

Wellington Electricity

10 Year Asset Management Plan

1 April 2026 – 31 March 2036

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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 incorrect, and some of the assumptions and forecasts may prove inaccurate. In addition, over time or due to future events, circumstances may change, and accordingly, some information, outcomes, and statements may need to be updated.

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Statement from the Chief Executive Officer

Wellington Electricity (WELL) is submitting this updated Asset Management Plan (AMP) for the regulatory period 1 April 2026 to 31 March 2036 at a time when the decisions taken now will materially influence how effectively the network responds to the next decade of change.

Prepared in accordance with Attachment A of the Commerce Commission Electricity Distribution Information Disclosure Determination 2012, this AMP sets out how WELL intends to respond to that challenge over the coming decade.

Electricity distribution planning in Wellington requires balancing customer expectations with longer-term decisions about how the network must evolve to remain secure, reliable, financially sustainable, and affordable. From my perspective, the challenge is no longer simply replacing ageing infrastructure. It is increasingly about deciding when investment is needed, where optionality should be preserved, and how service outcomes can be maintained affordably as demand patterns, resilience requirements, and regulatory settings continue to change.

Wellington presents one of the most demanding operating environments for electricity distribution in New Zealand. The network serves a region exposed to high winds, severe storms, constrained urban corridors, steep terrain, and significant seismic risk, as well as the highest concentration of residential gas connections in the country. Together, these factors shape both the cost and complexity of network investment while increasing uncertainty around how and where electricity demand will evolve, particularly if gas disconnection accelerates and heating, hot water, and cooking loads shift onto parts of the network not originally designed for coincident electrified demand. This reinforces why reliability and affordability remain central to WELL's planning. Maintaining a secure electricity supply in the capital requires a network that operates reliably under normal conditions and recovers at an acceptable pace following a disruptive event.

Over many years, WELL has invested in earthquake readiness for the seismic risks most relevant to this region. Storm response depends on how vegetation reacts to damaging high winds and on impacts on network equipment. We remain unfunded for resilience or storm hardening, and recent wind speeds in excess of 190 kph require response and recovery, as strengthening and vegetation removal would be ineffective. This relies on a degree of community resilience and preparedness for such events. The consequences of prolonged outages in Wellington extend well beyond individual customers. They affect transport, communications, emergency services, business activity, and the city's wider functioning.

Customer expectations are also evolving. Electricity is becoming more central to how customers heat, cool, move, and how they operate their businesses and home lives. While expectations of secure supply remain unchanged, we are starting to experience more damaging weather events. Across much of the network, customers continue to expect the level of service associated with N-1 security, where supply can be maintained through a single contingency event. Maintaining that level of reliability while responding to stronger storms that affect ageing assets amid increased electricity demand is becoming increasingly challenging.

The 2026 Asset Management Plan reflects that environment. Future demand growth remains uncertain in timing, scale, and location, due to drivers to reduce fossil fuels; the overall direction is clear. Existing customers are already changing how they use electricity through appliance electrification, cooling demand, and progressive decarbonisation. Over time, as electrification becomes more widespread, interactions

among customer loads are expected to increase, reducing diversity and placing greater pressure on parts of the network not originally designed for these emerging patterns.

Responding effectively requires more than traditional infrastructure reinforcement. Requiring better operational visibility, stronger supporting systems to support and improve asset information, and decision-making. Low-voltage monitoring, operational technology, asset data maturity, network modelling and analytics are now fundamental to understanding where constraints are emerging. The timing of price signals to support either deferral or implementation enables efficient investment and cost recovery. These capabilities are essential to operating a modern distribution network safely, effectively and cost-effectively, so customers who contribute to higher demand don't affect those reducing consumption during peak periods and should pay less for this behaviour. These signals inform our future network investment decisions and where we can leverage customer preferences.

WELL continues to collaborate with other electricity distribution businesses across New Zealand to share practical experience, improve planning approaches, and develop more efficient responses to emerging sector-wide challenges. As the industry responds to electrification, reliability needs, operational technology development, low-voltage network complexity, cost and affordability, this collaboration helps ensure that lessons are applied quickly, investment decisions benefit from broader sector experience and local network conditions. WELL also benefits from peer companies within the CK Infrastructure Holdings Limited group located in other countries, drawing on their networks and customer experiences.

WELL expects flexibility services to become an increasingly important part of the future electricity system as customer technologies such as electric vehicles, batteries, and distributed generation continue to expand. Over time, stronger pricing signals and greater customer responsiveness may help improve utilisation of existing network capacity and reduce the cost of managing some local constraints by deferral of infrastructure upgrades to subsequent years. However, WELL remains concerned that flexibility services will not mature quickly enough, or with sufficient reliability, to materially defer the need for network investment identified in this AMP.

A fully workable competitive market for distribution-level flexibility has yet to emerge; customer participation remains limited, and barriers remain around visibility, coordination, operational control, and confidence in service delivery during peak or emergency conditions. In practice, flexibility is expected to support efficient network operation, but not replace the underlying capacity and control needed to maintain customer service expectations and network security.

Even with these emerging tools and industry collaboration, the underlying requirement for network investment remains substantial. The decisions made over the next few years will influence not only costs but also the decisions available to respond to future uncertainty.

A central issue in making these necessary investment choices is that the funding available under the Commerce Commission's default price-quality path determination for the regulatory period from 1 April 2025 to 31 March 2030 (DPP4) does not fully support the pace and scale of expenditure required to maintain this long-term position. While the current regulatory settings place strong emphasis on short-term affordability, the practical consequence is that WELL must increasingly prioritise near-term interventions and defer larger coordinated investments that would otherwise provide both immediate and enduring benefit to customers. In some cases, that means adopting staged solutions where a single larger project would provide a more efficient long-term outcome. The effect of delaying efficient investment is already visible in the narrowing of

options across parts of the network, particularly where new customer demand, resilience requirements, and asset condition are converging.

This pressure is evident in both capital and operational expenditure. Maintaining N-1 security, responding to asset condition, accounting for climate resilience, and building the digital and operational capabilities needed for future network performance all require expenditure that increasingly exceeds default allowance levels. We are no longer operating in a 'business-as-usual' environment as assumed under the default price path. Operational expenditure pressures are particularly significant, with field service costs, insurance, systems capability, and the support required to deliver capital works all increasing faster than the regulatory framework currently recognises.

WELL remains committed to prudent expenditure, disciplined prioritisation, and maintaining value for customers. At the same time, I believe the scale of the investment challenge now points toward the need for a regulatory pathway that better aligns expenditure with long-term service outcomes, rather than relying solely on incremental deferral within a constrained allowance framework. This is informing WELL's current assessment of the funding mechanisms that will best support efficient investment over the period ahead.

Maintaining affordability remains an important part of that balance. Affordability is best supported over time by making timely and efficient investment decisions that avoid transferring greater cost, greater risk, or reduced service flexibility into future periods.

Deferring efficient expenditure may moderate near-term price impacts, but it can also narrow future optionality, increase the likelihood of disruptive interventions, and ultimately lead to higher costs when larger investments cannot be avoided and become coincident. Maintaining that balance is essential to retaining customer trust in both current service levels and future investment decisions.

This AMP reflects both current funding constraints and the longer-term realities the network must continue to address. It also reflects uncertainty around demand growth, shallow flexibility markets, transmission development, coastal adaptation, customer behaviour, the pace of domestic gas exit, and the future regulatory expectations. In particular, gas transition could materially reshape both peak demand and network utilisation over a relatively short period, requiring WELL to continue making least-regrets decisions that remain robust as these uncertainties become clearer.

Our responsibility has not changed; WELL ensures that Wellington's network remains safe, reliable, financially sustainable, affordable and capable of supporting the region's future, while continuing to make disciplined decisions that protect long-term customer and shareholder interests.

Greg Skelton

Chief Executive Officer

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1 Executive Summary

The purpose of this Asset Management Plan (AMP) is to describe Wellington Electricity Lines Limited's (WELL's) approach to managing its electricity distribution assets to deliver a safe, reliable, cost-effective, and sustainable long-term electricity supply. The AMP outlines how service levels, investment decisions, and asset management practices are aligned to customer expectations, regulatory requirements, and long-term network performance outcomes across the Wellington network.

1.1 Term Covered by the 2026 AMP

This AMP sets out WELL's asset management approach for the planning period from 1 April 2026 to 31 March 2036 and was certified by the Board of Directors on 25 March 2026.

1.2 Key Elements of the 2026 AMP

The key theme of this AMP is that the balance of New Zealand's energy trilemma has shifted towards prioritising customer affordability alongside sustainability. This is evidenced by changes in external policy settings that are shaping customer investment behaviour and leading to delays in major decarbonisation projects. These factors, together with the default price-quality path allowances from 1 April 2025 that do not adequately provide for WELL's efficient long-term investment, have shaped its investment outlook, with the reduced investment profile established in the 2025 AMP being maintained in the 2026 AMP. This represents a clear change from the more strongly decarbonisation-driven investment approach set out in WELL's 2024 AMP.

As announced in 2025, WELL has also commenced assessing whether the DPP4 (i.e., the regulatory period 1 April 2025 to 31 March 2030) settings are sustainable for continuing to supply customers at historically acceptable reliability levels. While its assessment is ongoing, WELL expects that additional investment may well be required and is currently investing above the DPP4 allowances. As the 2026 AMP is based on the DPP4 settings, the potential outcomes of any future customised price-quality path (CPP) application are not yet reflected in this planning period.

Notwithstanding this uncertainty, WELL remains focused on delivering a safe and reliable electricity supply. The 2026 AMP demonstrates WELL's continued commitment to investing in asset maintenance and condition-based renewal to ensure that customer requirements are met. Appendix B provides more details on the updates since the 2025 AMP.

1.3 Limitations of the DPP4 Allowances and the Case for a CPP Application

The DPP4 capital and operating allowances require WELL to prioritise between asset renewal, resilience, and system performance initiatives as customer reliability expectations rise, even as ageing assets are required to work harder to maintain service levels. Urban density, a high proportion of underground assets, constrained access windows, and higher reinstatement and traffic management costs mean that failures are more disruptive and materially more expensive to resolve than in the past.

Customer expectations for secure and reliable supply, together with the adoption of solar and other distributed energy resources (e.g., battery storage), are increasing the need for investment in secondary and enabling systems, including protection, SCADA, communications, DC supplies, and control infrastructure, consistent with WELL's position of not unnecessarily restricting customers' use of the network. These assets are critical to maintaining safe operation, rapid fault response, and effective network control, yet many are

reaching the end of their technical lives and face obsolescence and supportability risks. This AMP highlights the growing reliance on modern control, automation, and monitoring to manage the risk of underground cables, reduce outage duration, and support network resilience. Insufficient funding for these systems materially constrains WELL's ability to manage risk efficiently and safely.

WELL has also identified that to maintain acceptable levels of reliability and risk control, current expenditure must exceed DPP4 allowances. This position is not sustainable over the long term, and reducing expenditure to align strictly with DPP4 allowances would require deferring renewal and replacement activities that are otherwise justified based on asset condition, safety, and reliability. The outcome would be a progressive increase in asset failure risk, longer outages, and greater exposure to high-impact events, outcomes that are inconsistent with the purpose of Part 4 of the Commerce Act 1986, which is to promote the long-term benefit of consumers.

The Commerce Commission (the Commission) has recognised through previous CPP decisions and guidance that DPP settings cannot accommodate all network circumstances, particularly where an electricity distribution business faces a pronounced renewal profile, legacy asset risks, or region-specific constraints. CPPs provide a mechanism to assess, test, and approve a tailored investment programme where DPP4 allowances are demonstrably insufficient, while maintaining strong efficiency incentives and transparency for consumers. Importantly, a CPP allows investment to be sequenced and smoothed over time, avoiding the greater price and service shocks that arise when under-investment accumulates.

In this context, a CPP would represent a prudent and responsible regulatory pathway for WELL if the gap between efficient investment needs and DPP4 allowances persists. It enables WELL to demonstrate the necessity, efficiency, and customer benefits of additional investment, while providing regulatory certainty to support long-term planning and delivery. Absent a CPP, WELL would be required to continue managing increasing levels of asset risk within constrained allowances, to the detriment of reliability, resilience, and ultimately customer outcomes.

1.4 Reliability Performance

The regulatory regime governing WELL establishes reliability performance limits based on historical network performance. Under this framework, 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 updated WELL's reliability targets and limits for the five-year period commencing 1 April 2025. These limits broadly reflect historical performance and are intended to balance customer affordability with service quality. WELL's DPP4 reliability targets and limits are presented in Table 1-1.

Regulatory Year	1 April 2020 to 31 March 2025	1 April 2025 to 31 March 2030
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 1-1 WELL Regulatory Reliability Limits

Figure 1-1 illustrates WELL's historic unplanned SAIDI performance against the DPP3 (i.e., 1 April 2020 to 31 March 2025) regulatory limit, providing context for recent reliability outcomes and the basis for current DPP4 performance targets.

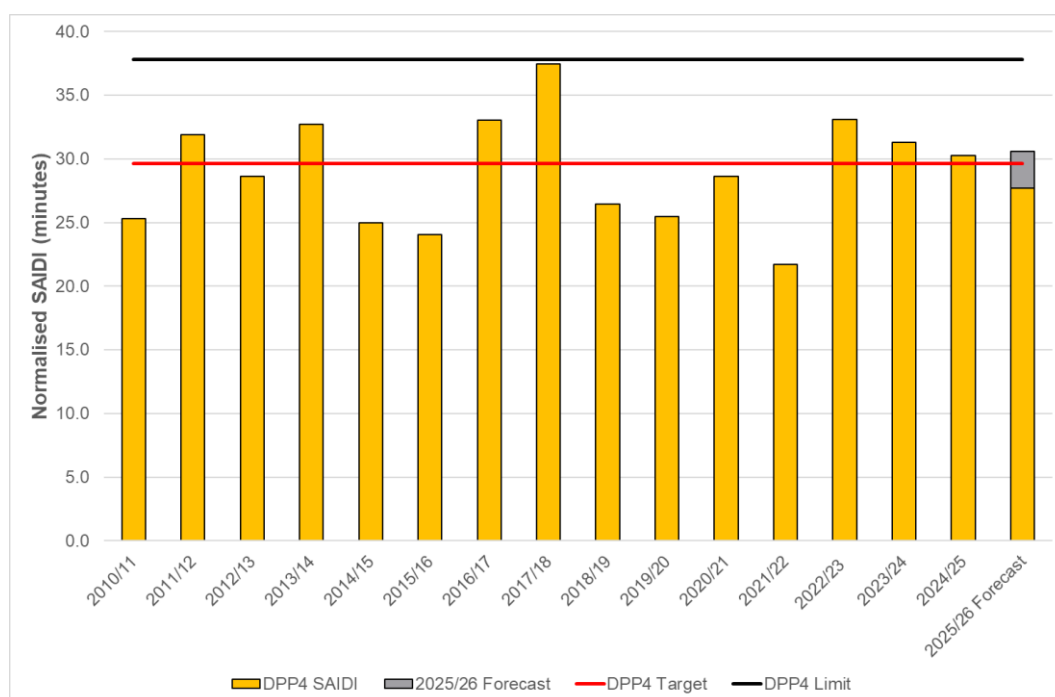


Figure 1-1 WELL's Historical Unplanned SAIDI Performance

WELL's forecast SAIDI and SAIFI targets are shown in Table 1-2. These targets assume that reliability beyond 2030 will continue to be measured using the DPP4 methodology, including the normalisation of Major Event Days.

Performance Targets	Disclosure Year Beginning 1 April									
	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035
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	12.89	13.35	12.82	11.40	10.92	11.29	12.46	11.43	11.64	10.26
Planned SAIFI target	0.083	0.086	0.082	0.073	0.070	0.073	0.080	0.074	0.075	0.066

Table 1-2 Network Reliability Performance Targets

WELL remains committed to maintaining its network such that unplanned reliability performance continues to align with historically acceptable levels. However, planned outage performance over the planning period is expected to scale with the size and complexity of the capital work programme.

While a substantial proportion of the forecast increase in expenditure relates to subtransmission and zone substation reinforcement projects, many of which can be delivered without any customer outages, there will also be a material increase in 11 kV reinforcement activities. These works typically require planned outages to safely isolate feeders and undertake construction, and as a result, are expected to increase planned SAIDI and SAIFI outage indices over the period.

In addition, the concentration and sequencing of works on the 11 kV network will, at times, require sections of the network to be operated at N security rather than N-1 while reinforcement or replacement activities are underway. Although such arrangements are carefully planned and managed to minimise customer impact, operating at reduced redundancy inherently increases exposure to unplanned outages should an unrelated fault occur during the outage window. This represents a managed and temporary increase in operational risk that is a direct consequence of delivering necessary renewal and reinforcement works within constrained outage windows.

WELL mitigates these risks through careful outage planning, temporary network reconfiguration, enhanced operational readiness, and prioritising work on critical feeders. Nevertheless, the increased volume of 11 kV works required to support long-term network performance and resilience is expected to result in higher planned outage indices over the period, reflecting the trade-off between short-term customer disruption and long-term reliability outcomes.

While WELL continues to operate within the current regulatory limits, maintaining historical reliability outcomes over the longer term will depend on the ability to fund timely asset renewal and system resilience. As outlined in this AMP, current DPP4 allowances constrain the investment required to manage rising asset health and obsolescence risks. These investment constraints make it likely that a CPP will be required to sustainably maintain reliability performance beyond the current regulatory period.

1.5 Network Expenditure

1.5.1 Network Capital Expenditure

Reflecting the different drivers of investment across the network, WELL groups its projected network capital expenditure forecasts into five categories:

1. **Asset Renewal**—expenditure associated with replacing assets through fleet condition assessment and routine renewal programmes. This includes both specific replacement projects and systematic renewals identified through asset health analysis, such as replacing poles, switchgear, and 11 kV/400 V substations.
2. **Reliability, Safety and Environment**—investment that is not directly driven by asset health, including projects targeting the worst-performing feeders, safety and environmental initiatives, and the substation seismic strengthening programme.
3. **System Growth**—expenditure required to support network development, driven by the timing, location, and scale of peak demand growth and other growth-related pressures across the network.
4. **Relocation Capital**—expenditure associated with the relocation of network assets, primarily arising from roading and infrastructure projects, where the costs are typically shared with Waka Kotahi NZ Transport Agency or other third parties.
5. **Customer Connection**—expenditure required to deliver customer-initiated capital projects, including new subdivisions, customer substations, and network connections.

While the level of investment forecast over the next ten years under the DPP4 settings is materially lower than that of the 2024 AMP, as discussed in Section 1.3, WELL is nonetheless entering a period of increased capital investment. This reflects WELL's historic approach of closely matching 33 kV capacity to demand in

order to minimise customer direct costs, which has resulted in limited spare capacity across parts of the network. As a consequence, relatively modest increases in demand are now causing 33 kV capacity constraints that require significant investment in reinforcement to resolve.

WELL's historical capital expenditure and the forecast network capital investment for the next ten years are shown in Figure 1-2.

