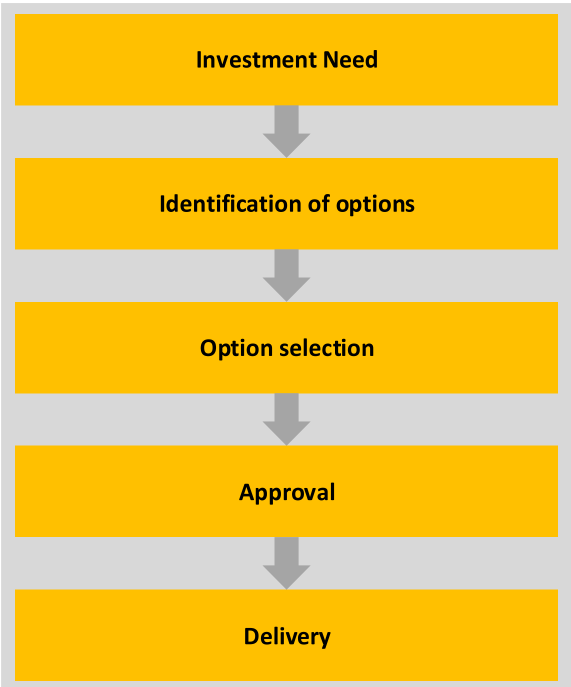



Figure 5-3 Investment Selection Process

### 5.3.1 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 asset health and criticality evaluation, whereas the need for network development expenditure comes from forecasting peak load growth on the network and developers signalling an intent to extend their subdivision or commercial investments.

#### 5.3.1.1 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.

#### 5.3.1.2 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 direct needs of its 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.

### 5.3.2 Option Identification

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

- Non-network solutions. This could include the use of Demand Side Management (DSM), Distributed Generation (DG), or connection agreements that include operating envelopes that allow customers to maximise their use of available capacity without requiring significant customer-funded investment in new capacity;
- 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.

### 5.3.3 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 the 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. Following final prioritisation, the list of projects for the following year informs the annual budget which is submitted for management approval and recommendation to the Board for approval.

### 5.3.4 Investment Approval

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

## 5.4 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.

### 5.4.1 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 – Omexom;
- Contestable capital works – Omexom, Connetics, Downer, and Ventia;
- 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.

#### 5.4.1.1 Fault Response, Maintenance and Minor Capital Works

Northpower Ltd was WELL's primary field service provider responsible for fault response and maintenance from 2011 to 2024. During 2024 WELL ran a contestable process for a new field services contract. Omexom New Zealand was successful and was contracted as the field services provider under a new Field Services Agreement (FSA) commencing on 1 January 2025.

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 Omexom 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 key functional areas between WELL and Omexom.

#### 5.4.1.2 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 Omexom 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 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.

#### 5.4.1.3 Vegetation Management

The outsourced contract for vegetation management was tendered competitively in 2018 with Treescape being successful. 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 FSA with regular meetings and performance incentives in place.

#### 5.4.1.4 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.

## 5.5 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 30-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.

## 5.6 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 areas of improvement identified in the AMMAT relate to improving the visibility to contractors of the multi-year work programme, which represents a "lifting of the bar" to ensure that appropriate resources will be available to deliver the Plan, and the need to identify the related additional asset management information system requirements.

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.

## 5.7 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 for managing risk, which is applied to all business activities, including policy development and business planning. WELL's risk management framework is discussed in Section 5.7.2.

Risk management is an integral part of good asset management practice. WELL's approach to managing asset-specific risks is discussed in Section 8.

### 5.7.1 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 Management 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 has 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 5.7.3.

### 5.7.2 Risk Management Framework

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

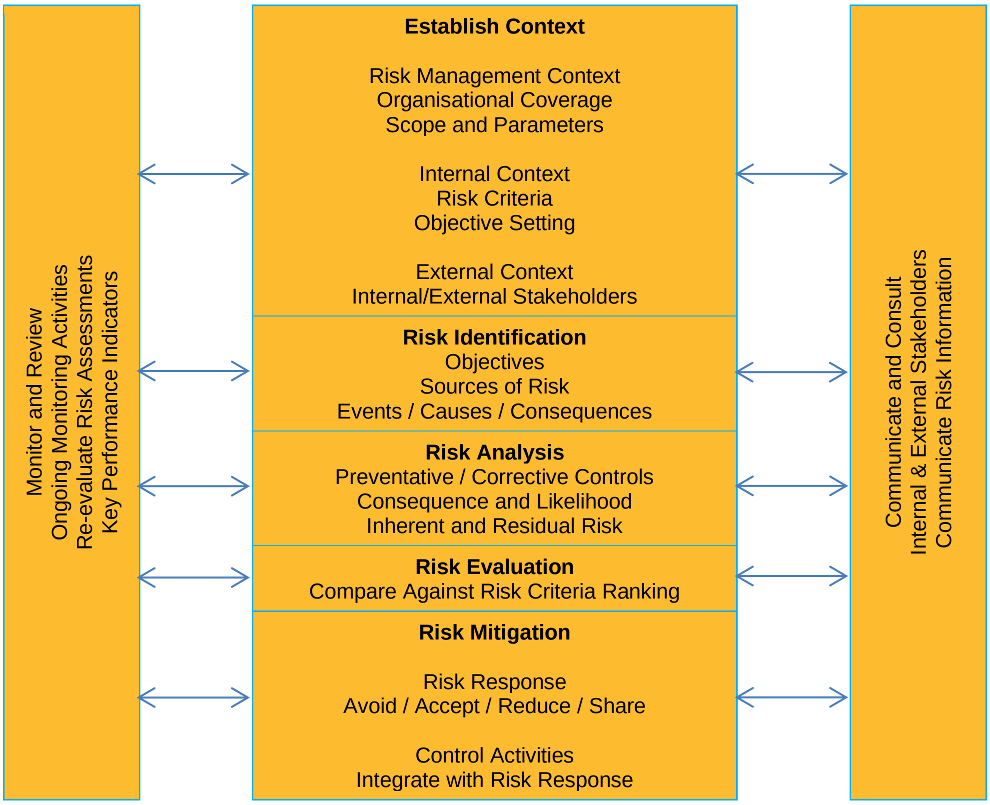



Figure 5-4 WELL's Risk Management Process

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 5.7.3 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). The risk rating is plotted on a risk chart with its likelihood score on the y-axis and overall consequence on the x-axis, with an example of the qualitative risk matrix shown in Figure 5-6.

| 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 5-5 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.

### 5.7.3 Key Business Risks and Controls

Rankings of risk events and control effectiveness were updated in December 2024, identifying no current extreme residual risks and only one high residual risk.

In total, 46 business risks were assessed by WELL. Table 5-1 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 5-1 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.

#### 5.7.3.1 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 the maximum foreseeable loss for assets that can reasonably be insured.

The balance (85% by replacement value) of WELL's network is not insured. 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. As such, the customer retains the risk on the uninsured portion of 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. This is not considered economic. Ex-post recovery of the full costs is therefore the regulatory recovery mechanism for managing this risk.

#### 5.7.3.2 Insurance Cover

WELL renews its insurance 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, electromagnetic radiation, financial loss (failure to supply), and professional indemnity and is renewed annually as at 30 September.

# 6 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.

The performance targets for these areas include:

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

The service levels also incorporate feedback received from the stakeholder groups discussed in Section 3.6.

## 6.1 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.

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.

### 6.1.1 Lost Time Injury Frequency Rate

WELL's staff and contractors recorded seven Lost Time Injuries (LTI) incidents in the industry reporting year ending June 2024. This resulted in an LTIFR for that period of 1.90 per 200,000 hours worked and a two-year rolling average of 1.20 per 200,000 hours worked. The trend in LTIFR is shown in Figure 6-1.

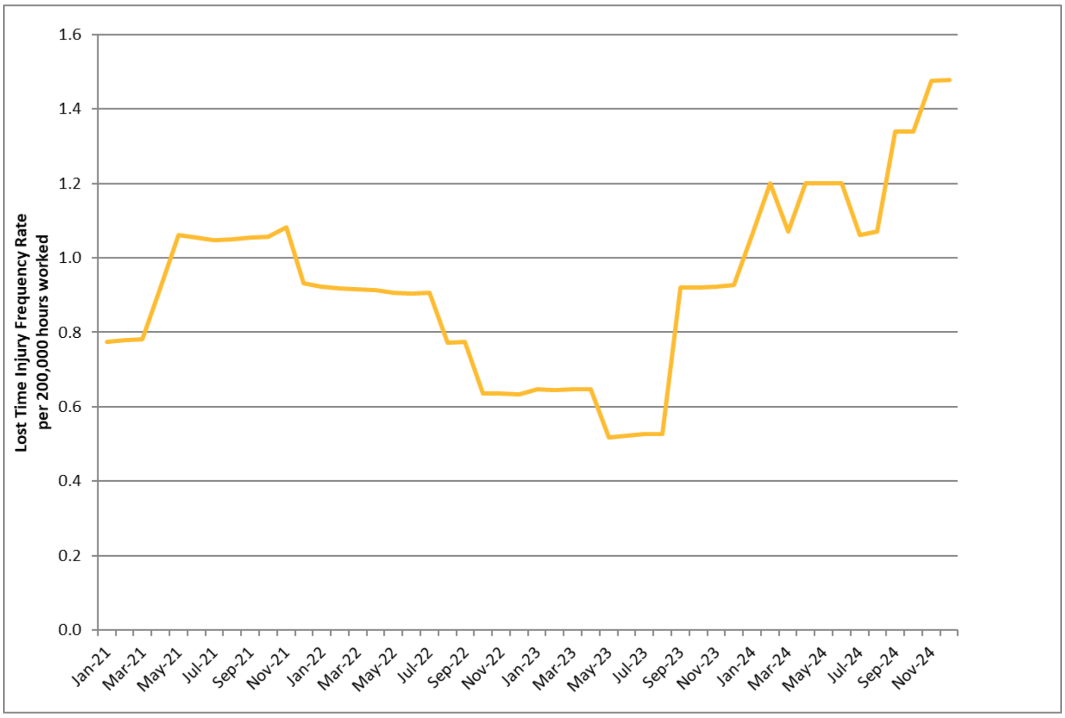



Figure 6-1 Lost Time Injury Frequency Rate (24-month Moving Average)

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 focusing on network-related critical risks and non-network-related risks and is actively working with service providers to ensure a balance is achieved.

#### 6.1.1.1 Planning Period Target

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

### 6.1.2 Total Notifiable Event Frequency Rate

The HSW Act introduced "notifiable events" which comprise notifiable injuries, notifiable illnesses, 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 three Notifiable Events in 2024. This resulted in a 2024 TNEFR of 4.01 per million hours worked and a two-year rolling average of 3.36.

#### 6.1.2.1 Planning Period Target

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

### 6.1.3 Incident and Near Miss Reporting

During 2024 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 2024 was 498 events reported. Approximately 99% of all reported events were classified as minor, 0.8% were classified as moderate, whilst 0% were of a serious nature. The total number of proactive reports received during 2024 was 106. These 106 are further broken down into two near miss events and 104 hazard observation reports.

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 the potential for harm exists, but where a release of energy has not occurred.

#### 6.1.3.1 Planning Period Target

WELL's current expectation for the 10-year planning period is to maintain the number of addressed hazard observation events reported at approximately 100 per year.

### 6.1.4 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 2020 levels, as shown in Figure 6-2. Monitoring continues to help ensure that this trend is continued. There remains a continued focus on compliance with higher risk scenarios such as temporary traffic management requirements, adherence to network standards, and public safety around worksites.

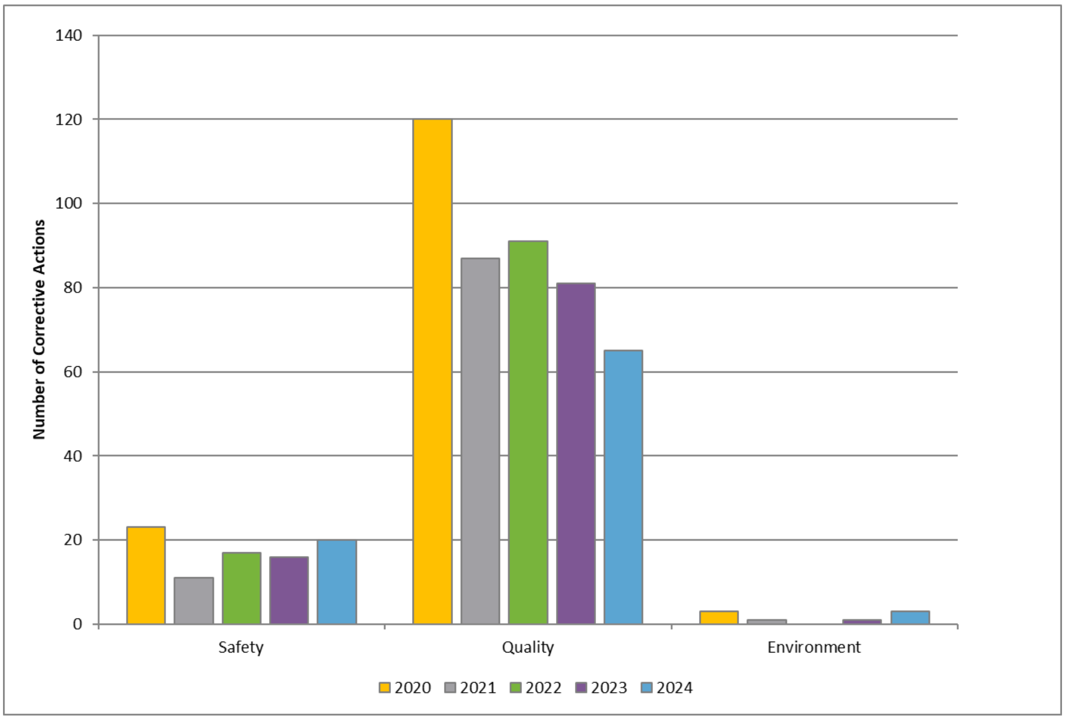



Figure 6-2 Corrective Actions Arising from Assessments 2020-2024

#### 6.1.4.1 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.

### 6.1.5 Health and Safety Initiatives

During 2025 focus will be placed on the following areas to further improve safety performance:

- Effectively transition to a new Field Service Provider;
- 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 the close-out of assessments;
- Maintain the application of the risk management framework and expand the risk assessment process with a 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 workplace 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 the development of practical and effective risk controls.

## 6.2 Reliability Performance

### 6.2.1 Reliability Measures

Network reliability is measured using two internationally recognised performance indicators, SAIDI[20] and SAIFI.[21] 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, that the electricity supply is not available to the average customer connected to the network during 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.[22]

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,[23] 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.

The SAIDI and SAIFI targets against WELL's historical performance, renormalised using the DPP3 methodology, are shown in Figure 6-3 to Figure 6-6.

[20] System Average Interruption Duration Index
[21] System Average Interruption Frequency Index
[22] Due to the effect of averaging, SAIFI is reported as a non-integer number.
[23] 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.

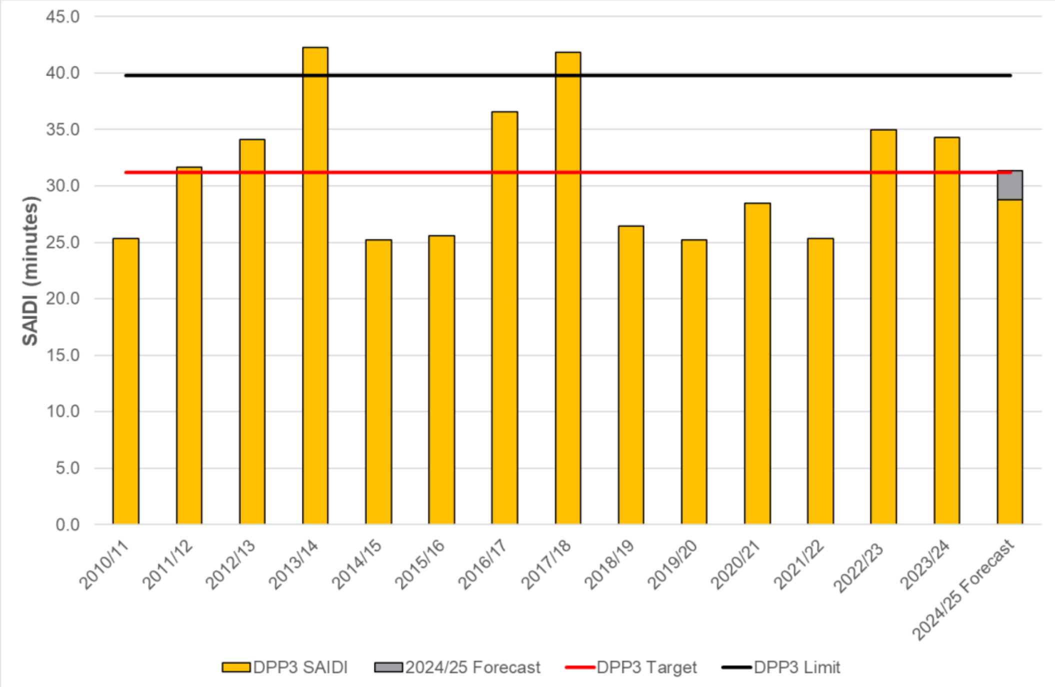



Figure 6-3 WELL Unplanned SAIDI Performance

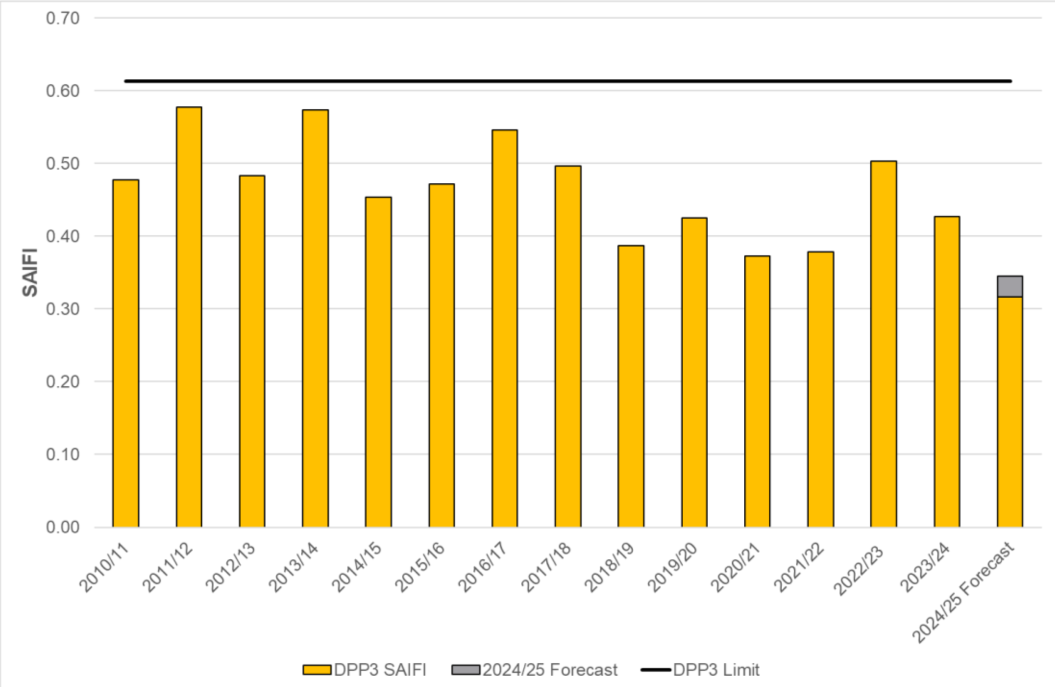



Figure 6-4 WELL Unplanned SAIFI Performance

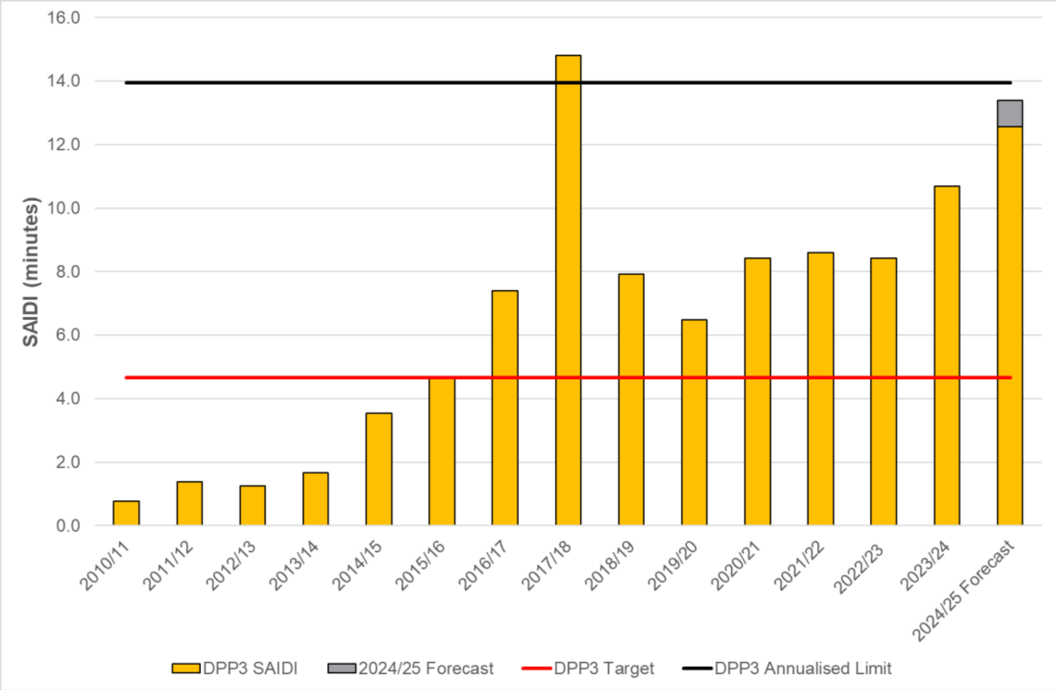



**Figure 6-5 WELL Planned SAIDI Performance**

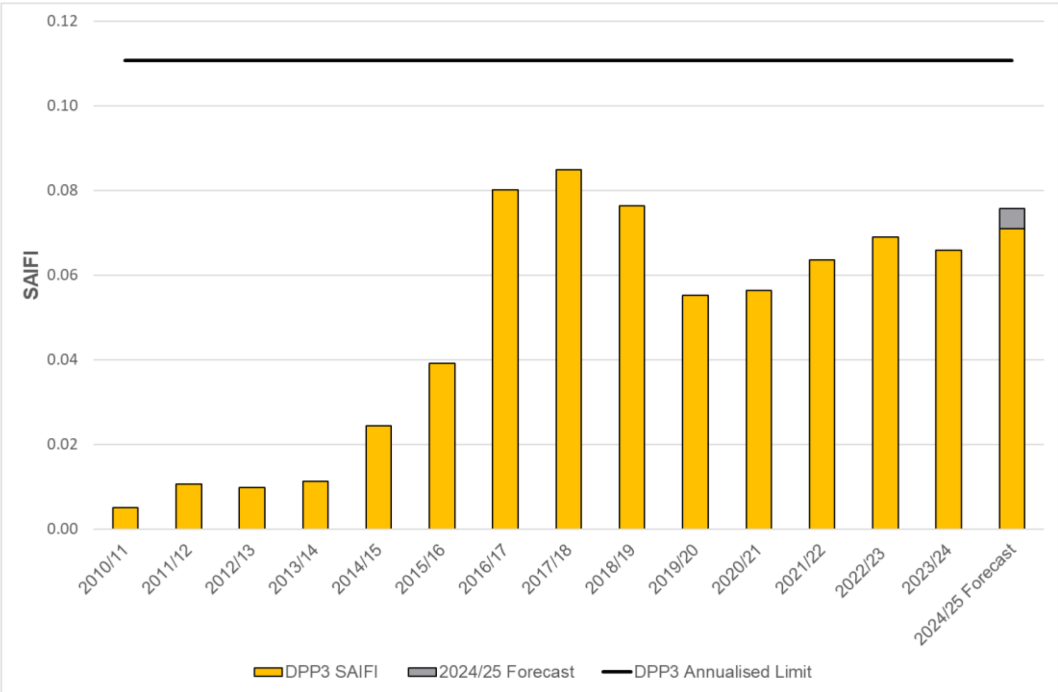



**Figure 6-6 WELL Planned SAIFI Performance**

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

- Maintain overall network reliability at historically acceptable levels;
- Deliver the cost-quality trade-offs that customers request; and
- Meet regulatory standards on power quality (discussed in Section 9.1).

### 6.2.2 Process for Measuring Reliability Performance

This section explains how reliability performance is recorded and validated.

#### 6.2.2.1 Outage Data Collection

The control system WELL uses to record SAIDI and SAIFI information is the PowerOn Advantage (PoA) SCADA network management system. PoA is used for the real-time management and monitoring of the high voltage network. Specifically, PoA provides information about the status of the network, including customer connection points and the status of devices like circuit breakers and fuses.

PoA 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.

For unplanned outages, PoA identifies there has been a fault and 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 PoA, 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 PoA.

#### 6.2.2.2 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 the outage;
- Number of customers impacted;
- Total customers minutes lost (calculated based on the time-stamped switching operations);
- 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 weekly and monthly network reliability reports which are used for reporting SAIDI and SAIFI indices. The monthly reports are then aggregated into the master database from which WELL's regulatory quality reporting for Quality Path compliance and Information Disclosure is derived.

#### 6.2.2.3 Planned outages

For planned outages, a Network Access Request (NAR) is electronically submitted by the contractor for the work to be undertaken. Once this has been assessed and accepted, the proposed switching operations are entered into PoA by the Network Controller prior to the event. During the event, PoA creates an incident and the Network Controller enters the time each switching operation occurred. Planned events are validated by the outage planners and network controllers by referring to the specific job documents. The validation process considers whether LV backfeeds or portable generation have been used to reduce the loss of supply.

### 6.2.3 Industry Comparison

WELL was one of the most reliable EDBs in New Zealand in 2023/24 as shown in Figure 6-7 and Figure 6-8. The data source is the annual Information Disclosures made by EDBs and made publicly available in August 2024. The benchmarking analysis shows that WELL's system reliability indices are currently performing well against networks that are comparable in either network type (i.e. predominantly urban underground), or customer count.

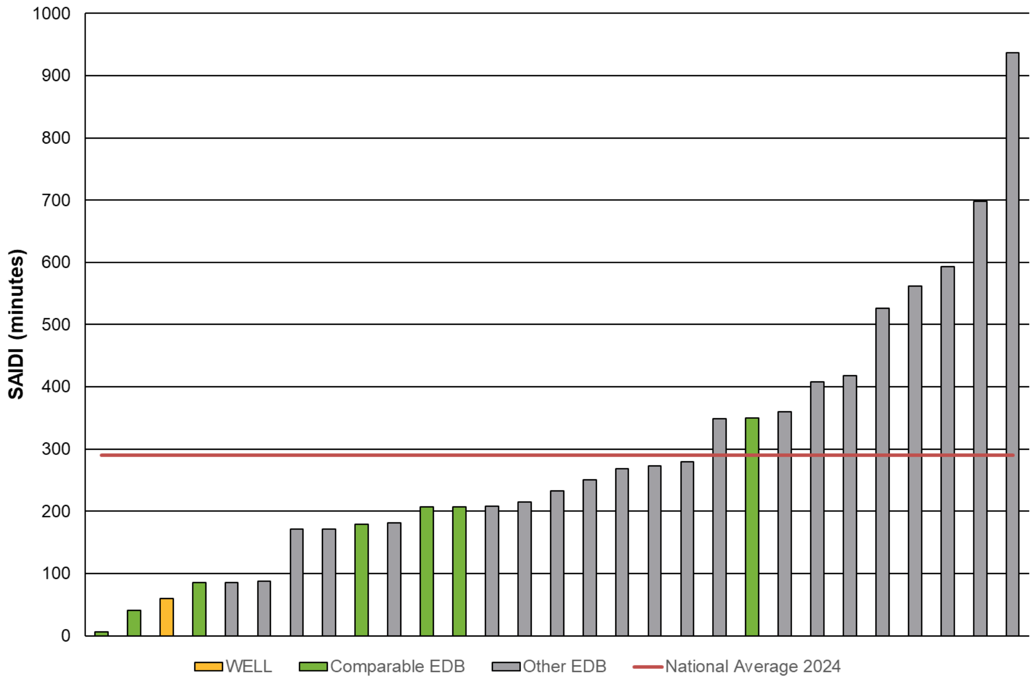



**Figure 6-7 SAIDI by EDB for 2023/24**

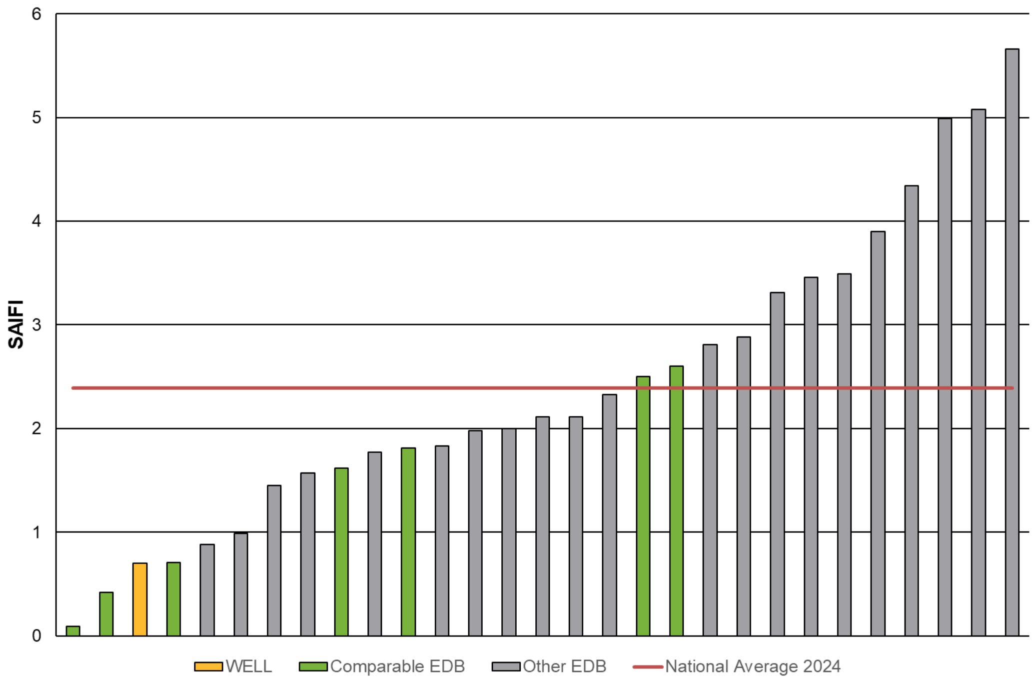



Figure 6-8 SAIFI by EDB for 2023/24

### 6.2.4 Reliability Performance in 2024/25

WELL's unplanned network performance for the 2024/25 regulatory year is forecast to be 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 2023/24 across a range of fault causes is shown as a waterfall chart in Figure 6-9. 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 the normalisation methodology under the regulatory Quality Path.

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.

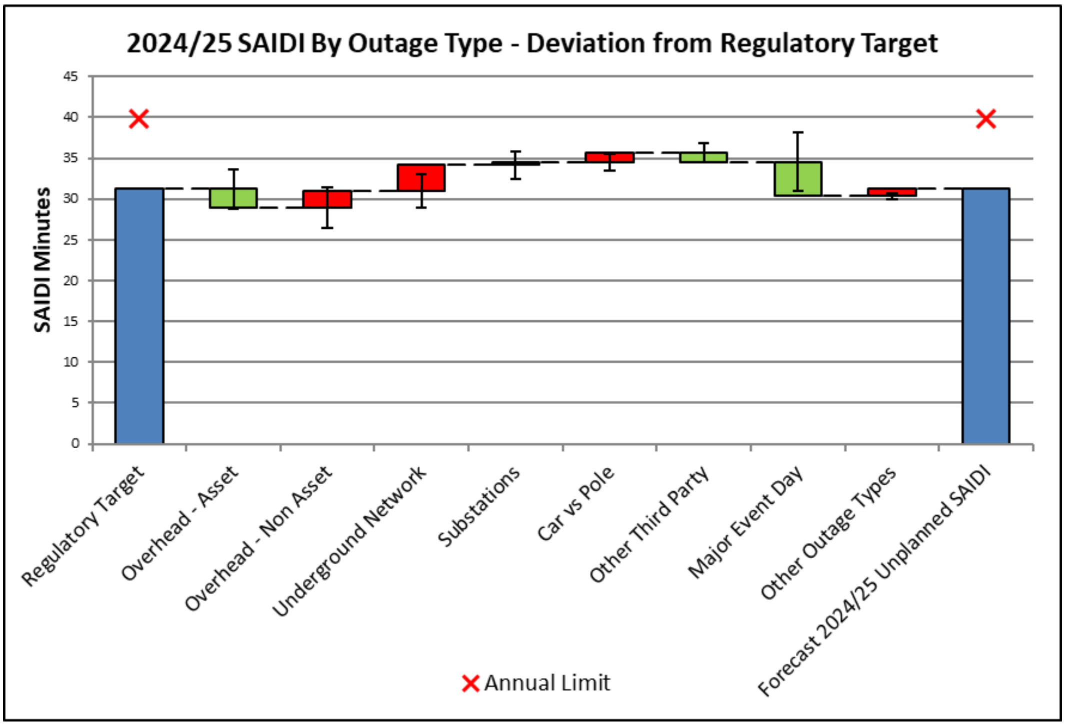



Figure 6-9 Waterfall Chart of 2024/25 SAIDI Performance by Outage Type

The equivalent chart for 2023/24 is shown in Figure 6-10.

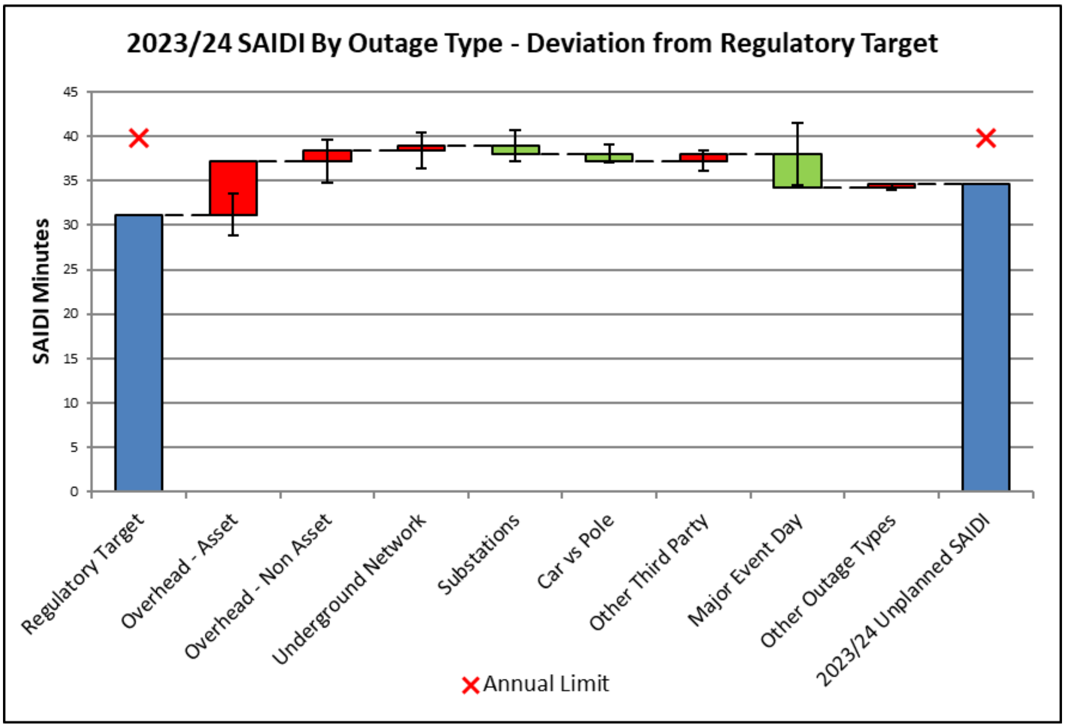



Figure 6-10 Waterfall Chart of 2023/24 SAIDI Performance by Outage Type

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

### 6.2.5 Reliability by Network Area

Figure 6-11 and Figure 6-12 show the SAIDI and SAIFI for 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.

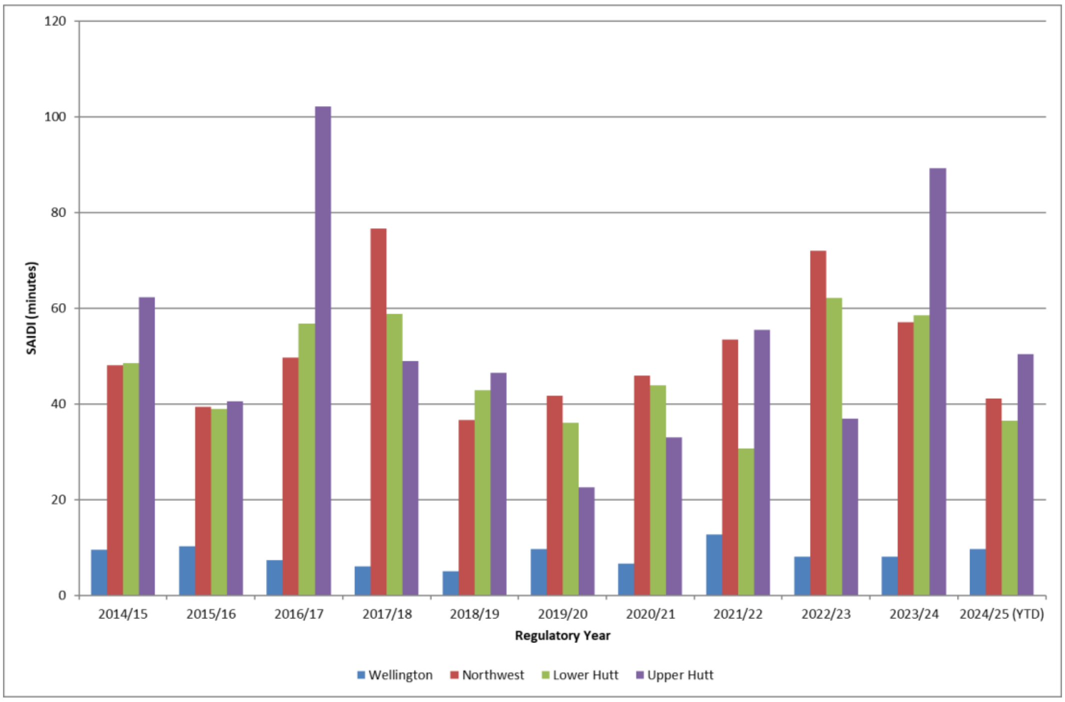



Figure 6-11 Unplanned SAIDI Performance by Network Area

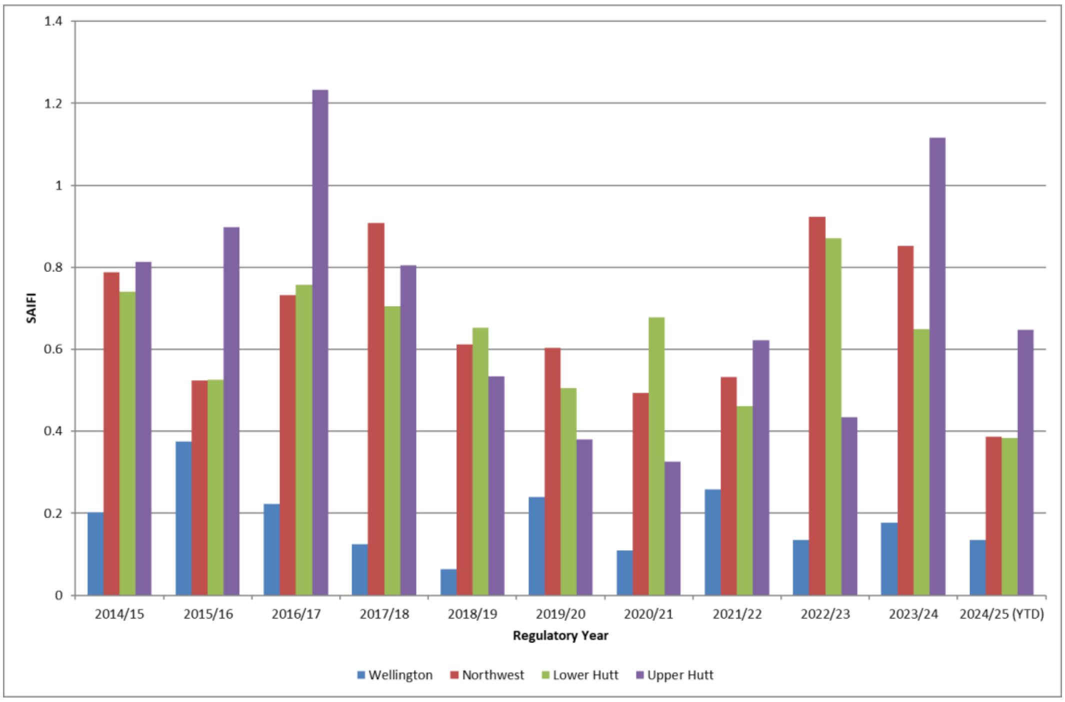



Figure 6-12 Unplanned SAIFI Performance by Network Area

## 6.3 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.

### 6.3.1 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 intensity per ICP. Table 6-1 illustrates the level of performance for each measure over the planning period together with key measures of network density.

| | Load factor | Zone substation transformer capacity utilisation | Loss ratio | Demand density kW/km | Volume density MWh/km | Connection point density ICP/km | Energy intensity kWh/ICP |
|---|---|---|---|---|---|---|---|
| Industry Median 2024 | 58.6% | 38.8% | 5.3% | 35.4 | 174.1 | 9.6 | 14,314 |
| WELL 2024 | 49.0% | 42.6% | 4.3% | 115.8 | 475.7 | 36.0 | 13,203 |
| WELL Target 2025-2035 | >50% | >40% | <5% | - | - | - | - |

Table 6-1 WELL Asset Efficiency Levels[24]

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

## 6.4 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 6.5 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

[24] Values as per the Pricewaterhouse Coopers (PwC) Electricity Line Business 2024 Information Disclosure Compendium.

- 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.

- 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 being passed back to customers as a price decrease. WELL believes that any penalties or payments relating to quality must relate to, 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 backstop for issues that are unable to be resolved internally and is rarely required.

## 6.5 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 its 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 responses to customers surveys and feedback received from customers at community engagement events, trade shows, and through WELL's various contact channels.

In 2024, WELL engaged in a number of customer experience and community engagement initiatives, with some examples being:

- **Connections:** Changes made to our pricing policy for small to medium network extensions in 2023 have now been in effect for sufficient time to assess their impact from a customer perspective. Customers were provided with a new two-tier pricing option which reduced the variability of the pricing which they would have experienced previously. Feedback from some customers who are new to the process includes surprise over the cost to connect. Those customers (such as property developers) who frequently use these services and have a better understanding of the process have been supportive of the improved and predictable nature of our connections pricing.

Price and time to connect are areas currently being reviewed by the Electricity Authority.

**Community Engagement:** WELL met with members of the Eastbourne and Normandale communities during 2024. In addition to a focus on each community's recent network reliability performance and how residents can contribute through vegetation control, presentations also covered the potential impacts to our network of government's plans to meet decarbonisation goals and how WELL would respond to those impacts. WELL also exhibited at the Eastbourne Resilience Expo, providing residents with an opportunity to ask safety and resilience-related questions.

Staff continued to meet in person with a number of customers who had lodged complaints, to better understand their experience and to help identify the root cause of their complaints. This is an important component of WELL's Root Cause Programme, described below.

WELL hosted stands at Wellington's Home & Living and Home & Garden Shows. For the former, WELL's stand was focused on showcasing how customers can save money on their power bills. The theme for the latter show focused on providing customers with an insight into the potential impacts of the government's decarbonisation targets on our electricity network. Customers had an opportunity to 'have a say' in relation to what is most important to them – choosing between Decarbonisation, Resilience, Reliability and whether they would be prepared to have someone manage part of their electricity consumption.

WELL also conducted a trial campaign to highlight the benefits of off-peak consumption. The campaign primarily utilised digital media to target specific areas, using a combination of different messaging types and measuring the response to those messages. Results were positive in generating interest but at this point in time it is too soon to understand what, if any, impact to off-peak consumption patterns the campaign may have had – both from a short-term or sustained impact point of view.

- **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. In previous years the programme has generated a 9% reduction in customer complaints but in 2024 we saw a slight increase in the volume of complaints received. Initial analysis suggests that increased numbers of people working from home who are impacted by planned outages are the primary driver of this change.

In 2025, WELL will be delivering:

- **Self-service Improvement:** Continued development of the web-based self-service platform to further improve its functionality and to deliver an improved customer experience. Changes will be made to add functionality which will allow large connection requests to be input into the Customer Initiated Works (CIW) portal.

- **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, in order 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. WELL also regularly engages with city councils with regard 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.

  In addition, as mentioned above a number of customers impacted by perceived poor service will be visited to better understand their experience and design improvements to our delivery.

- **Planned and Unplanned Outage Publication:** The EDNAR tool deployed in 2023 (see Section 10.1.1.2) enabled WELL to increase the level of automation in the planned work process and publish planned outages on its website. WELL used the opportunity to review the functionality provided by the website and added the capability to view recent planned and unplanned outages to the web-based application. In 2025 WELL plans to modify the mobile outage platform to offer the same outage reporting functionality as the website.

- **Community Education:** WELL will continue to engage with and educate customers on the impacts of the government's decarbonisation targets on our network, what we are planning to respond to those changes and what customers can do to influence their levels of electricity reliability, resilience, and costs.

### 6.5.1 Customer Surveys

WELL conducts a regular customer survey to understand customer perceptions across a range of factors. The survey includes questions which seek to understand whether customers' perception of whether the price-quality trade-off they receive for their electricity delivery is appropriately balanced. The sample ("Monthly Outage Sample") consists of customers who have recently experienced an outage, on the basis that they are more likely to have opinions on the subject, having recently been impacted and are therefore better qualified to provide a considered response. The results of that survey are compared in Figure 6-13 for two of the key price-quality trade-off questions.

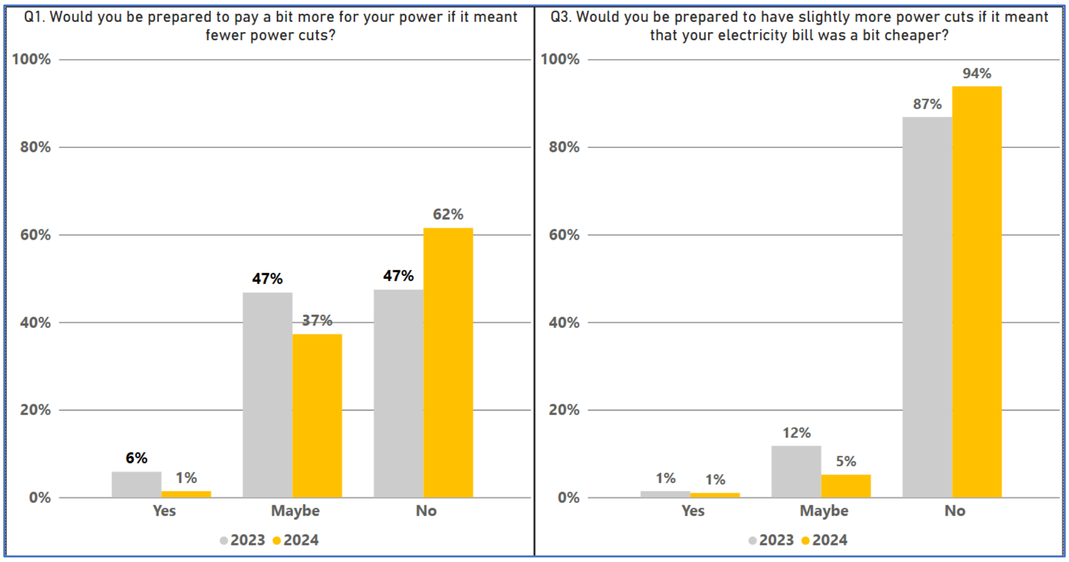



**Figure 6-13 Sample of 2024 Customer Survey Results**

For Question 1, the percentage of people willing to pay a bit more for power in return for fewer power cuts has reduced even further than in 2023. The remainder of customers were evenly split in 2023 between unsure or unwilling to pay more for fewer power cuts in 2023 but the 'No' response has increased once again within 2024. The results for Question 1 emphasise the importance of prioritising customer affordability in the current economic climate, which is a major element of this AMP.

The results for Question 3 suggest are even more pronounced than in 2023, indicating that customers are unwilling to experience a drop in the reliability of their power supply in response to a reduction in price.

### 6.5.2 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 upon between WELL and all retailers. An Urban Fault is defined as a network fault that results in a complete loss of supply to one or more points of connection within an urban area. A Rural Fault is any fault resulting in a 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 6-14.

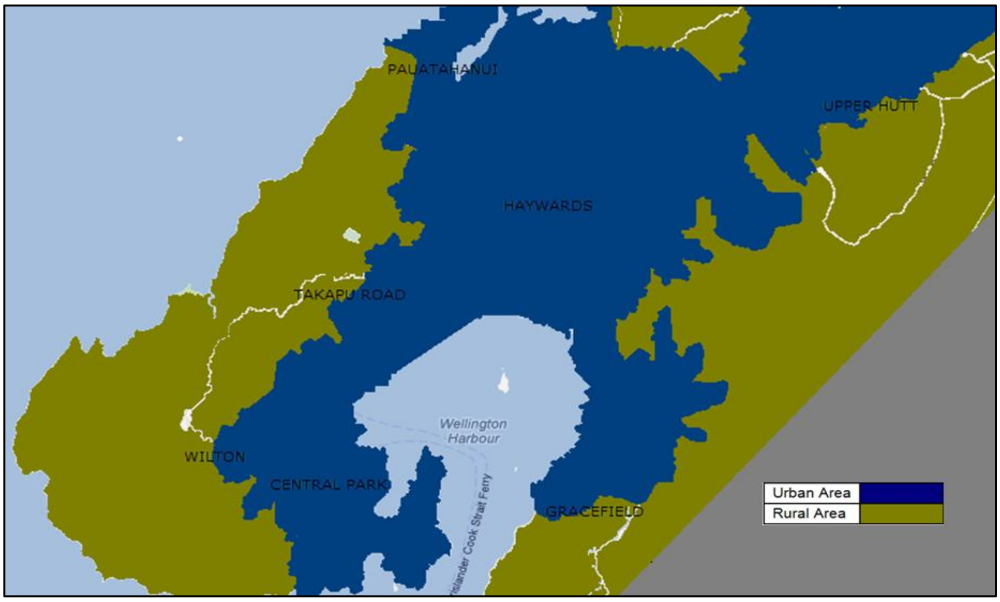



**Figure 6-14 Geographical Map of Power Restoration Areas**

#### 6.5.2.1 Planning Period Targets

The targets for the power restoration service levels remain consistent over the planning period 2025-2035, as set out in Table 6-2.

| | Urban | Rural |
|---|---|---|
| Maximum time to restore power | 3 hours | 6 hours |

**Table 6-2 Standard Power Restoration Service Level Targets 2025-2035**

### 6.5.3 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 also incentivises its primary field service provider to ensure customers impacted by prolonged outages are kept informed with accurate status updates.

WELL publishes information about unplanned outages on its website and mobile app, however, the primary path of information about outages is from WELL to retailers, who will then inform their customers. WELL's service levels for the notification of outages focus on the time taken to inform retailers. These notification service levels are set out in Table 6-3 (Unplanned outages) and Table 6-4 (Planned outages).

| Outage Type | Notification Action | Notification Service Level |
|---|---|---|
| Area Network Fault | Provide retailer(s), to the extent reasonably known at the time:<br>• A description of the reason for the interruption;<br>• The area affected; and<br>• An expected time for restoration. | Within 5 minutes of the fault being notified to WELL |
| Service Interruption | Provide retailer(s) with status updates | Within 5 minutes of new information becoming available; and<br>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 the partial or full restoration of supply |

Table 6-3 Unplanned Outage Notification Service Levels

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

Table 6-4 Planned Outage Notification Service Levels

### 6.5.4 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 6-5 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 | 3 working days |
| Where the application requires network expansion before approval | 3 working days |
| Where connection approval requires conditions to be met prior, a site visit, and/or network expansion | 3 working days |

Table 6-5 New Connection Notification Timeframes

### 6.5.5 Connection, Disconnection, Capacity Change Timeframes

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

| Activity | Requirements | Time to Action |
|---|---|---|
| Livening a new connection | Dependent on:<br>• All necessary equipment in place;<br>• Network upgrades or extensions not required; and<br>• All other necessary requirements met. | 10 working days |
| Temporary disconnections | If the retailer provides authority to do so.<br>If the 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. | 3 working days |
| Notification of capacity change request | WELL will advise the 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 the capacity change being made. | 3 working days |
| 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. | 10 working days |
| Vacant Site Disconnection | Provided that:<br>• Access is available; and<br>• There is an accessible isolating device (fuse) which isolates only the requested Point of Connection<br>If the 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 days |
| Permanent Disconnection/Decommission | Provided that:<br>• Access is available; and<br>• There is an accessible isolating device (fuse) which isolates only the requested Point of Connection<br>For complex decommissions where there is no accessible isolating device therefore excavation, outages and/or capping of network cables is required, WELL may not be able to meet this service level. | 10 working days |
| 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. | 3 working days |

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

### 6.5.6 Supply Quality Investigations

WELL monitors voltage quality on its low voltage network through customer reports of abnormal voltage. This is because WELL does not have ready access to smart meter voltage data that would allow it to undertake a more systematic review of voltages across its network.

When 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. The investigation of voltage quality problems is becoming significantly more complex due to the increasing prevalence of CER and the potential for two-way power flows. Table 6-7 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 6-7 Supply Quality Investigation Timeframes

The increased penetration of CER in the network is increasing the number of queries relating to the supply voltage. In many cases, investigation shows that the voltage at the point of supply is within the allowed range defined in the Electricity (Safety) Regulations 2010, and the cause is voltage rise within the customer's installation. An EDB's responsibility for voltage is to maintain 230V±6% at the point of supply. If this requirement is being met, then the EDB is not responsible for the voltage seen by appliances located within the installation. Public education is required to ensure that it is understood that voltage measured at the inverter (or some other smart appliance located within the installation) is not necessarily indicative of the supply voltage being outside of its acceptable range.

Where a voltage quality non-compliance is confirmed to exist in the network, WELL responds. These responses could include undertaking a distribution transformer tap setting change, altering network open points, or a CAPEX response such as installing larger distribution cables or an additional transformer. The challenge with these responses is the timeframe needed to undertake a thorough analysis, develop the most cost-effective solution, and implement the solution. This is particularly the case for responses that require planned outages and equipment procurement, as these are affected by supply chain lead times and outage notification requirements. In addition, it is essential to ensure that the identified voltage problem is being resolved in a manner that does not cause additional problems for other customers, for example by ensuring that lowering a tap setting in response to a report of high voltage during summer will not subsequently result in reports of low voltage during winter.

### 6.5.7 Customer Complaints

WELL receives customer complaints and enquires via its contact centre, website, or directly via its Customer Service email inbox,[25] and has adopted the Utilities Disputes Code of Practice for managing complaints. All 'Times to Action' (timeframes in which WELL responds to complaints and enquiries) comply with the Utilities Disputes rules and protocols. These are set out in Table 6-8.

[25] We_CustomerService@welectricity.co.nz

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

Table 6-8 Complaint and Enquiry Response Timeframes

### 6.5.8 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.

#### 6.5.8.1 Contact Centre Targets

There are currently four 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. 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.

#### 6.5.8.2 Planning Period Targets

The Contact Centre service level targets are to provide consistent performance over the planning period 2023-2033. These are shown in Table 6-9.

| SL | Service Element | Measure | Target | 2024 Performance |
|---|---|---|---|---|
| A1 | Grade of Service | Average service level across all categories | >=85% | 90.1% |
| A2 | Call response | Average wait time across all categories | <20 seconds | 13.8 seconds |
| A3 | Missed calls | Total missed/abandoned calls across all categories | <4% | 2.9% |
| C1 | Call Quality | Agent performance against 16 key quality criteria for a random selection of calls | >=85% | 89.5% |

Table 6-9 Contact Centre Service Level Targets 2023-2033

# 7 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.

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

- Reliability performance limits and targets;
- Reliability strategies;
- How WELL reports and forecasts reliability, and
- Reliability controls.

## 7.1 Reliability Performance Limits and Targets

The regulatory regime that applies to WELL sets reliability limits for each year that are based on historical performance. Unplanned outage limits are set at two standard deviations above the reference period average, while planned outage limits are set at a multiple of the reference period average. The regulatory limits for WELL are presented in Table 7-1.

| Regulatory Year | 2021/22-2024/25 | 2025/26-2029/30 |
|---|---|---|
| Annual Unplanned SAIDI Limit | 39.81 | 37.82 |
| Annual Unplanned SAIFI Limit | 0.6135 | 0.5829 |
| Period Planned SAIDI Limit | 55.76 | 76.66 |
| Period Planned SAIFI Limit | 0.4429 | 0.6089 |
| Extreme Event Customer Minutes Limit | 6 million | 6 million |

Table 7-1 WELL Regulatory Reliability Limits

Figure 7-1 shows the last 15 years of actual unplanned SAIDI renormalised using the DPP3 methodology, against the DPP3 unplanned SAIDI target and limit.

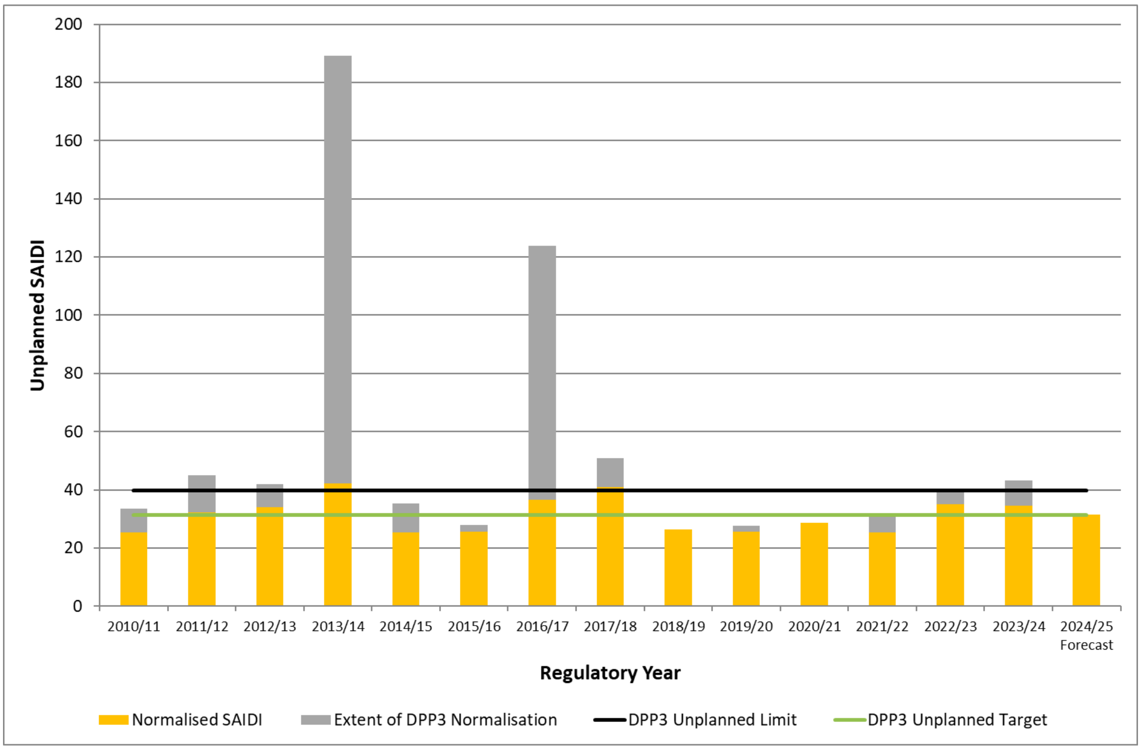



**Figure 7-1 DPP3 Normalisation Applied to Historical Unplanned SAIDI Performance**

WELL's targets for SAIDI and SAIFI are shown in Table 7-2. These targets assume that unplanned SAIDI and SAIFI beyond 2030 will be calculated using the same methodology as the DPP4 Determination, including the mechanism for normalising Major Event Days, and that WELL will have met its unplanned reliability targets to 2030.

| Regulatory Year | 2025/26 | 2026/27 | 2027/28 | 2028/29 | 2029/30 | 2030/31 | 2031/32 | 2032/33 | 2033/34 | 2034/35 |
|---|---|---|---|---|---|---|---|---|---|---|
| Unplanned SAIDI target | 29.64 | 29.64 | 29.64 | 29.64 | 29.64 | 29.64 | 29.64 | 29.64 | 29.64 | 29.64 |
| Unplanned SAIFI target | 0.457 | 0.457 | 0.457 | 0.457 | 0.457 | 0.457 | 0.457 | 0.457 | 0.457 | 0.457 |
| Planned SAIDI target | 13.77 | 12.75 | 12.30 | 13.23 | 11.36 | 12.71 | 11.51 | 12.36 | 11.26 | 11.26 |
| Planned SAIFI target | 0.078 | 0.072 | 0.070 | 0.075 | 0.064 | 0.072 | 0.065 | 0.070 | 0.064 | 0.064 |

**Table 7-2 Network Reliability Performance Targets**

WELL will need to increase its planned outage targets over the period due to an increase in its work programme. While most of the increase in expenditure will be related to subtransmission and zone substation reinforcement projects that can usually be completed without any customer outages, there will also be a significant increase in 11 kV reinforcement, which will increase planned outage indices.

The planned outage forecast is based on the following assumptions:

- Approximately 67% of recent Planned SAIDI has been due to capital works, with the balance being due to maintenance.

- Maintenance SAIDI will be constant into the future, i.e. there will be no significant change in the maintenance requirements for existing assets, or changes to work practices (e.g. increased generator usage or new rules around live work).

- Planned SAIDI due to capital work is proportional to the sum of Growth, Renewal, Relocation, and Quality of Supply expenditure, excluding expenditure on Subtransmission, Zone Substation, and Distribution Cable assets, as these projects can generally be delivered without requiring significant planned outages.

- Planned outage efficiency (SAIDI per CAPEX dollar) will remain constant throughout the period.

- Planned SAIFI is proportional to Planned SAIDI, i.e. Planned CAIDI will remain constant through the period due to the nature and duration of outages not changing.

### 7.1.1 Extreme Event Compliance Standard

DPP4 has retained the Extreme Event compliance standard first introduced with DPP3. 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 34.2 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 7-3.

| Extreme Event | Outage Duration to Exceed Standard | Solutions to Reduce Consequences |
|---|---|---|
| 33kV Cable Fire at Central Park GXP | 2 hours | • Cables within the switchroom have intumescent coatings.<br>• The planned expansion of the site to increase redundancy (Section 12.5.1). |
| Loss of Wainuiomata Zone Substation | 17 hours | • Fire suppression was installed in the Wainuiomata switchroom in 2021.<br>• Mobile substation and generation connection points. |
| Loss of Karori Zone Substation | 25 hours | • Pre-establish generation connection points.<br>• Improve 11 kV ties to adjacent zone substations (Section 9.4.43). |

Table 7-3 Top Three WELL Extreme Event Risks

## 7.2 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 7-4.

| Outage Type | Relevant Strategies |
|---|---|
| Unplanned | Asset Fleet Strategies, Network Development Strategies |
| Planned | Planned Outage Strategy |
| HILP | Resilience Strategy |

Table 7-4 Strategies Relating to Different Types of Outages

### 7.2.1 Unplanned Outages

**Asset Fleet Strategies**

Asset fleet strategies focus on the management of a specific asset fleet and are discussed in Section 8. 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. 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 outages, 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 is a key input into forecast fleet expenditure. These forecasting methods are described in Section 8.2.

**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 8.5.9.

**Network Development Strategies**

Network development strategies and plans ensure that the network remains at the targeted security levels, which helps maintain the integrity of the network when outages occur. These strategies are discussed in Section 9.

### 7.2.2 HILP Outages

**Resilience Strategy**

A specific portfolio strategy is the Resiliency Strategy discussed in Section 12. The Resiliency Strategy outlines the investment needed to mitigate HILP events. Following the 2016 Kaikoura earthquake, there was a heightened awareness by stakeholders of 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 its stakeholders and customers.

### 7.2.3 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 and the risks associated with reconfiguring the network, and include the protocols for communicating with customers when a planned outage is required.

## 7.3 Reliability Reporting

Figure 7-2 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's performance indicator. Governance decisions are formally noted in the Board papers and minutes.

| Governance Level | Meetings | Supporting Reports |
|---|---|---|
| Board | Quarterly Board meeting | Director Certified Disclosures (IDR, AMP, CS) |
| | | Reliability Board Papers |
| | | Company Performance and KPI Reporting |
| Executive | Fortnightly Executive Planning Meetings | Monthly Reliability Report |
| | | Monthly Customer Survey |
| | | Contractor KPI Dashboard Report |
| | Weekly Executive Update Meetings | Items escalated from management |
| Management | Monthly Reliability Strategy Meeting | Monthly Reliability Report |
| | Fortnightly Reliability Meeting | Weekly Reliability Summary |
| | Monthly Contractor Meeting | Contractor KPI Dashboard Report |
| | | Customer Complaints |
| | Contact Centre & Stakeholder Meetings | Contact Centre Metrics |
| | | Monthly Customer Survey |
| Operations and Engineering | Asset Failure Reviews, Outage Approval Process, Project Meetings etc. | Daily Outage Reporting |
| | | Event Driven Reports |
| | Customer Feedback Review | Customer Feedback Register |
| | Monthly Vegetation Management Forum | Post-Fault Vegetation Reporting |

**Figure 7-2 WELL's Reliability Reporting Structure**

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

### 7.3.1 Forecasting SAIDI by Fault Type

The forecast by SAIDI type is based on the historic monthly distribution of SAIDI due to each cause. This forecasting 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 7-3.

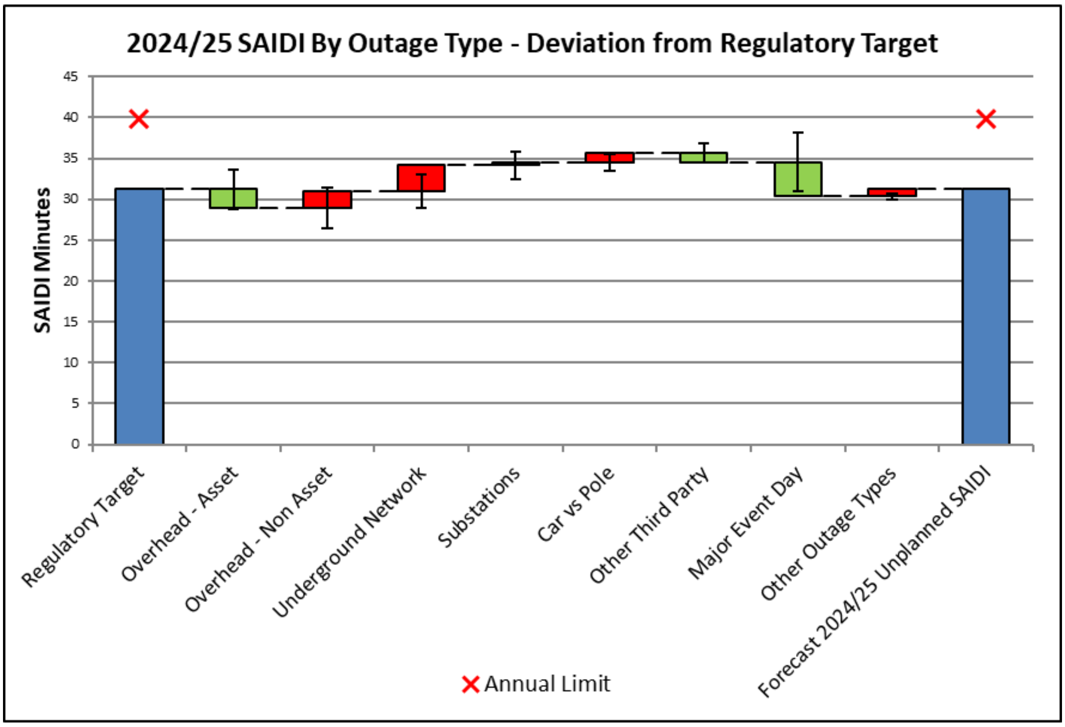



Figure 7-3 Waterfall Chart of 2024/25 SAIDI Performance by Outage Type

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 used since October 2017. The information is included in monthly reports to the Executive and network performance updates to the Board.

### 7.3.2 Reliability Trend Analysis

Detailed outage trend analysis is critical for providing confidence that the performance of the assets is not deteriorating. WELL's monthly reliability report to the Executive includes an analysis of trends in monthly SAIDI by outage type.

If any material trends are evident in the monthly SAIDI, these outage types are analysed in greater detail, breaking SAIDI down into its components of frequency of outages, duration of outages, and number of customers being affected, examining the trends in each to determine the underlying driver of the SAIDI trend. The trends in these components are then reviewed at the Reliability Strategy Meeting, to consider whether additional controls may be required to reverse the trend.

An example of this trend reporting is given in Figure 7-4.


Figure 7-4 Example Trend Analysis from Monthly Reliability Report

### 7.3.3 Wind Effect Normalisation

The majority of Unplanned SAIDI on WELL's network occurs on the overhead sections of the network, with monthly performance being very dependent on weather conditions. To test whether overhead network performance has been better or worse than expected for the given wind conditions, the overhead outage count is normalised by maximum daily wind gust speed. This allows for proactive analysis of overhead performance: if the overhead network is underperforming at low and moderate wind speeds, any underlying issues can be identified and rectified proactively, rather than being repaired reactively after a strong wind event.

Two types of fault are considered:

- Overhead outages caused by equipment failure, and
- Overhead outages with non-asset causes that are likely to be related to wind: vegetation, windborne debris, and no fault found.

The criteria used for normalisation is the number of outages that occur on a day relative to the maximum wind gust recorded on that day. Outage count is considered to be a better metric than SAIDI for this model, as SAIDI is significantly affected by factors such as fault location and response.

Daily wind gust data is sourced from MetService's Kelburn, Porirua, and Upper Hutt weather stations. For simplicity, the model does not consider the effect of wind direction. The baseline for the model is data from the reference period used for the DPP4 regulatory period, with the relationship between the average number of outages and daily wind gusts shown in Figure 7-5.

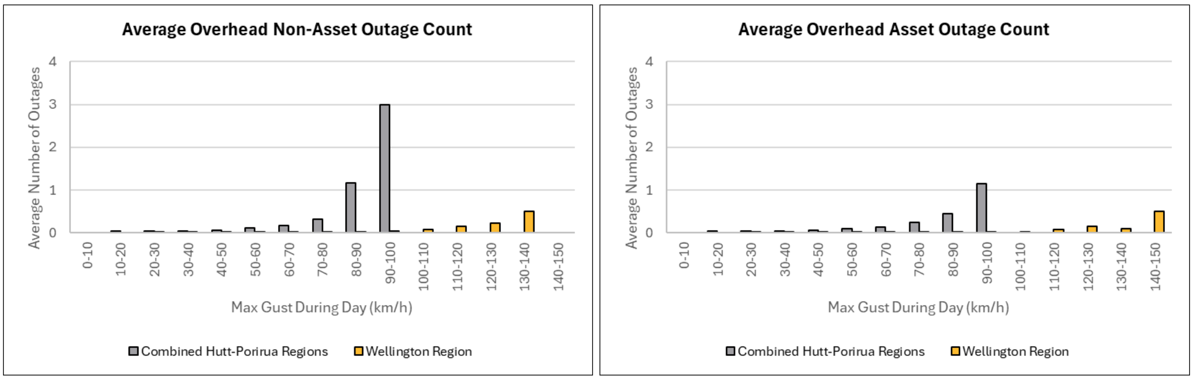



**Figure 7-5 Overhead Outages by Maximum Daily Wind Gusts for DPP4 Reference Period**

Applying these averages to the maximum daily wind gusts produces an expected number of annual outages for each year's wind conditions, which can then be compared to the actual number that was recorded. An example of this is shown in Figure 7-6, with the expected range being one standard deviation on either side of the expected average. These charts, presented to Management in the monthly reporting, show that the performance of the overhead network in 2024/25 has been better than average given the wind speeds that have been experienced, and therefore does not indicate a deterioration in performance.

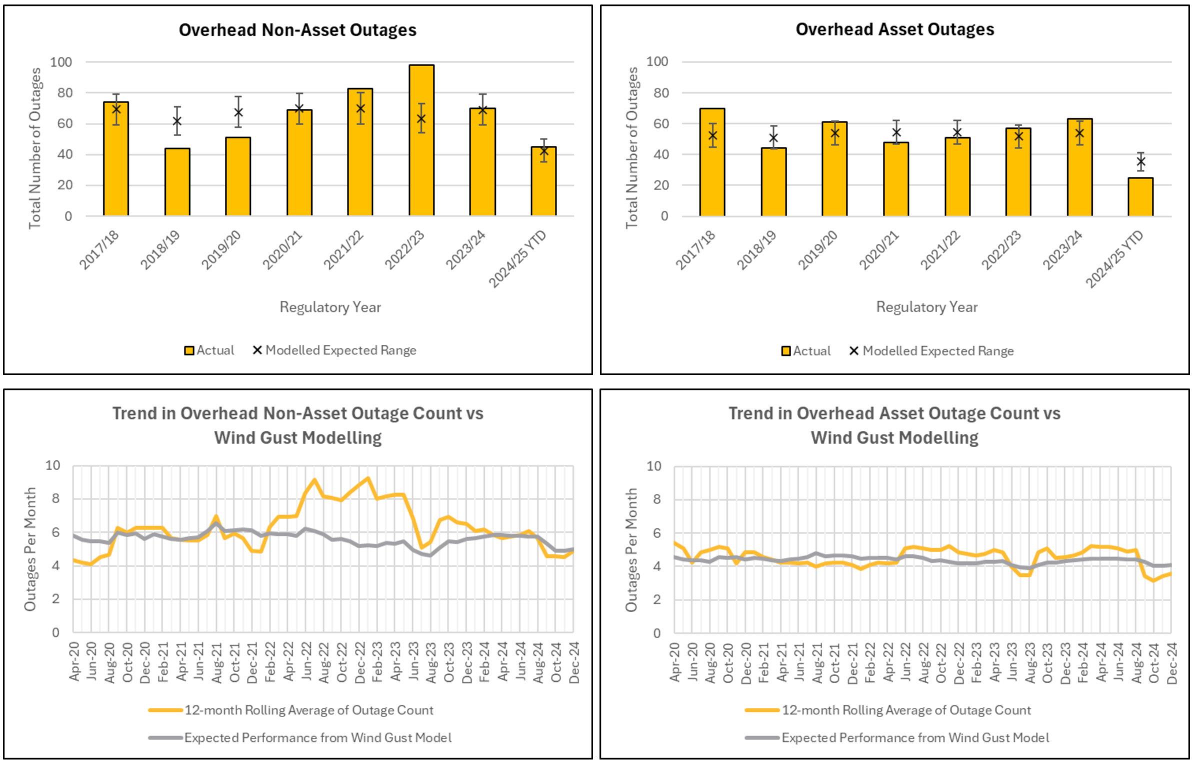



**Figure 7-6 Example Overhead Outage Normalisation**

### 7.3.4 Monthly Feeder Performance Summaries

The identification of specific areas of the network that are experiencing clusters of outages is essential for the early detection of emerging trends. To assist with this, the monthly reliability reporting includes feeder performance summaries, presented as pseudo-heatmaps. These heatmaps identify the number of outages of a particular cause affecting the feeder on a month-by-month basis. Large, complex feeders are subdivided into their major branches to help identify outages that are having a significant effect on overall reliability. An example pseudo-heatmap is presented in Figure 7-7.

| Feeder | Jan | Feb | Mar | Apr | May | Jun | Jul | Aug | Sep | Oct | Nov | Dec |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| Plimmerton 11 – Front End | | 1 | 1 | | | | | | | | | |
| Plimmerton 11 – Haywards Branch | | | | | | | | | | | | |
| Plimmerton 11 – Paekakariki Branch | | 1 | | | | | | | | | | |
| Plimmerton 11 – Various Spur Lines | | 1 | | 2 | | | | | | | | |
| Brown Owl 3 | | | 1 | | | | | 1 | | | | 1 |
| Wainuiomata 7 | | | 1 | | 1 | | | 1 | | | | |
| Johnsonville 10 | | | | 1 | | | | | 1 | 1 | | |
| Brown Owl 8 | | | | | | | | | | | 2 | |

Figure 7-7 Example Feeder Pseudo-Heatmap

Pseudo-heatmaps are generated for overhead asset failures, vegetation outages, and no fault found outages, as well as all-cause outages. They include all feeders that have experienced at least two outages from each cause over the past 12 months.

The use of pseudo-heatmaps provides a simplified, time-based view of the network, allowing easy identification of poorly performing feeders and potential emerging trends that require further detailed analysis.

### 7.3.5 Low Voltage Reliability

LV Outages are not included in formal SAIDI and SAIFI indicators but are tracked from a customer service and network condition perspective to identify trends and corrective actions.

A review of fault types and locations has indicated that overhead LV failures are concentrated Wellington's southern and eastern suburbs, particularly in coastal areas such as Island Bay, Lyall Bay, Evans Bay, and Miramar. In the Hutt Valley, overhead failures are highest in Petone. In Porirua, the highest number of overhead failures are in Titahi Bay. The common element in all these areas is proximity to the coast, followed by general exposure to the wind.

WELL will be undertaking further detailed investigations of failure modes in order to set up an LV reliability intervention programme targeting these poor performing areas, commencing in 2026.

## 7.4 Controls by Outage Cause

### 7.4.1 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 exceeds 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.

### 7.4.2 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 where 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.

### 7.4.3 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 utilise a risk-based approach to managing vegetation. The types and frequencies of vegetation surveys conducted by WELL are listed in Table 7-5. The annual vegetation management budget is based on the combination of surveys falling due, plus provisions for the estimated customer liaison required for cut or trim notices, and any first cuts that may be required.

| Survey Type | Definition | Survey Frequency |
| --- | --- | --- |
| Subtransmission Feeder | 33 kV circuit, with or without underbuilt 11 kV or LV | 2 years |
| Risk Feeder | Worst-performing 11 kV feeders | Annual |
| HV Survey | 11 kV circuit, with or without underbuilt LV | 3 years |
| LV Survey | LV circuit | 5 years |
| Rapid Response Survey | Out-of-cycle reactive survey | As required |

Table 7-5 Vegetation Management Surveys

Routine surveys include risk assessments of trees located outside the regulated zones. All parts of the network are assigned a potential reliability consequence, which establishes the level of detail required for tree assessments in that area. Each out-of-zone tree is 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 installed in areas prone to vegetation-related outages since 2018. WELL has purchased a quantity of conductor covers, which are available to be installed as areas of need are identified. 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 7-8. This chart shows that no vegetation outages have occurred in any of the areas where conductors have been installed after the installation of the covers.

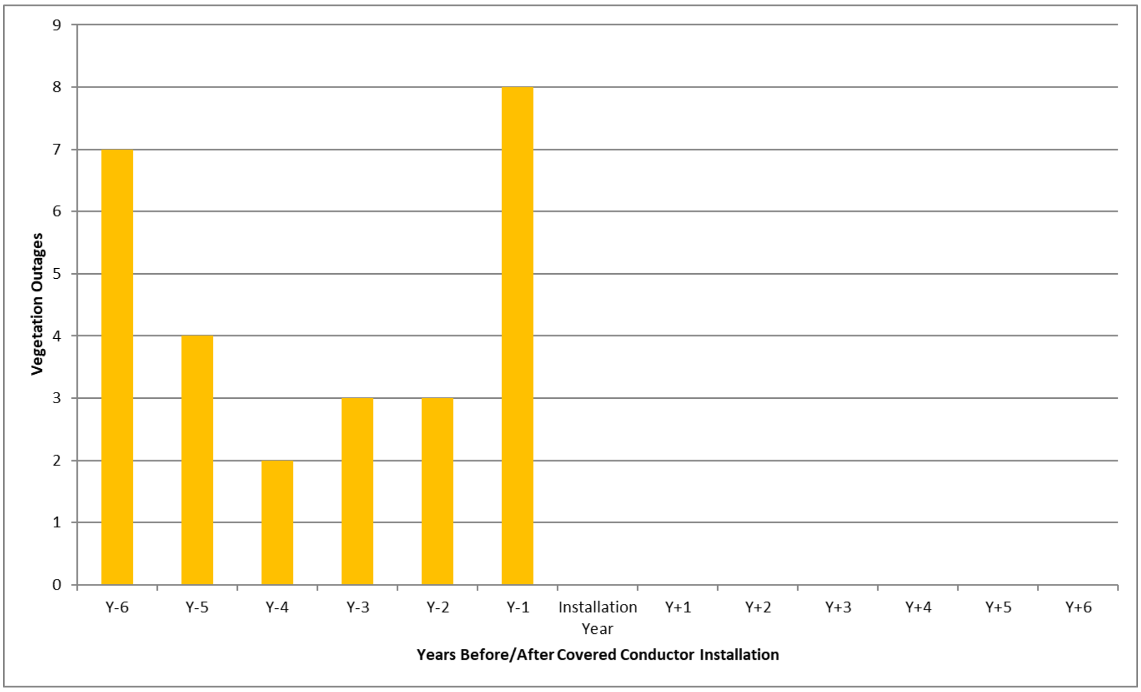



Figure 7-8 Aggregated Vegetation Outages in Covered Conductor Areas

### 7.4.4 Underground Equipment

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

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

WELL is collecting paper samples from faulted PILC cables with the intention of building a model of the relationship between paper condition and cable failure, to help inform future repair vs replace decisions.

### 7.4.5 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 currently developing a model of car vs pole risk, to help identify critical poles that are at risk of being damaged by vehicles and to inform decisions to manage that risk.

# 8 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.

## 8.1 Fleet Summary

A summary of the population for each of the Information Disclosure Requirements (IDR) categories and asset classes is shown in Table 8-1.

| IDR Category | Asset Class | Section | Measurement Unit | Quantity |
|---|---|---|---|---|
| Subtransmission | Subtransmission Cables | 8.5.1 | km | 147.8 |
| | Subtransmission Lines | 8.5.3.2 | km | 56.8 |
| Zone Substations | Zone Substation Transformers | 8.5.2.1 | number | 52 |
| | Zone Substation Circuit Breakers | 8.5.2.2 | number | 379 |
| | Zone Substation Buildings | 8.5.2.3 | number | 30 |
| Distribution and LV Lines | Distribution and LV Lines | 8.5.3.3 | km | 1,667.7 |
| | Streetlight Lines | 8.5.3.3 | km | 818.3 |
| | Distribution and LV Poles | 8.5.3.1 | number | 40,011 |
| Distribution and LV Cables | Distribution and LV Cables | 8.5.4 | km | 3,031.1 |
| | Streetlight Cables | 8.5.4 | km | 1,159.0 |
| Distribution Substations and Transformers | Distribution Transformers | 8.5.5.1 | number | 4,515 |
| | Distribution Substations | 8.5.5 | number | 3,976 |

| IDR Category | Asset Class | Section | Measurement Unit | Quantity |
|---|---|---|---|---|
| Distribution Switchgear | Distribution Circuit Breakers | 8.5.6 | number | 1,231 |
| | Distribution Reclosers | 8.5.7.1 | number | 18 |
| | Distribution Switchgear - Overhead | 8.5.7.2 | number | 2,661 |
| | Distribution Switchgear - Ground Mounted/Ring Main Units | 8.5.6 | number | 2,405 |
| Other Network Assets | Low Voltage Pits, Pillars, and Cabinets | 8.5.6.1 | number | 23,235 |
| | Protection Relays | 8.5.8.2 | number | 1,457 |
| | Load Control Plant | 8.5.9.4 | number | 25 |

Table 8-1 Asset Population Summary

## 8.2 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 a 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 incidents 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 of replacing it.

Non-traditional solutions may become an important tool for asset lifecycle planning if they allow end-of-life assets to be decommissioned, and either not be replaced or be replaced with an option that is significantly cheaper than would otherwise be required. Non-traditional solutions have not yet been developed to the scale and reliability necessary for EDBs to be able to rely on them when making these kinds of asset management decisions, particularly given the consequences that the EDB would be subject to if non-delivery of a third-party non-traditional solution resulted in a Quality Path Breach. As a result, non-traditional solutions are not currently considered to be a viable option for WELL's asset lifecycle planning.

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, renewal and refurbishment programmes.

## 8.3 Asset Health and Criticality Analysis

WELL uses the EEA Asset Health Indicator Guide - 2019. 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 is termed and influenced by end-of-life drivers. The scale is shown in Figure 8-1.

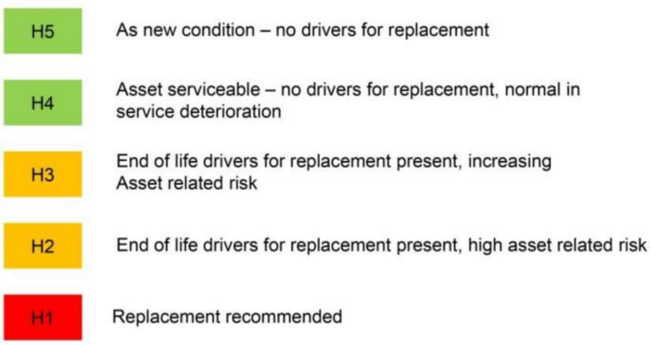



**Figure 8-1 EEA Asset Health Indicator Scale**

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 the 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 indicating risk. Each number in the matrix gives the number 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 8-2 and further discussed in Section 8.5.2.

| | | 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 | | | 1 | 1 | | | |
| | 2.0 | | | | 1 | | | |
| **Asset Health** | 2.5 | | | 1 | 2 | | | |
| | 3.0 | | | 10 | 12 | 3 | 6 | |
| | 4.0 | | | 7 | 4 | | 2 | |
| Best Health | 5.0 | | | | 2 | | | |

**Figure 8-2 Example Health-Criticality Matrix**

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 7. 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.

## 8.4 Maintenance Practices

### 8.4.1 Maintenance Standards

WELL contracts Omexom as its field services provider to undertake the network maintenance programme under a Field Services Agreement. 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.

### 8.4.2 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 an appropriate response to faults.
- **Vegetation management.** Planned and reactive vegetation work. WELL's approach to vegetation management is discussed in Section 7.4.3.
- **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 high load escorts, standover provisions for third-party contractors, and provision of asset plans for the 'B4Udig' programme, to prevent third-party damage to assets.
- **Asset replacement and renewal.** Reactive replacements that do not meet the criteria for capitalisation.

The forecast maintenance expenditure for 2025-2035 is summarised by asset class throughout this section.

## 8.5 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.

### 8.5.1 Subtransmission Cables

**Fleet Overview**

WELL owns approximately 143 km of subtransmission cables. These comprise 50 circuits connecting Transpower GXPs to WELL's zone substations. Approximately 37 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 from Central Park GXP to the 33 kV bus at Evans Bay is 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. The lengths and age profile of this asset class are shown in Table 8-2 and Figure 8-3.

| Construction | Design Voltage | Percentage | Quantity |
|---|---|---|---|
| Paper Insulated, Oil Pressurised | 33 kV | 29.1% | 41.6 km |
| Paper Insulated, Gas Pressurised | 33 kV | 27.5% | 39.2 km |
| Paper Insulated | 33 kV | 5.3% | 7.5 km |
| XLPE Insulated | 33 kV | 25.9% | 37.0 km |
| Paper Insulated, Oil Pressurised | 110 kV | 6.1% | 8.7 km |
| Paper Insulated, Oil Pressurised | 11 kV | 6.0% | 8.6 km |
| **Total** | | | **142.7 km** |

Table 8-2 Summary of Subtransmission Cables

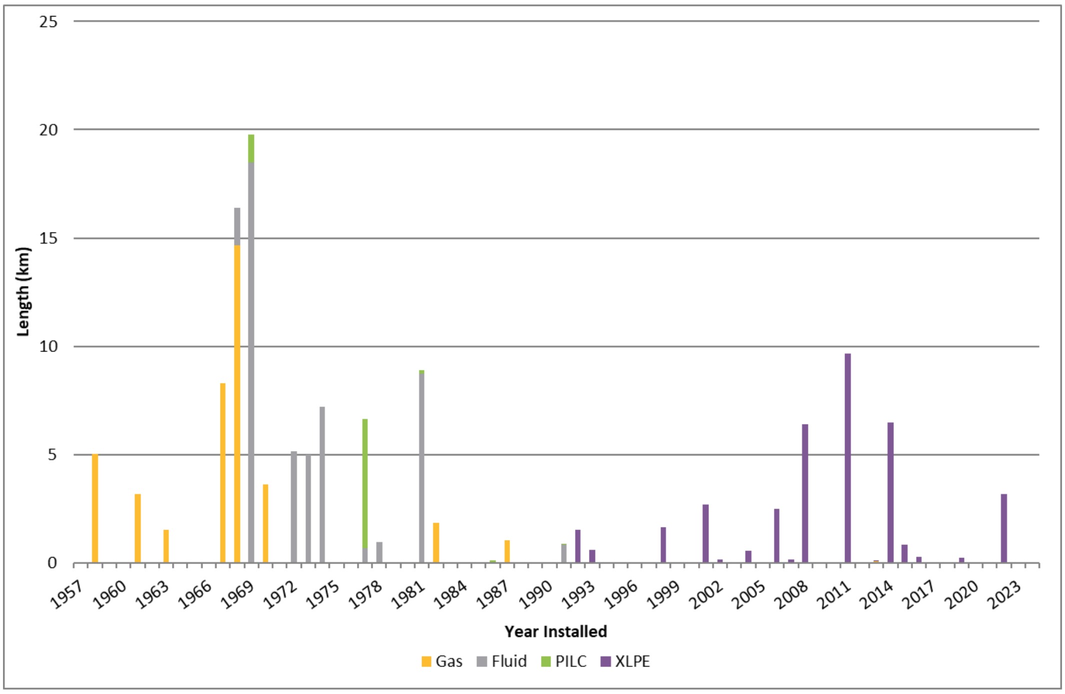



Figure 8-3 Age Profile of Subtransmission Cables

**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 subtransmission cable fleet:

| Priority Area | Objective |
|---|---|
| Safety and Environment | No injuries resulting from working on and around subtransmission cables.<br>Manage the environmental impact of fluid lost from fluid-filled cables. |
| Customer | Mitigate the risk of a 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 8-3 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; identify any third party works that may be putting cables at risk. | Weekly |

Table 8-4 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 mode 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 historical fault information for each cable is used to assess and prioritise the need for cable replacement, as well as determine the strategic spares to be held. Strategic spares for subtransmission cables are outlined in Table 8-5.

| Strategic Spares | |
|---|---|
| Medium lengths of cable | Medium lengths of fluid-filled cable are held in storage to allow the 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 8-5 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 8-4 shows the trend in gas leakage from WELL's gas-filled cables for the 12 months to the end of December 2024.

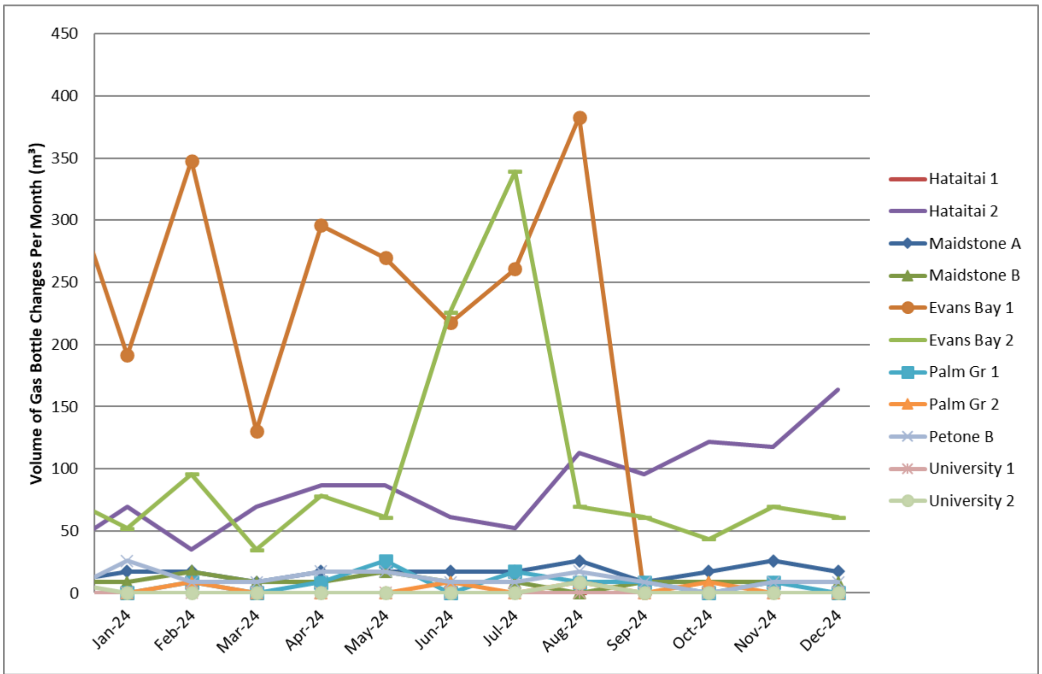



Figure 8-4 Monthly Gas-Filled Cable Leakage

### 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 8-5 shows the trend in fluid top ups from WELL's fluid-filled cables for the 12 months to the end of December 2024. Top ups can be required to replace fluid lost due to leaks, and due to the contraction of the fluid caused by colder ambient temperatures during winter.

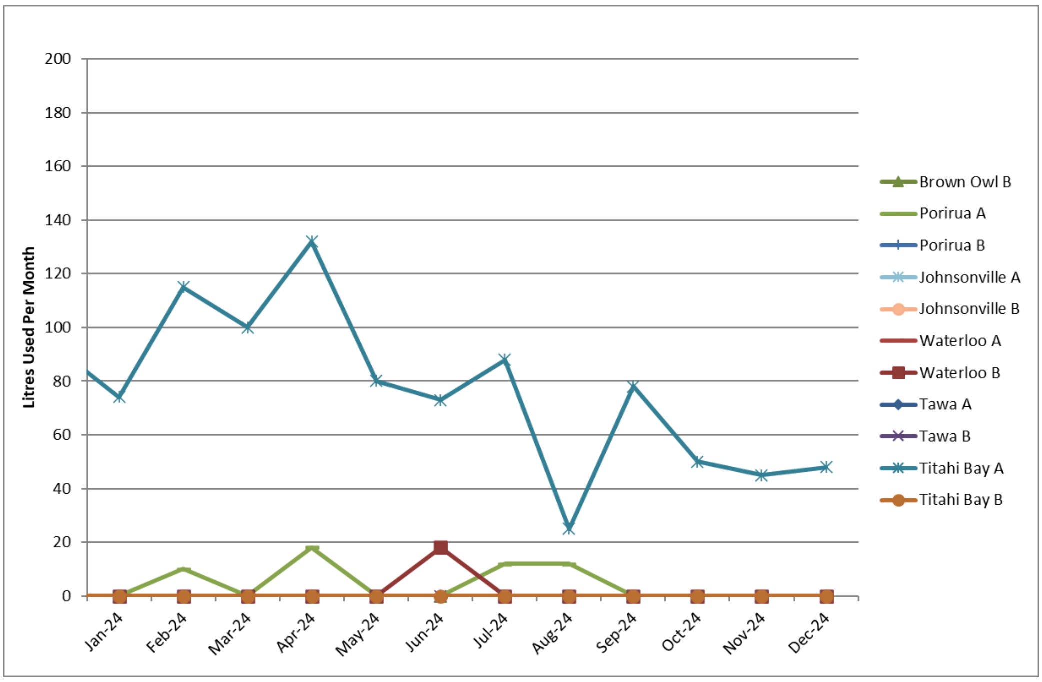



Figure 8-5 Monthly Fluid-Filled Cable Leakage

### 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 the University circuits, 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 yet in the fluid-filled cable fleet.

### Subtransmission Asset Health and Criticality Analysis

The Asset Health and Criticality Analysis results in the health-criticality matrix shown in Figure 8-6, with individual circuit scores and ratings being presented in Table 8-6. 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.

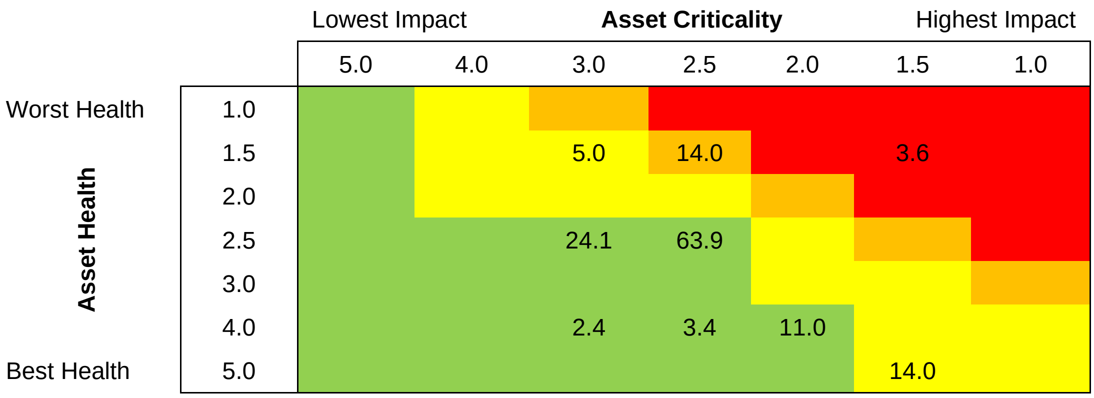



Figure 8-6 Subtransmission Cable Circuit Health-Criticality Matrix (km)

| Subtransmission Circuit | Length (km) | Primary Type | AHI | ACI | Rating |
|---|---|---|---|---|---|
| University 1 & 2 | 1.8/1.8 | Gas and XLPE | 1.8 | 1.9 | |
| Titahi Bay A & B (11kV) | 4.3/4.3 | Fluid | 1.6 | 2.9 | |
| Hataitai 2 | 2.4 | Gas | 1.9 | 2.9 | |
| Tawa A & B | 1.5/1.5 | Fluid | 1.9 | 2.9 | |
| Evans Bay 2 | 5.0 | Gas | 1.8 | 3.0 | |
| Palm Grove 1 & 2 | 3.2/3.2 | XLPE | 5.0 | 1.8 | |
| Frederick Street 1 & 2 | 1.6/1.6 | XLPE | 5.0 | 1.9 | |
| The Terrace 1 & 2 | 2.2/2.2 | XLPE | 5.0 | 1.9 | |
| Karori 1 & 2 | 4.9/4.9 | Gas | 2.9 | 2.8 | |
| Maidstone A & B | 5.0/5.0 | Gas | 2.8 | 2.9 | |
| Johnsonville A & B | 5.1/5.2 | Fluid | 2.8 | 2.9 | |
| Hataitai 1 | 2.4 | Gas | 2.9 | 2.9 | |
| Porirua A & B | 2.7/2.7 | Fluid | 2.9 | 2.9 | |
| Ira Street 1 & 2 | 2.5/2.5 | Gas | 2.9 | 2.9 | |
| Korokoro A & B | 5.3/5.3 | Fluid | 2.9 | 2.9 | |
| Kenepuru A & B | 0.8/0.8 | Fluid | 2.9 | 2.9 | |
| Evans Bay 3 & 4 (110kV) | 4.4/4.4 | Fluid | 2.9 | 2.9 | |
| Waikowhai Street A & B | 1.8/1.8 | Gas | 2.9 | 3.0 | |
| Trentham A & B | 2.1/0.8 | Fluid | 2.9 | 3.0 | |
| Waitangirua A & B | 1.6/1.4 | Fluid | 2.9 | 3.0 | |
| Brown Owl A & B | 0.9/0.9 | Fluid | 2.9 | 3.0 | |
| Naenae A & B | 3.8/3.8 | Fluid | 2.9 | 3.0 | |
| Waterloo A & B | 2.6/2.6 | Fluid | 2.9 | 3.0 | |
| Moore Street 1 & 2 | 5.2/5.2 | XLPE | 4.0 | 2.0 | |
| Wainuiomata A & B | 0.1/0.5 | PILC | 4.0 | 2.0 | |
| Ngauranga A & B | 0.3/0.3 | XLPE | 4.0 | 2.9 | |
| Seaview A & B | 1.4/1.4 | PILC | 4.0 | 2.9 | |
| Gracefield A & B | 0.1/0.1 | PILC | 4.0 | 3.0 | |
| Mana | 2.0 | XLPE | 4.0 | 3.0 | |
| Plimmerton | 0.2 | XLPE | 4.0 | 3.0 | |

Table 8-6 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 2024 AMP, are discussed below.

**University**

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

Both circuits experienced faults in 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 was expected to be required in approximately 10 years. Replacement is planned to occur in 2027.

**Titahi Bay**

The two fluid-filled Titahi Bay circuits have experienced multiple leaks since August 2021. The sequence of leaks occurring on these cables over the last five years indicates that the cables are approaching end-of-life, and work to replace these two circuits has now commenced in conjunction with a Porirua City Council urban cycleway project.

**Hataitai 2**

The gas-filled Hataitai circuit 2 developed a leak at the end of 2023, which gradually deteriorated over the course of 2024. The location of this leak was identified in December 2024, with repairs completed in March 2025.

**Tawa**

Condition assessment using an Uncrewed 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 was temporarily repaired, and it is expected that the cables would require replacement, however, a permanent repair solution has been developed to allow the cables to remain in service.

**Evans Bay**

The Evans Bay subtransmission circuits were installed in 1958 and are the oldest gas cables on the network.

Evans Bay circuit 1 was retired from service in September 2024 due to condition. A 33kV bus has been installed at Evans Bay, supplied from the two 110 kV-rated Ira Street fluid-filled cables (which run from Central Park to the Evans Bay substation compound, and are now labelled as Evans Bay circuits 3 and 4) and Evans Bay circuit 2. This has created 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 remaining Evans Bay cable.

The long-term plan is to run new cables to Evans Bay within the next 10 years, preferably in conjunction with planned transport projects, as discussed in Section 9.4.2.

## Renewal and Refurbishment

There are few cost-effective options for refurbishment or life extension of subtransmission cables once major leaks, discharge, or electrical insulation breakdown has occurred. In most cases, due to the cost of gas and fluid transition joints, it is likely to be most cost-effective to replace cables end to end in their entirety.

Significant projects for the renewal of subtransmission cables over the next 12 months are listed in Table 8-7.

| Project | Description |
|---|---|
| University Cables | Detailed design and procurement ahead of replacement during 2027. |
| Titahi Bay Cables | Continued ducting along the replacement cable route. |

Table 8-7 Subtransmission Cable Projects for 2025/26

**Expenditure Summary for Subtransmission Cables**

Table 8-8 details the expected expenditure on subtransmission cables by regulatory year. Note that some cables identified for replacement are detailed in the System Growth expenditure in Section 9.

| Expenditure Type | 2025/26 | 2026/27 | 2027/28 | 2028/29 | 2029/30 | 2030/31 | 2031/32 | 2032/33 | 2033/34 | 2034/35 |
|---|---|---|---|---|---|---|---|---|---|---|
| Titahi Bay Cable Replacement | 2,078 | 7,663 | - | - | - | - | - | - | - | - |
| University Cable Replacement | 1,393 | 1,966 | - | - | - | - | - | - | - | - |
| Maidstone Gas Cable Replacement | - | - | - | 8,417 | 8,417 | - | - | - | - | - |
| Karori Gas Cable Replacement | - | - | - | - | - | - | 6,489 | 15,124 | - | - |
| Waterloo Cable Replacement | - | - | - | - | - | - | - | - | 4,100 | 4,300 |
| **Capital Expenditure Total** | **3,471** | **9,629** | **-** | **8,417** | **8,417** | **-** | **6,489** | **15,124** | **4,100** | **4,300** |
| Preventative Maintenance | 103 | 103 | 102 | 101 | 101 | 100 | 100 | 100 | 99 | 98 |
| Corrective Maintenance | 480 | 480 | 420 | 420 | 420 | 350 | 350 | 350 | 350 | 350 |
| **Operational Expenditure Total** | **583** | **583** | **522** | **521** | **521** | **450** | **450** | **450** | **449** | **448** |

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

### 8.5.2 Zone Substations

#### 8.5.2.1 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, however, 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 8-7.

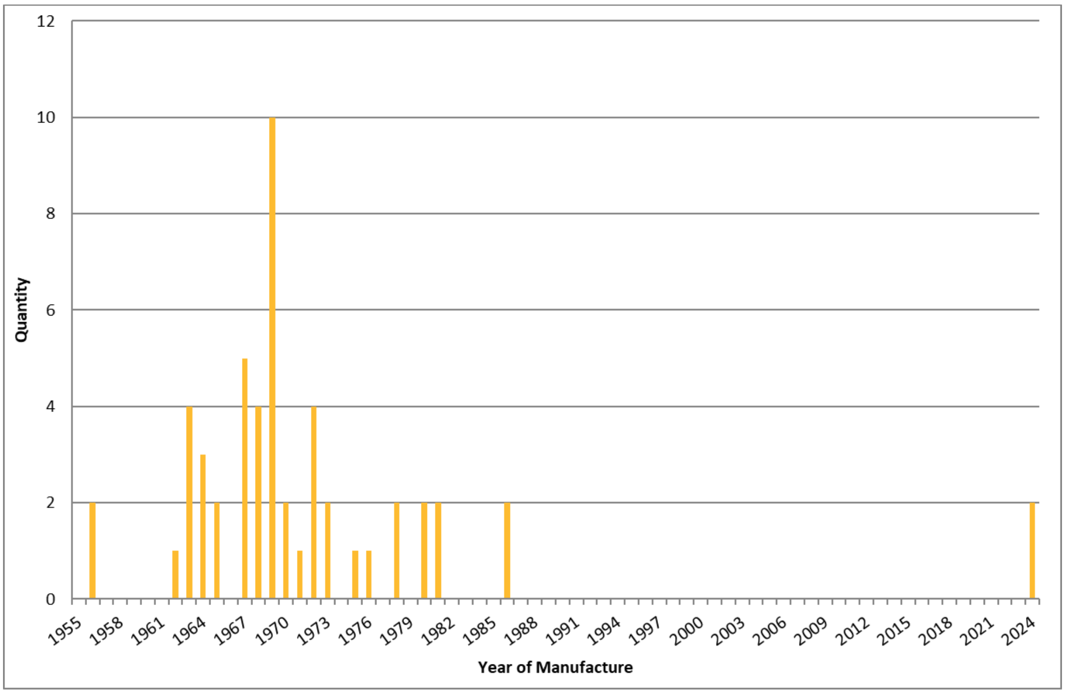



Figure 8-7 Age Profile of Zone Substation Transformers

The mean age of the transformer fleet is 53 years.

**Fleet Objectives**

In addition to WELL's broader asset management objectives that apply across the entire network, WELL has fleet-specific objectives for the power transformer fleet as detailed in Table 8-9.

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

Table 8-9 Fleet-Specific Objectives for Power Transformer Fleet

## Maintenance Activities

Routine planned inspection, testing and maintenance activities are undertaken on zone substation power transformers as detailed in Table 8-10.

| 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 the transformer, and diagnostic tests as required. Hot collar testing of bushings if appropriate. 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 8-10 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 8-11.

| 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 the Petone Zone Substation. This unit was refurbished in 2018.<br>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. |
| Mobile Substations | WELL owns two mobile substations that comprise trailer-mounted 10 MVA 33/11kV transformers and containerised 33 kV and 11 kV switchgear. |

Table 8-11 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 transformer internal condition. Furan analysis is undertaken with DGA oil tests, which shows the DP of the majority of transformers to be above 450 indicating at least 25 years of remaining life in the insulation. Figure 8-8 shows the Degree of Polymerisation by transformer age for WELL's power transformer fleet as measured during annual dissolved gas analysis from 2019 to 2024.

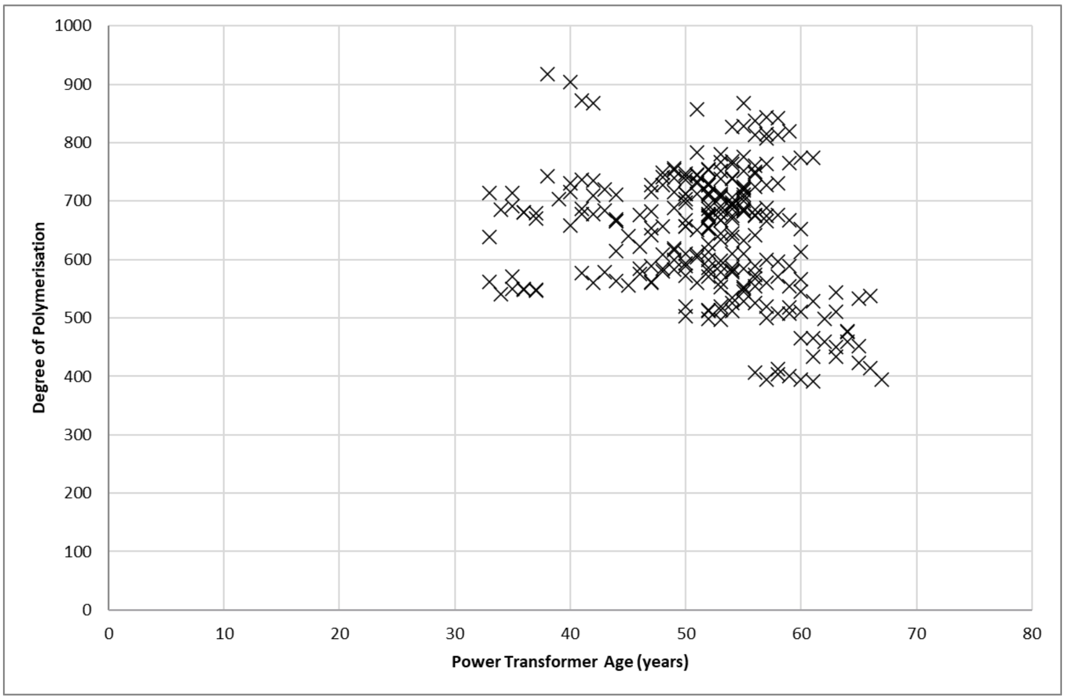



Figure 8-8 Power Transformer Degree of Polymerisation by Age

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 the tap changer and the main tank. The levels of migration are being monitored via ongoing oil sampling and DGA analysis.

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 8-9, with individual transformer scores and ratings being presented in Table 8-12.

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 | 1 | | | |
| | 2.0 | | | | 1 | | | |
| | 2.5 | | | 1 | 2 | | | |
| | 3.0 | | | 10 | 12 | 3 | 6 | |
| | 4.0 | | | 6 | 4 | 1 | 2 | |
| Best Health | 5.0 | | | | 2 | | | |

**Figure 8-9 Power Transformer Health-Criticality Matrix**

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

| Transformer | AHI | ACI | Rating |
|---|---|---|---|
| Waterloo B | 3.0 | 3.0 | |
| Wainuiomata B | 4.0 | 2.0 | |
| Ira Street T1 & T2 | 4.0 | 2.9 | |
| Maidstone A & B | 4.0 | 2.9 | |
| Gracefield A & B | 4.0 | 3.0 | |
| Trentham B | 4.0 | 3.0 | |
| Waterloo A | 4.0 | 3.0 | |
| Brown Owl B | 4.0 | 3.0 | |
| Naenae A | 4.0 | 3.0 | |
| Evans Bay T1 & T2 | 5.0 | 2.9 | |

Table 8-12 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.

**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 9.5, replacement of the transformers is planned for 2028 due to capacity constraints.

**Mana**

The Mana transformer is a South Wales unit that was manufactured in 1963 and has exhibited a low estimated DP value based on a Furan Analysis of 400. DGA on this unit shows no concerning signs in terms of combustible gases, carbon monoxide, or carbon dioxide. Online monitoring has been fitted to the transformer to provide a more detailed estimate of end-of-life, and this is indicating that replacement will be required within the period covered by this AMP.

**Kenepuru**

The Kenepuru transformers are Brush units that were manufactured in 1971. Kenepuru A has exhibited a low estimated DP value. Both transformers had a midlife refurbishment completed between 1998-2002, during which it was confirmed that Kenepuru A had a reduction in paper quality relative to other power transformers of a similar age and construction. DGA on this unit shows no concerning signs in terms of combustible gases, carbon monoxide, or carbon dioxide. The DP of both units will continue to be monitored through routine maintenance, with both units to be replaced as a pair within the period covered by 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 9.4 indicates that the most cost-effective option to manage the transformer health and criticality 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.

### Evans Bay

The transformers at Evans Bay were replaced for asset health reasons in 2024. A purpose-built transformer enclosure was constructed, and decommissioning of the existing transformer building was completed as part of the project works.

## Renewal and Refurbishment

Where a transformer is identified for relocation, refurbishment is generally performed if it is economical 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 economical.

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, and
- Transformer replacement at Kenepuru and Mana zone substations.

Transformer replacement projects that are triggered by capacity constraints rather than asset health and criticality, including Ngauranga and Porirua, are detailed in Section 9.5.

There are no projects for the renewal of power transformers over the next 12 months.

## Expenditure Summary for Power Transformers

Table 8-13 details the expected expenditure on power transformers by regulatory year. Transformers identified as having replacement driven by capacity instead of condition are provided in the System Growth expenditure detailed in Section 9.

| Expenditure Type | 2025/26 | 2026/27 | 2027/28 | 2028/29 | 2029/30 | 2030/31 | 2031/32 | 2032/33 | 2033/34 | 2034/35 |
|---|---|---|---|---|---|---|---|---|---|---|
| Kenepuru Transformer Replacement | - | - | 5,000 | - | - | - | - | - | - | - |
| Mana Transformer Replacement | - | - | - | - | 5,000 | - | - | - | - | - |
| **Capital Expenditure Total** | **-** | **-** | **5,000** | **-** | **5,000** | **-** | **-** | **-** | **-** | **-** |
| Preventative Maintenance | 345 | 345 | 345 | 345 | 345 | 345 | 345 | 345 | 345 | 345 |
| Corrective Maintenance | 120 | 120 | 120 | 120 | 120 | 120 | 120 | 120 | 120 | 120 |
| **Operational Expenditure Total** | **465** | **465** | **465** | **465** | **465** | **465** | **465** | **465** | **465** | **465** |

**Table 8-13 Expenditure on Power Transformers**
**($K in constant prices)**

### 8.5.2.2 Zone Substation Switchboards and Circuit Breakers

**Fleet Overview**

Circuit breakers are used in zone substations to control the power injected into the 11 kV distribution network. There are 381 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 8-10.

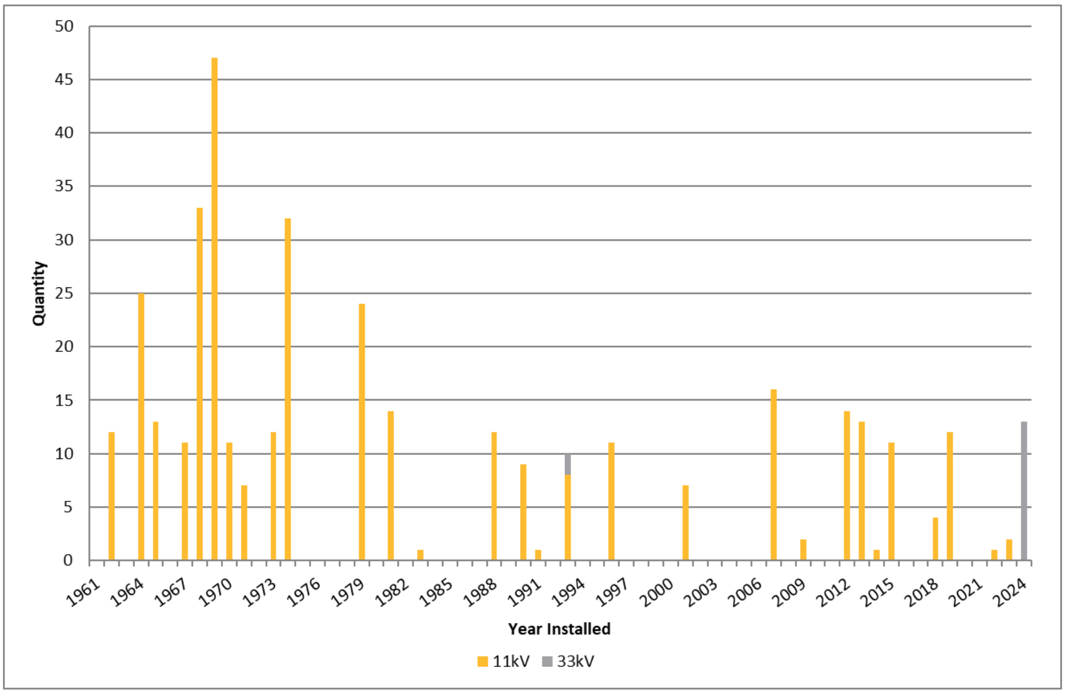



Figure 8-10 Age Profile for Zone Substation Circuit Breakers

The average age of the zone substation circuit breakers in the Wellington Network is approximately 41 years, with the age of individual breakers ranging from relatively new to more than 60 years. The mix of circuit breaker technologies reflects the age of the equipment. Older circuit breakers are oil-filled while newer units have vacuum interrupters. The majority of circuit breakers are oil-filled and require relatively higher maintenance regimes.

A new 33 kV switching station consisting of 13 circuit breakers, including a bus coupler, was installed at Evans Bay in 2024. The modular, prefabricated switching station has been positioned on a raised platform to reduce chance of equipment damage due to flooding.

There are two 33 kV Nissin KOR oil circuit breakers at Ngauranga which have been in service at this site for 32 years. Originally manufactured in the 1960s, they were installed in 1993 when the substation was constructed. These breakers will be decommissioned when the transformers are replaced in 2028 (see Section 9.5.2.3). Until then, a spare unit has been obtained from Transpower.

| Category | Quantity |
|---|---|
| 33 kV Circuit Breakers | 15 |
| 11 kV Circuit Breakers | 366 |
| Total | 381 |

Table 8-14 Summary of Zone Substation Circuit Breakers

| Manufacturer | Interrupter Type | Quantity |
|---|---|---|
| Nissin (33 kV) | Oil | 2 |
| Eaton (33 kV) | Vacuum | 13 |
| Reyrolle/RPS | Oil | 257 |
| | Vacuum | 93 |
| Siemens | Vacuum | 16 |
| **Total** | | **381** |

Table 8-15 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 8-16 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 on 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 on 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 |

| Activity | Description | Frequency |
|---|---|---|
| 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, and 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 the 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, cleaning and inspecting all switchboard fixed portion components, and undertaking condition and diagnostic tests as required. Maintain VTs and CTs. Return to service. | 8 yearly |
| 11 kV Circuit Breaker – Annual Operational Check | Backfeed supply, and 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 8-17 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 Pacific 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 8-18.

| 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 are 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. |
| 33 kV Nissin KOR Circuit Breaker | One complete unit held as a spare for the Ngauranga 33 kV circuit breakers |
| Mobile switchboard | WELL owns a containerised 11kV mobile switchboard. |

Table 8-18 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 the late 1960s onwards and there are over 600 units in service on the WELL network at both zone substation and distribution substation level.

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 8-11, with individual switchboard scores and ratings being presented in Table 8-19.

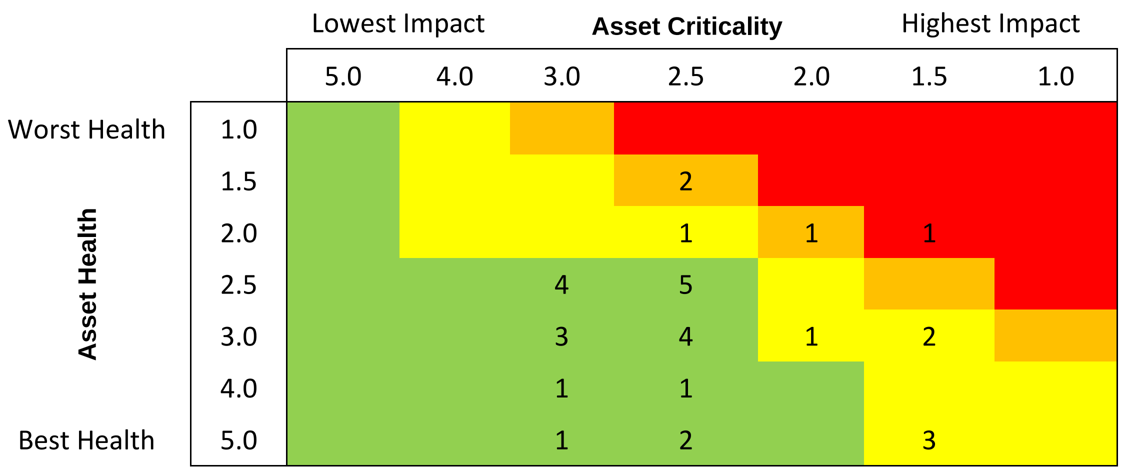



Figure 8-11 Zone Substation Switchboard Health-Criticality Matrix

| Switchboard | Model | AHI | ACI | Rating |
|---|---|---|---|---|
| Frederick Street | LM23T | 2.0 | 1.9 | |
| Kenepuru | LM23T | 1.9 | 2.9 | |
| Mana | LM23T | 1.9 | 2.9 | |
| Moore Street | LM23T | 2.0 | 2.0 | |
| Hataitai | LM23T | 2.0 | 2.9 | |
| University | LMT | 3.0 | 1.9 | |
| Nairn Street | LMT | 3.0 | 1.9 | |
| 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 | |
| Korokoro | LM23T | 2.9 | 2.9 | |
| Maidstone | LM23T | 2.9 | 2.9 | |
| Ngauranga | LMT | 2.9 | 2.9 | |
| Plimmerton | LM23T | 2.9 | 2.9 | |
| Porirua | LM23T | 2.9 | 2.9 | |
| Brown Owl | LM23T | 2.9 | 3.0 | |
| Naenae | LM23T | 2.9 | 3.0 | |
| Trentham | LM23T | 2.9 | 3.0 | |
| Waterloo | LMT | 2.9 | 3.0 | |
| Ira Street | LM23T | 3.0 | 2.9 | |
| Johnsonville | 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 | |
| Waitangirua | LM23T | 3.0 | 3.0 | |
| Evans Bay | LMVP | 4.0 | 2.9 | |
| Waikowhai Street | LMT | 4.0 | 3.0 | |
| Evans Bay 33 kV | XGIS | 5.0 | 2.9 | |
| Karori | LMVP | 5.0 | 2.9 | |
| Gracefield | LMVP | 5.0 | 3.0 | |

Table 8-19 Health-Criticality Scores for Zone Substation Switchboards

## Outcome of the Asset Health Analysis

### Frederick Street

The Reyrolle LMT switchboard at Frederick Street has had a number of stages of PD mitigation work since 2015. Subsequent PD testing has indicated that this ongoing work had been successful, however, it has also shown adjacent circuit breakers with high PD levels that have previously been masked. Further PD mitigation works will occur on these adjacent circuit breakers involving the two-breaker incomer for power transformer T1.

**Kenepuru**

Partial discharge mitigation work at Kenepuru has been underway since 2024 on two circuit breakers. This work is expected to be completed in 2025.

**Hataitai**

Maintenance work at Hataitai has not yet been successful in eliminating the partial discharge at this site. Replacement of one of the feeder cables is planned for 2025.

**Mana**

Partial discharge has been detected at Mana and has been relatively stable under the annual Partial Discharge surveys.

**Moore Street**

Partial discharge has been detected on three circuit breakers. This will be addressed by the installation of retrofit components during 2025.

**Kaiwharawhara**

Partial discharge has been detected on one of the LMVP circuit breakers. Initial Transient Earth Voltage (TEV) testing indicated high levels of PD originating from adjacent circuit breakers. Truck replacement and maintenance is scheduled in 2025.

**Renewal and Refurbishment**

WELL's fleet of zone substation circuit breakers is generally in good condition. Assuming that the ongoing programme to mitigate partial discharge issues as they are identified continues to be successful, no zone substation circuit breakers are expected to require replacement for health reasons during the next five years. There is no indication that the replacement of these switchboards needs to be driven purely by age, however, their condition will continue to be monitored through routine inspections and maintenance.

Switchboard replacement projects that are triggered by capacity constraints rather than asset health and criticality, including Ira Street and Porirua, are detailed in Section 9.

Significant projects for the renewal of zone substation circuit breakers over the next 12 months are listed in Table 8-20.

| Project | Description |
|---|---|
| Frederick Street | Partial discharge mitigation on the T1 incomer |
| Moore Street | Partial discharge mitigation of three feeder breakers. |
| Kenepuru | Partial discharge migration on the T1 incomer and one feeder breaker. |
| Kaiwharawhara | LMVP truck replacement and maintenance |
| Hataitai | Partial discharge mitigation on Feeder breaker. |

Table 8-20 Zone Substation Circuit Breaker Projects for 2025/26

**Expenditure Summary for Zone Substation Circuit Breakers**

Table 8-21 details the expected expenditure on zone substation circuit breakers by regulatory year.

| Expenditure Type | 2025/26 | 2026/27 | 2027/28 | 2028/29 | 2029/30 | 2030/31 | 2031/32 | 2032/33 | 2033/34 | 2034/35 |
|---|---|---|---|---|---|---|---|---|---|---|
| Partial Discharge Mitigation | 1,413 | 369 | 324 | 352 | 343 | 297 | 300 | 303 | 255 | 309 |
| **Capital Expenditure Total** | **1,413** | **369** | **324** | **352** | **343** | **297** | **300** | **303** | **255** | **309** |
| Preventative Maintenance | 100 | 100 | 100 | 100 | 100 | 100 | 100 | 100 | 100 | 100 |
| Corrective Maintenance | 20 | 20 | 20 | 20 | 20 | 20 | 20 | 20 | 20 | 20 |
| **Operational Expenditure Total** | **120** | **120** | **120** | **120** | **120** | **120** | **120** | **120** | **120** | **120** |

**Table 8-21 Expenditure on Zone Substation Circuit Breakers (\$K in constant prices)**

### 8.5.2.3 Zone Substation Buildings and Equipment

**Fleet Overview**

There are 27 zone substation buildings and three major 11 kV switching station buildings that function as zone 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 the New Building Standard (NBS) at Importance Level 4, except Naenae which is currently being strengthened.

The age profile of the major substation buildings is shown in Figure 8-12. The average age of the buildings is 52 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.

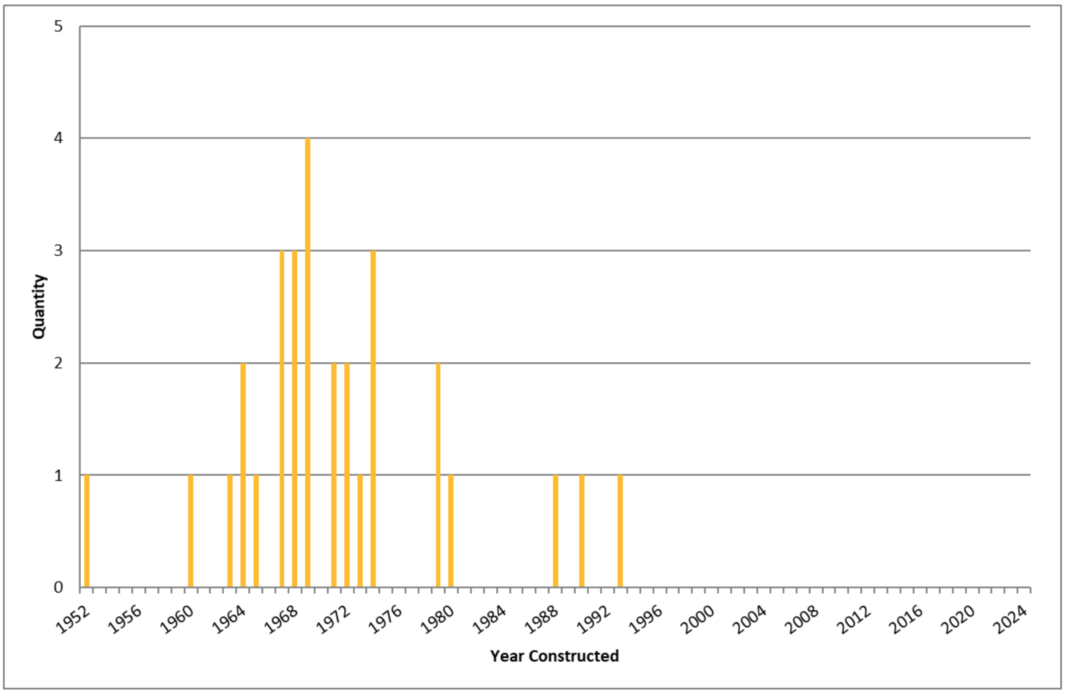



Figure 8-12 Age Profile of Major Substation Buildings

## 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 8-22 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, and undertake minor repairs as required. Thermal inspection of all equipment, handheld PD and Ultrasonic scan. Inspect and maintain oil containment systems, and 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 | Inspect and test fire suppression system (Inergen/gas flood). | 1 monthly |
| Fire Suppression System Maintenance | Maintain fire suppression systems | 12 monthly |
| Fire Alarm Test | Inspect and test passive fire alarm systems. | 1 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 8-23 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 are rectified. Building maintenance varies depending on 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. Where deterioration from the natural elements has resulted in maintenance being uneconomic to address weather tightness issues, these components are replaced in their entirety. This work is critical to ensure the ongoing reliability of the 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.

Significant projects for the renewal of zone substation buildings over the next 12 months are listed in Table 8-24.

| Project | Description |
|---|---|
| Naenae Sesimic Strenghtening | Completion of the seismic reinforcement of Naenae zone substation |

Table 8-24 Zone Substation Building Projects for 2025/26

**Expenditure Summary for Zone Substation Buildings**

Table 8-25 details the expected expenditure on zone substation buildings by regulatory year.

| Expenditure Type | 2025/26 | 2026/27 | 2027/28 | 2028/29 | 2029/30 | 2030/31 | 2031/32 | 2032/33 | 2033/34 | 2034/35 |
|---|---|---|---|---|---|---|---|---|---|---|
| Asset Replacement and Renewal Capex | 250 | 200 | 200 | 200 | 200 | 200 | 200 | 200 | 200 | 200 |
| **Capital Expenditure Total** | **250** | **200** | **200** | **200** | **200** | **200** | **200** | **200** | **200** | **200** |
| Preventative Maintenance | 100 | 100 | 100 | 100 | 100 | 100 | 100 | 100 | 100 | 100 |
| Corrective Maintenance | 305 | 305 | 305 | 305 | 305 | 305 | 305 | 305 | 305 | 305 |
| **Operational Expenditure Total** | **405** | **405** | **405** | **405** | **405** | **405** | **405** | **405** | **405** | **405** |

Table 8-25 Expenditure on Zone Substation Buildings
($K in constant prices)

### 8.5.3 Overhead Lines

#### 8.5.3.1 Poles

The total number of poles owned by WELL, including subtransmission, distribution, and low voltage lines, is 40,011. Of this number, 18% are wooden poles and 81% are concrete poles. The remaining 1% of poles are fibreglass or steel. Another 16,943 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 8-26.

| Pole Owner | Wood | Concrete/Other | Total |
|---|---|---|---|
| WELL | 7,191 | 32,820 | 40,011 |
| Customer | 6,098 | 601 | 6,699 |
| Chorus | 7,391 | 365 | 7,756 |
| Wellington City Council | 1,358 | 1,090 | 2,488 |
| **Total** | **22,038** | **34,876** | **56,914** |

Table 8-26 Summary of Poles

The average age of concrete/ other poles is 30 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.

An age profile of poles owned by WELL is shown in Figure 8-13.

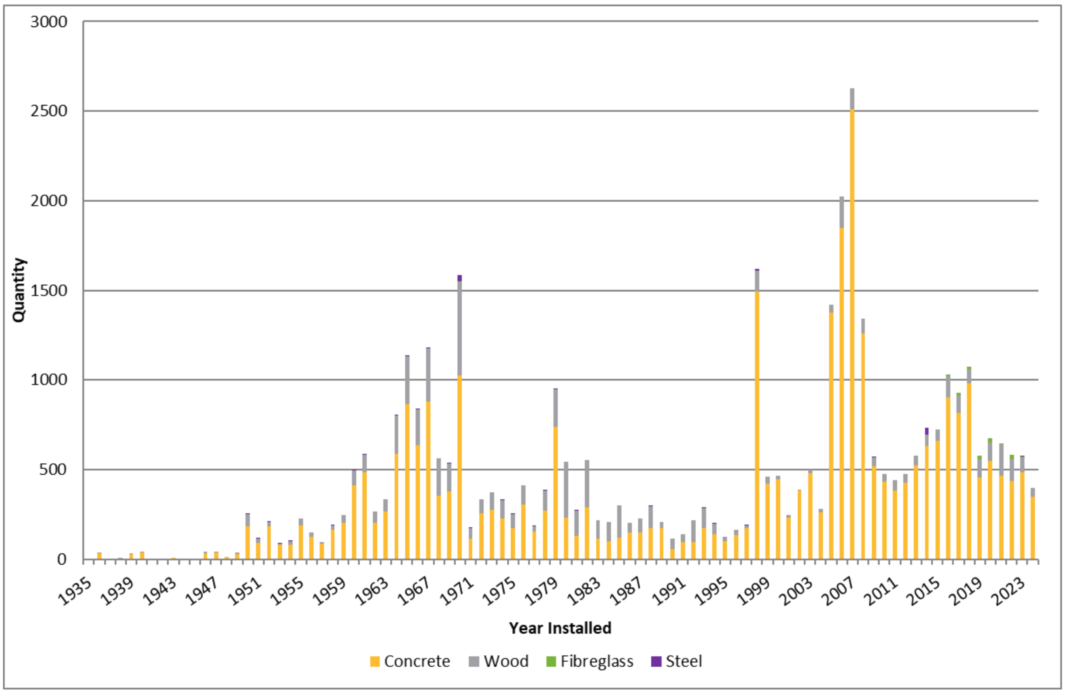



Figure 8-13 Age Profile of Poles

As WELL does not own customer service lines or poles, ongoing work is 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' are defined in the Electricity Act 1992. An example is 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 Vital (formerly known as CityLink) utilise WELL's poles for telephone, cable TV and UFB services.

#### 8.5.3.2 Subtransmission Lines

WELL's 56.8km of 33 kV subtransmission overhead lines are predominantly AAC conductors on both wood and concrete poles. Overhead lines are 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 Table 8-27 and Figure 8-14.

| Category | Quantity |
|---|---|
| 33 kV Overhead Line | 56.8km |

Table 8-27 Summary of Subtransmission Lines

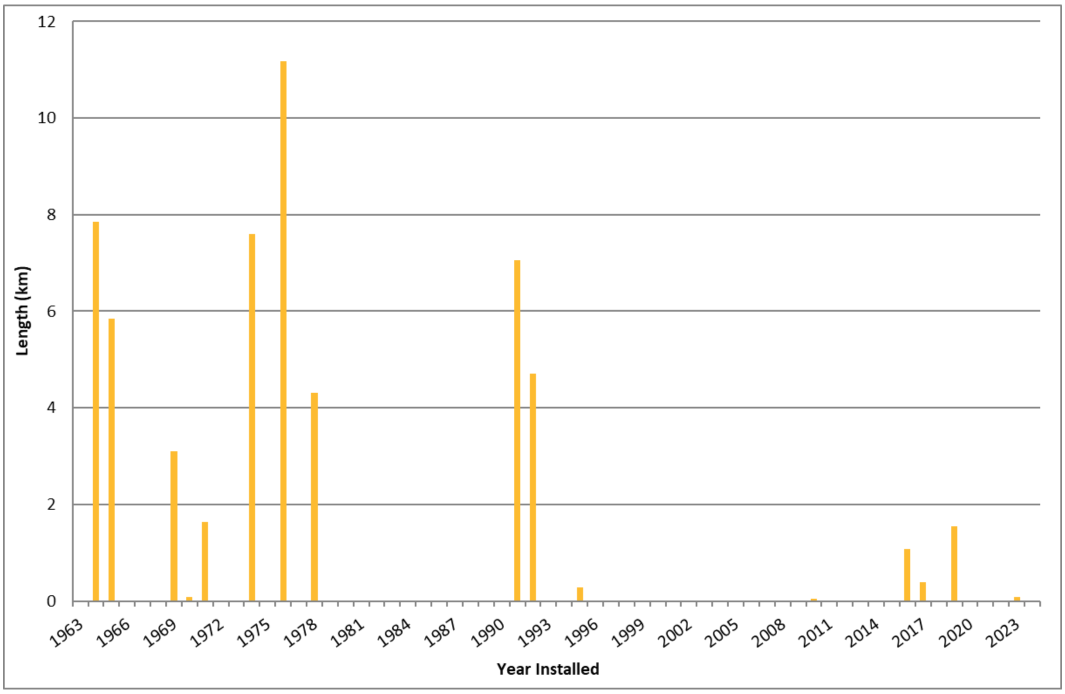



Figure 8-14 Age Profile of Subtransmission Line Conductors

#### 8.5.3.3 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 construction 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) have been used in a small number of tree encroachment areas, subject to District Plan allowances. Table 8-28 summarises the overhead line conductor fleet, with Figure 8-15 showing the age profile.

| Category | Quantity |
|---|---|
| 11 kV Line | 588.8 km |
| Low Voltage Line | 1070.9 km |
| Streetlight Conductor | 818.3 km |

Table 8-28 Summary of Distribution Overhead Lines

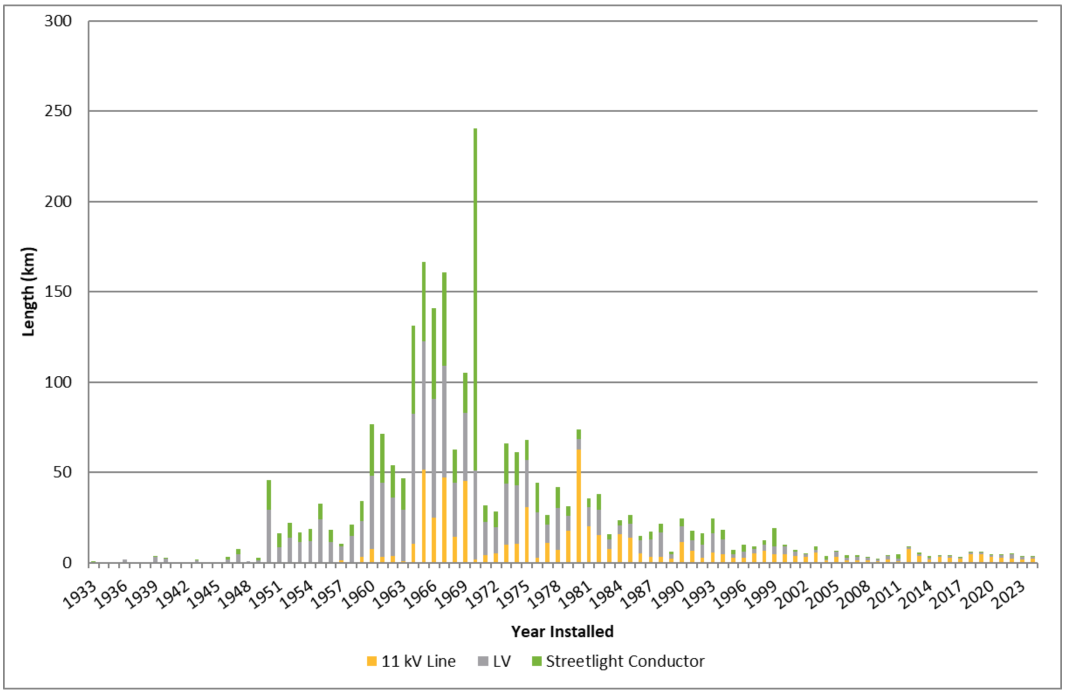



Figure 8-15 Age Profile of Distribution Overhead Line Conductors

## 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.<br>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 8-29 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 of 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 the unit, assessment of condition and replacement of the on-board battery, and replacement onto the live line using a hot stick. | 8 yearly |

**Table 8-30 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, the 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 visual-based criteria and historical failure rates. Assessment is moving to use a condition-based replacement profile based on a predictive model currently under development.

**<u>Pole Condition</u>**

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 1,400 poles are Deuar tested every year.

Approximately three-quarters of the poles installed in the Wellington area are concrete, which is durable when 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 8-16 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 | |
|---|---|---|---|---|---|---|---|---|
| Asset Health | | 5.0 | 4.0 | 3.0 | 2.5 | 2.0 | 1.5 | 1.0 |
| Worst Health | 1.0 | 1 | | | 1 | | | |
| | 2.0 | 242 | 28 | 46 | 8 | 1 | | |
| | 3.0 | 11,097 | 1,189 | 1,497 | 497 | 5 | 2 | |
| | 4.0 | 8,602 | 1,005 | 1,002 | 127 | 6 | 3 | |
| Best Health | 5.0 | 10,684 | 1,383 | 1,801 | 427 | 9 | | |

**Figure 8-16 Pole Health-Criticality Matrix**

The forecast future condition of the pole fleet is modelled using survival curves. Figure 8-17 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 the replacement of the arm.

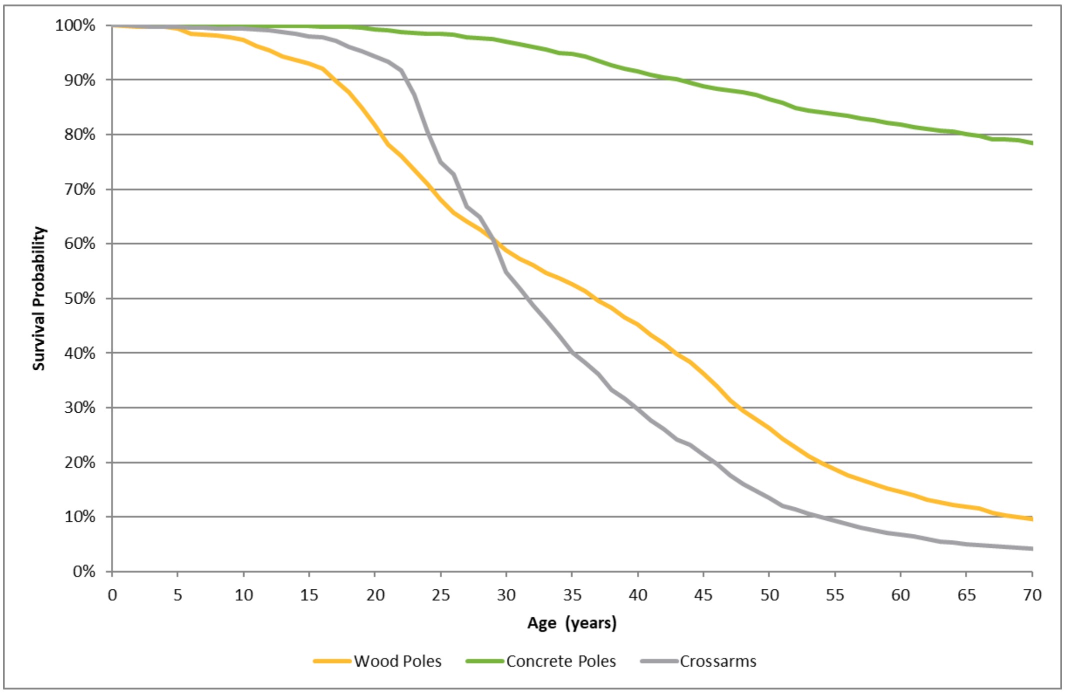



Figure 8-17 Pole and Crossarm Survival Curves

**Overhead Line Condition**

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 cracks 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 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.

The forecast future condition of the overhead line conductor and connector fleet is modelled using failures per kilometre of conductor installed. Figure 8-18 shows the failure rates for conductors, jumpers, and connectors.

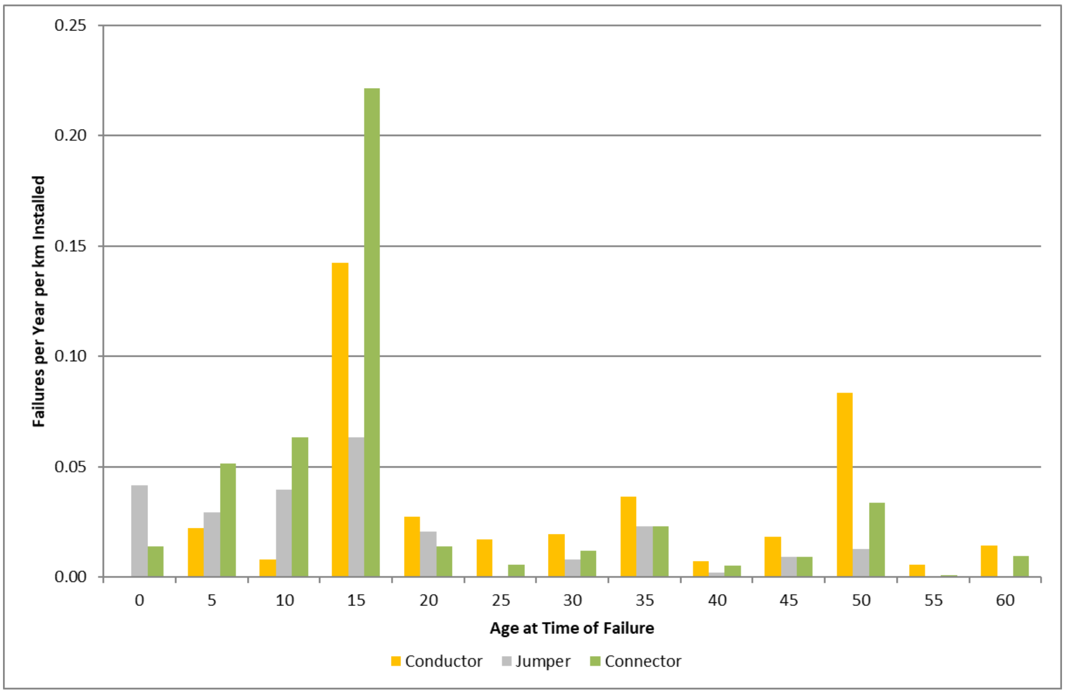



Figure 8-18 Overhead Conductor and Connector Failure Rate by Age

**Renewal and Refurbishment – Poles**

Wooden poles that are Deuar tested and fail the serviceability test are categorised as red tagged, yellow tagged, or blue 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 be reassessed in 2.5 years instead of the standard five year inspection cycle. For all pole tag colours, the climbing of tagged poles by contractors and third parties is prohibited.

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 the coming years in order to improve the prediction of when this increase will occur.

## Renewal and Refurbishment – Lines

Since 2009, WELL has invested in the 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.

Significant projects for the renewal of overhead lines over the next 12 months are listed in Table 8-31.

| Project | Description |
|---|---|
| Plimmerton Feeders | Further refurbishment stages of Plimmerton 8 and Plimmerton 11 |
| Titahi Bay Feeders | Refurbishment of Titahi Bay 6 |
| Melling Feeders | Further refurbishment stages of Melling 4 |
| Naenae Feeders | Further refurbishment stages of Naenae 11 |

Table 8-31 Overhead Line Projects for 2025/26

## Expenditure Summary for Overhead Lines

| Expenditure Type | 2025/26 | 2026/27 | 2027/28 | 2028/29 | 2029/30 | 2030/31 | 2031/32 | 2032/33 | 2033/34 | 2034/35 |
|---|---|---|---|---|---|---|---|---|---|---|
| Feeder Reliability Projects | 2,188 | 1,035 | 1,195 | 1,404 | 1,213 | 1,154 | 1,183 | 1,211 | 1,238 | 1,264 |
| Pole Replacement Programme | 8,635 | 6,487 | 6,164 | 5,929 | 5,110 | 4,910 | 4,715 | 4,526 | 4,343 | 4,166 |
| Reactive Capital Expenditure | 1269 | 1268 | 1266 | 1266 | 1266 | 1266 | 1266 | 1266 | 1266 | 1266 |
| **Capital Expenditure Total** | **12,092** | **8,790** | **8,625** | **8,599** | **7,589** | **7,330** | **7,164** | **7,003** | **6,847** | **6,696** |
| Preventative Maintenance | 685 | 679 | 672 | 673 | 676 | 678 | 676 | 670 | 665 | 659 |
| Corrective Maintenance | 996 | 996 | 996 | 996 | 996 | 996 | 996 | 996 | 996 | 996 |
| **Operational Expenditure Total** | **1,681** | **1,675** | **1,668** | **1,669** | **1,672** | **1,674** | **1,672** | **1,666** | **1,661** | **1,655** |

Table 8-32 Expenditure on Overhead Lines
($K in constant prices)

### 8.5.4 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 the 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) | 1,225 km |
| Low Voltage cable (incl. risers) | 1,806 km |
| Streetlight cable | 1,159 km |

Table 8-33 Summary of Distribution Cables

Approximately 85% of the underground 11 kV cables are PILC and PIAS and the remaining 15% are XLPE insulated cables, installed from 2000 onwards. 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 8-19.