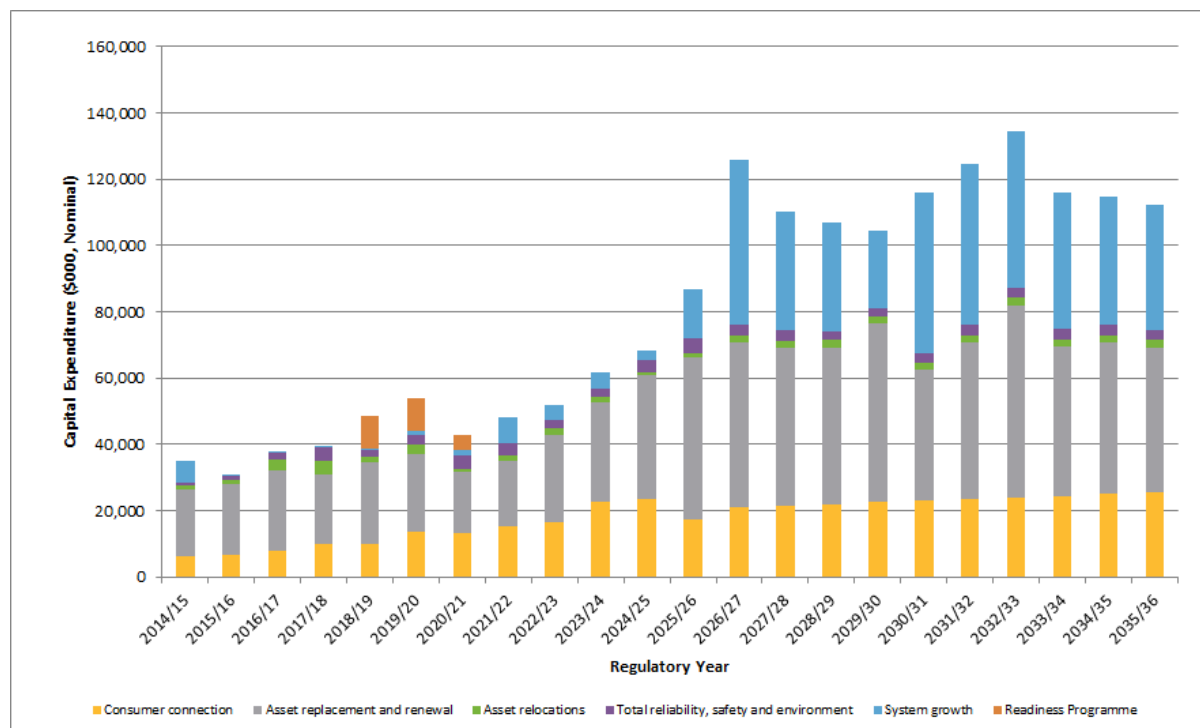


Figure 1-2 Network Capital Expenditure
(\$K in Nominal Prices, Gross of Customer Contributions)

1.5.2 Network Operational Expenditure

WELL groups its network operational expenditure forecast into four categories, reflecting the different drivers of operating costs across the network:

1. Service interruptions and emergencies—expenditure associated with responding to network faults, failures, and third-party incidents, including equipment repair and restoration following damage or in-service failure.
2. Vegetation management—planned and reactive vegetation control delivered through a risk-based programme, alongside administration of cut and trim zones to manage safety and reliability risks.
3. Routine and corrective maintenance and inspection—activities undertaken to maintain asset condition and manage network risk, comprising:
 - Preventive Maintenance – routine inspections, servicing, and condition assessment activities undertaken across the network. The outcomes of these activities inform corrective maintenance and renewal programmes
 - Corrective maintenance works – work undertaken to address defects identified through planned inspection and maintenance activities

- Value-added services – customer and third-party services to reduce the risk of third-party damage to underground assets, including cable mark outs, contractor standovers near network assets, and the provision of asset plans through the 'B4U Dig' programme
4. Asset replacement and renewal—expenditure on asset replacements that do not meet the criteria for capitalisation and are therefore treated as operational expenditure.

Historical and forecast network operational expenditure is shown in Figure 1-3.

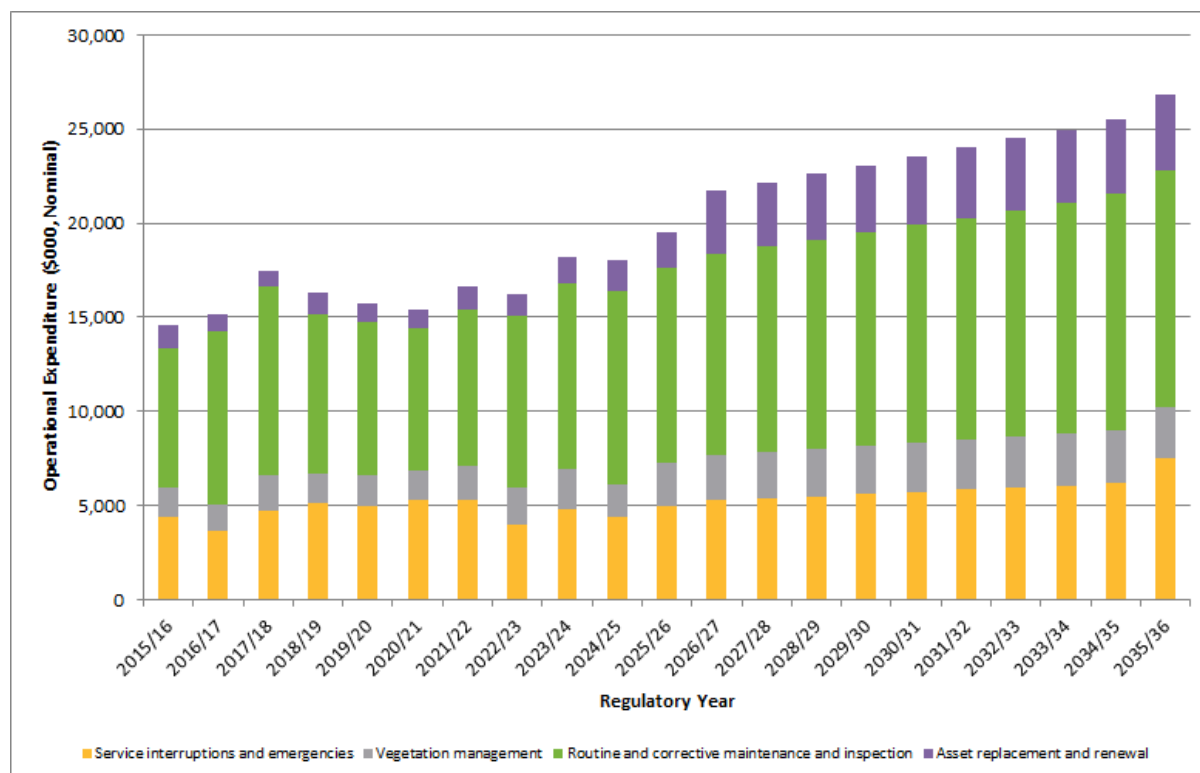


Figure 1-3 Network Operational Expenditure
(\$K in Nominal Prices)

The operating expenditure required to safely operate and maintain the network is increasing as the asset base ages and as greater effort is required to manage inspections, corrective maintenance, vegetation management, fault response, and third-party interactions. These pressures are compounded by the growing reliance on secondary systems and automation to manage network risk and customer impacts. If this level of prudent operational expenditure cannot be sustainably accommodated within the DPP4 allowances, a CPP will be required to align funding with efficient costs and maintain service levels over the longer term.

1.6 WELL's Capability to Deliver

Delivering the investment programme set out in this AMP requires a step change in resourcing compared with recent years. WELL has responded to this challenge by engaging an engineering consultancy to provide a Project Management Office (PMO) function and increasing its use of specialist civil contractors, in addition to the electrical contractors traditionally engaged on the network. Access to an external PMO enables WELL to scale its delivery capability as needed, providing flexibility to support the efficient delivery of larger and more complex projects.

The New Zealand electricity sector is also facing structural workforce challenges, including an ageing workforce and increasing global competition for skilled resources. Addressing these constraints requires

ongoing investment in workforce development across the industry. In response, WELL is actively supporting capability development by training three graduate engineers through a rotation programme covering all aspects of the business, as well as three trainee network controllers.

To further strengthen its delivery capabilities and ensure the provision of the least-cost service, WELL tendered its Field Services Contract in 2024 and appointed Omexom as its new Field Service Provider. Omexom is contracted to provide maintenance and fault-response services. This engagement will ensure that WELL continues to deliver maintenance and fault response services, supporting the safe, efficient, and cost-effective operation of the network across the Wellington region.

As a member of the CK Infrastructure Holdings Limited group, WELL also benefits from access to a broad pool of international expertise and experience. This connection provides visibility of global best practices, emerging technologies, and the lessons learned from comparable networks, supporting continuous improvement in asset management and service delivery.

2 Introduction

This Asset Management Plan (AMP) has been prepared in accordance with the Commission's Information Disclosure (ID) Determination, October 2012 (amended in November 2024). The AMP sets out WELL's long-term investment plans for the 10-year planning period from 1 April 2026 to 31 March 2036 (the planning period).

The AMP was approved and certified by the WELL Board of Directors on 25 March 2026.

2.1 Purpose of the AMP

The purpose of this AMP is to:

- Act as the primary document for communicating WELL's asset management practices, planning processes, and investment intentions to stakeholders, including the Commission
- Describe how stakeholder interests are identified, considered, and integrated into business planning to achieve an efficient balance between service levels, price and quality outcomes, and long-term cost-effective investment
- Demonstrate the alignment 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 are consolidated in this AMP and provide the foundation for the company's business planning processes, including the annual Business Plan and Budget, and for demonstrating compliance with the Information Disclosure requirements under Part 4 of the Commerce Act 1986.

2.2 Structure of this Document

This AMP is structured to provide stakeholders and other interested parties with a clear understanding of WELL's business, operational environment, and asset management approach. The AMP is structured into three main sections:

- Overview and Approach, which outlines WELL's business context and the principles and frameworks that underpin its asset management practices.
- Performance Targets and Levels of Service, which describes the safety, customer, and reliability outcomes that WELL is required to achieve, together with performance against those targets.
- 10-Year Investment Plan, which details WELL's asset base, asset-specific strategies, and forecast investment profile over the planning period to deliver the defined service levels.

Figure 2-1 illustrates the overall structure of this AMP and the relationships between these sections.

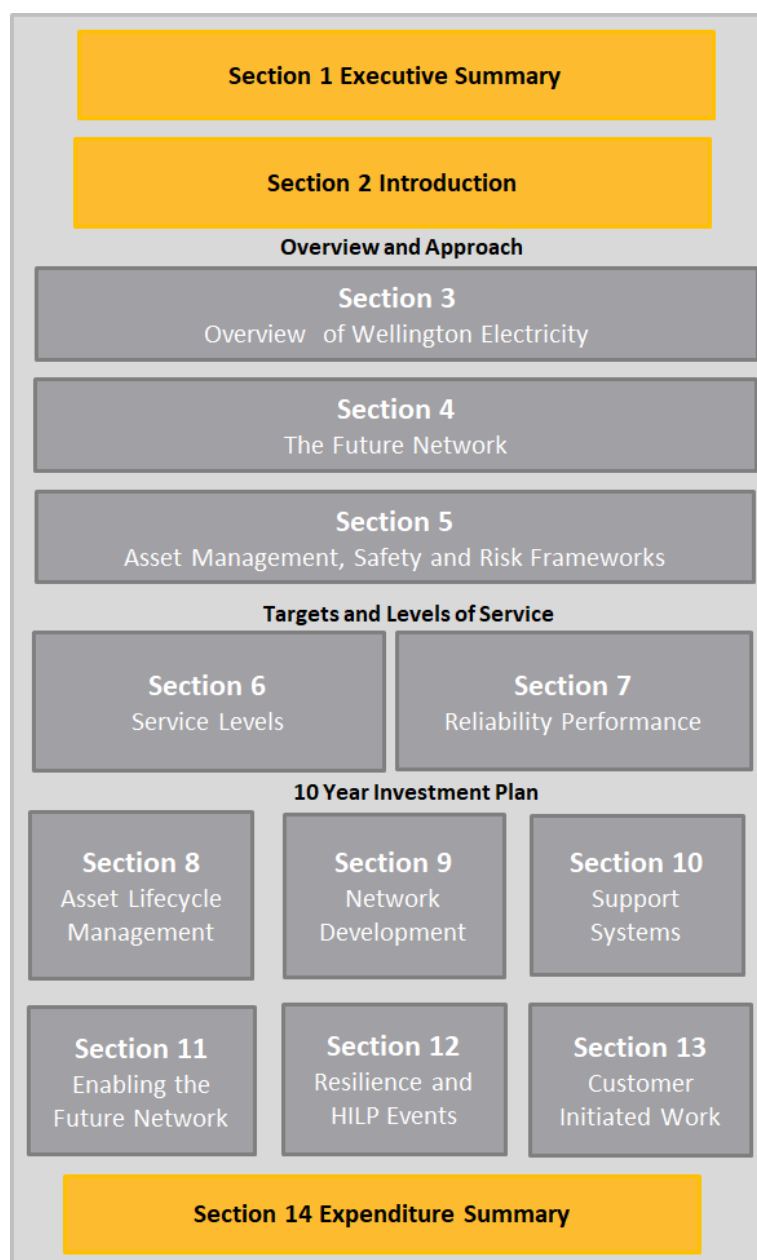


Figure 2-1 Structure of the 2026 AMP

2.3 Formats used in this AMP

The following conventions are used throughout this AMP:

- Financial values are expressed in constant 2026 New Zealand dollars, unless stated otherwise
- Calendar years are referenced as the year (e.g. 2026), and WELL's planning and financial years align with the calendar year
- Disclosure years are from 1 April to 31 March and are referenced as the Year Beginning 1 April
- Asset data presented in figures, tables, and graphs are as at 30 September 2025, unless stated otherwise

- Asset quantities or lengths are reported at the operating voltage rather than the design voltage. For example, WELL has 8.7 km of 110 kV cable operating at 33 kV; these lengths are therefore included in the 33 kV cable statistics rather than being reported as 110 kV assets.
- Discussion of the drivers for a potential WELL customised price-quality path CPP application, to support long-term investment beyond the DPP4 allowances, is highlighted in grey-shaded call-out boxes.

2.4 Investment Projections

The investment programme described in this AMP underpins WELL's business plan. It is subject to ongoing review as new information becomes available and asset management practices continue to be refined and optimised. Asset management strategies are developed having regard to:

- The obligation to provide a safe environment for staff, contractors, and the public.
- Customers' expectations for a reliable, resilient, and secure electricity supply.
- The condition, performance, and risk profile of network assets.
- Changes in business strategy driven by internal and external drivers, including demand growth and system complexity.
- The requirements and constraints of the regulatory framework.

Consistent with industry practice, network-initiated investments planned over the next two to three years are relatively well defined, reflecting committed programmes for asset renewal, maintenance, and system reinforcement. Forecasts for the latter part of the 10-year planning horizon are increasingly uncertain. This reflects both the long asset lives involved and the evolving balance among affordability, reliability, and resilience.

As outlined throughout this AMP, WELL is entering a period where asset renewal requirements, system reinforcement needs, and operational complexity are increasing concurrently. While the DPP4 price-quality path provides some funding certainty, the allowances set under DPP4 constrain WELL's ability to fund timely renewal and resilience investments at a level consistent with maintaining historical reliability and safety outcomes over the long term. This dynamic is consistent with issues identified by other electricity distribution businesses that have transitioned from DPPs to CPPs.

In particular, investment assumptions beyond the 2030 disclosure year reflect WELL's assessment that, under current DPP4 settings, deferral of prudent investment would progressively increase asset health, obsolescence, and resilience risks. Experience from previous CPP applicants demonstrates that sustained deferral of renewal and reinforcement expenditure can lead to step changes in cost, increased outage risk, and reduced flexibility in managing future demand and system shocks.

Accordingly, consistent with its peers' approach, WELL is actively assessing the scope and timing of a CPP application. A CPP would enable WELL to address emerging network risks in a planned and efficient manner, while maintaining service levels and providing transparency to customers and the Commission regarding the need for increased investment. At the time of preparing this AMP, the detailed scope and timing of a potential CPP application remain under development. However, based on current asset condition, forecast demand, and resilience requirements, WELL expects that a CPP will be required to sustainably support prudent investment beyond the current regulatory period.

3 Overview of WELL

WELL operates a critical electricity distribution network on behalf of the communities it serves. This section outlines WELL's mission and how it is translated into the asset management framework. It describes the governance and accountability arrangements, the areas supplied and the network operated, identifies key stakeholders, and summarises the external operating environment and the factors expected to influence 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.”

WELL's mission provides the foundation for all strategic and business planning. To deliver on this mission its business and asset management practices and policies are designed to:

- Provide a safe environment that is free from harm for staff, contractors and the public
- Deliver high-quality outcomes for customers while appropriately balancing cost and quality
- Operate in the most commercially efficient manner practicable within the current regulatory framework

These core principles are embedded in WELL's Business Plan, which is shaped by both internal and external operating conditions and defines the actions and outcomes required to achieve its mission.

This AMP is supported by WELL's asset management framework, objectives, and strategies. In turn, it informs WELL's 2026 Business Plan. Incorporating the interests of both customers and stakeholders. Reflecting the changing operating environment described in Sections 3.6 and 3.7.

Figure 1-3 illustrates the relationship between WELL's mission, the Business Plan and this AMP.

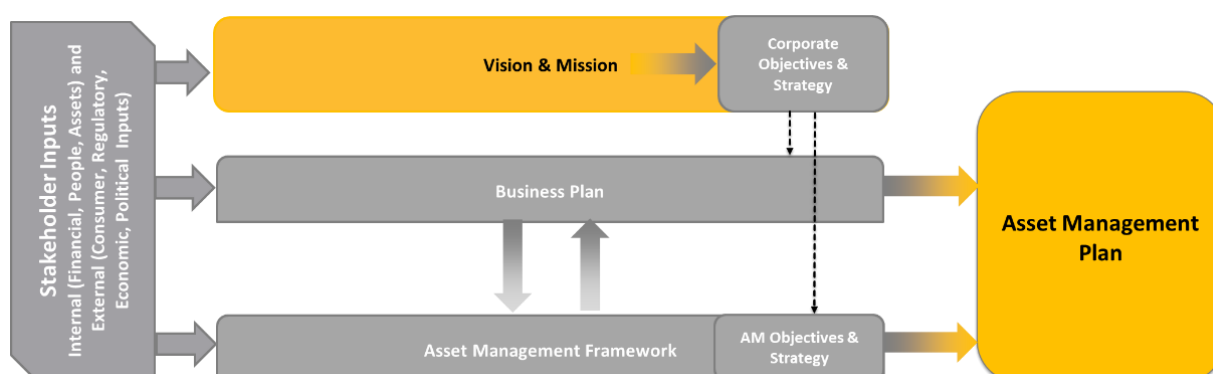


Figure 3-1 Interrelationship between WELL's Mission, the Business Plan, the Asset Management Framework and the AMP

The Asset Management Framework that underpins the alignment between WELL's mission, the Business Plan and this AMP is described further in Section 5.

3.2 Organisational Structure

3.2.1 Ownership

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

The CK Infrastructure Holdings Limited group has established a strong global presence through investments in the electricity sector worldwide. Having the support and backing of such an organisation puts WELL in a strong position to leverage significant intellectual property and resources and to access the latest developments in the electrical services industry.

WELL, is part of a group of electrical sector companies (such as Hong Kong Electric, CitiPower/ Powercor, United Energy, SA Power Networks and UK Power Networks¹), which meets via conference to discuss the latest developments in new technologies worldwide.

In addition, WELL attends joint technical and safety conferences with peer companies within the CK Infrastructure Holdings Limited group, where the latest trends and initiatives from all group business partners are shared.

Further information is available on WELL's website at 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. Management provides consolidated business reporting to the Board, including health and safety performance, capital and operational expenditure against budget, and network reliability performance against regulatory targets.

The Board reviews and approves each AMP, together with the annual budgets and financial forecasts.

3.2.3 Executive and Company Organisation Structure

The Chief Executive Officer is responsible for the overall management of WELL's business activities. WELL operates an outsourced service-delivery model for its field services, contact centre operations and certain specialist functions. The overall company organisation structure is presented in Figure 3-2.

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

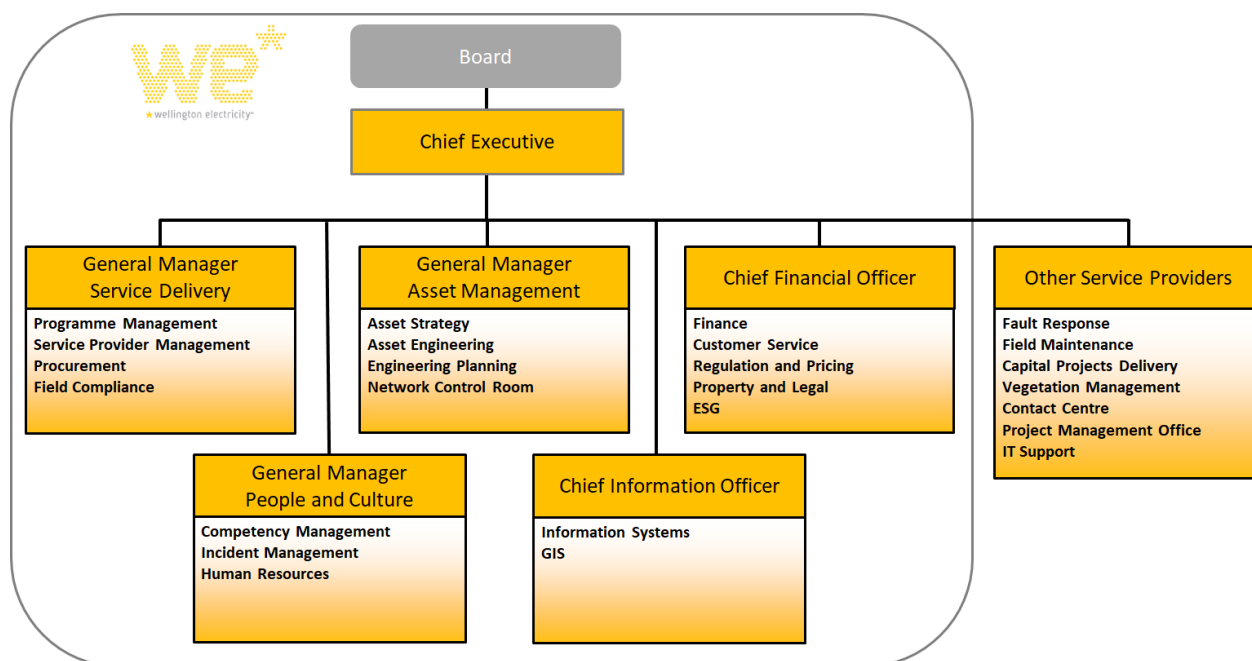


Figure 3-2 WELL Organisation Structure

3.2.4 Financial Oversight, Capital Expenditure Evaluation and Review

WELL maintains a Delegated Financial Authorities (DFA) framework, approved by the Board, which defines the approval limits for staff at different levels across the business.