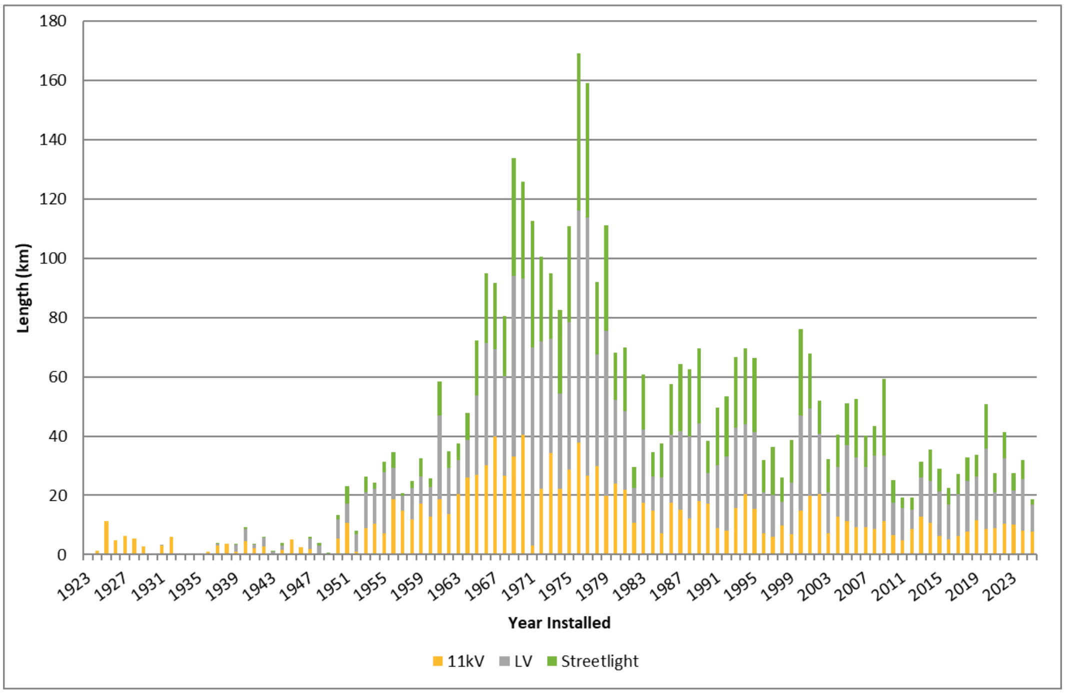



Figure 8-19 Age Profile of Distribution Cables

**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 the risk of a potential decrease in service or price shock caused by an under-forecast of cable replacement required.<br>Avoid repeat 11kV outages due to cable condition. |
| Cost | Reduce cable replacement costs. |

Table 8-34 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 a sufficient understanding of the results produced by these tools and match them to actual cable performance to provide confidence in their suitability as a condition assessment tool to:

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

## 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 8-20 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 | - | - | - | - | - | - | - |
| **Asset Health** | 2.0 | 4.7 | 8.5 | 28.9 | 8.9 | 37.7 | 26.3 | - |
| | 3.0 | 13.5 | 23.6 | 84.1 | 22.9 | 21.8 | 19.5 | - |
| | 4.0 | 52.5 | 147.7 | 279.6 | 83.3 | 65.7 | 26.6 | - |
| Best Health | 5.0 | 34.8 | 37.6 | 97.3 | 37.6 | 37.9 | 7.7 | - |

Figure 8-20 11 kV Cable Health-Criticality Matrix (km)

The forecast future condition of the distribution cable fleet is modelled using failures per km 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 8-21 shows the failure rates for cables, joints, and terminations.

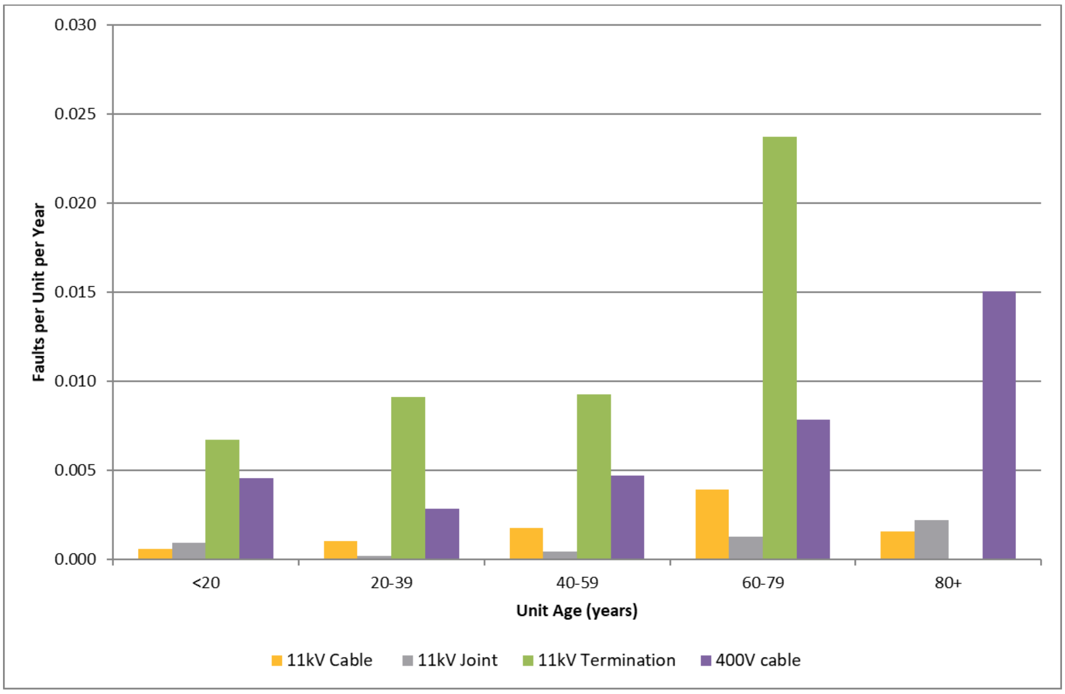



Figure 8-21 Cable Failure Rate by Age

The failure rate data indicates that outdoor terminations are the weakest component of the 11 kV cable system, with a higher rate of failure at all ages, and a significant increase in failures beyond 60 years old.

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 conditions without intervention, which is presented in Figure 8-22. The actions to control this trend and maintain performance at current levels are described in the following section on Renewal and Refurbishment.

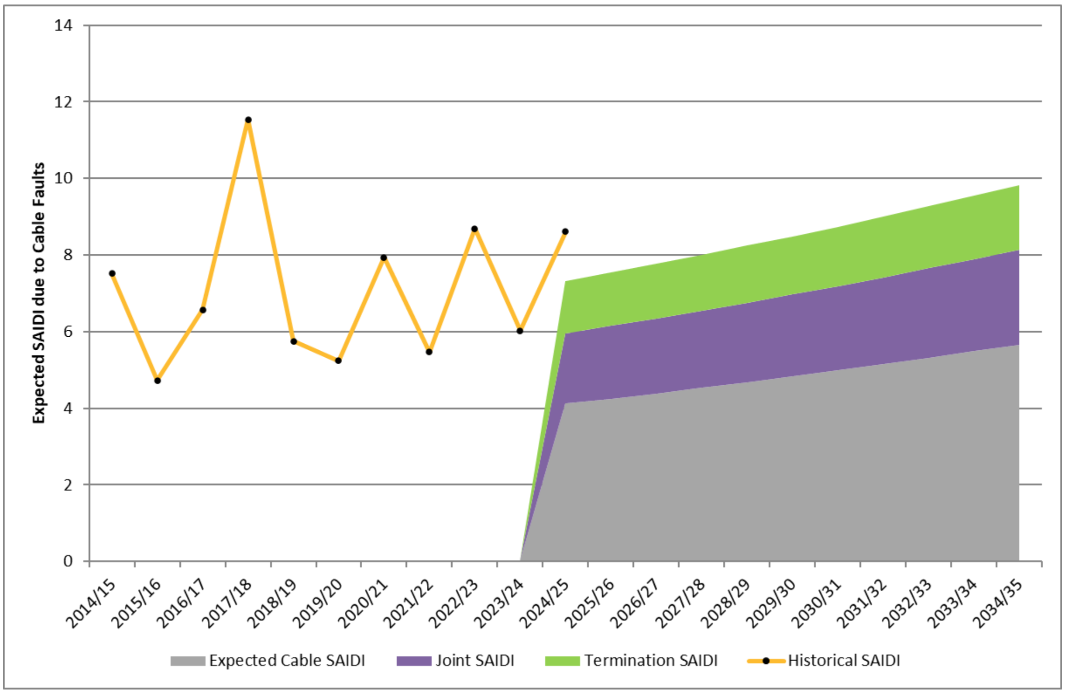



Figure 8-22 Forecast 11kV Cable Fleet Performance Trend without Intervention

**Renewal and Refurbishment**

The volume of cable in service and the high unit cost of replacement make the underground cable network a significant risk for WELL. Allowing the fleets to run to failure would result in a gradual reduction in quality of supply as shown in Figure 8-22, 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 cable fleets 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 the 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 (see Section 8.5.8.3);

- The early failure of cable fittings, particularly those 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.

WELL will eventually need to commence a large programme of distribution cable renewals. WELL's preferred approach is to use the strategies listed above to manage the customer impact of the distribution cable fleet for the period of this AMP, delaying the commencement of that programme. The purpose of this is to support customer affordability by avoiding superimposing distribution cable renewal costs onto network reinforcement costs being driven by decarbonisation load growth. The performance of the cable fleet will continue to be closely monitored to ensure that this approach remains viable and is delivering the best outcomes for the long-term benefit of customers.

Significant projects for the renewal of distribution cables are listed in Table 8-35.

| Project | Description |
| --- | --- |
| Haywards Feeder Reinforcement under SH2 | It is a multi-year project that requires multiple cable relocations. It is under the feasibility study and design phase. |

Table 8-35 Distribution Cable Projects for 2025/26

## Expenditure Summary for Distribution and LV Cable

Table 8-36 details the expected expenditure on distribution and LV cable by regulatory year.

| Expenditure Type | 2025/26 | 2026/27 | 2027/28 | 2028/29 | 2029/30 | 2030/31 | 2031/32 | 2032/33 | 2033/34 | 2034/35 |
| --- | --- | --- | --- | --- | --- | --- | --- | --- | --- | --- |
| Asset Replacement and Renewal Capex | 63 | 1,654 | 2,522 | 989 | 1,138 | 3,173 | 3,173 | 3,173 | 3,173 | 3,173 |
| Reactive Capital Expenditure | 3,076 | 3,073 | 3,069 | 3,069 | 3,069 | 3,069 | 3,069 | 3,069 | 3,069 | 3,069 |
| **Capital Expenditure Total** | **3,139** | **4,727** | **5,591** | **4,058** | **4,207** | **6,242** | **6,242** | **6,242** | **6,242** | **6,242** |
| Corrective Maintenance | 101 | 101 | 101 | 101 | 101 | 101 | 101 | 101 | 101 | 101 |
| **Operational Expenditure Total** | **101** | **101** | **101** | **101** | **101** | **101** | **101** | **101** | **101** | **101** |

Table 8-36 Expenditure on Distribution and LV Cable
($K in constant prices)

### 8.5.5 Distribution Substations

#### 8.5.5.1 Distribution Transformers

**Fleet Overview**

Of the distribution transformer population, 60% are ground-mounted and 40% are pole-mounted. The pole-mounted units are installed on single and double-pole structures and are predominantly three-phase units rated between 10 kVA 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 on the coast, a transformer may not reach this age due to corrosion. The age profile of distribution transformers is shown in Figure 8-23.

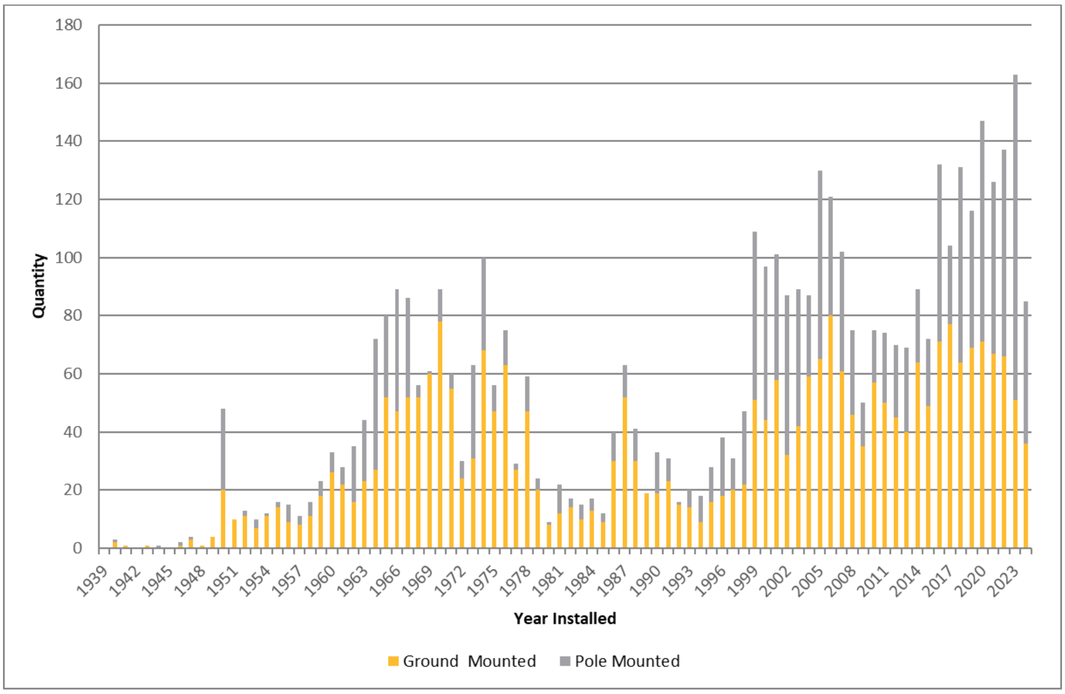



Figure 8-23 Age Profile of Distribution Transformers

In addition to pole and integral pad mount berm substations, WELL owns 518 indoor substation kiosks and occupies a further 668 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 8-37.

| Category | Quantity |
|---|---|
| Distribution transformers | 4,515 |
| **Distribution transformers – Total** | **4,515** |
| WELL owned substations | 3,976 |
| Customer-owned substations containing WELL owned equipment | 665 |
| **Distribution substations – Total** | **4,641** |

Table 8-37 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.<br>Substations located in road reserves not to be a risk to public safety.<br>Compliance with asbestos regulations is maintained. |
| Customer | Meet customer needs for the provision of information relating to transformers installed inside their buildings. |
| Network Performance | Ensure weather tightness to prevent damage to internal equipment. |

Table 8-38 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, and 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. | 1 monthly |
| Visual Inspection and Thermal Image<br>(Ground Mount Transformer) | Visual inspection of equipment, and condition assessment based on visible defects. Thermal image of accessible connections. Handheld PD and Ultrasonic scan. | Annual |
| Visual Inspection and Thermal Image<br>(Pole Transformer) | Visual inspection of equipment, and condition assessment based on visible defects. Thermal image of accessible connections. | Annual |
| Transformer oil test | Dissolved gas analysis of transformers supplying critical consumers. | 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 8-39 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. 34 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 8-24 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.

| | | 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 | - | 6 | 1 | - |
| Asset Health | 2.0 | 5 | 16 | 35 | 9 | 23 | 5 | - |
| | 3.0 | 273 | 453 | 808 | 213 | 302 | 94 | - |
| | 4.0 | 260 | 463 | 881 | 178 | 104 | 59 | - |
| Best Health | 5.0 | 93 | 49 | 151 | 12 | 13 | 8 | - |

**Figure 8-24 Distribution Transformer Health-Criticality Matrix**

The forecast future condition of the distribution transformer fleet is modelled using survival curves. Figure 8-25 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 for replacement of pole-mounted transformers reflecting their greater exposure to lightning and their lower accessibility for repairs.

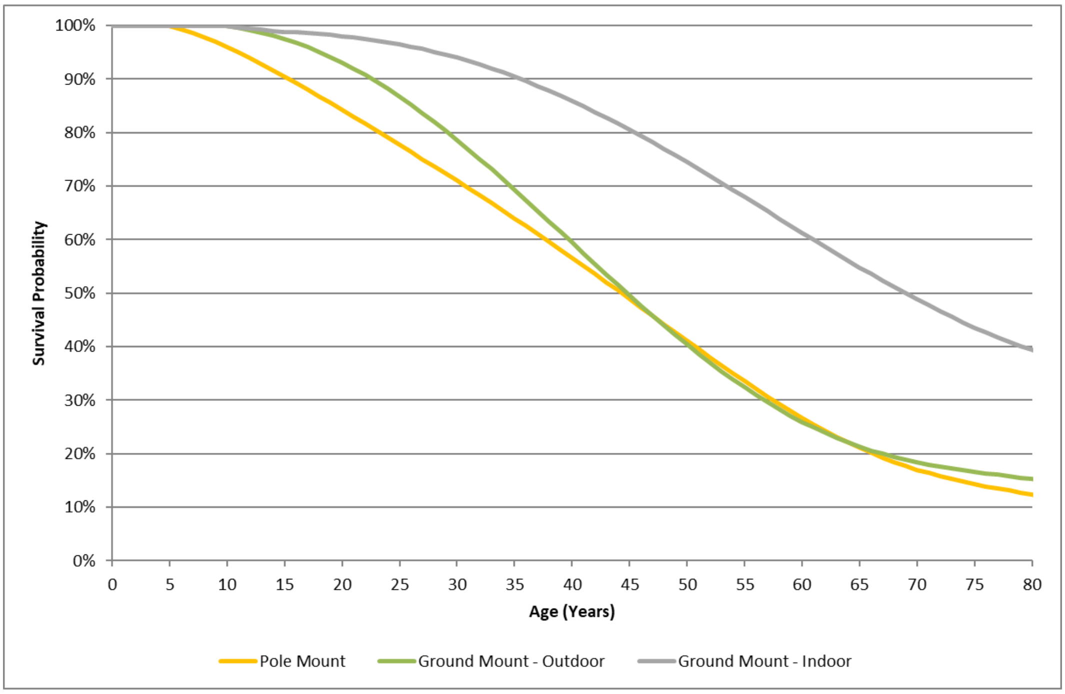



**Figure 8-25 Distribution Transformer Survival Curves**

WELL is installing transformer monitors on 50 transformers identified by modelling as likely to be constrained, as discussed in Section 11.2.2.3. In addition to providing safety-related functions for the monitored transformers, for example broken neutral and stolen earth detection, this will improve WELL's awareness of distribution transformer fleet performance and utilisation through extrapolation of results from the monitored transformers.

**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 the cost and residual life of the unit. Typical condition issues include rust, heavy insulating fluid leaks, and integrity and security of the unit. 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 integral substation units 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 was installed, however, it was found that the reduced civil cost was offset by the additional cost of purchasing a specialised transformer rather than a standard design.

WELL has preferred the use of canopy-type substations (with LV switchgear, HV switchgear, and transformer pre-installed inside a common metal canopy) for new installations where practicable; however, space constraints and the rapidly increasing cost of these units is resulting in greater use of standalone transformers and separate ring main units.

**Expenditure Summary for Distribution Substations**

Table 8-40 details the expected expenditure on distribution substations by regulatory year.

| Expenditure Type | 2025/26 | 2026/27 | 2027/28 | 2028/29 | 2029/30 | 2030/31 | 2031/32 | 2032/33 | 2033/34 | 2034/35 |
|---|---|---|---|---|---|---|---|---|---|---|
| Seismic Strengthening | 572 | 462 | 448 | - | - | - | - | - | - | - |
| Asset Replacement and Renewal Capex | 5,177 | 4,221 | 4,819 | 3,034 | 3,642 | 5,018 | 5,290 | 5,374 | 5,374 | 5,373 |
| Reactive Capital Expenditure | 2,747 | 2,744 | 2,741 | 2,741 | 2,741 | 2,741 | 2,741 | 2,741 | 2,741 | 2,741 |
| **Capital Expenditure Total** | **8,496** | **7,427** | **8,008** | **5,775** | **6,383** | **7,759** | **8,031** | **8,115** | **8,115** | **8,114** |
| Preventative Maintenance | 768 | 768 | 768 | 768 | 768 | 768 | 768 | 768 | 768 | 768 |
| Corrective Maintenance | 760 | 760 | 760 | 760 | 760 | 760 | 760 | 760 | 760 | 760 |
| **Operational Expenditure Total** | **1,528** | **1,528** | **1,528** | **1,528** | **1,528** | **1,528** | **1,528** | **1,528** | **1,528** | **1,528** |

**Table 8-40 Expenditure on Distribution Substations**
**($K in constant prices)**

### 8.5.6 Ground Mounted Distribution Switchgear

**Fleet Overview**

This section covers ring main units (RMUs) and switching equipment that is often installed outdoors. It does not include zone substation circuit breakers, which are discussed in Section 8.5.2. There are 1,231 distribution circuit breakers and 2,405 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 750 kVA 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 8-26 and Figure 8-27.

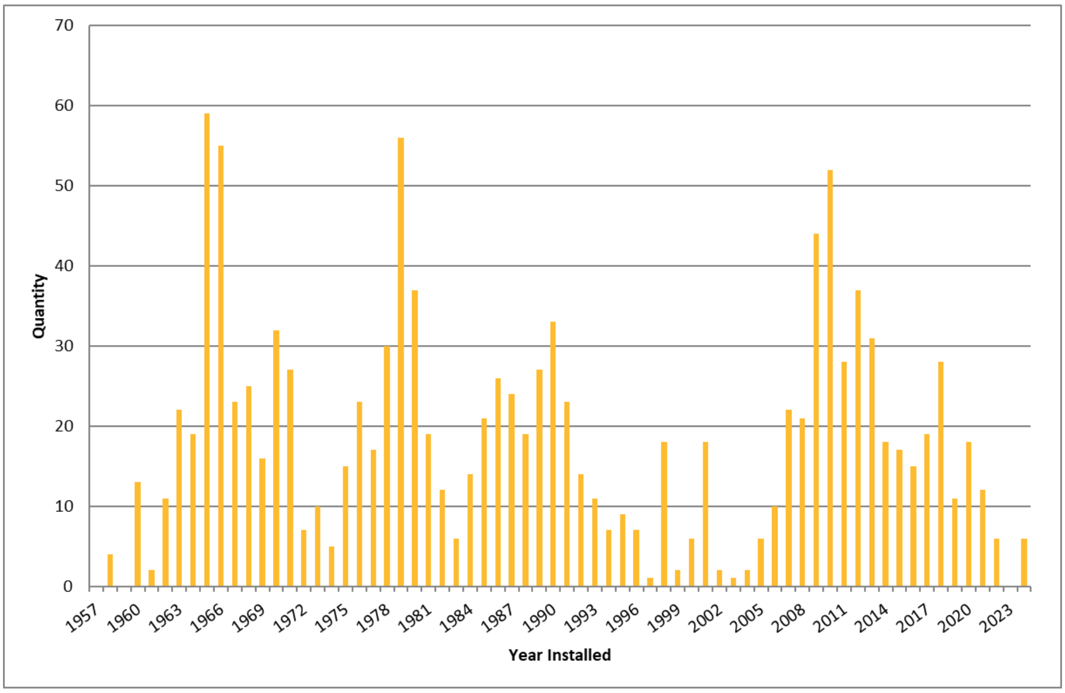



Figure 8-26 Age Profile for Distribution Circuit Breakers

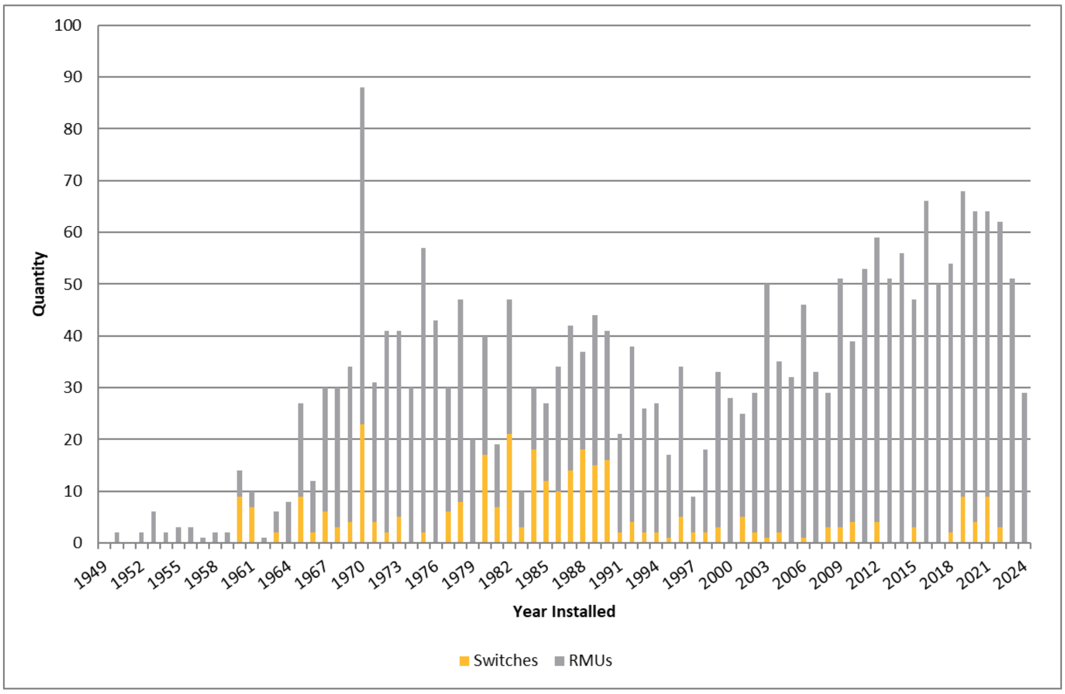



Figure 8-27 Age Profile of Other Ground-Mounted Distribution Switchgear

The average age of distribution circuit breakers in the network is around 34 years, while the average age of ring main units is 27 years. A summary of circuit breakers and ground-mounted distribution switchgear, of both stand-alone and ring main unit types, is shown in Table 8-41 and Table 8-42.

| Category | Quantity |
|---|---|
| Distribution Circuit Breakers | 1,231 |
| Oil Insulated Switches | 278 |
| Oil Insulated RMUs | 137 |
| $SF_6$ Insulated Switches | 49 |
| $SF_6$ Insulated RMUs | 989 |
| Resin Insulated Switches | 13 |
| Resin Insulated RMUs | 924 |

**Table 8-41 Summary of Ground-Mounted Distribution Switchgear**

| Manufacturer | Breaker Type | Quantity |
|---|---|---|
| ABB | $SF_6$ | 27 |
| AEI | Oil | 47 |
| BTH | Oil | 53 |
| Entec | Vacuum | 25 |
| GEC/Alstom | Oil | 45 |
| Hawker Siddeley | Vacuum | 21 |
| Merlin Gerin / Schneider | $SF_6$ | 300 |
| Reyrolle | Oil | 596 |
| | Vacuum | 59 |
| South Wales | $SF_6$ | 37 |
| Statter | Oil | 16 |
| Siemens | $SF_6$ | 5 |
| **Total** | | **1,231** |

**Table 8-42 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.

| Priority Area | Objective |
|---|---|
| Safety and Environment | No injuries resulting from working on and around distribution switchgear.<br>Only use $SF_6$ filled equipment where no technically-suitable and cost-effective non-$SF_6$ alternatives exist.<br>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 8-43 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 on visible defects. Thermal image of accessible connections. Handheld PD and Ultrasonic scan. | Annually |
| Switchgear Maintenance (Magnefix) | Clean and maintain the Magnefix unit, inspect and replace link caps as required, test fuses, and 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, and return to service. Trip timing test before and after service | 5 yearly |
| Switch Maintenance (Oil Switch) | Clean and maintain the oil switch unit, drain the oil check internally, and check terminations and cable compartments. Ensure correct operation of the unit. Refill with clean oil. | 5 yearly |
| Circuit Breaker Maintenance (Vacuum or Gas CB) | Withdraw CB and maintain carriage and mechanisms as required, record the condition of interrupter bottles where possible, and 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 the 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, cleaning and inspecting all switchboard fixed portion components, and undertaking condition and diagnostic tests as required. Maintain VTs and CTs. Return to service. | 10 yearly |

Table 8-44 Inspection and Routine Maintenance Schedule for Distribution Switchgear

**Distribution Switchgear Condition**

The switchgear installed on the WELL network is generally in good condition. 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, partial discharge issues, or poor oil condition and insulation levels.

Figure 8-28 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 | |
|---|---|---|---|---|---|---|---|---|
| **Asset Health** | | 5.0 | 4.0 | 3.0 | 2.5 | 2.0 | 1.5 | 1.0 |
| Worst Health | 1.0 | | | | | | | |
| | 1.5 | 15 | 36 | 108 | 23 | 1 | | |
| | 2.0 | | | 1 | | | | |
| | 2.5 | 88 | 198 | 352 | 160 | 236 | 99 | |
| | 3.0 | 109 | 176 | 533 | 161 | 403 | 137 | |
| | 4.0 | 49 | 66 | 266 | 65 | 107 | 41 | |
| Best Health | 5.0 | 11 | 26 | 64 | 15 | 17 | 7 | |

**Figure 8-28 Distribution Switchgear Health-Criticality Matrix**

Specific condition issues for distribution switchgear are:

**Schneider Ringmaster**

A number of gas depressurisation events have occurred on Schneider Ringmaster switchgear, with the first recorded loss of gas occurring in 2011 after about 10 years in service. These have been identified as only affecting Ringmaster RMUs and not circuit breakers. The affected RMUs were manufactured between 2000 and 2005, and 90 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**

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 operation. 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 resources to be prioritised to the 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**

One Long and Crawford ring main unit remains in service on the network. The replacement of this unit is on hold pending the customer's decision on their future power supply requirements. Operational controls are in place that prohibit the live operation of this switchgear.

**Statter**

As of October 2024, there are 34 sites with Statter switchgear, with 89 units in service including circuit breakers, oil switches, and fuse switches, installed between 1960 and 1990.

There have been past instances where Statter switchgear has failed to operate requiring operating restrictions to be in place that prohibit live operation 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 controls 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 2036.

**<u>Renewal and Refurbishment</u>**

**HV Distribution Switchgear (Ground Mounted)**

As noted above, this section excludes zone substation circuit breakers, which are discussed in Section 8.5.2.2.

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 the 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.

In rare cases, when any switchgear device fails, the reason for the failure is studied and a cost-benefit analysis is 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 switches with identified issues around age, condition and known operational issues. These are being replaced based on the risk assessment for that type.

Oil-insulated switchgear is no longer installed, with vacuum or gas ($SF_6$) insulated types now being used. WELL intends to phase out the use of $SF_6$ for new distribution switchgear due to that gas' contribution to climate change, however, there are currently no $SF_6$-free units on the New Zealand market that meet WELL's requirements.

Significant projects for the renewal of ground-mounted switchgear over the next 12 months are listed in Table 8-45.

| Project | Description |
|---|---|
| Normandale Bridge | Completion of Statter switchgear replacement |
| Esplanade E | Completion of GEC switchgear replacement |
| Mountbatten Grove | Statter/GEC switchgear replacement |
| Vogel Street | Statter switchgear replacement |
| 92 Washington Avenue | BTH switchgear replacement |

Table 8-45 Significant Ground Mounted Switchgear Projects for 2025/26

**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 that time. 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 8-46 details the expected expenditure on ground-mounted switchgear by regulatory year.

| Expenditure Type | 2025/26 | 2026/27 | 2027/28 | 2028/29 | 2029/30 | 2030/31 | 2031/32 | 2032/33 | 2033/34 | 2034/35 |
|---|---|---|---|---|---|---|---|---|---|---|
| Statter Replacement Programme | 2,939 | 2,665 | 2,707 | 1,684 | - | - | - | - | - | - |
| Partial Discharge Mitigation | 269 | 554 | 541 | 352 | 258 | 253 | 248 | 243 | 238 | 233 |
| Other Asset Replacement and Renewal Capex | 4,325 | 3,586 | 3,569 | 4,514 | 6,781 | 3,217 | 3,162 | 3,141 | 2,973 | 3,032 |
| Reactive Capital Expenditure | 572 | 571 | 570 | 570 | 570 | 570 | 570 | 570 | 570 | 570 |
| **Capital Expenditure Total** | **8,105** | **7,376** | **7,387** | **7,120** | **7,609** | **4,040** | **3,980** | **3,954** | **3,781** | **3,835** |
| Preventative Maintenance | 665 | 710 | 831 | 926 | 852 | 966 | 689 | 782 | 860 | 720 |
| Corrective Maintenance | 420 | 420 | 420 | 420 | 420 | 420 | 420 | 420 | 420 | 420 |
| **Operational Expenditure Total** | **1,085** | **1,130** | **1,251** | **1,346** | **1,272** | **1,386** | **1,109** | **1,202** | **1,280** | **1,140** |

**Table 8-46 Expenditure on Ground-mounted Switchgear ($K in constant prices)**

### 8.5.6.1 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 23,235 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 backfeeds during outages, as well as provide the ability to sectionalise large LV circuits. A high-level breakdown of types is listed in Table 8-47.

| Type | Quantity |
|---|---|
| Customer service pillar | 17,171 |
| Customer service pit | 4,303 |
| Link pillars, pits and cabinets | 1,761 |
| **Total** | **23,235** |

**Table 8-47 Summary of LV Units**

An age profile of LV units is shown in Figure 8-29.[26]

[26] There are 6,403 low voltage pillars, pits, cabinets and LV boards that have unknown installation dates and these have not been included in the age profile.

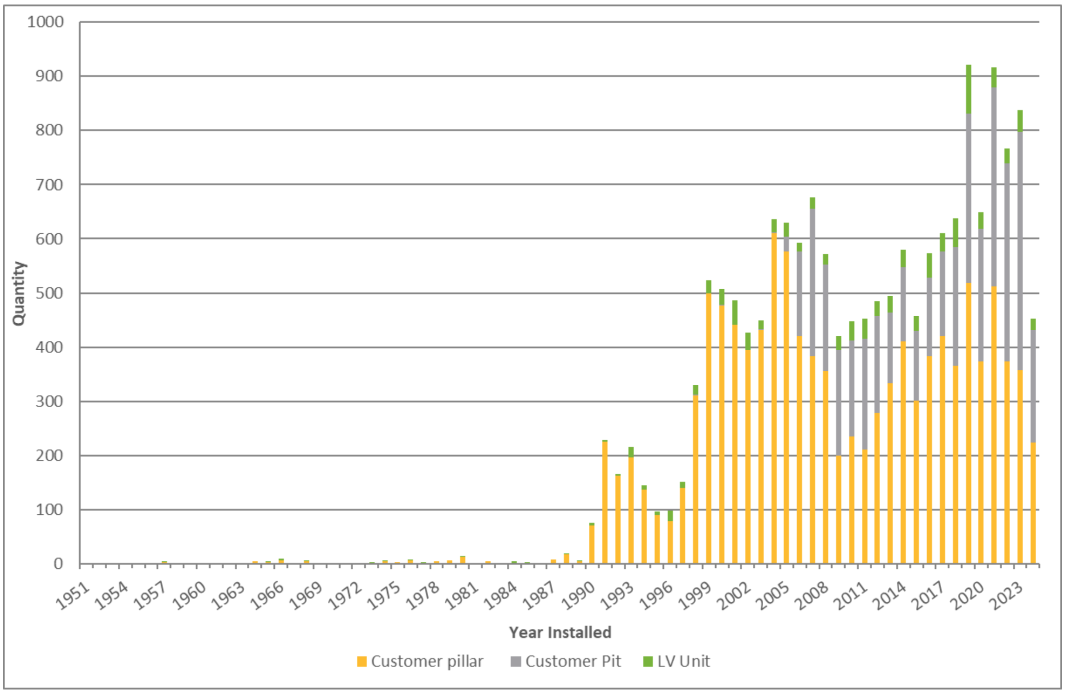



Figure 8-29 Age Profile of Pillars, Pits and Cabinets

## 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.<br>LV units located in road reserve to not be a risk to public safety. |

Table 8-48 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:

| Activity | Description | Frequency |
|---|---|---|
| Inspection of Service Pillars | Visual inspection and condition assessment of service pillar, minor repairs to the 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 8-49 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.

## Pit and Pillar Condition

Figure 8-30 shows the health-criticality matrix of WELL's LV pits and pillars. LV asset health is determined by the asset's condition including the recorded defects and aging, while asset criticality is determined by the type and location of the asset.

| | | Lowest Impact | | **Asset Criticality** | | | Highest Impact | |
|---|---|---|---|---|---|---|---|---|
| | | 5.0 | 4.0 | 3.0 | 2.5 | 2.0 | 1.5 | 1.0 |
| Worst Health | 1.0 | 17 | | | | | | |
| **Asset Health** | 2.0 | 164 | 25 | 22 | | | | |
| | 3.0 | 4,709 | 524 | 129 | | | | |
| | 4.0 | 3,149 | 182 | 20 | | | | |
| Best Health | 5.0 | 13,559 | 634 | 100 | | | | |

Figure 8-30 LV Asset Health-Criticality Matrix

## 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 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 8-50 details the expected expenditure on low voltage pits and pillars by regulatory year.

| Expenditure Type | 2025/26 | 2026/27 | 2027/28 | 2028/29 | 2029/30 | 2030/31 | 2031/32 | 2032/33 | 2033/34 | 2034/35 |
|---|---|---|---|---|---|---|---|---|---|---|
| Asset Replacement and Renewal Capex | 554 | 1,385 | 451 | 440 | 429 | 421 | 421 | 421 | 421 | 421 |
| Reactive Capital Expenditure | 2,100 | 2,098 | 2,095 | 2,095 | 2,095 | 2,095 | 2,095 | 2,095 | 2,095 | 2,095 |
| **Capital Expenditure Total** | **2,654** | **3,483** | **2,546** | **2,535** | **2,524** | **2,516** | **2,516** | **2,516** | **2,516** | **2,516** |
| Preventative Maintenance | 244 | 244 | 244 | 244 | 244 | 244 | 244 | 244 | 244 | 244 |
| Corrective Maintenance | 146 | 146 | 146 | 146 | 146 | 146 | 146 | 146 | 146 | 146 |
| **Operational Expenditure Total** | **390** | **390** | **390** | **390** | **390** | **390** | **390** | **390** | **390** | **390** |

**Table 8-50 Expenditure on Low Voltage Pits and Pillars**
**($K in constant prices)**

### 8.5.7 Pole-mounted Distribution Switchgear

#### 8.5.7.1 Reclosers and Line Circuit Breakers

**Fleet Overview**

Automatic circuit reclosers are pole-mounted circuit breakers that protect the rural 11 kV overhead network. WELL uses reclosers to minimise the customer impact of transient faults on overhead lines in rural areas. Identical equipment, with the reclosing function disabled, is used to provide automatic fault sectionalisation of overhead lines in urban areas.

The majority of the 18 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 Table 8-51.

| Manufacturer | Insulation | Model | Quantity |
|---|---|---|---|
| G&W | Solid/Vacuum | Viper-S | 17 |
| Reyrolle | Oil | OYT | 1 |
| **Total** | | | **18** |

**Table 8-51 Summary of Recloser Types**

The age profile of WELL's reclosers is shown in Figure 8-31.

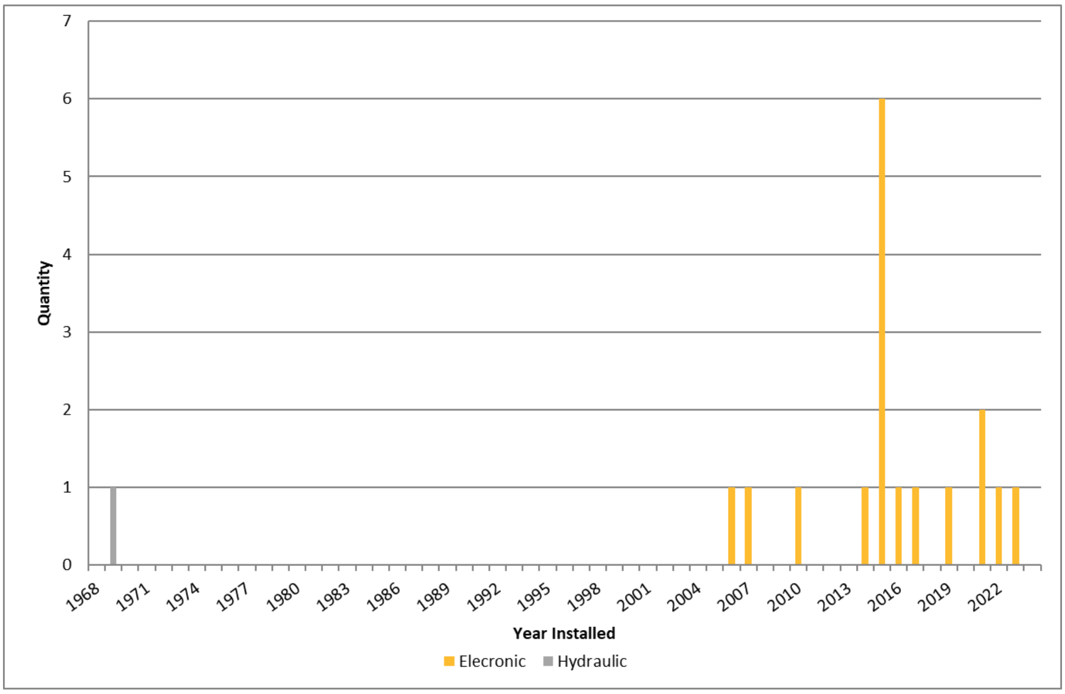



Figure 8-31 Age Profile of Reclosers

## 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 the use of reclosing complies with best industry practices for public safety and wildfire risk minimisation. |
| Customer | Ensure reclosers are functioning correctly to minimise customer disruption. |

Table 8-52 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 on 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, inspecting and maintaining contacts, changing oil as required, prove correct operation. | 3 yearly |
| Inspection and Testing of Batteries | Routine visual inspection of batteries, chargers and associated equipment inside the electronic recloser control panel. Discharge test of batteries to confirm health | 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 8-53 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 modern vacuum types, in good condition, and performing as expected.

Additional line circuit breakers will be installed on urban overhead feeders in order to reduce the customer impact of outages on these feeders.

## Expenditure Summary for Reclosers

Table 8-54 details the expected expenditure on reclosers by regulatory year.

| Expenditure Type | 2025/26 | 2026/27 | 2027/28 | 2028/29 | 2029/30 | 2030/31 | 2031/32 | 2032/33 | 2033/34 | 2034/35 |
|---|---|---|---|---|---|---|---|---|---|---|
| Feeder Reliability Projects– Switchgear | 679 | 1,473 | 1,242 | 687 | 990 | 1,178 | 1,155 | 1,133 | 1,110 | 1,089 |
| **Capital Expenditure Total** | **679** | **1,473** | **1,242** | **687** | **990** | **1,178** | **1,155** | **1,133** | **1,110** | **1,089** |
| Preventative Maintenance | 11 | 12 | 12 | 13 | 14 | 15 | 15 | 15 | 15 | 15 |
| Corrective Maintenance | 10 | 10 | 10 | 10 | 10 | 10 | 10 | 10 | 10 | 10 |
| **Operational Expenditure Total** | **21** | **22** | **22** | **23** | **24** | **25** | **25** | **25** | **25** | **25** |

Table 8-54 Expenditure on Reclosers
($K in constant prices)

### 8.5.7.2 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 8-55.

| Category | Quantity |
|---|---|
| Gas Switches | 72 |
| Air Break Switches | 316 |
| Knife Links | 31 |
| Dropout Fuses | 2,203 |
| Dropout Sectionalisers | 12 |
| **Total** | **2,661** |

Table 8-55 Summary of Pole-Mounted Distribution Switchgear

The age profiles of these devices are shown in Figure 8-32.

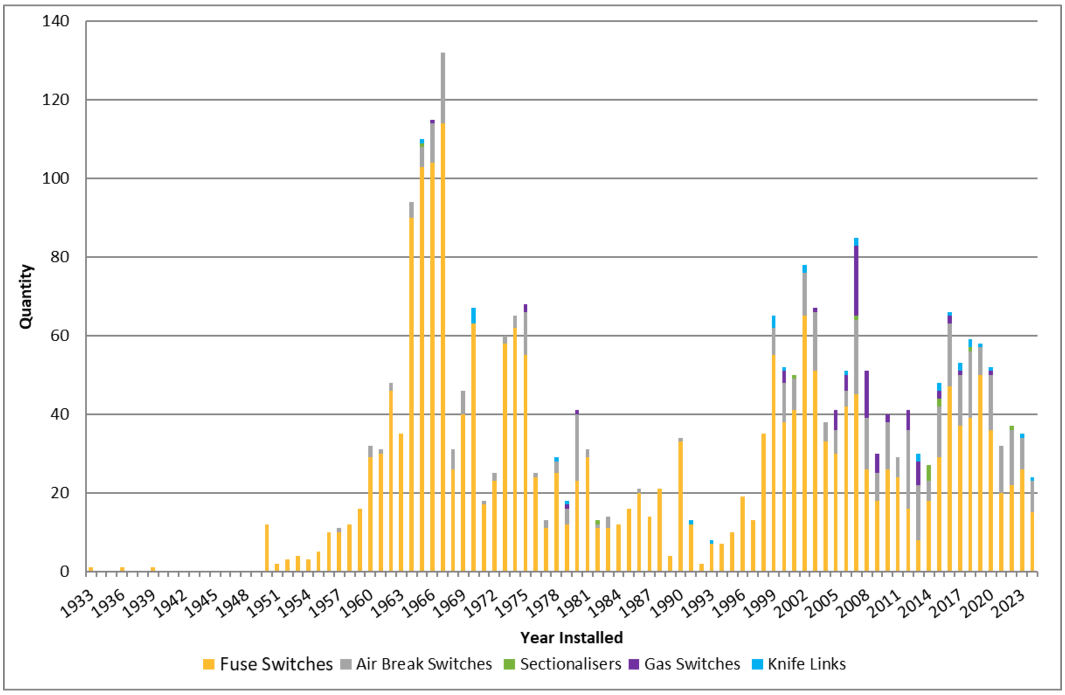



Figure 8-32 Age Profile of Overhead Switchgear and Devices

**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.<br>Overhead switchgear located in road reserve to not be a risk to public safety. |

Table 8-56 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 8-57.

| Activity | Description | Frequency |
|---|---|---|
| Visual Inspection and Thermal Image | Visual inspection of equipment and condition assessment based on visible defects. Thermal image of accessible connections. | Annually |
| ABS Service | Maintained air break switch, clean and adjust contacts, and check correct operation. | 3 yearly |
| HV Knife Link Service | Maintain knife links, clean and adjust contacts, and 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 8-57 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 do 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.

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 lived and more cost-effective solution.

The forecast future condition of the overhead switch fleet is modelled using survival curves, shown in Figure 8-33. The survival curve is based on the age at which switches have been replaced.

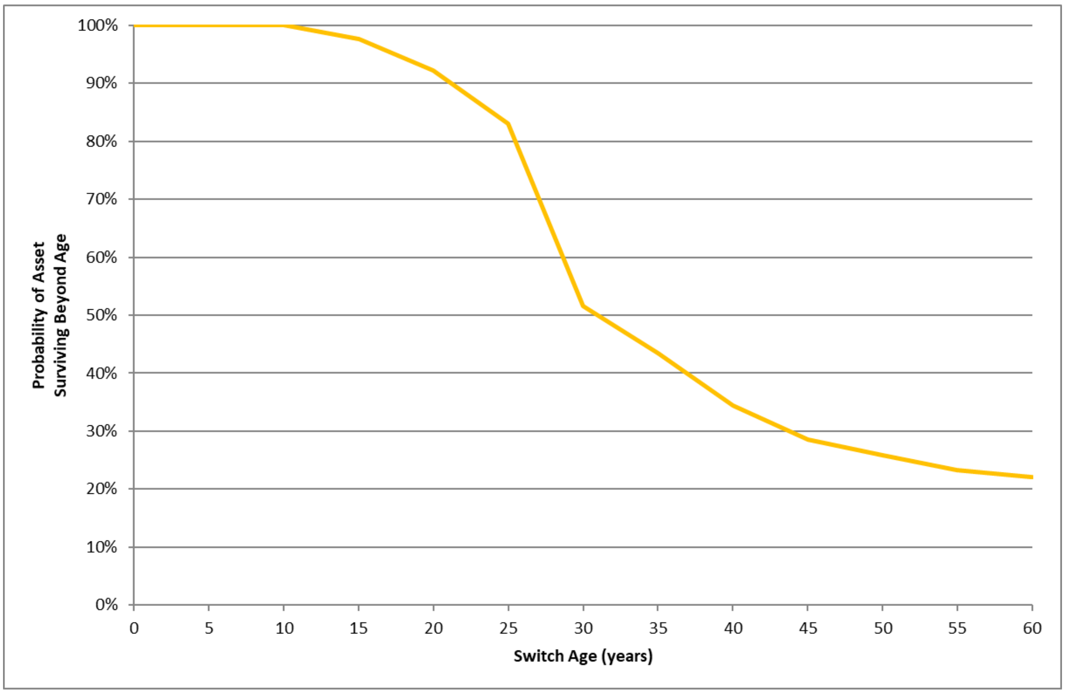



**Figure 8-33 Overhead Switch Survival Curve**

## Renewal and Refurbishment

Any renewal activity on these assets is driven by 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 crossarm 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 8-58 details the expected expenditure on overhead switchgear by regulatory year.

| Expenditure Type | 2025/26 | 2026/27 | 2027/28 | 2028/29 | 2029/30 | 2030/31 | 2031/32 | 2032/33 | 2033/34 | 2034/35 |
|---|---|---|---|---|---|---|---|---|---|---|
| Reactive Capital Expenditure | 489 | 150 | 163 | 163 | 163 | 163 | 163 | 163 | 163 | 163 |
| **Capital Expenditure Total** | **489** | **150** | **163** | **163** | **163** | **163** | **163** | **163** | **163** | **163** |
| Preventative Maintenance | 282 | 282 | 282 | 282 | 282 | 282 | 282 | 282 | 282 | 282 |
| Corrective Maintenance | 30 | 30 | 30 | 30 | 30 | 30 | 30 | 30 | 30 | 30 |
| **Operational Expenditure Total** | **312** | **312** | **312** | **312** | **312** | **312** | **312** | **312** | **312** | **312** |

Table 8-58 Expenditure on Overhead Switchgear
($K in constant prices)

### 8.5.8 Other System Fixed Assets

#### 8.5.8.1 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 8-59 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 economical.

**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 five-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 8-60 details the expected expenditure on substation batteries by regulatory year.

| Expenditure Type | 2025/26 | 2026/27 | 2027/28 | 2028/29 | 2029/30 | 2030/31 | 2031/32 | 2032/33 | 2033/34 | 2034/35 |
|---|---|---|---|---|---|---|---|---|---|---|
| Asset Replacement and Renewal Capex | 592 | 365 | 365 | 365 | 365 | 365 | 365 | 365 | 365 | 365 |
| **Capital Expenditure Total** | **592** | **365** | **365** | **365** | **365** | **365** | **365** | **365** | **365** | **365** |
| Preventative Maintenance | 76 | 76 | 76 | 76 | 76 | 76 | 76 | 76 | 76 | 76 |
| Corrective Maintenance | 10 | 10 | 10 | 10 | 10 | 10 | 10 | 10 | 10 | 10 |
| **Operational Expenditure Total** | **86** | **86** | **86** | **86** | **86** | **86** | **86** | **86** | **86** | **86** |

**Table 8-60 Expenditure on Substation Batteries ($K in constant prices)**

### 8.5.8.2 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 and 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 1,454 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 8-34. This serves to enable a clear reference for asset management planning and expenditure forecasting. The types of protective devices and their applications vary depending on the level of security required and the risk to supply.

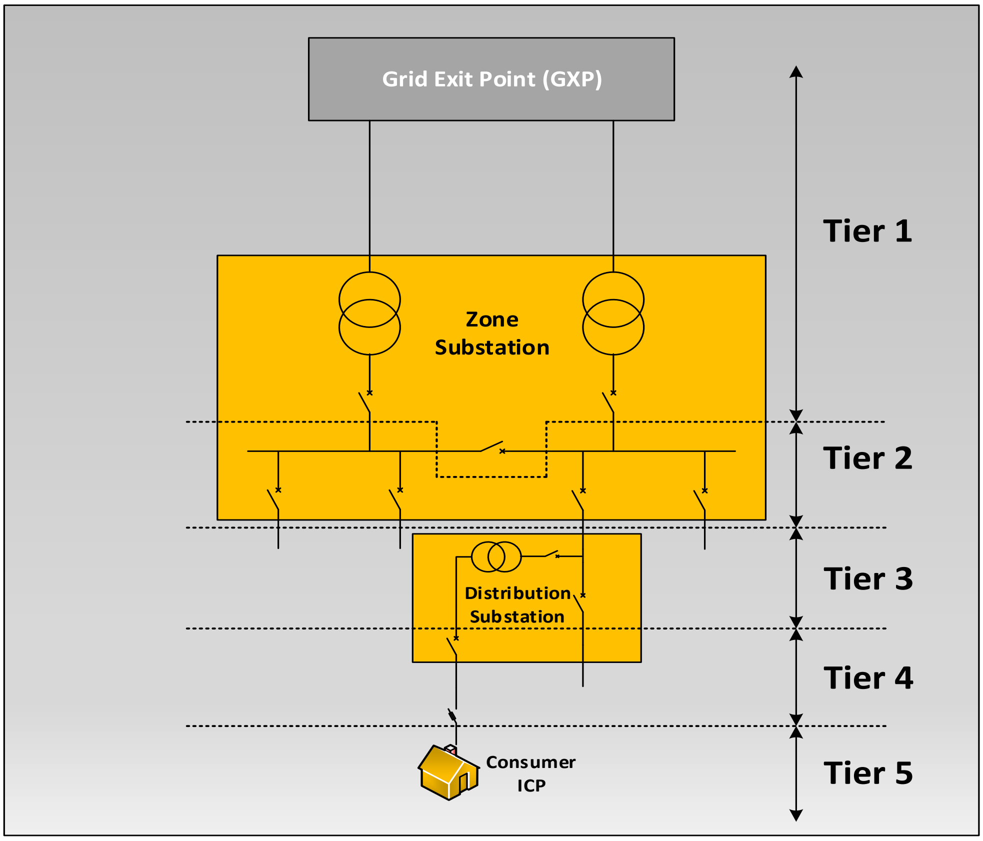



Figure 8-34 WELL Protection Tier System

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. Overcurrent and earth fault (OC/EF) protection is employed as the primary protection in situations where differential protection is not required (such as radial feeders with normally open points), and as backup protection on circuits with differential protection.

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 the 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 power flow.

Automatic Under Frequency Load Shedding (AUFLS) relays are currently 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 8-35.

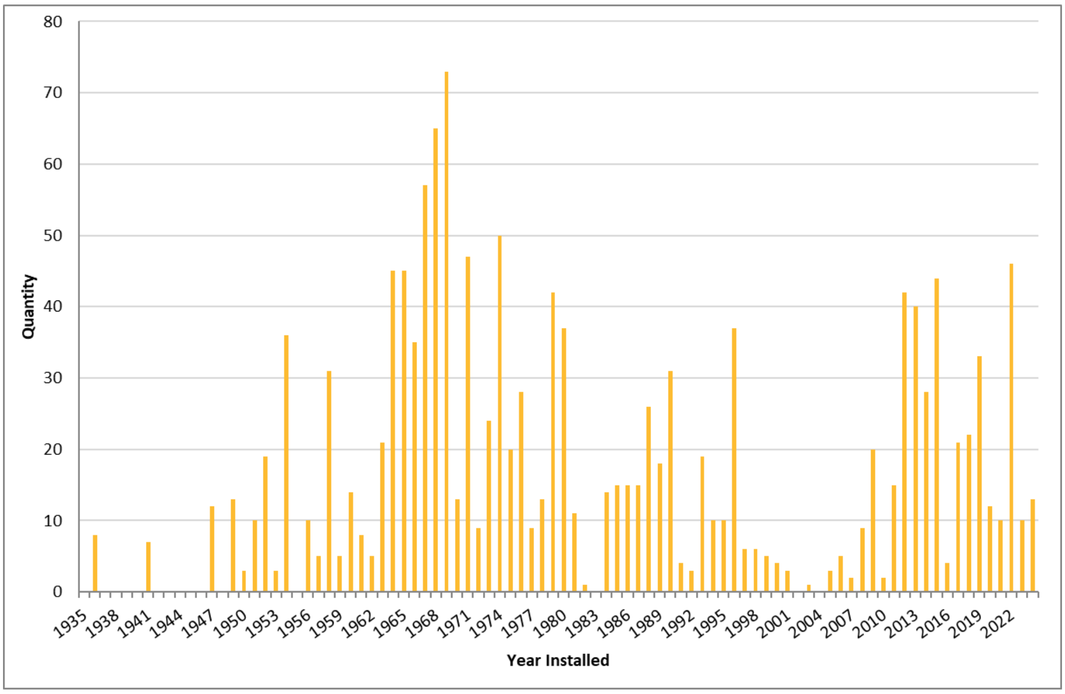



Figure 8-35 Age Profile of Protection Relays

**Maintenance Activities**

The following routine planned testing and maintenance activities are undertaken on protection relays:

| Activity | Description | Frequency |
|---|---|---|
| Protection Testing for Electromechanical Relays | Visual inspection and testing of the relay using secondary injection. Confirm as-tested settings against expected settings. Update of test record and results into the Protection Database. | 2 yearly (Tier 1 & 2)<br>5 yearly (Tier 3) |
| Protection Testing for Numerical Devices | Visual inspection, clearing of local indications, and testing of the 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 the Protection Database. | 2 yearly (Tier 1 & 2)<br>5 yearly (Tier 3) |
| Numerical Relay Battery Replacement | Replacement of backup battery in numeric relays. | 4 yearly (Tier 1 & 2)<br>5 yearly (Tier 3) |

Table 8-61 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, electromechanical protective devices have a long service life and WELL's fleet is in good condition. Rarely does an electromechanical protective device fail in service, and deterioration is identified during routine maintenance testing. Numerical protective devices have a shorter service life, and failures can occur in service, however, the self-diagnostic capabilities of numerical protective devices ensure alarms are raised when deterioration is detected.

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 in 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, it 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.

The Authority has revised the arrangements for Automatic Under-Frequency Load Shedding (AUFLS), and there is a requirement for EDBs to move from the current two-block scheme to a four-block scheme by June 2025. WELL is replacing the AUFLS relays at a number of the GXPs supplying its network in order to implement this change.

The following programmes and projects are included in the asset replacement and maintenance budgets:

- Ongoing replacement of devices with identified risk;
- Annual preventative maintenance program;
- Tier 1 replacement programme;
- Tier 2 replacement programme;
- Tier 3 replacement programme; and
- AUFLS relay replacements.

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 8-62 details the expected expenditure on protection relays by regulatory year.

| Expenditure Type | 2025/26 | 2026/27 | 2027/28 | 2028/29 | 2029/30 | 2030/31 | 2031/32 | 2032/33 | 2033/34 | 2034/35 |
|---|---|---|---|---|---|---|---|---|---|---|
| Tier 1 Replacement Programme | 146 | - | 897 | 880 | 859 | 850 | 850 | 850 | 850 | 850 |
| Tier 2 Replacement Programme | - | - | 672 | 704 | 687 | 673 | 660 | 647 | 635 | 622 |
| Tier 3 Replacement Programme | - | 458 | 450 | 262 | 256 | 251 | 246 | 241 | 236 | 231 |
| AUFLS Relay Replacement | 2,427 | - | - | - | - | - | - | - | - | - |
| **Capital Expenditure Total** | **2,573** | **458** | **2,019** | **1,846** | **1,802** | **1,774** | **1,756** | **1,738** | **1,721** | **1,703** |
| Preventative Maintenance | 164 | 164 | 164 | 164 | 164 | 164 | 164 | 164 | 164 | 164 |
| Corrective Maintenance | 10 | 10 | 10 | 10 | 10 | 10 | 10 | 10 | 10 | 10 |
| Standards / Process | 47 | 46 | 45 | 44 | 43 | 42 | 41 | 40 | 40 | 39 |
| **Operational Expenditure Total** | **221** | **220** | **219** | **218** | **217** | **216** | **215** | **214** | **214** | **213** |

**Table 8-62 Expenditure on Protection Relays (\$K in constant prices)**

### 8.5.8.3 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 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.

An age profile of SCADA RTUs is shown in Figure 8-36.

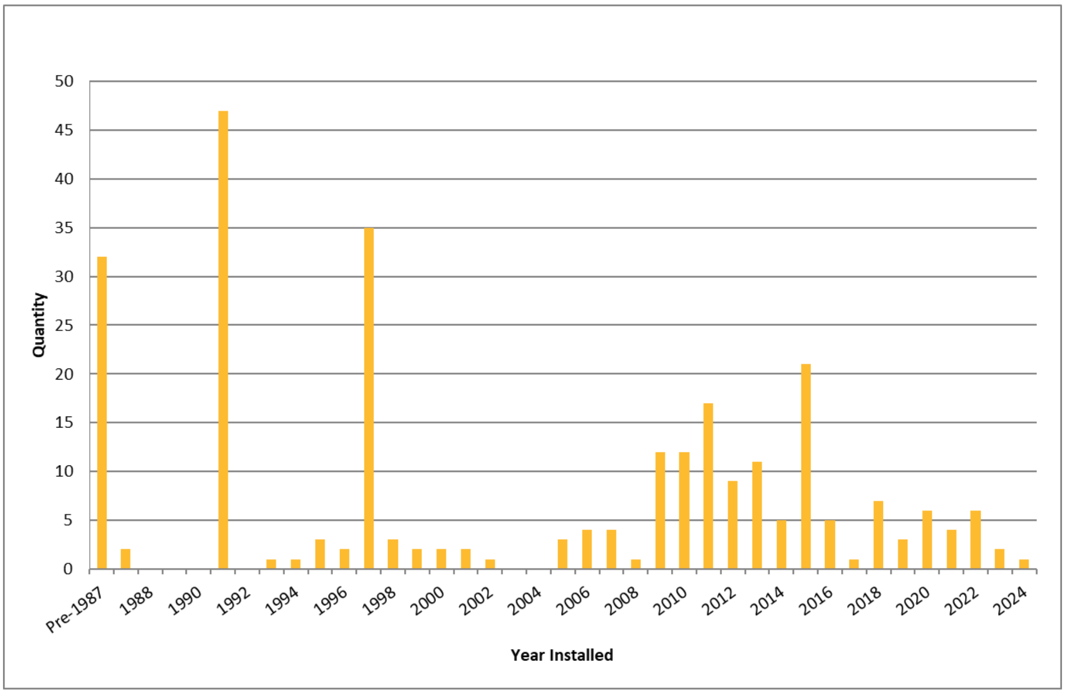



Figure 8-36 Age Profile of SCADA RTUs

To date, WELL has approximately 267 SCADA-provisioned sites, utilising multi-generational RTUs and communication protocols.

The most common communication links are copper pilot and fibre optic cables. Typically, copper pilots are WELL owned, while some of the fibre links are WELL owned and others are under lease agreements. An age profile of WELL-owned communication cables is shown in Figure 8-37.

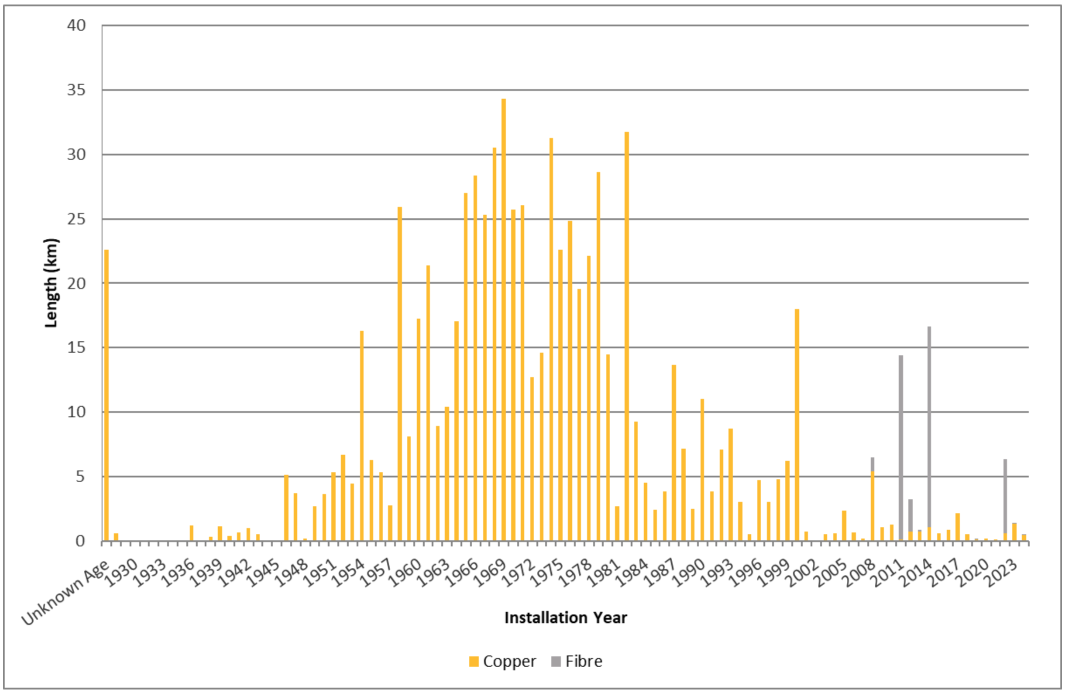



Figure 8-37 Age Profile of Communication Cables

## 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 are 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.

Communication cables that carry protection circuits are tested in conjunction with the protection relays that operate over those cables. Cables carrying SCADA circuits are tested when the connected SCADA equipment is replaced, or when the performance of those circuits is identified as being degraded.

## SCADA System Component Challenges

### SCADA Radio

Analogue radio is still used by WELL to service a small number of non-critical sites. 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. The private APN service provider is retiring their 2G/3G cellular network in 2025, affecting sites that utilise these networks. WELL is undertaking site modifications to convert the affected sites to 4G.

**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 custom-built devices, 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.

**<u>Renewal and Refurbishment</u>**

The asset replacement budget provides for the ongoing replacement of obsolete RTUs throughout the network. Obsolete RTUs that may have an 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.

Part of WELL's strategy for managing the impact of 11 kV underground cable faults (see Section 8.5.4) is to increase the number of circuit breakers and remote-controlled switches on the underground network. WELL intends to commence a programme of retrofitting ring main units with motor drives and RTUs , prioritising the units to be upgraded by their potential reliability impact.

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;
- Migrating cellular-connected equipment off the legacy 2G/3G cellular networks;
- Substation Data Network Renewal including Conitel replacement;
- Retrofitting SCADA control to existing automation-enabled switchgear, and

- End of Life RTU Replacement (Reactive).

WELL does not currently have an active programme for renewing communications cables. New fibre optic cables are installed in conjunction with 33 kV cable replacement projects, to provide communications and protection signalling, and to enable potential future condition assessment tools such as distributed temperature sensing (DTS). Existing communications cables are repaired reactively as their performance degrades.

**Expenditure Summary for SCADA and Communications Assets**

Table 8-63 details the expected expenditure on SCADA and communications assets by regulatory year.

| Expenditure Type | 2025/26 | 2026/27 | 2027/28 | 2028/29 | 2029/30 | 2030/31 | 2031/32 | 2032/33 | 2033/34 | 2034/35 |
|---|---|---|---|---|---|---|---|---|---|---|
| Zone RTU Replacement Programme | 1,000 | 500 | 700 | 700 | 700 | 700 | 700 | 700 | 700 | 700 |
| Common Alarm Replacement Programme | 616 | 500 | 500 | 500 | 500 | 500 | 500 | 500 | 500 | 500 |
| Distribution RTU Replacement Programme | - | 200 | 224 | 263 | 228 | 200 | 200 | 200 | 200 | 200 |
| Substation Data Network | 524 | 300 | 300 | 300 | 300 | 300 | 300 | 300 | 300 | 300 |
| SCADA control retrofits | - | 200 | 200 | 200 | 200 | 200 | 200 | 200 | 200 | 200 |
| 2G/3G Cellular Network Migration | 236 | - | - | - | - | - | - | - | - | - |
| Reactive Capital Expenditure | 139 | 139 | 139 | 139 | 139 | 139 | 139 | 139 | 139 | 139 |
| **Capital Expenditure Total** | **2,515** | **1,839** | **2,063** | **2,102** | **2,067** | **2,039** | **2,039** | **2,039** | **2,039** | **2,039** |
| 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 8-63 Expenditure on SCADA and Communications Assets ($K in constant prices)**

### 8.5.9 Other Network Assets

#### 8.5.9.1 Metering

WELL does not own any metering assets on customer premises. These are owned by retailers and metering service provider companies.

WELL-owned check meters are installed at GXPs. These meters provide data for WELL's load control system, described in Section 8.5.9.4. Replacement of these legacy electronic check meters is now necessary at five GXPs due to the enhanced reporting specifications mandated by regulation for the AUFLS scheme, with this work to be completed in 2025. This replacement programme will also extend to the check meters at the remaining four GXPs not directly required for AUFLS reporting, as these units have reached end of life, bringing the fleet onto a standardised platform and maintenance regime.

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.

### 8.5.9.2 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 10 MVA mobile substations and one mobile 11 kV switchboard.

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

### 8.5.9.3 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 pose a risk failure. These relays are being progressively replaced.

### 8.5.9.4 Load Control Equipment

**Fleet Overview**

WELL uses a ripple injection signal load control system to inject 475 Hz and 1050 Hz 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 to provide legacy tariff signalling on behalf of retailers. All ripple injection is controlled automatically by a Catapult master station, but can also be controlled manually at the injection plant in emergencies.

There are 25 ripple injection plants on the network, predominantly located at GXPs and zone substations. The Southern area has a 475 Hz signal injected into the 33 kV network with two static plants 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 nominal 1050 Hz signal injected at 11 kV at each zone substation.

1050 Hz signals are produced by motor generator sets. The signal has a frequency that is lower than 1050 Hz due to slip in the induction motor. The design slip at full load is 0.7%, giving a signalling frequency range of 1042-1050 Hz under varying loading conditions. The standard receivers used in the Northeast and Northwest areas are tuned to 1042 Hz.

WELL will continue operating its ripple injection system for the foreseeable future. This is due to concerns associated with the reliability, resilience, and speed of alternative hot water control methods that operate over public cellphone networks.

The age profile of the ripple plant is shown in Figure 8-38.

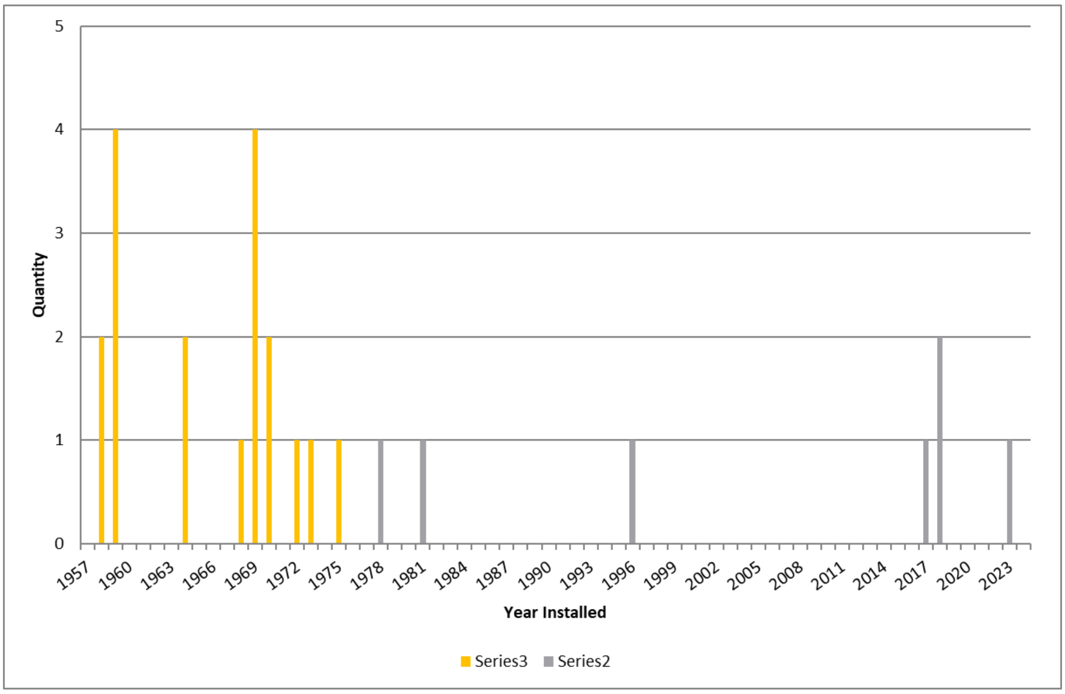



Figure 8-38 Age Profile of Ripple Plant

## 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, and 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 blocking cells at GXPs as required. | 5 yearly |

Table 8-64 Inspection and Routine Maintenance Schedule for Ripple Plant

## Strategic Spares

The spares held for the load control plant are shown in Table 8-65.

| Strategic Spares | |
|---|---|
| Injection plant | A spare 24 kVA rotary motor generator set is held for the 11 kV ripple system in the Hutt Valley.<br>A spare 300 kVA static transmitter is held at Frederick Street.<br>A spare 300 kVA static transmitter and coupling cell is held in the Hutt valley.<br>An assortment of coupling cell equipment is held in store. |
| Controllers | A spare Load Control PLC is kept as a strategic spare. |

Table 8-65 Spares Held for Load Control Plant

## Renewal and Refurbishment

### Primary Equipment

The rotary injection fleet is progressively being upgraded with static units as units approach end of life and/or capacity limits.

### 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. Some spare parts are available, and units will be replaced either in conjunction with the replacement of their ripple plant, or reactively as they fail and the spares are consumed.

## Expenditure Summary for Other Network Assets

Table 8-66 details the expected expenditure on other network assets by regulatory year.

| Expenditure Type | 2025/26 | 2026/27 | 2027/28 | 2028/29 | 2029/30 | 2030/31 | 2031/32 | 2032/33 | 2033/34 | 2034/35 |
|---|---|---|---|---|---|---|---|---|---|---|
| Ripple Injection Plant Renewal | 561 | 923 | 902 | 880 | 859 | 1,263 | 1,238 | 1,214 | 1,190 | 1,166 |
| Reactive Capital Expenditure | 418 | 418 | 417 | 417 | 417 | 417 | 417 | 417 | 417 | 417 |
| AVRR Replacement Programme | 463 | 230 | 271 | - | - | - | - | - | - | - |
| **Capital Expenditure Total** | **1,442** | **1,571** | **1,590** | **1,297** | **1,276** | **1,680** | **1,655** | **1,631** | **1,607** | **1,583** |
| 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 8-66 Expenditure on Other Network Assets
($K in constant prices)

### 8.5.10 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.

#### 8.5.10.1 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.

#### 8.5.10.2 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.

#### 8.5.10.3 Protection Relays and Metering

WELL owns 33 kV line 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 that provides data for WELL's load control system and AUFLS reporting.

#### 8.5.10.4 SCADA, RTUs and Communications Equipment

WELL owns SCADA RTUs and associated communications equipment at all GXPs.

#### 8.5.10.5 DC Power Supplies and Battery Banks

WELL owns battery banks and DC supply equipment at all GXPs.

#### 8.5.10.6 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 Takapu Road, Melling, Gracefield, and Upper Hutt GXPs.

## 8.6 Asset Replacement and Renewal Summary for 2025-2035

The total projected capital budget for asset replacement and renewal for 2025 to 2035 is presented in Table 8-67. 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 | 2025/26 | 2026/27 | 2027/28 | 2028/29 | 2029/30 | 2030/31 | 2031/32 | 2032/33 | 2033/34 | 2034/35 |
|---|---|---|---|---|---|---|---|---|---|---|
| Subtransmission | 3,471 | 9,629 | - | 8,417 | 8,417 | - | 6,489 | 15,124 | 4,100 | 4,300 |
| Zone Substations | 1,663 | 569 | 5,524 | 552 | 5,543 | 497 | 500 | 503 | 455 | 509 |
| Distribution Poles and Lines | 9,904 | 7,755 | 7,430 | 7,195 | 6,376 | 6,176 | 5,981 | 5,792 | 5,609 | 5,432 |
| Distribution Cables | 3,139 | 4,727 | 5,591 | 4,058 | 4,207 | 6,242 | 6,242 | 6,242 | 6,242 | 6,242 |
| Distribution Substations | 7,924 | 6,965 | 7,560 | 5,775 | 6,383 | 7,759 | 8,031 | 8,115 | 8,115 | 8,114 |
| Distribution Switchgear | 11,248 | 11,009 | 10,096 | 9,818 | 10,296 | 6,719 | 6,659 | 6,633 | 6,460 | 6,514 |
| Other Network Assets | 4,695 | 4,033 | 5,837 | 5,410 | 5,310 | 5,658 | 5,615 | 5,573 | 5,532 | 5,490 |
| **Total** | **42,044** | **44,687** | **42,038** | **41,225** | **46,532** | **33,051** | **39,517** | **47,982** | **36,513** | **36,601** |

**Table 8-67 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 8-68. This budget is relatively constant and is set by the asset strategies and maintenance standards that define inspection tasks and frequencies.

| Asset Category | 2025/26 | 2026/27 | 2027/28 | 2028/29 | 2029/30 | 2030/31 | 2031/32 | 2032/33 | 2033/34 | 2034/35 |
|---|---|---|---|---|---|---|---|---|---|---|
| Subtransmission | 103 | 103 | 102 | 101 | 101 | 100 | 100 | 100 | 99 | 98 |
| Zone Substations | 545 | 545 | 545 | 545 | 545 | 545 | 545 | 545 | 545 | 545 |
| Distribution Poles and Lines | 685 | 679 | 672 | 673 | 676 | 678 | 676 | 670 | 665 | 659 |
| Distribution Cables | - | - | - | - | - | - | - | - | - | - |
| Distribution Substations | 768 | 768 | 768 | 768 | 768 | 768 | 768 | 768 | 768 | 768 |
| Distribution Switchgear | 1,202 | 1,248 | 1,369 | 1,465 | 1,392 | 1,507 | 1,230 | 1,323 | 1,401 | 1,261 |
| Other Network Assets | 308 | 308 | 308 | 308 | 308 | 308 | 308 | 308 | 308 | 308 |
| **Total** | **3,611** | **3,651** | **3,764** | **3,860** | **3,790** | **3,906** | **3,627** | **3,714** | **3,786** | **3,639** |

**Table 8-68 Preventative Maintenance by Asset Category ($K in constant prices)**

The forecast corrective maintenance expenditure by asset category is shown in Table 8-69. This excludes capitalised maintenance, which is instead incorporated into the Asset Renewal and Replacement expenditure forecast in Table 8-67. 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 | 2025/26 | 2026/27 | 2027/28 | 2028/29 | 2029/30 | 2030/31 | 2031/32 | 2032/33 | 2033/34 | 2034/35 |
|---|---|---|---|---|---|---|---|---|---|---|
| Subtransmission | 480 | 480 | 420 | 420 | 420 | 350 | 350 | 350 | 350 | 350 |
| Zone Substations | 445 | 445 | 445 | 445 | 445 | 445 | 445 | 445 | 445 | 445 |
| Distribution Poles and Lines | 996 | 996 | 996 | 996 | 996 | 996 | 996 | 996 | 996 | 996 |
| Distribution Cables | 101 | 101 | 101 | 101 | 101 | 101 | 101 | 101 | 101 | 101 |
| Distribution Substations | 760 | 760 | 760 | 760 | 760 | 760 | 760 | 760 | 760 | 760 |
| Distribution Switchgear | 606 | 606 | 606 | 606 | 606 | 606 | 606 | 606 | 606 | 606 |
| Other Network Assets | 140 | 140 | 140 | 140 | 140 | 140 | 140 | 140 | 140 | 140 |
| **Total** | **3,528** | **3,528** | **3,468** | **3,468** | **3,468** | **3,398** | **3,398** | **3,398** | **3,398** | **3,398** |

**Table 8-69 Corrective Maintenance by Asset Category ($K in constant prices)**

### 8.6.1 Reliability, Safety and Environmental Programmes for 2025-2035

Asset management expenditure that is not directly the result of asset health drivers is categorised into the 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 8-70.

| Programme | 2025/26 | 2026/27 | 2027/28 | 2028/29 | 2029/30 | 2030/31 | 2031/32 | 2032/33 | 2033/34 | 2034/35 |
|---|---|---|---|---|---|---|---|---|---|---|
| Feeder Reliability Projects – Lines | 2,188 | 1,035 | 1,195 | 1,404 | 1,213 | 1,154 | 1,183 | 1,211 | 1,238 | 1,264 |
| Feeder Reliability Projects – Switchgear | 679 | 1,473 | 1,242 | 687 | 990 | 1,178 | 1,155 | 1,133 | 1,110 | 1,089 |
| Switchgear SCADA Control Retrofit | - | 200 | 200 | 200 | 200 | 200 | 200 | 200 | 200 | 200 |
| **Total Quality of Supply** | **2,867** | **2,708** | **2,637** | **2,291** | **2,403** | **2,532** | **2,538** | **2,544** | **2,548** | **2,553** |
| AUFLS Relay Replacement | 2,427 | - | - | - | - | - | - | - | - | - |
| **Total Legislative and Regulatory** | **2,427** | **-** | **-** | **-** | **-** | **-** | **-** | **-** | **-** | **-** |
| Asset Readiness Expenditure (See Section 12) | 1,520 | 462 | 448 | - | - | - | - | - | - | - |
| **Total Other Reliability, Safety and Environment** | **1,520** | **462** | **448** | **-** | **-** | **-** | **-** | **-** | **-** | **-** |

Table 8-70 Reliability, Safety and Environmental Capital Expenditure ($K in constant prices)

### 8.6.2 Asset Management Expenditure

The total capital and operational expenditure forecasts are shown in Table 8-71 and Table 8-72. 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 | 2025/26 | 2026/27 | 2027/28 | 2028/29 | 2029/30 | 2030/31 | 2031/32 | 2032/33 | 2033/34 | 2034/35 |
|---|---|---|---|---|---|---|---|---|---|---|
| Asset Replacement & Renewal | 42,044 | 44,687 | 42,038 | 41,225 | 46,532 | 33,051 | 39,517 | 47,982 | 36,513 | 36,601 |
| Other Reliability, Safety & Environment | 1,520 | 462 | 448 | - | - | - | - | - | - | - |
| Legislative and Regulatory | 2,427 | - | - | - | - | - | - | - | - | - |
| Quality of Supply | 2,867 | 2,708 | 2,637 | 2,291 | 2,403 | 2,532 | 2,538 | 2,544 | 2,548 | 2,553 |
| **Total Capital Expenditure on Asset Replacement Safety and Quality** | **48,858** | **47,857** | **45,123** | **43,516** | **48,935** | **35,583** | **42,055** | **50,526** | **39,061** | **39,154** |

**Table 8-71 Asset Management Capital Expenditure Forecast**
**($K in constant prices)**

| Category | 2025/26 | 2026/27 | 2027/28 | 2028/29 | 2029/30 | 2030/31 | 2031/32 | 2032/33 | 2033/34 | 2034/35 |
|---|---|---|---|---|---|---|---|---|---|---|
| Service interruptions & emergency maintenance | 4,691 | 4,751 | 4,823 | 4,900 | 4,979 | 4,979 | 4,979 | 4,979 | 4,979 | 4,979 |
| Vegetation management | 1,872 | 1,896 | 1,925 | 1,956 | 1,987 | 1,987 | 1,987 | 1,987 | 1,987 | 1,987 |
| Routine & corrective maintenance and inspection maintenance | 10,904 | 11,044 | 11,212 | 11,391 | 11,575 | 11,575 | 11,575 | 11,575 | 11,575 | 11,575 |
| Asset replacement & renewal maintenance | 1,704 | 1,726 | 1,752 | 1,780 | 1,809 | 1,809 | 1,809 | 1,809 | 1,809 | 1,809 |
| **Total Network Operational Expenditure** | **19,170** | **19,417** | **19,713** | **20,027** | **20,351** | **20,351** | **20,351** | **20,351** | **20,351** | **20,351** |

**Table 8-72 Network Operational Expenditure Forecast**
**($K in constant prices)**

# 9 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 the service levels and network performance described in Sections 6 and 7.

New Zealand's First Emissions Reduction Plan (ERP1) was published in May 2022 and established a number of decarbonisation programmes in order to meet the country's commitment to achieving net-zero emissions by 2050. WELL's 2024 AMP was based on demand growth forecasts from mid-2023, built around the ERP1 assumptions. At that time, the uptake of EVs was growing strongly, projects were underway to decarbonise public transport, and a number of large residential and commercial developments were being planned.

WELL has seen significant changes in the forecast rates of decarbonisation over the last 18 months, and particularly in the four months prior to the publication of this AMP. These include an increased focus on affordability being in balance with sustainability. Changes in central government policy regarding the removal of incentives for EV uptake, major public transport electrification projects being delayed, rephasing of customer decarbonisation projects, and delays to major new residential and commercial developments are signs that the economy has slowed down.

The updated demand forecasts are still based on an assumption of net-zero by 2050, however, while the 2050 target has been reiterated in the October 2024 Government Policy Statement on Electricity, the action to support this has needed to adjust to the current economic conditions.

Figure 9-1 shows the change in the system maximum demand forecasts between the two AMPs, with the 2025 forecast being based on current growth trends, revised assumptions about the future rate of decarbonisation, and customer-initiated projects that have been contracted for. The details of these changes in decarbonisation forecasts are discussed in Section 9.2.2.

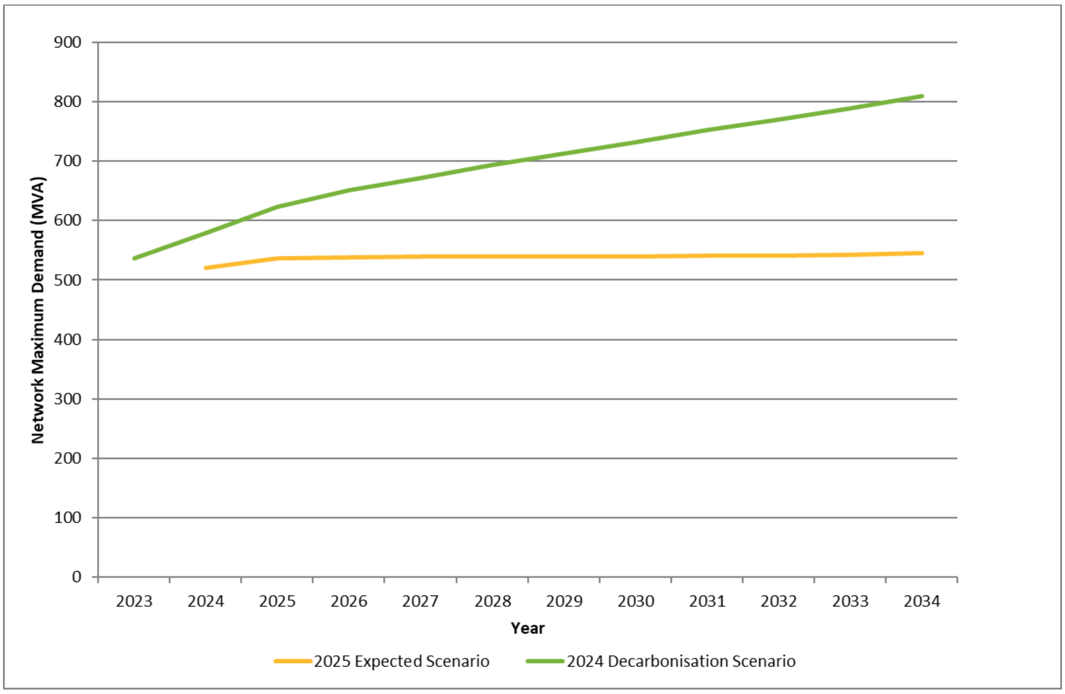



**Figure 9-1 Change in Year Demand Forecast from 2024 AMP to 2025 AMP**

Combining this demand growth uncertainty with the lead time required for delivering significant new capacity, this is a risk that WELL's investment plan will manage by:

- Continued use of Time of Use pricing to shape discretionary demand away from peak periods, as well as exploring other innovative pricing options to incentivise demand flexibility;
- Coordinating capacity investment with the required end-of-life asset renewals;
- Ensuring interventions are designed early and ready to be built should the need eventuate sooner than expected;
- Installing cable ducting ahead of cables being required, in conjunction with other infrastructure providers' projects to minimise future construction times, and
- Exploring the application of the "Readiness Spares" concept previously used for earthquake readiness, to support reinforcement projects by minimising equipment delivery times.

It is important to note that this lower level of demand increase when aggregated and diversified to the Network level does not capture how demand is changing at the disaggregated subtransmission and zone substation level. Fewer of WELL's zone substations are expected to exceed the loading limits defined in WELL's security of supply policy in 10 years than were forecast in 2024, however there are still localised 33 kV constraints that will develop that must be solved, even at the lower levels of growth forecast.

Figure 9-2 shows the change in +10-year maximum demand at WELL's zone substations relative to their rated capacity changes from the 2024 forecast to the updated 2025 forecast. This illustrates the areas where the change in decarbonisation forecasts has delayed the need for capacity-triggered investment, and the areas that still require investment in capacity, even at slower rates of electrification, due to low levels of existing capacity headroom.

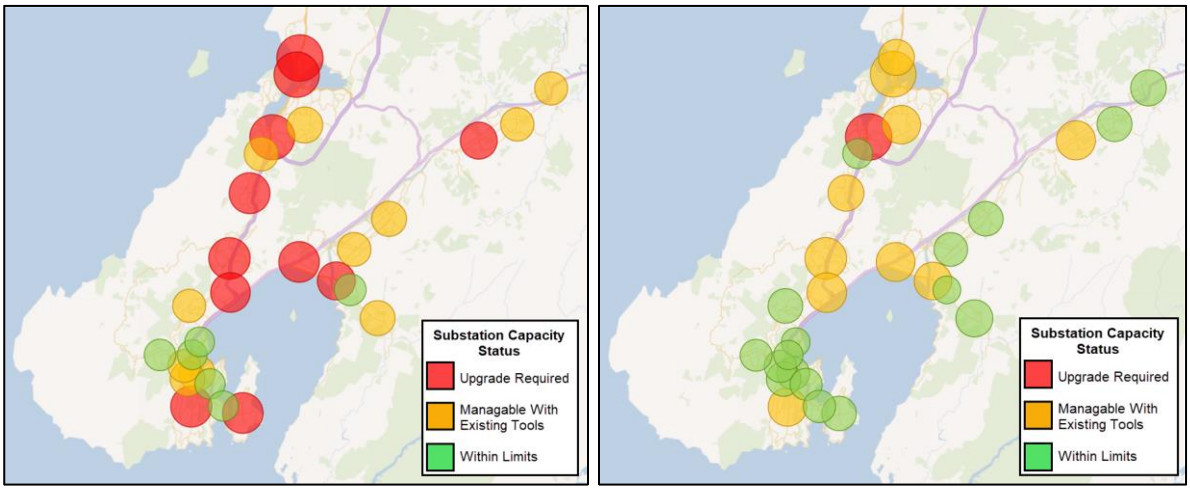



**Figure 9-2 Change in +10 Year Zone Substation Demand vs Capacity Without Intervention from 2024 AMP (Left) to 2025 AMP (Right)**

WELL will need to invest in new capacity to solve these constraints, while managing timing risk to ensure this investment is not too early (with customers paying for assets before they are needed), or too late (leading to either quality risk or connection requests being delayed). There are strong synergies between this investment and the need to replace major asset fleets such as power transformers and subtransmission cables as they approach end of life. In the forecasts underpinning WELL's 2024 AMP, the need for more capacity was usually the first investment trigger, resulting in asset replacements being brought forward. However, the revised demand forecasts have resulted in resequencing of the investment programme, delaying some investment. Synergies will still be achieved, however, in some cases, the trigger point for investment will now be the asset reaching end of life rather than the need for capacity, subject to no large load step changes that then require capacity investment.

## 9.1 Network Planning Policies and Standards

The policy and standards underpinning system reinforcement 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.

### 9.1.1 Security Criteria

The design of WELL's network is based on the security criteria shown in Table 9-1 (subtransmission criteria) and Table 9-2 (distribution criteria).

The security criteria are consistent with industry practice[27] 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 increasing costs to customers to remove the small risk altogether.

The WELL subtransmission network consists of a series of radial 33 kV circuits from Transpower's GXPs to the zone substations. The subtransmission circuits usually connect directly to the high voltage terminals of the 33/11 kV power transformers, with the exception being at Evans Bay where three subtransmission circuits

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

connect to a 33 kV bus. 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 interruption to customers 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 9-1 shows the applicable security criteria for the subtransmission network.

| Type of Load | Security Criteria |
|---|---|
| CBD | N-1 capacity, for 99.5% of the time in a year.<br>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.<br>For the remaining times, supply will be restored within 3 hours following an interruption. |

Table 9-1 Security Criteria for the Subtransmission Network

### Distribution

Table 9-2 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.<br>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.<br>For the remaining times, supply will be restored within 3 hours following an interruption. |
| Predominantly residential with some rural feeders | N-1 capacity for 95% of the time in a year.<br>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 is dependent on repair time. |
| Underground spurs supplying up to 400kVA. | Loss of supply upon failure. Supply restoration is dependent on repair time. |
| HV direct / LV Supply to customer | Loss of supply upon failure unless the customer specified a higher security requirement. Supply restoration is dependent on repair time. |

Table 9-2 Security Criteria for the Distribution Network

**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 customers, which are typically designed for 'N' security. In such situations, an interruption will last for the time taken to complete 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 12) but, when they occur, longer supply interruptions than shown in the tables are possible.

Most of the 11 kV feeders in the Wellington CBD, some locations around Wellington city suburbs, and the Porirua commercial centre are operated in a closed ring configuration with radial secondary feeders interconnecting neighbouring rings or zone substations. This arrangement provides a high level of security and hence a high level of supply reliability. The urban 11 kV network outside these areas typically comprises radial feeders with a number of mid-feeder switchboards with circuit breakers.

[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.

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 customers 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 9-3. 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 Type | Pre-Contingent Loading | Post-Contingent Loading |
|---|---|---|
| Two Feeder Ring | 50% | 100% |
| Three Feeder Ring | 67% | 100% |
| Four Feeder Ring | 75% | 100% |
| Radial Feeder with Backfeeds | 67% | 100% |
| Radial Spur without Backfeeds | 100% | - |

**Table 9-3 11 kV Feeder Utilisation during Normal and Contingency Operation**

A customer may desire a level of security above or below that offered by a standard connection. Should this arise, WELL conducts a risk assessment to determine whether the proposed customer connection will adversely impact levels of security for existing customers, and the reputational risk to WELL for the customer's services being interrupted. If the proposed connection does not impact existing customers, WELL may offer a range of alternatives that provide different levels of security at different costs, to allow the customer to make an informed decision regarding the price/quality trade-off. The customer can then choose to pay for an appropriate level of security to meet their needs for the load that is being supplied.

### 9.1.2 Asset Capacity Definition

Primary assets in the WELL network are classified into the following hierarchy of categories with planning criteria and operational requirements for the different assets shown in Table 9-4.

| 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 HV 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 9-4 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 thermal resistivity, the load profile and resulting thermal inertia, mutual heating due to adjacent conductors and configuration of the 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 24 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 11 outlines the development plans and trial projects that have a 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 loading against the security standard.

### 9.1.3 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 a nominal 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 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.

The 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. Flexibility services may be required in future to implement suitable power quality response modes to meet supply quality requirements.

### 9.1.4 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 supplies 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.

### 9.1.5 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.

### 9.1.6 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 the magnitudes and phase angle of each harmonic component. High levels of harmonic distortion can cause power quality problems for nearby customers and can reduce the capacity of transformers. It is common to use a single quantity, 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.

### 9.1.7 Standardised Designs

The implementation of standardised designs for common developments allows for improvements in safety by design principles, a significant reduction in design expenditure and 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 asset and installation specifications. At present, design standards are utilised for protection design, zone substation and distribution level earthing, and LV reticulation.

There is no standardisation of high voltage (HV) network augmentation because these are dependent on the customer's specific requirements for the project.

### 9.1.8 Standardised Cost Model

The implementation of a standardised cost model enables efficient project cost estimation. WELL is currently updating its standardised cost model, using costs incurred by previously completed projects as a guide for future project costs. This standardised cost model has been utilised to estimate costs for future network growth projects described in this Chapter.

The standardised cost model is under continual improvement, as completed projects are added to the input to provide updated costs for building block items.

### 9.1.9 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 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).

### 9.1.10 Non-Network Solution Policy

Non-network solutions include cost-reflective pricing, load control, demand-side management solutions, and network reconfigurations.

WELL uses time-of-use pricing as a means of incentivising customers to move energy use outside of peak periods. WELL is continuing to refine its pricing strategy to reflect the cost of building new capacity to meet increasing peak demand, and is testing innovative commercial mechanisms (see Section 11.3.3.3) to better signal available capacity to its customers.[29] This use of cost-reflective pricing proactively shapes the demand curve, delaying the need to increase network capacity, and reducing the need for more costly demand-side management solutions.

WELL's load control system is used to reduce maximum demand on the network by moving hot water demand to low load periods. The demand forecasts that drive WELL's network reinforcement programme assume that control of hot water will continue per current practice. Changes that reduce WELL's ability to shape peak demand through hot water control, either by increasing it or decreasing it, may have an impact on the required timing of network reinforcement investment.

[29] https://www.welectricity.co.nz/disclosures/pricing/future-pricing

The options available for network reconfiguration typically include:

- Open point shifts using existing infrastructure to reduce loading on highly loaded feeders;
- Operational changes to better utilise existing network capacity over the 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 evaluated before any network investment. WELL monitors feeder loading using SCADA alarm limits to provide indication prior to thermal overload of assets and to make sure that the voltage is within acceptable limits. Where there is a risk of exceeding the thermal limits due to equipment failure or constraints, network controllers can:

- Initiate shedding of hot water load to move load away from maximum demand periods; and
- Fine-tune network open points to optimise feeder loading and feeder customer numbers.

There is also uncertainty with the fast-changing nature of the emerging technologies. WELL's approach to assessing these is described in Section 11. WELL has found through its Resi-Flex project (discussed in Section 11.3.3.3) that potential providers of non-traditional solutions do not currently have the capability to provide non-network solutions to the scale and dependability required to supplant traditional network-based solutions for the capacity increments that WELL requires. WELL does not currently pro-actively share information about areas of load constraint on its LV network with potential providers of non-traditional solutions, however it is currently refining its LV constraint maps and intends to publish these in 2025.

### 9.1.11 Impact of Distributed Energy Resources

The magnitude of distributed energy resources (DER) installed in the WELL network is relatively low[30] although there is increasing availability of distributed generation, energy storage, and flexible demand.

Given the intermittent nature of DER and the uncertainty of many DER projects, a conservative approach is taken when assessing their impact. This is often based on a worst-case scenario. Any investment decisions will only consider DER where the resource is deemed reliable and the DER project is certain.

#### 9.1.11.1 Connection Policy

WELL welcomes enquiries from third parties interested in installing embedded generation or storage capacity in its network. WELL has a Distribution Code and Network Connection Standard that includes the procedures for the assessment and connection of distributed generation in line with Part 6 of the Electricity Industry Participation Code 2010.

For each third-party request for new generation or storage on the network, WELL conducts a risk assessment for the new connection. The location, timing, and scale of the new connection are assessed using network planning tools to identify possible risks and/or benefits for the scheme. Part of this risk assessment also quantifies the uncertainty around the third-party scheme. WELL's processes regarding quantifying uncertainty of future step changes are described in Section 9.2.1.2.

[30] Installed capacity, excluding standby generation and Mill Creek (connected at 33 kV), is 3% of the system maximum demand.

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.

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.

#### 9.1.11.2 Information Sharing with Potential Distributed Generation Providers

WELL has published a network constraint map on its website that indicates locations subject to DG export constraints on the LV network. This map will be enhanced during 2025 to incorporate the updated LV hosting capacity modelling discussed in Section 11.3.2.1.

WELL shares its GIS data with potential customers on request, subject to the customer agreeing to usage terms.

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

## 9.2 Demand Forecast 2025 to 2035

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.

While the overall WELL load is traditionally winter peaking, recent trends have shown that Moore Street zone substation within the Wellington CBD is now summer peaking.

### 9.2.1 Demand Forecast Methodology

There is a negative correlation between WELL's total network demand profile and the ambient temperature, with the system maximum demand occurring on the coldest weekdays in winter. In addition, the rating of some network assets such as cables can vary depending on ambient temperature conditions.

WELL develops separate summer and winter demand forecasts using historical trends in peak demand with the addition of confirmed future step changes. For each zone substation, historical summer and winter demand trends are analysed to establish:

1. An average peak demand forecast growth rate based on the subtransmission security criteria defined in Table 9-1 (i.e. 99.5th percentile for zone substations within the CBD and 98th percentile for all other zone substations); and

2. 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:

   a) high and low population growth scenarios indicated by local government, and

   b) confirmed future step change demand.

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 security constraints to determine the subtransmission security of supply.

The growth scenarios are aggregated 'bottom-up' from feeder level to provide GXP, regional, and system-wide forecasts allowing for diversity at each level. An overview of the demand forecast methodology is shown in Figure 9-3.

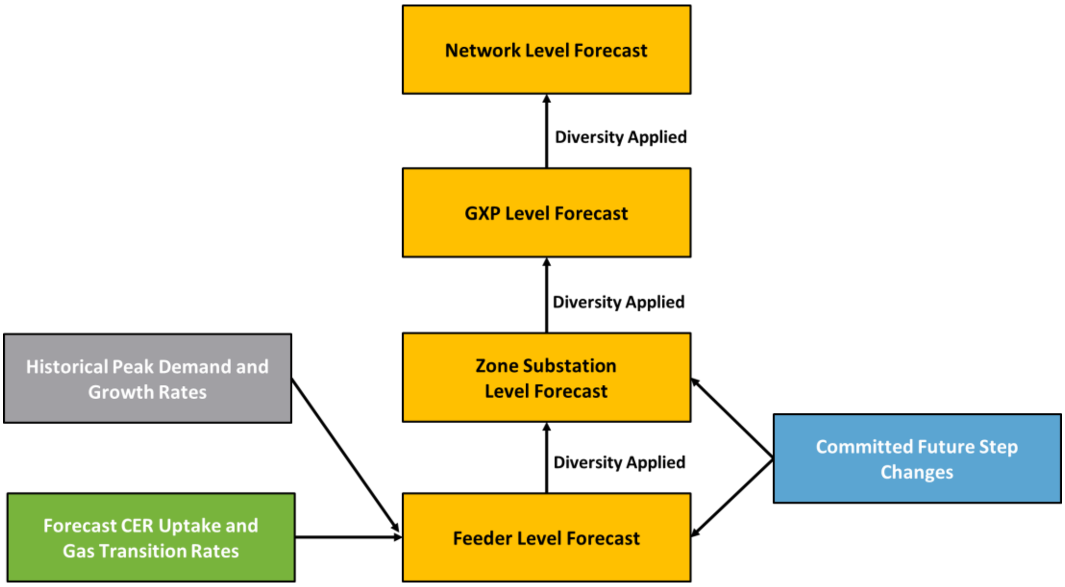



Figure 9-3 Demand Forecasting Methodology

This model is used to determine when subtransmission and feeder level constraints are likely to occur and provide an annual maximum demand that can be used in load flow modelling.

### 9.2.1.1 Forecasting 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 conditions causing significant outages or abnormal operation of the network;
- 5-minute demand data per zone substation feeders is captured by the SCADA system. The demand at each GXP is metered through the time-of-use revenue metering.

To calculate the peak demand, the forecast is based on the following information and applies assumptions listed earlier in this section:

- Step change loads, based on confirmed customer connection requests, are included in the forecast;
- The impact from EV uptake and gas to electricity transition forecasts is included;
- Diversity factors[31] that provide peak coincident demand are calculated from historical data; and
- Typical demand profiles based on the majority load type in the zone substation.
- Historical data for the zone substation.

These assumptions, data sets and trend analysis are reviewed each year, and the expected impacts of any changes are incorporated into the forecast.

#### 9.2.1.2 Step Change Loads

Confirmed step change loads are accounted for in the load forecast. These step-change loads may be the result of:

- Major developments that introduce large new loads onto the network with a total connection capacity above 450 kVA or ADMD capacity above 200 kVA;
- New electricity generation that is expected to materially and reliably reduce peak demand; or
- Load reductions caused by the movement or closure of businesses.

Known step changes are categorised into the following three groups based on the level of uncertainty:

- C1: network connection offer signed by the developer.
- C2: from local council plans assessment of development potential that is close to eventuating or is highly likely to proceed, or signalled by the developer still exploring development options and WELL has not received an application for connection.
- C3: Speculative – based on potential trends.

The demand forecast for this AMP utilises only the C1 scenario to determine network constraints, on the assumption that any C2 or C3 step changes that trigger significant investment in new capacity will be subject to price path reopeners.

[31] Diversity factors represent the difference in times of peak demand between different sites.

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.

### 9.2.2 Changes in Assumptions for the 2025 AMP

The forecast includes assumed rates for EV uptake and gas-to-electricity transition. 2024 saw a significant reduction in these trends, and these rates have been updated for the 2025 AMP. This section explains these changes.

#### 9.2.2.1 Private Electric Vehicle Charging

The period from 2021 to 2023 saw exponential growth in the number of EVs registered in Wellington, with registrations increasing at an average rate of 60% per year over that time, and over 4,000 vehicles being registered in 2023 alone. WELL's 2024 demand forecast included an assumption that this growth would stabilise to linear growth at a rate of 5,000 vehicles per year, equivalent to the national fleet growing at 50% of EECA's "High Growth" rate (see Figure 4-9). Instead, government policy changes in 2024 reduced the uptake rate of EVs, with fewer than 1,500 EVs being registered in Wellington in 2024.

WELL has updated its demand forecast for this AMP to assume the current rate of 12% per year growth in EVs will continue, from 5% of the light passenger fleet in Wellington in 2024, to 17% of the fleet by 2035, reflecting the high growth rates of the last few years transitioning to EECA's "Low Growth" scenario. The ADMD per EV is 0.9 kW.

Figure 9-4 compares the historic EV uptake rate with the forecasts used in the 2024 and 2025 AMPs.

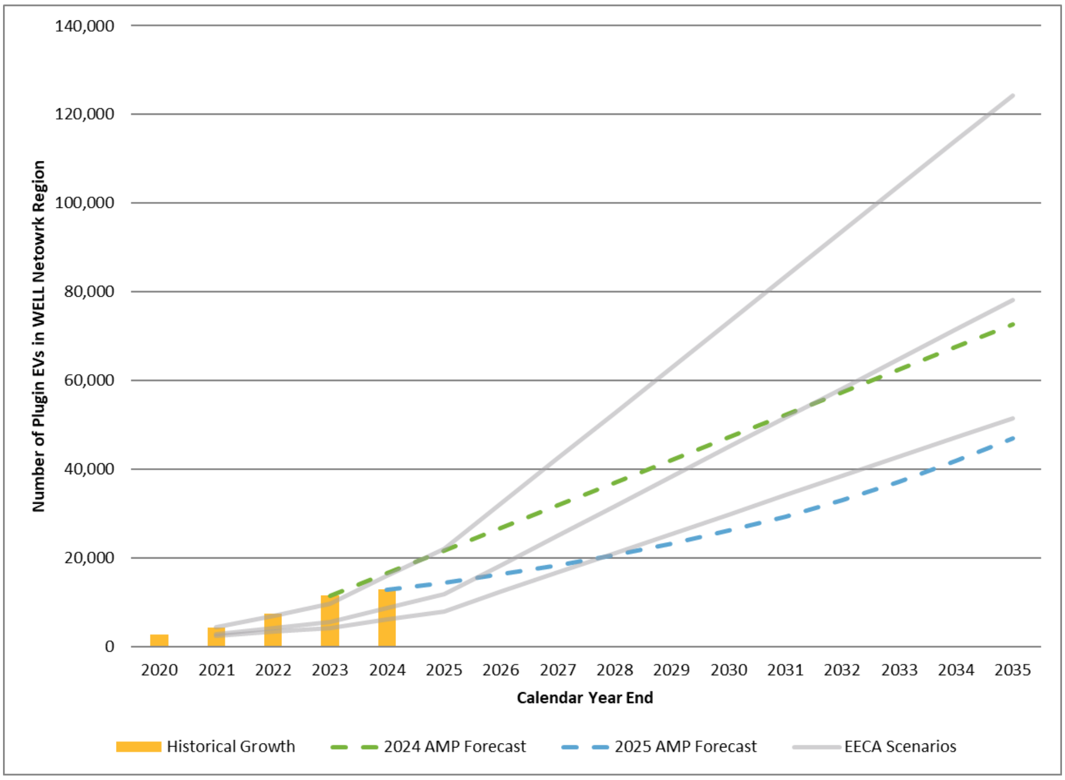



Figure 9-4 EV Uptake Forecast Rates

#### 9.2.2.2 Public EV Charging

The 2024 demand forecast included an assumption that public EV charging points would be operating at full capacity during the peak demand period. This assumption was based on feedback from potential operators that had approached WELL with requirements that their charge points have sufficient network capacity to operate at full utilisation at all times.

Since 2024, concerns have been raised by the charge point industry about the cost of connecting public EV charging points, with the requirement for anytime full utilisation being a key driver of those costs. WELL's assumption is now that in order to minimise those connection costs, public EV charge points operators will be prepared to accept operating envelopes that allow them to operate at full utilisation outside of peak demand periods, but reduced capacity during periods of network constraints in order to minimise connection costs.

This has been reflected in WELL's demand forecast by assuming that public charge points will operate to an envelope that caps their utilisation at 10% of their rated capacity during peak demand periods.

#### 9.2.2.3 Commercial and Industrial Process Heat

The 2024 AMP assumed that the government would publish a Gas Transition Plan leading to a rapid exit of gas from commercial and industrial process heat, supported by decarbonisation programmes like GIDI funding, based on WELL's engagement with its major customers and an external study by DETA, and policies banning gas exploration.

DETA surveyed 156 commercial and industrial sites in Wellington, receiving responses from approximately 20% of these, and identifying 40 MW of potential electrification. Despite the low response rate, responses were received from most of the largest gas users in the region, so for the purposes of the demand forecast, WELL assumed that this 40 MW represented 67% of the total potential electrification across all sites including those that did not respond to the survey.

Commercial and industrial customers have largely delayed their decarbonisation projects due to cost and the withdrawal of government funding for these projects. WELL's assumption is now that biofuels will replace fossil gas instead of electricity for these applications, and has eliminated 60 MW of commercial and industrial process heat from its demand forecast.

#### 9.2.2.4 Residential Gas to Electricity Transition

Approximately 65,000 of WELL's 160,000 residential customers have a reticulated gas connection for cooking, water heating, and space heating. WELL had assumed in its 2024 AMP that the government's intended Gas Transition Plan would prioritise biomethane towards hard-to-electrify loads rather than residential usage, and that rising gas prices due to the depletion of new fields coupled with a ban on new exploration, and rapidly increasing gas connection due to the Commission allowing accelerated depreciation of gas network assets, would lead to 50% of residential gas customers transitioning to electrical appliances by 2035. The increase in residential ADMD was assumed to be 2 kW per transitioning customer.

WELL has seen no evidence of a residential gas transition occurring, despite rapidly increasing gas connection charges. Engagement with suppliers of gas appliances has indicated that gas cooking and water heating appliances reaching end of life are generally being replaced with new gas appliances rather than converting to electricity. As such, WELL has now assumed a residential transition rate of 10% of the 65,000 gas customers transitioning to electricity by 2035.

#### 9.2.2.5 Public Transport Projects

WELL's 2024 AMP included an assumption that public transport electrification projects that agencies and operators were in discussion with it about were certain to go ahead. This including 25 MW of additional capacity for rail, 15.5 MW of bus charging capacity, 20 MW for the electrification of port operations, and 2 MW of aircraft charging.

All of these projects have either been cancelled, delayed, or significantly scaled back. WELL is currently assuming that public transport electrification projects that have not yet contracted for capacity will not occur, and any that do end up proceeding and require new capacity will be subject to price-path reopeners.

#### 9.2.2.6 Summary of Changes

These changes are summarised in Table 9-5.

| Demand Type | 2035 MW in 2024 AMP | 2035 MW in 2025 AMP |
|---|---|---|
| Private EV Charging | +55 MW<br>(5,100 new EVs per year) | +28 MW<br>(12% growth per year) |
| New Commercial EV Charging | +11 MW<br>(Full utilisation at peak) | +1 MW<br>(10% utilisation at peak) |
| Process Heat | +60 MW<br>(1.5x signalled electrification) | 0 MW<br>(Biofuel instead of electrification) |
| Residential Gas | +68 MW<br>(50% transition) | +13 MW<br>(10% transition) |
| Public Transport Electrification | +63 MW<br>(All projects to proceed) | 0 MW<br>(Projects cancelled or delayed) |
| **Decarbonisation Demand** | **+257 MW** | **+42 MW** |

Table 9-5 Material Changes to WELL's Decarbonisation Demand Forecasting Assumptions

### 9.2.3 Typical Load Profiles

Typical annual demand profiles for the CBD and residential loads are shown in Figure 9-5 and Figure 9-6 respectively. 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.

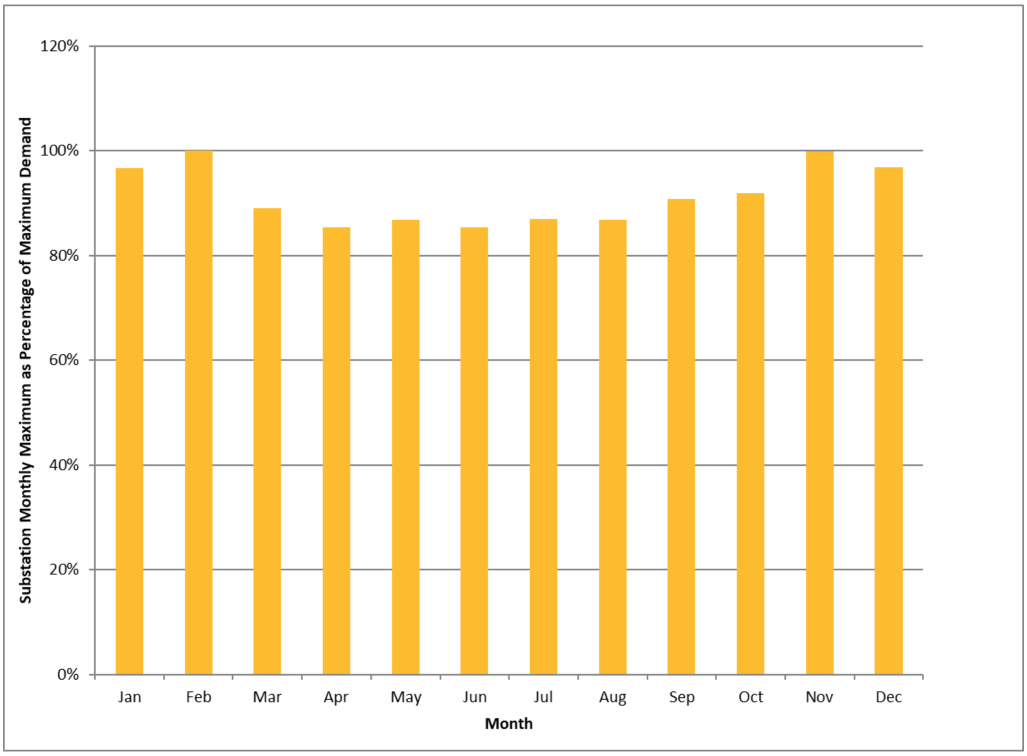



Figure 9-5 Typical CBD Commercial Area Monthly Peak Load Profile

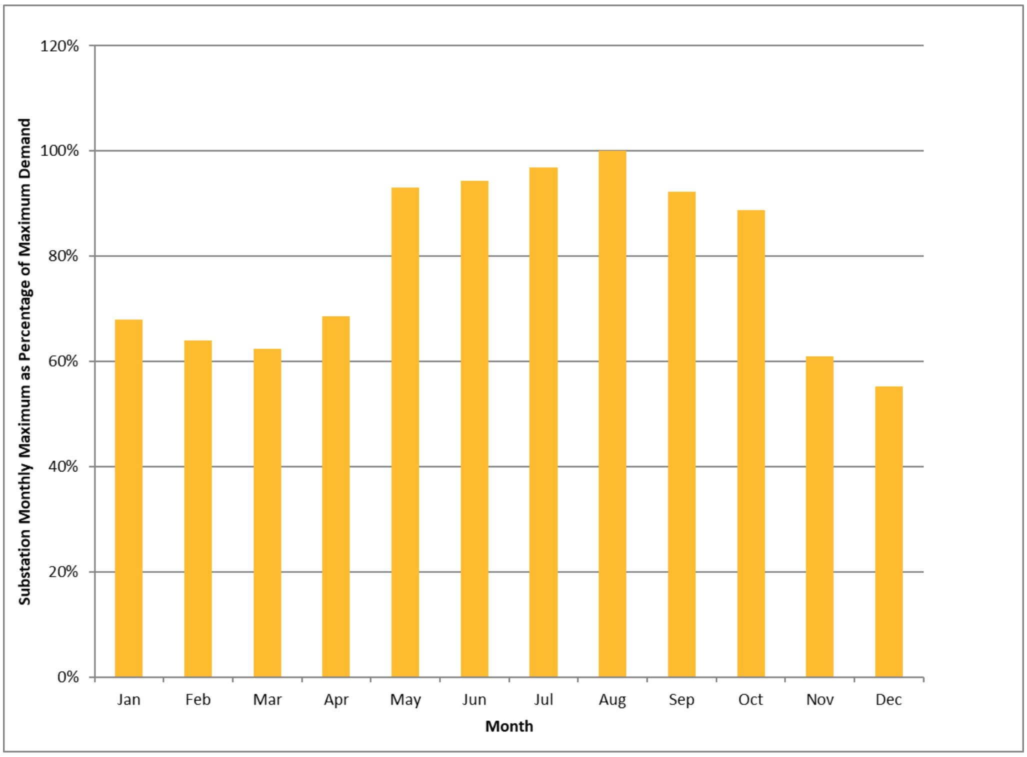



Figure 9-6 Typical Residential Monthly Peak Load Profile

Typical daily demand profiles for CBD and typical residential loads are shown in Figure 9-7 and Figure 9-8. These graphs illustrate that the CBD daily profile peaks and then remains relatively flat through the day, whereas the residential load profile has 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.

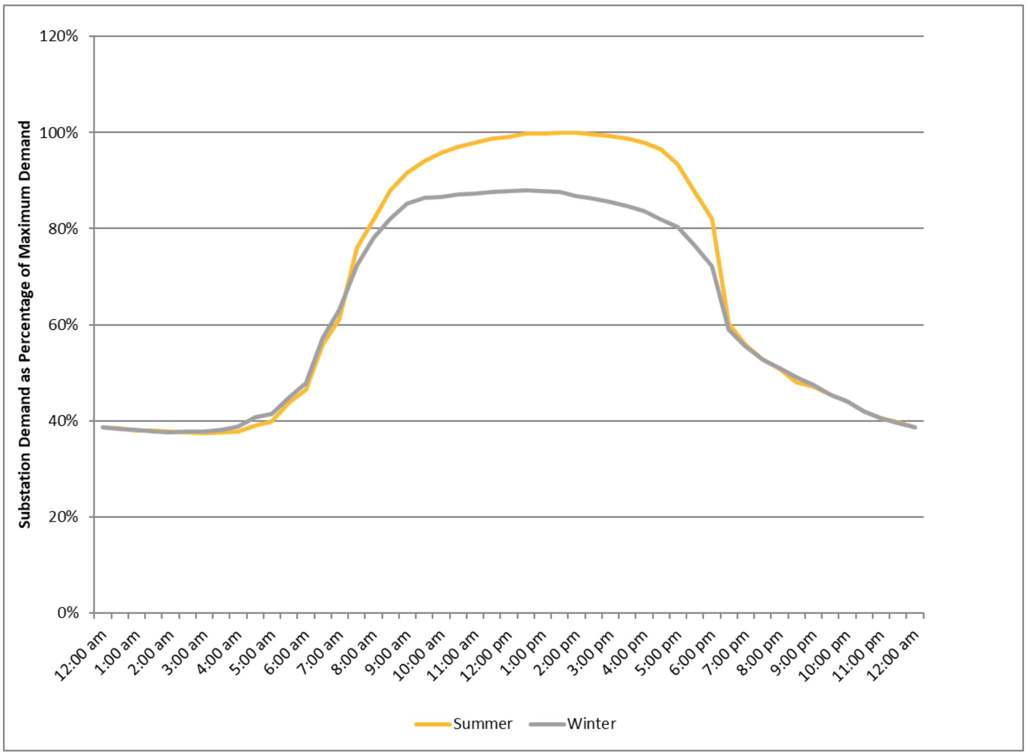



**Figure 9-7 Typical CBD Commercial Area Zone Substation Daily Load Profile**

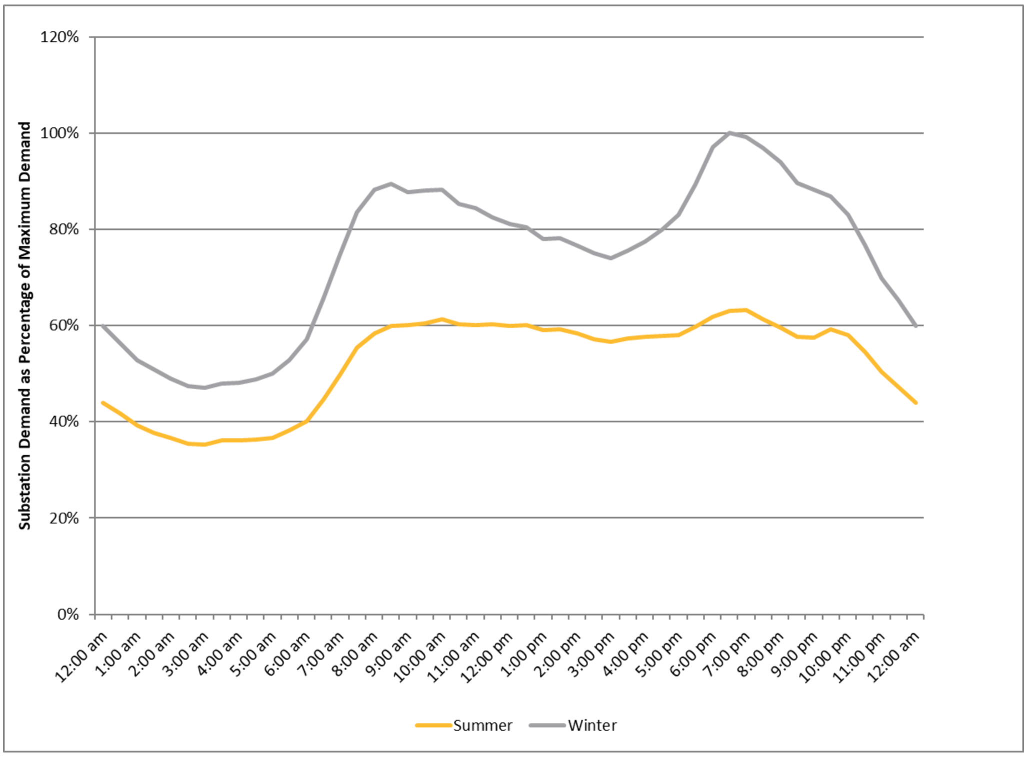



**Figure 9-8 Typical Residential Zone Substation Daily Load Profile**

### 9.2.4 Wellington Regional Maximum Demand Forecast

Table 9-6 shows the network maximum demand forecast to 2034. These figures assume an average winter. In practice the actual maximum demand will be influenced by the rate of decarbonisation of transport and heating, customer EV charging behaviour, and whether the winter is milder or colder than average.

| Network | Maximum Demand (MW) | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|
| | 2024 Actual | 2025 | 2026 | 2027 | 2028 | 2029 | 2030 | 2031 | 2032 | 2033 | 2034 |
| Total System Maximum Demand (MW) | 521 | 536 | 538 | 539 | 539 | 539 | 539 | 540 | 541 | 543 | 545 |

Table 9-6 Forecast Network Maximum Demand

Table 9-7 shows the contribution of each GXP and major DG to the 2024 winter maximum demand.

| Location | 2024 Coincident Maximum Demand (MW) | | | | | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | Central Park | Gracefield | Haywards | Kaiwharawhara | Melling | Pauatahanui | Takapu Road | Upper Hutt | Wilton | Mill Creek | Wellington Wind | Silverstream | Southern Landfill | Other Small DG | Total |
| Coincident Maximum Demand (MW) | 155 | 60 | 34 | 24 | 57 | 19 | 93 | 31 | -3 | 48 | 1 | 2 | 0 | 0 | **521** |

Table 9-7 2024 Coincident Maximum Demand

### 9.2.5 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 9-8 shows the GXP level forecast by area and Table 9-9 shows the zone substation level forecast by area. For both tables, the totals are non-coincident peak demand values. Years where the forecast demand exceeds the present firm N-1 capacity at the site (excluding available 11 kV backfeeds from neighbouring substations and future capacity upgrades) are marked in red, and addressed in the detailed regional analysis in Sections 9.4 to 9.6.

| Area | GXP | Winter N-1 Capacity | Actual and Forecast Peak Demand[32] (MVA) | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | | | 2024 Actual | 2025 | 2026 | 2027 | 2028 | 2029 | 2030 | 2031 | 2032 | 2033 | 2034 |
| Southern | Central Park 33 kV | 224 | 155 | 158 | 158 | 157 | 155 | 154 | 152 | 151 | 150 | 149 | 148 |
| | Central Park 11 kV | 30 | 20 | 21 | 21 | 21 | 21 | 21 | 20 | 20 | 20 | 20 | 19 |
| | Wilton 33 kV[33] | 110 | 46 | 48 | 48 | 48 | 47 | 47 | 47 | 46 | 46 | 46 | 45 |
| | Kaiwharawhara 11 kV | 38 | 27 | 27 | 26 | 26 | 25 | 25 | 25 | 24 | 24 | 24 | 23 |
| Northwestern | Pauatahanui 33 kV | 24 | 19 | 20 | 20 | 20 | 20 | 20 | 20 | 21 | 21 | 21 | 21 |
| | Takapu Road 33 kV | 116 | 94 | 97 | 99 | 100 | 101 | 102 | 103 | 104 | 105 | 106 | 107 |
| Northeastern | Gracefield 33 kV | 80 | 60 | 62 | 62 | 62 | 62 | 63 | 63 | 64 | 64 | 65 | 65 |
| | Haywards 33 kV | 24 | 19 | 22 | 22 | 23 | 23 | 24 | 24 | 25 | 25 | 26 | 27 |
| | Melling 33 kV | 65 | 33 | 34 | 34 | 34 | 34 | 34 | 34 | 35 | 35 | 35 | 35 |
| | Upper Hutt 33 kV | 53 | 31 | 33 | 33 | 34 | 34 | 34 | 35 | 35 | 35 | 36 | 36 |
| | Haywards 11 kV | 30 | 18 | 18 | 19 | 19 | 19 | 20 | 20 | 20 | 20 | 21 | 21 |
| | Melling 11 kV | 34 | 24 | 24 | 24 | 24 | 24 | 24 | 24 | 23 | 23 | 23 | 23 |

**Table 9-8 GXP Level Forecast**

[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.

[33] Meridian's 60 MW Mill Creek wind farm generates into WELL's 33 kV network at Wilton. These maximum demand figures for Wilton assume that Mill Creek is not generating during peak periods.

| Area | Zone Substation | Winter N-1 Capacity | Actual and Forecast Peak Demand (MVA) | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | | | 2024 Actual | 2025 | 2026 | 2027 | 2028 | 2029 | 2030 | 2031 | 2032 | 2033 | 2034 |
| Southern | 8 Ira Street | 20 | 15.1 | 15.8 | 16.3 | 16.5 | 16.5 | 16.5 | 16.6 | 16.6 | 16.7 | 16.8 | 16.9 |
| Southern | Evans Bay | 24 | 13.1 | 13.2 | 13.2 | 13.2 | 13.3 | 13.3 | 13.4 | 13.5 | 13.6 | 13.7 | 13.9 |
| Southern | Frederick Street | 30 | 24.8 | 24.9 | 24.4 | 24.6 | 24.7 | 24.3 | 23.9 | 23.6 | 23.3 | 23.0 | 22.8 |
| Southern | Hataitai | 21 | 15.2 | 15.4 | 15.3 | 15.2 | 15.1 | 15.1 | 15.0 | 14.9 | 14.9 | 14.9 | 14.8 |
| Southern | Palm Grove | 23 | 22.8 | 23.0 | 22.8 | 22.5 | 22.3 | 22.2 | 22.0 | 21.9 | 21.8 | 21.7 | 21.7 |
| Southern | Terrace | 30 | 20.1 | 20.6 | 20.1 | 19.6 | 19.2 | 18.8 | 18.4 | 18.1 | 17.8 | 17.5 | 17.3 |
| Southern | University | 20 | 16.3 | 17.2 | 16.8 | 16.4 | 16.1 | 15.7 | 15.4 | 15.1 | 14.8 | 14.6 | 14.3 |
| Southern | Nairn Street | 22 | 19.2 | 19.8 | 20.3 | 20.0 | 19.7 | 19.5 | 19.2 | 19.0 | 18.8 | 18.6 | 18.5 |
| Southern | Karori | 20 | 13.5 | 14.3 | 14.3 | 14.2 | 14.1 | 14.1 | 14.0 | 14.0 | 14.0 | 14.0 | 14.0 |
| Southern | Moore Street | 30 | 17.5 | 18.1 | 18.2 | 18.5 | 18.2 | 17.8 | 17.5 | 17.2 | 16.9 | 16.7 | 16.4 |
| Southern | Waikowhai Street | 15 | 13.0 | 12.9 | 12.8 | 12.8 | 12.8 | 12.7 | 12.7 | 12.7 | 12.7 | 12.7 | 12.7 |
| Northwestern | Mana | 7 | 10.8 | 10.9 | 10.9 | 10.9 | 11.0 | 11.0 | 11.1 | 11.1 | 11.2 | 11.3 | 11.4 |
| Northwestern | Plimmerton | 7 | 5.8 | 5.9 | 5.9 | 6.0 | 6.1 | 6.2 | 6.3 | 6.4 | 6.5 | 6.6 | 6.8 |
| Northwestern | Johnsonville | 16 | 19.9 | 19.9 | 19.9 | 20.0 | 20.0 | 20.1 | 20.1 | 20.2 | 20.4 | 20.5 | 20.7 |
| Northwestern | Kenepuru | 18 | 10.2 | 11.7 | 11.5 | 11.4 | 11.3 | 11.3 | 11.2 | 11.1 | 11.1 | 11.1 | 11.0 |
| Northwestern | Ngauranga | 10 | 10.4 | 11.0 | 11.0 | 11.1 | 11.1 | 11.1 | 11.2 | 11.2 | 11.3 | 11.4 | 11.5 |
| Northwestern | Porirua | 20 | 21.0 | 21.5 | 22.2 | 22.8 | 23.5 | 24.2 | 25.0 | 25.7 | 26.0 | 26.2 | 26.5 |
| Northwestern | Tawa | 16 | 13.8 | 14.1 | 14.3 | 14.5 | 14.5 | 14.5 | 14.6 | 14.6 | 14.7 | 14.8 | 14.9 |
| Northwestern | Waitangirua | 16 | 14.0 | 14.5 | 15.2 | 15.4 | 15.6 | 15.8 | 16.1 | 16.4 | 16.7 | 17.0 | 17.3 |
| Northeastern | Gracefield | 23 | 9.8 | 10.7 | 10.7 | 10.8 | 10.8 | 10.9 | 11.0 | 11.2 | 11.3 | 11.4 | 11.6 |
| Northeastern | Korokoro | 16 | 17.3 | 17.4 | 17.3 | 17.3 | 17.2 | 17.2 | 17.2 | 17.2 | 17.2 | 17.2 | 17.2 |
| Northeastern | Seaview | 14 | 14.1 | 14.2 | 14.1 | 14.1 | 14.0 | 14.0 | 14.0 | 14.0 | 14.0 | 14.0 | 14.0 |
| Northeastern | Wainuiomata | 20 | 17.0 | 17.3 | 17.5 | 17.6 | 17.9 | 18.5 | 18.7 | 19.0 | 19.2 | 19.5 | 19.8 |
| Northeastern | Trentham | 19 | 15.4 | 17.4 | 18.0 | 18.4 | 18.7 | 19.1 | 19.5 | 20.0 | 20.4 | 20.9 | 21.4 |
| Northeastern | Naenae | 18 | 14.0 | 14.6 | 14.6 | 14.7 | 14.7 | 14.8 | 14.9 | 15.0 | 15.1 | 15.2 | 15.3 |
| Northeastern | Waterloo | 20 | 15.5 | 15.6 | 15.6 | 15.6 | 15.6 | 15.6 | 15.7 | 15.7 | 15.8 | 15.9 | 16.0 |
| Northeastern | Brown Owl | 18 | 15.3 | 15.5 | 15.7 | 16.1 | 16.5 | 16.7 | 16.9 | 17.0 | 17.2 | 17.4 | 17.6 |
| Northeastern | Maidstone | 18 | 13.5 | 14.6 | 14.7 | 14.7 | 14.7 | 14.8 | 14.9 | 14.9 | 15.0 | 15.1 | 15.3 |

Table 9-9 Zone Substation Level Forecast

## 9.3 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 is largely electrically independent and has 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;
- Subtransmission development needs;
- HV distribution network development needs; and
- A summary of the network development plan.

The total expenditure profile from these plans is summarised in Section 9.8.

## 9.4 Southern Area NDRP

This section provides a summary of the Southern Area NDRP.

### 9.4.1 GXP Development Plans

The Southern network is supplied from four GXP points at three locations, Central Park, Wilton and Kaiwharawhara. Transpower owns the supply transformers at the GXPs. The transformer capacity and the peak system demand are set out in Table 9-9. The forecast in Table 9-9 considers only committed developments.

| GXP | Continuous Capacity (MVA) | Cyclic Summer / Winter Capacity (MVA) | Peak Demand (MVA) | |
|---|---|---|---|---|
| | | | 2024 | 2034 |
| Central Park 33 kV | 2x100<br>1x120 | 2 x 108/112<br>1 x 146/147 | 155 | 148 |
| Central Park 11 kV | 2x25 | 29/30 | 20 | 19 |
| Wilton 33 kV[34] | 2x100 | 103/110 | 46 | 45 |
| Kaiwharawhara 11 kV | 2x30 | 38/38 | 27 | 23 |

Table 9-10 Southern Area GXP Capacities

The development needs at each GXP are discussed below.

#### 9.4.1.1 Central Park GXP

The peak demand on the Central Park GXP in 2024 was 154.9 MVA.

The Central Park 33 kV bus is normally operated closed and supplies eight zone substations via double 33 kV subtransmission circuits, and two 33/11 kV transformers. 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 33 kV bus sections to provide N-1 security.

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 12.

[34] Wilton 33 kV peak demand excluding injection from Mill Creek generation.

### 9.4.1.2 Wilton GXP

The peak demand on the Wilton GXP in 2024 excluding injection from the Mill Creek wind farm was 46.2 MVA. Wilton supplies zone substations at Karori, Moore Street, and 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 is terminated to an individual bus section.

Transpower has 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.

### 9.4.1.3 Kaiwharawhara GXP

The peak demand on the Kaiwharawhara GXP in 2024 was 26.7 MVA. The Kaiwharawhara GXP supplies the Kaiwharawhara zone substation directly from the 110/11 kV transformer LV circuit breakers.

Based on the estimated growth scenarios and potential step change growth accounted for within the planning period, the load at Kaiwharawhara is forecast to change as shown in Figure 9-9. The subtransmission capacity constraints are plotted for comparison.

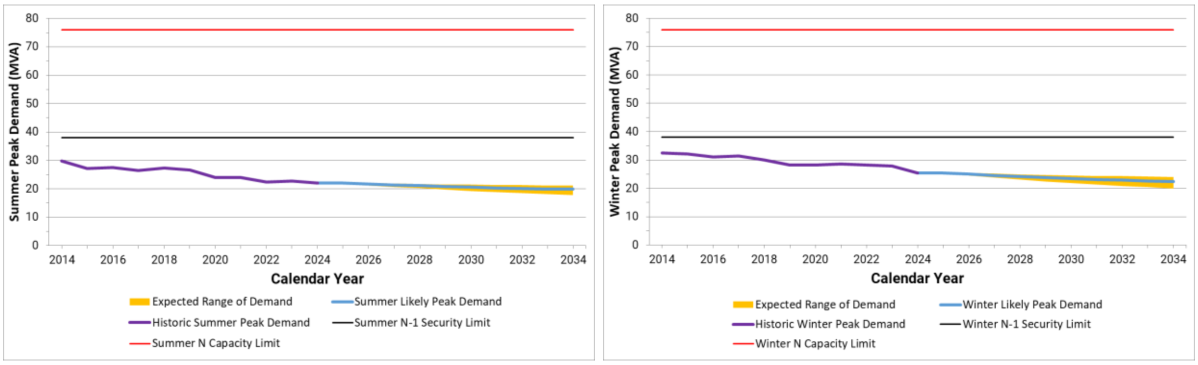



**Figure 9-9 Kaiwharawhara Demand Forecast**

## 9.4.2 Subtransmission Network Development Needs

This section describes the identified security of supply constraints and development needs for the Southern Area subtransmission network.

Many zone substations in the Southern Area have flat or declining trends in their maximum demand. The reasons for this include a series of milder winters, increased energy efficiency of commercial buildings, working from home, business closures due to economic conditions, and the Wellington city population having declined since 2020. There is currently no evidence of this trend of declining maximum demand reversing, and as such WELL's demand forecast has taken this as the underlying trend upon which the decarbonisation forecasts and future step changes are then added to.

A supply capacity and demand overview of each zone substation is listed in Table 9-11. The Evans Bay 33kV Bus represents the aggregate load and Installation Control Points (ICPs) of the 8 Ira Street and Evans Bay Zone Substations.

| Zone Substation | Season | Subtransmission N-1 branch rating (MVA) | Constraining Branch | Peak Demand C1 (MVA) | | ICP Count as at 2024 |
|---|---|---|---|---|---|---|
| | | | | 2024 | 2034 | |
| Palm Grove | Winter | 20.0 | Transformer | 22.8 | 21.7 | 10,451 |
| | Summer | 20.0 | Transformer | 16.6 | 17.2 | |
| 8 Ira Street | Winter | 20.0 | Transformer | 15.1 | 16.9 | 4,897 |
| | Summer | 15.0 | 33kV Cables | 12.1 | 13.9 | |
| Frederick Street | Winter | 30.0 | Transformer | 24.8 | 22.8 | 7,363 |
| | Summer | 30.0 | Transformer | 20.4 | 20.7 | |
| Karori | Winter | 20.0 | 33kV Cables | 13.5 | 14.0 | 6,198 |
| | Summer | 15.0 | 33kV Cables | 9.4 | 11.7 | |
| Moore Street | Winter | 30.0 | Transformer | 17.5 | 16.4 | 869 |
| | Summer | 30.0 | Transformer | 18.9 | 16.3 | |
| Nairn Street | Winter | 22.0 | 11kV Incomer | 19.2 | 18.5 | 7,597 |
| | Summer | 22.0 | 11kV Incomer | 14.4 | 14.1 | |
| University | Winter | 20.0 | Transformer | 16.3 | 14.3 | 6,034 |
| | Summer | 20.0 | Transformer | 12.6 | 11.6 | |
| Waikowhai Street | Winter | 15.0 | Transformer | 13.0 | 12.7 | 5,804 |
| | Summer | 15.0 | Transformer | 8.7 | 9.1 | |
| Evans Bay | Winter | 24.0 | Transformer | 13.1 | 13.9 | 4,688 |
| | Summer | 24.0 | Transformer | 9.4 | 9.8 | |
| Hataitai | Winter | 21.0 | 33kV Cables | 15.2 | 14.8 | 7,178 |
| | Summer | 15.0 | 33kV Cables | 10.3 | 10.0 | |
| The Terrace | Winter | 30.0 | Transformer | 20.1 | 17.5 | 1,765 |
| | Summer | 30.0 | Transformer | 19.6 | 15.3 | |
| Evans Bay 33kV Bus | Winter | 37.0 | 33kV Cables | 27.4 | 29.9 | 9,585 |
| | Summer | 29.7 | 33kV Cables | 20.3 | 17.1 | |

**Table 9-11 Southern Area Zone Substation Capacities**

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 branch rating (MCBR).[35]

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 onto 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, with a continuous rating in the range of 20-30 MVA, fitted with oil circulation pumps and cooling fans if necessary to provide a higher cyclic rating; and

[35] Maximum continuous branch rating (MCBR) vs cyclic capacity: MCBR is used for capacity planning, and cyclic rating (for a specified limited duration) is used for operations to cover short-term peak loading and contingencies.

- 11 kV cabling from the 11 kV bushings of the transformers to the switchboard incomers, 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 the duration of potential overload assessed against the security criteria using a load duration curve. Forecast 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.

#### 9.4.2.1 8 Ira Street

The peak load supplied by 8 Ira Street is currently within the N-1 capacity of the subtransmission circuits. Table 9-12 shows the seasonal constraint levels and the minimum offload requirements.

| Circuit | Season | Constraining N-1 branch rating (MVA) | Peak Demand @ 2024 (MVA) | Minimum offload for N-1 @ 2024 peak (MVA) |
|---|---|---|---|---|
| 8 Ira Street | Winter | 20.0 | 15.1 | 0.0 |
| | Summer | 15.0 | 12.1 | 0.0 |

Table 9-12 Current 8 Ira Street Subtransmission Constraints

Based on the estimated growth scenarios and step change growth accounted for within the planning period, the load at 8 Ira Street is forecast to change as shown in Figure 9-10. The subtransmission capacity constraints are plotted for comparison.

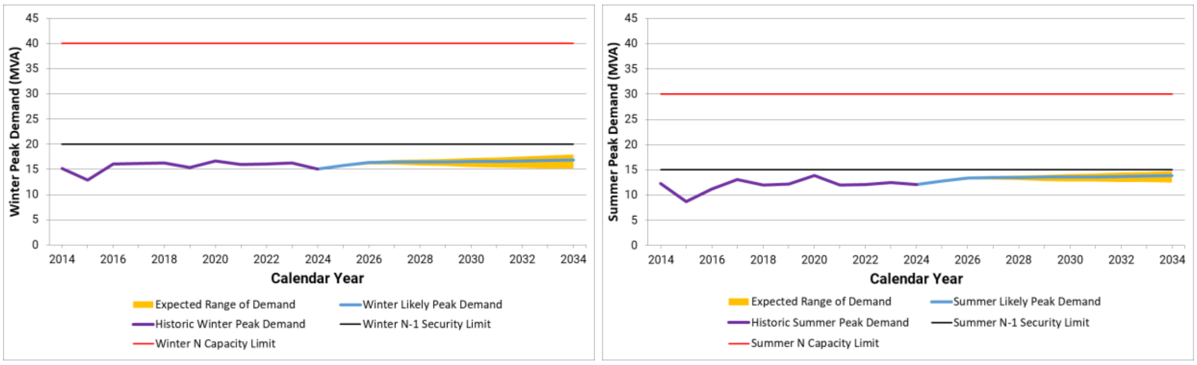



Figure 9-10 8 Ira Street Demand Forecast

The 8 Ira Street peak demand has been stable since 2016 and is forecast to remain within the summer and winter subtransmission N-1 capacity for the duration of this plan. The following works are proposed at the site:

- Replacement of the 11 kV switchgear at Ira Street, which has been necessary in order to create additional feeders to support a major customer project at Moa Point, currently underway. This is discussed further in Section 13.6.

- Replacement of the gas-filled cables from Evans Bay to 8 Ira Street, proposed for 2031.

This stepwise approach to increasing the capacity at 8 Ira Street is preferred over the alternative options of offloading demand to Evans Bay or building a new zone substation, as it allows expenditure on capacity increases to be phased to match any demand growth as it is realised.

### 9.4.2.2 Evans Bay

The peak demand supplied from Evans Bay is currently within the N-1 capacity of the subtransmission circuits. Table 9-13 shows the seasonal constraint levels and the minimum offload requirements on each circuit.

| Circuit | Season | Constraining N-1 branch rating (MVA) | Peak Demand @2024(MVA) | Minimum offload for N-1 @ 2024 peak (MVA) |
|---|---|---|---|---|
| Evans Bay | Winter | 24.0 | 13.1 | 0.0 |
| | Summer | 24.0 | 9.4 | 0.0 |

Table 9-13 Current Evans Bay Subtransmission Constraints

Based on the estimated growth scenarios and step change growth accounted for within the planning period, the load at Evans Bay is forecast to change as shown in Figure 9-10. The subtransmission capacity constraints are plotted for comparison.

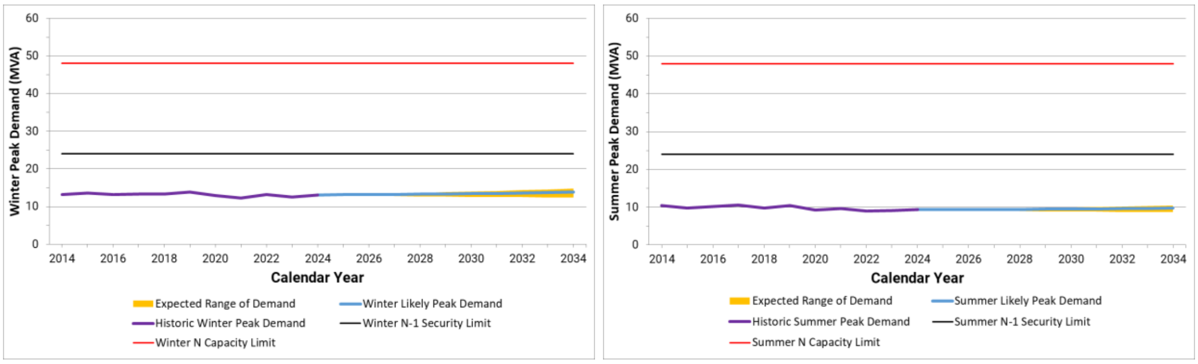



Figure 9-11 Evans Bay Demand Forecast

The Evans Bay peak demand has been stable since 2014 and is forecast to remain within the summer and winter subtransmission N-1 capacity for the duration of this plan.