3.2.4.1 Major Project Financial Approval and Governance

WELL's policies for the authorisation and payment of project expenditure, together with the DFA framework, establish the procedure for approving capital expenditure.²

Capital projects with a value greater than \$400,000 are reviewed and approved by the Capital Investment Committee (CIC), a subcommittee of the Board. The CIC reviews each project's business case, confirms that the appropriate due diligence has been taken, and determines whether the proposed investment aligns with WELL's strategic direction.

The CIC is authorised to approve network projects included in the approved budget and customer connection projects up to \$2 million. For projects outside these parameters, the CIC provides the Board with a recommendation for consideration and approval.

3.2.5 Asset Management Accountability

The Chief Executive Officer leads the Executive Leadership Team and is accountable to the Board for WELL's overall performance and strategic direction.

The General Manager – Asset Management is responsible for asset engineering, network planning, standards, project approvals, works prioritisation, and the operation of the network control room. This role also has accountability for the introduction and management of new technology on the network.

² Approval of operational expenditure follows a similar process.

The General Manager – Service Delivery is responsible for delivering capital and maintenance works, with accountability for safety, quality, and environmental performance, as well as managing outsourced field services contracts.

The Chief Financial Officer is responsible for finance, customer service, regulatory management, legal and property functions, information technology support, and WELL's environmental, social and governance (ESG) strategies and targets.

The General Manager – People and Culture is responsible for human resources, for the oversight of WELL's competency management, incident management, and quality and safety systems.

WELL's staff and external service providers have the capability and training required to deliver this AMP, with programmes in place to maintain competency in line with good industry practice.

3.2.5.1 Asset Management Group

The Asset Management function is organised into four specialist areas: asset engineering, asset planning, asset strategy, and network control and operations. The responsibilities for each area are described in Table 3-1.

Asset Management Teams	Asset Management Responsibilities
Asset Engineering	• Safety-by-Design for asset replacements • Asset and network management • Condition-based risk management • Reliable service levels for customers • Approval of asset management projects and budgets • Quality performance management • Network policies and standards • Technical engineering support • Development and prioritisation of the 3–12-month TOTEX work plan • Analysis of asset data to inform decision-making
Asset Planning	• Safety-by-Design for new builds • Network load forecasting • Reinforcement planning • Review of large customer connection requests
Asset Strategy	• Strategic network development planning to a 30-year horizon. • Network resilience initiatives. • Innovation and flexibility workstreams.
Network Operations	• Network operations and safety • Outage management • Fault response and management • Control Room • Operationalising new technologies on the network

Table 3-1 Asset Management Team Responsibilities

3.2.5.2 Service Delivery Group

The Service Delivery function is responsible for delivering capital and maintenance works on the network and for managing specialist service contracts. The specific 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) - Delivery of reactive maintenance and value-added 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 function is responsible for commercial, regulatory and financial management activities. The specific responsibilities of this function 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 - Management of property and land
Environmental, Social and Governance (ESG)	- Implementation of corporate ESG strategy - Delivery of agreed ESG targets

Table 3-3 Commercial and Finance Team Responsibilities

3.2.5.4 Information Technology Group

The Information Technology function is responsible for delivering and supporting business and operational information systems. The specific responsibilities of this function are described in Table 3-4.

Information Technology Team	Asset Management Responsibilities
Information Technology	- Operational system maintenance and upgrades - Business support systems

Table 3-4 Information Technology Team Responsibilities

3.2.5.5 People and Culture Group

The People and Culture function is responsible for human resources and for the oversight of WELL's competency management, incident management, and quality and safety systems. The specific responsibilities of this function 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 - Adherence to Health & Safety and Environmental legislation
Human Resources	The capability of people to deliver Asset Management functions

Table 3-5 People and Culture Team Responsibilities

3.2.5.6 Other Service Providers

WELL, outsources the majority of its field services and its customer contact centre operations. It retains the overarching accountability for the health and safety of all contracted parties.

The General Manager – Service Delivery is responsible for managing field service contacts, while the Chief Financial Officer is responsible for managing the customer contact centre contract.

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

- 24-hour fault dispatch and response, maintenance, capital works – Omexom
- Contestable capital works – Omexom, Downer, Connetics, and other approved contractors
- Vegetation management – Treescape
- Customer contact centre – Telnet

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

Further details on the roles and services provided by the service providers are provided in Section 4.

3.3 Distribution Area

WELL owns and operates the electricity distribution network supplying approximately 182,000 customers across the Wellington central business district (CBD) and the major urban residential centres of Wellington City, Porirua, Lower Hutt, and Upper Hutt. The network serves pockets of commercial and light-industrial load, as well as surrounding rural communities, and includes a small number of large industrial and agricultural loads.

WELL's network spans the jurisdictions of four territorial authorities: Wellington City, Porirua City, Hutt City, and Upper Hutt City Councils, each with distinct requirements for permitted activities, including road corridor access and environmental compliance. In addition, the entire network area is subject to regional planning and consenting requirements administered by the Greater Wellington Regional Council.

Prior to industry deregulation, electricity distribution in the region was the responsibility of two separate organisations. As a result, network design standards and equipment specifications were developed differently across the historic network areas. One historic area now forms the Southern region of WELL's network, while the other has been subdivided into the Northwestern and Northeastern areas to reflect the natural geographic and electrical boundaries. These three planning areas are illustrated in Figure 3-3.

For planning and operational purposes, WELL's network is structured into three areas:

- Southern Area - supplied by the Wilton, Central Park, and Kaiwharawhara grid exit points (GXPs)
- Northwestern Area - supplied by the Takapu Road and Pauatahanui GXPs
- Northeastern Area - supplied by the Upper Hutt, Haywards, Melling, and Gracefield GXPs

The network configuration for each of the three planning areas is described in Section 3.4. Each region is disaggregated into Network Development and Reinforcement Plan regions, which are addressed in Section 9 as part of the detailed regional planning framework.



Figure 3-3 WELL Network Area

3.4 The Network

WELL's electricity distribution system has a total length of approximately 4,903 km (excluding streetlight circuits), of which around 65% is underground. The network is supplied from Transpower's national transmission grid through nine GXPs. Central Park, Haywards, and Melling GXPs supply the network at both

33 kV and 11 kV, while Kaiwharawhara supplies only at 11 kV. The remaining GXPs, Gracefield, Pauatahanui, Takapu Road, Upper Hutt and Wilton, supply the network at 33 kV only.

The 33 kV subtransmission system distributes supply from the GXPs to 27 zone substations and is designed to operate at the N-1 security standard.³ The system is generally radial, with each circuit supplying a dedicated power transformer. Exceptions include the Tawa and Kenepuru substations, where two circuits branch from the Takapu Road GXP to supply four transformers (two at each substation), and the Evans Bay/Ira Street arrangement, where three circuits from Central Park supply four transformers via a 33 kV bus. All 33 kV circuits supplying zone substations in the Southern area are underground, while those in the Northwestern and Northeastern areas comprise a combination of underground and overhead construction. 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 transformers rated at 33/11 kV. Most zone substations are configured with a pair of transformers, each supplied from a different side of a Transpower bus where available. The Plimmerton and Mana substations are exceptions, each having a single 33 kV supply to a single transformer. These substations are interconnected by a normally closed 11 kV tie cable and operate as a single N-1 substation, despite being geographically separated by approximately 1.5 km.

Zone substations, in turn, supply the 11 kV distribution system, which delivers electricity to larger customers and to approximately 4,681 distribution transformers located in commercial buildings, industrial sites, kiosks, berm-side, and on overhead poles. The 11 kV network has a total length of approximately 1,814 km, of which around 68% is underground. Within the Wellington CBD⁵, approximately 71% of 11 kV feeders operate in a closed-ring configuration, with the remainder comprising radial feeders that provide interconnection between neighbouring rings or adjacent zone substations.

Most customers are supplied from distribution substations via the low-voltage distribution network. The total low-voltage network length is approximately 2,877 km, of which around 63% is underground. In addition, approximately 1,977 km of low-voltage lines and cables are dedicated to street-lighting services.

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

3.4.1 Southern Area

The Southern Area network is supplied by the Central Park, Wilton, and Kaiwharawhara GXPs, which collectively serve Wellington City, the Eastern Suburbs, and the CBD. The configuration of the Southern Area subtransmission network is illustrated in Figure 3-4.

³ N-1 equals 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.

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.

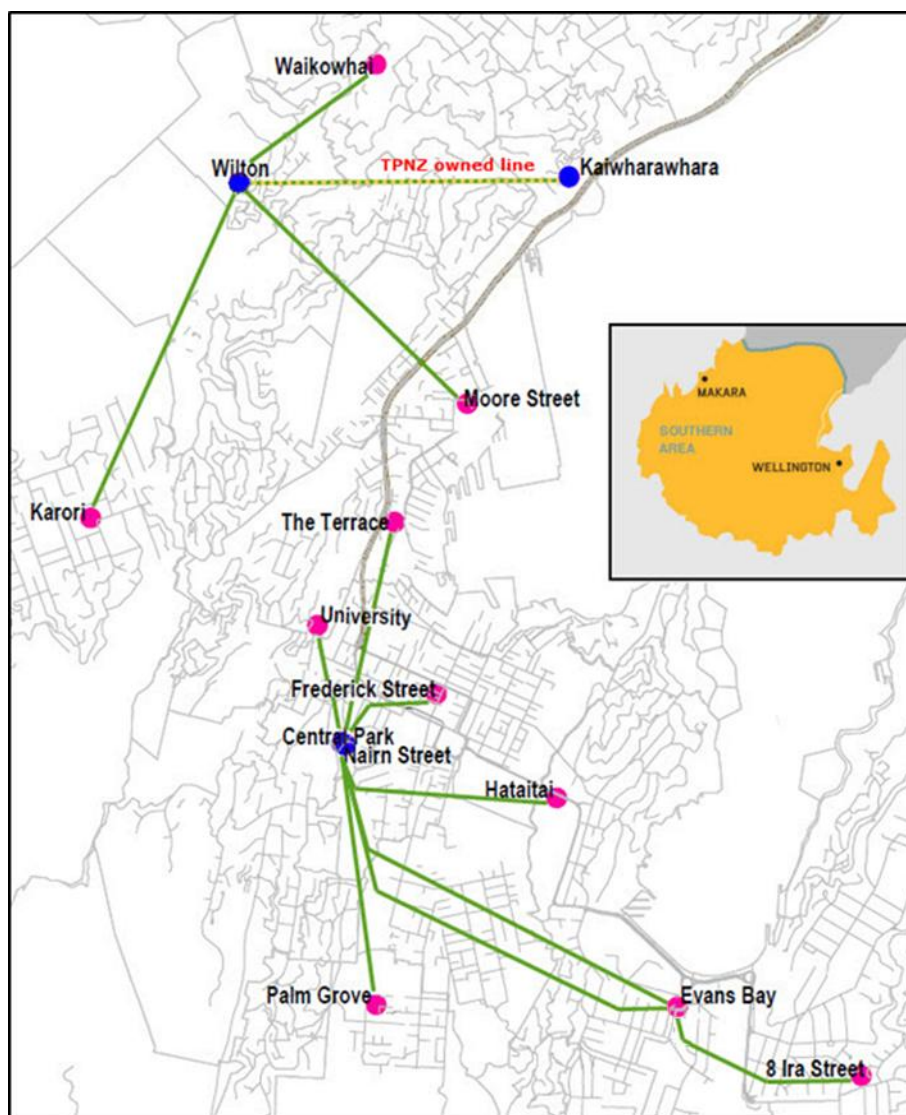


Figure 3-4 Wellington Southern Area Subtransmission Network

3.4.1.1 Central Park

Transpower's Central Park GXP comprises three 110/33 kV transformers, T5 (120 MVA) and T3, T4 (100 MVA units), supplying a 33 kV indoor bus. The site also includes two Transpower-owned 33/11 kV (25 MVA) transformers that supply station services 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. Because there is no 110 kV bus at Central Park, an outage on any of these circuits directly affects the transformer connected to it.

Central Park GXP supplies seven WELL zone substations—namely Ira Street, Evans Bay, Hataitai, Palm Grove, Frederick Street, University, and The Terrace—via double circuit 33 kV underground cables. In addition, Central Park supplies the adjacent Nairn Street zone substation at 11 kV via two underground 11 kV duplex circuits (four cables). The security of supply from Central Park has been identified as a risk, and potential mitigation options are discussed in Section 12.

3.4.1.2 Wilton

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

3.4.1.3 Kaiwharawhara

Kaiwharawhara GXP is supplied by two 110 kV circuits from Wilton GXP and incorporates two 110/11 kV transformers, each rated at 38 MVA. WELL takes supply at 11 kV supply from Transpower's Kaiwharawhara GXP and distributes this through a WELL-owned switchboard located within the GXP.

3.4.1.4 Southern Area Summary

Supply Point	Connection Voltage (kV)	Maximum Demand – 2025 (MVA)	Firm Capacity ⁶ (summer/winter MVA)	Volumes – 2025 (GWh)	ICP Count
Central Park 33 kV	33	152	217/223	589	44,025
Central Park 11 kV	11	21	30/30	83	7,887
Wilton 33 kV ⁷	33	45	103/110	-34	13,109
Kaiwharawhara 11 kV	11	27	38/38	120	5,708
Total				758	70,729

Table 3-6 Summary of Southern Area GXPs

3.4.2 Northwestern Area

The Northwestern Area network is supplied by the Pauatahanui and Takapu Road GXPs, which collectively serve Porirua City and the Tawa, Johnsonville, and Ngauranga areas of Wellington City. The configuration of the Northwestern Area GXP and subtransmission network is illustrated in Figure 3-5.

⁶ Firm Capacity is the N-1 transformer capacity.

⁷ Wilton 33 kV Volumes – 2025 (GWh) are net of 233 GWh injected by Mill Creek Generation into the GXP.

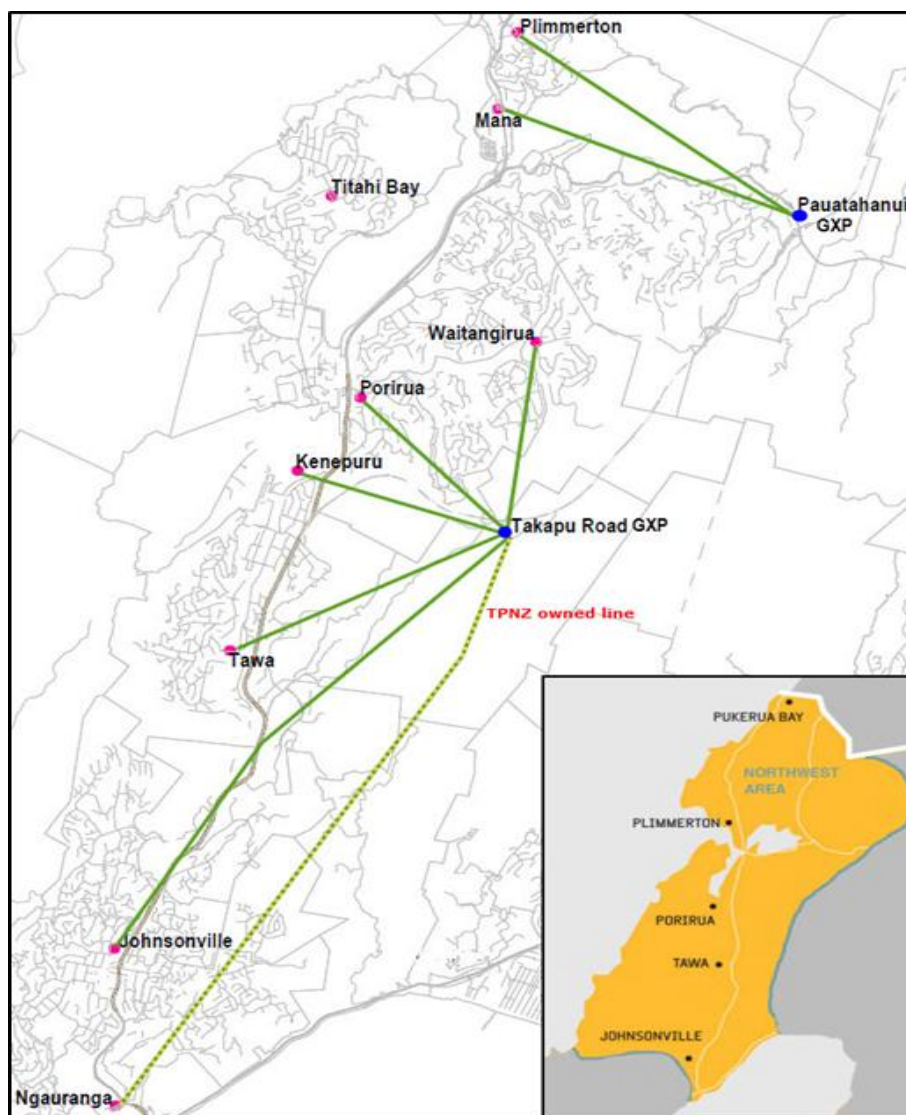


Figure 3-5 Wellington Northwestern Area Subtransmission Network

3.4.2.1 Pauatahanui

Transpower's Pauatahanui GXP comprises two 110/33 kV transformers, each nominally rated at 20 MVA. Pauatahanui GXP supplies the Mana and Plimmerton zone substations, each via a single 33 kV overhead circuit. The two zone substations are interconnected by a dedicated 11 kV tie, providing a degree of redundancy when either 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, each nominally rated at 90 MVA, supplying a 33 kV indoor bus. Takapu Road GXP supplies six WELL zone substations, 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 transition to underground cables at the urban boundary. The circuits supplying 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 – 2025 (MVA)	Firm Capacity (summer/winter MVA)	Volumes – 2025 (GWh)	ICP Count
Pauatahanui 33 kV	33	20	22/24	67	7,420
Takapu Road 33 kV	33	99	111/116	404	35,785
Total				471	43,205

Table 3-7 Summary of Northwestern Area GXPs

3.4.3 Northeastern Area

The Northeastern Area network is supplied by the Upper Hutt, Haywards, Melling and Gracefield GXPs, which collectively serve the Hutt Valley and the surrounding hill communities. The configuration of the Northeastern Area subtransmission network is illustrated in Figure 3-6.

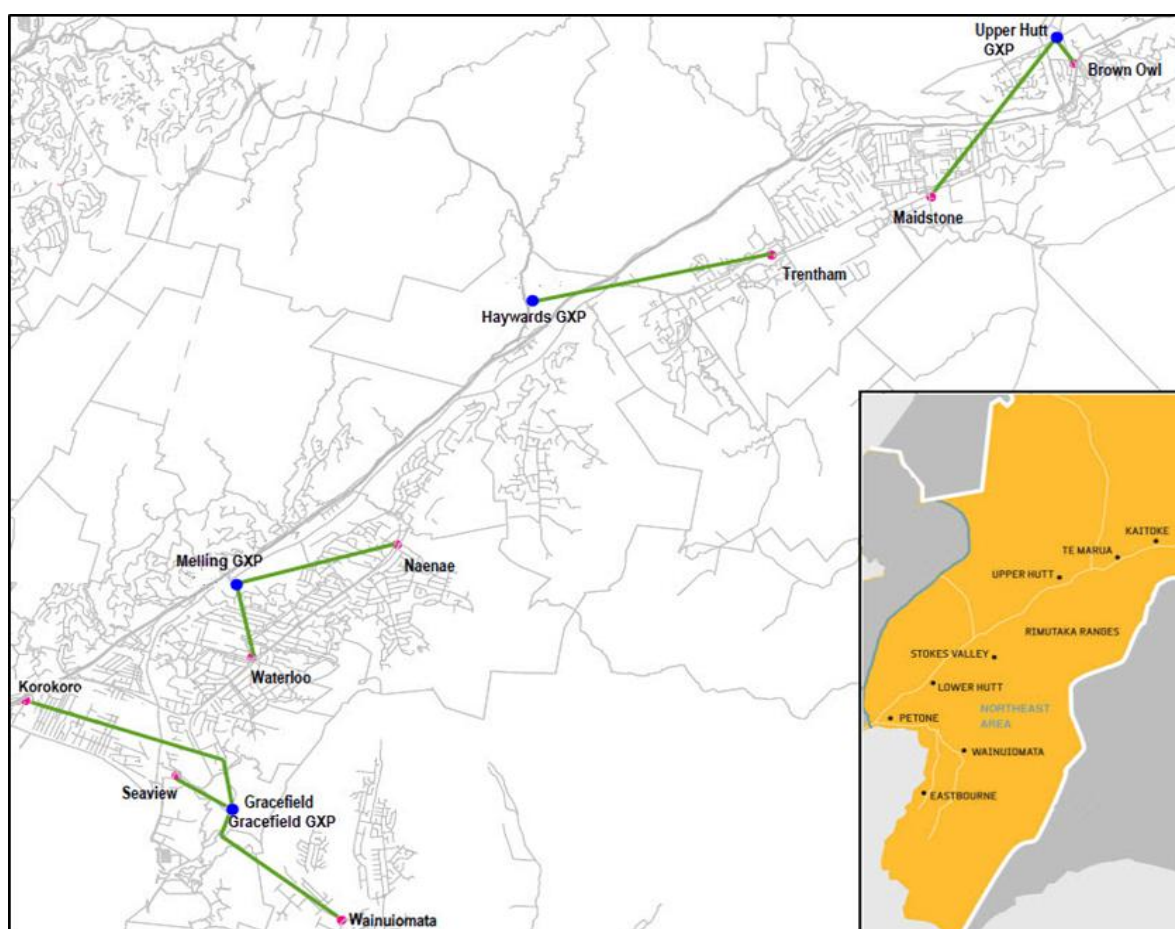


Figure 3-6 Wellington Northeastern Area Subtransmission Network

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 the 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 receives supply via two 33 kV circuits serving the 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 a 33 kV indoor bus. Melling GXP supplies the Waterloo and Naenae zone substations via duplicated 33 kV underground circuits. The site 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 experienced a winding fault, and Transpower temporarily installed a 60 MVA strategic spare transformer in its place.

Gracefield GXP supplies four WELL zone substations, Seaview, Korokoro, Gracefield, and Wainuiomata, each via double-circuit 33 kV connections. The circuit to Wainuiomata is predominantly overhead, while underground cables supply the remaining 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

Table 3-8 summarises the key technical and customer metrics for the Northeastern Area.

Supply Point	Connection Voltage (kV)	Maximum Demand – 2025 (MVA)	Firm Capacity (summer/winter MVA)	Volumes – 2025 (GWh)	ICP Count
Gracefield 33 kV	33	62	76/80	258	20,811
Haywards 33 kV ⁸	33	21	24/24	75	6,598
Melling 33 kV	33	35	64/65	135	13,446
Upper Hutt 33 kV	33	32	51/53	133	11,736
Haywards 11 kV	11	19	30/30	67	7,252
Melling 11 kV	11	25	32/34	104	8,266
Total				772	68,109

Table 3-8 Summary of Northeastern Area GXPs

⁸ Haywards 33 kV volumes – 2025 (GWh) are net of 13 GWh injected by Silverstream Generation into the GXP.

3.4.4 Embedded Generation

A wide range of embedded generation connected to WELL's network, including 3,863 PV installations with a combined capacity of approximately 20.38 MVA. The largest embedded generation site is the Mill Creek wind farm at 60 MW, which connects to WELL-owned 33 kV circuits from the Wilton GXP. Of the 3,863 ICPs with PV installations, 725 are equipped with battery storage. From the end of 2024, WELL began recording battery, with the total installed capacity now reaching 4MWh.

In addition, nine diesel generation sites with an installed capacity of approximately 16.3 MVA are connected to the network, the largest being a 10 MVA installation at Wellington Hospital. Other embedded generation includes two landfill-gas turbine sites, the Brooklyn wind turbine, and a number of small-scale hydroelectric generation stations commissioned at Greater Wellington Regional Council water storage and pumping stations.

3.4.5 Embedded Distribution Networks

Several third-party embedded networks operate within WELL's network area, typically serving apartment buildings, commercial buildings, and campus-style developments such as retirement villages. WELL generally provides a bulk supply point, while the ownership, management and service levels of the assets within these embedded networks remain the responsibility of the respective owners and are therefore excluded from this AMP.

3.5 Balancing Network Growth with Asset Renewal

Investment in WELL's network is increasingly driven by the electrification of the economy in support of New Zealand's net-zero 2050 objective. Growth in electric vehicles, distributed energy resources, electrified processes, and space heating is expected to increase peak demand. This places additional pressure on network capacity, secondary systems, and asset condition. At the same time, much of the network is ageing. Depreciation funding is projected to cover only around 50% of the replacement cost of assets reaching the end-of-life, creating a widening reinvestment gap as renewal volumes increase.

Cost pressures further compound this challenge. Indexation to CPI does not adequately reflect input cost escalation. Key areas such as skilled labour, contractor rates, traffic management, and road-closure costs have risen exponentially in recent years. The DPP framework has supported the delivery of a reliable and affordable network under historical demand and growth conditions. These conditions, however, are changing as the scale of asset renewal required coincides with a step-change in capacity and system capability. The investment needed to support long-term growth driven by decarbonisation is unlikely to be supported by the fixed and smoothed allowances under DPP4.

WELL's network is predominantly located within a city-based, urban brownfields environment, which materially increases the cost and complexity of delivery. Much of the network was originally constructed more than 50 years ago, when land use was less intensive, and community expectations regarding disruption were materially lower. Today, works must be undertaken within constrained corridors, alongside critical infrastructure, and in close proximity to residents, businesses, and transport routes. Disturbances that may have been acceptable at the time of original construction, i.e., extended road closures, open trenching, and prolonged access restrictions, are no longer tolerable. As a result, projects require more extensive traffic management, stakeholder engagement, reinstatement standards, and, in some cases, trenchless or staged construction methodologies, all of which add material costs, programme risk, and delivery complexity.

3.5.1 WELL is a winter peaking network driven by residential demand

On the Wellington network, peak demand occurs in winter when residential heating is at its highest. Maximum demand in any given year is therefore strongly influenced by the characteristics of the coldest winter weekday. Colder and wetter conditions lead to higher evening peak loads, resulting in significant year-to-year variability in maximum demand. This variability centres on an underlying long-term decline of approximately 0.5% per annum, which is believed to reflect increasing energy efficiency across the housing stock and residential appliances.

Delivered energy volumes are not directly correlated with maximum demand. While maximum demand is driven by extreme weather conditions on the coldest day of the year, annual volumes are influenced by whether the year as a whole is milder or colder than average, as well as by prevailing economic conditions.

As shown in Table 3-9, approximately 90% of connections on the Wellington network are residential.

Customer Type	ICP Count
Residential	162,958
Large Commercial	536
Medium Commercial	493
Small Commercial	16,437
Large Industrial	231
Small Industrial	531
Unmetered	859
Individual Contracts	191
Total	182,236

Table 3-9 WELL's Customer Mix as of January 2026

While the majority of connections on WELL's network are residential, a significant number of customers have large, sensitive or strategically important loads. These customers contribute disproportionately to peak demand and play a critical role in the social and economic functioning of the Wellington region. They include:

- Parliament and central government agencies
- Hospitals, emergency services, and civil defence organisations
- Council-owned infrastructure, including water and wastewater pumping stations and street lighting
- Major transport and logistics infrastructure providers, such as Waka Kotahi, Wellington International Airport, and CentrePort
- Large tertiary education institutions, including Victoria University of Wellington, Massey University, Whitireia and WelTec
- Customers with sensitive operational requirements, such as the stock exchange, Wētā FX, Datacom, and the Department of Corrections

The number and density of these customers are atypical for a New Zealand distribution network. Accordingly, the provision of a reliable and resilient network is of critical importance to WELL's customers and to the wider Wellington region.

WELL's Customer Services team manages the relationship with retailers and customers and coordinates the management of major customers' requirements on a case-by-case basis. This includes managing the impacts of outages and prioritising asset management. Customers with significant electricity use, specialised operational requirements or who provide essential services are proactively notified in advance of planned outages and following any unplanned outages that affect their supply.

Customer interests are identified and incorporated into asset management decision-making through several formal mechanisms, as discussed further in Section 3.6.

3.6 WELL's Stakeholders

WELL has identified nine key stakeholder groups whose interests are considered in the asset management approach and in defining the service outcomes for each group. These stakeholder groups comprise:

- Customers and the Community at Large
- Iwi
- Retailers
- Regulators
- Transpower
- Central and local government
- Industry organisations
- Staff and contractors
- Debt capital market funders
- Shareholders

The characteristics of each stakeholder group are described below, including how their interests are identified, their expectations of WELL, and the way these interests are incorporated into WELL's asset management processes. The service levels that result from these stakeholder considerations 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 a combination of direct feedback, including surveys, queries and complaints, and community engagement activities. Key customer interests include public safety, network reliability, and the price paid for that reliability. These interests are reflected in WELL's asset management practices through compliance with regulated quality standards, public safety initiatives and targeted customer engagement programmes.

WELL uses a range of communication channels to engage with customers and the wider community, including community meetings, participation in public events, the WELL website and mobile application, public disclosure documents, newspapers, radio and digital advertising, and email and telephone communications. A key focus for 2026 is exploring an expanded use of social media to support more timely, accessible and high-quality customer engagement.

WELL also operates outage-reporting applications across both web and mobile platforms. These applications provide information on the location of unplanned outages and forecast restoration times and display recent outages and upcoming planned outages on the website platform. A screen shot of WELL's web-based outage reporting application is shown in Figure 3-7.

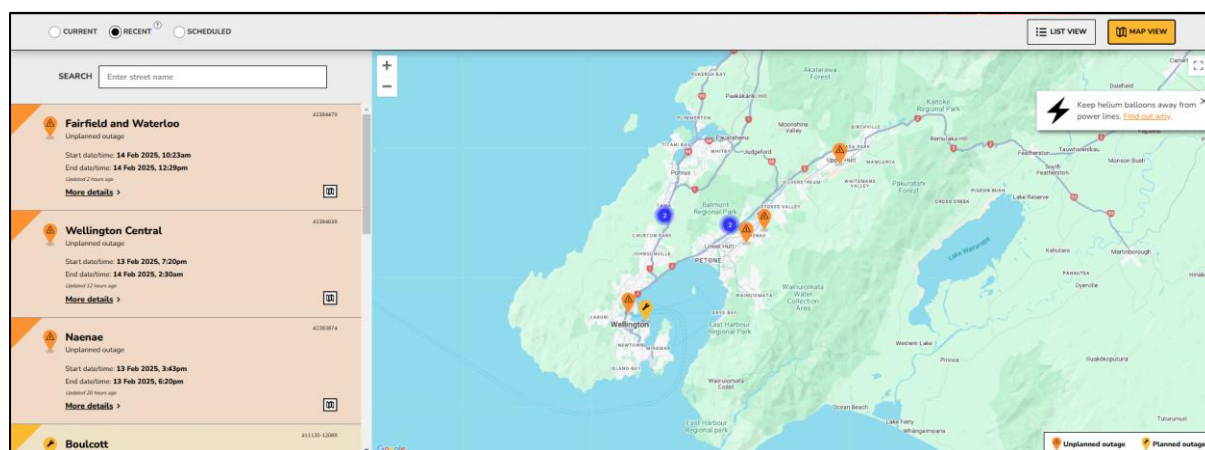


Figure 3-7 WELL's Web-based Outage Reporting Application

Improving the customer experience by enhancing the accuracy of estimated restoration times remains an ongoing focus for WELL and its contractors.

3.6.1.2 Iwi

WELL is committed to strengthening its relationships with local iwi and to building partnerships on open, timely and respectful communication. WELL seeks to foster mutual understanding of priorities and expectations and to support early engagement in projects, thereby enabling collaborative decision-making and positive outcomes for all parties.

3.6.1.3 Retailers

Retailers are WELL's direct contractual customers and rely on the network to deliver electricity to end-use consumers. Retailers also seek WELL's support in enabling innovative products and services that benefit their customers.

Retailer and customer quality-of-supply interests are addressed through WELL's compliance with the regulatory quality targets defined in the Commission's price-quality path and the service levels outlined in Section 5.

WELL consults with retailers prior to implementing changes to its line-charge pricing structure to ensure that proposed changes account for retailer feedback and operational considerations.

3.6.1.4 Regulators

WELL is principally regulated by WorkSafe New Zealand, the Commission and the Electricity Authority (the Authority). Together, these agencies shape the regulatory environment within which WELL manages its assets and delivers electricity network services.

WorkSafe New Zealand focuses on continuous improvement in workplace safety and on the effective identification and management of risks to protect the welfare of workers and the public. These obligations are embedded in WELL's asset management practices through a comprehensive framework of health and safety, environmental, quality policies and procedures. This framework includes reporting requirements and processes for consulting, cooperating, and coordinating 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 concerned with ensuring that customers receive electricity at fair and reasonable prices and receive service that delivers sustainable, long-term benefits. WELL addresses these regulatory expectations by complying with reliability and quality standards, adhering to price-quality regulations, participating in regulatory development processes, and preparing information disclosures.

3.6.1.5 Transpower

Transpower's interests are communicated through the Electricity Industry Participation Code 2010 (the Code), regular relationship meetings, direct business communications, annual planning documents, and grid notifications and warnings. Through these channels, Transpower seeks to ensure the sustainable recovery of revenue associated with connected and interconnected transmission assets and requires assurance that downstream distribution and generation do not adversely affect the integrity or performance of those assets.

Transpower also has a direct interest in the safe and efficient operation of the national grid, including the management of rolling outages, automatic under-frequency load shedding (AUFLS), and broader demand-side management initiatives. WELL addresses these interests by applying defined operational standards and procedures, making prudent, targeted investments in its network, and maintaining ongoing engagement with Transpower through regular operational and planning forums.

3.6.1.6 Central and Local Government

The interests of central and local government are communicated through legislation, regulations, regular engagement meetings, direct business communications, and participation in working groups. In addition to being significant customers, central and local government agencies, through street lighting, electrified public transport, and water management services, have a strong interest in WELL's compliance with statutory and regulatory obligations.

These stakeholders also require assurance that appropriate lifeline obligations are met to support emergency response arrangements, and that robust contingency planning is in place to manage a significant civil defence event. More broadly, they seek confidence that customers receive a safe and reliable supply of electricity at competitive prices, that the network's operations do not adversely impact the environment, and that sufficient and prudent investment is being made to accommodate forecast growth.

WELL addresses these interests through strict compliance with legislative and regulatory requirements, active participation in policy development processes, the preparation of required submissions, and the implementation of Emergency Response Plans and Environmental Management Plans.

3.6.1.7 Industry Organisations

The interests of industry organisations, including Engineering New Zealand, the Electricity Engineers Association (EEA), and Electricity Networks Aotearoa (ENA), are identified through regular executive-level engagement, attendance at sector workshops, and participation in industry working groups. These organisations promote the application of good industry practice and expect a strong and sustained focus on professional standards, capability development, with continuous improvement.

WELL responds to these expectations through the ongoing training and development of staff competencies. Aligning its asset management and community engagement strategies with recognised industry frameworks and best-practice guidelines.

As a designated lifeline utility, WELL also maintains close working relationships with the Wellington Lifelines Group (WeLG). WeLG's role is to support coordination among essential service providers to ensure operational continuity during emergencies and major civil defence events. WELL's participation in this forum strengthens its emergency preparedness and resilience planning, as further discussed in Section 12.

3.6.1.8 Staff and Contractors

The interests of staff and contractors are identified through individual and team discussions, regular meetings, direct business communications, contractual agreements, and staff culture surveys. Collectively, these stakeholders seek a safe, supportive, and engaging working environment, alongside job satisfaction, fair and equitable remuneration, effective mitigation of workplace risks, and work continuity of work.

WELL meets these expectations through comprehensive health and safety policies and initiatives, structured performance and development reviews, and coordinated work-planning processes that support both workforce well-being and operational efficiency.

3.6.1.9 Debt Capital Market Funders

WELL accesses debt capital markets to support funding of the investment programme outlined in this AMP. To date, funding has been primarily through bank facilities and private placement issues. These funding partners have a strong interest in WELL's financial resilience, creditworthiness, and the sustainability of its long-term investment profile.

WELL addresses these interests through the preparation of robust capital and operational expenditure forecasts, financial modelling, and risk management practices. Providing clear visibility of its risk profile and funding requirements, supporting informed investment and lending decisions.

3.6.1.10 Shareholders

Shareholder interests are articulated through governance arrangements. Including, Board meetings and mandates, the Business Plan, and WELL's strategic objectives. Shareholders expect that safety be non-negotiable, that fair and sustainable returns on their investment be delivered. Compliance with legislative and regulatory requirements, constructive and transparent relationships with key stakeholders, and effective stewardship of the network and the business.

WELL responds to these expectations through established governance and assurance processes, including regular Board reporting on asset management performance, compliance obligations, service levels, and budgetary outcomes, ensuring that shareholder expectations are systematically monitored and met.

3.6.2 Managing Potential Conflicts between Stakeholder Interests

Conflicts between stakeholder interests are managed on a case-by-case basis through a balanced assessment of risks and benefits, supported by consultation with the affected parties, where appropriate, the development of innovative “win-win” solutions. Notwithstanding this collaborative approach, safety remains paramount. WELL will not compromise the safety of the public, its staff, or its service providers in managing competing stakeholder expectations.

WELL is a member of the Utility Disputes Limited (UDL) scheme, which provides a dispute-resolution process for customer complaints. In addition, WELL’s Distribution Agreement includes formal dispute-resolution mechanisms for managing disputes with electricity retailers.

3.7 Operating Environment

WELL operates within the broader New Zealand business environment and the global economy. This context encompasses financial market conditions, legislative and regulatory settings, and the pace of technological changes. Together, these factors shape the operating environment in which WELL plans, funds, and delivers its asset management and investment programmes.

WELL actively monitors these external influences and incorporates them into its strategic planning, risk management, and asset management decision-making to ensure the ongoing resilience, adaptability, and sustainability of the network and the business.

3.7.1 Legislative and Regulatory Environment

WELL is subject to a comprehensive suite of legislative and regulatory obligations that govern the operation, performance, and investment of its electricity distribution network. Compliance with these obligations is achieved through the adoption and application of best-practice asset management policies and procedures that underpin this AMP.

WELL maintains regular and constructive engagement with both the Authority and the Commission through participation in working groups, conferences, workshops, consultations, and the preparation of the information disclosures. These engagements support regulatory compliance, inform regulatory development, and ensure that WELL remains aligned with evolving regulatory expectations.

The key legislative and regulatory obligations applicable to WELL are detailed below.

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

Building on its strong safety and environmental performance, and in accordance with the requirements of the Health and Safety at Work Act 2015, WELL maintains a strong focus on the early identification and management of safety and environmental risks. Consistent with its commitment to continual improvement, risk considerations are embedded at the earliest stages of project development.

Risk assessments are undertaken with contractors prior to the award of works and are actively monitored throughout the project lifecycle to identify and respond to any changes in risk profile. The cost and time implications associated with these risk management requirements are incorporated into project budgets and

delivery schedules. WELL also undertakes weekly incident reviews with service providers and regularly monitors the effectiveness of implemented control measures, with a strong emphasis on prioritising engineering controls over process and administrative controls wherever practicable.

The key elements of the HSW Act that form the primary focus for WELL's health and safety framework include:

- The concept of the PCBU, including officer due diligence duties.
- Consultation, cooperation and coordination between PCBUs.
- The extension of hazard management to incorporate risk management at the worker level.
- Worker engagement, participation, and representation.

WELL continues to strengthen consultation, cooperation and coordination arrangements with all principals and service providers, particularly in the management of interface boundaries.

To support these, WELL has implemented a compliance management system that underpins its obligations under the Health and Safety at Work Act 2015 and NZS 7901: Public Safety Management (PSMS). Compliance performance and statutory timeframes are reported quarterly to the Board.

3.7.1.2 Price Quality Compliance

WELL is subject to the price and quality controls contained in Part 4 of the Commerce Act 1986 and currently operates under the Default Price-quality Path (DPP).

3.7.1.3 Information Disclosure

WELL is subject to a comprehensive suite of annual public information disclosure obligations. To ensure accurate and timely reporting, WELL's business processes and information systems are aligned with the Electricity Distribution Information Disclosure Determination 2012, ensuring that information is prepared and disclosed in the prescribed form.

3.7.1.4 Default Distributor Agreements

Electricity retailers' contracts with electricity distribution businesses for the provision of distribution services. WELL maintains a Default Distribution Agreement (DDA) with each retailer, with the terms of these agreements prescribed by Code.

3.7.1.5 Pricing Roadmap

WELL has published a pricing roadmap outlining the planned development of its distribution pricing over the next 3-5 years.⁹ This roadmap includes the progressive introduction of more cost-reflective pricing structures to provide clear price signals that encourage off-peak energy use.