### 9.4.2.3 Frederick Street

The peak demand supplied by Frederick Street is currently within the N-1 capacity of the subtransmission circuits. Table 9-14 shows the seasonal constraint levels and the minimum offload requirements on each circuit.

| Circuit | Season | Constraining N-1 branch rating (MVA) | Peak Demand @ 2024 (MVA) | Minimum offload for N-1 @ 2024 peak (MVA) |
|---|---|---|---|---|
| Frederick Street | Winter | 30.0 | 24.8 | 0.0 |
| | Summer | 30.0 | 20.4 | 0.0 |

Table 9-14 Current Frederick Street Subtransmission Constraints

Based on the estimated growth scenarios and step change growth accounted for within the planning period, the load at Frederick Street is forecast to change as shown in Figure 9-12. The subtransmission capacity constraints are plotted for comparison.

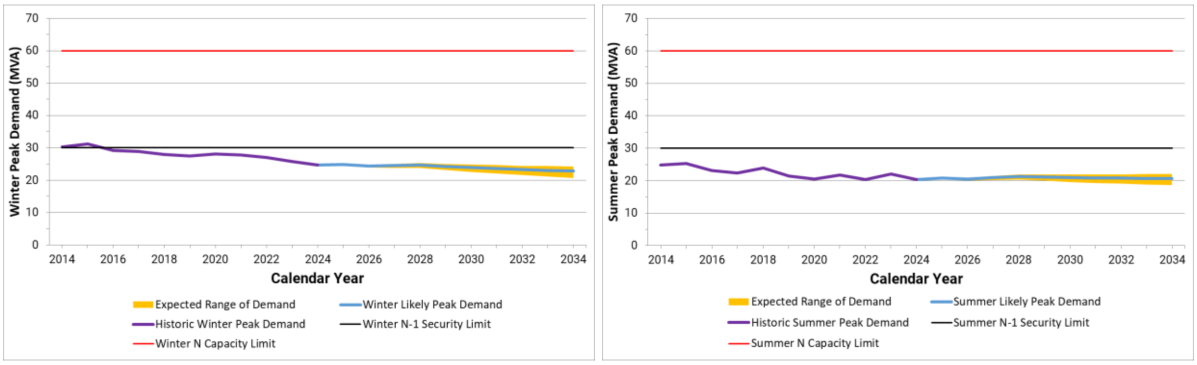



Figure 9-12 Frederick Street Demand Forecast

The Frederick Street peak demand has declined since 2015 and is forecast to remain within the summer and winter subtransmission N-1 capacity for the duration of this plan.

### 9.4.2.4 Hataitai

The peak demand supplied from Hataitai is currently within the N-1 capacity of the subtransmission circuits. Table 9-15 shows the seasonal constraint levels and the minimum offload requirements on each circuit.

| Circuit | Season | Constraining N-1 branch rating (MVA) | Peak Demand @ 2024 (MVA) | Minimum offload for N-1 @ 2024 peak (MVA) |
|---|---|---|---|---|
| Hataitai | Winter | 21.0 | 15.2 | 0.0 |
| | Summer | 15.0 | 10.3 | 0.0 |

Table 9-15 Current Hataitai Subtransmission Constraints

Based on the estimated growth scenarios and step change growth accounted for within the planning period, the load at Hataitai is forecast to change as shown in Figure 9-13. The subtransmission capacity constraints are plotted for comparison.


Figure 9-13 Hataitai Demand Forecast

The Hataitai peak demand has been stable since 2014 and is forecast to remain within the winter and summer subtransmission N-1 capacity for the duration of this plan.

### 9.4.2.5 Karori

The peak demand supplied from Karori is currently within the N-1 capacity of the subtransmission circuits. Table 9-16 shows the seasonal constraint levels and the minimum offload requirements on each circuit.

| Circuit | Season | Constraining N-1 branch rating (MVA) | Peak Demand @ 2024 (MVA) | Minimum offload for N-1 @ 2024 peak (MVA) |
|---|---|---|---|---|
| Karori | Winter | 20.0 | 13.5 | 0.0 |
| | Summer | 15.0 | 9.4 | 0.0 |

Table 9-16 Current Karori Subtransmission Constraints

Based on the estimated growth scenarios and step change growth accounted for within the planning period, the load at Karori is forecast to change as shown in Figure 9-14. The subtransmission capacity constraints are plotted for comparison.

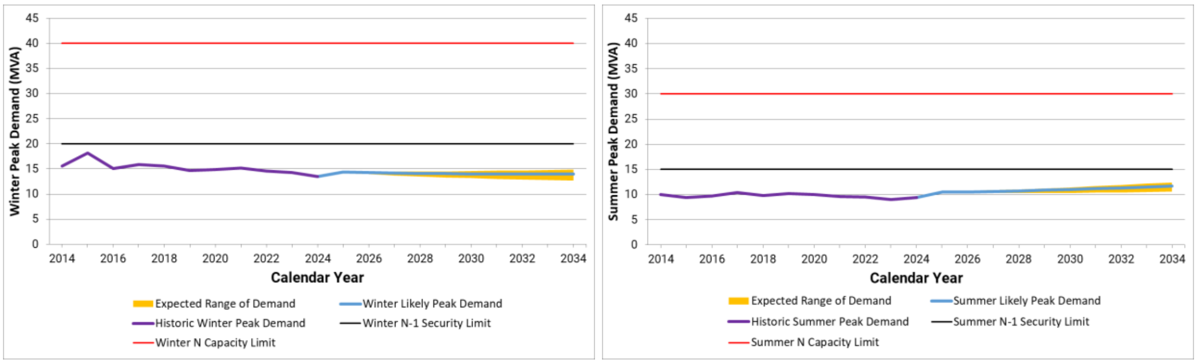



Figure 9-14 Karori Demand Forecast

The Karori peak demand has been stable since 2016 and is forecast to remain within the winter and summer subtransmission N-1 capacity for the duration of this plan.

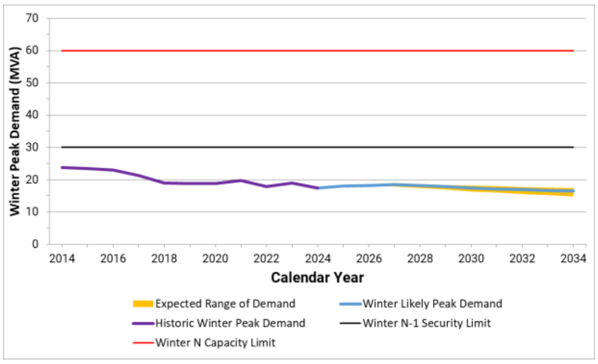
### 9.4.2.6 Moore Street

The peak demand supplied from Moore Street is currently within the N-1 capacity of the subtransmission circuits. Table 9-17 shows the seasonal constraint levels and the minimum offload requirements on each circuit.

| Circuit | Season | Constraining N-1 branch rating (MVA) | Peak Demand @ 2024 (MVA) | Minimum offload for N-1 @ 2024 peak (MVA) |
|---|---|---|---|---|
| Moore Street | Winter | 30.0 | 17.5 | 0.0 |
| | Summer | 30.0 | 18.9 | 0.0 |

Table 9-17 Current Moore Street Subtransmission Constraints

Based on the estimated growth scenarios and step change growth accounted for within the planning period, the load at Moore Street is forecast to change as shown in Figure 9-15. The subtransmission capacity constraints are plotted for comparison.



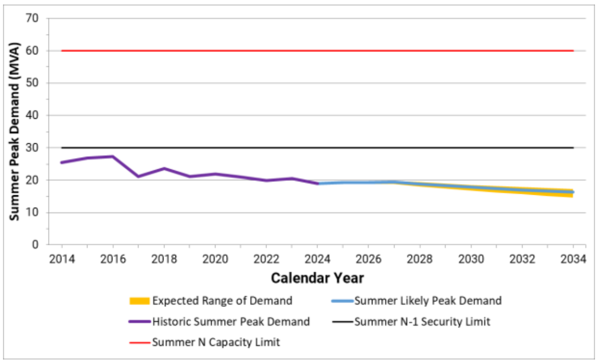




Figure 9-15 Moore Street Demand Forecast

The Moore Street peak demand has declined since 2016, and is forecast to remain within the winter and summer subtransmission N-1 capacity for the duration of this plan.

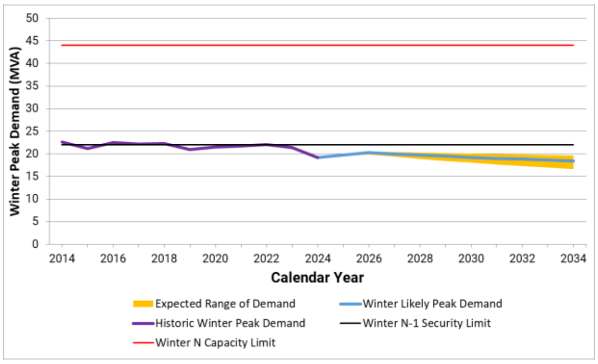
### 9.4.2.7 Nairn Street

The peak demand supplied from Nairn Street currently exceeds the N-1 rating of the 11 kV incomer cables. Table 9-18 shows the seasonal constraint levels and the minimum offload requirements on each circuit.

| Circuit | Season | Constraining N-1 branch rating (MVA) | Peak Demand @ 2024 (MVA) | Minimum offload for N-1 @ 2024 peak (MVA) |
|---|---|---|---|---|
| Nairn Street | Winter | 22.0 | 19.2 | 0.0 |
| | Summer | 22.0 | 14.4 | 0.0 |

Table 9-18 Current Nairn Street Subtransmission Constraints

Based on the estimated growth scenarios and step change growth accounted for within the planning period, the load at Nairn Street is forecast to change as shown in Figure 9-16. The subtransmission capacity constraints are plotted for comparison.



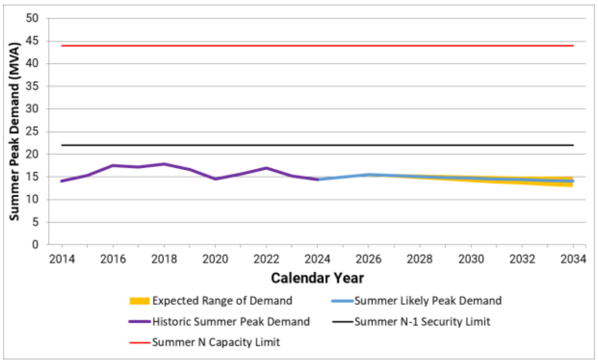




Figure 9-16 Nairn Street Demand Forecast

The Nairn Street peak demand has been stable since 2014 and is forecast to remain within the winter and summer subtransmission N-1 capacity for the duration of this plan.

### 9.4.2.8 Palm Grove

The winter peak demand at Palm Grove currently exceeds the N-1 capacity of the transformers as shown in Table 9-19.

| Circuit | Season | Constraining N-1 branch rating (MVA) | Peak Demand @ 2024 (MVA) | Minimum offload for N-1 @ 2024 peak (MVA) |
|---|---|---|---|---|
| Palm Grove | Winter | 20.0 | 22.8 | 2.8 |
| | Summer | 20.0 | 16.6 | 0.0 |

Table 9-19 Current Palm Grove Subtransmission Constraints

Based on the growth scenarios and the development accounted for within the planning period, the load at Palm Grove is forecast to grow as shown in Figure 9-17.

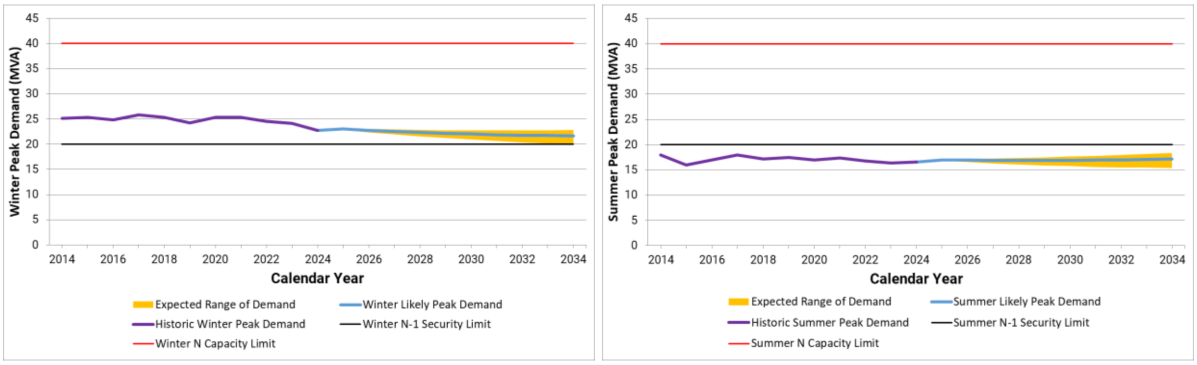



Figure 9-17 Palm Grove Demand Forecast

The Palm Grove peak demand is presently above the winter subtransmission N-1 capacity, however winter demand at the substation has been flat or declining for the last 10 years. This security constraint is currently managed through post-contingent offloads through the 11 kV network to adjacent zone substations.

A major customer development has been proposed in the Newtown area, of a size that would require the construction of a new zone substation. This would transfer significant load away from Palm Grove, resolving the security constraint. This customer decarbonisation project has not progressed beyond early discussions between WELL and the customer, and it is not clear yet whether the project will proceed, and to what timeframe. The declining trend in maximum demand and the availability of 11 kV transfer capacity enables WELL to wait until the customer's situation is resolved before deciding whether it will be necessary to invest in additional capacity at Palm Grove.

If this customer project is not able to procced, the alternative option would be to upgrade the 33/11 kV transformers at Palm Grove. WELL will determine which option to pursue once the customer is able to provide clarity on their intentions.

#### 9.4.2.9 The Terrace

The peak demand at The Terrace is currently within the N-1 capacity of the subtransmission circuits as shown in Table 9-20.

| Circuit | Season | Constraining N-1 branch rating (MVA) | Peak Demand @ 2024 (MVA) | Minimum offload for N-1 @ 2024 peak (MVA) |
|---|---|---|---|---|
| The Terrace | Winter | 30.0 | 20.1 | 0.0 |
| | Summer | 30.0 | 19.6 | 0.0 |

Table 9-20 Current The Terrace Subtransmission Constraints

Based on the estimated growth scenarios and step change growth accounted for within the planning period, the load at The Terrace is forecast to change as shown in Figure 9-18. The subtransmission capacity constraints are plotted for comparison.

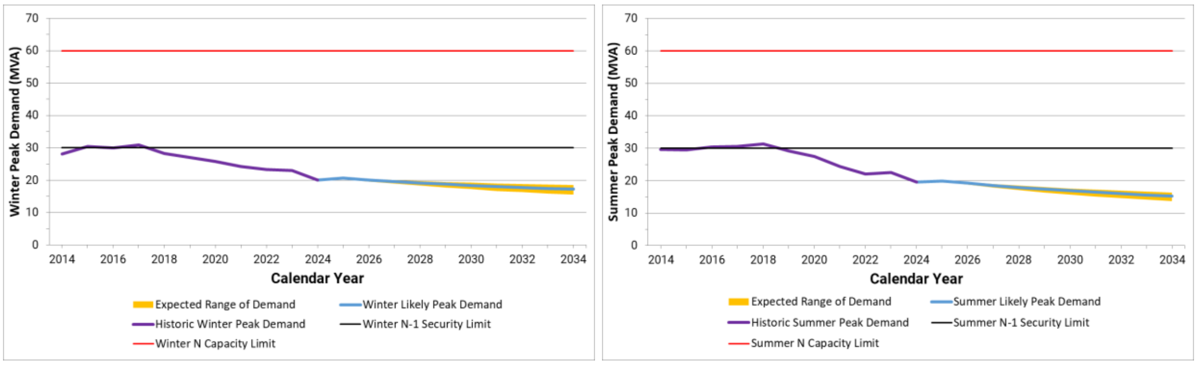



**Figure 9-18 The Terrace Demand Forecast**

The Terrace peak demand has declined significantly since 2018, and is forecast to remain within the winter and summer subtransmission N-1 capacity for the duration of this Plan.

### 9.4.2.10 University

The peak demand supplied from University is currently within the N-1 capacity of the subtransmission circuits. Table 9-21 shows the seasonal constraint levels and the minimum offload requirements on each circuit.

| Circuit | Season | Constraining N-1 branch rating (MVA) | Peak Demand @ 2024 (MVA) | Minimum offload for N-1 @ 2024 peak (MVA) |
|---|---|---|---|---|
| University | Winter | 20.0 | 16.3 | 0.0 |
| | Summer | 20.0 | 12.6 | 0.0 |

**Table 9-21 Current University Subtransmission Constraints**

Based on the estimated growth scenarios and step change growth accounted for within the planning period, the load at University is forecast to change as shown in Figure 9-19. The subtransmission capacity constraints are plotted for comparison.

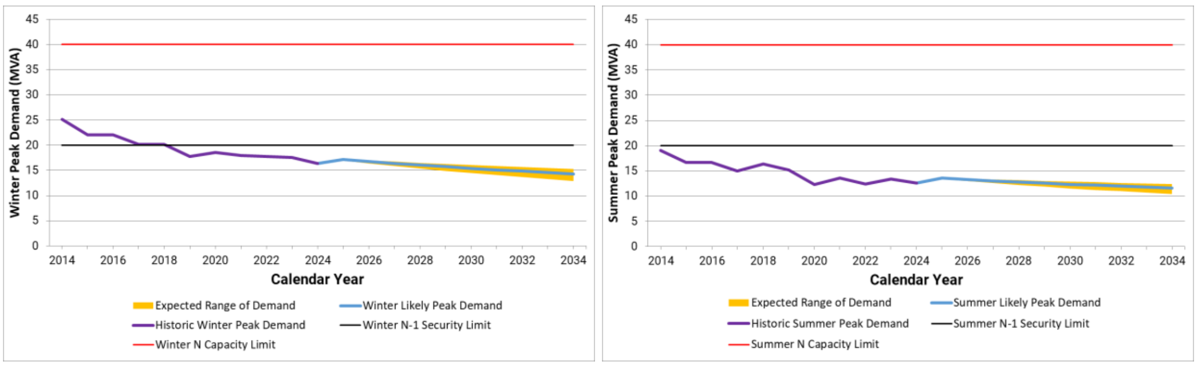



**Figure 9-19 University Demand Forecast**

The University peak demand has declined significantly since 2014, and is forecast to remain within the winter and summer subtransmission N-1 capacity for the duration of this Plan.

### 9.4.2.11 Waikowhai Street

The peak demand supplied from Waikowhai Street is currently within the N-1 capacity of the subtransmission circuits. Table 9-22 shows the seasonal constraint levels and the minimum offload requirements on each circuit.

| Circuit | Season | Constraining N-1 branch rating (MVA) | Peak Demand @ 2024 (MVA) | Minimum offload for N-1 @ 2024 peak (MVA) |
|---|---|---|---|---|
| Waikowhai Street | Winter | 15.0 | 13.0 | 0.0 |
| | Summer | 15.0 | 8.7 | 0.0 |

**Table 9-22 Current Waikowhai Street Subtransmission Constraints**

Based on the estimated growth scenarios and step change growth accounted for within the planning period, the load at Waikowhai Street is forecast to change as shown in Figure 9-20. The subtransmission capacity constraints are plotted for comparison.

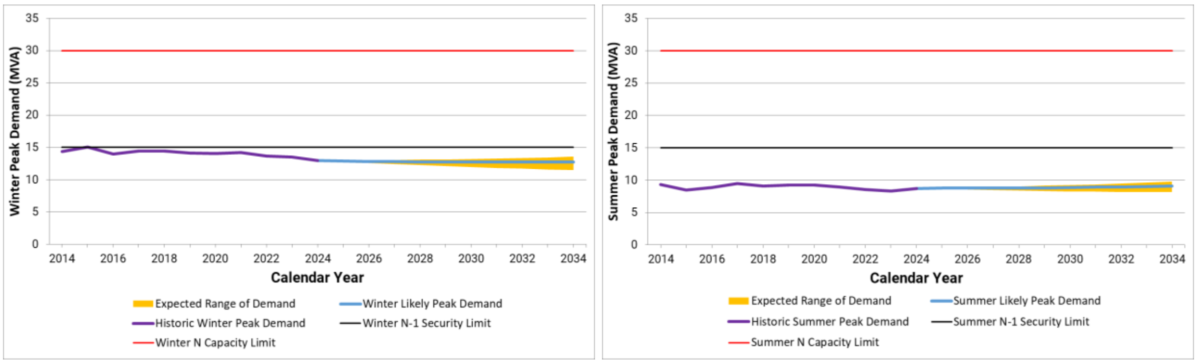



**Figure 9-20 Waikowhai Street Demand Forecast**

The Waikowhai Street peak demand has been stable since 2014 and is forecast to remain within the winter and summer subtransmission N-1 capacity for the duration of this Plan.

### 9.4.3 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 interdependencies and their effect on the Wellington CBD network as a whole.

Each zone substation supplies the respective 11 kV distribution network, with most zone substations having interconnectivity 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.

Existing constraints are currently managed operationally by offloading customers to adjacent 11 kV feeders should an outage occur. Longer term, these constraints will be solved with targeted upgrades. Other feeders have reinforcement projects proposed, which are listed in Section 9.4.4.2.

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 worst-case because in most scenarios an isolated 11kV feeder section will also disconnect 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.

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 outcomes and impacts of these possible future step-change demands are uncertain, difficult to estimate, and have not been included in the assessment above. WELL is aware some step 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.

Projects to resolve existing distribution-level constraints are summarised in Section 9.4.4.3.

### 9.4.4 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.

#### 9.4.4.1 Non-network Solutions

Prior to any investment in any infrastructure being considered, the first step is to evaluate non-network solutions, discussed in Section 9.1.10, to defer investment.

#### 9.4.4.2 Major Projects for 2025/26

Table 9-23 lists major projects currently underway or planned to start over the next 12 months.

| Project | Description |
|---|---|
| Ira Street Switchboard | Replacement of 11 kV switchboard at 8 Ira Street to allow the connection of a major customer project at Moa Point. |
| Moa Point | Reinforcement of 11 kV network from 8 Ira Street to Moa Point and Wellington International Airport to allow the connection of a major customer project at Moa Point. |

Table 9-23 Southern Area Projects for 2025/26

The Ira Street Switchboard and Moa Point projects have been triggered by the capacity requirements of a major customer project operating to an urgent timeframe. The required work is not provided for in WELL's capital expenditure allowances for DPP4, and WELL therefore intends to apply to the Commission to reopen its DPP4 price path, however the urgency of the customer's need and the importance for the region of the customer's project has required WELL to commence investment ahead of that reopener being able to be submitted. This is discussed further in Section 13.6

#### 9.4.4.3 Development Plan Summary

A summary of the development plan for this area is listed in Table 9-24. This represents the preferred solutions for constraints that are either existing or are likely to occur. It excludes reinforcement to resolve constraints that would be triggered by potential major customer-initiated projects that have not yet been contracted for delivery. System Growth expenditure that is conditional on customer work is summarised in Section 13.6.

Detailed project planning and option engineering will be completed at the project scope development and approval stage.

| Project | Description | Constraint Relieved | Target Completion | Investment |
|---|---|---|---|---|
| **Subtransmission Constraints** | | | | |
| Ira Street Switchboard | Replace 8 Ira Street 11kV Switchboard | Ira Street 11kV feeder capacity supporting customer projects. | 2026 | $5.3M |
| Hataitai 33kV Bus | Install 33kV Bus at Hataitai, cut in Hatatai and Evans Bay cables | Evans Bay and Hataitai 33kV cables health and criticality | 2030 | $9.8M |
| Hataitai-Evans Bay 33kV Cable Upgrade | Run new 33kV cables from proposed Hataitai 33kV Bus to Evans Bay 33kV Bus | Evans Bay 33kV cable health and criticality | 2030 | $9.5M |
| Ira Street 33kV Cables | Replace Ira Street 33kV gas cables | Ira Street 33kV cable health and criticality | 2031 | $11.5M |
| Hataitai 33kV Cables | Replace 33kV gas-filled cables from Central Park to Hataitai | Hataitai 33kV cables health and criticality | 2032 | $18.3M |
| University-Karori Resilience Project | Reinforce existing 11kV ties between University and Karori. | Karori 33kV cables health and criticality | 2032 | $8.6M |
| **Distribution Constraints** | | | | |
| Abattoirs 11kV feeder | Upgrade short section of cable on Kaiwharawhara 6/7/9/10 | Kaiwharawhara 6/7/9/10 | 2026 | $0.8M |
| Ira Street Eastern 11kV Cable | Reinforce the 11kV network between 8 Ira Street, Moa Point and the Airport | Ira Street 8/9, Ira Street 6 | 2026 | $4.3M |
| Moa Point | Upgrade Moa Point switchboard. | Ira Street 8/9 | 2026 | $8.4M |
| Northern Miramar 11kV Reinforcement | Run new feeder from Ira St to Devonshire Rd | Ira Street 11, Evans Bay 2/4 | 2027 | $1.6M |
| Karori West 11kV Reinforcement | New sub-feeder from 9 Parkvale Road to near Burrows Ave | Karori 3/6 | 2027 | $2.8M |
| Ira Street Western 11kV Cable | Reinforce the 11kV network between Evans Bay, Moa Point and the Airport | Ira Street 8/9, Evans Bay 8 | 2028 | $15.8M |
| Frederick Street 3/4/5/8 11kV Reinforcement | Run new cables to 176 Wakefield Street. | Frederick Street 3/4/5/6 | 2028 | $6.9M |
| Frederick Street 13/14 11kV Reinforcement | Run new feeder to Mein Street | Frederick Street 13/14 | 2029 | $5.5M |

Table 9-24 Southern Area Development Summary

## 9.5 Northwestern Area NDRP

This section provides a summary of the Northwestern Area NDRP.

### 9.5.1 GXP Development Plans

The Northwestern Area is supplied from two GXPs, Takapu Road and Pauatahanui. Transpower owns the supply transformers at the GXPs. The transformer capacity and the peak system demand are set out in Table 9-25. The forecast in Table 9-25 considers only committed developments.

| GXP | Continuous Capacity (MVA) | Transformer Cyclic Summer / Winter Capacity (MVA) | Peak Demand (MVA) | |
|---|---|---|---|---|
| | | | 2024 | 2034 |
| Takapu Road 33 kV | 2x90 | 111/116 | 94 | 107 |
| Pauatahanui 33 kV | 2x20 | 22/24 | 19 | 21 |

Table 9-25 Northwestern Area GXP Capacities

The investment needs identified at Transpower GXPs have been detailed in Transpower's Transmission Planning Report. The development needs at each GXP are discussed further below.

#### 9.5.1.1 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 2024 was 93.7 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-rated double-circuit tower line. The line is owned and maintained by Transpower.

#### 9.5.1.2 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 maximum demand on the Pauatahanui GXP in 2024 was 19.4 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 by a normally-closed 11 kV bus tie cable, 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. WELL is presently working with Transpower regarding options for mitigating the risk posed by flooding at the Pauatahanui site. This project is discussed in Section 12.

### 9.5.2 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 twelve 33 kV subtransmission circuits supplying eight zone substations. Each zone substation supplies the 11 kV distribution network with interconnectivity via switched open points to adjacent zones. All 11 kV feeders are radial from the zone substations except for the meshed ring feeders supplying the Porirua CBD and Titahi Bay substation. The load summary of each zone substation is listed in Table 9-26.

| Zone Substation | Season | Subtransmission N-1 branch rating (MVA) | Constraining Branch | Peak Demand C1 (MVA) | | ICP Count as at 2024 |
|---|---|---|---|---|---|---|
| | | | | 2024 | 2034 | |
| Johnsonville | Winter | 16.0 | 33kV Cables | 19.9 | 20.7 | 9,073 |
| | Summer | 11.6 | 33kV Cables | 13.9 | 15.1 | |
| Ngauranga | Winter | 10.0 | Transformer | 10.4 | 11.5 | 4,565 |
| | Summer | 10.0 | Transformer | 8.1 | 9.7 | |
| Mana | Winter | 7.0 | 11kV Intertie | 10.8 | 11.1 | 4,824 |
| | Summer | 7.0 | 11kV Intertie | 7.2 | 8.1 | |
| Porirua | Winter | 20.0 | Transformer | 21.0 | 26.5 | 4,023 |
| | Summer | 14.3 | 33kV Cables | 15.4 | 18.9 | |
| Plimmerton | Winter | 7.0 | 11kV Intertie | 5.8 | 6.5 | 2,436 |
| | Summer | 7.0 | 11kV Intertie | 4.0 | 4.6 | |
| Kenepuru | Winter | 18.3 | 33kV Cables | 10.2 | 11.0 | 2,324 |
| | Summer | 13.7 | 33kV Cables | 10.7 | 13.4 | |
| Tawa | Winter | 16.0 | Transformer | 13.8 | 14.9 | 5,492 |
| | Summer | 14.6 | 33kV Cables | 10.0 | 11.1 | |
| Waitangirua | Winter | 16.0 | Transformer | 14.0 | 17.3 | 6,231 |
| | Summer | 15.2 | 33kV Cables | 9.6 | 15.0 | |

**Table 9-26 Northwestern Area Zone Substation Capacities**

The development needs for the Northwestern Area at the subtransmission and distribution level are outlined in the following sections.

The Northwestern Area is characterised by a mix of older suburbs that have experienced high levels of infill housing and high-density residential intensification near public transport corridors, and expanding greenfield residential subdivisions in suburbs such as Churton Park, Aotea, and Whitby.

The zone substations that are forecast to be constrained during the planning period are described below.

#### 9.5.2.1 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 9-27 shows the seasonal constraint levels and the minimum offload requirements.

| Zone substation | Season | Subtransmission N-1 Constraining N-1 branch rating (MVA)rating (MVA) | Peak Demand @ 2024 (MVA) | Minimum offload for N-1 @ peak (MVA) |
|---|---|---|---|---|
| Johnsonville | Winter | 16.0 | 19.9 | 3.9 |
| | Summer | 11.5 | 13.9 | 2.4 |

Table 9-27 Current Johnsonville Subtransmission Constraints

Figure 9-21 shows the forecast demand for Johnsonville zone substation based on the estimated growth scenarios and development within the planning period. The subtransmission capacity constraints are plotted for comparison.


Figure 9-21 Johnsonville Demand Forecast

The Johnsonville peak demand presently exceeds the winter and summer subtransmission N-1 capacity, but has been stable since 2017.

WELL intends to transfer some load from Johnsonville to a proposed new zone substation at Grenada, currently planned for 2028. Alternative options to this solution include increasing the capacity at Johnsonville through replacement of the 33 kV cables and transformers, which will ultimately be required for asset health reasons, however the Grenada substation is preferred as an initial step as it offers security benefits to Tawa and Ngauranga zone substations in addition to Johnsonville, and is therefore a cost-effective solution.

### 9.5.2.2 Kenepuru

Maximum demand at Kenepuru is within available N-1 subtransmission capacity. Table 9-28 shows the seasonal constraint levels and the minimum offload requirements.

| Circuit | Season | Constraining N-1 branch rating (MVA) | Peak Demand @ 2024 (MVA) | Minimum offload for N-1 @ peak (MVA) |
|---|---|---|---|---|
| Kenepuru | Winter | 18.3 | 10.2 | 0.0 |
| | Summer | 13.7 | 10.7 | 0.0 |

Table 9-28 Current Kenepuru Subtransmission Constraints

Figure 9-22 shows the forecast demand for Kenepuru zone substation based on the estimated growth scenarios and development within the planning period. The subtransmission capacity constraints are plotted for comparison.

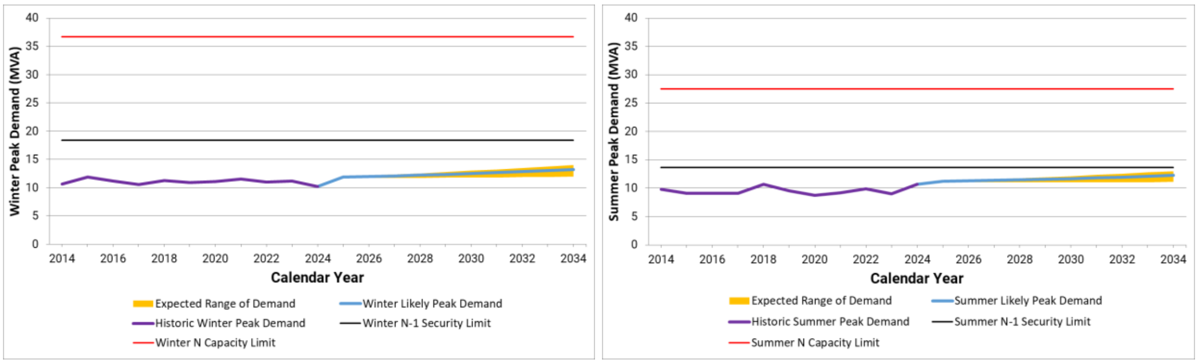



**Figure 9-22 Kenepuru Demand Forecast**

The Kenepuru peak demand has been stable since 2014 and is forecast to remain within the winter and summer subtransmission N-1 capacity for the duration of this Plan.

WELL is currently planning to install a new feeder from Kenepuru into the Elsdon industrial area in order to transfer load away from Porirua zone substation. WELL will continue to monitor the load growth and will investigate options to mitigate system constraints if any future step load growth is confirmed.

### 9.5.2.3 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 9-29 shows the seasonal constraint levels and the minimum offload requirements.

| Circuit | Season | Constraining N-1 branch rating (MVA) | Peak Demand @ 2024 (MVA) | Minimum offload for N-1 @ peak (MVA) |
|---|---|---|---|---|
| Ngauranga | Winter | 10.0 | 10.4 | 0.4 |
| | Summer | 10.0 | 8.1 | 0.0 |

**Table 9-29 Current Ngauranga Subtransmission Constraints**

Figure 9-23 shows the forecast demand for Ngauranga zone substation based on the estimated growth scenarios and development within the planning period. The subtransmission capacity constraints are plotted for comparison.

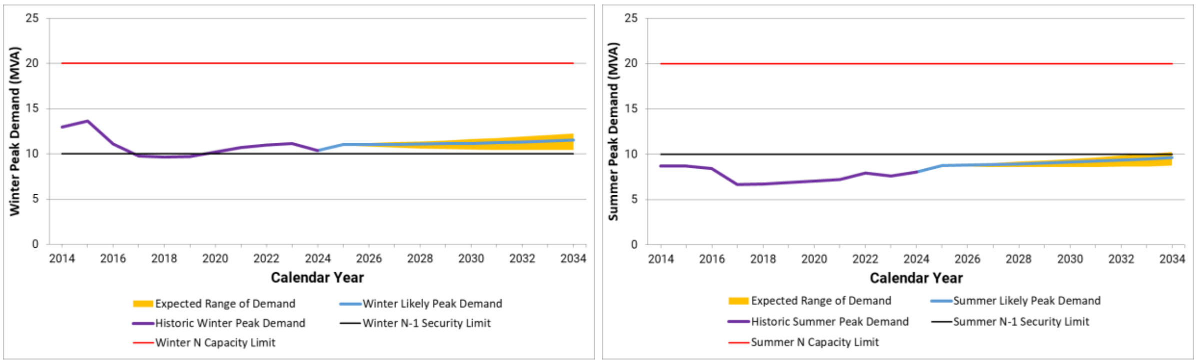



**Figure 9-23 Ngauranga Demand Forecast**

The Ngauranga peak demand presently exceeds the winter subtransmission N-1 capacity. WELL plans to resolve this issue by replacing the Ngauranga transformers with higher capacity units by 2028. This aligns with the transformers approaching end of life, so replacement of this equipment is a cost-effective solution.

This will provide sufficient capacity for the foreseeable future, with WELL planning to manage security operationally through 11 kV connections to adjacent zone substations in the interim.

#### 9.5.2.4 Mana

Mana zone substation is supplied via a single subtransmission circuit (comprising 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 transfer 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 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 (14 MVA).

This may require transferring Mana load to adjacent zone substations, as summarised in Table 9-30.

| Circuit | Season | Maximum Mana-Plimmerton Bus-tie capacity (MVA) | Peak Demand @ 2024 (MVA) | Minimum offload for N-1 @ peak (MVA) |
|---|---|---|---|---|
| Mana | Winter | 7.0 | 10.8 | 3.8 |
| | Summer | 7.0 | 7.2 | 0.2 |

**Table 9-30 Current Mana Subtransmission Constraints**

Figure 9-24 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 9-24 Mana Demand Forecast**

The Mana peak demand presently exceeds the winter and summer subtransmission N-1 capacity. Maximum demand at the substation has been stable since 2014. WELL plans to upgrade the 11 kV ties to neighbouring zone substations in 2028, to transfer demand away from Mana to Porirua and Waitangirua.

### 9.5.2.5 Plimmerton

Plimmerton zone substation is supplied via a single subtransmission circuit (comprising 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 transfer 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 11 kV bus tie cable between Mana and Plimmerton is (7 MVA), or
- Ensuring the combined Mana and Plimmerton load does not exceed the capacity of the single subtransmission circuit at Mana (14 MVA).

This may require transferring some load to other zone substations, as summarised in Table 9-31.

| Circuit | Season | Maximum Mana-Plimmerton Bus-tie capacity (MVA | Peak Demand @ 2024 (MVA) | Minimum offload for N-1 @ peak (MVA) |
|---|---|---|---|---|
| Plimmerton | Winter | 7.0 | 5.8 | 0.0 |
| | Summer | 7.0 | 4.0 | 0.0 |

**Table 9-31 Current Plimmerton Subtransmission Constraints**

Figure 9-25 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 9-25 Plimmerton Demand Forecast**

The Plimmerton peak demand has been stable since 2014 and is forecast to remain within the winter subtransmission N-1 capacity for the duration of the plan.

There are major residential and commercial developments currently going through the Fast Track Consenting process for the area north of Plimmerton. If these developments are consented, WELL would propose to construct a new zone substation north of Plimmerton to support the developments, subject to the Commission approving a price-path reopener for the work.

### 9.5.2.6 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 9-32 shows the seasonal constraint levels and the minimum offload requirements.

| Circuit | Season | Constraining N-1 branch rating (MVA) | Peak Demand @ 2024 (MVA) | Minimum offload for N-1 @ peak (MVA) |
|---|---|---|---|---|
| Porirua | Winter | 20.0 | 21.0 | 1.0 |
| | Summer | 14.2 | 15.4 | 1.2 |

Table 9-32 Current Porirua Subtransmission Constraints

Figure 9-26 shows the forecast demand for Porirua zone substation based on the estimated growth scenarios and development within the planning period. The subtransmission capacity constraints are plotted for comparison.

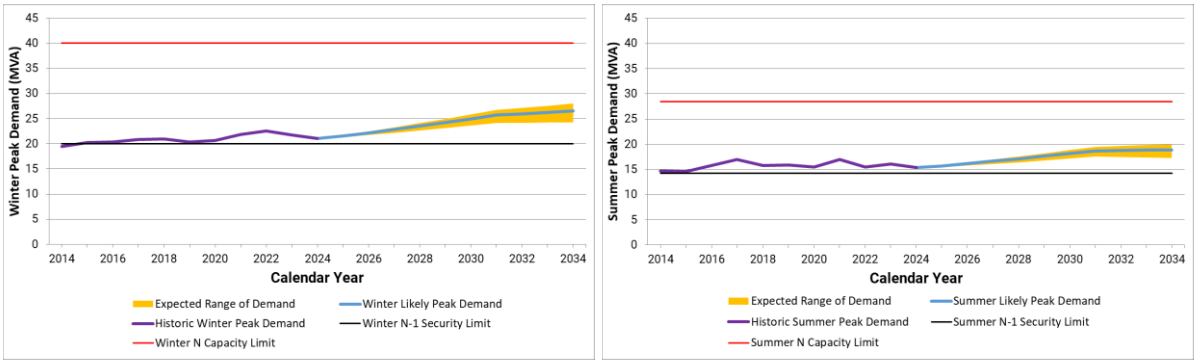



Figure 9-26 Porirua Demand Forecast

The Porirua peak demand marginally exceeds the winter and summer subtransmission N-1 capacity, with demand having grown at a very slow rate. Further growth is projected due to residential redevelopment planned for Porirua East.

WELL intends to transfer load from Porirua to Kenepuru in 2026 through the construction of a new 11 kV feeder from Kenepuru that will strengthen the ties between the two zone substations, increasing the ability for security at Porirua to be managed operationally while WELL plans for the upgrade of Porirua in 2031 to increase its capacity.

### 9.5.2.7 Tawa

The peak demand supplied from Tawa is currently within the N-1 capacity of the subtransmission circuits. Table 9-33 shows the seasonal constraint levels and the minimum offload requirements.

| Circuit | Season | Constraining N-1 branch rating (MVA) | Peak Demand @ 2024 (MVA) | Minimum offload for N-1 @ peak (MVA) |
|---|---|---|---|---|
| Tawa | Winter | 16.0 | 13.8 | 0.0 |
| | Summer | 14.6 | 10.0 | 0.0 |

Table 9-33 Current Tawa Subtransmission Constraints

Figure 9-27 shows the forecast demand for Tawa zone substation based on the estimated growth scenarios and development within the planning period. The subtransmission capacity constraints are plotted for comparison.

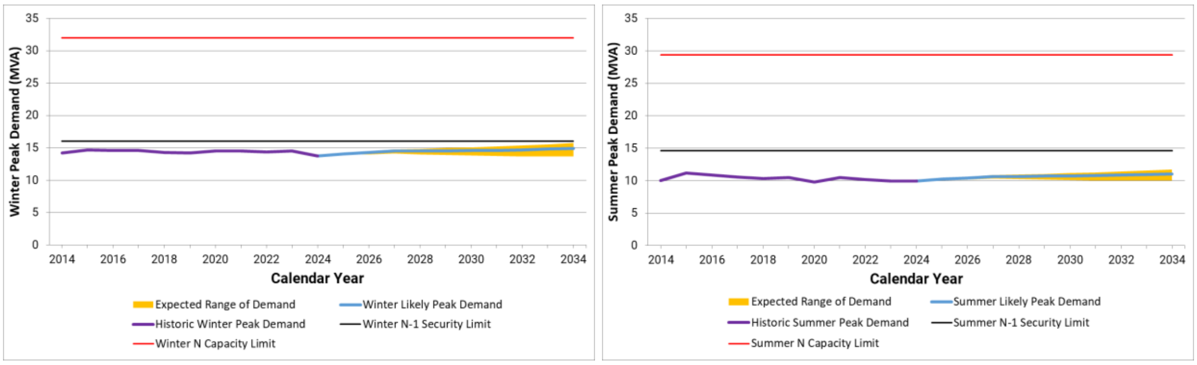



**Figure 9-27 Tawa Demand Forecast**

The Tawa peak demand has been stable since 2014 and is forecast to remain within the winter and summer subtransmission N-1 capacity for the duration of this Plan.

### 9.5.2.8 Waitangirua

The peak demand supplied by Waitangirua is currently within the N-1 branch rating of the subtransmission circuits. Table 9-34 shows the seasonal constraint levels and the minimum offload requirements.

| Zone substation | Season | Constraining N-1 branch rating (MVA) | Peak Demand @ 2024 (MVA) | Minimum offload for N-1 @ peak (MVA) |
|---|---|---|---|---|
| Waitangirua | Winter | 16.0 | 14.0 | 0.0 |
| | Summer | 15.2 | 9.6 | 0.0 |

**Table 9-34 Current Waitangirua Subtransmission Constraints**

Figure 9-28 shows the forecast demand for Waitangirua zone substation based on the estimated growth scenarios and development within the planning period. The subtransmission capacity constraints are plotted for comparison.

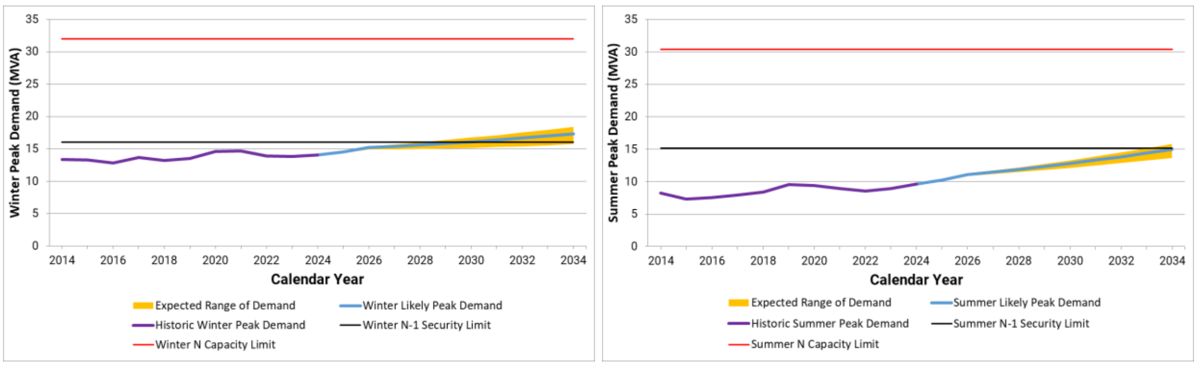



**Figure 9-28 Waitangirua Demand Forecast**

The Waitangirua peak demand is forecast grow due to residential subdivisions in the Whitby area, and to exceed the winter subtransmission N-1 capacity from 2030. WELL will continue monitoring load growth and manage the security risk through operational controls before determining whether investment in additional subtransmission capacity at the substation is justified. This ability will be strengthened through the targeted replacement of strategic 11 kV cables to increase the transfer capacity between Waitangirua and neighbouring zone substations, and being supported by the upgrade of Porirua zone substation proposed for 2031.

### 9.5.3 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.

Existing constraints are currently managed operationally by offloading customers to adjacent 11 kV feeders should an outage occur. Longer term, many of these constraints will be solved when the feeders are reconfigured as part of the construction of a new zone substation in Grenada. Other feeders have reinforcement projects proposed, which are listed in Section 9.5.4.2.

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.

Projects to resolve existing distribution-level constraints are summarised in Section 9.5.4.3.

### 9.5.4 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 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.

#### 9.5.4.1 Non-network Solutions

Prior to any investment in any infrastructure being considered, the first step is to evaluate non-network solutions, discussed in Section 9.1.10, to defer investment.

#### 9.5.4.2 Major Projects for 2025/26

Table 9-35 lists major projects currently underway or planned to start over the next 12 months.

| Project | Description |
|---|---|
| Kenepuru Feeder | New 11 kV feeder from Kenepuru zone substation to Elsdon, to offload demand from Porirua zone substation. |

Table 9-35 Northwestern Area Projects for 2025/26

### 9.5.4.3 Development Plan Summary

A summary of the development plan for this area is listed in Table 9-36. This represents the preferred solutions for constraints that are either existing or are likely to occur. It excludes reinforcement to resolve constraints that would be triggered by potential major customer-initiated projects that have not yet been contracted for delivery. System Growth expenditure that is conditional on customer work is summarised in Section 13.6.

Detailed project planning and option engineering will be completed at the project scope development and approval stage.

| Project | Description | Constraint Relieved | Target Completion | Investment |
|---|---|---|---|---|
| **Subtransmission** | | | | |
| Grenada zone substation – Stage 1 | New zone substation at Grenada | Johnsonville zone substation | 2028 | $6.5M |
| Ngauranga transformer upgrade | Replace Ngauranga transformers | Ngauranga transformers | 2028 | $9.0M |
| Porirua Zone Substation | Upgrade of zone substation | Porirua 33 kV cables, power transformers, and 11kV switchboard | 2031 | $23.1M |
| Johnsonville 33kV Cable | Project to manage the capacity, health, and criticality of the fluid-filled cables to Johnsonville. | Johnsonville 33kV cables | 2033 | $22.9M |
| Kenepuru-Porirua-Titahi Bay | Improve 11 kV connections between Kenepuru and Titahi Bay. | Porirua and Kenepuru zone substations | 2034 | $7.0M |
| **Distribution** | | | | |
| Waitangirua link | New Waitangirua feeder to supply the Whitby area | Waitangirua 5 and 11 | 2026 | $1.2 M |
| New Kenepuru feeders | New 2x11 kV feeders to Mohuia Cr to offload Porirua Zone Substation | Porirua Zone Substation, Porirua 6, Kenepuru 9 | 2026 | $12.7M |
| Grenada-Ngauranga link | Run overhead line from Grenada to Ngauranga 4 | Ngauranga 4, 7, and 9 | 2027 | $0.6 M |
| Eastern Porirua 11kV Reinforcement | Offload Porirua 9 & 12 to Waitangirua 6 &10, upgrade cable sections | Porirua 12 | 2027 | $1.5M |
| Johnsonville 11 Reinforcement | Upgrade cable sections and split LV ties across transformers | Johnsonville 11 | 2027 | $4.3M |
| Whitby cable replacement | Replace strategic cable sections and split transformer LV ties on Waitangirua 5 & 11 | Waitangirua 5 and 11 | 2027 | $4.3M |
| Tawa 8 LV Separation | Separate LV ties on 11kV feeder Tawa 8 and offload to Tawa 13 | Tawa 8 | 2028 | $0.9M |
| Tawa Strategic 11 kV Cable Upgrades | Replace constraining sections of 95mm$^2$ cable | Tawa 11, Johnsonville 2 | 2028 | $2.4M |
| Mana 2 Feeder Reinforcement | Replace strategic cable sections and split transformer LV ties on Mana 2 | Waitangirua 5 and 11, Mana 2 | 2029 | $2.8M |
| New Ngauranga feeder | Install new Ngauranga feeders to Abattoirs, offload Kaiwharawhara 6/7/9/10 | Kaiwharawhara 6/7/9/10 | 2029 | $8.1M |
| Tawa 13 LV separation | Split transformer LV ties on Tawa 13 | Tawa 13 | 2030 | $0.9M |
| Johnsonville 6 Reconfiguration | Offload onto Johnsonville 8 and split LV ties across transformers | Johnsonville 6 | 2030 | $1.0M |

Table 9-36 Northwestern Area Development Summary

## 9.6 Northeastern Area NDRP

This section provides a summary of the Northeastern Area NDRP.

### 9.6.1 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 9-37. The forecast in Table 9-37 considers only committed developments.

| GXP | Continuous Capacity (MVA) | Transformer Cyclic Summer / Winter Capacity (MVA) | Peak Demand (MVA) | |
|---|---|---|---|---|
| | | | 2024 | 2034 |
| Gracefield 33 kV | 1x60 + 1x85 | 76/80 | 60 | 65 |
| Upper Hutt 33 kV | 2x40 | 51/53 | 31 | 36 |
| Melling 33 kV | 2x50 | 64/65 | 33 | 35 |
| Melling 11 kV | 2x25 | 32/34 | 24 | 23 |
| Haywards 33 kV | 2x25 | 25/25 | 19 | 27 |
| Haywards 11 kV | 2x30 | 30/30 | 18 | 21 |

Table 9-37 Northeastern Area GXP Capacities

#### 9.6.1.1 Gracefield

The Gracefield GXP comprises two parallel 110/33 kV transformers, one nominally rated at 60 MVA and one rated at 85 MVA, with winter N-1 cyclic capacities of 80 MVA and 113 MVA, respectively. The maximum demand on the Gracefield GXP was 60.5 MVA in 2024. Gracefield GXP supplies zone substations at Wainuiomata, Gracefield, Seaview, and Korokoro.

#### 9.6.1.2 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 switchboard.

The maximum demand in 2024 was 19.2 MVA on the Haywards 33 kV GXP, and 18.1 MVA on the Haywards 11 kV GXP.

#### 9.6.1.3 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 2024 was 31.5 MVA. Upper Hutt supplies zone substations at Brown Owl and Maidstone each via double 33 kV circuits.

#### 9.6.1.4 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 2024 was 33.2 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 2024 was 23.7 MVA. The Melling 11 kV GXP supplies the WELL network directly from a Transpower-owned 11 kV switchboard.

### 9.6.2 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 11 kV distribution network with interconnectivity via switched open points to adjacent zones. The Haywards and Melling 11 kV switchboards directly feed into the distribution network. The characteristics of each zone substation are listed in Table 9-38.

| Zone Substation | Season | Subtransmission N-1 branch rating (MVA) | Constraining Branch | Peak Demand C1 (MVA) | | ICP Count as at 2024 |
|---|---|---|---|---|---|---|
| | | | | 2024 | 2034 | |
| Korokoro | Winter | 15.5 | 33kV Cables | 17.3 | 17.2 | 3,865 |
| | Summer | 13.3 | 33kV Cables | 13.6 | 14.1 | |
| Seaview | Winter | 13.8 | 33kV Cables | 14.1 | 14.0 | 3,671 |
| | Summer | 10.6 | 33kV Cables | 11.5 | 11.3 | |
| Waterloo | Winter | 20.1 | 33kV Cables | 15.5 | 16.0 | 6,285 |
| | Summer | 12.0 | 33kV Cables | 11.5 | 12.6 | |
| Brown Owl | Winter | 18.4 | Transformer | 15.3 | 17.6 | 6,934 |
| | Summer | 12.9 | 33kV Cables | 10.4 | 14.2 | |
| Gracefield | Winter | 23.0 | Transformer | 9.8 | 11.6 | 2,744 |
| | Summer | 23.0 | Transformer | 7.7 | 9.8 | |
| Maidstone | Winter | 17.6 | 33kV Cables | 13.5 | 15.3 | 4,452 |
| | Summer | 10.2 | 33kV Cables | 10.0 | 11.4 | |
| Naenae | Winter | 18.3 | 33kV Cables | 14.0 | 15.3 | 6,616 |
| | Summer | 13.9 | 33kV Cables | 9.4 | 10.7 | |
| Trentham | Winter | 19.1 | 33kV Cables | 15.4 | 21.4 | 6,357 |
| | Summer | 14.7 | 33kV Cables | 11.2 | 17.0 | |
| Wainuiomata | Winter | 20.0 | Transformer | 17.0 | 19.8 | 7,605 |
| | Summer | 20.0 | Transformer | 11.2 | 13.5 | |

Table 9-38 Northeastern Area Zone Substation Capacities

The Northeastern Area is characterised by a mix of old industrial areas in Lower Hutt with flat or declining demand, older suburbs that have experienced high levels of infill housing and high-density residential intensification near public transport corridors, and expanding residential subdivisions in Upper Hutt.

### 9.6.2.1 Brown Owl

The peak demand supplied by Brown Owl is currently within the N-1 capacity of the zone substation. Table 9-39 shows the seasonal constraint levels and the minimum offload requirements.

| Zone substation | Season | Subtransmission N-1 branch rating (MVA) | Peak Demand @ 2024 (MVA) | Minimum offload for N-1 @ peak (MVA) |
|---|---|---|---|---|
| Brown Owl | Winter | 18.4 | 15.3 | 0.0 |
| | Summer | 12.9 | 10.4 | 0.0 |

Table 9-39 Current Brown Owl Subtransmission Constraints

Figure 9-29 shows the forecast demand for Brown Owl zone substation based on the estimated growth scenarios and development within the planning period. The subtransmission capacity constraints are plotted for comparison

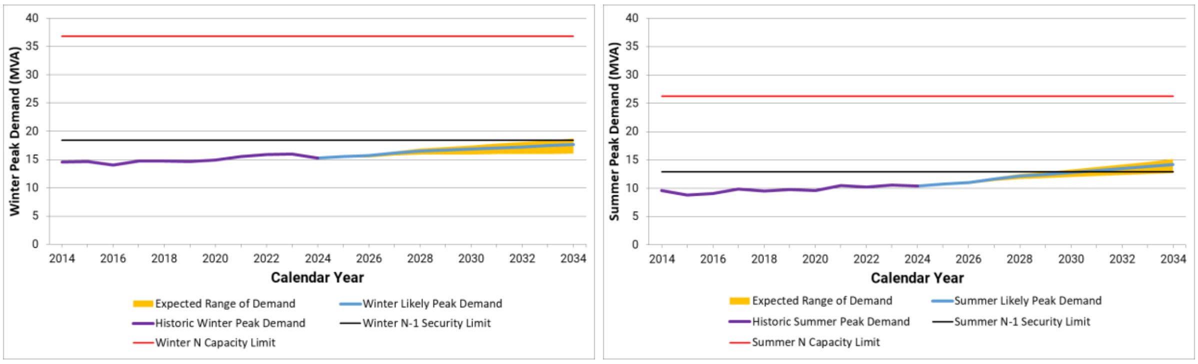



Figure 9-29 Brown Owl Demand Forecast

The Brown Owl peak demand is forecast to exceed the summer subtransmission N-1 capacity in 2031 due to residential subdivisions north of Upper Hutt, however demand in the area has been stable since 2014. WELL will continue to monitor load growth in the area in order to determine whether investment in additional capacity at the substation is justified.

### 9.6.2.2 Gracefield

The peak demand supplied by Gracefield is currently within the N-1 capacity of the subtransmission circuits. Table 9-40 shows the seasonal constraint levels and the minimum offload requirements.

| Zone substation | Season | Constraining N-1 branch rating (MVA) | Peak Demand @ 2024 (MVA) | Minimum offload for N-1 @ peak (MVA) |
|---|---|---|---|---|
| Gracefield | Winter | 23.0 | 9.8 | 0.0 |
| | Summer | 23.0 | 7.7 | 0.0 |

Table 9-40 Current Gracefield Subtransmission Constraints

Figure 9-30 shows the forecast demand for Gracefield zone substation based on the estimated growth scenarios and development within the planning period. The subtransmission capacity constraints are plotted for comparison.

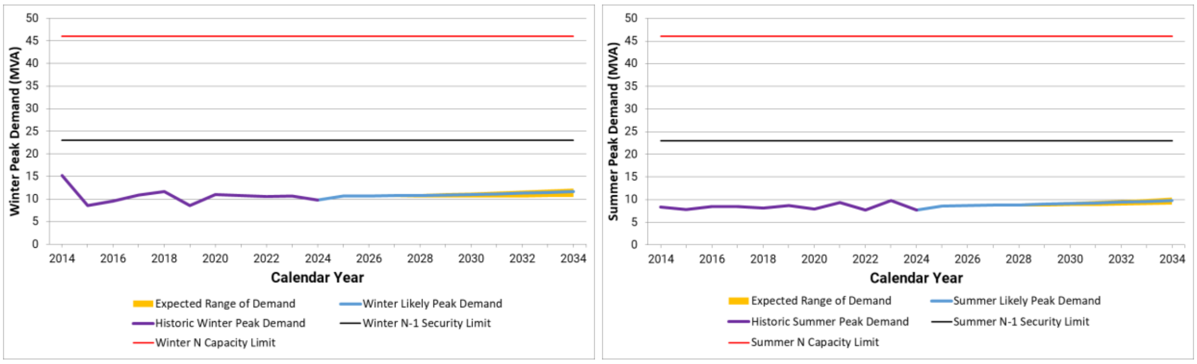



**Figure 9-30 Gracefield Demand Forecast**

The Gracefield peak demand has been stable since 2015 and is forecast to remain within the winter and summer subtransmission N-1 capacity for the duration of this plan.

### 9.6.2.3 Haywards

The peak demand supplied by Haywards is currently within the N-1 11 kV capacity of the Transpower transformers. Table 9-41 shows the seasonal constraint levels and the minimum offload requirements.

| Zone substation | Season | Constraining N-1 branch rating (MVA) | Peak Demand @ 2024 (MVA) | Minimum offload for N-1 @ peak (MVA) |
|---|---|---|---|---|
| Haywards | Winter | 30.0 | 16.9 | 0.0 |
| | Summer | 30.0 | 11.3 | 0.0 |

**Table 9-41 Current Haywards Subtransmission Constraints**

Figure 9-31 shows the forecast demand for Haywards zone substation based on the estimated growth scenarios and development within the planning period. The subtransmission capacity constraints are plotted for comparison.

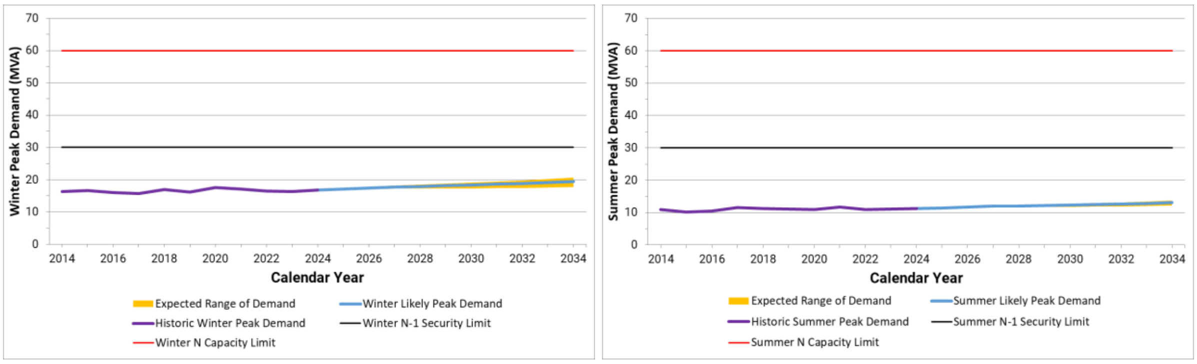



**Figure 9-31 Haywards Demand Forecast**

The Haywards peak demand has been stable since 2014 and is forecast to remain within the winter and summer subtransmission N-1 capacity for the duration of this plan.

### 9.6.2.4 Korokoro

The peak demand at Korokoro currently exceeds the N-1 capacity of subtransmission circuits. Table 9-42 shows the seasonal constraint levels and the minimum offload requirements on each circuit.

| Zone substation | Season | Constraining N-1 branch rating (MVA) | Peak Demand @ 2024 (MVA) | Minimum offload for N-1 @ peak (MVA) |
|---|---|---|---|---|
| Korokoro | Winter | 15.5 | 17.3 | 1.8 |
| | Summer | 13.3 | 13.6 | 0.3 |

Table 9-42 Current Korokoro Subtransmission Constraints

Figure 9-32 shows the forecast demand for Korokoro zone substation based on the estimated growth scenarios and development within the planning period. The subtransmission capacity constraints are plotted for comparison.


Figure 9-32 Korokoro Load Forecast

The Korokoro peak demand presently exceeds the winter and summer subtransmission N-1 capacity, however demand has been declining since 2014, and the constraint is able to be managed operationally through post-contingent offloads through the 11 kV network to adjacent zone substations.

The options for resolving the constraint at Korokoro are:

- Relocating 11 kV cables away from the Korokoro subtransmission cables outside Seaview zone substation, to remove a thermal pinch point.
- Redeveloping Petone zone substation in order to transfer load away from Korokoro on the 11 kV network.
- Replace and upgrade the 33 kV cables and power transformers at Korokoro.

Investment in increasing capacity at Korokoro is currently not justified due to the declining trend in load and the low level of risk. WELL will continue monitoring changes in demand and potential major customer projects, and will manage the security risk through operational controls until the business case for investment in additional capacity at the site becomes clear.

### 9.6.2.5 Maidstone

The peak demand supplied by Maidstone currently equals the N-1 capacity of subtransmission circuits in summer. Table 9-43 shows the seasonal constraint levels and the minimum offload requirements on each circuit.

| Zone substation | Season | Constraining N-1 branch rating (MVA) | Peak Demand @ 2024 (MVA) | Minimum offload for N-1 @ peak (MVA) |
|---|---|---|---|---|
| Maidstone | Winter | 17.6 | 13.5 | 0.0 |
| | Summer | 10.2 | 10.0 | 0.0 |

Table 9-43 Current Maidstone Subtransmission Constraints

Figure 9-33 shows the forecast demand for Maidstone zone substation based on the estimated growth scenarios and development within the planning period. The subtransmission capacity constraints are plotted for comparison.


Figure 9-33 Maidstone Demand Forecast

The Maidstone peak demand is presently at the summer subtransmission N-1 capacity, with demand having been stable since 2016.

The constraining 33 kV cables are planned for replacement due to asset health in 2030 as identified in Section 8.5.1. In the interim, security of supply will be managed operationally by shifting load to adjacent substations, with targeted projects to reinforce those 11 kV ties.

### 9.6.2.6 Melling

The peak demand supplied by Melling is currently within the N-1 capacity of the Transpower point of supply. Table 9-44 shows the seasonal constraint levels and the minimum offload requirements on each circuit.

| Zone substation | Season | Constraining N-1 branch rating (MVA) | Peak Demand @ 2024 (MVA) | Minimum offload for N-1 @ peak (MVA) |
|---|---|---|---|---|
| Melling | Winter | 34.0 | 21.4 | 0.0 |
| | Summer | 32.0 | 15.6 | 0.0 |

Table 9-44 Current Melling Subtransmission Constraints

Figure 9-34 shows the forecast demand for Melling zone substation based on the estimated growth scenarios and development within the planning period. The subtransmission capacity constraints are plotted for comparison.

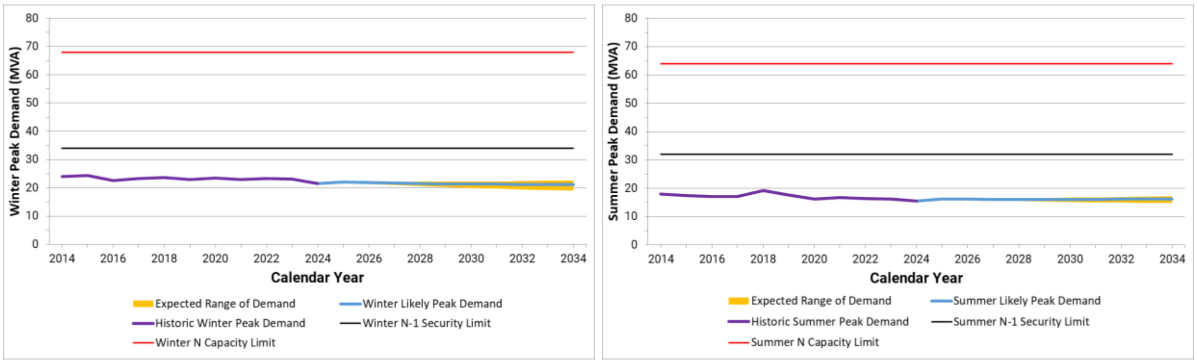



**Figure 9-34 Melling Demand Forecast**

The Melling peak demand has been stable since 2014 and is forecast to remain within the winter and summer subtransmission N-1 capacity for the duration of this plan.

### 9.6.2.7 Naenae

The peak demand supplied by Naenae is currently within the N-1 capacity of the subtransmission circuits. Table 9-45 shows the seasonal constraint levels and the minimum offload requirements.

| Zone substation | Season | Constraining N-1 branch rating (MVA) | Peak Demand @ 2024 (MVA) | Minimum offload for N-1 @ peak (MVA) |
|---|---|---|---|---|
| Naenae | Winter | 18.3 | 14.0 | 0.0 |
| | Summer | 13.9 | 9.4 | 0.0 |

**Table 9-45 Current Naenae Subtransmission Constraints**

Figure 9-35 shows the forecast demand for Naenae zone substation based on the estimated growth scenarios and development within the planning period. The subtransmission capacity constraints are plotted for comparison.

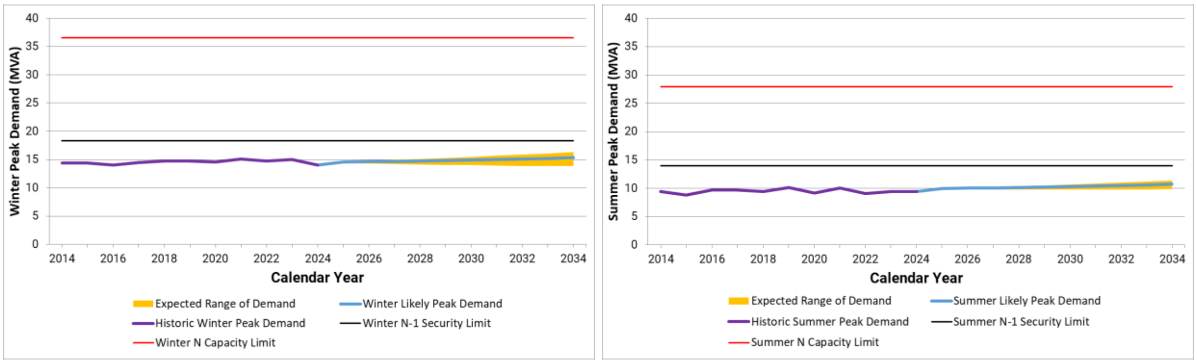



**Figure 9-35 Naenae Demand Forecast**

The Naenae peak demand has been stable since 2014 and is forecast to remain within the winter and summer subtransmission N-1 capacity for the duration of this plan.

### 9.6.2.8 Seaview

The peak demand supplied by Seaview currently exceeds the summer and winter N-1 capacity of the subtransmission circuits. Table 9-46 shows the seasonal constraint levels and the minimum offload requirements.

| Zone substation | Season | Constraining N-1 branch rating (MVA) | Peak Demand @ 2024 (MVA) | Minimum offload for N-1 @ peak (MVA) |
|---|---|---|---|---|
| Seaview | Winter | 13.8 | 14.1 | 0.3 |
| | Summer | 10.6 | 11.5 | 0.9 |

**Table 9-46 Current Seaview Subtransmission Constraints**

Figure 9-36 shows the forecast demand for Seaview zone substation based on the estimated growth scenarios and development within the planning period. The subtransmission capacity constraints are plotted for comparison.

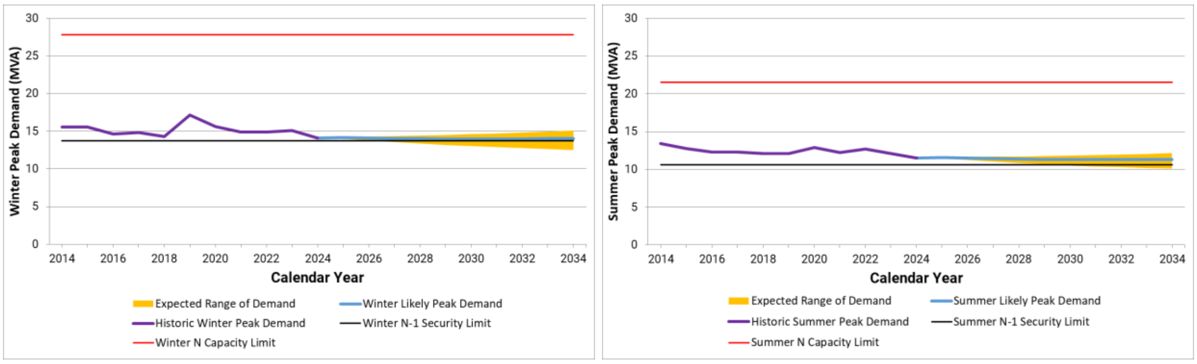



**Figure 9-36 Seaview Demand Forecast**

The Seaview peak demand is presently above the winter and summer subtransmission N-1 capacity, however there has been a declining trend since 2014. WELL will monitor load at the site and can manage security of supply operationally by shifting load to adjacent substations through the 11 kV network until customer load growth is confirmed.

### 9.6.2.9 Trentham

The peak demand supplied by Trentham is currently within the N-1 capacity of the subtransmission circuits. Table 9-47 shows the seasonal constraint levels and the minimum offload requirements.

| Zone substation | Season | Constraining N-1 branch rating (MVA) | Peak Demand @ 2024 (MVA) | Minimum offload for N-1 @ peak (MVA) |
|---|---|---|---|---|
| Trentham | Winter | 19.1 | 15.4 | 0.0 |
| | Summer | 14.7 | 11.2 | 0.0 |

**Table 9-47 Current Trentham Subtransmission Constraints**

Figure 9-37 shows the forecast demand for Trentham zone substation based on the estimated growth scenarios and development within the planning period. The subtransmission capacity constraints are plotted for comparison.

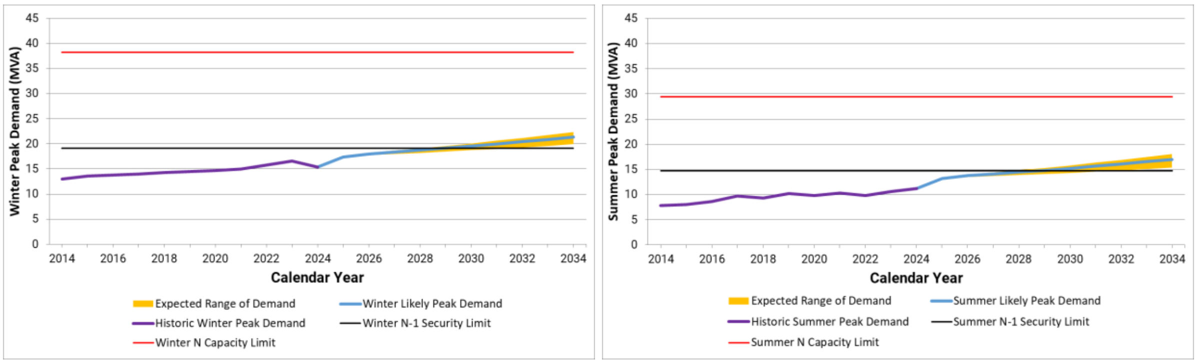



**Figure 9-37 Trentham Demand Forecast**

The demand at Trentham has been increasing since 2014 due to residential developments in the area. Peak demand is forecast to exceed the winter and summer subtransmission N-1 capacity in 2030. WELL proposes to replace the constraining fluid-filled 33 kV cables in 2027.

WELL will closely monitor demand growth due to the ultimate capacity at Trentham being limited by the 25 MVA transformers at Haywards GXP.

### 9.6.2.10 Wainuiomata

The peak demand supplied by Wainuiomata is currently within the N-1 capacity of the subtransmission circuits. Table 9-48 shows the seasonal constraint levels and the minimum offload requirements.

| Zone substation | Season | Constraining N-1 branch rating (MVA) | Peak Demand @ 2024 (MVA) | Minimum offload for N-1 @ peak (MVA) |
|---|---|---|---|---|
| Wainuiomata | Winter | 20.0 | 17.0 | 0.0 |
| | Summer | 20.0 | 11.2 | 0.0 |

**Table 9-48 Current Wainuiomata Subtransmission Constraints**

Figure 9-38 shows the forecast demand for Wainuiomata zone substation based on the estimated growth scenarios and development within the planning period. The subtransmission capacity constraints are plotted for comparison.