⁹ <https://www.welectricity.co.nz/disclosures/pricing/future-pricing>

3.7.1.6 Requirements Driven by Local Authorities

WELL must comply with the requirements of the local authorities within its network area. To support this, WELL monitors notified resource consent applications and proposed changes to district plans and provides comments and submissions when required.

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

WELL manages vegetation in the vicinity of its network in accordance with the Electricity (Hazards from Trees) Regulations, recognising that vegetation encroachment can compromise the safe and reliable supply of electricity. These regulations prescribe minimum clearance distances from electrical conductors, and WELL is required to notify tree owners of their obligations regarding the safe management and removal of vegetation. WELL has established a Vegetation Management Agreement with an external service provider to deliver these services across the network.

3.7.2 The Changing Technology Environment

There is a growing interest in consumer energy resources (CER) and in the implications of these technologies for transmission and distribution networks, metering systems, centralised generation, and electricity retailers. CER technologies also create new opportunities for customers, including the potential to participate in emerging markets in which customers may allow their assets to be used to support demand management and network operations.

The continued growth of energy storage, electric vehicles, and market-trading environments is driving the development of increasingly intelligent electrical networks and expanding WELL's ability to influence the timing and location of energy consumption. To manage these changes effectively, greater visibility of energy flows is required, supported by real-time network monitoring and improved digitised data. WELL actively monitors technology trends and adoption rates that are likely to affect the electricity sector, including (but not limited to) the uptake of residential and commercial photovoltaics systems, battery technology, the penetration of electric vehicles in Wellington's vehicle fleet, and emerging technologies used in network monitoring, design, and operation. As these technologies become more affordable, their influence on customer behaviour and network utilisation is expected to increase.

A number of industry-level changes are required to support the efficient integration of these emerging technologies, including:

- New technology standards—the development of standards that enable lower-cost and more efficient integration of new technologies.
- Congestion standards—the establishment of common definitions and mechanisms that allow distribution network congestion to be valued and resolved through market-based solutions.
- Low voltage monitoring—improved monitoring of the low-voltage network, particularly in areas with high CER penetration, where visibility has historically been limited, monitoring and impacts are likely to be most pronounced.
- Efficient pricing signals—the introduction of pricing structures that reflect the benefits and costs of new technologies, while avoiding cross-subsidisation of customers who are unable to install CER

- Consumption and power quality data—agreement on the type, quality, and management of consumption and power quality data required to support safe and efficient low-voltage network operation, including standards for data collection, storage, protection, and use
- Regulatory support—a regulatory framework that provides industry participants with appropriate tools and allowance to implement these changes, including suitable regulatory settings for price-quality regulated businesses.

In parallel with its engagement with industry participants and regulators, WELL continues to learn from sector experience and to trial emerging technologies. WELL considers structured trials to be a prudent and flexible approach to managing the uncertainty associated with technological change, while avoiding the risk of premature or excessive network investment. WELL considers that the deployment of new technologies, combined with close collaboration across the sector, will enable efficient monitoring and management of the low-voltage network and deliver sustainable long-term benefits for New Zealand.

In addition to its active engagement with regulators and industry participants, WELL leverages its position within the CK Infrastructure Holdings Limited group to access global expertise in deploying emerging technologies. This provides WELL with unique access to intellectual property, technical expertise, and proven implementation approaches drawn from its sister companies worldwide. WELL also collaborates closely with peer electricity distribution businesses, technology providers, and other industry participants to incorporate New Zealand-specific experience and insights into CER integration.

3.7.2.1 Electric Vehicles

The increasing availability of affordable electric vehicles could significantly alter electricity demand and supply patterns across the network. Over the longer term, electric vehicle adoption in New Zealand is expected to continue to increase, driven by several key factors, including:

- Electric vehicles lower operating costs than internal combustion engines, reflecting both higher fossil fuel prices and the greater efficiency of battery-based energy conversion.
- New Zealand's high proportion of renewable energy generation, which makes electric vehicles an attractive option for environmentally and cost-conscious customers.
- Ongoing advancements in energy storage systems, electric drive technologies, and charging infrastructure that will continue to improve electric vehicle efficiency, performance, and range.

To support the efficient and secure uptake of electric vehicles, WELL led the EV Connect programme, an industry-wide initiative focused on enabling energy delivery through the existing network. The programme was established to facilitate the adoption of electric vehicles while maintaining network security and reliability. A key outcome of EV Connect was the development of an industry roadmap outlining the actions required of distribution networks to accommodate growing electric-vehicle penetration.¹⁰

3.7.3 The Financial Environment

WELL's financial performance is influenced by the regulatory price-control framework determined by the Commission and by the cost and availability of debt funding from global debt capital markets. In this context, WELL regularly reviews whether prevailing regulatory settings remain appropriate to meet customers' long-

¹⁰ <https://www.wellcity.co.nz/major-projects/innovation-projects/ev-connect>

term needs, balancing the relative simplicity and lower compliance costs of operating under a DPP against the ability to sustainably fund large, lumpy capital programmes under alternative price paths, such as a CPP.

As outlined elsewhere in this AMP, WELL is currently investing above the DPP4 allowances and is actively assessing whether a CPP application is required to support prudent and sustainable investment over the longer term. While this assessment is ongoing, it is clear that continued reliance on DPP4 allowances would place increasing pressure on financial sustainability as asset renewal, reliance, and system growth investment requirements escalate.

Targeted funding for innovation and non-traditional solutions has been available through government initiatives, such as the Low Emission Transport Fund (LETF). In addition, DPP4 includes an allowance equivalent to 0.8% of allowable revenue to partially fund projects that develop or deploy new technologies to reduce long-term costs or improve service quality. WELL expects that application mechanisms under Clause 54Q of Part 4 of the Commerce Act 1986 may also support energy efficiency and innovation by enabling certain technology investments to be accommodated within existing regulatory allowances.

WELL continues to manage its financial performance prudently, prioritising expenditure to areas of highest risk and customer benefit while maintaining reliability and service quality within the price-quality framework. To support delivery of the investment programme set out in this AMP, WELL maintains access to global debt capital markets and appropriate financing facilities, ensuring it is well positioned to respond to both forecast investment needs and emerging system risk.

4 The Future Network

In 2024, WELL updated its long-term network planning to forecast investment in net-zero 2050 electrification, reflecting changing demand patterns, electrification trends, and evolving customer expectations. That analysis confirmed that delivering a reliable and resilient future network would require a material step-up in capital investment as electrification to replace fossil fuels doubles the network demand over time, alongside the ongoing renewal of ageing asset fleets.

In November 2024, the Commission finalised its determination of the Default Price-Quality Path for the period 1 April 2025 to 31 March 2030 (DPP4). The higher starting prices and overall allowance uplift under DPP4 largely reflect CPI outturns exceeding the Commission's 2.2% forecast applied in DPP3 (the period 1 April 2020 to 31 March 2025), rather than a commensurate increase in underlying expenditure allowances. In this respect, the DPP4 price path primarily resets revenues to reflect inflation outcomes relative to earlier forecasts.

Notwithstanding this general uplift, the Commission set WELL's allowances at approximately 40% of the capital expenditure proposed in its 2024 AMP. This leaves WELL materially short of the funding required to deliver its forecast investment programme, including maintaining N-1 security to meet its reliability and service obligations, while incorporating 2050 demand requirements at the time of asset replacement. Under the DPP4 allowances, investment will need to be optimally sized and pragmatically sequenced to follow prevailing demand trends rather than longer-term demand projections.

The DPP4 outcome reflects a broader regulatory emphasis on short-term affordability and economic conditions. In response, WELL has sequenced its investment programme to align with the approved allowances, adopting a more incremental, staged delivery strategy. While this approach remains consistent with maintaining required security and reliability standards, it reduces opportunities to bundle projects efficiently, coordinate reinforcement with asset renewal, and size assets for longer-term demand trajectories.

At the same time, the operating environment remains highly dynamic. Electric-vehicle uptake, public-transport electrification, the pace of the transition away from fossil gas, and the development of flexibility services continue to evolve. These drivers introduce uncertainty into both the timing and scale of demand growth. Combined with long lead times for major subtransmission and zone substation projects, this uncertainty underscores the importance of regulatory flexibility to enable efficient investment sequencing.

Current DPP4 allowances are proving insufficient to accommodate the scale and timing of emerging investment requirements, as evidenced by ongoing expenditure above allowance and the need to progress defined reopener projects. For example, WELL's contribution to supporting the Wellington Metro Rail network upgrades, previously signalled in the 2024 AMP, was excluded from DPP4 allowances and must now be addressed through a price path reopener application.

Accordingly, unlike previous AMPs, this Section no longer presents a 30-year pathway aligned to a fixed decarbonisation timetable. Instead, it provides context for the 10-year planning horizon, explaining the regulatory constraints, demand uncertainty, and investment trade-offs that shape the network development strategy disclosed in this AMP.

4.1 Changes from the 2025 Asset Management Plan

WELL's 2024 AMP sets out the investment required to support full decarbonisation by 2050, based on the information available at the time. This approach prioritised cost-efficient capacity delivery by sizing new assets, typically with expected lives exceeding 45 years, to accommodate forecast demand growth over a 30-year horizon driven by decarbonisation.

Over the past three years, 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 experience is consistent with broader national trends, with businesses identifying the economic downturn, inflation, and labour shortages as key constraints.¹¹ WELL's 2026 AMP, therefore, reflects revised demand forecasts. While the long-term objective of decarbonisation by 2050 remains unchanged, the slower uptake in the early years of the transition has delayed the timing of some network reinforcement investments, with a proportion of the previously planned expenditure now expected to fall beyond the 10-year AMP horizon. Figure 4-1 illustrates the change in demand forecasts between the 2025 and 2026 AMPs.

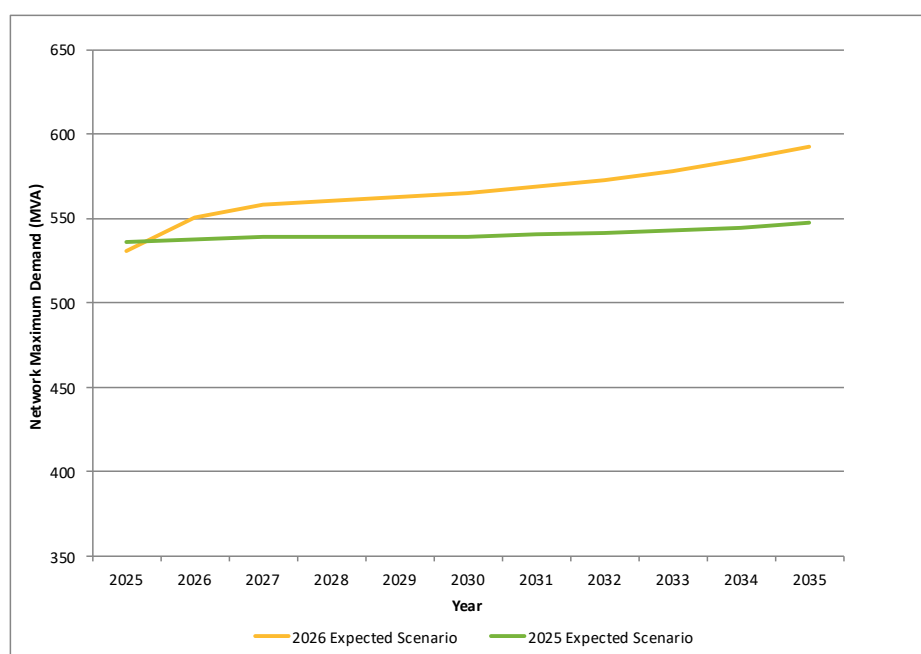


Figure 4-1 Change in WELL's System Demand Forecast between 2025 and 2026 AMPs

The DPP4 capital allowances approved by the Commission materially constrain WELL's ability to deliver the full scope of network investment required to meet forecast demand. As a result, WELL has re-prioritised its programme toward smaller, staged capacity investments that address near-term requirements, with larger reinforcement projects deferred beyond the DPP4 period. This change in WELL's Capex Forecast between 2025 and 2026 AMPs is illustrated in Figure 4-2.

Customer-initiated and other discrete capacity projects cannot be sustainably accommodated within the existing price path without displacing essential asset renewal and quality-of-supply investment. Accordingly, such projects will need to be progressed through price path reopeners or alternative regulatory mechanisms, reinforcing the need for additional expenditure beyond the base DPP4 allowances.

¹¹ World Economic Forum Global Risks Report 2025

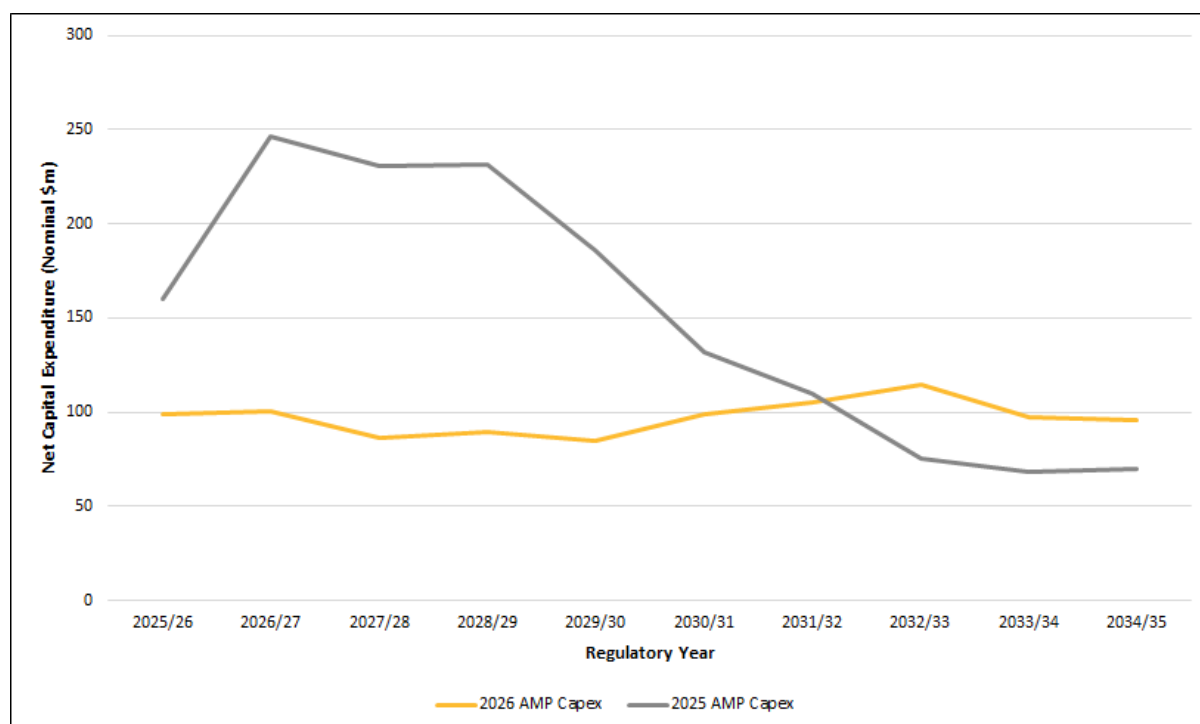


Figure 4-2 Change in WELL's Capex Forecast between 2025 and 2026 AMPs
(Net of Customer Contributions and Excluding Potential Customer-initiated Reopeners)

As a consequence of aligning investment with customer affordability expectations under the regulatory regime, WELL is required to adopt a higher-cost programme over the long term than the more efficient programme that was proposed in the 2024 AMP. In particular, some network capacity will need to be delivered through incremental upgrades over an asset's life, which may result in asset stranding if larger units replace smaller ones before they reach expected tenure, rather than a single, optimally sized investment. In addition, the ability to bundle works into larger, more efficient programmes is reduced. Further details on the nature and cost implications of these changes are provided in Appendix B.

4.1.1 On-going Development and Refinement of the AMP

WELL is making good progress in defining the investment required to build the capability and capacity needed to meet future demand. Forecast models continue to be refined as understanding develops, incorporating insights from innovation projects (discussed in Section 11) and new information on the scale and timing of demand growth.

As a result, readers should expect the forecast disclosures to evolve over time as AMP's processes and assumptions are further developed, tested, and refined. Unlike the historic business-as-usual operating environment, EDBs must continually adapt their investment plans to manage uncertainty, reflecting an improving understanding of how network services are changing, reduced reliance on fossil fuels that shifts energy to growing electrification requirements, and respond to the new capabilities required to support those changes.

4.2 The Drivers of Change

Over the last decade, the Wellington distribution network has operated in a largely business-as-usual environment, characterised by modest growth in new connections, sufficient capacity headroom within existing assets, and a steady asset replacement programme. Previous AMPs have therefore focused on asset health, maintaining existing asset fleets, and preserving the existing quality of supply. Accordingly, the

majority of investments made have been directed toward replacing ageing assets as they reach the end of their useful lives. The supporting regulatory framework has reinforced this approach, emphasising efficiency by setting expenditure allowances and quality targets based on historical performance, and incentivising networks to deliver the same level of service at a lower cost.

WELL uses demand management tools, including ripple control, to manage congestion and capacity constraints as they arise across the network. These tools enable load to be redistributed across Wellington's meshed 11 kV network, and when necessary, allow controlled load reduction during periods of constraint to maintain network performance. As population growth in the Wellington region continues and electrification increases demand, WELL expects to use ripple control in a more sophisticated and proactive manner to help manage emerging capacity constraints while longer-term network solutions are developed.

This approach has enabled WELL to achieve incremental growth and manage short winter demand spikes without incurring the costs of new network capacity, thereby minimising impacts on customer prices and increasing network efficiency and utilisation. CPP funding would support the transition of WELL's ripple control from reactive load shedding toward proactive, targeted demand management, leveraging smart meters as a scalable non-network solution to defer or avoid network investment.

The sustained focus on efficiency has delivered tangible benefits for customers. Wellington customers experience low distribution prices alongside high levels of supply reliability. The benchmarking analysis¹² presented in Figure 4-3 demonstrates that WELL is positioned among the lowest-cost and most reliable EDBs in New Zealand, shown as the yellow diamond in the low SAIDI, low-cost quadrant of the chart, with the other EDBs displayed as grey diamonds. Unfortunately, we now need to enter the cycle to increase infrastructure investment, which is beyond the DPP's "business-as-usual" expenditure premise.

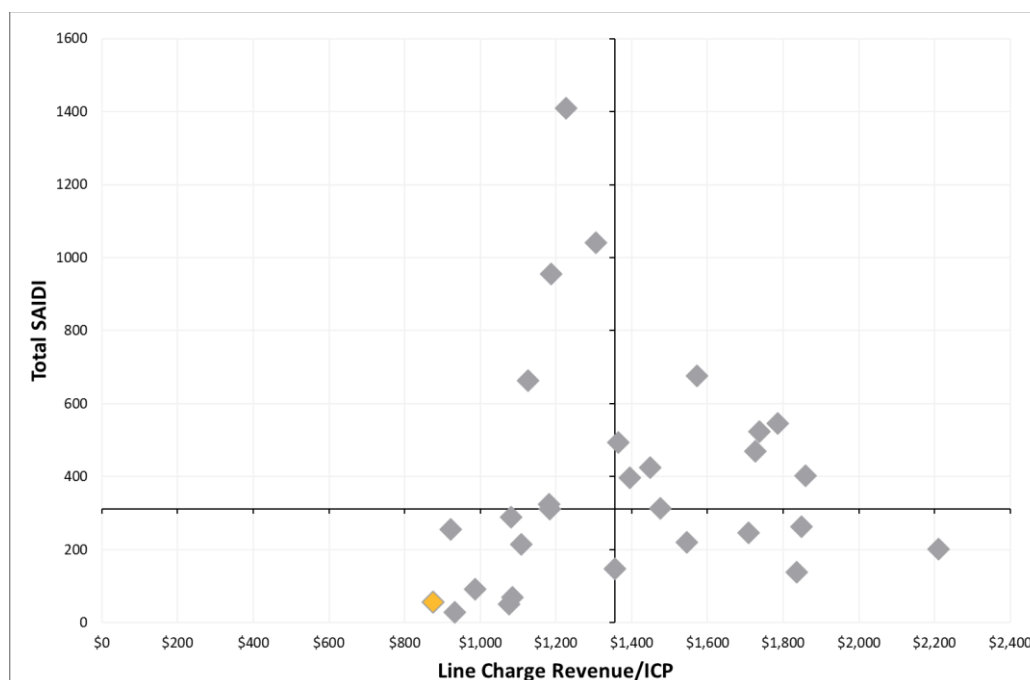


Figure 4-3 Quality vs Price Benchmarking Analysis (2023-2025)

¹² 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 sources of uncertainty in future demand growth on WELL's network relate to the pace and scale of transport electrification, including both private electric vehicles and public transport, and the increasingly unlikely prospect that long-term fossil gas will remain a viable or available energy source beyond 2030 for commercial, industrial, or residential customers.