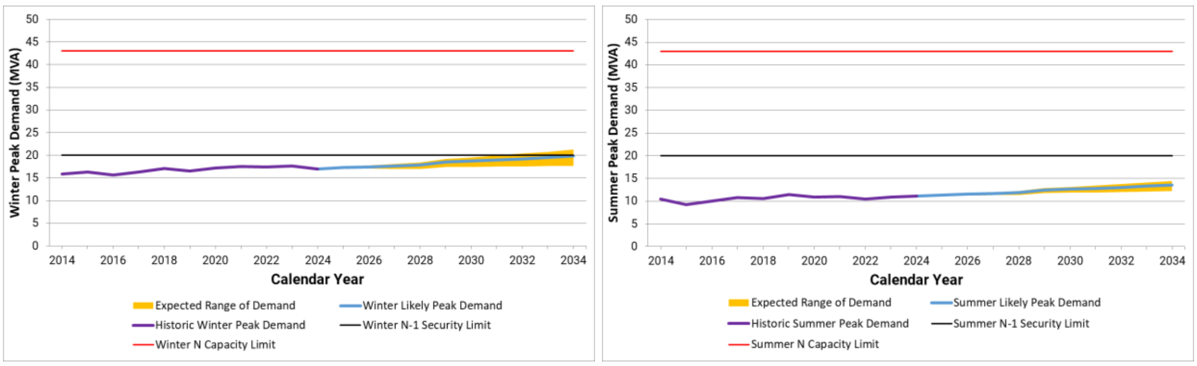



**Figure 9-38 Wainuiomata Demand Forecast**

The Wainuiomata peak demand is growing slowly but is forecast to remain within the subtransmission N-1 capacity for the duration of this plan.

### 9.6.2.11 Waterloo

The peak demand supplied by Waterloo is currently within the summer and winter N-1 capacity of the subtransmission circuits. Table 9-49 shows the seasonal constraint levels and the minimum offload requirements.

| Zone substation | Season | Constraining N-1 branch rating (MVA) | Peak Demand @ 2024 (MVA) | Minimum offload for N-1 @ peak (MVA) |
|---|---|---|---|---|
| Waterloo | Winter | 20.1 | 15.5 | 0.0 |
| | Summer | 12.0 | 11.5 | 0.0 |

**Table 9-49 Current Waterloo Subtransmission Constraints**

Figure 9-39 shows the forecast demand for Waterloo zone substation based on the estimated growth scenarios and development within the planning period. The subtransmission capacity constraints are plotted for comparison.

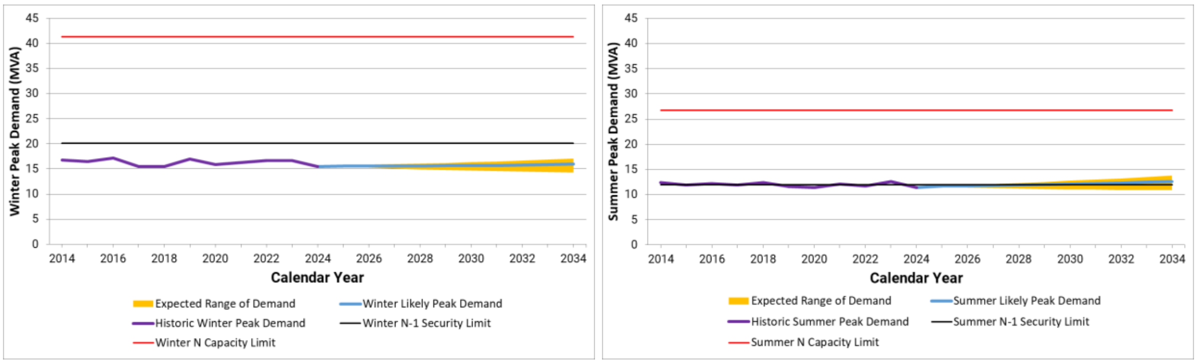



**Figure 9-39 Waterloo Demand Forecast**

The Waterloo peak demand is currently at the summer subtransmission N-1 security limit, however demand has been stable since 2014. WELL will monitor load growth and increase the 11 kV transfer capacity to neighbouring zone substations with targeted upgrade projects, to manage security until the constraining fluid-filled 33 kV cables are replaced for asset health, currently expected to be in 2035 as identified in Section 8.5.1.

## 9.6.3 Distribution Level Development Needs

There are no meshed feeders in the Northeastern Area, so all feeders are radial with a 67% security criteria as defined in Table 9-3.

Existing constraints are currently managed operationally by offloading customers to adjacent 11 kV feeders should an outage occur. Longer term, these constraints will be solved with targeted upgrades. Other feeders have reinforcement projects proposed, which are listed in Section 9.6.4.2.

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 outcomes and impacts of these possible future step load change demands are uncertain, difficult to estimate, and have 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.

Projects to resolve existing distribution-level constraints are summarised in Section 9.6.4.3.

### 9.6.4 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.

#### 9.6.4.1 Non-network Solutions

Prior to any investment in any infrastructure being considered, the first step is to evaluate non-network solutions, discussed in Section 9.1.10, to defer investment.

#### 9.6.4.2 Major Projects for 2025/26

Table 9-23Table 9-50 lists major projects currently underway or planned to start over the next 12 months.

| Project | Description |
|---|---|
| Haywards 2822 | Overlay of a section of 11kV cable along State Highway 58 on Haywards 2822 to relieve a constraint into the Moonshine Hill area. |

**Table 9-50 Northeastern Area Projects for 2025/26**

#### 9.6.4.3 Development Plan Summary

A summary of the development plan for this area is listed in Table 9-51. This represents the preferred solutions for constraints that are either existing or are likely to occur. It excludes reinforcement to resolve constraints that would be triggered by potential major customer-initiated projects that have not yet been contracted for delivery. System Growth expenditure that is conditional on customer work is summarised in Section 13.6.

Detailed project planning and option engineering will be completed at the project scope development and approval stage.

| Project | Description | Constraint Relieved | Target Completion | Investment |
|---|---|---|---|---|
| **Subtransmission Constraints** | | | | |
| Trentham 33kV Cables | Replace the Trentham fluid-filled 33kV cable | Trentham 33kV cables | 2027 | $4.3M |
| Trentham-Maidstone Inter-tie Reinforcement | Upgrade strategic sections of cable and overhead line between Trentham and Maidstone Zone Substation and SCADA-ise open points | Maidstone 33kV cables, Maidstone transformers, Trentham transformers | 2028 | $6.4M |
| **Distribution Constraints** | | | | |
| Haywards 2822 | Upgrade constraining lengths of 11kV cable. | Haywards 2822 | 2026 | $1.3M |
| Waterloo 11kV Feeder Reconfiguration | Offload onto Melling 3 and Waterloo 11. Split LV ties. | Waterloo 6 | 2027 | $0.8M |
| Malone Road and Godley Street Link | Link 17 Godley Street with Malone Street spur | Waterloo 5, Seaview 12 | 2027 | $1.9M |
| New 11kV Feeder to Maymorn | New 11kV feeder from Brown Owl to Maymorn | Brown Owl 5, Brown Owl 8 | 2027 | $3.3M |
| Naenae-Melling Reconfiguration | Offload Naenae feeders onto Melling and split LV ties. | Naenae feeder capacity. | 2029 | $1.0M |
| Haywards-Trentham Feeder Reconfiguration | Offload Haywards 2722 onto Trentham 5. Split up LV ties in on Haywards 2722. | Haywards 2722, Trentham 5 | 2030 | $1.0M |
| Haywards 2842 LV Separation | Separate LV ties on 11kV feeder Haywards 2842 | Haywards 2842 | 2030 | $0.8M |
| Trentham 12 LV Separation | Separate LV ties on 11kV feeder Trentham 12 | Trentham 12 | 2030 | $0.8M |
| Wainuiomata 6 and 13 Reconfiguration | Offload onto Wainuiomata 3 and Wainuiomata 13. Split LV ties | Wainuiomata 6, Wainuiomata 13 | 2030 | $1.0M |
| Brown Owl 2 LV Separation | Separate LV ties on 11kV feeder Brown Owl 2 | Brown Owl 2 | 2030 | $0.8M |
| Naenae 6 LV Separation | Separate LV ties on 11kV feeder Naenae 6 | Naenae 6, Haywards 2782 | 2030 | $0.8M |
| Eastbourne 11kV Feeder Upgrades | Cables from Gracefield Zone Substation cut in between Totara St and Rona St, new cable between Rona St and Transit Camp, upgrade far end of overhead line | Gracefield 3, Gracefield 9 | 2035 | $14.7M |

**Table 9-51 Northeastern Area Development Summary**

## 9.7 Low Voltage Reinforcement

Historically, LV capacity has been invisible to distribution network planners, preventing the development of LV network growth CAPEX. Networks have not been funded to develop the tools and processes to provide visibility of the LV network, manage the connection of large new customer devices, and incorporate flexibility.

Given the expected rapid demand growth in Wellington outlined in Section 4, WELL commissioned ANSA to provide a LV constraint risk tool which:

1. Establishes the hosting capacity of each LV asset on each residential LV network.
2. Applies a demand forecast to those assets.
3. Identifies when those assets will run out of capacity.
4. Applies a standard cost model to each asset that needs reinforcing with additional capacity.
5. Aggregates those costs to provide a CAPEX forecast for the next 50 years.

Since this work was not funded by DPP3 allowances, WELL submitted an Innovation Project Allowance application, and had to find savings from other parts of the business to fund the 50% share that was not covered by the innovation mechanism. Data access and quality has been difficult, relying on one-off data requests from Retailers to avoid high data purchase costs, and the use of statistical methods to infer missing data.

In future, networks will need funding to develop tools and processes that provide on-going visibility of the LV network. WELL is incorporating the ANSA solution into business-as-usual network planning processes, however it is also necessary to develop other capabilities that are complementary to the ANSA tool, including near-real-time constraint and capacity monitoring targeted at the assets identified by the tool as being at risk of constraint.

### 9.7.1 Methodology

The ANSA tool builds a spatial model of LV assets, including customer ICPs, the transformers that supply those connections, and the connecting conductors. The model allows different power flows to be applied to the network models, testing whether each asset has the capacity to host changes in electricity demand.

The ANSA model then applies different growth models to the network models. The model uses Monte Carlo simulation to calculate the impact on the capacity of the LV assets for different combinations of:

- EV uptake rates;
- Gas to electricity transition rates;
- PV uptake rates;
- Average EV charger size (1.8 kW, 3.7 kW, 7.4kW), and
- EV charging patterns (proportion of EVs charging at 6pm, 9pm, 12am, and 3am, able to be set as a charging profile).

The simulation provides a probability of when each asset will exceed its capacity, then applies standardised costs for the reinforcement of each constrained asset. The aggregated reinforcement costs form the network growth CAPEX.

### 9.7.2 Study Scope

The Wellington network is a winter evening peaking network and residential customers drive peak demand. The study therefore focused on residential LV networks. The study assessed 1,860 residential urban LV networks, capturing the majority of residential customers.

Rural networks below 100kVA were excluded as they supply fewer customers, resulting in higher design ADMDs, and are also less likely to have reticulated gas connections.

Commercial and industrial networks were also excluded as they are unlikely to be contributing to winter evening peak demand, and increases in demand are more likely to require customer-initiated projects, allowing constraints to be identified and resolved before they occur.

Since the results presented in WELL's 2024 AMP, the model has been updated and enhanced to:

- Utilise the significant improvements in LV GIS data quality that resulted from the output of the previous study, including modelling of LV ties between transformers,
- Incorporate PV hosting capacity results into the CAPEX forecast,
- Update forecast EV and gas transition uptake rates to reflect the significant reductions seen in these over the last 12 months,
- Reflect regional variations in EV uptake (see Section 4.2.1.1), and
- Implement WELL's standards regarding the cyclic rating of assets during the winter evening peak relative to their nameplate ratings.

### 9.7.3 Assumptions and Limitations

The following assumptions and limitations apply:

1. There may be factors other than capacity constraints that trigger conductor and transformer replacement, such as age and condition. Only reinforcement due to load increases is considered in this study.
2. It is assumed that there are no mechanical constraints in upgrading conductors. These upgrades may be limited by wind and other structural loading.
3. The determination of customers with gas connections, assessment of gas consumers' demand, and the assignment of demand during modelling is limited due to imperfections in ascertaining gas consumers, the nature of their gas use (i.e. water heating, cooking, and space heating), and the technology that might replace that use (e.g. traditional electric hot water cylinders, heat pump cylinders, or electric continuous flow heating).
4. The CAPEX forecast used for this AMP is the expenditure required to address constraints that the model assesses as having a 50% likelihood of occurring, with the CAPEX contribution of each constraint to the forecast being halved to reflect that on average only half of these constraints are expected to occur.

### 9.7.4 Results

The study tested a range of different charging behaviour and the following growth scenarios:

| Scenario | EV Uptake Rate | Gas Transition Rate | PV Uptake Rate |
|---|---|---|---|
| Slow Decarbonisation | Slow | None | Slow |
| Residential Gas Exit | Slow | Rapid | Slow |
| Moderate Growth | Moderate | Slow | Moderate |
| Rapid Decarbonisation | Rapid | Rapid | Rapid |

Table 9-52 Uptake Rates Applied to ANSA LV Growth Scenario

Figure 9-40 provides the cumulative CAPEX to 2050 for these four scenarios. The model updates discussed in Section 9.7.2, particularly the reduced decarbonisation forecasts and the use of seasonal transformer ratings, has significantly reduced the CAPEX forecast for the first 10 years compared to that presented in the 2024 AMP.

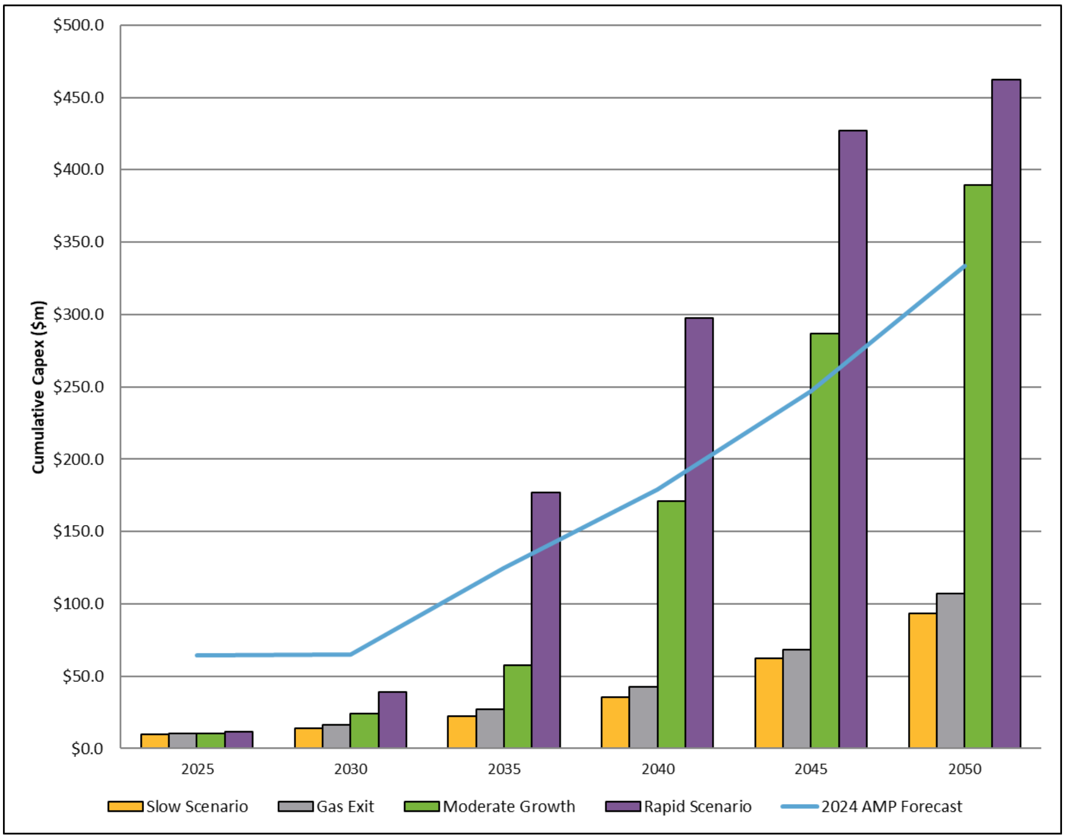



Figure 9-40 Cumulative ANSA LV Reinforcement CAPEX by Regulatory Period and Growth Scenario

The study allows the impact of different assumptions on the forecast to be tested. Figure 9-41 compares the present value of the LV reinforcement CAPEX under the “Moderate Growth” scenario for the 50-year study period for networks that have a 100% probability of becoming constrained, for two average charger sizes and two charging behaviours: 50% diversity at 6pm versus a shifted pattern that moves the majority of charging outside of the evening peak. This illustrates the extent to which changes in charging patterns can influence the ability of the network to accommodate EV uptake, and consequentially the cost to customers.

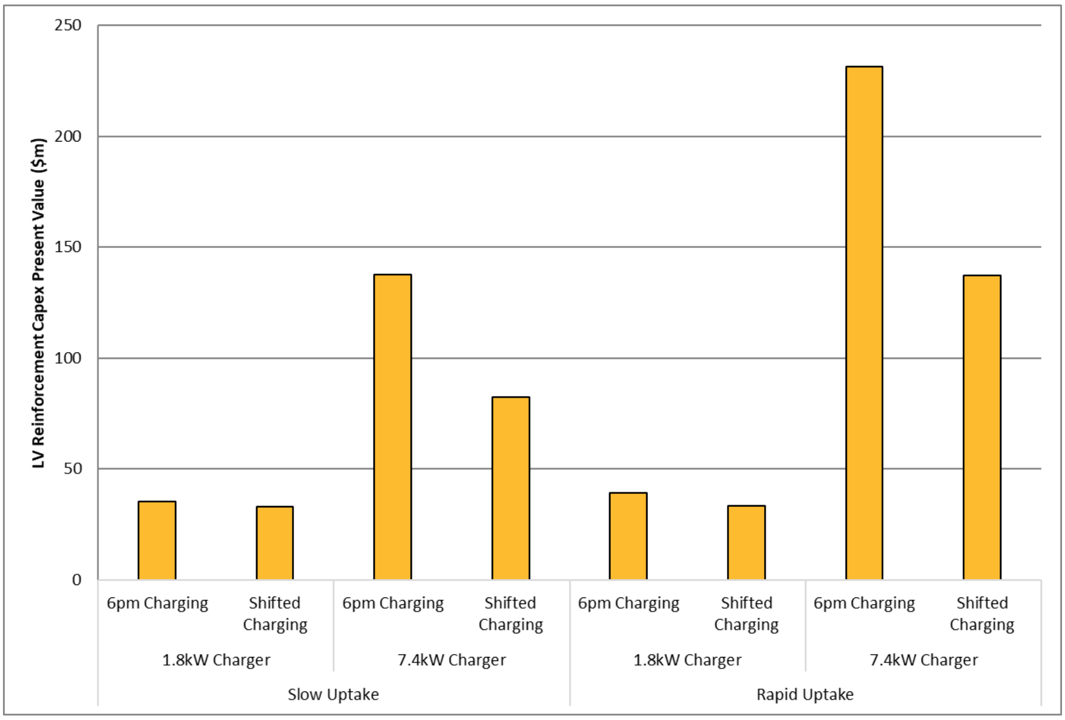



**Figure 9-41 EV Charging Scenario Impact on ANSA LV Reinforcement CAPEX**

### 9.7.4.1 AMP Scenario

The base scenario used for the ANSA LV reinforcement forecast in this AMP assumes:

- Seasonal winter transformer ratings at 120% of nameplate.
- An average EV charger size of 3.7 kW.
- A 6pm EV charging time and 50% EV charging diversity. This provides benchmark for assessing the value of this demand being shifted outside of the peak demand period.
- An average PV inverter size of 5 kW, Volt-VAr control not mandated, and an upper voltage limit of +6%.
- Slow gas transition under an assumption that biogas will replace fossil gas for customers remaining connected to the gas network, moderate EV growth rates, and moderate PV uptake. The penetration rates are summarised in Table 9-53.

| Asset Type | 2025 | 2030 | 2035 | 2040 | 2045 | 2050 |
|---|---|---|---|---|---|---|
| Residential Gas Penetration | 42% | 40% | 38% | 36% | 34% | 31% |
| Electric Vehicle Uptake | 6% | 15% | 29% | 45% | 62% | 76% |
| PV Uptake | 2% | 5% | 10% | 17% | 24% | 28% |

**Table 9-53 Penetration Rates Used in Base AMP LV Reinforcement Scenario**

Figure 9-42 provides the ANSA forecast of the CAPEX required to resolve the constraints identified out to 2050 in the base AMP scenario.

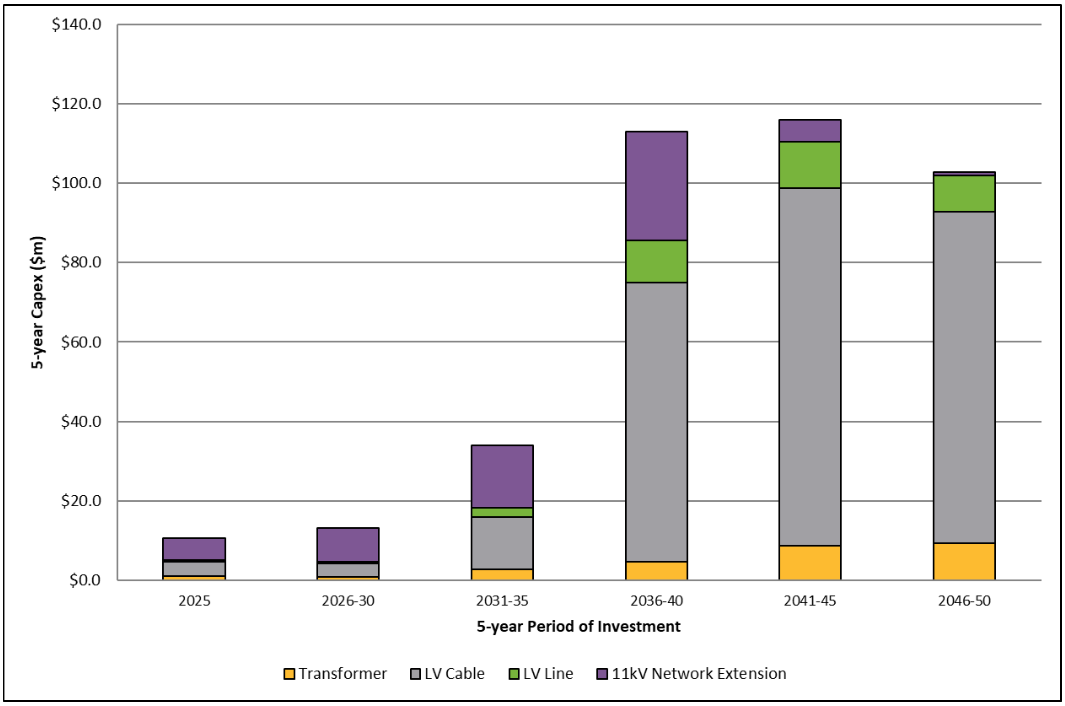



**Figure 9-42 Forecast LV Reinforcement CAPEX to 2050 for Base AMP Scenario**

As the ANSA model is probabilistic, these results do not directly trigger investment. Instead, the results produce a heat map of areas where capacity may be constrained, such as shown in Figure 9-43, which is then used to target further investigations to confirm whether there is currently a need to invest. This targeted approach avoids the expense of installing monitoring equipment on all transformers or procuring network-wide coverage of smart metering data, and focuses expenditure on the areas that are likely to need it. This approach is discussed further in Section 11.3.2.

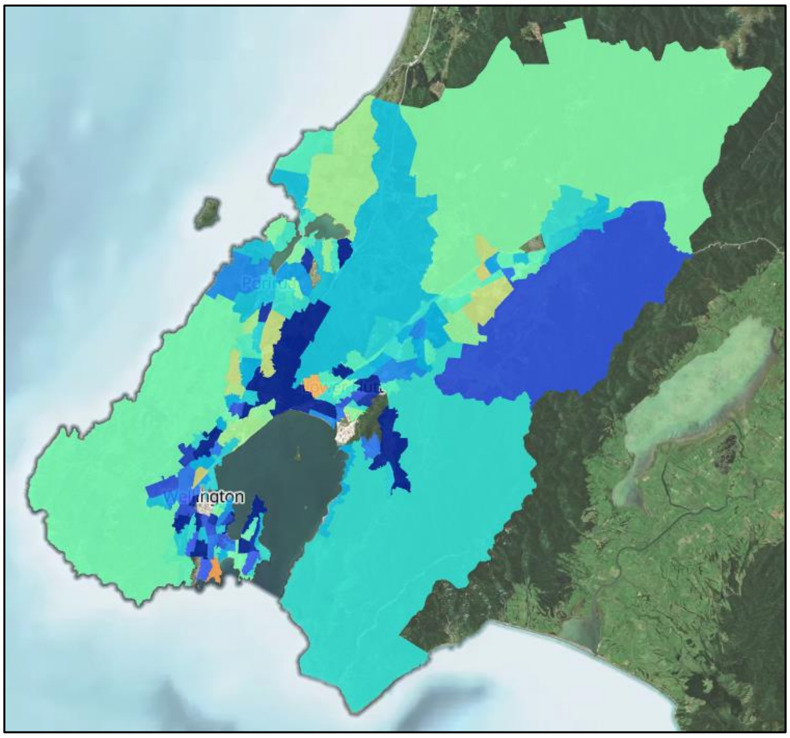


**Figure 9-43 Example ANSA Heat Map (Median 6pm EV Hosting Capacity at SA2 Level)**
**Image © ANSA® 2025**

## 9.8 System Growth and Reinforcement Summary for 2025-2035

From the details in the sections above, WELL's total forecast capital expenditure for system growth and security of supply for 2025 to 2035 by asset category is summarised in Table 9-54.

| Asset Category | 2025/26 | 2026/27 | 2027/28 | 2028/29 | 2029/30 | 2030/31 | 2031/32 | 2032/33 | 2033/34 | 2034/35 |
|---|---|---|---|---|---|---|---|---|---|---|
| Subtransmission | 477 | 4,296 | 251 | 5,846 | 6,223 | 20,838 | 19,983 | 9,853 | 6,497 | - |
| Zone Substations | 398 | 8,986 | 6,905 | 4,731 | 5,482 | 18,352 | 10,313 | 312 | 9,295 | 6,453 |
| Distribution Poles and Lines | - | 190 | - | - | - | - | - | - | - | - |
| Distribution Cables | 15,720 | 22,763 | 17,792 | 17,670 | 6,838 | 1,309 | 9,652 | 27,894 | 16,209 | 20,850 |
| Distribution Substations | - | - | - | - | - | - | - | - | - | - |
| Distribution Switchgear | 57 | 504 | - | - | - | - | - | - | - | - |
| Other Network Assets | - | - | - | - | - | - | - | - | - | - |
| **Total** | **16,651** | **36,739** | **24,948** | **28,247** | **18,543** | **40,499** | **39,948** | **38,058** | **32,000** | **27,303** |

**Table 9-54 Capital Expenditure Forecast by Asset Type**
**($K in constant prices)**

# 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.

## 10.1 WELL Information Systems

Information Technology (IT) is a key enabler in the distribution of electricity. Information and communication technologies have a pervasive reach and are now impacting every area of the business. There is increasing convergence of traditional engineering and IT disciplines, especially in regard to Operational Technology[36] (OT). This section briefly describes the primary digital tools used by WELL, and related renewal activities.

### 10.1.1 Asset and Operational Systems

The information systems WELL uses to manage its asset information are described below.

#### 10.1.1.1 SCADA

A GE PowerOn Advantage 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.

Outage reports are recorded by the GE PowerOn 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.

#### 10.1.1.2 Planned Outage Management

EDNAR is used for managing Network Access Requests and planned outage workflow. All planned outage requests are submitted electronically into EDNAR by the field contractor, and reviewed by WELL's Outage Planning Team before the switching is written in PowerOn Advantage. EDNAR has automated notification to retailers of planned outages and the publication of additional notice about intended interruptions to WELL's website.

#### 10.1.1.3 Load Management System

A Catapult Load Management System is used for managing hot water load control, and the switching of streetlights and other controllable loads, via WELL's ripple control system.

#### 10.1.1.4 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 Electric Office GIS application for planning, designing and operating the distribution system and this is the primary repository of network asset information.

[36] Operational Technology is defined as IT systems that enable the power system to operate.

The GIS interfaces to WELL's maintenance management system (SAP PM), the billing system (Gentrack), the field service provider's works management system, and the B4UDig underground asset location platform.

WELL frequently shares its GIS data with interested parties, subject to a data usage agreement. In the last 12 months this has included the Wellington Underground Asset Register,[37] other infrastructure providers, and organisations exploring options for embedded generation.

#### 10.1.1.5 Drawing Management System

WELL stores all GXP, substation, system drawings, and historic asset information diagrams in ProjectWise in PDF and CAD format. WELL is currently reviewing the system for building an automated workflow for access and approvals of the drawings.

#### 10.1.1.6 Power System Modelling

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.

#### 10.1.1.7 Cable Rating Modelling

CYMCAP is used to model the ratings of underground cables at all voltages for existing cables in service and new developments.

#### 10.1.1.8 LV Voltage Drop Modelling

LVDrop is used to model LV electrical networks to ascertain voltage drops and the 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.

#### 10.1.1.9 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. WELL is currently looking at building an automated workflow for access and approvals of the configuration parameters and moving the database to a secure cloud-based repository.

#### 10.1.1.10 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 hosted in Melbourne by WELL's sister company Powercor. WELL is currently exploring options for its replacement.

[37] https://nzuar.org/

##### 10.1.1.11 Supplier Management

WELL has implemented State of Flux as its supplier management tool. This tool consolidates project financial reporting and KRA reporting across the various contracts. Further work is in progress that will extend the capability of the tool to manage the full lifecycle of network projects.

### 10.1.2 Billing System

Gentrack is used to manage ICP and revenue data, 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 Advantage systems to provide visibility of customers affected by planned and unplanned network outages. Gentrack interfaces with the SAP financial system for billing purposes.

The Gentrack system is currently hosted in Melbourne by Powercor. The billing system requires overhaul and WELL is looking at options to modernise it. A key requirement for the updated system is the ability to support future network pricing structures, as discussed in Section 11.3.4.

### 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, accounts payable, and general accounting.

SAP is hosted in Melbourne by Powercor. WELL is currently exploring options for its replacement.

### 10.1.4 System Upgrades and Replacement Planning

WELL has initiated a number of significant projects to upgrade or implement core systems. The status of these upgrades is provided in Table 10-1.

| System | Status |
|---|---|
| GIS | Upgrade completed in 2022. |
| HR/Payroll | Upgrade completed in 2022. |
| Billing | Overhaul of the system is planned to modernise the billing solution |
| SCADA | Upgrade completed in 2023. |
| Load Management | Upgrade completed in 2023. |
| Planned Outage Management | Implementation completed in 2023. |
| Finance/Plant Management | Project scoping is underway. |
| Supplier Management | Implemented in 2024, with additional work planned for 2025. |
| Project Management | Project scoping is underway. |
| Inventory Management | Project scoping is underway. |
| Network Resilience Risk Analysis | Implementation completed in 2025. |

Table 10-1 Status of Support System Replacement Programme

## 10.2 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 continues to invest on an ongoing basis in training, systems and processes that enhance cyber security monitoring and protection.

WELL has performed multiple Cyber Security Audits in 2024, both internal and external. A number of improvements have been implemented based on the findings of these audit reports. This process will continue in future years as part of our Cyber Security response programme.

## 10.3 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 Omexom who input asset information into the GIS and SAP PM information systems.

## 10.4 Data Quality

Robust and timely asset information is needed to drive asset management activities such as development, maintenance, refurbishment, and replacement.

Data quality is measured by the data's usefulness for specific purposes and includes the following dimensions:

- **Accuracy:** Data recorded in information systems must be factual, timely, clear, and consistent. Data should be checked at the source whenever possible.
- **Completeness:** All mandatory data in a dataset must be completed. Default codes are used only where appropriate, not as substitutes for actual data. Data should reflect the complete capture of all WE* activities, with regular spot checks, audits, and comparisons between systems to identify missing data.
- **Consistent:** All the data items when stored in multiple information systems should be as consistent as possible and have the least number of conflicts.
- **Timeliness:** Timely recording of data is crucial, especially in distribution services, ensuring data is available when needed for service delivery and reporting.
- **Validity:** All the data must be valid and where possible should conform to the syntax (format, type, range) of its definition.
- **Uniqueness:** All the data items should have the least number of duplicate records.

Apart from the above data quality dimensions, the following are some characteristics of data that are defined for data managed by each information system and are part of the data quality framework.

- **Availability:** All data must be able to be used or obtained where possible.
- **Confidentiality**: All data items should be protected against unauthorised access and misuse.

- **Responsibility:** All the data information systems must have roles and responsibilities assigned for maintaining data quality that is who is responsible and who is accountable.

Data management and governance is critical for WELL, particularly with new data requirements emerging as the electricity industry evolves. WELL has completed a review of its data management and is implementing the most important findings of this review and including them in any future system replacement requirements.

Significant improvements have been made to WELL's asset data quality over the last 12 months, particularly in the area of LV connectivity as a result of the ANSA LV Constraint Risk Modelling project (see Section 11.3.2.1). However, WELL is becoming increasingly reliant on data provided by external parties, for example smart metering data (see Section 11.3.2.6). The lack of a regulated New Zealand data quality standard for this, such as the Australian Meter Data File Format (MDFF), will hamper networks' abilities to make operational use of this data in future. WELL's LV Management workstreams (discussed in Section 11.3.2) are intended to allow WELL to make cost-effective progress in LV management despite this third-party data quality limitation.

## 10.5 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.

## 10.6 Non-network Land and Building Assets

In 2024 WELL relocated its corporate disaster recovery site and backup network control room away from Transpower's Haywards GXP due to Transpower terminating WELL's lease of the site.

WELL's head office in Petone is located in a tsunami evacuation zone.[38] A project is underway for WELL to relocate its head office away from the coast in order to mitigate this risk. This relocation will be completed in 2025/26. The project involves the construction of a new building with seismic performance at Importance Level 3, the relocation of WELL's primary control room to the new building, and the development of the associated systems and processes to support modern ways of working.

WELL's network building assets are discussed in Section 8.5.2.3 (Zone Substations) and Section 8.5.5 (Distribution Substations).

[38] https://www.huttcity.govt.nz/services/emergency-management/useful-information/maps

## 10.7 Non-Network Asset Expenditure Forecast

From the details in the sections above, WELL's non-network expenditure forecast is summarised in Table 10-2.

| Expenditure Type | 2025/26 | 2026/27 | 2027/28 | 2028/29 | 2029/30 | 2030/31 | 2031/32 | 2032/33 | 2033/34 | 2034/35 |
|---|---|---|---|---|---|---|---|---|---|---|
| GIS | 300 | 154 | 158 | 163 | 168 | 173 | 178 | 184 | 189 | 195 |
| SCADA | - | - | - | 700 | - | - | - | - | 900 | - |
| Load Management | 20 | 21 | 21 | 22 | 22 | 23 | 24 | 24 | 25 | 26 |
| Operational IT Infrastructure | 100 | 61 | 1,998 | 65 | 102 | 69 | 71 | 73 | 75 | 78 |
| Mobile Operations Tools | 100 | 103 | 106 | 109 | 112 | 115 | 119 | 122 | 126 | 130 |
| Outage Management | 20 | 200 | 20 | 22 | 22 | 23 | 24 | 24 | 25 | 26 |
| Asset Management | 1,865 | 200 | 206 | 212 | 219 | 225 | 232 | 239 | 246 | 253 |
| Engineering Tools | 20 | 21 | 21 | 22 | 22 | 23 | 24 | 24 | 25 | 26 |
| Other Systems (e.g. Billing, Financial, Website) | 1,715 | 441 | 454 | 468 | 482 | 1,046 | 511 | 526 | 542 | 558 |
| IT Infrastructure | 1,875 | 570 | 201 | 207 | 213 | 2,219 | 626 | 233 | 240 | 247 |
| Head Office Relocation | 18,000 | - | - | - | - | - | - | - | - | - |
| Capitalised Leases | 546 | 2,076 | 249 | 992 | 170 | 546 | 546 | 546 | 546 | 546 |
| **Total Non-network Capital Expenditure** | **24,561** | **3,847** | **3,434** | **2,982** | **1,532** | **4,462** | **2,355** | **1,995** | **2,939** | **2,085** |
| System Operations and Network Support | 10,901 | 11,041 | 11,209 | 11,388 | 11,572 | 11,572 | 11,572 | 11,572 | 11,572 | 11,572 |
| Business Support | 14,149 | 14,332 | 14,550 | 14,782 | 15,021 | 15,214 | 15,417 | 15,417 | 15,417 | 15,417 |
| **Total Non-network Operational Expenditure** | **25,050** | **25,373** | **25,758** | **26,169** | **26,592** | **26,786** | **26,989** | **26,989** | **26,989** | **26,989** |

**Table 10-2 Non-Network Expenditure Forecast
($K in constant prices)**

# 11 Enabling the Future Network

This section looks beyond traditional network investment to discuss the new tools and capabilities that WELL needs in order to cost-effectively manage its network in future. WELL's systems will evolve gradually with an initial focus on developing tools to assist the uptake of Customer-owned Energy Resources (CER) and to appropriately value the cost of constraints on its network.

## 11.1 Innovation Practices

WELL's desired outcome from its innovation workstreams is to reduce the impact of CER on the network peak demand, delaying capital investment and therefore reducing the rate of electricity price increases for its customers.

Success for these innovation practices is defined by them:

- Being proven to meet the network use case;
- Being proven to be commercially attractive for participants, and
- Having a lower lifecycle cost than traditional network expenditure.

If this can be proven by the trials, then subsequent commercial adoption depends on the availability of allowances to allow WELL to fund the practice.

WELL collaborates with other companies in industry forums, for example through its leadership of EV Connect (see Section 11.2.3.1) and its participation in industry groups. WELL is directly engaging with other EDBs and companies through commercial trials that are underway (see Section 10.2.3.3). WELL believes that collaboration with other companies across the electricity supply chain is essential for realising the desired benefits, with shared learning producing efficiencies and stacking value for customers.

A significant component of innovation activities is developing tools for the acquisition and analysis of information required to identify and predict network constraints, particularly metering data to indicate the performance of the low voltage network. The accurate targeting of innovation practices at constraints will be critical for meeting their success criteria. Information will be sourced in a coherent and efficient manner when a workstream is established to explore the relevant use case.

## 11.2 Development Programmes

### 11.2.1 Supporting Regulatory Changes

Electricity distribution services are regulated directly by both the Commission (who sets funding levels and quality targets) and the Authority (who sets market participation rules) and are also subject to indirect regulation by entities like EECA (who sets standards for the operation of customer appliances) and MBIE (who administers electricity legislation and regulations). Important regulatory changes are needed to support EDBs' delivery of decarbonisation-related investment, and the promotion and incorporation of flexibility services.

The Government Policy Statement on Electricity in October 2024 highlighted the important role flexibility services will play in ensuring networks can maintain a secure supply of electricity. Important changes to the Code are needed to realise this benefit.

#### 11.2.1.1 Code Changes to Support the Uptake of EVs

Changes are needed to the Code to support the secure connection of large EV chargers:

- A requirement for all large EV chargers to apply to connect to a network. The assessment process should be automated so as not to slow the connection process and would identify where EDBs would need a more in-depth assessment to ensure the devices can operate within the existing network capacity.

- Standards to ensure large EV chargers are capable of being remotely managed, with appropriate permissions are in place.

#### 11.2.1.2 Code Changes to Support Flexibility Services

Further changes are needed to the Code to support the development and operation of a full flexibility service:

- Providing EDBs with streamlined access to smart meter data (both consumption data and power quality data) and information on the location and operating characteristics of large CER, under clearly defined and mandated quality standards. This data is needed as an input into the systems that are needed to identify congestion on the LV network. The collection and supply of metering data is a natural monopoly, and therefore requires careful price-quality regulation to ensure that the cost of its provision to EDBs (which will ultimately be paid for by customers, who have already paid for its initial collection by the MEP) is reasonable.

- Implementing an industry-wide hierarchy of needs. Network operators (both EDBs and Transpower) have been able to maintain a secure electricity system by having priority access to hot water ripple control in emergency situations – that is, when direct intervention is needed to 'keep the lights on'. Currently, the Code provides this capability for hot water ripple control via the DDA. These are rare events that would have a limited impact on competing flexibility services. Networks need to retain this priority access as the highest element of the value stack, as flexibility cannot exist without a secure and stable electricity system. This capability needs to be expanded to new devices beyond water heating, including those managed by flexibility providers not currently captured in the Code. This capability will ensure a stable and secure electricity system that flexibility services can be built on.

#### 11.2.1.3 Other Regulatory Changes

In all cases, regulatory changes must be carefully considered to ensure that cross-subsidisations are not being created, for example to avoid energy poverty being exacerbated by rules that result in customers who cannot afford CER, or renters who have no option to install PV at their residence, cross-subsidising wealthier customers who are able to afford CER.

In addition, EDBs must retain the ability to manage operational network security to meet the regulatory obligations that they are accountable for. These include regulatory quality targets applied under Part 4 of the Commerce Act 1986 (SAIDI and SAIFI targets), power quality obligations under the Electricity (Safety) Regulations and the Code (including adherence to the permitted voltage range for electrical supply), and liability under the Consumer Guarantees Act for any power quality damage to customer appliances.

### 11.2.2 LV Management

WELL's immediate focus for LV management is on developing LV visibility by combining GIS spatial data with ICP level consumption, voltage data, and transformer monitoring information. WELL's approach has been to develop key concepts as building blocks into trials and pilot programmes, that leverage previous work and build towards the goal of allowing the market to manage LV constraints in realtime. These building blocks and their interrelationships are shown in Figure 11-1.

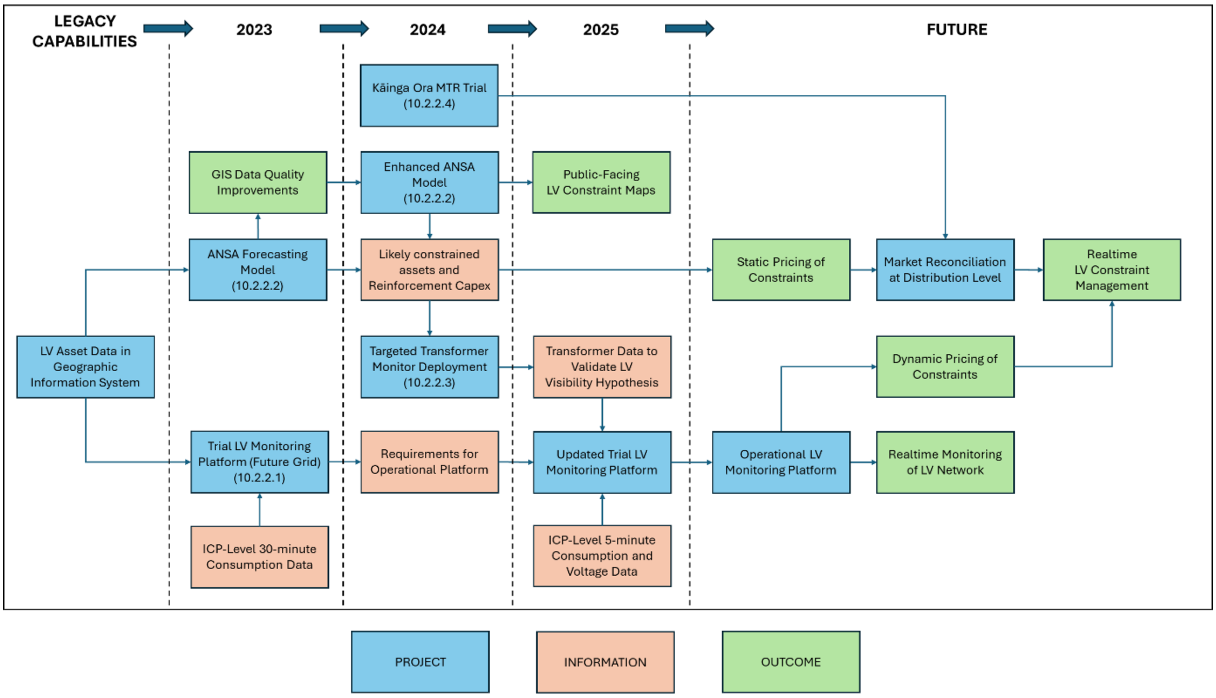



Figure 11-1 Key LV Visibility Building Blocks

### 11.2.2.1 Future Grid Pilot

During 2022, WELL participated with seven other EDBs in Ara Ake's EDB Challenge. This was focused on identifying potential solutions, both from New Zealand and internationally, for incorporating flexibility into EDB's asset management processes.

With the increase in electrification and increased deployment of CER within the network, greater visibility of the LV network is becoming more important for both planning timeframes and real-time operations. Increased LV visibility will help EDBs identify network constraints, enable proactive identification and resolution of power quality issues, and form the basis for any future market for flexibility services. All of these use cases will provide significant benefit to customers.

As a result of the Challenge, WELL chose to partner with Future Grid. Future Grid is a LV network visibility and management platform, currently in use with a number of WELL's Australian sister companies, which WELL identified as being a good fit to help resolve LV network information gaps, including constraint mapping and modelling the impact of flexibility services on network operations.

A pilot of Future Grid's "Compass" software ran during 2023.[39] The findings of the trial were:

1. Third party ICP consumption data and WELL's spatial data were successfully incorporated into the tool.
2. Half hour consumption data was able to provide useful asset management insights, however having cost-effective access to voltage data is critical for the majority of use cases for the tool.

[39] https://www.araake.co.nz/projects/edb-challenge/

3. It is essential for regulation to provide for the ongoing funding of software, data procurement, and people to run and maintain it.

WELL will use the experience of the Future Grid pilot to develop a set of requirements for the procurement of a network-wide LV management platform. As well as providing greater visibility of LV constraints, this platform will have significant value for the proactive identification of abnormal network conditions that can have a public safety impact, such as deteriorating neutral connections.[40]

#### 11.2.2.2 ANSA LV Constraint Risk Modelling

WELL commissioned ANSA in 2023 to develop a low voltage constraint risk and capex forecasting tool. The tool analysed WELL's residential LV network, combining GIS data, consumption data, decarbonisation load growth forecasts, and standard costs, to forecast LV constraints and the CAPEX required to resolve them over a 50-year horizon.

The output of this tool was incorporated into WELL's System Growth CAPEX forecast presented in the 2024 AMP. It has also been used to target the next steps in WELL's LV management strategy, and to identify areas for improvement for the LV asset data held in WELL's GIS.

This model was updated in late 2024 to incorporate the improved GIS data, revised decarbonisation scenarios, and hosting capacity forecasts for PV. The results of the updated model are presented in Section 9.7.

The output of the updated ANSA model will be used in 2025 to create LV capacity maps for the benefit of customers considering investment in CER, and ultimately will help inform locational pricing that sets a value on constraints to incentivise their effective management.

#### 11.2.2.3 Piloting Transformer Monitoring Equipment

WELL is currently considering the most effective and efficient combination of data to provide visibility of the LV network. The currently hypothesis is that the aggregation of ICP-level consumption and quality data with a five-minute resolution, targeted at areas identified by the probabilistic ANSA model as being likely to be constrained, will be sufficient to provide the required insight into LV network performance, and that the procurement of 100% smart meter data coverage or the wide-scale rollout of transformer monitoring equipment will not provide sufficient marginal benefit to justify its cost.

WELL is testing this hypothesis through the deployment of 50 transformer monitors, targeting suburbs where the network has been identified by the ANSA model as being likely to be congested, with these suburbs spanning a range of socioeconomic and decarbonisation criteria as shown in Table 11-1.

[40] See "Leveraging Meter Data", Page 287, WELL Asset Management Plan 2022.

| Suburb | Socioeconomic Decile (1 = low deprivation, 10 = high deprivation) | EV Uptake per ICP (February 2024) | Gas Transition |
|---|---|---|---|
| Johnsonville | Decile 3-5 | 4.8% | Unknown |
| Tawa | Decile 1-7 | 5.9% | Unknown |
| Cannons Creek | Decile 10 | 0.9% | Unknown |
| Naenae | Decile 9-10 | 2.5% | High |

Table 11-1 Suburbs Targeted for Transformer Monitor Pilot

The alignment of the pilot suburbs to the 2023 ANSA study[41] is shown in Figure 11-2.

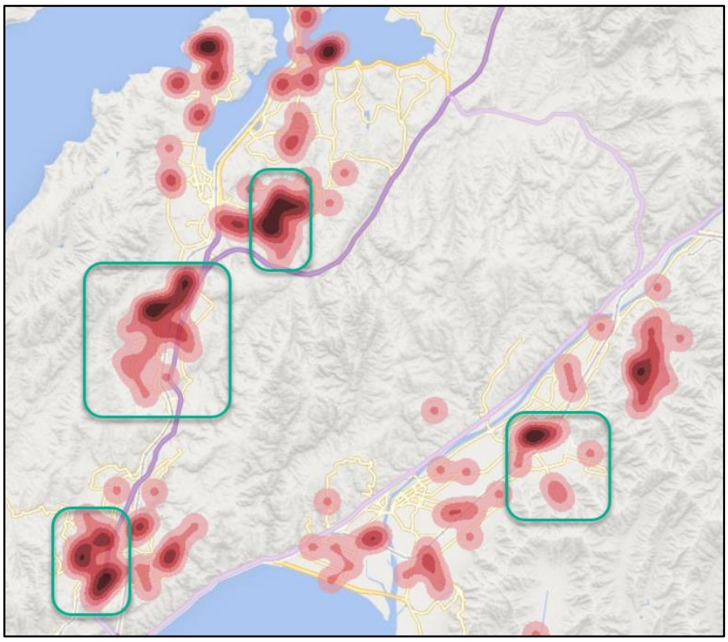


Figure 11-2 Alignment of Transformer Monitor Study Locations to LV Constraint Model Heatmap

The objectives of this project are:

1. Allowing the testing of the LV visibility hypothesis through the trial deployment of a small number of transformer monitors, with the results to be compared to the insights that can be achieved through the use of ICP-level data on its own.

2. Further testing of the Future Grid "Compass" LV monitoring platform through the ingestion of transformer monitor data.

3. Validating the ANSA model results for the monitored transformers.

4. Reviewing safety related functions (including broken neutral, stolen earth, and 11kV conductor down detection) for the transformer monitors, to assess how these functions could be integrated into operational practices.

[41] See Section 9.7, WELL Asset Management Plan 2024.

5. Improving WELL's awareness of distribution transformer fleet performance and utilisation (including voltage, current, and transformer temperature) through extrapolation of results from the monitored transformers.

The project is currently underway and expected to be implemented before Winter 2025.

#### 11.2.2.4 Wellington Multiple Trading Trial

In 2022 WELL partnered with Kāinga Ora, Ara Ake, Paua to the People, Bluecurrent, and Intellihub to test Multiple Trading Relationships.[42] The challenge that Kāinga Ora wanted to solve was to maximise the benefit of any excess electricity generated by PV installed on their properties, while allowing tenants to continue to benefit from self-consumption of PV generation and to continue purchasing electricity from the retailer of their choice.

The trial went live in May 2024, and is currently ongoing. To date, the trial has involved 180 residential Kāinga Ora properties on WELL's network. The Electricity Authority has granted Code exemptions for these installations to have separate ICPs for consumption and export. The consumption ICP is registered to the tenant's retailer, and the export ICP is registered to Kāinga Ora's retailer. This has allowed Kāinga Ora to monetise excess solar, using the funds to benefit a wider group of tenants including those without PV installed, while maintaining the tenants' consumer rights.

The Multiple Trading Trial won the prize for Energy Project of the Year at the 2024 New Zealand Energy Excellence Awards.[43]

This project is valuable for exploring ways that the benefits of CER can be shared with people in energy hardship, and for understanding how the electricity market must change to fully realise the value of flexibility services. From the network perspective, the reconciliation of the market at LV instead of at GXP-level will be critical for the valuing and clearance of LV constraints, and the Multiple Trading Trial is a step towards understanding how that might be implemented.

#### 11.2.2.5 Public EV Charging Points as a Network Solution

Public EV charging points have specific locational and electrical requirements that can require reinforcement of the 11 kV network to deliver the expected service levels. Enabling EV charge points to work in harmony with the network will be critical for the cost-effective rollout of public charging infrastructure. To this end, WELL is currently engaging with an EV charge point operator to deliver a project that will demonstrate a public charge point that can operate to a successful commercial model, while dynamically adapting its charging rates to the available 11 kV network capacity and providing network support at times of constraint. This project is currently in development, with further information to be disclosed at a later date.

#### 11.2.2.6 Developing Access to Data

The provision of ICP-level data is essential for the use of the models and tools identified in this section. It is not expected to be cost-effective, or to the long-term benefit of customers, for EDBs to invest to deploy their own equipment to gather and store this data, when it is already being collected at the existing smart meter.

Changes are needed to the Electricity Code to provide EDBs with streamlined access to smart meter data (both consumption data and power quality data). The collection and supply of metering data is a natural

[42] https://kaingaora.govt.nz/en_NZ/about-us/sustainability-at-kainga-ora/solar-innovation/
[43] https://www.araake.co.nz/news/kainga-ora-solar-programme-awarded-for-breaking-new-ground

monopoly, and therefore requires careful regulation to ensure that the cost of its provision to EDBs (which will ultimately be paid for by customers, despite them having already paid for its initial collection) is reasonable.

WELL's pilot of the Future Grid platform has focused on whether the software could be connected to the various data sources and whether those data sources provide the information at the level of quality needed. This required the development of data agreements and the handling of large third-party data sources.

WELL engaged with a Metering Equipment Provider about the provision of voltage data for the Future Grid trial. Voltage data was ultimately excluded from the project scope because the cost of the data exceeded the budget for the project and the coverage was limited, with only 1,000 ICPs (6% coverage of the trial sample) being able to be provided. The lack of ready access to five-minute voltage data is a significant barrier to the deployment of tools for identifying and managing LV constraints.

As well as the requirement for five-minute data, this pilot confirmed WELL's view that EDBs do not need to store or directly interact with the vast quantities of raw metering data that are generated by a network of its size. WELL's requirement is for the insights that can be generated from that data: identification of potential safety issues, asset utilisation, and the locations of constraints. These insights can be generated by algorithms running on data stored by a third party, eliminating the need to transfer large quantities of data, and the unnecessary duplication of digital storage infrastructure across multiple parties.

#### 11.2.2.7 Leveraging the Research and Development of WELL's Sister Companies

WELL's sister networks, United Energy (UE) and South Australia Power Networks (SAPN) have been developing a DSO capability over the last six years. Their development programmes have highlighted the complexity and time it takes to develop the DSO functionality and the supporting tools needed. WELL is leveraging their knowledge and experience to design its own research and development programmes. Important lessons from Australia for the NZ industry include:

1. Expect a large data correction and cleansing element. The Australian deployment of LV management software like Future Grid highlighted errors in the underlying GIS and ICP data. In 2023 WELL sent a sample of data from ICPs on its network to UE for analysis with their tools. This identified that the quality of metering data available in NZ at that time was inadequate for use in operational LV management tools.

2. Expect a multiple year development timeframe. Incorporating the LV visibility and management into network management functions is complex and will need to be staged.

### 11.2.3 The Development of Flexibility Services

WELL supports the development of third-party demand management on its network. This benefits our customers by allowing them to realise a financial return on their investment in CER, growing the quantity of CER on the network, and ultimately allowing for the aggregation of CER to the scale needed to provide WELL with access to reliable non-wires alternatives to traditional investments in new network capacity for the benefit of its customers.

CER needs to be carefully managed within technical limits to ensure that its use does not create adverse reliability or power quality impacts on customers, and to ensure that it is able to support the electricity system under network emergency conditions. A stable network is a fundamental requirement without which flexibility markets cannot exist.

### 11.2.3.1 EV Connect Roadmap

EV Connect was an industry-wide work programme that focused on how more energy can be delivered through the existing network. This is part of an Energy Efficiency & Conservation Authority (EECA) Low Emissions Vehicle Contestable Fund (LEVCF) project. The purpose of EV Connect was to understand how best to support EV adoption while maintaining network security.

WELL 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, 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.

Recommended 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 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 Roadmap is summarised in Figure 11-3.

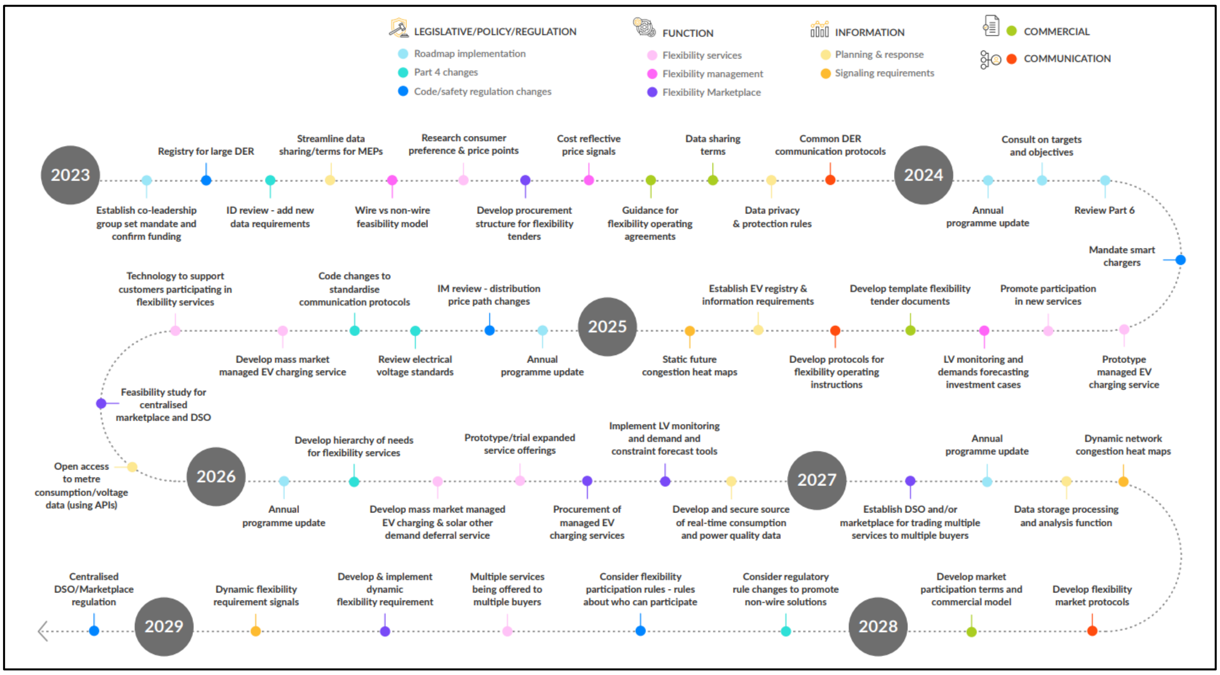



Figure 11-3 EV Connect Roadmap[44]

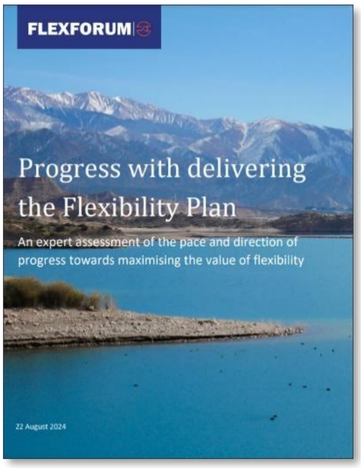
[44] https://www.welectricity.co.nz/about-us/major-projects/ev-connect/

### 11.2.3.2 FlexForum

The FlexForum is a cross-industry group formed in February 2022 to identify the actions needed to integrate CER into the electricity system and markets to maximise its benefits for New Zealand. The purpose of the group is to:

> *"deliver the practical, scalable and least-regrets steps that enable households, businesses and communities to make the choices which maximise the benefits of flexibility".*[45]

The FlexForum is the natural progression of WELL's EV Connect programme and is implementing the actions identified by EV Connect. WELL is an active participant and supporter of the FlexForum.




Practically, an immediate outcome of the programme will be trials that can be scaled into operational solutions. The intent is for the FlexForum members to develop trials together – the membership representing flexibility providers with access to controllable customer devices, retailers with the ability to develop scalable customer products, and flexibility service users (EDBs, Transpower etc) who will develop their internal processes and systems to use the services.

The FlexForum released an update to progress against the Flexibility Plan in August 2024. More details about the FlexForum and the Flexibility Plan can be found at https://flexforum.nz/.

### 11.2.3.3 Resi-Flex

Resi-Flex is a collaboration between WELL and the Christchurch EDB Orion, to develop and trial commercial mechanisms that support residential flexibility. The goal is to produce a simple and attractive customer proposition for households that rewards customers for shifting their electricity use.

The benefits of doing this collaboratively are that it increases the scale of the trials, pools resources and expertise to allow faster implementation, and produces a consistent approach across EDBs. Figure 11-4 provides a summary of the trial steps.

[45] FlexForum, Flexibility Plan 1.0, https://flexforum.nz/flexibility-plan/

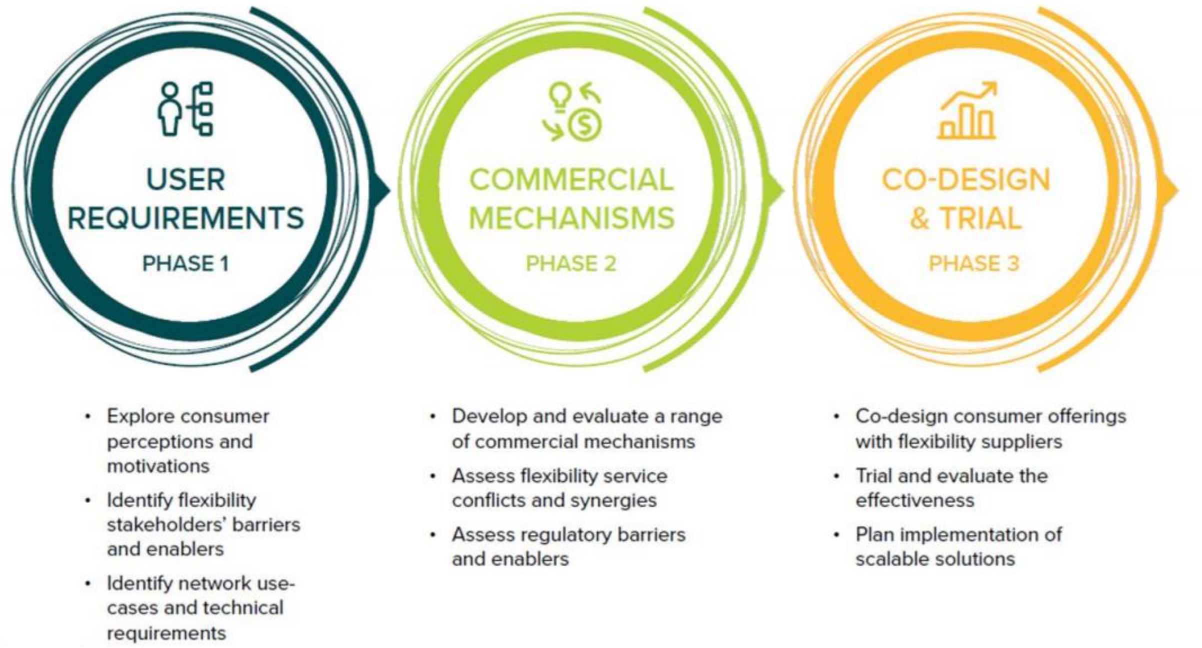



**Figure 11-4 Resi-Flex Project Stages**

The User Requirements phase of the project was completed in 2023 and the results were presented at the 2023 Electricity Engineers' Association conference. The findings from the User Requirements phase have been shared publicly in the project's first public report.[46] The second phase, the development of commercial incentives, has been completed with the development of a Commercial Framework which has been used to develop a set of three commercial mechanisms to be trialled in phase three (Co-design and Trial). The Commercial Framework has been passed onto the Electricity Networks Aotearoa Future Network Forum, which will be using it for their commercial flexibility workstream.

The third and final phase is now underway. In March 2024 an Expression of Interest was released to find trial partners, seeking to co-design trials in partnership with flexibility stakeholders (e.g., retailers, flexibility suppliers, aggregators, end-consumer integrators, or a mix of actors partnering together). These trials are now being developed, to test a range of commercial mechanisms and consumer offerings that will incentivise greater use of flexibility resources in the future and help stimulate the flexibility market.

#### 11.2.3.4 Flexibility Commercial Framework

As part of the Resi-Flex project, WELL and Orion have developed a commercial framework for flexibility services. This includes a framework for deciding when flexibility services will provide a viable alternative to traditional services and how this could be priced by the EDB. The framework will also provide a range of different commercial models that EDBs could offer to flexibility providers.

The commercial framework includes methodologies for calculating and setting flexibility price signals and a calculator for calculating the value of flexibility payments. The framework also includes a selection of different commercial mechanisms. Figure 11-5 summarises the mechanisms and classifies them by the three methods of trading flexibility.

[46] https://www.welectricity.co.nz/news/document/323


Figure 11-5 Flexibility Commercial Mechanisms

### 11.2.4 Tariff Pricing Reform

WELL is revising its tariff structure to provide stronger and clearer price signals to encourage off-peak electricity use. The pricing framework that its new tariffs are being built around also supports tariffs for flexibility services, including tariffs for managed services. WELL's Pricing Roadmap provides details about the price reforms and can be found at https://www.welectricity.co.nz/disclosures/pricing/future-pricing/.

Specific changes being made to support a network-wide flexibility include:

- Progressively simplifying WELL's price structures, with the intended outcome being a phasing out the off-peak price signal, leaving only the peak period price signal. This will provide a clearer signal of the value of flexibility while ensuring that customers are not penalised for using the network when it is not constrained. The fixed costs of operating the distribution network will be entirely recovered through the fixed price component.
- Developing a new long-run marginal cost methodology that will more accurately calculate the strength of a tariff price signal.
- Introducing new tariffs, including exploring differential pricing for congested areas.
- Continuing to encourage the uptake of ToU prices. Around 95% of residential customers are now receiving ToU prices. Last year, we simplified our ToU prices by combining our EVB and residential ToU tariffs to make it easier for retailers and customers to use.
- Expanding the use of operating envelopes to provide customers with a cost-effective connection to the network where the timing of their demand can be flexed to fit within available capacity.

# 12 Resilience

## 12.1 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 Civil Defence Emergency Management (CDEM) Act 2002, 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.

There are steps networks can and should take to reduce the vulnerability of their networks, and to increase their ability to respond to varied, unpredictable, and complex events, however, networks cannot be hardened to the point where they are resilient against all threats. Overhead networks will always be vulnerable during storms, as they cannot be designed to withstand the shock loading of large windborne debris. Similarly, underground networks will always be vulnerable to earth movement such as landslides and liquefaction.

Increasing the resilience of communities as a whole requires the collaboration of Civil Defence, Local Authorities, lifeline utilities, and other agencies. This will ensure that the most appropriate protections are in place, for example stop banks that are able to provide coordinated protection for communities and infrastructure in an overall more cost-effective manner than each organisation undertaking its own flood hardening in isolation. Community hubs will be critical for supporting recovery after a major event, providing welfare, standalone power, and a distribution point for food and water.

Decarbonisation introduces additional elements to resilience. As the community transitions transportation and heating fuels away from petrol and gas to electricity being the only source of household energy, electricity outages will have a much greater impact than they currently do. Conversely, EVs have the potential to increase household resilience through the use of their batteries to supply critical household appliances through Vehicle to Load capability (V2L).

Any new technologies need to be carefully considered through the lens of resilience before being accepted for use on the distribution network. For example, communication systems that play a critical role in managing the security of the network and its recovery following an event, such as the hot water control system that is used for emergency load shedding, cannot be allowed to fail. The operation of these systems would be placed at risk if they transitioned to new technology that was reliant on cellphone networks, due to the inevitable overloading of cellphone networks that occurs following a major event, and the short battery backup times at cell towers. This vulnerability has been demonstrated by the Christchurch and Kaikoura earthquakes, and again during Cyclone Gabrielle. It is essential that telecommunications network operators, as providers of critical infrastructure, adjust their contingency plans to accommodate the long outages on the electrical supply network that can occur during major events, rather than optimising their systems for business-as-usual operation.

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; and
- Future resilience work – WeLG Regional Resilience Project.

A significant amount of work was undertaken to improve earthquake readiness under WELL's 2018 CPP. Delivery of the Readiness CPP greatly improved WELL's ability to respond to emergencies. 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 12.5 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 gas-filled subtransmission cables.

## 12.2 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.

NIWA is forecasting that the climate in the Wellington region will continue changing for the foreseeable future.[47] The average temperature in the region is expected to increase by 0.75-1.25°C by 2040. This increase in average temperature will result in fewer cold days and an increase in the number of hot days, potentially changing the nature of the electricity network load patterns. Rainfall events are expected to become more severe in both frequency and magnitude, increasing the risk of flooding and landslides. 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. Wellington already has one of the highest wind zones in the country due to its position on Cook Strait and between the 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 2.82 mm per year from 1961 to 2019, through a combination of climate factors and seismic subsidence, with the rate of rise continuing to accelerate.[48] Sea level rise is a long-term problem, with significant variations in possible scenarios, and effects becoming significant towards the end of the century.[49] 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 Cyclone Dovi in 2022 and the large storm surges that caused damage on the south coast of Wellington in April 2020 and June 2021.

A coordinated 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, WELL's Inundation Zones Policy will over time help WELL to better protect assets at risk of storm inundation and sea level rise. 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.

47 "Climate change projections for west of Wellington's Tararua and Remutaka Ranges" NIWA, September 2022.

48 "Update on sea-level rise projections for Wellington City" NIWA, March 2021.

49 "Sea Level Rise Options Analysis" Tonkin & Taylor, June 2013.

## 12.3 Emergency Response and Contingency Planning

WELL follows the 4Rs approach to hazard management, as outlined by the National Emergency Management Agency (NEMA).[50] The 4Rs are described in the context of EDBs in the EEA Resilience Guide[51] 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.

### 12.3.1 Civil Defence

NEMA is responsible for emergency management on a national scale. Emergency management is governed through the CDEM Act 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.

### 12.3.2 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.

### 12.3.3 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 governments. 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 stormwater 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:

[50] https://www.civildefence.govt.nz/cdem-sector/the-4rs/
[51] https://eea.co.nz/publication/resilience-guide-pdf/

- 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. 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. This has to some extent been alleviated by the Transmission Gully route, as was demonstrated when State Highway 59 (the former section of State Highway 1 that was bypassed by Transmission Gully) was closed for six weeks in 2022 due to a landslide.

Through 2018 and 2019 WeLG conducted a project on regional disaster response and recovery, as discussed in Section 12.5. A key component of this project was the 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.

### 12.3.4 Resilience Explorer

WELL has implemented the Resilience Explorer tool from Urban Intelligence. This online tool overlays WELL's GIS data with environmental hazard data, providing a consistent view of the risks posed to the network. WELL will be undertaking analysis using the tool over the course of 2025, commencing with flood risk, to determine the scope and timing of any future resilience and climate adaptation projects that may be required.

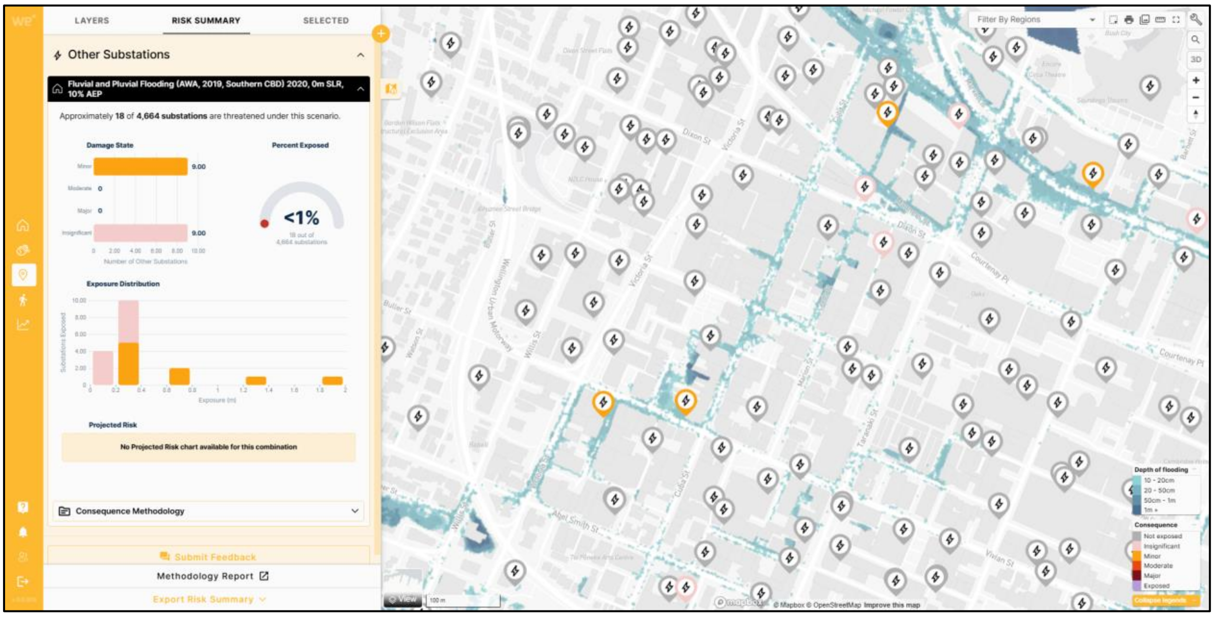



**Figure 12-1 WELL's Resilience Explorer Tool**

### 12.3.5 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.

#### 12.3.5.1 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 and Kaikoura earthquakes and the Wellington June 2013 storm have been incorporated into these plans.

#### 12.3.5.2 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 lives, relieving distress, and restoring the electricity supply.

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

#### 12.3.5.3 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.

#### 12.3.5.4 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.

#### 12.3.5.5 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 (DR) site at Tawa.

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 the Haywards DR site and operate from there until the end of January 2017.

WELL has relocated its primary DR site, including its primary data centre, backup control room, and essential business continuity functions, from Transpower's Haywards substation to a new building in Tawa. The new location offers significant resilience benefits, being a fully seismically rated building (100% NBS at Important Level 4) located in a different "island" to WELL's head office in Petone.[52] The relocation project was completed during 2024.