4.2.1.1 Electric Vehicle Growth

Wellington had experienced a rapid increase in the uptake of electric vehicles in recent years. As of 31 October 2025, the WELL network area includes approximately 260,000 light passenger vehicles, of which around 13,600 are electric or plug-in hybrids.¹³

Growth in the electric light passenger vehicle fleet was relatively steady prior to 2021, before accelerating sharply following the introduction of the Government's Clean Car Discount programme. The subsidy materially reduced the upfront price differential between fossil-fuel and electric vehicles, leading to a significant increase in electric-vehicle registrations between 2021 and 2023. Following the programme's expiry at the end of 2023 and the introduction of Road User Charges, the rate of electric-vehicle uptake declined markedly throughout 2024 and 2025.

The proportion of electric vehicles within the total light passenger vehicle fleet across WELL's network area is shown in Figure 4-4. The impact of the Clean Car Subsidy on electric registrations, highlighting the surge from July 2021 and the subsequent decline following its removal, is illustrated in Figure 4-5.

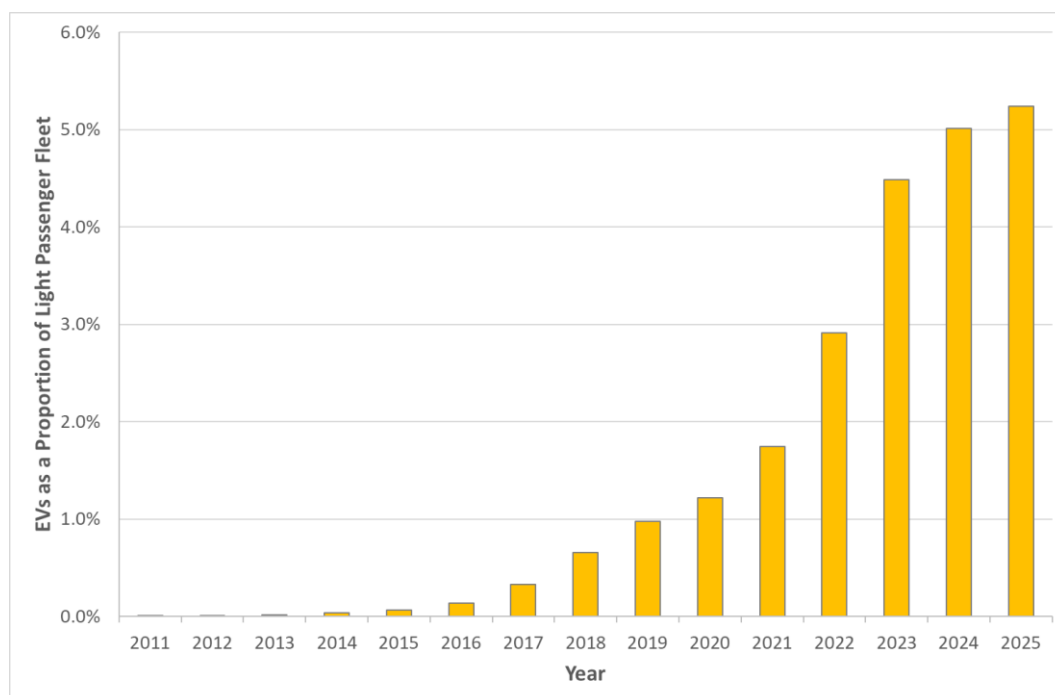


Figure 4-4 EVs as a Proportion of the Light Passenger Fleet in the WELL Network Area

¹³ Waka Kotahi NZ Transport Agency Open Data Portal

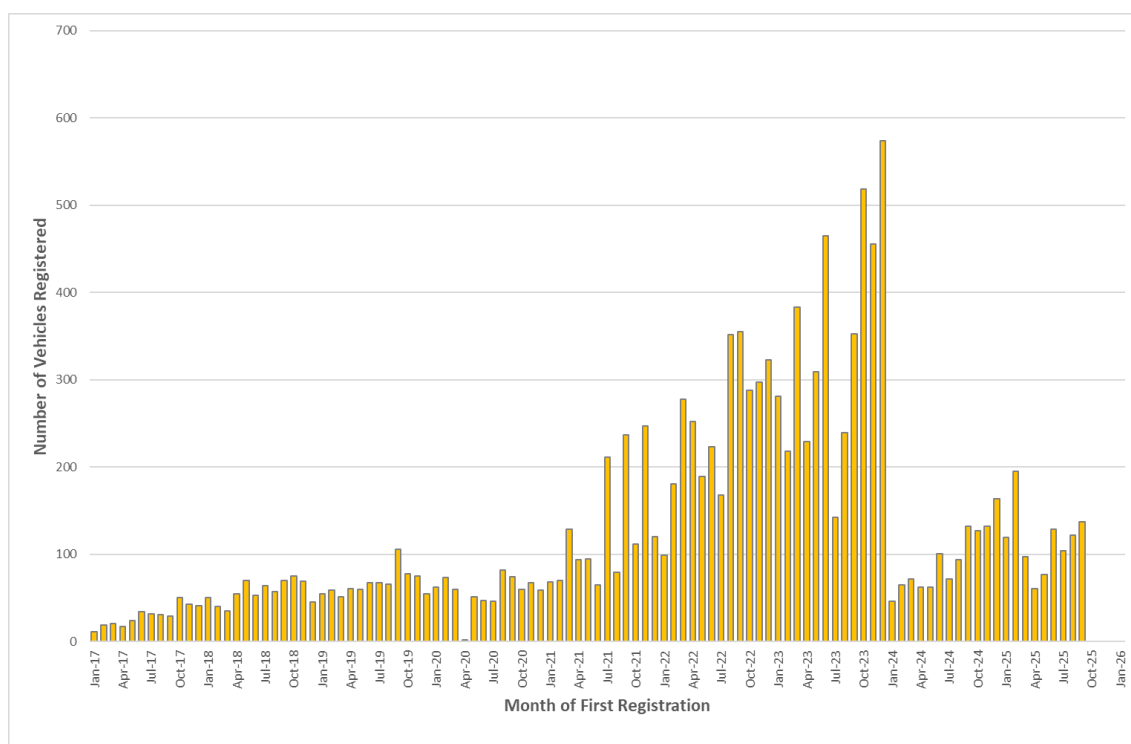


Figure 4-5 Monthly Registrations of EVs and PHEVs in the WELL Network Area

Electric vehicle uptake and its associated impact on electricity demand are subject to considerable uncertainty. Factors such as government subsidies, supply constraints, the pace of technology improvement, customer preferences, and charging behaviours all contribute to variability in both the timing and scale of uptake.

To better understand these dynamics, WELL procured electric vehicle location data from NZTA in early 2024. The data was provided at the Statistical Area (SA2) level, dividing the Greater Wellington region into 174 areas with an average of approximately 1,000 residential dwellings per area. This data was used to develop a heat map of electric vehicle registrations per 100 ICPs, presented in Figure 4-6.

The analysis highlights substantial variation in electric vehicle penetration across the region, ranging from approximately 0.5% of ICPs in areas of high deprivation to around 20% of ICPs in some rural lifestyle suburbs.

While electric vehicle registration provides a useful indication of uptake and the potential scale of network impact, it does not reveal where or how vehicles are being charged. At present, EDBs do not have access to information on private charging locations. This limits networks' ability to accurately forecast and manage congestion on low-voltage networks, where most residential electric vehicle chargers are expected to be connected.

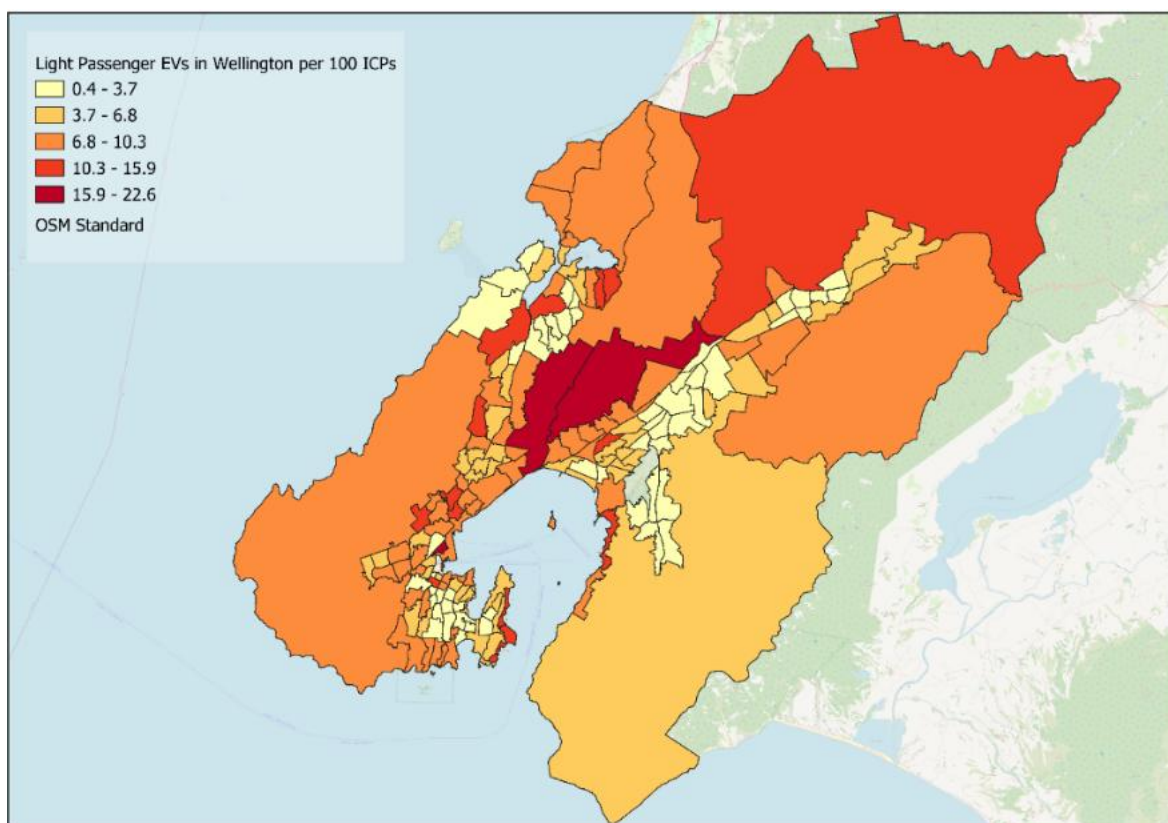


Figure 4-6 Estimated EV Uptake per ICP by Statistical Area as of February 2024

4.2.1.2 Electrified Public Transport

WELL's 2024 demand forecast assumed increased electricity demand arising from the expansion of Wellington's electric rail capacity, the electrification of the regional bus fleet, and the electrification of elements of air transport. These assumptions reflect active discussions at the time between WELL and transport operators regarding support for their decarbonisation programmes.

Over the past 12 months, however, public transport operators have scaled back, deferred, or cancelled several of these initiatives. As a result, WELL cannot reliably predict whether these projects will proceed, nor the timing or magnitude of any resulting impact on network maximum demand. Accordingly, demand associated with these projects has been excluded from our investment forecast in this AMP. If these projects progress, the required expenditure would be sought through a CPP application or, where eligible, through the reopener mechanisms available under the DPP framework.

4.2.1.3 The Impact of Shifting Reticulated Gas use to Electricity

Under the ERP, the central government is expected to develop a transition plan for natural gas. Until this plan is published, the implications for demand on WELL's network remain uncertain. Fossil gas demand may transition to biogas, hydrogen, the electricity network, or a combination of these alternatives.

Gas transition pathway uncertainty

Although the national gas transition work programme increasingly reflects a managed transition rather than an abrupt exit from fossil gas, neither the pace nor the dominant pathway of that transition is yet clear. Current regulatory and industry positions recognise that future gas demand may decline unevenly, influenced by gas supply conditions, appliance replacement cycles, customer economics, and the extent to which

renewable gas alternatives such as biogas or hydrogen become technically and commercially viable. This means the electricity sector cannot assume that fossil gas demand will transfer directly or uniformly onto electricity networks, even though a material shift toward electrification remains a credible medium to long-term demand risk for parts of WELL's network.

A material shift toward electricity would significantly impact WELL's network demand. Approximately 65,000 properties are currently connected to the reticulated natural gas connection,¹⁴ consuming around 3,600 TJ per annum for water heating, space heating, and cooking. These properties represent 35-40% of WELL's residential customer base. Historically, WELL's network has been designed and operated to reflect the widespread use of gas as a residential fuel, with gas-heated dwellings typically exhibiting a very low after-diversity maximum demand (ADMD).

Customer fuel-switching behaviour

Regardless of government policy, it is likely that some customers will choose to transition away from gas, driven by increasing gas costs resulting from tightening gas conditions¹⁵ as well as higher fixed daily charges, resulting from the Commission allowing accelerated depreciation of gas networks. However, current market feedback indicates that widespread fuel switching from gas to electricity driven by price is not yet occurring. Instead, changes in energy choices are more commonly associated with end-of-life appliance replacement or new builds. Industry feedback also suggests that a growing share of new homes are installing LPG systems, while many customers replacing gas hot water systems at the end-of-life are choosing heat pump hot water cylinders. As a result, the pace of any broader transition away from gas is likely to be gradual and primarily constrained by appliance replacement cycles and customers' willingness and ability to invest in alternative technologies, even if gas prices increase materially over time.

Network demand implications

Any large-scale transition from gas will inevitably increase WELL's winter peak demand. While increased electric water heating can be partially managed through an extension of EDBs' ripple control capabilities (see Section 4.2.2.1), where electricity retailers participate, this approach gives their customers greater flexibility to participate in demand management by shifting hot water heating outside peak periods, reducing peak-driven network investment while maintaining expected service outcomes.

There may also be an efficient role for appropriate and targeted cross-subsidisation of controllable hot water load, such as contributions toward heat-pump hot water systems where these deliver peak-demand reduction comparable to ripple control, where the cost is lower than alternative network or ripple-plant augmentation and benefits are shared across network users. Implementation of such arrangements would require retailer participation on behalf of customers, including enrolment, control enablement, and ongoing demand-response delivery.

Cooking and space-heating loads are additional non-discretionary loads that contribute directly to the evening peak. Highlighting more broadly that the pace, scale, and composition of electrification-driven demand growth, together with customers' hot water and appliance choices, fuel-switching decisions, and behavioural responses, introduce significant uncertainty as to how peak demand will evolve across the network.

¹⁴ PowerCo 2025 Gas Asset Management Plan, Appendix 6.

¹⁵ <https://www.mbie.govt.nz/about/news/gas-production-forecast-to-fall-below-demand>

Case Study 1 – The Impact of Electric Vehicles and the Gas Transition on the Low-Voltage Network

The electrification of transport and the transition from gas to electricity for residential space and water heating are expected to materially increase demand on WELL's low-voltage network, primarily through higher load from existing customer connections rather than new connections. To better understand the scale and timing of these impacts, WELL has commissioned ANSA to develop a low-voltage forecasting tool focused on residential low-voltage networks.

The purpose of the tool is to assess how different asset utilisation and constraint risk across individual low-voltage networks. For each network, the model estimates the proportion of assets, distribution transformers, low-voltage underground cables, and low-voltage overhead lines, that are likely to become constrained across a range of electric-vehicle (EV) uptake and gas-to-electricity transition scenarios. Using asset-specific upgrade costs, the model then converts these constraint outcomes into forecast LV reinforcement capital expenditure by regulatory period, based on a defined constraint risk threshold.

The resulting low-voltage reinforcement capital expenditure forecasts are presented in Table 4-1. The table compares the cumulative low-voltage reinforcement expenditure required to address low-voltage constraints through 2050 across a selection of growth scenarios, and includes the impact of the 2025 increase in the allowable voltage range from $\pm 6\%$ to $\pm 10\%$. These scenarios combine varying rates of electric-vehicle uptake and residential gas electrification, including one in which rapid electric-vehicle uptake is accompanied by EDB price structures that successfully incentivise charging outside network peak-demand periods.

		EV Uptake Rate		
		Slow	Rapid	Rapid with Flex
Gas Transition	None	\$34m	\$129m	\$26m
	Rapid	\$47m	\$146m	\$31m

Table 4-1 Cumulative LV Reinforcement Capex to 2050 by Growth Scenario

The results highlight the scale of future low-voltage investment Capex required to manage congestion under different decarbonisation pathways. They also demonstrate the potential for significant cost reductions where cost-reflective pricing signals encourage customers to shift discretionary demand, particularly electric vehicle charging, away from peak periods. Importantly, the modelling shows that when pricing signals influence consumption patterns in one category of demand, this can create capacity headroom that reduces the network impact, and associated costs, of electrification in other end uses.

The ANSA study is discussed in more detail in Section 11.2.2.3.

In addition to the high prevalence of gas as a residential fuel, the Wellington region also includes numerous large commercial and industrial gas users. To support planning for a potential transition to alternative energy

sources, including electricity, DETA has surveyed major gas consumers across the Wellington network. Responses to this survey indicate that approximately 90 MW of existing gas load could, if electrified, translate into up to 40 MW of additional electricity demand.

WELL is supporting further analysis through EECA's Regional Energy Transition Accelerator (RETA) programme to improve understanding of the costs and practicalities of gas users' transitioning to alternative fuels. However, this analysis must be undertaken with care. High-level or externally led assessments may not fully account for the requirements for electricity networks to maintain spare capacity to meet operational and contingency needs for supply security and reliability (Quality regulation penalty avoidance), potentially resulting in an understatement of the network investment required to support electrification at scale.

While WELL supports the continued use of gas as a transition fuel, we are losing confidence that this has been adequately planned or supported. Ongoing utilisation of existing gas transmission and distribution infrastructure helps maximise the value of these assets for the community, while deferring some of the electricity network reinforcement that would otherwise be required to electrify heating for a significant proportion of WELL's customer base.

4.2.2 Consumer Energy Resources and Flexibility Services

CERs are customer-owned devices that generate, store, or actively manage electricity consumption. These assets are purchased by customers and connected within homes and businesses. A common example of CER is smart, web-enabled electric vehicle chargers. When enabled, electric vehicle charging can be remotely managed, with the customer's agreement, to defer charging to periods of lower electricity prices, delivering cost savings without requiring active customer intervention.

In the near term, gas water heating will be replaced by electric units, which may also be considered CER if they are storage or managed-demand appliances.

The electricity sector has identified flexibility services as a critical enabler of New Zealand's Emissions reduction objectives. Key policy and strategic documents, including the October 2024 Government Policy Statement on Electricity, the 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 play in managing demand and supply uncertainty, while moderating customer bill increases.

Despite this recognised potential, a flexible service based on smart, connected, and actively managed CER remains at an early stage of development. Industry-wide solutions capable of delivering the scale required to materially offset traditional network investment have yet to emerge. There remains uncertainty regarding the reliability of flexibility services as a substitute for conventional capacity, the speed at which they can scale, and their availability at the times and locations where network support is required. While the long-term value proposition is widely acknowledged, further capability development and operational experience are required before the expected benefits can be relied upon with confidence.

Case Study 2 – Managing Aggregated Demand

Figure 4-7 presents a simplified example illustrating why the use of large CER on the low-voltage network must be actively coordinated. The example considers a representative low-voltage network supplied by a 300 kVA distribution transformer, assuming that 30% of connected households have installed large electric vehicle chargers. If these electric vehicle chargers operate simultaneously during periods when the LV network is already heavily loaded, the combined demand can exceed the transformer's thermal and voltage limits. This would increase the risk of outages or unacceptable voltage levels for customers and, if unmanaged, would require the EDB to invest in upgrading the transformer to restore compliance with network performance standards.

By contrast, when large EV chargers are smart-enabled and their operations are coordinated, aggregate charging demand can be managed to remain within the existing transformer's operating limits. This allows EVs to be charged in a way that meets customer needs while using spare capacity on existing assets, without adversely affecting other customers' supply. In doing so, coordinated charging can defer or avoid network reinforcement, creating a cost benefit that is shared across all customers.

However, this outcome is dependent on coordination being consistently effective. Aggregated demand must remain within network limits for each peak demand period over the asset's remaining life. Any failure of coordination that results in demand exceeding asset capacity can lead to thermal overloading, accelerated asset degradation, or outages. Where an EDB relies on third-party control arrangements to manage demand, it may be exposed to reduced power quality, unplanned costs, and potential regulatory or statutory liabilities arising from actions beyond its direct operational control.



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

Accordingly, before flexibility services based on coordinated CER can be relied upon as a substitute for traditional capacity investment, EDBs must have a very high degree of confidence in the predictability, reliability, and enforceability of the third-party control mechanism.

Initial progress has largely been led by electricity retailers, though this activity has typically occurred among smaller retailers that lack the geographic concentration needed to materially assist EDBs in managing localised network constraints. As flexible services rely on aggregating customer-owned assets, the pace at which flexible demand can scale is fundamentally dependent on customer investment and participation decisions. Recent slowdowns in EV uptake and distributed generation connections (both less than 3%

adoption at the ICP level on the Wellington network) highlight that the availability of flexibility services cannot be assumed, and that EDBs must remain cautious about relying solely on flexibility to address future network constraints.

4.2.2.1 Extending Hot Water Control

Transitioning the approximately 65,000 gas connections used for hot water heating, space heating, and cooking in the Wellington region, a large-scale transition of gas load to electricity would result in a material increase in peak demand on the electricity distribution network. EECA may have a role in promoting or price equalising the cost of a 0.5kW heat pump HW cylinder against a traditional 3kW element HWC. The 80% reduction in demand will benefit consumers materially by deferring network investment during a gas transition. To manage this transition in a timely, coordinated, and cost-effective manner, EDBs will need to extend their existing hot water ripple control systems to capture new electric hot water load as gas appliances are replaced.

Extending ripple control capability will require:

- Additional funding to increase the capacity of EDBs' ripple plants.
- Priority access for EDBs to meter-controlled hot water for system security purposes, including load shedding in response to a Network Emergency declared by the EDB or Grid Emergency declared by the System Operator.
- Supportive policy setting to ensure that new electric hot water installations are connected to ripple control, recognising that ripple control remains the fastest, most resilient, and most reliable technology available for the rapid shedding of hot water load during emergency conditions.

Without these extensions, networks may be unable to maintain system stability during the interim period before sufficient network capacity can be built within approved regulatory allowances. While decentralised retailer-led control of hot water load is emerging, it remains uncertain whether such arrangements can deliver the level of coordination, equity, and consistency required to reliably keep demand within network voltage and current limits, particularly during peak demand periods.

EDBs are directly accountable for power quality and supply obligations under the Commerce Act, the Consumer Guarantees Act, and Electricity (Safety) Regulations, but do not benefit from the protections afforded to the transmission grid under the Code. As a result, retaining direct control of hot water load through EDB-operated ripple control systems during peak demand periods is likely to remain essential for EDBs to meet their regulatory responsibilities while managing the transition from gas to electricity.

4.2.2.2 Supporting Regulatory Framework and Hierarchy of Needs

Careful planning is required to design a regulatory framework that ensures flexibility services are available whenever they are needed to maintain network security, both by electricity distribution businesses (EDBs) and by the System Operator. In the first instance, flexibility services must be contracted to be available during emergency conditions, where direct intervention is required to maintain supply and protect system security. Once the distribution network and grid are operating stably, flexibility services should be able to operate where they deliver the greatest value to customers, subject to constraints that ensure that they do not adversely affect other customers' power quality.

In practice, this points to the development of a flexibility market that allocates services to their highest-value use, based on willingness to pay, while operating within guardrails defined by the physical limits of the distribution network, including current and voltage constraints. Such a market would also require prioritisation rules to ensure that networks retain access to flexibility services during emergency events. The existing regulatory framework governing service provision between EDBs and retailers provides a useful precedent. Under the Default Distribution Agreement (DDA), parties other than EDBs may provide load-control services on the distribution network but must make those services available to EDBs and the System during emergencies. Similar obligations could be extended to flexibility service providers that are not retailers.

The market arrangements used to manage constraints on the New Zealand transmission grid also provide a template for how flexibility services could operate within distribution networks. Under such an approach, an EDB would signal the value/cost of relieving/not relieving local network constraints through mechanisms such as operating envelopes, peak-demand price signals, or capacity-based pricing, while retailers optimise their portfolios of load, generation, and storage to respond at least-cost. This would both clear the constraint and provide the EDB with a transparent economic signal on whether traditional network investment represents the more efficient long-term solution.

EDB's shifting demand at peak also changes the generation stack and retail energy price. However, these avoided revenues are not currently available for flexibility payments, as the market is not aligned with this mechanism.

Flexibility services based on customer-owned devices connected to distribution networks may also be dispatched by parties outside the distribution network, such as the System Operator, to manage grid-level security. In these circumstances, careful coordination is required to manage interactions between grid-level services and the obligations EDBs must meet under the Code. For example, Automatic Under Frequency Load Shedding (AUFLS) may disconnect distribution load to support system frequency, which could inadvertently interrupt virtual power plants or demand-side services that have been separately contracted by the System Operator.

EDBs must therefore retain the ability to ensure that third-party CER operations remain within the distribution network's operating limits. EDBs are directly accountable for power quality and network performance and face material financial and legal consequences for non-compliance, including significant penalties for quality breaches and liability for damage to customer appliances. To continue meeting these regulatory obligations, EDBs require visibility into how third-party-controlled devices are contracted for or operating on their networks, as well as the ability to apply corrective measures or penalties when third-party actions adversely affect the network's safe and reliable operation.

4.2.3 Changing Customer Expectations

Emerging technologies are providing customers with new capabilities and choices, fundamentally changing how electricity is used and managed. Table 4-2 summarises the resulting changes in customer requirements and the associated impacts on the distribution network.

New Customer Requirement	Impact on Network	Potential Network Investment
New large appliances, such as electric vehicle chargers.	Residential ADMD is exceeding the low-voltage network's capacity.	Reinforcement of the low-voltage network. Increasing distribution transformer sizes. 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 who want to share the spare electricity they have stored or generated.	Two-way power flows on the low-voltage network. Voltage profiles are becoming less predictable.	Increased visibility and control of the low-voltage network.

Table 4-2 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. In particular, the replacement of underground cables and power transformers has commenced and is expected to continue over the next 25 years. Together, the renewal of these two asset fleets is a step change in the scale and timing of the replacement programme.

There are strong synergies between asset renewal and network reinforcement, as many assets nearing the end of their useful lives may also require additional capacity. In the 2024 AMP, capacity constraints were typically the primary investment trigger, with asset replacements brought forward to align with anticipated growth associated with the ERP. Under the revised demand forecasts presented in the 2025 AMP and this AMP, these capacity trigger points are now expected to occur later than previously assumed, allowing asset replacement by age to be ahead of capacity requirements.

While these synergies remain, the sequencing of investment will differ in some cases. For certain assets, the primary trigger for replacement will now be asset condition and end-of-life considerations, rather than an immediate requirement for additional capacity.

The convergence of asset renewal and capacity reinforcement requirements represents a material shift in the scale and coordination of investment required over the coming decade. Efficient delivery increasingly depends on aligning end-of-life replacement with capacity upgrades when these drivers coincide, thereby minimising duplication of work, reducing disruption, and improving whole-of-life efficiency.

The smoothing and fixed-allowance structure inherent in the DPP limits the flexibility to efficiently sequence these coordinated investments, thereby increasing the risk of staged upgrades, fragmented delivery, or deferral beyond the economically optimal timing. In this context, a CPP is likely to better align revenue allowances with the efficient timing of combined renewal and reinforcement activities, supporting prudent risk management, whole-of-life efficiency, and the delivery of long-term benefits to consumers while maintaining required safety and reliability standards.

4.3 Subtransmission Investment Programme

WELL's 33 kV subtransmission network and zone substations are critical to meeting customers' future electricity needs. Over the next 10 years, planned investment in these assets will bring together multiple workstreams into a single, coordinated programme.

The objectives of this programme are to:

- Ensure the ongoing safety of network assets for the public and workers.
- Incrementally increase network capacity to support growth and decarbonisation at a pace that remains affordable for customers.
- Maintain network quality at a level that aligns with customer expectations and willingness to pay.
- Reduce resilience risks associated with earthquakes and a changing climate.

Figure 4-8 provides a high-level overview of WELL's zone substations and 33 kV network, illustrating how asset condition, capacity, resilience, and criticality are driving investment decisions over the next 10 years and Table 4-3 sets out the definitions for the site ratings.

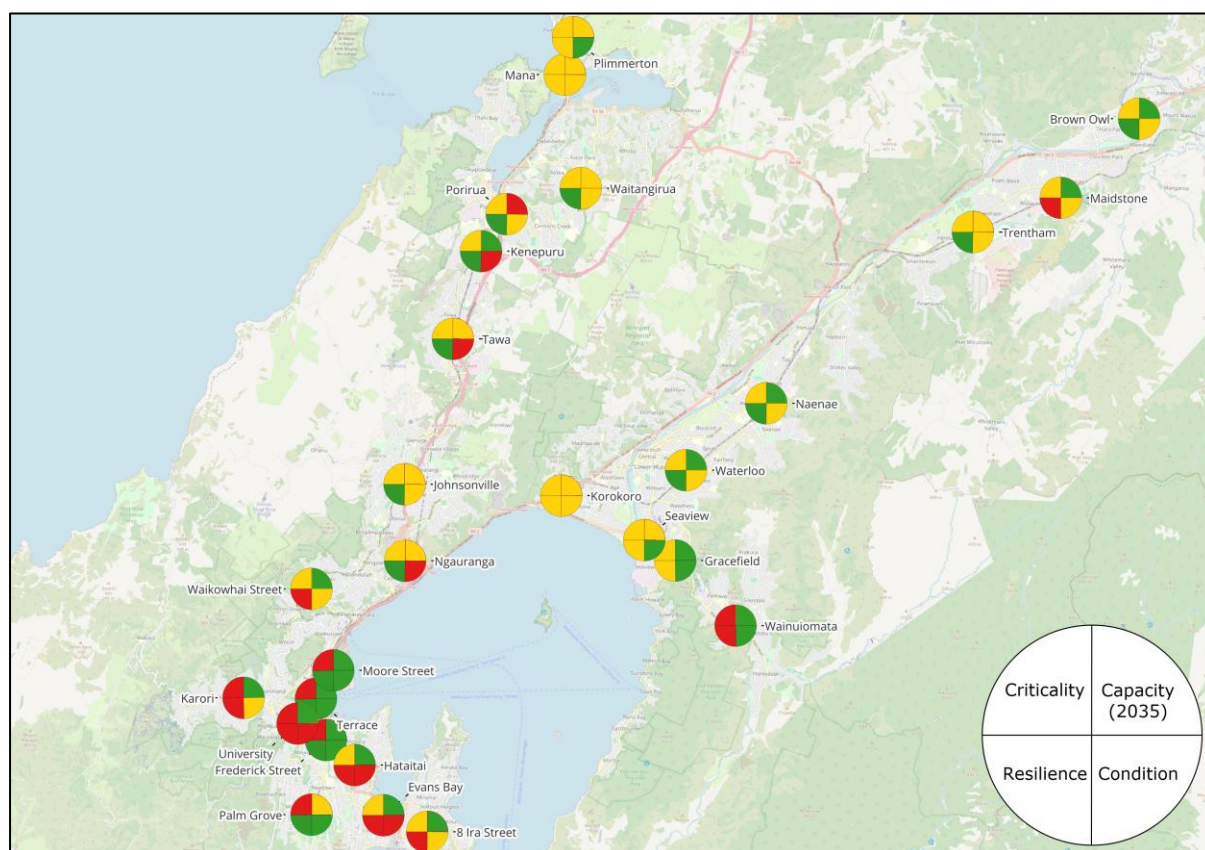


Figure 4-8 WELL's Subtransmission and Zone Substation Planning Statuses

Aspect	Red Rating	Orange Rating	Green Rating
Capacity (Section 9.6)	2035 Maximum Demand exceeding present N-1 capacity and outside the 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 the present N-1 capacity.
Condition (Section 8.3)	33 kV cable or power transformer Asset Health Index 2 or less.	33 kV cable or power transformer; AHI between 2 and 3. ¹⁶	33 kV cable or power transformer AHI 3 or greater.
Resilience (Section 12)	Gas-filled 33 kV cables (Section 12.5.2). Located at the network edge with limited 11 kV interconnectivity.	Located within a tsunami evacuation zone.	All other zone substations.
Criticality (Section 8.3)	Supplying a major hospital. Supplying Wellington CBD. Potential N-2 Extreme Outage (Section 7.1.1).	All other zone substations.	-

Table 4-3 Ratings for Consolidated View

Table 4-4 summarises the issues identified in Figure 4-8, the corresponding solutions, and references to the relevant sections of this Plan.

Zone Substation	Rating	Key Issues	10-year Plan	Timeframe	2026 AMP Reference
8 Ira Street		Resilience (Gas Cables)	Replacement of 33 kV gas cable sections between the Evans Bay 33 kV bus and Ira Street	2031	9.8.2.2 12.5.2
Brown Owl		33 kV Fluid Cables	-	-	9.13.2.1
Evans Bay		33 kV Cable Condition Resilience (Gas Cables)	Replacement of 33 kV gas cable sections between the Hataitai 33kV bus and Evans Bay	2030	9.8.2.6 12.5.2
Frederick Street		Criticality (CBD)	Improved 11 kV ties to allow offload to adjacent zone substations	2029	9.8.2.3
Gracefield		Resilience (Tsunami Zone)	-	-	12.4.2.2
Hataitai		33 kV Cable Condition Resilience (Gas Cables)	Repaired and being monitored New 33 kV bus at Hataitai. Replacement of 33 kV cables between Central Park and Hataitai, aligned with State Highway 1 projects	2030 2032	8.5.3 9.8.2.7 12.5.2
Johnsonville		33 kV Fluid Cables Capacity	Develop a new zone substation in Grenada to offload Johnsonville and Ngauranga	2028	9.10.2.1
Karori		Resilience (Gas Cables, Network Edge)	Reinforce 11 kV ties between the University and Karori Replace 33 kV gas cables	2027 2033	8.5.3 9.9.2.1 12.5.2
Kenepuru		Transformer Condition	Replace power transformers	2028	8.5.2.8
Korokoro		Resilience (Tsunami Zone)	-	-	9.12.2.1

¹⁶ 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	2026 AMP Reference
Maidstone		Gas Cable Condition Resilience (Gas Cables)	Replace 33 kV gas cables	2030	8.5.3 12.5.2
Mana		Capacity Resilience (Tsunami Zone)	Reinforce 11 kV ties south of Mana	2027	9.11.2.1
		Transformer Condition	Replace the power transformer	2030	8.5.2.8
Moore Street		Criticality (CBD)	Ongoing demand and asset condition monitoring	-	9.9.2.2
Naenae		33 kV Fluid Cables	Reinforce 11 kV ties to adjacent substations	2027	9.12.2.6
Ngauranga		Capacity Transformer Condition	Replace power transformers	2028	9.10.2.2 8.5.2.8
Palm Grove		Capacity Criticality (Hospitals)	Solution pending customer decision. Ongoing demand and asset condition monitoring	-	9.8.2.1
Porirua		Capacity	New 11 kV feeders from Kenepuru to increase transfer to Kenepuru	2026	9.11.2.2
			Replace 33 kV fluid cables, power transformers and 11 kV switchgear	2030	
Seaview		Resilience (Tsunami Zone)	-	-	9.12.2.2
Tawa		33 kV Cable Condition	Repaired and being monitored	-	8.5.1 9.10.2.3
The Terrace		Criticality (CBD)	Ongoing demand and asset condition monitoring	-	9.8.2.8
Trentham		Capacity	Replace 33 kV fluid cables	2027	9.13.2.4
University		33kV Cable Condition Resilience (Gas Cables) Criticality (CBD)	Replace 33 kV cables	2027	8.5.1
			Reinforce 11 kV ties between the University and Karori	2032	9.8.2.5 12.5.2
Waikowhai		Resilience (Gas Cables)	Replace 33 kV gas cables	2037	9.9.2.39.9.2.3 12.5.2
Wainuiomata		Resilience (Network Edge)	Reinforcement of 11 kV feeders from Gracefield to increase transfer to Wainuiomata	2031	9.12.2.7
Waitangirua		Capacity	Reinforcement of 11 kV feeders to increase transfer to Porirua and Mana	2027	9.11.2.5
Waterloo		Fluid Cable Condition	Reinforce 11 kV ties to adjacent substations	2027	9.12.2.3
			Replace 33 kV fluid cables	2035	8.5.1

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

The coordination challenges and efficiencies described above reflect a broader, system-level shift in how essential infrastructure must now be delivered across New Zealand. Electricity, water, transport, and telecommunications networks are increasingly being invested in concurrently to support growth, resilience, and decarbonisation. Efficient outcomes, therefore, depend not only on individual asset decisions but on the ability of infrastructure providers to align planning horizons, funding cycles, and delivery schedules.

However, where regulatory funding settings are fixed within defined five-year blocks, opportunities for coordinated delivery across infrastructure sectors may be constrained, particularly where partner organisations operate under different regulatory or fiscal frameworks. In this context, a CPP is likely to provide greater flexibility to align revenue allowances with the efficient coordination of investment timing, supporting whole-of-life efficiency, prudent risk management, and improved long-term outcomes for consumers across interconnected infrastructure systems.

4.4 Demand Uncertainty

EDBs will need to invest in additional network capacity to support the 2050 emissions reduction targets. However, there remains significant uncertainty about both the rate of demand growth and the sequence of new capacity requirements. As demand is the primary determinant of the timing of reinforcement programmes, this uncertainty will necessitate ongoing adjustment to the sequencing and prioritisation of investment. In some cases, WELL will be unable to connect new demand until capacity investment is completed under the current incremental investment approach. The 2024 AMP approach brought capacity investment earlier so new demand could be readily accommodated. This is the trade-off made in the DPP4 decision from the Commission.

The key sources of demand uncertainty, and the resulting need to re-sequence work programmes, include:

- The pace of transition away from fossil gas—the electricity system is expected to supply some or all of the energy use currently provided by natural gas, but the timing and extent of this transition remain uncertain.
- The development of flexibility services—is dependent on a functioning market; the market's ability to scale sufficiently to support reliability and efficient asset utilisation remains largely academic and is unproven. If the market does not mature as anticipated, additional network capacity will be required to maintain service standards.
- Electric vehicle uptake rates—though electric vehicle adoption has exceeded the assumptions in the 2022 ERP, uptake has slowed following changes in government policy. Case Study 3 examines the implications of this uncertainty for demand forecasts.
- The location of demand growth—many EDBs have limited visibility of low-voltage demand growth, including where customers are charging electric vehicles or electrifying appliances. While customers are required to connect distributed generation, there is currently no equivalent requirement to notify the EDBs of the installation of large electric vehicle chargers or household battery systems.

Case Study 3 – The Uncertainty in Electric Vehicle Uptake Forecasts

Electric vehicle uptake is influenced by a range of interrelated factors, including government subsidy, vehicle affordability, and manufacturers' ability to supply vehicles in sufficient volumes. Changes in any of these drivers can materially affect the rate of adoption of electric vehicles and, in turn, the timing and scale of electricity demand growth on the distribution network.

EECA's 2019 electric vehicle growth scenarios illustrate this uncertainty by modelling different uptake trajectories based on the speed at which EVs achieve price parity with internal combustion engine vehicles. The timing of price parity is, in turn, affected by factors such as technology and production costs, government subsidies, and other policy incentives. Figure 4-9 presents these EECA scenarios, overlaid with actual EV fleet data from 2021 to 2025, to provide context on how realised uptake compares with earlier expectations.

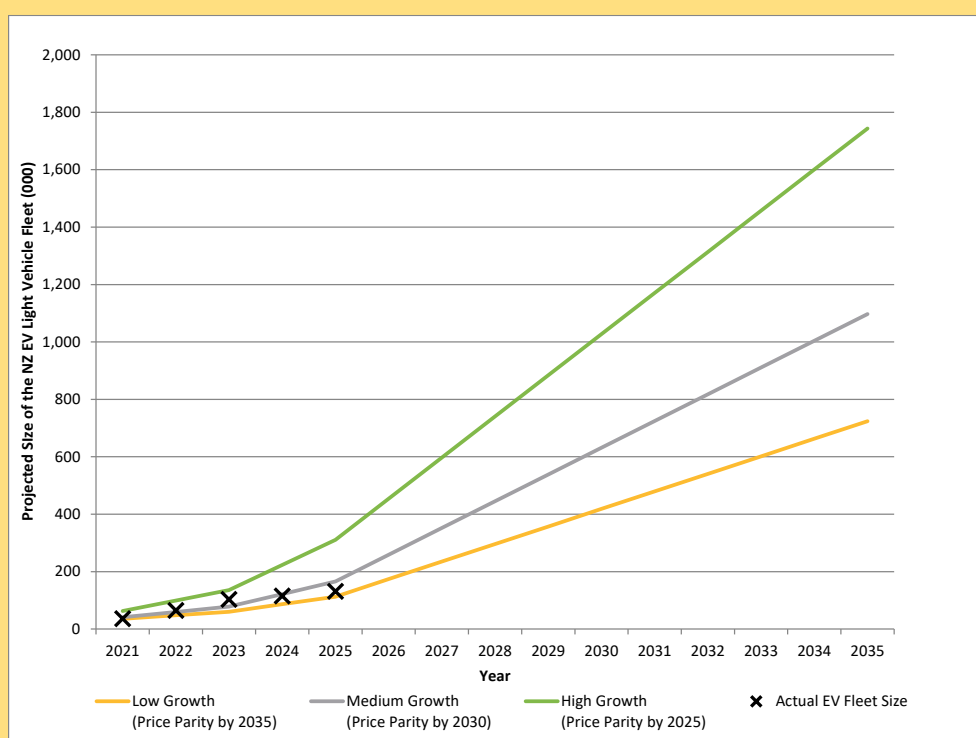


Figure 4-9 EECA's New Zealand EV Uptake Scenarios (2019)

4.4.1 The Impact of Demand Uncertainty

Forecast demand is the primary driver of the timing of new network capacity investment. Rapid demand requires EDBs to bring forward network reinforcement programmes, while slower demand growth allows investment to be deferred.