WELL has installed Starlink connections into all of its backup data centres and control rooms, to provide emergency communications links. This is a lesson from Cyclone Gabrielle, where the failure of terrestrial communication systems hampered response and recovery.

#### 12.3.5.6 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.

#### 12.3.5.7 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.

#### 12.3.5.8 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.

#### 12.3.5.9 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 the use of the DR sites and access to earthquake-specific equipment and systems including:

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[52] In the context of resilience, "islands" reflect the expected separation of WELL's network into isolated operational regions following a major earthquake due to damage to the roading network. The three islands are broadly defined as Wellington south of Ngauranga Gorge, Porirua and Wellington's suburbs north of Ngauranga Gorge, and Hutt Valley.

- Safe building entry;
- Emergency spares locations and access; and
- Mobile substations and data centres.

#### 12.3.5.10 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 the 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 was regularly updated throughout the pandemic as government guidance evolved, and to incorporate best practices learned from WELL's sister companies overseas.

WELL operated with two control rooms in separate locations, alternating shifts between the main control room and DR site to minimise the crossover of controllers. This enabled the control room to operate with a minimum degree of risk through all stages of the pandemic.

The Plan also describes working arrangements for each alert level, with staff being split across two sites to reduce the impact of disease entering the workplace. During elevated alert levels, WELL transitioned to staff largely working from home, with only the network control room and some senior management working from the two operational sites.

#### 12.3.5.11 Other Emergency Response Plans

WELL has other emergency response plans including:

- Priority notification procedures to key staff and contractors;
- Total Loss of Zone Substation Plan;
- Network Spares Management Policy;
- Loss of Transpower Grid Exit Point Plan (Transpower Plan);
- Emergency Load Shedding Plan;
- Participant Rolling 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.

## 12.4 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 practices 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.

### 12.4.1 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 earthquakes and tsunamis. Studies have been undertaken on behalf of WELL by GNS and other external providers have supported the development of WELL's Storm Inundation Policy. WELL will also utilise the Resilience Explorer Tool (refer to Section 12.3.4) to identify flooding risks.

### 12.4.2 Strategies to Mitigate the Impact of HILP Events

A discussion on the following HILP events is covered below:

- Major storm events;

- High-impact asset failure;
- Upstream supply failure;
- Major earthquake;
- Flooding and inundation, and
- Wildfire.

#### 12.4.2.1 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 7.4, 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 100 km/h for approximately 24 hours, peaking at over 200 km/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, predominantly at the low voltage level, 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, field crew fatigue management, SCADA system capacity, and capacity to scale up emergency staff in an event.

#### 12.4.2.2 High-Impact Asset Failure

WELL network’s system security standard is designed to provide a security of N-1 at the 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 part of the route selection process for new subtransmission cables. WELL's mobile substations provide another method for restoring limited supply following a major asset failure.

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. Decarbonisation will exacerbate these limitations as the electrification of loads currently supplied by fossil fuel increases demand and reduces capacity headroom on the electrical network.

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.

### 12.4.2.3 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 providing supply at both voltages. Table 12-1 lists the number of ICPs supplied by each GXP that supplies WELL's network.

| GXP | ICP Count (2024) |
|---|---|
| Central Park | 49,985 |
| Takapu Road | 34,820 |
| Melling | 21,013 |
| Gracefield | 20,208 |
| Haywards | 13,494 |
| Wilton | 12,874 |
| Upper Hutt | 11,389 |
| Pauatahanui | 7,265 |
| Kaiwharawhara | 5,596 |
| **Total** | **176,644** |

Table 12-1 ICP Numbers per Transpower GXP

**Central Park**

While the loss of any of these GXPs will result in the loss of supply to one or more zone substations and a significant number of customers, Central Park substation presents the highest risk. A failure at Central Park would have the largest impact in terms of both load loss and customers without supply. It supplies seven zone substations and a switching station, with over 50,000 customer connections and a maximum demand of approximately 150 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 zone substations. The area supplied by Central Park contains much of Wellington's CBD and includes a number of critical sites of national and regional importance such as Government premises, Wellington Regional Hospital, Wellington International Airport, and Moa Point Wastewater Treatment Plant.

The Central Park site, shown in Figure 12-2, is constrained by the limited available space within its small geographic footprint, having been built in its current location in around 1944. It contains electrical assets in close proximity to one another, resulting in a number of security of supply vulnerabilities. Large Transpower sites such as Penrose or Haywards are often 300-400m across, while Central Park is barely over 50m across with no fire separation between two of the transformers or between bus sections in the 33 kV switchroom.

Figure 12-2 Central Park Substation

Central Park supplies significant load across central Wellington and there is no alternative supply point in the event of a major earthquake or fire causing a failure at the site. The potential loss of supply at Central Park is therefore an unacceptable risk and as such, there is ongoing work between WELL and Transpower to expand the site and improve supply diversity. This is discussed further in Section 12.5.1.

**Melling**

Melling GXP supplies three WELL zone substations and circa 21,000 customer connections, comprising the primary commercial and residential areas of Lower Hutt, New Zealand's sixth most populous city.

Melling, shown in Figure 12-3, is located within the stop banks of the Hutt River, placing it at risk of flooding and erosion. The switchgear at the site is located in an elevated switchroom above the expected flood level, however, there is a risk of scouring and debris damaging the 110/33 kV transformers and 110 kV towers in the yard.

Transpower has assessed the flood risk for the site. Wellington Electricity is in discussion with Transpower and Greater Wellington Regional Council about a potential relocation of the site in conjunction with the Riverlink flood protection work (see Section 12.4.2.5), however, this work is not currently funded.

**Figure 12-3 Melling Substation (Hutt River Stop Bank Location Shown in Blue)**

The major costs for WELL associated with relocating Melling GXP relate to the oil-filled 33kV cables supplying Waterloo and Naenae. These cables are currently proposed for replacement due to asset health during DPP5. There would be additional costs associated with replacing the load control plant currently located in a WELL-owned building on the Transpower site.

In the event of a flood interrupting supply from Melling GXP, WELL would transfer the load to Haywards and Gracefield GXPs. This transfer capability has been estimated as 54% of the winter peak demand and 67% of the summer peak demand. The remaining customers will be without supply until Transpower is able to restore power to the GXP. In the event of the Transpower outage being prolonged, WELL would deploy its earthquake readiness spares (see Section 12.4.2.4) to re-establish a temporary overhead 33 kV connection from other GXPs to its affected zone substations.

**Pauatahanui**

Pauatahanui GXP is located north of Porirua city, supplying circa 7,000 customers via WELL's Plimmerton and Mana substations.

Pauatahanui GXP is situated within a 1-in-10-year flood zone.[53] The most recent significant flooding event at the site occurred in 2016, with 0.6m of water through the site causing damage to WELL's batteries and communications equipment at the site.

Transpower is investigating options for either upgrading or relocating Pauatahanui GXP to resolve the flood risk. WELL is assessing options for the relocation of WELL's equipment as part of this project.

The consequences of flooding at Pauatahanui are unlikely to include loss of supply to WELL's substations. In an event similar to 2016, the consequences for WELL are likely to be the loss of its SCADA connection to the site, and the battery backup for the protection intertripping to Mana and Plimmerton zone substations, both of which can be managed operationally.

### 12.4.2.4 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 12-4, a map of the region created by GNS science.

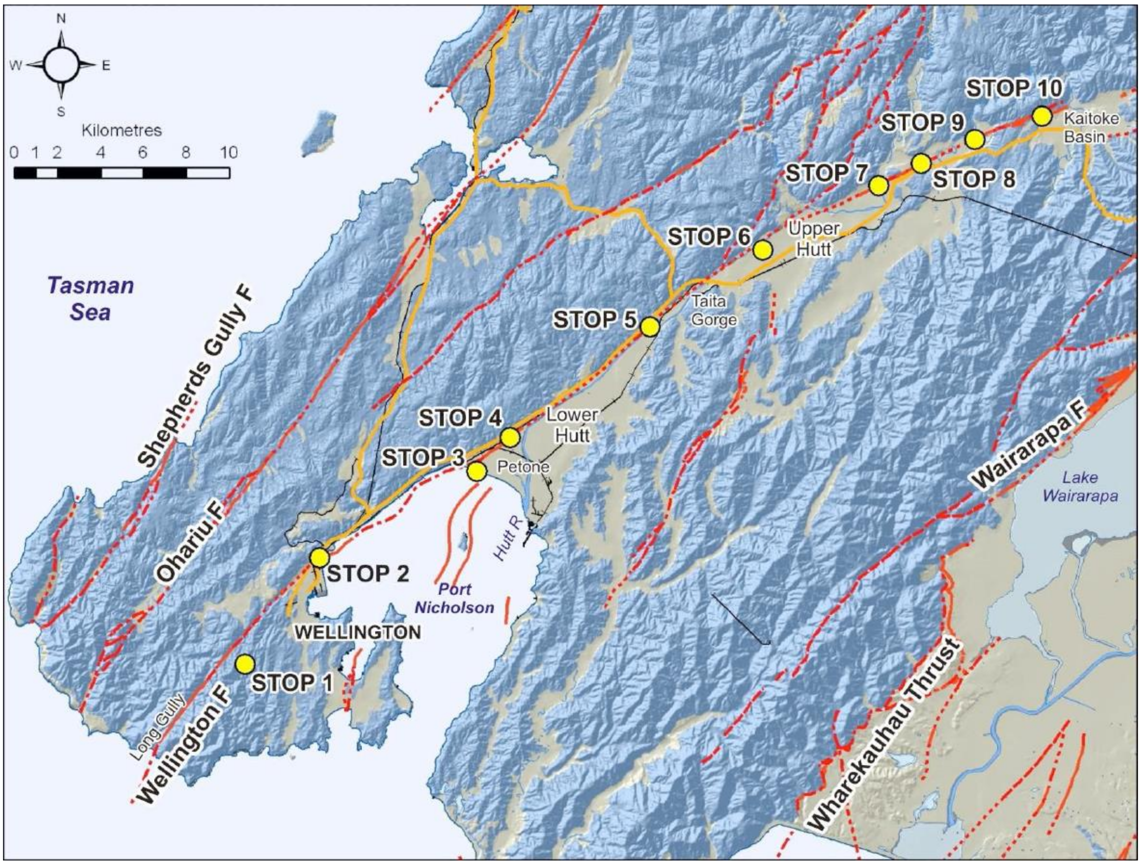


**Figure 12-4 Wellington Region Fault Lines[54]**

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 Remutaka

[53] https://poriruacity.govt.nz/your-council/city-planning-and-reporting/district-plan/proposed-district-plan/past-consultations/porirua-flood-mapping/

[54] 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).

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.

In addition to these local fault lines, the Hikurangi Subduction Zone to the east of North Island has been assessed as having a 25% probability of causing a magnitude 8+ earthquake in the next 50 years.[55]

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. Damage to transport links is expected to prevent road movement between Wellington and the Hutt Valley for a period of weeks.[56]

To identify potential resilience improvements, WELL has estimated the 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.

Restoration time estimates were separated into the time for transport into the area to be available and the time to repair the 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 readiness 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 storage locations throughout the network to reduce the impact of severed transport links, and to allow repair and restoration of the network to begin without needing to rely on resources from outside the region.

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

[55] https://www.eastcoastlab.org.nz/home/article/216/
[56] “Restoring Wellington’s Transport Links after a Major Earthquake” WeLG/WREMO, March 2013.

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 are unlikely to 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 the New Building Standard (NBS). As a part of the CPP, this programme was expanded to include the strengthening of 91 significant substations to a minimum of 67% of NBS.

A risk related to a major earthquake is the potential for a tsunami to affect Wellington. WELL's head office in Petone is located in a tsunami evacuation zone.[57] WELL has commenced a project to relocate its head office away from the coast in order to mitigate this risk, to occur in 2025/26.

#### 12.4.2.5 Flooding and Storm Inundation

In addition to causing widespread damage in the overhead network, major storms can result in flooding and landslides 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. In addition, flooding can cause lasting damage by destroying secondary systems such as protection and control equipment and accelerating the corrosion of metallic components.

WELL will be undertaking modelling of flood risk to its distribution network in 2025, utilising the Resilience Explorer tool discussed in Section 12.3.4.

**Porirua Zone Substation**

Porirua Zone Substation supplies circa 7,000 customers in Porirua City, Cannons Creek, Aotea, and Titahi Bay. It has been identified that the switchroom and transformer yard at the Porirua zone substation are at risk of stormwater ponding. The 11kV switchroom is currently planned to be relocated and rebuilt in a lower-risk position on site in 2031. Refer to Section 9.5.4 for more information about this project.

**Riverlink**

Riverlink is a Greater Wellington Regional Council-led project to strengthen Lower Hutt's defences against flooding from the Hutt River.[58] WELL has a number of important assets that will be protected by the new stop banks. The cost of each individual asset owner protecting themselves against flooding would be significantly greater than the cost being expended by the Regional Council, and the mitigation provided will be more secure. This is one of the lessons that has been learned from Cyclone Gabrielle, where stop banks were overtopped, leading to failures of the infrastructure that they were protecting. The 33kV subtransmission cables between Melling GXP and Petone substation, as well as several distribution substations, are expected to be relocated outside of the stop banks by the project. Refer to Section 13.5 for more information about this project.

[57] https://www.huttcity.govt.nz/services/emergency-management/useful-information/maps
[58] https://teawakairangi.co.nz/

#### 12.4.2.6 Wildfire

The Wellington region has not traditionally been susceptible to wildfire. However, it has been identified through engagement with the Greater Wellington Regional Council that there are several areas where the risk of wildfire is significant, and the size and number of these areas are likely to grow due to climate change. A particular area of wildfire risk is East Harbour Regional Park, where a coastal environment with high wind and low rainfall levels can produce a combination of flammable vegetation and electrical tracking caused by high levels of salt deposition on insulators.

WELL has engaged with its Australian sister companies to understand the strategies that they employ to minimise bushfire risk. WELL is using this information to develop its own wildfire mitigation policy, to be published in 2025. This policy will include enhanced design standards for wildfire-prone areas, protection and control strategies (such as auto-reclose blocks during periods of elevated risk) and communication protocols with relevant agencies.

### 12.4.3 Summary of Primary Resilience Risks

Table 12-2 summarises WELL's primary network resilience risks, and the actions underway to address them.

| Risk | Risk Type | Action |
|---|---|---|
| Major Earthquake | Seismic | Readiness CPP completed in 2021, including procurement of spares and substation strengthening (Section 12.4.2.5).<br>Replacement of gas-filled 33 kV cables (Section 12.5.2). |
| Tsunami | Flooding | Relocation of WELL head office by 2026 (Section 10.6). |
| Central Park GXP | Fire | Transpower project to extend the site by 2027 (Section 12.5.1). |
| Melling GXP | Flooding | Transpower to develop a long-term plan in 2025. |
| Pauatahanui GXP | Flooding | Transpower to develop long-term plan by 2025. |
| Porirua Zone Substation | Flooding | 11kV switchboard relocation planned for 2031 (Section 9.5.4). |
| Flood or Storm Surge Event | Flooding | Undertake distribution network flood risk assessment during 2025 using Resilience Explorer (Section 12.3.4).<br>Engagement with Greater Wellington's ongoing Riverlink project (Section 12.4.2.5).<br>Trialling submersible low voltage pillars on Wellington's south coast. |
| Wildfire | Fire | Engagement with Greater Wellington to identify high fire risk areas.<br>Engagement with Australian sister companies to understand their bushfire risk reduction strategies.<br>Wildfire Risk Reduction Policy to be implemented in 2025. |

Table 12-2 Summary of Primary Resilience Risks

WELL has previously undertaken a resilience self-assessment using the Resilience Management Maturity Assessment Tool (RMMAT) detailed in the EEA Resilience Guide.[59] This guide is currently being updated by the EEA, and WELL will undertake a new self-assessment once the revised guide is published.

[59] See Section 12.6, WELL Asset Management Plan 2023

## 12.5 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[60].

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 Table 12-3.

| Initiative | Owner | Indicative Cost (2019) | Status |
|---|---|---|---|
| Central Park Substation improved resilience | Transpower, WELL | $40m | In Progress (Section 12.5.1) |
| Seismic upgrade of cables and creation of 33kV rings | WELL | $160m | In Progress (Section 12.5.2) |
| Central Park to Frederick Street Cable Replacement | WELL | $5m | Complete |

**Table 12-3 Electricity Expenditure for Preferred Regional Resilience Investment Option**
Source: Wellington Lifelines Project Report, 2019

The preferred option involved 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 was already planned for replacement for capacity reasons.

The WeLG RRP initiatives were not included within the 2018 CPP discussed in Section 12.4.2.4 as this was focused on the quick implementation of readiness initiatives. As such these longer term 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 implemented as part of the readiness 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.

[60] https://wremo.nz/about-wremo/wremo-library/reports/

### 12.5.1 Central Park

As described in Section 12.4.2.3, there is a significant risk posed by a potential loss of supply at Central Park GXP.

WELL has been working with Transpower to address concerns around the lack of supply diversity resulting from the configuration of Central Park since 2009. In 2018, Transpower commenced system planning analysis of a 'longlist' of potential solutions to determine how much load can be supplied if a HILP event such as a major earthquake or fire was to occur. Following this, a Grid Reliability Standards assessment of the costs and benefits of proposed solutions was undertaken alongside a Grid Investment Test. This passed in 2021 following engagement with the Commission and Authority.

A Solution Study Report commissioned by Transpower on behalf of WELL was completed In October 2024. This defined the options and scope of the required investment in ensuring diversity of supply to central Wellington and its southern and eastern suburbs.

The most effective means of reducing this risk is for Transpower to construct a secondary substation at a nearby location, which will be operated as a physically separated extension of the existing GXP. This will allow WELL to transfer half of its Central Park 33 kV feeders (one per zone substation) onto an independent supply, providing operational flexibility to restore as much load to the city as possible should a loss of supply occur at Central Park. Transpower's schedule for delivery of the project is to have the site commissioned in 2027.

The secondary substation will be constructed, owned, and operated by Transpower, which will be funded under a new customer connection contract and recovered as a pass-through cost to end-consumers. WELL will be required to facilitate reconfiguration and connection of its 33 kV subtransmission system. As the scope of the project was finalised after the publication of WELL's 2024 AMP, this expenditure was not included in WELL's capital expenditure allowance for DPP4. WELL therefore expects to submit a price path reopener application to the Commission to cover the associated capital expenditure costs.

### 12.5.2 Fluid-Filled Subtransmission Cables

The majority of the subtransmission cables in the WELL network are fluid-pressurised cables, 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 8.5.1.

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 earthquake readiness project provided spare 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 Regional Resilience Project 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. Subtransmission rings will allow for greater load transfer between zone substation and GXPs and the associated cable replacement would enable diversification of cable routes. The new 33 kV bus at Evans Bay discussed in Section 9.4.2.2 is the first step in creating the subtransmission rings for Wellington's eastern suburbs.

The replacement of gas cables will be completed as 33 kV circuits are replaced due to condition or capacity. The need to upgrade subtransmission cables due to large customer-initiated projects may accelerate some of this work, however, changes in customer intentions and decarbonisation forecasts since the 2024 AMP, along with the resequencing of projects in response to the DPP4 price-path determination, has extended the timeframe for completing the programme compared to what was presented in the 2024 AMP. The gas-filled subtransmission cables are planned for replacement as outlined in Table 12-4.

| Subtransmission Circuits | Cable Type | Project Completion Timeframe | Change from 2024 AMP | 2025 Project Driver |
|---|---|---|---|---|
| University | Nitrogen | 2027 | +1 year | Condition |
| Evans Bay | Nitrogen | 2030 | +3 years | Condition |
| Maidstone | Nitrogen | 2030 | -2 years | Condition |
| Ira Street | Nitrogen | 2031 | +3 years | Condition |
| Hataitai | Nitrogen | 2032 | +5 years | Condition |
| Karori | Nitrogen | 2033 | +4 years | Criticality |
| Waikowhai | Nitrogen | 2037 | +6 years | Condition |

**Table 12-4 Timeframe for Gas-Filled Cable Replacement**

# 13 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 new technologies (e.g. energy storage systems, demand response programmes etc) will also affect WELL's ability to maintain supply quality and network capacity.

## 13.1 Connection Application Process

Applications for connections are made through WELL's website, allowing customers to register their request for a new connection.[61] These are broadly categorised into either residential or business connections, with fuse sizing requirements of 60A, 100A, or greater than 100A rating requests.

The approach to communication with customers is determined by the complexity of the work. The customer's retailer is WELL's point of contact for a standard residential new connection. The service levels for communication with retailers about new connections are defined in the Code and the DDA, and are provided in Section 6.5.4. Projects that require network extensions are managed directly with the customer's representative by WELL's Service Delivery team. Communication for the livening process is undertaken directly between WELL's Field Service Provider and the customer's electrician.

A key element of communication with customers is setting clear expectations of timeframes, and the customer's responsibilities, early in the new connection process. The current lead time for new connections requiring a new point of supply is displayed on the new connections request portal on WELL's website.

Simple new connections (typically residential customers) can usually be completed within three months using standard designs and pricing. In addition, WELL regularly surveys customers and electricians to monitor the performance of the process and look for further ways it could be improved. The timeframes for larger and more complex connections that require network extensions are established as WELL works with the customer to determine the alignment of available capacity with the customer's needs, and the scope of work that is required to close any gap between the two.

Delays can occur on both the network and customer side of the new connection process. Network-related delays can be caused by contractor availability, the variability of work volumes, and the lead times for any major materials that may be required, such as transformers. Delays can also be caused by incomplete information being provided to WELL, the installation not being ready to be connected on the agreed date, and essential documents such as the installation's certificate of compliance not being complete.

Throughout this process for new connections, WELL seeks to minimise the cost to customers through the use of standardised designs and materials, competitive tendering to multiple contractors, and a customer contributions policy that seeks to ensure fairness between existing, new, and future customers. WELL's customer contributions policy is discussed further in Section 13.7.

[61] https://www.welectricity.co.nz/getting-connected/new-online-forms-holder/get-connected/

## 13.2 New Connections and ICPs

The number of new dwellings consented annually in the Wellington Region across the four local authorities covered by WELL's network peaked in 2022, with 2023 and 2024 showing a significant reduction. Figure 13-1 shows the number of new dwellings consented over the last eight years.

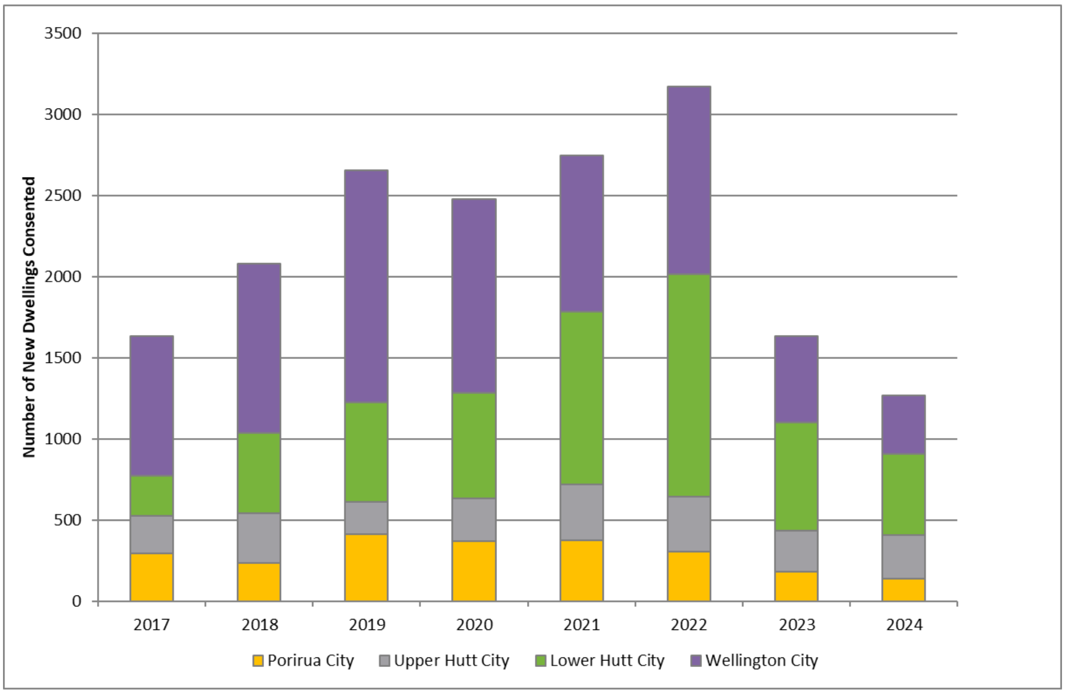


**Figure 13-1 Number of New Dwellings Consented in the Wellington Region[62]**

Figure 13-2 shows the trend in the types of dwellings being consented in the Wellington Region. There has been a clear trend towards the development of multi-unit dwellings, including apartments, retirement villages, and townhouses. This shows that recent residential growth in Wellington has primarily been driven by housing intensification.

[62] https://www.stats.govt.nz/information-releases/building-consents-issued-december-2024/

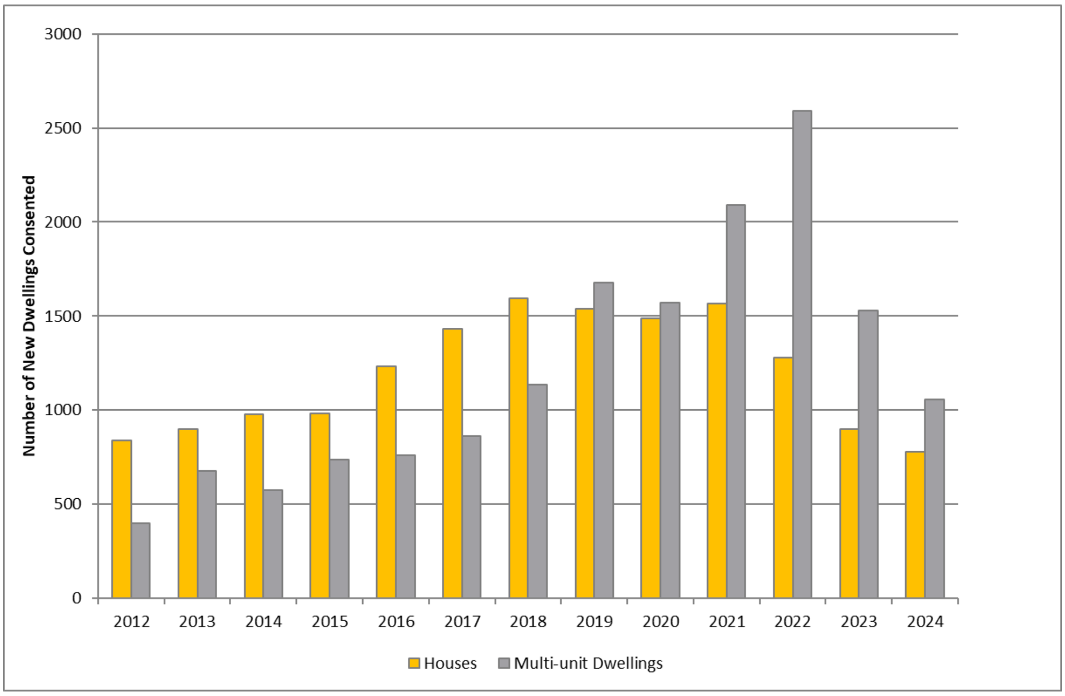


Figure 13-2 Types of New Dwellings Consented in the Wellington Region[63]

Figure 13-3 shows the number of new connections added to the Wellington network since 2019 and the expected new connections for the next five years. The number of new ICP connections does not align with building consents due to the lag between consent approval and connecting to the network (which can be between one and five years) and because some dwellings containing multiple units are serviced by a single ICP connection.

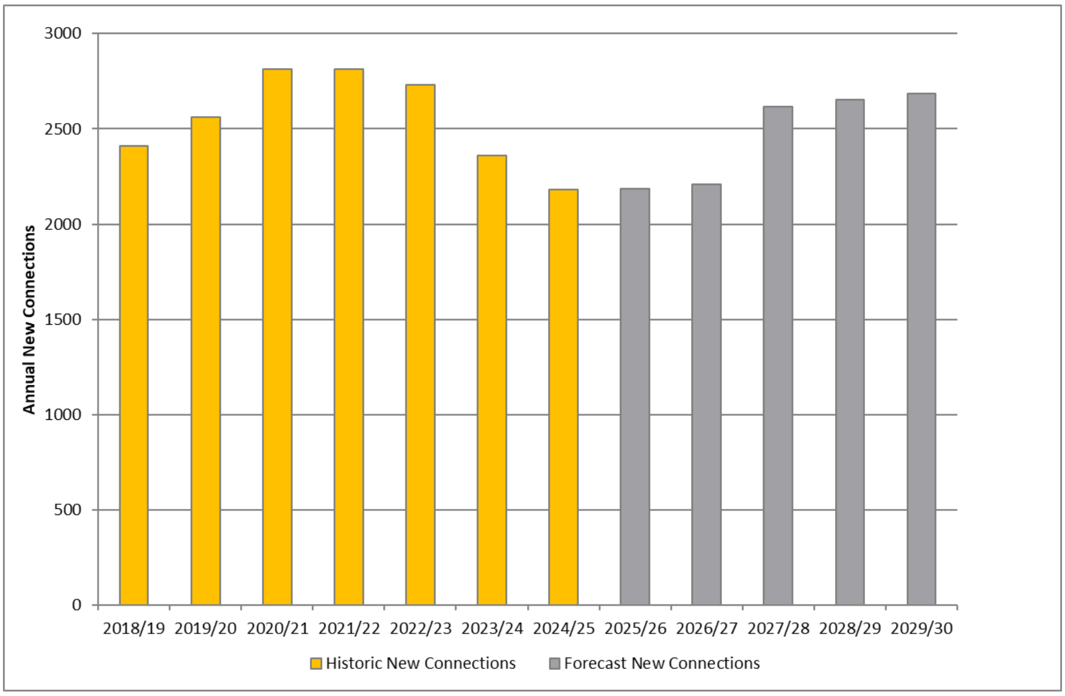


Figure 13-3 New Connections in the Wellington Region

[63] https://www.stats.govt.nz/information-releases/building-consents-issued-december-2024/

WELL expects the current levels of new connections to continue for the next two years, before growing to around 2,600 new connections per year. This is based on WELL's forward work programme indicating that the development of previously consented large subdivisions is continuing.

## 13.3 Substations and Subdivisions

Substation projects include new transformers and HV connections, often required to meet the capacity requirements of new businesses. 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.

### 13.3.1 Industrial and Commercial Gas Conversions

Included in the substation connection forecast is a forecast for commercial and industrial gas-to-electricity conversions. DETA surveyed major gas users in Wellington in 2023, which indicated there could be up to 40 MW of new electricity capacity needed across 34 entities, with the results of this being factored into the customer substation capital expenditure forecast in WELL's 2024 AMP. Subsequent discussions with major gas users since the DETA survey was completed has indicated that many of these customers are now delaying their electrification plans. WELL will continue to refine its forecast as more information is gathered for each conversion.

### 13.3.2 Subdivisions

Despite the downturn in residential consenting discussed in Section 13.2, significant new residential developments have been proposed for land to the north of Porirua and Upper Hutt. Some of these developments are listed projects under the Fast-track Approvals Act 2024. While the release of sections in these developments to the market will occur over many years, significant enabling infrastructure would be needed to support these developments as they grow, including the installation of 11 kV and zone substation assets sized to provide the necessary capacity for the final state of the developments. Due to the evolving scope and timeframe for these projects, it is expected that WELL will apply to fund these major new subdivisions as reopeners to its price path.

### 13.3.3 Public EV Charge Points

WELL's preferred approach is to offer public EV charge point operators a dynamic operating envelope at their location of choice, rather than requiring extensive 11 kV reinforcement before connecting these new loads. This allows public EV charging to cost-effectively connect, utilising existing network capacity, while pricing in the impact of network constraints on charging during peak periods. This allows EV customers to choose charging locations and available charge rates across the public EV charging network that offers the price/quality combination they are prepared to accept.

## 13.4 Capacity Changes

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

## 13.5 Relocations

Relocation projects are primarily initiated by Waka Kotahi 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.

WELL is engaging with the Greater Wellington Regional Council-led Riverlink project.[64] This project will strengthen Lower Hutt's defences against flooding from the Hutt River, and construct a new bridge and interchange on State Highway 2 at Melling. The project is expected to require the customer-funded relocation of 33 kV cables, 11 kV cables, and distribution substations.

## 13.6 Reopeners for Large New Connections

The DPP regulatory framework allows network operators to apply for additional allowances for unforeseen new connections, network reinforcement, or relocations that were not included in the regulatory allowance calculation set every five years.

Due to the size of the network investment required to support large connection projects relative to WELL's own network-initiated investment, and the uncertainty surrounding the customers' scope and timeframe, WELL expects to fund the network augmentation required to support large new connections as they are confirmed either as reopeners to its price path, or as Large Connection Contracts.

Table 13-1 summarises the expenditure that would be required to support possible large customer projects, and is contingent on those projects going ahead, that is not currently included in the expenditure forecasts in this AMP due to uncertainties about whether the projects will proceed, their scope, their timing, and their size relative to WELL's capital expenditure allowances. WELL will seek to reopen its price path for these customer projects if they are confirmed.

| Major Customer Project | Indicative Related Expenditure |
|---|---|
| KiwiRail Network Capacity Upgrade[65] | $103m |
| Hospital Electrification[66] | $57m |
| Fast Track Residential Development North of Porirua[67] | $45m |
| Riverlink Relocations | $37m |
| Moa Point Sewerage Treatment Plant | $35m |
| Bus Charging Depot | $8m |
| **Total** | **$250m** |

**Table 13-1 Possible Large Customer Projects (Gross of Customer Contributions)**

### 13.6.1 Moa Point Sewerage Treatment Plant

Wellington City Council (WCC) is currently upgrading its Moa Point sewerage treatment plant.[68] This is critical regional infrastructure that requires a significant increase in the electrical capacity to the site, requiring a new 11 kV switching station and two new 11 kV feeders from WELL's Ira Street zone substation, which in turn

[64] https://teawakairangi.co.nz/
[65] Expected to require capacity upgrades for Petone and Tawa zone substations.
[66] Expected to require a new substation in Newtown.
[67] Expected to require a capacity upgrade and relocation for Plimmerton zone substation.
[68] https://wellington.govt.nz/your-council/projects/moa-point-sludge-minimisation-facility

requires the replacement of the 11 kV switchboard at Ira Street to provide the necessary additional feeder circuit breakers.

The scale of this work is outside of what WELL can reasonably accommodate within its DPP4 capital expenditure allowances, and WELL will apply to the Commission to reopen its DPP4 price path. However, due to the criticality of the project, and WCC's timeframe for the new plant being operational, WELL has had to commence its investment ahead of the allowances being available.

## 13.7 Capital Contributions

The cost of connecting to the network or altering existing services is the capital cost of designing and installing the new connection assets or any new assets needed to adjust a customer's existing services. These costs are for assets that only the connecting customer benefits from and are funded by a combination of tariff and upfront customer capital contribution.

A customer capital contribution payment is a one-off payment made at the start of a project and is used to directly fund capital works. The Input Methodologies used to calculate the ongoing allowances an EDB has to fund the operation of its network require that customer capital contributions are excluded from the allowance calculation. This reflects that the customer rather than WELL has funded some or all of the capital costs of connecting. This also means that the customer capital contribution is excluded from tariffs, ensuring the assets are not paid for twice.

Customer capital contributions are excluded from allowances by subtracting the contributions from the value of the assets added to the Regulatory Asset Base (RAB). The RAB records the value of the assets that the EDB has invested in and is used to calculate the allowances that the EDB is provided to recover the cost of purchasing the assets and the return for making that investment. Excluding customer capital contributions from the RAB ensures a customer's investment is not included in the revenue used to set tariffs, i.e. ensuring that the costs of the assets funded directly by customers are not included in the overall target revenue and therefore that those costs are excluded from tariffs.

WELL calculates customer capital contributions as the incremental cost of the new connection or change to the existing connection plus a contribution towards the shared network costs, less the incremental revenue provided by a new connection or a change to an existing connection.

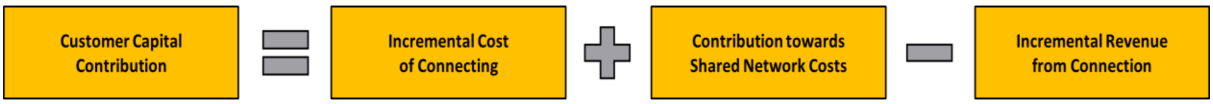


Figure 13-4 Customer Capital Contribution Calculation

This ensures that the connecting customer receiving the benefits from the connection funds all of the costs of connecting or augmenting the existing connection over the life of the assets that benefit solely them through a combination of the capital contribution and tariffs. This ensures that existing customers are not cross subsidising the cost of the new connection, while still contributing towards the cost of any shared assets that they benefit from.

## 13.8 Customer Connections Summary for 2025-2035

The total forecast customer connection capital expenditure for 2025 to 2035 is presented in Table 13-2.

| Customer Type | 2025/26 | 2026/27 | 2027/28 | 2028/29 | 2029/30 | 2030/31 | 2031/32 | 2032/33 | 2033/34 | 2034/35 |
|---|---|---|---|---|---|---|---|---|---|---|
| Substation | 7,206 | 8,217 | 8,244 | 8,284 | 8,327 | 8,327 | 8,327 | 8,327 | 8,327 | 8,327 |
| Subdivision | 4,295 | 4,897 | 4,913 | 4,937 | 4,963 | 4,963 | 4,963 | 4,963 | 4,963 | 4,963 |
| High Voltage Connection | 636 | 622 | 610 | 598 | 586 | 586 | 586 | 586 | 586 | 586 |
| Residential Customers | 5,216 | 6,106 | 6,148 | 6,201 | 6,256 | 6,256 | 6,256 | 6,256 | 6,256 | 6,256 |
| Public Lighting | 342 | 335 | 329 | 322 | 316 | 316 | 316 | 316 | 316 | 316 |
| **Total Gross** | **17,695** | **20,178** | **20,244** | **20,343** | **20,448** | **20,448** | **20,448** | **20,448** | **20,448** | **20,448** |

Table 13-2 Customer Connection Capital Expenditure Forecast
($K in constant prices)

## 13.9 Asset Relocations Summary for 2025-2035

The forecast asset relocation capital expenditure, which is primarily related to either roading projects or the undergrounding of the existing overhead network for subdivision development, is presented in Table 13-3. This excludes the potential major customer-initiated relocations summarised in Section 13.6 that have not yet been contracted for delivery.

| Programme | 2025/26 | 2026/27 | 2027/28 | 2028/29 | 2029/30 | 2030/31 | 2031/32 | 2032/33 | 2033/34 | 2034/35 |
|---|---|---|---|---|---|---|---|---|---|---|
| Asset Relocations | 1,915 | 1,921 | 1,931 | 1,941 | 1,941 | 1,941 | 1,941 | 1,941 | 1,941 | 1,915 |
| **Total Gross** | **1,915** | **1,921** | **1,931** | **1,941** | **1,941** | **1,941** | **1,941** | **1,941** | **1,941** | **1,915** |

Table 13-3 Asset Relocation Capital Expenditure Forecast
($K in constant prices)

# 14 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.

## 14.1 Capital Expenditure 2025-2035

### 14.1.1 Customer Connections

The total forecast customer connection capital expenditure for 2025 to 2035, as discussed in Section 13, is presented in Table 14-1.

| Customer Type | 2025/26 | 2026/27 | 2027/28 | 2028/29 | 2029/30 | 2030/31 | 2031/32 | 2032/33 | 2033/34 | 2034/35 |
|---|---|---|---|---|---|---|---|---|---|---|
| Substation | 7,206 | 8,217 | 8,244 | 8,284 | 8,327 | 8,327 | 8,327 | 8,327 | 8,327 | 8,327 |
| Subdivision | 4,295 | 4,897 | 4,913 | 4,937 | 4,963 | 4,963 | 4,963 | 4,963 | 4,963 | 4,963 |
| High Voltage Connection | 636 | 622 | 610 | 598 | 586 | 586 | 586 | 586 | 586 | 586 |
| Residential Customers | 5,216 | 6,106 | 6,148 | 6,201 | 6,256 | 6,256 | 6,256 | 6,256 | 6,256 | 6,256 |
| Public Lighting | 342 | 335 | 329 | 322 | 316 | 316 | 316 | 316 | 316 | 316 |
| **Total** | **17,695** | **20,178** | **20,244** | **20,343** | **20,448** | **20,448** | **20,448** | **20,448** | **20,448** | **20,448** |

**Table 14-1 Customer Connection Capital Expenditure Forecast
($K in constant prices)**

### 14.1.2 System Growth

The total forecast capital expenditure for system growth and security of supply for 2025 to 2035, is presented in Table 14-2.

| Asset Category | 2025/26 | 2026/27 | 2027/28 | 2028/29 | 2029/30 | 2030/31 | 2031/32 | 2032/33 | 2033/34 | 2034/35 |
|---|---|---|---|---|---|---|---|---|---|---|
| Subtransmission | 477 | 4,296 | 251 | 5,846 | 6,223 | 20,838 | 19,983 | 9,853 | 6,497 | - |
| Zone Substations | 398 | 8,986 | 6,905 | 4,731 | 5,482 | 18,352 | 10,313 | 312 | 9,295 | 6,453 |
| Distribution Poles and Lines | - | 190 | - | - | - | - | - | - | - | - |
| Distribution Cables | 15,720 | 22,763 | 17,792 | 17,670 | 6,838 | 1,309 | 9,652 | 27,894 | 16,209 | 20,850 |
| Distribution Substations | - | - | - | - | - | - | - | - | - | - |
| Distribution Switchgear | 57 | 504 | - | - | - | - | - | - | - | - |
| Other Network Assets | - | - | - | - | - | - | - | - | - | - |
| **Total** | **16,651** | **36,739** | **24,948** | **28,247** | **18,543** | **40,499** | **39,948** | **38,058** | **32,000** | **27,303** |

**Table 14-2 System Growth Capital Expenditure Forecast**
**($K in constant prices)**

### 14.1.3 Asset Replacement and Renewal

The total forecast capital expenditure for asset replacement and renewal for 2025 to 2035 as discussed in Section 8 is presented in Table 14-3. This includes provision for replacements that arise from condition assessment programmes during the year.

| Asset Category | 2025/26 | 2026/27 | 2027/28 | 2028/29 | 2029/30 | 2030/31 | 2031/32 | 2032/33 | 2033/34 | 2034/35 |
|---|---|---|---|---|---|---|---|---|---|---|
| Subtransmission | 3,471 | 9,629 | - | 8,417 | 8,417 | - | 6,489 | 15,124 | 4,100 | 4,300 |
| Zone Substations | 1,663 | 569 | 5,524 | 552 | 5,543 | 497 | 500 | 503 | 455 | 509 |
| Distribution Poles and Lines | 9,904 | 7,755 | 7,430 | 7,195 | 6,376 | 6,176 | 5,981 | 5,792 | 5,609 | 5,432 |
| Distribution Cables | 3,139 | 4,727 | 5,591 | 4,058 | 4,207 | 6,242 | 6,242 | 6,242 | 6,242 | 6,242 |
| Distribution Substations | 7,924 | 6,965 | 7,560 | 5,775 | 6,383 | 7,759 | 8,031 | 8,115 | 8,115 | 8,114 |
| Distribution Switchgear | 11,248 | 11,009 | 10,096 | 9,818 | 10,296 | 6,719 | 6,659 | 6,633 | 6,460 | 6,514 |
| Other Network Assets | 4,695 | 4,033 | 5,837 | 5,410 | 5,310 | 5,658 | 5,615 | 5,573 | 5,532 | 5,490 |
| **Total** | **42,044** | **44,687** | **42,038** | **41,225** | **46,532** | **33,051** | **39,517** | **47,982** | **36,513** | **36,601** |

**Table 14-3 Asset Replacement and Renewal Capital Expenditure Forecast**
**($K in constant prices)**

### 14.1.4 Asset Relocations

The forecast asset relocation capital expenditure, primarily related to roading projects, is presented in Table 14-4.

| Programme | 2025/26 | 2026/27 | 2027/28 | 2028/29 | 2029/30 | 2030/31 | 2031/32 | 2032/33 | 2033/34 | 2034/35 |
|---|---|---|---|---|---|---|---|---|---|---|
| Roading Relocations | 1,915 | 1,921 | 1,931 | 1,941 | 1,941 | 1,941 | 1,941 | 1,941 | 1,941 | 1,915 |
| **Total** | **1,915** | **1,921** | **1,931** | **1,941** | **1,941** | **1,941** | **1,941** | **1,941** | **1,941** | **1,915** |

**Table 14-4 Asset Relocation Capital Expenditure Forecast (\$K in constant prices)**

### 14.1.5 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 14-5.

| Programme | 2025/26 | 2026/27 | 2027/28 | 2028/29 | 2029/30 | 2030/31 | 2031/32 | 2032/33 | 2033/34 | 2034/35 |
|---|---|---|---|---|---|---|---|---|---|---|
| Feeder Reliability Projects – Lines | 2,188 | 1,035 | 1,195 | 1,404 | 1,213 | 1,154 | 1,183 | 1,211 | 1,238 | 1,264 |
| Feeder Reliability Projects – Switchgear | 679 | 1,473 | 1,242 | 687 | 990 | 1,178 | 1,155 | 1,133 | 1,110 | 1,089 |
| Switchgear SCADA Control Retrofit | - | 200 | 200 | 200 | 200 | 200 | 200 | 200 | 200 | 200 |
| **Total Quality of Supply** | **2,867** | **2,708** | **2,637** | **2,291** | **2,403** | **2,532** | **2,538** | **2,544** | **2,548** | **2,553** |
| AUFLS Relay Replacement | 2,427 | - | - | - | - | - | - | - | - | - |
| **Total Legislative and Regulatory** | **2,427** | **-** | **-** | **-** | **-** | **-** | **-** | **-** | **-** | **-** |
| Readiness Expenditure | 1,520 | 462 | 448 | - | - | - | - | - | - | - |
| **Total Other Reliability, Safety and Environment** | **1,520** | **462** | **448** | **-** | **-** | **-** | **-** | **-** | **-** | **-** |

**Table 14-5 Reliability, Safety and Environmental Capital Expenditure (\$K in constant prices)**

### 14.1.6 Non-network Assets

The forecast capital expenditure for non-network assets is presented in Table 14-6.

| Routine Expenditure | 2025/26 | 2026/27 | 2027/28 | 2028/29 | 2029/30 | 2030/31 | 2031/32 | 2032/33 | 2033/34 | 2034/35 |
|---|---|---|---|---|---|---|---|---|---|---|
| Software and Licenses | 4,040 | 1,140 | 986 | 1,718 | 1,047 | 1,628 | 1,112 | 1,143 | 2,078 | 1,214 |
| IT Infrastructure | 1,975 | 631 | 2,199 | 272 | 315 | 2,288 | 697 | 306 | 315 | 325 |
| Head Office Relocation | 18,000 | - | - | - | - | - | - | - | - | - |
| Capitalised Leases | 546 | 2,076 | 249 | 992 | 170 | 546 | 546 | 546 | 546 | 546 |
| **Total Non-network Assets** | **24,561** | **3,847** | **3,434** | **2,982** | **1,532** | **4,462** | **2,355** | **1,995** | **2,939** | **2,085** |

**Table 14-6 Non-Network Asset Capital Expenditure Forecast ($K in constant prices)**

### 14.1.7 Capital Expenditure Summary

The total combined capital expenditure on assets is presented in Table 14-7.

| Category | 2025/26 | 2026/27 | 2027/28 | 2028/29 | 2029/30 | 2030/31 | 2031/32 | 2032/33 | 2033/34 | 2034/35 |
|---|---|---|---|---|---|---|---|---|---|---|
| Customer Connection | 17,695 | 20,178 | 20,244 | 20,343 | 20,448 | 20,448 | 20,448 | 20,448 | 20,448 | 20,448 |
| System Growth | 16,651 | 36,739 | 24,948 | 28,247 | 18,543 | 40,499 | 39,948 | 38,058 | 32,000 | 27,303 |
| Asset Replacement & Renewal | 42,044 | 44,687 | 42,038 | 41,225 | 46,532 | 33,051 | 39,517 | 47,982 | 36,513 | 36,601 |
| Asset Relocations | 1,915 | 1,921 | 1,931 | 1,941 | 1,941 | 1,941 | 1,941 | 1,941 | 1,941 | 1,915 |
| Quality of Supply | 2,867 | 2,708 | 2,637 | 2,291 | 2,403 | 2,532 | 2,538 | 2,544 | 2,548 | 2,553 |
| Legislative and Regulatory | 2,427 | - | - | - | - | - | - | - | - | - |
| Other Reliability, Safety & Environment | 1,520 | 462 | 448 | - | - | - | - | - | - | - |
| **Subtotal – Network Capital Expenditure** | **85,119** | **106,695** | **92,246** | **94,047** | **89,867** | **98,471** | **104,392** | **110,973** | **93,450** | **88,820** |
| Non-Network Assets | 24,561 | 3,847 | 3,434 | 2,982 | 1,532 | 4,462 | 2,355 | 1,995 | 2,939 | 2,085 |
| **Total – Capital Expenditure on Assets** | **109,680** | **110,542** | **95,680** | **97,029** | **91,399** | **102,933** | **106,747** | **112,968** | **96,389** | **90,905** |

**Table 14-7 Capital Expenditure Forecast ($K in constant prices)**

## 14.2 Operational Expenditure 2025-2035

The total forecast operational expenditure for 2025 to 2035 is shown in Table 14-8.

| Category | 2025/26 | 2026/27 | 2027/28 | 2028/29 | 2029/30 | 2030/31 | 2031/32 | 2032/33 | 2033/34 | 2034/35 |
|---|---|---|---|---|---|---|---|---|---|---|
| Service interruptions & emergencies maintenance | 4,691 | 4,751 | 4,823 | 4,900 | 4,979 | 4,979 | 4,979 | 4,979 | 4,979 | 4,979 |
| Vegetation management | 1,872 | 1,896 | 1,925 | 1,956 | 1,987 | 1,987 | 1,987 | 1,987 | 1,987 | 1,987 |
| Routine & corrective maintenance and inspection | 10,904 | 11,044 | 11,212 | 11,391 | 11,575 | 11,575 | 11,575 | 11,575 | 11,575 | 11,575 |
| Asset replacement & renewal maintenance | 1,704 | 1,726 | 1,752 | 1,780 | 1,809 | 1,809 | 1,809 | 1,809 | 1,809 | 1,809 |
| **Subtotal – Network Operational Expenditure** | **19,170** | **19,417** | **19,713** | **20,027** | **20,351** | **20,351** | **20,351** | **20,351** | **20,351** | **20,351** |
| System Operations and Network Support | 10,901 | 11,041 | 11,209 | 11,388 | 11,572 | 11,572 | 11,572 | 11,572 | 11,572 | 11,572 |
| Business Support | 14,149 | 14,332 | 14,550 | 14,782 | 15,021 | 15,214 | 15,418 | 15,418 | 15,418 | 15,418 |
| **Subtotal – Non-network Operational Expenditure** | **25,050** | **25,373** | **25,758** | **26,169** | **26,592** | **26,786** | **26,990** | **26,990** | **26,990** | **26,990** |
| **Total – Operational Expenditure** | **44,220** | **44,790** | **45,471** | **46,196** | **46,943** | **47,137** | **47,340** | **47,340** | **47,340** | **47,340** |

**Table 14-8 Operational Expenditure Forecast**
**($K in constant prices)**

# Appendix A Assumptions

| Area | Assumption | Reason for Assumption | Possible Impact and Variation to Plan |
|---|---|---|---|
| The Energy Trilemma[69] | Customer affordability will be the primary focus for DPP4, with support for decarbonisation playing a secondary role. | The Commission's DPP4 Determination emphasised short-term customer affordability, indicating that a coordinated programme of investment to support decarbonisation requires greater scrutiny than is possible under the DPP. | WELL's 2024 AMP focused strongly on cost-effective long-term investment to support the Government's Emissions Reduction Plan through to 2050.<br>In response to the DPP4 Determination, WELL has revised its network reinforcement programme in this AMP to identify smaller incremental capacity increases to meet short-term load growth while delaying the larger investments that would have otherwise met both short- and long-term needs with a single project. |
| Government Policy - Decarbonisation | It is assumed that the current Emissions Reduction Plan will remain in place for the duration of this Plan. | Both major political parties are committed to net zero carbon by 2050, with the latest example of this support being the October 2024 Government Policy Statement on Electricity. | A change of government policy (for example regarding the use of gas or the balance between affordability and decarbonisation targets) may alter the speed of decarbonisation investment, with consequential impacts on the timing of network reinforcement needs and meeting the 2050 target. |
| Gas Transition | WELL supports the continued use of gas as a transition fuel.<br>This Plan assumes that if New Zealand is to transition from natural gas as a residential fuel to electricity by 2050, the majority of this transition will occur outside the Planning Period covered by this Plan. | Other fuel transitions (for example relating to the residential use of coal) have occurred over periods greater than 10 years.<br>Early indications are that hydrogen will be prioritised to heavy transport fleets instead of pipelines. | Increasing gas prices due to accelerated depreciation for gas networks and gas shortages, may result in customers exiting gas irrespective of government policy, leading to demand growing faster than forecast. |

[69] https://www.worldenergy.org/transition-toolkit/world-energy-trilemma-framework

| Area | Assumption | Reason for Assumption | Possible Impact and Variation to Plan |
|---|---|---|---|
| Demand and Consumption | This Plan is based on future demand growth scenarios that were built on the information that was available at the time.<br><br>It is assumed that significant decarbonisation-related load growth in peak demand (MW) and volume (GWh) will not accelerate until after 2030. | The publication of the Emissions Reduction Plan provides a pathway for New Zealand to meet its 2050 Net Zero Carbon obligations and places significant reliance on the transition away from fossil fuels to electricity.<br><br>The indication from WELL's major customers is that they are not expecting to undertake significant investment in decarbonising their operations prior to 2030, primarily due to the removal of government incentives such as GIDI funding.<br><br>The changes in decarbonisation assumptions are detailed in Section 9.2.2. | Growth in maximum demand at higher levels than forecast may require rescoping and resequencing of projects, or bring forward network reinforcement investment.<br><br>Growth that requires network reinforcement faster than can be practically delivered may impact quality performance. |
| Demand-side Management and Flexibility Markets | Demand-side management will be led by retailers and aggregators in response to price signals from the EDB.<br><br>Flexibility services as a competitive market will not grow to the scale required within the timeframe required to defer network reinforcement expenditure identified in this AMP.<br><br>A stable distribution network is a fundamental prerequisite for flexibility markets, requiring a clear hierarchy of needs with the maintenance of network security and power quality as the highest priority.<br><br>It is assumed that the stability of the network will be supported by EDB-controlled ripple control of hot water, which will continue to provide rapid, effective, and coordinated demand management during system emergency events. | It is not appropriate for price-quality regulated EDBs to be competing for access to services against unregulated competitive businesses.<br><br>Trends in customer uptake of electric vehicles and rooftop PV has slowed, indicating that flexible demand will not grow as rapidly as had previously been expected.<br><br>Customer engagement has shown that customers generally have limited understanding of demand response and are reluctant to participate.<br><br>Dynamic control of hot water heating via the smart meter has not yet been demonstrated to have the speed and reliability required for supporting network stability. | WELL's approach articulated in this AMP is to develop a framework for the pricing of distribution network constraints that ensures appropriate guardrails are maintained for quality of supply.<br><br>This framework also provides a clear signal to the EDB of the economic case for network investment to resolve constraints. |

| Area | Assumption | Reason for Assumption | Possible Impact and Variation to Plan |
|---|---|---|---|
| Inflation | 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. | Capex and Opex inflation is based on the New Zealand Reserve Bank February 2025 Monetary Forecast.<br><br>CPI is used as a general forecast inflation rate, recognising current inflation volatility and that selecting different inflation measures is unlikely to add any accuracy. | The focus of the capex and opex forecast is on ensuring base costs capture recent high inflation rates. WELL recognises that the regulatory model provides a natural hedge against forecast errors and that the forecast is used to signal the size of future cost increases, rather than being used to set nominal project budgets.<br><br>Section 4.3.3 of this plan discussed the impact of increasing costs. |
| Operational Expenditure | WELL's operational expenditure will increase relative to historical levels. | The primary drivers of this increase in operational expenditure are:<br>• A new Field Services Agreement that catches up on industry-specific costs having increased at a rate faster than CPI;<br>• Systems and data for managing the LV network;<br>• Insurance costs increasing as a result of the increasing frequency and severity of climate change-driven weather events across the world. | The regulatory framework may not provide the OPEX allowances forecast to support WELL's CAPEX programme. In that event, WELL would reprioritise its CAPEX plan to reflect the size of its support functions funded by OPEX allowances.<br><br>Specific costs may escalate faster than the forecast inflation rates. WELL will reprioritise its work programmes to reflect any differences in actual costs and regulatory allowances. |
| Insurance Costs | It is assumed that insurance costs will increase by 10% in 2025, 7% in 2026, and 5% in each of the subsequent five years. | These figures are based an assumption that the commercial and industrial insurance market is softening slightly, with 2024 seeing a smaller increase than the average for the prior five years, due to the recent trend in international claims being for predominantly residential losses. | A change in international insurance markets that sees premiums returning to rates of increase that exceed that allowed for in the DPP4 allowances would require WELL to offset the difference by finding further OPEX savings in other parts of its business. |

| Area | Assumption | Reason for Assumption | Possible Impact and Variation to Plan |
|---|---|---|---|
| Unplanned Outage Quality Standard | It is assumed that the methodology for setting future quality targets will remain consistent with the Commission's 2024 determination for 2025-2030. | The targets adopted in this plan align with the Commission's 2024 determination for 2025-2030. This reflects WELL's intention to maintain network reliability at current levels. | Any change in quality targets, additional measures for LV quality of supply, or alteration in the assessment method, may lead to an increase in the level of investment needed to measure and maintain network performance. |
| Planned Outage Quality Standard | It is assumed that the Planned Outage Quality Standards imposed under Price-Quality Regulation will not unreasonably constrain the work programme required to deliver the capacity required by customers. | All planned work must be undertaken safely. While some work can occur live or without interrupting the supply to customers, in many cases this is not possible, and the supply must be interrupted in order to allow the work to safely occur.<br><br>The assumptions behind WELL's Planned outage targets are detailed in Section 7.1. | A Planned Outage Quality Standard that does not accommodate the volume of work needed to deliver the network capacity required to support customers' activities will result in delays in that capacity being built, in order to avoid a compliance breach. |
| Transmission Network | Significant development of the transmission grid, and grid exit point connections, will be required in order to support decarbonisation goals.<br><br>It is assumed that Transpower will manage the transmission grid and grid exit points to appropriate standards of resilience, including flood risk.<br><br>It is assumed that these projects will be able to be agreed upon, funded, and delivered in accordance with the timeframe of the need. | WELL is engaging with Transpower about the transmission network needs identified in Section 9 and Section 12.4.2.3. | A change to the configuration or capability of the transmission system, or a change in transmission operator priorities to focus on supporting new generation at the expense of upgrading distribution connections, could lead to a requirement for increased levels of investment on the network to provide capacity or security from within the distribution network in the absence of adequate grid capability. |

| Area | Assumption | Reason for Assumption | Possible Impact and Variation to Plan |
|---|---|---|---|
| Public Safety | Compliance with requirements for public safety management will not adversely impact the existing network assets located in the public domain.<br>Significant asset renewals for other utilities will not lead to an increase in third party interference with works. | 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. | 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. |
| Technology – LV Monitoring | It will not be cost-effective to monitor the entire LV network. WELL will focus its monitoring on areas shown by modelling as likely to be constrained. | The market price for smart meter data, held by monopoly metering equipment providers, is currently at a level that the purchase by the an EDB of 100% coverage of its network would pose unreasonable costs on customers, who are already paying for the metering equipment and the data collection through their retailer. | Regulation that limits the price for access to power quality data from smart meters to the incremental cost of provision of the data would increase the areas where it would be cost-effective for EDBs to monitor, however there will still be areas with low likelihoods of constraint where the procurement of data will impose unnecessary costs on customers for no benefit. |
| Resource Management Regulation | Changing resource management rules will not result in retrospective compliance requirements for lawfully installed existing assets. | Historic practice has been for lawfully established land use to continue being permitted under changing resource management rules. | Changes to existing network assets required by any new resource management regulation may affect WELL's ability to supply its customers.<br>Changes to the law regarding the allocation of the cost of other utilities relocating WELL's assets as part of their own renewal programmes would force costs onto WELL that are not funded under the current regulatory regime and may affect WELL's ability to deliver its programmes. |

| Area | Assumption | Reason for Assumption | Possible Impact and Variation to Plan |
|---|---|---|---|
| Climate Change Adaptation – Coastal Environments | Banks and insurance companies will be the lead agencies that drive decisions about defence or managed retreat in response to storm surges, sea level rise, and coastal erosion. | WELL has an obligation to supply existing customers. It cannot remove its network from potential inundation zones while there are customers that must be supplied.<br><br>There has not been any indication from TLAs that any areas of WELL's network will be subject to managed retreat. | Managed retreat would require relocation or removal of WELL's assets in the affected areas.<br><br>The details of each defend/retreat decision will determine whether WELL will need to adapt elements of its network in affected areas to be resistant to inundation, such as the conversion of underground networks to overhead. |
| High Impact, Low Probability Events | It is assumed that the delivery of this Plan will not be being disrupted by a HILP event such as a major earthquake. | Extreme disruptive events can be prepared for but cannot be predicted.<br><br>WELL expects to be able to respond to routine major events such as storms and moderate earthquakes with its existing tools: its contingency planning, mutual aid agreements, strategic spares, and the readiness investments it has undertaken.<br><br>The Input Methodologies allow for the recovery of expenditure to recover immediate response costs and to apply for a different price path to fund recovery. | An extreme disruptive event resulting in destruction of significant parts of WELL's network would require elements of this Plan to be revised. |

# Appendix B Update from 2024 Plan

## Material Progress and Changes Since Previous Plan

During the past year, WELL has continued the review of its asset management strategy and practices. Progress against the gaps identified in the 2024 AMP, along with progress and material changes to network development projects and lifecycle asset management plans, is shown in the Table B-1.

| 2025 AMP Section | Item | Description |
|---|---|---|
| 3.2.3 | Company Structure | **Update:** WELL has established a new Chief Information Officer role. |
| 4.1 | Changes from the 2024 Asset Management Plan | **Update:** The impact of changes in decarbonisation rate forecasts on WELL's investment programme is discussed. |
| 4.2.2 | Flexibility Markets | **Update:** WELL has refined its position on flexibility services as being a market-led approach of valuing and clearing constraints, with the EDB providing guardrails based on the current and voltage limits for the network. |
| 7.1 | Reliability Performance Targets | **Update:** WELL has updated its Planned SAIDI and Planned SAIFI targets for the planning period, and listed the assumptions behind the forecast. |
| 7.3.4 | Monthly Feeder Performance Summaries | **Update:** A new section has been added discussing WELL's approach to monitoring trends in HV feeder reliability. |
| 8.5.1 | Subtransmission Cable Renewal | **Update:** The replacement of the Titahi Bay fluid-filled cables (operated at 11kV) is underway, with ducting having commenced in coordination with a city council urban cycleway project. Completion is now expected to be in 2027. |
| 8.5.2 | Power Transformer Renewal | **Update:** The replacement of the transformers at Evans Bay is now complete.<br><br>Kenepuru A has been identified through testing as having a deteriorated condition. Replacement of both units at Kenepuru is expected to occur in 2028. |
| 9.2.2 | Demand Forecast Assumptions | **Update:** This section details changes in WELL's demand forecasting assumptions compared to the 2024 AMP. |
| 9.4.2.1 | Ira Street zone substation capacity | **2024 AMP:** A stepwise approach to increasing capacity at 8 Ira Street is preferred over the alternative options of offloaded demand to Evans Bay or building a new zone substation, as it allows expenditure to be phased to match demand growth. |

| 2025 AMP Section | Item | Description |
|---|---|---|
| | | **Update:** This stepwise approach is continuing, however there has been minor adjustments to the expected timing of component upgrades. The switchboard is committed for replacement in 2025/26 to support a customer project at Moa Point. The 33 kV cables are now proposed for 2031, and replacement of the power transformers is not expected to be required in the next 10 years. |
| 9.4.2.2 | Evans Bay zone substation capacity. | **2024 AMP:** work is underway to install a 33 kV bus and replace the power transformers at Evans Bay, and it is proposed to replace the 33 kV cables from Central Park to Evans Bay. |
| | | **Update:** The 33 kV bus and power transformer replacement at Evans Bay is now complete.<br><br>The 33 kV cable upgrade is now proposed to include a 33 kV bus at Hataitai, and the replacement of the section of Evans Bay cables between Hataitai and Evans Bay. The section from Central Park to Hataitai will be upgraded at a later date, ideally coordinated with a proposed NZTA redevelopment of State Highway 1 at the Basin Reserve and Mount Victoria Tunnel. |
| 9.4.2.9 | Palm Grove zone substation capacity | **2024 AMP:** Demand at Palm Grove will be managed through the construction of a new zone substation at Newtown by approximately 2026. |
| | | **Update:** Changes in customer intensions have made it unclear whether a new zone substation will be constructed. Declining demand at Palm Grove and the availability of 11 kV backfeeds allows WELL to wait for the customer's situation to be resolved before deciding whether it will be necessary to invest in additional capacity at Palm Grove. |
| 9.5.2.6 | Porirua zone substation capacity | **2024 AMP:** The upgrade of Porirua zone substation will commence in 2025. |
| | | **Update:** Capacity at Porirua will be added in smaller increments to assist with customer affordability. The first stage is the installation of new 11 kV feeders from Kenepuru, to offload Porirua. This allows the upgrade of the zone substation to be deferred until 2031. |

| 2025 AMP Section | Item | Description |
|---|---|---|
| 9.6.2.9 | Trentham zone substation capacity | **2024 AMP:** WELL plans to build another zone substation in the area to offload Trentham, to be initially developed as an 11 kV switching station. |
| | | **Update:** The Trentham 33 kV fluid-filled cables will now be replaced to maximise use of the available 33 kV capacity from Haywards GXP. The interconnectivity between Trentham and Maidstone will be improved through the upgrade of cable and overhead line sections. |
| 9.7 | LV CAPEX Forecast | **Update:** WELL has updated its LV reinforcement CAPEX forecast based on updated modelling and revised residential decarbonisation load growth forecasts. |
| 11.3.2 | LV Management Projects | **Update:** An update is provided on WELL's innovation projects relating to LV network management. |
| 12.3.4 | Resilience Explorer | **Update:** WELL has implemented the Resilience Explorer platform to provide a tool for the systematic analysis of environmental risks to the network. |
| 12.4.3 | Resilience Risks | **Update:** WELL has provided an update of its primary network resilience risks, and the actions underway to address them. |
| Schedule 11b | Insurance Costs | **Update:** WELL's 2024 AMP assumed a continuation of WELL's insurance costs increasing at their historical trend of 15% per year since 2017 (shown in Figure 4-10). The commercial and industrial insurance market softened slightly in 2024, and WELL has updated these assumed increases to 10% in 2025, 7% in 2026, and 5% in the subsequent five years. |
| Schedule 12a | Asset Condition | **Update:** WELL has updated the data accuracy score for LV connections from 1 to 2, to reflect improvements in LV connectivity data. |
| Schedule 12b | Zone Substation Security of Supply Classifications | **Update:** In line with the Commissions' instructions for the updated format of Schedule 12b, WELL's zone substations in the Wellington CBD that operate with a split 11 kV bus to reduce fault levels (see Section 9.1.1) are now classified as "N-1 Switched" in this schedule, due to the brief outage that would occur prior to the bus section circuit breaker being closed via SCADA. |

| 2025 AMP Section | Item | Description |
|---|---|---|
| Schedule 12c | DG Connections | **Update:** WELL has revised its forecasts for the annual increase in DG connections, as the previous trend of exponential growth in new connections has ceased. Linear growth in the number of new connections is now assumed. |
| Schedule 13 | Asset Management Maturity Assessment | **Update:** WELL has revised some of its AMMAT scores from 3 to 2. This represents a "lifting of the bar", where the operating environment is changing and WELL's standards and processes, while appropriate for meeting historical needs, now need to be strengthened in order to meet future requirements. These changes are as follows:<br><br>**Question 11:** WELL's asset management fleet strategies are being reviewed in 2025, with significant focus on secondary systems such as protection relays and communications equipment, to increase the level of detail in the multi-year work plan.<br><br>**Question 27:** WELL has identified that in order to effectively deliver its plan, stronger communication is needed with contractors, particularly civil contractors, to ensure that they have visibility of the multi-year work programme and can resource appropriately.<br><br>**Question 63:** WELL has identified that it is becoming increasingly reliant on data provided by third parties, and that further work is required to define and enforce data quality standards for external data providers. |

Table B-1 Material Changes in the 2025 AMP

## Comparison of Financial Performance to Previous Plan

Comparisons between forecast expenditure for the 2024/25 regulatory year from the 2024 AMP, and the forecast expenditure in the current AMP, are shown below in Table B-2 for operational expenditure and Table B-3 for capital expenditure.

| Expenditure Category | 2024/25 Forecast from 2024 AMP | 2024/25 Forecast from 2025 AMP | Variation to 2024 AMP |
|---|---|---|---|
| Service Interruptions and Emergencies | 5,490 | 4,409 | -1,081 |
| Vegetation Management | 2,349 | 1,759 | -590 |
| Routine and Corrective Maintenance and Inspection | 11,362 | 10,248 | -1,114 |
| Asset Replacement and Renewal | 1,525 | 1,602 | +77 |
| System Operations and Network Support | 10,556 | 10,245 | -311 |
| Business Support | 13,207 | 13,298 | +91 |
| **Operational Expenditure** | **44,488** | **41,561** | **-2,927** |

**Table B-2 Comparison of Operational Expenditure against 2024 AMP Forecasts ($K, forecast in nominal dollars)**

Network Operating Expenditure was less than forecast, primarily due to greater than forecast capitalisation of reactive and corrective maintenance, driven by changes in the ratio in occurrence of overhead faults to underground faults, and a timing difference in costs coming through from a new vegetation maintenance contract. Non-network Operating Expenditure was approximately in line with forecast.

| Expenditure Category | 2024/25 Forecast from 2024 AMP | 2024/25 Forecast from 2025 AMP | Variation to 2024 AMP |
|---|---|---|---|
| Customer Connection | 14,687 | 23,518 | +8,831 |
| System Growth | 2,822 | 2,913 | +91 |
| Asset Replacement and Renewal | 31,105 | 37,370 | +6,265 |
| Asset Relocations | 1,511 | 1,074 | -437 |
| Reliability, Safety and Environment | 3,270 | 3,618 | +348 |
| Expenditure on Non-network Assets | 4,642 | 10,885 | +6,243 |
| **Gross Capital Expenditure** | **58,037** | **79,379** | **+21,342** |
| Customer Contributions | 10,832 | 12,246 | +1,414 |
| **Net Capital Expenditure** | **47,530** | **67,774** | **+20,244** |

**Table B-3 Comparison of Capital Expenditure against 2024 AMP Forecasts ($K, forecast in nominal dollars)**

Expenditure on Customer Connections was higher than forecast in the 2024 AMP. This reflects customer work continuing at high levels, despite a downturn in economic conditions and lower consenting rates. The difference also includes WELL's Unforeseeable Major Capex Project reopener for the Wēta FX project.[70]

Expenditure on Asset Replacement and Renewal was higher than forecast in the 2024 AMP. Approximately $3m of this difference relates to the early procurement of assets for work planned for the 2025 financial year, with that expenditure being brought forward to reduce the impact of procurement lead times on the delivery of the work programme. There was also a greater than forecast rate of capitalisation of maintenance.

Expenditure on Non-network Assets was higher than forecast in the 2024 AMP, due to WELL's Unforeseeable Major Capex Project Reopener for the relocation of its Disaster Recovery site, and the purchase of land ahead of WELL's head office relocation in 2025/26.

[70] https://comcom.govt.nz/regulated-industries/electricity-lines/electricity-lines-price-quality-paths/electricity-lines-default-price-quality-path/2020-2025-electricity-default-price-quality-path?target=documents&root=361041

# Appendix C Schedules

| | |
|---|---|
| Company Name | Wellington Electricity |
| AMP Planning Period | 1 April 2025 – 31 March 2035 |

## 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). EDBs must express the information in this schedule (11a) as a specific value rather than ranges. Any supporting information about these values may be disclosed in Schedule 15 (Voluntary 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 | | | | | | | | | | | | | |
| 9 | | **11a(i): Expenditure on Assets Forecast** | **$000 (in nominal dollars)** | | | | | | | | | | |
| 10 | | Consumer connection | 23,518 | 18,085 | 21,076 | 21,568 | 22,106 | 22,665 | 23,118 | 23,580 | 24,052 | 24,533 | 25,024 |
| 11 | | System growth | 2,913 | 17,018 | 38,373 | 26,579 | 30,695 | 20,553 | 45,787 | 46,068 | 44,766 | 38,393 | 33,413 |
| 12 | | Asset replacement and renewal | 37,370 | 42,969 | 46,675 | 44,786 | 44,798 | 51,577 | 37,367 | 45,571 | 56,439 | 43,808 | 44,792 |
| 13 | | Asset relocations | 1,074 | 1,955 | 2,000 | 2,047 | 2,098 | 2,151 | 2,194 | 2,238 | 2,283 | 2,328 | 2,375 |
| 14 | | Reliability, safety and environment: | | | | | | | | | | | |
| 15 | | Quality of supply | 3,278 | 2,930 | 2,828 | 2,809 | 2,490 | 2,664 | 2,863 | 2,927 | 2,992 | 3,057 | 3,124 |
| 16 | | Legislative and regulatory | - | 2,480 | - | - | - | - | - | - | - | - | - |
| 17 | | Other reliability, safety and environment | 340 | 1,553 | 483 | 477 | - | - | - | - | - | - | - |
| 18 | | **Total reliability, safety and environment** | 3,618 | 6,964 | 3,311 | 3,287 | 2,490 | 2,664 | 2,863 | 2,927 | 2,992 | 3,057 | 3,124 |
| 19 | | **Expenditure on network assets** | 68,494 | 86,991 | 111,435 | 98,267 | 102,188 | 99,610 | 111,329 | 120,383 | 130,532 | 112,119 | 108,728 |
| 20 | | **Expenditure on non-network assets** | 12,885 | 25,101 | 4,018 | 3,658 | 3,240 | 1,698 | 5,045 | 2,716 | 2,347 | 3,526 | 2,552 |
| 21 | | **Expenditure on assets** | 81,379 | 112,092 | 115,454 | 101,925 | 105,428 | 101,308 | 116,374 | 123,099 | 132,879 | 115,645 | 111,279 |
| 22 | | | | | | | | | | | | | |
| 23 | *plus* | Cost of financing | 641 | 883 | 909 | 803 | 830 | 798 | 916 | 969 | 1,046 | 911 | 876 |
| 24 | *less* | Value of capital contributions | 12,246 | 14,028 | 16,153 | 16,530 | 16,943 | 17,371 | 18,377 | 18,744 | 19,119 | 19,502 | 19,892 |
| 25 | *plus* | Value of vested assets | - | - | - | - | - | - | - | - | - | - | - |
| 26 | | | | | | | | | | | | | |
| 27 | | **Capital expenditure forecast** | 69,774 | 98,947 | 100,209 | 86,197 | 89,315 | 84,734 | 98,914 | 105,325 | 114,806 | 97,055 | 92,264 |
| 28 | | | | | | | | | | | | | |
| 29 | | Assets commissioned | 55,700 | 107,800 | 93,767 | 86,056 | 87,625 | 94,138 | 103,004 | 105,325 | 114,806 | 97,055 | 92,264 |
| 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 | | | | | | | | | | | | | |
| 32 | | | **$000 (in constant prices)** | | | | | | | | | | |
| 33 | | Consumer connection | 23,518 | 17,695 | 20,178 | 20,244 | 20,343 | 20,448 | 20,448 | 20,448 | 20,448 | 20,448 | 20,448 |
| 34 | | System growth | 2,913 | 16,652 | 36,739 | 24,948 | 28,247 | 18,543 | 40,499 | 39,948 | 38,058 | 32,000 | 27,303 |
| 35 | | Asset replacement and renewal | 37,370 | 42,044 | 44,687 | 42,038 | 41,225 | 46,532 | 33,051 | 39,517 | 47,982 | 36,513 | 36,601 |
| 36 | | Asset relocations | 1,074 | 1,913 | 1,915 | 1,921 | 1,931 | 1,941 | 1,941 | 1,941 | 1,941 | 1,941 | 1,941 |
| 37 | | Reliability, safety and environment: | | | | | | | | | | | |
| 38 | | Quality of supply | 3,278 | 2,867 | 2,708 | 2,637 | 2,291 | 2,403 | 2,532 | 2,538 | 2,544 | 2,548 | 2,553 |
| 39 | | Legislative and regulatory | - | 2,427 | - | - | - | - | - | - | - | - | - |
| 40 | | Other reliability, safety and environment | 340 | 1,520 | 462 | 448 | - | - | - | - | - | - | - |
| 41 | | **Total reliability, safety and environment** | 3,618 | 6,814 | 3,170 | 3,085 | 2,291 | 2,403 | 2,532 | 2,538 | 2,544 | 2,548 | 2,553 |
| 42 | | **Expenditure on network assets** | 68,494 | 85,118 | 106,689 | 92,237 | 94,036 | 89,867 | 98,471 | 104,391 | 110,973 | 93,450 | 88,846 |
| 43 | | Expenditure on non-network assets | 12,885 | 24,561 | 3,847 | 3,434 | 2,982 | 1,532 | 4,462 | 2,355 | 1,995 | 2,939 | 2,085 |
| 44 | | **Expenditure on assets** | 81,379 | 109,679 | 110,536 | 95,671 | 97,018 | 91,399 | 102,933 | 106,746 | 112,968 | 96,389 | 90,931 |
| 45 | | | | | | | | | | | | | |
| 46 | | **Subcomponents of expenditure on assets (where known)** | | | | | | | | | | | |
| 48 | | Energy efficiency and demand side management, reduction of energy losses | | | | | | | | | | | |
| 49 | | Overhead to underground conversion | | | | | | | | | | | |
| 50 | | Research and development | | | | | | | | | | | |
| 52 | | | | | | | | | | | | | |

| | Current Year CY | CY+1 | CY+2 | CY+3 | CY+4 | CY+5 | CY+6 | CY+7 | CY+8 | CY+9 | CY+10 |
|---|---|---|---|---|---|---|---|---|---|---|---|
| **Difference between nominal and constant price forecasts** | **$000** | | | | | | | | | | |
| Consumer connection | - | 389 | 898 | 1,323 | 1,763 | 2,217 | 2,670 | 3,132 | 3,604 | 4,085 | 4,576 |
| System growth | - | 366 | 1,634 | 1,631 | 2,448 | 2,010 | 5,288 | 6,120 | 6,708 | 6,393 | 6,110 |
| Asset replacement and renewal | - | 925 | 1,988 | 2,748 | 3,573 | 5,045 | 4,316 | 6,054 | 8,457 | 7,295 | 8,191 |
| Asset relocations | - | 42 | 85 | 126 | 167 | 210 | 253 | 297 | 342 | 388 | 434 |
| Reliability, safety and environment: | | | | | | | | | | | |
| Quality of supply | - | 63 | 120 | 172 | 199 | 261 | 331 | 389 | 448 | 509 | 571 |
| Legislative and regulatory | - | 53 | - | - | - | - | - | - | - | - | - |
| Other reliability, safety and environment | - | 33 | 21 | 29 | - | - | - | - | - | - | - |
| **Total reliability, safety and environment** | - | 150 | 141 | 202 | 199 | 261 | 331 | 389 | 448 | 509 | 571 |
| **Expenditure on network assets** | - | 1,873 | 4,746 | 6,030 | 8,151 | 9,743 | 12,859 | 15,992 | 19,560 | 18,670 | 19,882 |
| Expenditure on non-network assets | - | 540 | 171 | 224 | 258 | 166 | 583 | 361 | 352 | 587 | 467 |
| **Expenditure on assets** | - | 2,413 | 4,917 | 6,254 | 8,410 | 9,909 | 13,441 | 16,353 | 19,912 | 19,257 | 20,348 |

**Commentary on options and considerations made in the assessment of forecast expenditure**

*EDBs may provide explanatory comment on the options they have considered (including scenarios used) in assessing forecast expenditure on assets for the current disclosure year and a 10 year planning period in Schedule 15*

## 11a(ii): Consumer Connection

| | Current Year CY | CY+1 | CY+2 | CY+3 | CY+4 | CY+5 |
|---|---|---|---|---|---|---|
| *Consumer types defined by EDB** | **$000 (in constant prices)** | | | | | |
| Substation | 14,073 | 7,206 | 8,217 | 8,244 | 8,284 | 8,327 |
| Subdivision | 4,455 | 4,295 | 4,897 | 4,913 | 4,937 | 4,963 |
| High Voltage Connection | 329 | 636 | 622 | 610 | 598 | 586 |
| Residential Customers | 4,009 | 5,216 | 6,106 | 6,148 | 6,201 | 6,256 |
| Public Lighting | 652 | 342 | 335 | 329 | 322 | 316 |
| **include additional rows if needed* | | | | | | |
| **Consumer connection expenditure** | 23,518 | 17,695 | 20,178 | 20,244 | 20,343 | 20,448 |
| *less* Capital contributions funding consumer connection | 11,712 | 12,387 | 14,125 | 14,171 | 14,240 | 14,314 |
| **Consumer connection less capital contributions** | 11,806 | 5,309 | 6,053 | 6,073 | 6,103 | 6,134 |

## 11a(iii): System Growth

| | Current Year CY | CY+1 | CY+2 | CY+3 | CY+4 | CY+5 |
|---|---|---|---|---|---|---|
| Subtransmission | 19 | 477 | 4,296 | 251 | 5,846 | 6,223 |
| Zone substations | 985 | 398 | 8,986 | 6,905 | 4,731 | 5,482 |
| Distribution and LV lines | 199 | - | 190 | - | - | - |
| Distribution and LV cables | 435 | 15,720 | 22,763 | 17,792 | 17,670 | 6,838 |
| Distribution substations and transformers | 24 | - | - | - | - | - |
| Distribution switchgear | 1 | 57 | 504 | - | - | - |
| Other network assets | 1,251 | - | - | - | - | - |
| **System growth expenditure** | 2,913 | 16,652 | 36,739 | 24,948 | 28,247 | 18,543 |
| *less* Capital contributions funding system growth | - | - | - | - | - | - |
| **System growth less capital contributions** | 2,913 | 16,652 | 36,739 | 24,948 | 28,247 | 18,543 |

| | | Current Year CY | CY+1 | CY+2 | CY+3 | CY+4 | CY+5 |
|---|---|---|---|---|---|---|---|
| 97 | | *Current Year CY* | *CY+1* | *CY+2* | *CY+3* | *CY+4* | *CY+5* |
| 98 | | | | | | | |
| 99 | **11a(iv): Asset Replacement and Renewal** | **$000 (in constant prices)** | | | | | |
| 100 | Subtransmission | 5,513 | 3,471 | 9,629 | - | 8,417 | 8,417 |
| 101 | Zone substations | 746 | 1,663 | 569 | 5,524 | 552 | 5,543 |
| 102 | Distribution and LV lines | 9,939 | 9,904 | 7,755 | 7,430 | 7,195 | 6,376 |
| 103 | Distribution and LV cables | 1,138 | 3,139 | 4,727 | 5,591 | 4,058 | 4,207 |
| 104 | Distribution substations and transformers | 11,578 | 7,924 | 6,965 | 7,560 | 5,775 | 6,383 |
| 105 | Distribution switchgear | 1,957 | 11,248 | 11,009 | 10,096 | 9,818 | 10,296 |
| 106 | Other network assets | 6,498 | 4,695 | 4,033 | 5,837 | 5,410 | 5,310 |
| 107 | **Asset replacement and renewal expenditure** | 37,370 | 42,044 | 44,687 | 42,038 | 41,225 | 46,532 |
| 108 | *less* Capital contributions funding asset replacement and renewal | - | - | - | - | - | - |
| 109 | **Asset replacement and renewal less capital contributions** | 37,370 | 42,044 | 44,687 | 42,038 | 41,225 | 46,532 |
| 110 | | | | | | | |
| 111 | | *Current Year CY* | *CY+1* | *CY+2* | *CY+3* | *CY+4* | *CY+5* |
| 112 | | | | | | | |
| 113 | **11a(v): Asset Relocations** | | | | | | |
| 114 | *Project or programme** | **$000 (in constant prices)** | | | | | |
| 115 | Relocation Projects | 1,074 | 1,913 | 1,915 | 1,921 | 1,931 | 1,941 |
| 116 | | | | | | | |
| 117 | | | | | | | |
| 118 | | | | | | | |
| 119 | | | | | | | |
| 120 | **include additional rows if needed* | | | | | | |
| 121 | All other project or programmes - asset relocations | - | - | - | - | - | - |
| 122 | **Asset relocations expenditure** | 1,074 | 1,913 | 1,915 | 1,921 | 1,931 | 1,941 |
| 123 | *less* Capital contributions funding asset relocations | 535 | 1,339 | 1,341 | 1,345 | 1,351 | 1,358 |
| 124 | **Asset relocations less capital contributions** | 539 | 574 | 575 | 576 | 579 | 582 |
| 125 | | | | | | | |
| 126 | | *Current Year CY* | *CY+1* | *CY+2* | *CY+3* | *CY+4* | *CY+5* |
| 127 | | | | | | | |
| 128 | **11a(vi): Quality of Supply** | | | | | | |
| 129 | *Project or programme** | **$000 (in constant prices)** | | | | | |
| 130 | Feeder Reliability Projects – Lines | 3,278 | 2,188 | 1,035 | 1,195 | 1,404 | 1,213 |
| 131 | Feeder Reliability Projects – Switchgear | | 679 | 1,473 | 1,242 | 687 | 990 |
| 132 | Switchgear SCADA Control Retrofit | | - | 200 | 200 | 200 | 200 |
| 133 | | | | | | | |
| 134 | | | | | | | |
| 135 | **include additional rows if needed* | | | | | | |
| 136 | All other projects or programmes - quality of supply | - | - | - | - | - | - |
| 137 | **Quality of supply expenditure** | 3,278 | 2,867 | 2,708 | 2,637 | 2,291 | 2,403 |
| 138 | *less* Capital contributions funding quality of supply | - | - | - | - | - | - |
| 139 | **Quality of supply less capital contributions** | 3,278 | 2,867 | 2,708 | 2,637 | 2,291 | 2,403 |
| 140 | | | | | | | |

| | | | Current Year CY | CY+1 | CY+2 | CY+3 | CY+4 | CY+5 |
|---|---|---|---|---|---|---|---|---|
| 141 | | | Current Year CY | CY+1 | CY+2 | CY+3 | CY+4 | CY+5 |
| 142 | | | | | | | | |

## 143 11a(vii): Legislative and Regulatory

| | | | Current Year CY | CY+1 | CY+2 | CY+3 | CY+4 | CY+5 |
|---|---|---|---|---|---|---|---|---|
| 144 | | *Project or programme** | **$000 (in constant prices)** | | | | | |
| 145 | | AUFLS Relay Replacement | - | 2,427 | - | - | - | - |
| 150 | | **include additional rows if needed* | | | | | | |
| 151 | | All other projects or programmes - legislative and regulatory | | | | | | |
| 152 | | **Legislative and regulatory expenditure** | - | 2,427 | - | - | - | - |
| 153 | *less* | Capital contributions funding legislative and regulatory | | | | | | |
| 154 | | **Legislative and regulatory less capital contributions** | - | 2,427 | - | - | - | - |
| 155 | | | | | | | | |
| 156 | | | Current Year CY | CY+1 | CY+2 | CY+3 | CY+4 | CY+5 |

## 157 11a(viii): Other Reliability, Safety and Environment

| | | | Current Year CY | CY+1 | CY+2 | CY+3 | CY+4 | CY+5 |
|---|---|---|---|---|---|---|---|---|
| 158 | | *Project or programme** | **$000 (in constant prices)** | | | | | |
| 159 | | Seismic Strengthening | 340 | 572 | 462 | 448 | - | - |
| 160 | | Mobile Generator Transformers | - | 948 | - | - | - | - |
| 164 | | **include additional rows if needed* | | | | | | |
| 165 | | All other projects or programmes - other reliability, safety and environment | - | - | - | - | - | - |
| 166 | | **Other reliability, safety and environment expenditure** | 340 | 1,520 | 462 | 448 | - | - |
| 167 | *less* | Capital contributions funding other reliability, safety and environment | - | - | - | - | - | - |
| 168 | | **Other reliability, safety and environment less capital contributions** | 340 | 1,520 | 462 | 448 | - | - |
| 169 | | | | | | | | |
| 170 | | | Current Year CY | CY+1 | CY+2 | CY+3 | CY+4 | CY+5 |

## 172 11a(ix): Non-Network Assets

| | | Current Year CY | CY+1 | CY+2 | CY+3 | CY+4 | CY+5 |
|---|---|---|---|---|---|---|---|
| 173 | **Routine expenditure** | | | | | | |
| 174 | *Project or programme** | **$000 (in constant prices)** | | | | | |
| 175 | Software and Licenses | 472 | 4,040 | 1,140 | 986 | 1,718 | 1,047 |
| 176 | IT Infrastructure | 392 | 1,975 | 631 | 2,199 | 272 | 315 |
| 177 | Capitalised Leases | 2,000 | 546 | 2,076 | 249 | 992 | 170 |
| 178 | | | | | | | |
| 180 | **include additional rows if needed* | | | | | | |
| 181 | All other projects or programmes - routine expenditure | 141 | - | - | - | - | - |
| 182 | **Routine expenditure** | 3,006 | 6,561 | 3,847 | 3,434 | 2,982 | 1,532 |
| 183 | **Atypical expenditure** | | | | | | |
| 184 | *Project or programme** | | | | | | |
| 185 | Office and DR Site Relocations | 9,880 | 18,000 | - | - | - | - |
| 190 | **include additional rows if needed* | | | | | | |
| 191 | All other projects or programmes - atypical expenditure | - | - | - | - | - | - |
| 192 | **Atypical expenditure** | 9,880 | 18,000 | - | - | - | - |
| 193 | | | | | | | |
| 194 | **Expenditure on non-network assets** | 12,885 | 24,561 | 3,847 | 3,434 | 2,982 | 1,532 |

safer together

| | |
|---|---|
| *Company Name* | **Wellington Electricity** |
| *AMP Planning Period* | **1 April 2025 – 31 March 2035** |

## 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.

| *sch ref* | | | | | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| *7* | | | *Current Year CY* | *CY+1* | *CY+2* | *CY+3* | *CY+4* | *CY+5* | *CY+6* | *CY+7* | *CY+8* | *CY+9* | *CY+10* |
| *8* | | | | | | | | | | | | | |
| *9* | **Operational Expenditure Forecast** | | **$000 (in nominal dollars)** | | | | | | | | | | |
| *10* | Service interruptions and emergencies | | 4,409 | 4,794 | 4,962 | 5,139 | 5,325 | 5,519 | 5,630 | 5,742 | 5,857 | 5,974 | 6,094 |
| *11* | Vegetation management | | 1,759 | 1,913 | 1,980 | 2,051 | 2,125 | 2,203 | 2,247 | 2,292 | 2,337 | 2,384 | 2,432 |
| *12* | Routine and corrective maintenance and inspection | | 10,248 | 11,144 | 11,535 | 11,945 | 12,378 | 12,830 | 13,087 | 13,348 | 13,615 | 13,888 | 14,165 |
| *13* | Asset replacement and renewal | | 1,602 | 1,742 | 1,803 | 1,867 | 1,935 | 2,005 | 2,045 | 2,086 | 2,128 | 2,170 | 2,214 |
| *14* | **Network Opex** | | 18,017 | 19,592 | 20,281 | 21,001 | 21,763 | 22,557 | 23,008 | 23,469 | 23,938 | 24,417 | 24,905 |
| *15* | System operations and network support | | 10,245 | 11,140 | 11,532 | 11,942 | 12,375 | 12,826 | 13,083 | 13,345 | 13,611 | 13,884 | 14,161 |
| *16* | Business support | | 13,298 | 14,461 | 14,969 | 15,501 | 16,063 | 16,649 | 17,201 | 17,780 | 18,135 | 18,498 | 18,868 |
| *17* | Non-network solutions provided by a related party or third party | *Not Required before DY2025* | - | - | - | - | - | - | - | - | - | - | - |
| *18* | **Non-network opex** | | 23,543 | 25,601 | 26,501 | 27,442 | 28,437 | 29,475 | 30,284 | 31,124 | 31,747 | 32,382 | 33,029 |
| *19* | **Operational expenditure** | | 41,561 | 45,193 | 46,782 | 48,444 | 50,200 | 52,033 | 53,292 | 54,593 | 55,685 | 56,798 | 57,934 |
| *20* | | | *Current Year CY* | *CY+1* | *CY+2* | *CY+3* | *CY+4* | *CY+5* | *CY+6* | *CY+7* | *CY+8* | *CY+9* | *CY+10* |
| *21* | | | | | | | | | | | | | |
| *22* | | | **$000 (in constant prices)** | | | | | | | | | | |
| *23* | Service interruptions and emergencies | | 4,409 | 4,691 | 4,751 | 4,823 | 4,900 | 4,979 | 4,979 | 4,979 | 4,979 | 4,979 | 4,979 |
| *24* | Vegetation management | | 1,759 | 1,872 | 1,896 | 1,925 | 1,956 | 1,987 | 1,987 | 1,987 | 1,987 | 1,987 | 1,987 |
| *25* | Routine and corrective maintenance and inspection | | 10,248 | 10,904 | 11,044 | 11,212 | 11,391 | 11,575 | 11,575 | 11,575 | 11,575 | 11,575 | 11,575 |
| *26* | Asset replacement and renewal | | 1,602 | 1,704 | 1,726 | 1,752 | 1,780 | 1,809 | 1,809 | 1,809 | 1,809 | 1,809 | 1,809 |
| *27* | **Network Opex** | | 18,017 | 19,170 | 19,417 | 19,713 | 20,027 | 20,351 | 20,351 | 20,351 | 20,351 | 20,351 | 20,351 |
| *28* | System operations and network support | | 10,245 | 10,901 | 11,041 | 11,209 | 11,388 | 11,572 | 11,572 | 11,572 | 11,572 | 11,572 | 11,572 |
| *29* | Business support | | 13,298 | 14,149 | 14,332 | 14,550 | 14,782 | 15,021 | 15,214 | 15,418 | 15,418 | 15,418 | 15,418 |
| *30* | Non-network solutions provided by a related party or third party | *Not Required before DY2025* | - | - | - | - | - | - | - | - | - | - | - |
| *31* | **Non-network opex** | | 23,543 | 25,050 | 25,373 | 25,758 | 26,169 | 26,592 | 26,786 | 26,990 | 26,990 | 26,990 | 26,990 |
| *32* | **Operational expenditure** | | 41,561 | 44,220 | 44,790 | 45,471 | 46,196 | 46,943 | 47,137 | 47,340 | 47,340 | 47,340 | 47,340 |
| *33* | **Subcomponents of operational expenditure (where known)** | | | | | | | | | | | | |
| *35* | | | | | | | | | | | | | |
| *36* | Energy efficiency and demand side management, reduction of energy losses | | - | - | - | - | - | - | - | - | - | - | - |
| *37* | Direct billing* | | - | - | - | - | - | - | - | - | - | - | - |
| *38* | Research and Development | | - | - | - | - | - | - | - | - | - | - | - |
| *39* | Insurance | | 2,915 | 3,204 | 3,424 | 3,592 | 3,768 | 3,953 | 4,147 | 4,350 | 4,350 | 4,350 | 4,350 |
| *41* | ** Direct billing expenditure by suppliers that direct bill the majority of their consumers* | | | | | | | | | | | | |
| *42* | | | | | | | | | | | | | |
| *43* | | | *Current Year CY* | *CY+1* | *CY+2* | *CY+3* | *CY+4* | *CY+5* | *CY+6* | *CY+7* | *CY+8* | *CY+9* | *CY+10* |
| *44* | | | | | | | | | | | | | |
| *45* | **Difference between nominal and real forecasts** | | **$000** | | | | | | | | | | |
| *46* | Service interruptions and emergencies | | - | 103 | 211 | 315 | 425 | 540 | 650 | 763 | 878 | 995 | 1,114 |
| *47* | Vegetation management | | - | 41 | 84 | 126 | 170 | 215 | 259 | 304 | 350 | 397 | 445 |
| *48* | Routine and corrective maintenance and inspection | | - | 240 | 491 | 733 | 987 | 1,255 | 1,512 | 1,773 | 2,040 | 2,313 | 2,590 |
| *49* | Asset replacement and renewal | | - | 37 | 77 | 115 | 154 | 196 | 236 | 277 | 319 | 361 | 405 |
| *50* | **Network Opex** | | - | 422 | 864 | 1,289 | 1,736 | 2,206 | 2,657 | 3,118 | 3,587 | 4,066 | 4,554 |
| *51* | System operations and network support | | - | 240 | 491 | 733 | 987 | 1,255 | 1,511 | 1,773 | 2,040 | 2,312 | 2,590 |
| *52* | Business support | | - | 311 | 638 | 951 | 1,281 | 1,628 | 1,987 | 2,362 | 2,718 | 3,080 | 3,450 |
| *53* | Non-network solutions provided by a related party or third party | *Not Required before DY2025* | - | - | - | - | - | - | - | - | - | - | - |
| *54* | **Non-network opex** | | - | 551 | 1,129 | 1,684 | 2,268 | 2,883 | 3,498 | 4,135 | 4,757 | 5,392 | 6,040 |
| *55* | **Operational expenditure** | | - | 973 | 1,992 | 2,973 | 4,004 | 5,089 | 6,155 | 7,252 | 8,344 | 9,458 | 10,594 |
| *56* | | | | | | | | | | | | | |
| *57* | **Commentary on options and considerations made in the assessment of forecast expenditure** | | | | | | | | | | | | |
| *58* | *EDBs may provide explanatory comment on the options they have considered (including scenarios used) in assessing forecast operational expenditure for the current disclosure year and a 10 year planning period in Schedule 15.* | | | | | | | | | | | | |

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| *Company Name* | **Wellington Electricity** |
| *AMP Planning Period* | **1 April 2025 – 31 March 2035** |

## 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* | | | | | | | | | | | | |
| *9* | **Voltage** | **Asset category** | **Asset class** | **Units** | **H1** | **H2** | **H3** | **H4** | **H5** | **Grade unknown** | **Data accuracy (1–4)** | **% of asset forecast to be replaced in next 5 years** |
| *10* | All | Overhead Line | Concrete poles / steel structure | No. | - | 0.20% | 30.74% | 27.86% | 40.62% | 0.57% | 3 | 1.41% |
| *11* | All | Overhead Line | Wood poles | No. | 0.03% | 3.59% | 58.85% | 22.70% | 12.60% | 2.24% | 3 | 18.70% |
| *12* | All | Overhead Line | Other pole types | No. | - | - | 0.85% | 1.69% | 97.46% | - | 3 | - |
| *13* | HV | Subtransmission Line | Subtransmission OH up to 66kV conductor | km | - | 13.81% | 59.42% | 21.22% | 5.56% | - | 2 | - |
| *14* | HV | Subtransmission Line | Subtransmission OH 110kV+ conductor | km | - | - | - | - | - | - | N/A | |
| *15* | HV | Subtransmission Cable | Subtransmission UG up to 66kV (XLPE) | km | - | 6.68% | - | 55.11% | 38.22% | - | 3 | 6.68% |
| *16* | HV | Subtransmission Cable | Subtransmission UG up to 66kV (Oil pressurised) | km | - | 16.02% | 83.98% | - | - | - | 3 | 22.21% |
| *17* | HV | Subtransmission Cable | Subtransmission UG up to 66kV (Gas pressurised) | km | - | 21.46% | 78.54% | - | - | - | 3 | 27.77% |
| *18* | HV | Subtransmission Cable | Subtransmission UG up to 66kV (PILC) | km | - | 1.28% | 55.80% | 42.93% | - | - | 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. | - | - | 15.40% | - | 84.60% | - | 4 | 15.40% |
| *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. | - | 16.12% | 63.39% | 2.46% | 18.03% | - | 3 | 11.20% |
| *34* | HV | Zone substation switchgear | 3.3/6.6/11/22kV CB (pole mounted) | No. | - | - | - | - | - | - | N/A | |
| *35* | | | | | | | | | | | | |

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| | | | | | Asset condition at start of planning period (percentage of units by grade) | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | Voltage | Asset category | Asset class | Units | H1 | H2 | H3 | H4 | H5 | Grade unknown | Data accuracy (1–4) | % of asset forecast to be replaced in next 5 years |
| 39 | HV | Zone Substation Transformer | Zone Substation Transformers | No. | - | 5.77% | 65.38% | 25.00% | 3.85% | - | 4 | 11.54% |
| 40 | HV | Distribution Line | Distribution OH Open Wire Conductor | km | 0.32% | 13.89% | 71.78% | 9.13% | 4.88% | | 3 | 3.40% |
| 41 | HV | Distribution Line | Distribution OH Aerial Cable Conductor | km | - | 43.39% | 11.19% | 0.13% | 45.29% | - | 3 | - |
| 42 | HV | Distribution Line | SWER conductor | km | - | - | 100.00% | - | - | | 3 | - |
| 43 | HV | Distribution Cable | Distribution UG XLPE or PVC | km | - | - | 0.89% | 32.51% | 66.60% | | 3 | - |
| 44 | HV | Distribution Cable | Distribution UG PILC | km | 0.00% | 8.87% | 67.86% | 23.14% | 0.13% | - | 3 | 1.08% |
| 45 | HV | Distribution Cable | Distribution Submarine Cable | km | - | - | 100.00% | - | - | - | 3 | - |
| 46 | HV | Distribution switchgear | 3.3/6.6/11/22kV CB (pole mounted) - reclosers and sectionalisers | No. | - | 5.56% | 16.67% | 50.00% | 27.78% | - | 3 | 5.56% |
| 47 | HV | Distribution switchgear | 3.3/6.6/11/22kV CB (Indoor) | No. | - | 1.39% | 69.61% | 28.76% | 0.25% | - | 3 | 8.09% |
| 48 | HV | Distribution switchgear | 3.3/6.6/11/22kV Switches and fuses (pole mounted) | No. | - | 1.25% | 67.13% | 19.83% | 11.37% | 0.42% | 3 | 7.84% |
| 49 | HV | Distribution switchgear | 3.3/6.6/11/22kV Switch (ground mounted) - except RMU | No. | - | 48.29% | 49.32% | 1.03% | 1.37% | | 3 | 37.67% |
| 50 | HV | Distribution switchgear | 3.3/6.6/11/22kV RMU | No. | - | 1.26% | 80.69% | 11.60% | 6.45% | - | 3 | 4.12% |
| 51 | HV | Distribution Transformer | Pole Mounted Transformer | No. | - | 0.83% | 45.45% | 35.96% | 17.76% | - | 3 | 9.71% |
| 52 | HV | Distribution Transformer | Ground Mounted Transformer | No. | 0.30% | 2.74% | 67.32% | 21.84% | 7.81% | - | 3 | 8.18% |
| 53 | HV | Distribution Transformer | Voltage regulators | No. | - | - | - | - | - | - | N/A | |
| 54 | HV | Distribution Substations | Ground Mounted Substation Housing | No. | - | 0.68% | 58.13% | 37.71% | 3.49% | - | 3 | 3.14% |
| 55 | LV | LV Line | LV OH Conductor | km | 0.51% | 15.51% | 79.77% | 3.06% | 1.15% | - | 2 | 0.93% |
| 56 | LV | LV Cable | LV UG Cable | km | 0.04% | 3.86% | 70.80% | 15.77% | 9.53% | | 2 | 0.45% |
| 57 | LV | LV Streetlighting | LV OH/UG Streetlight circuit | km | 0.05% | 19.40% | 65.37% | 11.10% | 4.08% | | 2 | 0.51% |
| 58 | LV | Connections | OH/UG consumer service connections | No. | - | 5.97% | 75.20% | 8.53% | 10.30% | - | 2 | - |
| 59 | All | Protection | Protection relays (electromechanical, solid state and numeric) | No. | 0.14% | 0.68% | 82.05% | 8.33% | 8.81% | - | 3 | 6.76% |
| 60 | All | SCADA and communications | SCADA and communications equipment operating as a single system | Lot | 11.99% | 36.70% | 14.61% | 23.60% | 13.11% | - | 3 | 39.39% |
| 61 | All | Capacitor Banks | Capacitors including controls | No. | - | - | - | - | - | - | N/A | |
| 62 | All | Load Control | Centralised plant | Lot | - | 20.00% | 60.00% | - | 20.00% | - | 3 | 20.00% |
| 63 | All | Load Control | Relays | No. | - | - | - | - | - | - | N/A | |
| 64 | All | Civils | Cable Tunnels | km | - | - | 100.00% | - | - | - | 3 | - |

Company Name: Wellington Electricity
AMP Planning Period: 1 April 2025 – 31 March 2035

## SCHEDULE 12b: REPORT ON FORECAST CAPACITY

This schedule requires a breakdown of current and forecast capacity and constraints for each zone substation. 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) | Current peak load period | Installed operating capacity (MVA) | Current security of supply classification (type) | Current constraint type | Current available capacity (MVA) | Peak load period +5 yrs | Available capacity +5 yrs (MVA) | Security of supply classification +5 yrs (type) | Peak load period +10 yrs | Min. available capacity +10 yrs (MVA) | Max. available capacity +10 yrs (MVA) | Security of supply classification +10 yrs (type) | Forecast constraint type | Year of any forecast constraint | Constraint primary cause | Constraint solution type | Constraint solution progress | Temporary constraint solution remaining lifespan | Explanation |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | | | *Not Required before DY2025* | *Not Required before DY2025* | *Not Required before DY2025* | *Not Required before DY2025* | *Not Required before DY2025* | *Not Required before DY2025* | *Not Required before DY2025* | *Not Required before DY2025* | *Not Required before DY2025* | *Not Required before DY2025* | *Not Required before DY2025* | *Not Required before DY2025* | *Not Required before DY2025* | *Not Required before DY2025* | *Not Required before DY2025* | *Not Required before DY2025* | *Not Required before DY2025* | *Not Required before DY2025* | |
| 8 | | | | | | | | | | | | | | | | | | | | | |
| 9 | 8 Ira Street | 15 | Winter | 20 | N-1 switched | No constraint | 5 | Winter | 3 | N-1 switched | Winter | 2 | 5 | N-1 switched | No constraint | 10+ | Not applicable | Not required | Not applicable | Not applicable | |
| 10 | Brown Owl | 15 | Winter | 18 | N-1 | No constraint | 3 | Winter | 2 | N-1 | Winter | 0 | 2 | N-1 | Security | 10+ | Zone substation transformer | Undecided | Planning stage | Not applicable | Demand forecast is highly dependent on future customer intentions. Current approach is to monitor load and use 11kV post-contingent offloads until growth is confirmed.<br>Temporary measure is load control and post contingency offload to neighbouring zone substations. |
| 11 | Evans Bay | 13 | Winter | 24 | N-1 switched | No constraint | 11 | Winter | 11 | N-1 switched | Winter | 9 | 12 | N-1 switched | No constraint | 10+ | Not applicable | Not required | Not applicable | Not applicable | |
| 12 | Frederick Street | 25 | Winter | 30 | N-1 switched | No constraint | 5 | Winter | 6 | N-1 switched | Winter | 6 | 9 | N-1 switched | No constraint | 10+ | Not applicable | Not required | Not applicable | Not applicable | |
| 13 | Gracefield | 10 | Winter | 23 | N-1 | No constraint | 13 | Winter | 12 | N-1 | Winter | 11 | 13 | N-1 | No constraint | 10+ | Not applicable | Not required | Not applicable | Not applicable | |
| 14 | Hataitai | 15 | Winter | 21 | N-1 switched | No constraint | 6 | Winter | 6 | N-1 switched | Winter | 5 | 8 | N-1 switched | No constraint | 10+ | Not applicable | Not required | Not applicable | Not applicable | |
| 15 | Johnsonville | 20 | Winter | 16 | N-1 | Security | 0 | Winter | 0 | N-1 | Winter | 0 | 0 | N-1 | Security | None | Subtransmission circuit | Divert load to alternative substation | Planning stage | > 3 years | Preferred solution is a permanent load transfer to proposed Grenada zone substation from 2028.<br>Temporary measure is load control and post contingency offload to neighbouring zone substations. |
| 16 | Karori | 13 | Winter | 20 | N-1 switched | No constraint | 7 | Winter | 6 | N-1 switched | Winter | 5 | 7 | N-1 switched | No constraint | 10+ | Not applicable | Not required | Not applicable | Not applicable | |
| 17 | Kenepuru | 10 | Winter | 18 | N-1 | No constraint | 8 | Winter | 7 | N-1 | Winter | 7 | 8 | N-1 | No constraint | 10+ | Not applicable | Not required | Not applicable | Not applicable | Project to increase 11kV transfer capacity to Porirua in 2025/26.<br>Transformer replacement for Asset Health in 2028. |
| 18 | Korokoro | 17 | Winter | 16 | N-1 | Security | 0 | Winter | 0 | N-1 | Winter | 0 | 0 | N-1 | Security | None | Subtransmission circuit | Undecided | Planning stage | > 3 years | Demand forecast is highly dependent on future customer intentions. Current approach is to monitor load and use 11kV post-contingent offloads until growth is confirmed.<br>Temporary measure is load control and post contingency offload to neighbouring zone substations. |
| 19 | Maidstone | 13 | Winter | 18 | N-1 | No constraint | 4 | Winter | 3 | N-1 | Winter | 1 | 4 | N-1 | No constraint | 10+ | Not applicable | Not required | Not applicable | Not applicable | Replace 33kV cables for Asset Health in 2030. |
| 20 | Mana | 11 | Winter | 7 | N-1 | Security | 0 | Winter | 0 | N-1 | Winter | 0 | 0 | N-1 | Security | None | Distribution back-up circuit capacity | Network upgrade | Planning stage | > 3 years | Mana has one 14MVA transformer plus a normally -closed 11kV tie to Plimmerton rated to 7MVA. The N-1 capacity at the substation is limited to the 7MVA rating of this 11kV tie.<br>The Mana-Plimmerton 11kV bus tie is proposed for upgrade in 2027.<br>The transformer is expected to be replaced for asset health in 2030. |
| 21 | Moore Street | 17 | Summer | 30 | N-1 switched | No constraint | 13 | Summer | 12 | N-1 switched | Summer | 13 | 15 | N-1 switched | No constraint | 10+ | Not applicable | Not required | Not applicable | Not applicable | |
| 22 | Naenae | 14 | Winter | 18 | N-1 | No constraint | 4 | Winter | 3 | N-1 | Winter | 2 | 4 | N-1 | No constraint | 10+ | Not applicable | Not required | Not applicable | Not applicable | |
| 23 | Nairn Street | 19 | Winter | 22 | N-1 | No constraint | 3 | Winter | 3 | N-1 | Winter | 2 | 5 | N-1 | No constraint | 10+ | Not applicable | Not required | Not applicable | Not applicable | |
| 24 | Ngauranga | 10 | Winter | 10 | N-1 | Security | 0 | Winter | 0 | N-1 | Winter | 0 | 0 | N-1 | Security | None | Zone substation transformer | Network upgrade | Planning stage | > 3 years | Temporary measure is load control and post contingency offload.<br>Preferred solution is a power transformer upgrade, and permanent load transfer to proposed Grenada zone substation in 2028 |
| 25 | Palm Grove | 23 | Winter | 20 | N-1 switched | Security | 0 | Winter | 0 | N-1 switched | Winter | 0 | 0 | N-1 switched | Security | None | Zone substation transformer | Divert load to alternative substation | Planning stage | > 3 years | Preferred solution is to transfer load to proposed adjacent zone substation from 2028, subject to a major customer project proceeding, otherwise 11kV reinforcement to facilitate offload. |
| 26 | Plimmerton | 6 | Winter | 7 | N-1 | No constraint | 1 | Winter | 1 | N-1 | Winter | 0 | 1 | N-1 | Security | 10+ | Not applicable | Not required | Not applicable | Not applicable | Plimmerton has one 14MVA transformer plus a normally -closed 11kV tie to Mana rated to 7MVA. The N-1 capacity at the substation is limited to the 7MVA rating of this 11kV tie. |
| 27 | Porirua | 21 | Winter | 20 | N-1 | Security | 0 | Winter | 0 | N-1 | Winter | 0 | 0 | N-1 | Security | None | Zone substation transformer | Divert load to alternative substation | Planning stage | > 3 years | Temporary measure is load control and post contingency offload.<br>Permanent load transfer to Kenepuru zone substation in 2026.<br>Site upgrade currently proposed for 2030. |
| 28 | Seaview | 14 | Winter | 14 | N-1 | Security | 0 | Winter | 0 | N-1 | Winter | 0 | 1 | N-1 | Security | None | Subtransmission circuit | Undecided | Planning stage | > 3 years | Demand forecast is highly dependent on future customer intentions. Current approach is to monitor load and use post-contingent 11kV offloads until growth is confirmed. |
| 29 | Tawa | 14 | Winter | 16 | N-1 | No constraint | 2 | Winter | 1 | N-1 | Winter | 0 | 2 | N-1 | No constraint | 10+ | Not applicable | Not required | Not applicable | Not applicable | |
| 30 | The Terrace | 20 | Winter | 30 | N-1 switched | No constraint | 10 | Winter | 11 | N-1 switched | Winter | 12 | 15 | N-1 switched | No constraint | 10+ | Not applicable | Not required | Not applicable | Not applicable | |
| 31 | Trentham | 15 | Winter | 19 | N-1 | No constraint | 4 | Winter | 0 | N-1 | Winter | 0 | 0 | N-1 | Security | 5 | Subtransmission circuit | Network upgrade | Planning stage | Not applicable | Proposed subtransmission fluid cable replacement in 2027. |
| 32 | University | 16 | Winter | 20 | N-1 switched | No constraint | 4 | Winter | 4 | N-1 switched | Winter | 5 | 7 | N-1 switched | No constraint | 10+ | Not applicable | Network upgrade | Planning stage | Not applicable | Subtransmission gas cable upgrade in 2027 due to Asset Health. |
| 33 | Waikowhai Street | 13 | Winter | 15 | N-1 switched | No constraint | 2 | Winter | 2 | N-1 switched | Winter | 1 | 3 | N-1 switched | No constraint | 10+ | Not applicable | Not required | Not applicable | Not applicable | |
| 34 | Wainuiomata | 17 | Winter | 20 | N-1 | No constraint | 3 | Winter | 2 | N-1 | Winter | 0 | 2 | N-1 | Security | 10+ | Zone substation transformer | Not required | Not applicable | Not applicable | |
| 35 | Waitangirua | 14 | Winter | 16 | N-1 | No constraint | 2 | Winter | 0 | N-1 | Winter | 0 | 0 | N-1 | Security | 4 | Zone substation transformer | Network upgrade | Planning stage | Not applicable | Preferred solution is 11kV reinforcement to increase transfer capacity to neighbouring zone substations from 2027. |
| 36 | Waterloo | 15 | Winter | 20 | N-1 | No constraint | 5 | Winter | 4 | N-1 | Winter | 3 | 6 | N-1 | No constraint | 10+ | Not applicable | Not required | Not applicable | Not applicable | |

37 [1] *Extend table as necessary to disclose all capacity and constraint information by each zone substation*

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| | |
|---|---|
| *Company Name* | **Wellington Electricity** |
| *AMP Planning Period* | **1 April 2025 – 31 March 2035** |

## 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 during year by consumer type* | **Number of connections** | | | | | |
| *9* | | *Current Year CY* | *CY+1* | *CY+2* | *CY+3* | *CY+4* | *CY+5* |
| *10* | | | | | | | |
| *11* | *Consumer types defined by EDB** | | | | | | |
| *12* | Domestic | 1,617 | 1,697 | 1,716 | 2,032 | 2,059 | 2,086 |
| *13* | Small Commercial | 418 | 439 | 444 | 526 | 533 | 540 |
| *14* | Medium Commercial | 14 | 14 | 15 | 17 | 18 | 18 |
| *15* | Large Commercial | 15 | 16 | 16 | 19 | 19 | 19 |
| | Small Industrial | 17 | 18 | 18 | 22 | 22 | 22 |
| | Large Industrial | 1 | 1 | 1 | 1 | 1 | 1 |
| *16* | Unmetered | 99 | - | - | - | - | - |
| *17* | **Connections total** | 2,182 | 2,185 | 2,210 | 2,617 | 2,652 | 2,687 |
| *18* | **include additional rows if needed* | | | | | | |
| *19* | | | | | | | |
| *20* | | | | | | | |
| *21* | | | | | | | |
| *22* | **Distributed generation** | *Current Year CY* | *CY+1* | *CY+2* | *CY+3* | *CY+4* | *CY+5* |
| *23* | Number of connections made in year | 592 | 637 | 687 | 737 | 786 | 836 |
| *24* | Capacity of distributed generation installed in year (MVA) | 3 | 3 | 3 | 4 | 4 | 4 |
| *25* | **12c(ii) System Demand** | | | | | | |
| *26* | | *Current Year CY* | *CY+1* | *CY+2* | *CY+3* | *CY+4* | *CY+5* |
| *27* | **Maximum coincident system demand (MW)** | | | | | | |
| *28* | GXP demand | 470 | 485 | 487 | 488 | 488 | 489 |
| *29* | *plus* Distributed generation output at HV and above | 51 | 51 | 51 | 51 | 51 | 51 |
| *30* | **Maximum coincident system demand** | 521 | 536 | 538 | 539 | 539 | 540 |
| *31* | *less* Net transfers to (from) other EDBs at HV and above | - | - | - | - | - | - |
| *32* | **Demand on system for supply to consumers' connection points** | 521 | 536 | 538 | 539 | 539 | 540 |
| *33* | **Electricity volumes carried (GWh)** | | | | | | |
| *34* | Electricity supplied from GXPs | 2,313 | 2,334 | 2,355 | 2,376 | 2,397 | 2,419 |
| *35* | *less* Electricity exports to GXPs | 97 | 97 | 97 | 97 | 97 | 97 |
| *36* | *plus* Electricity supplied from distributed generation | 240 | 240 | 240 | 240 | 240 | 240 |
| *37* | *less* Net electricity supplied to (from) other EDBs | - | - | - | - | - | - |
| *38* | **Electricity entering system for supply to ICPs** | 2,456 | 2,477 | 2,498 | 2,519 | 2,540 | 2,562 |
| *39* | *less* Total energy delivered to ICPs | 2,350 | 2,370 | 2,390 | 2,411 | 2,431 | 2,452 |
| *40* | **Losses** | 106 | 107 | 107 | 108 | 109 | 110 |
| *41* | | | | | | | |
| *42* | **Load factor** | 54% | 53% | 53% | 53% | 54% | 54% |
| *43* | **Loss ratio** | 4.3% | 4.3% | 4.3% | 4.3% | 4.3% | 4.3% |

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| *Network / Sub-network Name* | |

## SCHEDULE 12d: REPORT FORECAST INTERRUPTIONS AND DURATION

This schedule requires a forecast of SAIFI and SAIDI for disclosure and a 5 year planning period. The forecasts should be consistent with the supporting information set out in the AMP as well as the assumed impact of planned and unplanned SAIFI and SAIDI on the expenditures forecast provided in Schedule 11a and Schedule 11b.

| *sch ref* | | *Current Year CY* | *CY+1* | *CY+2* | *CY+3* | *CY+4* | *CY+5* |
|---|---|---|---|---|---|---|---|
| *8* | | | | | | | |
| *9* | | | | | | | |
| *10* | **SAIDI** | | | | | | |
| *11* | Class B (planned interruptions on the network) | 13.8 | 13.8 | 12.8 | 12.3 | 13.2 | 11.4 |
| *12* | Class C (unplanned interruptions on the network) | 33.4 | 29.6 | 29.6 | 29.6 | 29.6 | 29.6 |
| *13* | **SAIFI** | | | | | | |
| *14* | Class B (planned interruptions on the network) | 0.08 | 0.08 | 0.07 | 0.07 | 0.07 | 0.06 |
| *15* | Class C (unplanned interruptions on the network) | 0.36 | 0.46 | 0.46 | 0.46 | 0.46 | 0.46 |

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**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 discrete 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. | | In setting an organisation's asset management strategy, it is important that it is consistent with any other policies and strategies that the organisation has and has taken into account the requirements of relevant stakeholders. This question examines to what extent the asset management strategy is consistent with other organisational policies and strategies (eg, as required by PAS 55 para 4.3.1 b) and has taken account of stakeholder requirements as required by PAS 55 para 4.3.1 c). Generally, this will take into account the same polices, strategies and stakeholder requirements as covered in drafting the asset management policy but at a greater level of detail. | Top management. The organisation's strategic planning team. The management team that has overall responsibility for asset management. | The organisation's asset management strategy document and other related organisational policies and strategies. Other than the organisation's strategic plan, these could include those relating to health and safety, environmental, etc. Results of stakeholder consultation. |
| 11 | Asset management strategy | In what way does the organisation's asset management strategy take account of the lifecycle of the assets, asset types and asset systems over which the organisation has stewardship? | 2 | An Asset Management Strategy has been published to cover the total management of assets. Asset Fleet Strategies have been developed for primary asset classes, and are being reviewed in 2025. Strategies for secondary asset classes are currently in development. | | 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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**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.<br><br>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.<br>OR<br>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.<br><br>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.<br>OR<br>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.<br><br>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.<br><br>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 |
|---|---|---|---|---|---|---|---|---|
| 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? | 2 | The plan is communicated to relevant employees, stakeholders, and to some contracted service providers. All asset strategies are published as controlled documents. Further work is required to increase visibility of plans for future work to all contractors. | | 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)?<br><br>(Note this is about resources and enabling support) | 3 | WELL has implemented a Project Management Office (PMO) that manages the outsourced project management of large projects. The outsourced work packages will include end-to-end design and construction, allowing WELL's internal resources to focus on critical BAU programmes. Coupled with this WELL is engaging with a broader range of contractors, with a greater focus on civil expertise, to enable them to build the skills and teams necessary to deliver the work plan. | | 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 12 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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**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).<br>OR<br>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.<br><br>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.<br><br>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)?<br><br>(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.<br><br>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.<br><br>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? | 2 | Top management recognise that a step change in investment is required, and is developing a delivery strategy and resourcing plan in response. This includes the need for additional resources, both internal and outsourced, and new capability above current levels. | | 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, routine reporting, 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 5 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.<br><br>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.<br><br>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.<br><br>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.<br><br>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 regularly 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.<br><br>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.<br><br>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.<br><br>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 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 5 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? | 2 | WELL recognises that it needs additional asset management information systems, and needs to develop systems and processes to manage those.<br><br>WELL undertook an Asset Information Maturity Assessment in 2023, and has developed a work programme that will ensure that asset information improvement investment is allocated to where it will deliver the most value. | | 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.<br><br>The maintenance and development of asset management information systems is a poorly understood specialist activity that is akin to IT management but different from IT management. This group of questions provides some indications as to whether the capability is available and applied. Note: To be effective, an asset information management system requires the mobilisation of technology, people and process(es) that create, secure, make available and destroy the information required to support the asset management system. | The organisation's strategic planning team. The management team that has overall responsibility for asset management. Information management team. Operations, maintenance and engineering managers | Details of the process the organisation has employed to determine what its asset information system should contain in order to support its asset management system. Evidence that this has been effectively implemented. |
| 63 | Information management | How does the organisation maintain its asset management information system(s) and ensure that the data held within it (them) is of the requisite quality and accuracy and is consistent? | 2 | 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. Further work is needed to define and enforce data quality standards for external data providers (e.g. smart metering data) | | The response to the questions is progressive. A higher scale cannot be awarded without achieving the requirements of the lower scale.<br><br>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.<br><br>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.<br><br>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.<br><br>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.<br><br>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 cases 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 | WELL aligns its risk approach with that of CKI by using 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. These actions are tracked using 1FICs tool, with visbility of progress against these actions at Board level. | | 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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| 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.<br><br>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.<br><br>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.<br><br>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.<br><br>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 primary assets against Asset Health Indicators that is based on the AHI 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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| 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.<br><br>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.<br><br>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.<br><br>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.<br><br>The assessor is advised to note in the Evidence section why this is the case and the evidence seen. |

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|---|---|
| *Company Name* | **Wellington Electricity** |
| *AMP Planning Period* | **1 April 2025 – 31 March 2035** |
| *Asset Management Standard Applied* | **PAS 55** |

**SCHEDULE 13: REPORT ON ASSET MANAGEMENT MATURITY (cont)**

| Question No. | Function | Question | Score | Evidence—Summary | User Guidance | Why | Who | Record/documented Information |
|---|---|---|---|---|---|---|---|---|
| 105 | Audit | What has the organisation done to establish procedure(s) for the audit of its asset management system (process(es))? | 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 meetings. The 1Fics software package 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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|---|---|
| *Company Name* | **Wellington Electricity** |
| *AMP Planning Period* | **1 April 2025 – 31 March 2035** |
| *Asset Management Standard Applied* | **PAS 55** |

**SCHEDULE 13: REPORT ON ASSET MANAGEMENT MATURITY (cont)**

| Question No. | Function | Question | Maturity Level 0 | Maturity Level 1 | Maturity Level 2 | Maturity Level 3 | Maturity Level 4 |
|---|---|---|---|---|---|---|---|
| 105 | Audit | What has the organisation done to establish procedure(s) for the audit of its asset management system (process(es))? | The organisation has not recognised the need to establish procedure(s) for the audit of its asset management system. | The organisation understands the need for audit procedure(s) and is determining the appropriate scope, frequency and methodology(s). | The organisation is establishing its audit procedure(s) but they do not yet cover all the appropriate asset-related activities. | The organisation can demonstrate that its audit procedure(s) cover all the appropriate asset-related activities and the associated reporting of audit results. Audits are to an appropriate level of detail and consistently managed. | The organisation's process(es) surpass the standard required to comply with requirements set out in a recognised standard.<br><br>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.<br><br>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.<br><br>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.<br><br>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 27 November 2024)*

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 2025.

The difference from 2024/25 to 2033/34 represents inflation. Inflation is based on the Reserve Bank February 2025 Monetary Policy Statement (https://www.rbnz.govt.nz/-/media/project/sites/rbnz/files/publications/monetary-policy-statements/2025/feb-19224/mps_report_feb2025.pdf).

| 2025/26 | 2026/27 | 2027/28 | 2028-2035 |
|---|---|---|---|
| 2.2% | 2.2% | 2.0% | 2.0% |

*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 2025.

The difference from 2025/26 to 2034/35 represents inflation. Inflation is based on the Reserve Bank February 2025 Monetary Policy Statement (https://www.rbnz.govt.nz/-/media/project/sites/rbnz/files/publications/monetary-policy-statements/2025/feb-19224/mps_report_feb2025.pdf).

| 2025/26 | 2026/27 | 2027/28 | 2028-2035 |
|---|---|---|---|
| 2.2% | 2.2% | 2.0% | 2.0% |

# Appendix D 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 | 5.1, 5.2 |
| 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** | 5.1 |
| 3.3.4 states how the different documented plans relate to one another, with particular reference to any plans specifically dealing with asset management | 6.1 |
| 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, 4 & Appendix A |
| 3.10 An overview of asset management strategy and delivery | 5.1, 5.3 |
| 3.11 An overview of systems and information management data | 11.1 |
| 3.11.1 To support the Report on Asset Management Maturity disclosure and assist interested persons to assess the maturity of systems and information management, the AMP should describe: | |
| (a) the processes used to identify asset management data requirements that cover the whole of life cycle of the assets; | |
| (b) the systems used to manage asset data and where the data is used, including an overview of the systems to record asset conditions and operation capacity and to monitor the performance of assets; | |
| (c) the systems and controls to ensure the quality and accuracy of asset management information; | |
| (d) the extent to which these systems, processes and controls are integrated; | |
| (e) how asset management data informs the models that an EDB develops and uses to assess asset health; and | 8.3 |
| (f) how the outputs of these models are used in developing capital expenditure projections. | 8.3, 8.5 |

| Information Disclosure Requirements 2012 clause | AMP section |
|---|---|
| 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 | 11.3 |
| 3.13 A description of the processes used within the **EDB** for-<br>3.13.1 managing routine asset inspections and **network** maintenance<br>3.13.2 planning and implementing **network** development projects<br>3.13.3 measuring **network** performance. | <br>8.4, 10.1.1.10<br>9.2<br>6.2.2 |
| 3.14 An overview of asset management documentation, controls and review processes | 5.4 |
| 3.15 An overview of communication and participation processes | 3.6, 5.1 |
| 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. | Yes |
| **Assets Covered**<br>4. The **AMP** must provide details of the assets covered, including-<br>4.1 a high-level description of the service areas covered by the **EDB** and the degree to which these are interlinked, including-<br>4.1.1 the region(s) covered<br>4.1.2 identification of large **consumers** that have a significant impact on network operations or asset management priorities<br>4.1.3 description of the load characteristics for different parts of the **network**<br>4.1.4 peak demand and total energy delivered in the previous year, broken down by **sub-network**, if any. | <br>3.3<br>3.4<br>3.5<br>3.5 & 9.2<br>3.5<br>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, 9.4–9.6 |
| 4.2.3 a description of the distribution system, including the extent to which it is underground; | 3.4, 8.5.4 |
| 4.2.4 a brief description of the **network**'s distribution substation arrangements; | 3.4, 8.5.5 |
| 4.2.5 a description of the **low voltage network** including the extent to which it is underground; and | 3.4, 8.5.4 |
| 4.2.6 an overview of **secondary assets** such as protection relays, ripple injection systems, SCADA and telecommunications systems. | 8.5.8 |
| 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 |
| <u>**Network Assets by Category**</u> | |
| 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, 8.5 |
| 4.4.2 description and quantity of assets; | 8.1 |
| 4.4.3 age profiles; and | 8.5 |
| 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. | 8.5 |
| 4.5 The asset categories discussed in clause 4.4 above should include at least the following- | |
| 4.5.1 the categories listed in the Report on Forecast Capital Expenditure in Schedule 11a(iii); | 8.5.1-9 |
| 4.5.2 assets owned by the EDB but installed at bulk electricity supply points owned by others; | 8.5.10 |
| 4.5.3 **EDB** owned mobile substations and generators whose function is to increase supply reliability or reduce peak demand; and | 8.5.9.2 |
| 4.5.4 other generation plant owned by the **EDB**. | 8.5.9.2 |

| Information Disclosure Requirements 2012 clause | AMP section |
|---|---|
| **Service Levels**<br>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**. | 6 |
| 6. Performance indicators for which targets have been defined in clause 5 above must include **SAIDI** and **SAIFI** values for the next 5 **disclosure years**. | 7.1 |
| 7. Performance indicators for which targets have been defined in clause 5 above should also include-<br>7.1 **Consumer** oriented indicators that preferably differentiate between different consumer types;<br>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. | 6.5<br>6.4, 8.5 |
| 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. | 6, 7.1 |
| 9. Targets should be compared to historic values where available to provide context and scale to the reader. | 6 |
| 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. | 7.1 |
| **Network Development Planning**<br>11. **AMP**s must provide a detailed description of **network** development plans, including—<br>11.1 A description of the planning criteria and assumptions for **network** development; | 9.1, 9.2 |
| 11.2 Planning criteria for network developments should be described logically and succinctly. Where probabilistic or scenario-based planning techniques are used, this should be indicated and the methodology briefly described; | 9.1, 9.2 |
| 11.3 A description of strategies or processes (if any) used by the **EDB** that promote cost efficiency including through the use of standardised assets and designs; | 9.1.7 |

| Information Disclosure Requirements 2012 clause | AMP section |
|---|---|
| 11.4 The use of standardised designs may lead to improved cost efficiencies. This section should discuss-<br>11.4.1 the categories of assets and designs that are standardised;<br>11.4.2 the approach used to identify standard designs. | <br>8.2 & 9.1.7<br>8.2 & 9.1.7 |
| 11.5 A description of strategies or processes (if any) used by the **EDB** that promote the energy efficient operation of the **network**. | 9.1.9 |
| 11.6 A description of the criteria used to determine the capacity of equipment for different types of assets or different parts of the **network**. | 9.1.2 |
| 11.7 A description of the process and criteria used to prioritise **network** development projects and how these processes and criteria align with the overall corporate goals and vision. | 5.2 |
| 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;<br>11.8.1 explain the load forecasting methodology and indicate all the factors used in preparing the load estimates;<br>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;<br>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<br>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. | <br>9.2.1<br>9.4-9.6<br>9.4-8.6<br>9.1.11 |
| 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-<br>11.9.1 the reasons for choosing a selected option for projects where decisions have been made;<br>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;<br>11.9.3 consideration of planned innovations that improve efficiencies within the **network**, such as improved utilisation, extended asset lives, and deferred investment. | <br>9.4-9.7<br>9.4-9.7<br>9.1.10 |

| Information Disclosure Requirements 2012 clause | AMP section |
|---|---|
| 11.10 A description and identification of the **network** development programme including **non-network solutions** and actions to be taken, including associated expenditure projections. The **network** development plan must include-<br>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;<br>11.10.2 a summary description of the programmes and projects planned for the following four years (where known); and<br>11.10.3 an overview of the material projects being considered for the remainder of the **AMP planning period**. | 9.4-9.7 |
| 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. | 9.1.11 |
| 11.12 A description of the **EDB**'s policies on **non-network solutions**, including-<br>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;<br>11.12.2 the potential for **non-network solutions** to address **network** problems or constraints; and<br>11.12.3 how information on current and forecast constraints (both load and injection) is shared with potential providers of **non-network solutions**. This must include any information **low voltage network** constraints, including the constraint information the **EDB** derives from the data specified under clause 17.2.2 of Attachment A. | 9.1.10 |
| **Lifecycle Asset Management Planning (Maintenance and Renewal)**<br>12. The **AMP** must provide a detailed description of the lifecycle asset management processes, including—<br>12.1 The key drivers for maintenance planning and assumptions;<br>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- | 8.4 & 8.5 |
| 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; | 8.5 |
| 12.2.2 any systemic problems identified with any particular asset types and the proposed actions to address these problems; and | 8.5 |
| 12.2.3 budgets for maintenance activities broken down by asset category for the **AMP planning period**. | 8.6 |

| Information Disclosure Requirements 2012 clause | AMP section |
|---|---|
| 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; | 8.2, 8.5 |
| 12.3.2 a description of innovations made that have deferred asset replacement; | 8.5 |
| 12.3.3 a description of the projects currently underway or planned for the next 12 months; | 8.5 |
| 12.3.4 a summary of the projects planned for the following four years (where known); and | 8.5 |
| 12.3.5 an overview of other work being considered for the remainder of the **AMP planning period**. | 8.5–8.6 |
| 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 |
| 12.5 Identification of the approach used for developing **capital expenditure** projections for lifecycle asset management. This must include an explanation of: | |
| 12.5.1 the approach that the **EDB** uses to inform its **capital expenditure** projections for lifecycle asset management; and | 8.2–8.3 |
| 12.5.2 the rationale for using the approach for each asset category. | 8.3 |
| 12.6 Identification of **vegetation management** related maintenance. This must include an explanation of the approach and assumptions that the **EDB** uses to inform its **vegetation management** related maintenance. | 7.4.3 |
| 12.7 The **EDB's** consideration of non-network solutions to inform its **capital and operational expenditure** projections for lifecycle asset management. This must include an explanation of the approach and assumptions the **EDB** used to inform these expenditure projections. | 8.2 |
| **Non-Network Development, Maintenance and Renewal** | |
| 13. **AMP**s must provide a summary description of material non-network development, maintenance and renewal plans, including— | |
| 13.1 a description of **non-network assets**; | 10.1-10.6 |
| 13.2 development, maintenance and renewal policies that cover them; | 10.1–10.4 |
| 13.3 a description of material **capital expenditure** projects (where known) planned for the next five years; | 10.1.4 |
| 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; | 5.7 |
| 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; | 12.4 |
| 14.3 A description of the policies to mitigate or manage the risks of events identified in sub clause 14.2; | 5.7.3, 12.4 |
| 14.4 Details of emergency response and contingency plans. | 12.3 |
| 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; | 6 |
| 15.3 An evaluation and comparison of the results of the asset management maturity assessment disclosed in the Report on Asset Management Maturity set out in Schedule 13 against relevant objectives of the EDB's asset management and planning processes. | 5.6 |
| 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. | 5.6 |
| **Capability to Deliver** | |
| 16. **AMPs** must describe the processes used by the **EDB** to ensure that- | |
| 16.1 The AMP is realistic and the objectives set out in the plan can be achieved; | 2.5, 4.3 |
| 16.2 The organisation structure and the processes for authorisation and business capabilities will support the implementation of the AMP plans. | 3.2 |
| **Requirements to provide qualitative information in narrative form** | |
| 17. AMPs must include qualitative information in narrative form, as prescribed in clauses 17.1-17.7 below: | |
| *Notice of planned and unplanned interruptions* | |
| 17.1 a description of how the **EDB** provides notice to and communicates with **consumers** regarding **planned interruptions** and **unplanned interruptions**, including any changes to the **EDB's** processes and communications in respect of **planned interruptions** and **unplanned interruptions**; | 6.5.3 |

| Information Disclosure Requirements 2012 clause | AMP section |
|---|---|
| *Voltage quality*<br>17.2 a description of the **EDB's** practices for:<br>17.2.1 monitoring voltage, including:<br>(a) the **EDB's** practices for monitoring voltage quality on its **low voltage network**;<br>(b) work the **EDB** is doing on its **low voltage network** to address any known non-compliance with the applicable voltage requirements of the Electricity (Safety) Regulations 2010;<br>(c) how the **EDB** responds to and reports on voltage quality issues when the **EDB** identifies them, or when they are raised by a stakeholder;<br>(d) how the **EDB** communicates with affected **consumers** regarding the voltage quality work it is carrying out on its **low voltage network**; and<br>(e) any plans for improvements to any of the practices outlined at clauses 17.2.1-17.2.4 above; | 6.5.6 |
| 17.2.2 monitoring load and injection constraints, including:<br>(a) any challenges and progress towards collecting or procuring data required to inform the EDB of current and forecast constraints on its low voltage network, including historical consumption data; and<br>(b) and analysis and modelling (including any assumptions and limitations) the EDB undertakes, or intends to undertake, with the data described in clause 17.2.2(a). | 11.3.2.6<br>11.3.2 |
| *Customer service practices*<br>17.3 a description of the **EDB's** customer service practices, including:<br>17.3.1 the **EDB's** customer engagement protocols and customer service measures – including customer satisfaction with the **EDB's** supply of **electricity distribution services**;<br>17.3.2 the **EDB's** approach to planning and managing customer **complaint** resolution; | 6.5.1<br>6.5.7 |

| Information Disclosure Requirements 2012 clause | AMP section |
|---|---|
| *Practices for connecting new consumers and altering existing connections* | |
| 17.4 a description of the **EDB's** practices for connecting **consumers**, including: | |
| 17.4.1 the **EDB's** approach to planning and management of- | 13.1 |
| (a) connecting new **consumers** (offtake and injection connections), and overcoming commonly encountered issues; and | |
| (b) alterations to existing connections (offtake and injection connections); | |
| 17.4.2 how the **EDB** is seeking to minimise the cost to **consumers** of new or altered connections; | 13.1 |
| 17.4.3 the **EDB's** approach to planning and managing communication with **consumers** about new or altered connections; and | 13.1 |
| 17.4.4 commonly encountered delays and potential timeframes for different connections. | 6.5.4, 6.5.5, 13.1 |
| 17.4.5 the **EDB**'s approach to sharing information on current and forecast constraints (both load and injection) with potential new **consumers**. This must include any information on **low voltage network** constraints, including the constraint information the **EDB** derives from the data specified under clause 17.2.2(a) of Attachment A. | 9.1.11.2, 13.1 |
| *New connections likely to have a significant impact on network operations or asset management priorities* | |
| 17.5 A description of the following: | 9.1.10, 9.2.1.1 |
| 17.5.1 how the **EDB** assesses the impact that new demand, generation, or storage capacity will have on the **EDB's network**, including: | |
| (a) how the **EDB** measures the scale and impact of new demand, generation, or storage capacity; | |
| (b) how the **EDB** takes the timing and uncertainty of new demand, generation, or storage capacity into account; | |
| (c) how the **EDB** takes other factors into account, eg, the network location of new demand, generation, or storage capacity; and | |
| 17.5.2 how the **EDB** assesses and manages the risk to the **network** posed by uncertainty regarding new demand, generation, or storage capacity; | |

| Information Disclosure Requirements 2012 clause | AMP section |
|---|---|
| *Innovation practices*<br>17.6 a description of the following:<br>17.6.1 any **innovation practices** the **EDB** has planned or undertaken since the last **AMP** or **AMP update** was publicly disclosed, including case studies and trials;<br>17.6.2 the **EDB’s** desired outcomes of any **innovation practices**, and how they may improve outcomes for **consumers**;<br>17.6.3 how the **EDB** measures success and makes decisions regarding any **innovation practices**, including how the **EDB** decides whether to commence, commercially adopt, or discontinue these practices;<br>17.6.4 how the **EDB’s** decision-making and **innovation practices** depend on the work of other companies, including other **EDBs** and providers of non-network solutions; and<br>17.6.5 the types of information the **EDB** uses to inform or enable any **innovation practices**, and the **EDB’s** approach to seeking that information. | 11.1 |

# Appendix E Glossary of Abbreviations

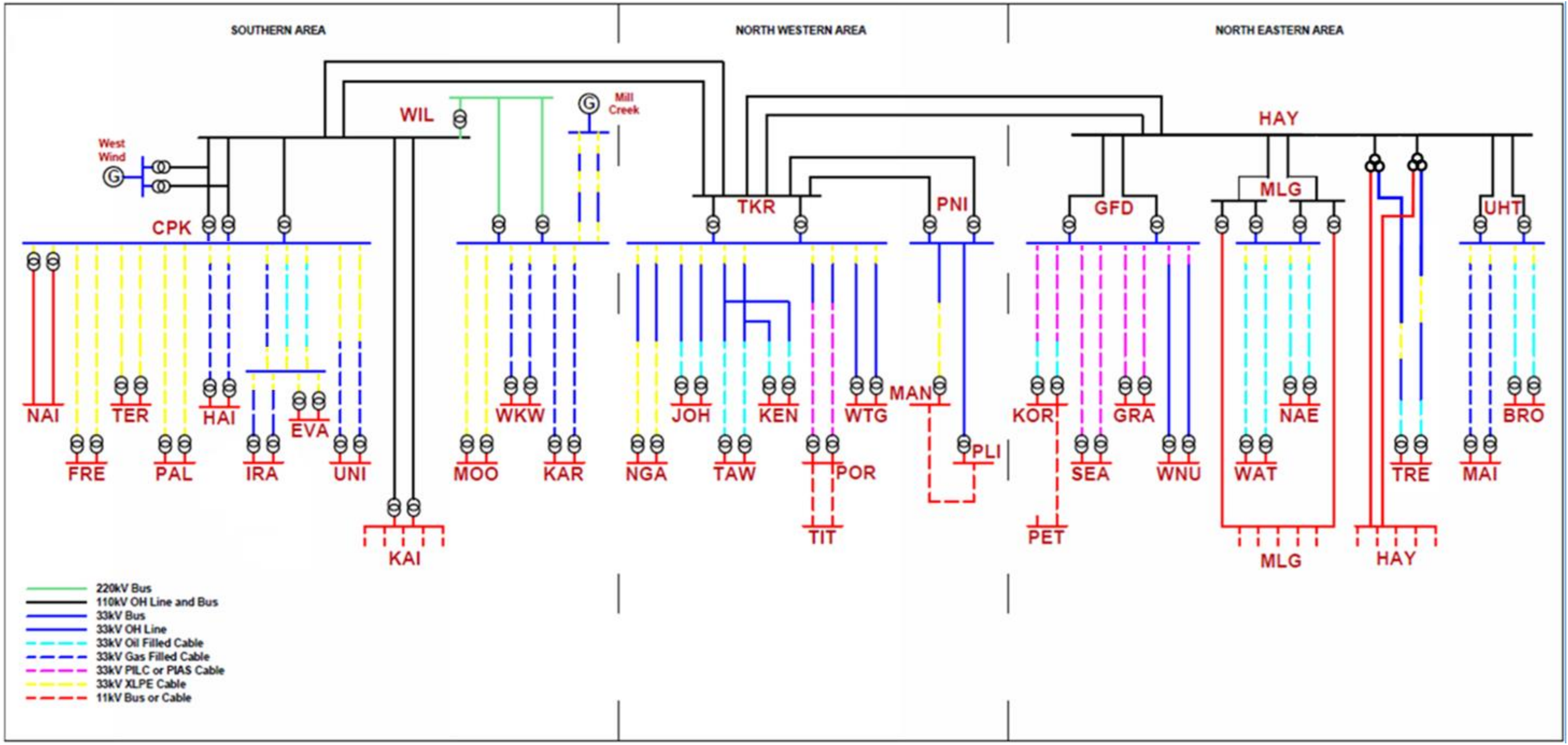
| | |
|---|---|
| AAC | All Aluminium Conductor |
| AAAC | All Aluminium Alloy Conductor |
| ABS | Air Break Switch |
| ACSR | Aluminium Conductor Steel Reinforced |
| ADMS | Advanced Distribution Management System |
| ADSS | All Dielectric Self Supporting |
| ACI | Asset Criticality Indicator |
| AHI | 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 Act |
| CEO | Chief Executive Officer |
| CER | Consumer-owned Energy Resource |
| CIA | Cyber Security and Data Confidentiality, Integrity and Availability |
| CIC | Capital Investment Committee |
| CKI | Cheung Kong Infrastructure Holdings Limited |
| CMP | Crisis Management Plan |
| CPI | Consumer Price Index |
| CPP | Customised Price Path |
| CT | Current Transformer |
| Cu | Copper |
| DC | Direct Current |
| DDA | Default Distributor Agreement |
| 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 |
| ERP | Emergency Response Plan |
| ESG | Environmental, Social, and Governance |
| ETR | Estimated Time of Restoration |
| EV | Electric Vehicle |
| FDIR | Fault Detection, Isolation and Restoration |
| FPI | Fault Passage Indicator |
| FSA | Field Services Agreement |
| 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 injury frequency rate 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 |
| MW | Megawatt |
| MWFM | Mobile Workforce Management |
| MVA | Megavolt Ampere |
| NBS | New Building Standard |
| NCR | Network Control Room |
| NDRP | Network Development and Reinforcement Plan |
| NIWA | National Institute of Water and Atmospheric Research |
| NPV | Net Present Value |
| OCB | Oil Circuit Breaker |
| OD-ID | Outdoor to Indoor conversion |
| 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 |
| 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 |
| $SF_6$ | Sulphur Hexafluoride |
| SPS | Special Protection Scheme |
| TASA | Tap Changer Activity Signature Analysis |
| TCA | Transformer Condition Assessment |
| TNIFR | Total notifiable injury frequency rate 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 |
| XLPE | Cross Linked Polyethylene insulation |

# Appendix F  Single Line Diagram



# Appendix G Director Certification

## Schedule 17 Certification for Year-beginning Disclosures

Clause 2.9.1

We, Richard Pearson and Charles Tsai, being directors of Wellington Electricity Lines Limited certify that, having made all reasonable enquiry, to the best of our knowledge:

a) The following attached information of Wellington Electricity Lines Limited prepared for the purposes of clauses 2.4.1, 2.6.1, 2.6.3, 2.6.6 and 2.7.2 of the Electricity Distribution Information Disclosure Determination 2012 in all material respects complies with that determination.

b) The prospective financial or non-financial information included in the attached information has been measured on the basis consistent with regulatory requirements or recognised industry standards.

c) The forecasts in Schedules 11a, 11b, 12a, 12b, 12c and 12d are based on objective and reasonable assumptions which both align with Wellington Electricity Lines Limited's corporate vision and strategy and are documented in retained records.

| | |
|---|---|
| Richard Pearson<br>Chairman | Charles Tsai<br>Director |
| 28 March 2025 | 28 March 2025 |