As demand patterns become more volatile, determining when and where new capacity is required will become increasingly complex. EDBs will no longer be able to closely align capacity with demand as they have historically. Some drivers of electrification may lead to rapid, unanticipated increases in load during a regulatory period, requiring networks to adjust investment plans quickly. For example, a rapid exit from fossil

gas could introduce significant new electricity demand before regulatory allowances can respond. Other drivers may evolve more gradually, reducing the immediacy of investment re-profiling.

To manage this uncertainty, EDBs will need the ability to actively re-sequence work programmes in response to changing demand growth rates. This will require ongoing refinement of demand forecasting models and adoption of more flexible planning processes, ensuring that capacity is delivered ahead of demand while maintaining supply security. In re-sequencing their programmes to manage volatile and potentially rapid demand growth, EDBs will need to consider:

- Long lead times for major projects—large subtransmission investments can have lead times of up to three years. The work programme, therefore, allows faster-than-expected growth within the build window, with sufficient capacity buffers to accommodate high-growth scenarios.
- Ability of delivery resources—the timing of network investment may also be constrained by the availability of skilled labour, materials, and specialist contractors. If multiple EDBs and other infrastructure providers are investing concurrently, both locally and internationally, resource shortages may intensify. Investment forecasting must therefore account for both demand uncertainty and delivery constraints.

Effective management of these challenges will require regulatory mechanisms that provide greater flexibility to align funding with investment timing. The current regulatory framework provides allowances in five-year blocks, based on an assumption that demand growth is relatively predictable, i.e., that the past is a good predictor of the future. While some flexibility exists through mechanisms that allow additional allowances for unforeseen large customer projects, access to these allowances is limited, and the approval process can be lengthy.

WELL considers that increased regulatory flexibility is required to enable efficient re-sequencing of investment programmes across regulatory periods. Given that major subtransmission upgrades typically have design and construction cycles of 3 to 4 years, relatively rigid 5-year regulatory funding periods may no longer be fit for purpose. Longer planning horizons, or mechanisms that allow work programmes to be re-ordered between regulatory periods, may be required to better align expenditure with evolving demand.

4.4.2 Regulatory Implications of Demand Uncertainty

The demand uncertainty described above has implications not only for forecasting accuracy, but also for the efficiency of regulatory funding settings. Historically, network investment could be sequenced with a high degree of confidence that demand growth would follow relatively stable trends. Under those conditions, five-year regulatory allowances aligned reasonably well with investment planning cycles.

The current environment differs materially. Demand growth is increasingly influenced by policy settings, customer behaviour, the uptake of electrification, and the uncertain development of flexibility services. These drivers can result in step changes in load within a regulatory period or, conversely, slower-than-expected uptake that shifts reinforcement triggers beyond the current planning window. Major subtransmission and zone substation projects require multi-year lead times for design, consenting, procurement, and construction. Efficient delivery, therefore, depends on the ability to bring forward or defer investment as uncertainty resolves.

While the existing DPP framework provides limited mechanisms to address discrete, unforeseen customer projects, it does not readily accommodate systemic volatility in demand growth across multiple locations and asset classes. Increasing reliance on reopeners or incremental project staging may reduce short-term expenditure pressures but can increase long-term costs and reduce opportunities for coordinated delivery. In this context, greater regulatory flexibility may be required to enable efficient re-sequencing of network investment programmes as demand trajectories evolve. A CPP is likely to provide a more durable mechanism to align revenue allowances with efficient investment timing under uncertainty, while maintaining incentives for cost control and service performance.

4.4.3 Increasing Costs

WELL has experienced cost inflation that exceeds the general national inflation and expects this trend to continue as electricity sector work programmes expand and the availability of specialised equipment and skilled labour becomes increasingly more constrained.

In parallel, significant investment is expected in replacing New Zealand's ageing water infrastructure, which will further intensify competition for civil construction resources and place additional upward pressure on costs.

Figure 4-10 illustrates changes in key electricity industry costs since 2013 relative to movement in CPI.

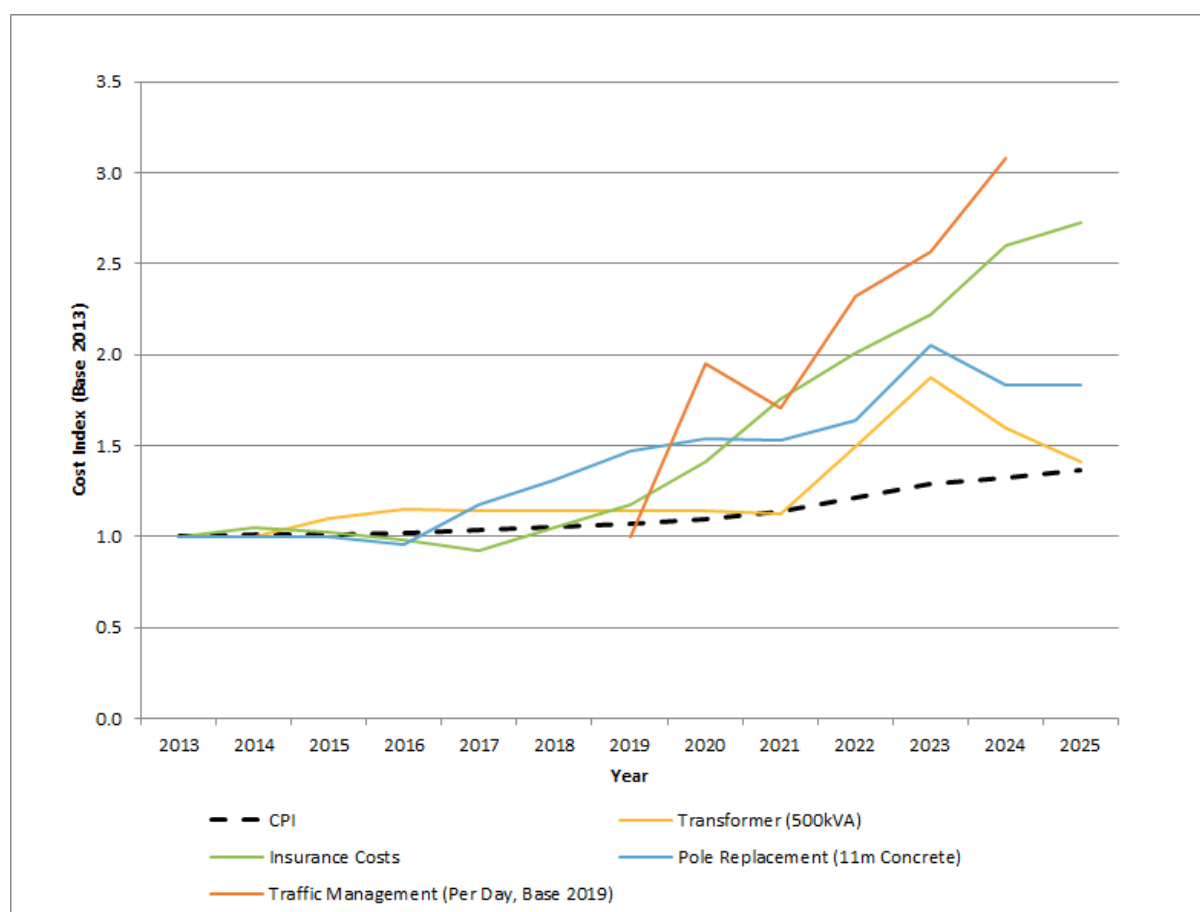


Figure 4-10 Examples of Cost Escalations Relative to CPI

4.4.4 Resource and Materials Scarcity

The Boston Consulting Group's *'The Future is Electric'* estimates that electricity networks, across both transmission and distribution, will need to invest approximately \$100 billion to provide New Zealand with access to the renewable energy required to decarbonise. This investment will occur alongside parallel decarbonisation programmes internationally and the replacement of other ageing domestic infrastructure, including water networks.

This step change in infrastructure investment is expected to place significant pressure on the availability of both materials and skilled labour in a tight post-COVID market. While acute pandemic-related disruptions have eased, structural workforce constraints, competing national infrastructure programmes, and supply chain fragility persist into 2026. The labour shortages experienced during COVID-19 highlighted the impact that constrained resources can have on delivery capability and programme timing, as well as the sustained upward pressure on contractor and specialist labour costs. These dynamics remain relevant, increasing both cost risk and scheduling uncertainty for future works.

Careful, coordinated planning will therefore be required to ensure that sufficient labour, expertise, and materials are available when needed to deliver future work programmes. To support this, EDBs will need to provide clear and credible signals of their forward investment plans to both electrical and civil contractors, enabling those businesses to commit resources and build capability with confidence over multiple years.

4.4.5 Coordination with Other Infrastructure Programmes

Approximately 60% of WELL's network is underground and is often located within shared corridors alongside other infrastructure assets, including potable water, stormwater, and wastewater pipes. When water assets are renewed, maintained, or repaired, electricity assets within these corridors may need to be relocated. While the current regulatory framework allows the cost of relocating assets to be recovered from water companies, these activities still draw on scarce civil and electrical contracting resources that are also required to deliver WELL's asset replacement and reinforcement programmes.

At the same time, water programmes present opportunities to reduce overall costs through coordinated delivery. Where electricity and water assets share the same corridor, underground civil works can be aligned, enabling ducts to be installed as part of water upgrades. This approach avoids the need to repeat costly excavation and reinstatement works when electricity assets are later replaced or reinforced, improving efficiency and reducing disruption for customers and communities.

Case Study 4 – Coordinating Work with Other Infrastructure Providers

In 2023, Wellington Electricity commenced a project to reinforce the electricity supply in the Waitangirua area to enable planned residential development. With WELL's zone substation located on the western side of Waitangirua, and growth occurring in the east towards Transmission Gully, the Waitangirua Link Road was identified as the most efficient route for extending the electricity network from source to demand.

Early engagement with Porirua City Council identified that Wellington Water Limited (WWL) also required new water infrastructure along the same corridor to meet planned development. All parties recognised the importance of delivering these infrastructure upgrades in a timely and coordinated manner, while minimising cost and disruption for the local community. Delivering the electricity and water upgrades as separate projects presented several challenges, including:

- **Timing**—WELL required additional electricity capacity by 2025, while WWL's delivery timeframe was initially later. Aligning investment schedules required both organisations to adjust their plans.
- **Physical constraints**—Limited berm space, increased safety risks when working around live assets, and higher reinstatement and traffic management costs would have made a second, standalone project inefficient and disruptive.
- **Regulatory and funding alignment**—Differences in regulatory periods and funding years required careful coordination and re-profiling of expenditure.
- **Commercial arrangements**—agreement was required on commercial terms, risk allocation, and warranty arrangements between multiple asset owners.
- **Technical and quality requirements**—asset owner requirements needed to be clearly defined and embedded throughout the design, construction, and quality assurance processes.

Through sustained collaboration, the parties resolved these issues and developed a coordinated design and commercial framework that delivered clear efficiencies. Construction is now underway as a single integrated project, with materially lower total cost and reduced disruption compared with delivering two separate infrastructure projects.

Beyond the immediate cost and delivery benefits, this project has established a framework, relationships, and delivery precedent that will support future cross-utility collaboration. The lessons learned from this project will be valuable in enabling more efficient, coordinated infrastructure delivery as multiple networks invest simultaneously to support growth, resilience, and decarbonisation.

4.4.6 Delivery Strategy

WELL's delivery strategy for its future work programme is built around three complementary components:

- A Field Services Contract that delivers the maintenance programmes required to sustain safety and service quality.
- Competitive tendering for routine, network-initiated asset replacement projects.

- A Project Management Office (PMO) that oversees the outsourced delivery of large design-and-build work packages, which are often triggered by customer-initiated projects.

The new FSA Agreement, which went to market in 2024 and was awarded to Omexom to commence work in 2025, has enabled refinements to the unit-rate approach to work and to exclusive Cape Projects, thereby providing a complementary balance of resources across network activities. Similarly, to enable larger programs of work, our current Capex contractors are being engaged to transition to a unit-rate approach to reduce delays caused by tendering, so more visible long-term work programs provide the opportunity to recruit resources for training against a larger program of work.

Within the business, the realignment of duties between planning and delivery ensures clear standards to shorten lead times and prevents delays caused by internal processes.

Eventually, WELL expects that work standards will be established to enable field resources to complete work under an “Engineer, Procure and Construct” process, allowing smaller work types to be delivered directly from field resource businesses to network standards and reducing bureaucratic delays in the market.

Using the PMO to manage large customer-driven projects helps insulate WELL’s business-as-usual activities from variability in customer requirements and delivery timelines, ensuring these projects do not detract from WELL’s core responsibility to maintain network safety and quality. In addition, this approach provides contractors with clear visibility into the forward pipeline of work, enabling efficiencies through larger, multi-year work packages and giving them greater confidence to invest in the capabilities and resources needed to deliver projects in the Wellington region.

WELL recognises that the efficient delivery of its forward work programme must be supported by credible evidence of deliverability, including organisational capability, contractor capacity, procurement discipline, and realistic scheduling assumptions. The Commission has made clear, particularly in its guidance and determinations relating to CPPs, that proposed expenditure must be not only efficient and prudent, but also demonstrably achievable within prevailing market and resource constraints.

In response, WELL’s delivery strategy combines a structured field services contract for core maintenance activities, competitive tendering for routine replacement works, and a dedicated PMO to manage larger, design-and-build programmes. This model provides contractors with visibility of the forward pipeline, supports multi-year work packaging where appropriate enabling the staged sequencing of projects to reflect labour availability, supply-chain lead times, and consenting requirements. These arrangements are intended to provide assurance that the scale and timing of the investment programme are realistic, deliverable, and would meet the Commission’s expectations should a CPP application be progressed.

5 Asset Management, Safety and Risk Frameworks

This section outlines WELL's asset management frameworks, including its approach to health, safety and quality, and environmental management, together with its risk management processes and governance arrangements.

WELL's asset management framework is aligned with the company's vision, mission, corporate strategy, and objectives, and is embedded throughout this AMP. The framework reflects the principles of the international standard ISO 55001 and provides a clear line of sight between WELL's strategic objectives, investment decisions, service delivery outcomes, and customer preferences. The key components of the framework are illustrated in Figure 5-1.

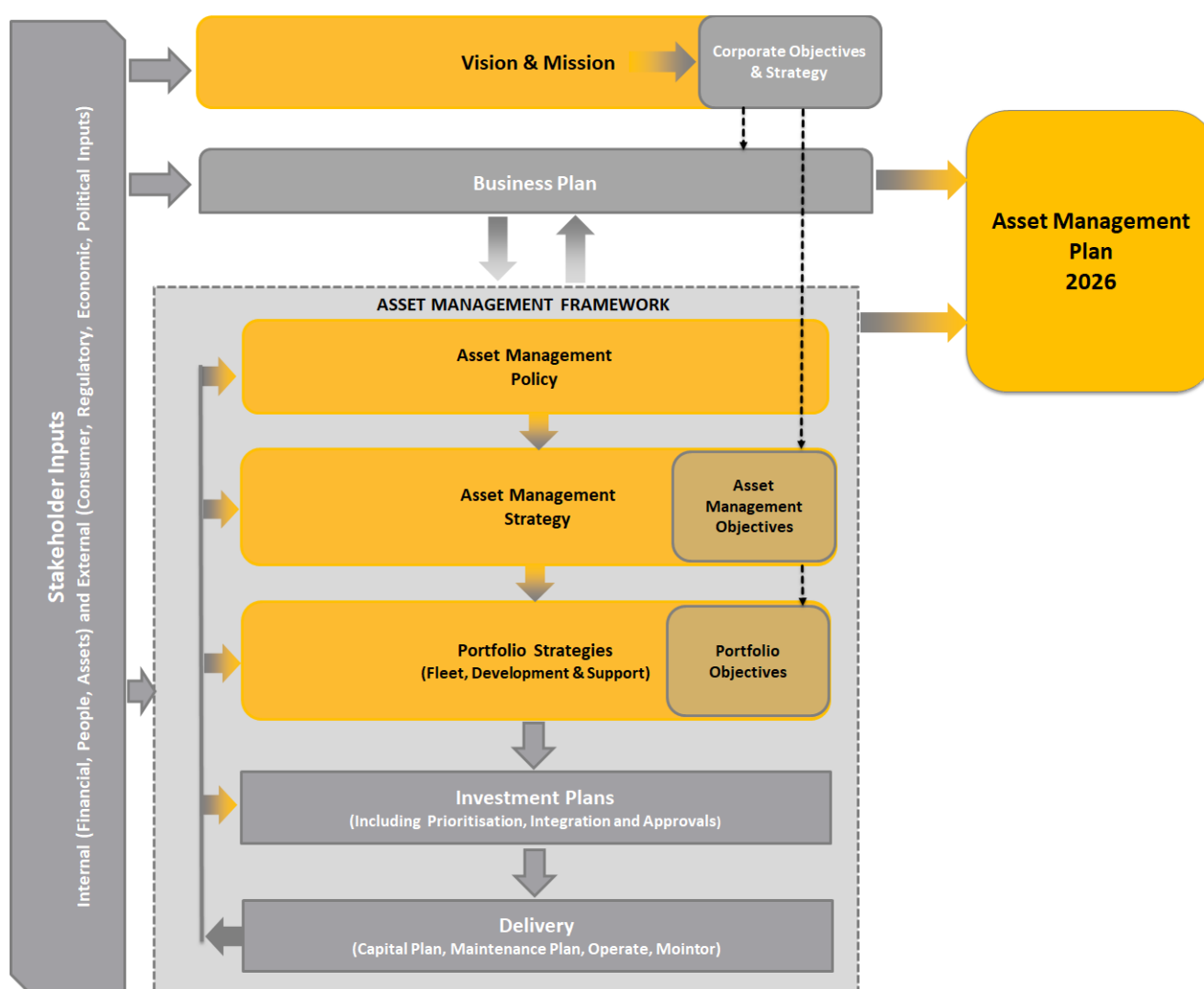


Figure 5-1 Asset Management Framework

The frameworks described in this section demonstrate that WELL's asset management approach is underpinned by structured governance, formalised risk management processes, and statutory safety obligations. These frameworks are not discretionary; they establish minimum intervention thresholds based on safety risk, compliance obligations, asset condition, and resilience exposure. When risks approach defined tolerance levels, particularly for public safety, health and safety compliance, major asset failure, or exposure to catastrophic events, intervention is required to reduce risk to an acceptable level.

The ability to act at these efficient risk thresholds depends on sufficient and appropriately timed funding. Under a constrained and smoothed allowance framework, the scope to defer risk-mitigating investment may be limited without increasing residual risk beyond WELL's stated appetite or regulatory obligations. This is particularly relevant where safety-driven projects, compliance-driven upgrades, cybersecurity investments, resilience enhancements, and contractor capability requirements converge. Incremental deferral in such circumstances may reduce near-term expenditure but can increase the likelihood and consequence of adverse events, ultimately increasing long-term cost and consumer risk.

The risk profile outlined in this section also highlights the exposure associated with low-probability, high-impact events, including catastrophic natural hazards. While WELL maintains insurance cover for key strategic assets, a significant portion of the network remains uninsured due to market limitations and prohibitive costs. In the event of a material loss affecting uninsured assets, ex post recovery through a CPP is likely to be required to restore the network. This underscores the CPP framework's structural role in managing residual catastrophic risk within the regulatory system.

More broadly, the integration of ISO 55001-aligned asset management processes, structured investment selection, and enterprise risk management creates a disciplined basis for determining when investment is prudent and necessary. Where the scale and timing of risk-mitigating investment exceed the flexibility available under the DPP, a CPP may be better suited to align revenue allowances with efficient expenditure levels. In this context, a CPP is likely to provide a more durable mechanism to ensure that safety, compliance, resilience, and risk-management obligations are met without compromising whole-of-life efficiency or long-term consumer benefit.

The following sections provide a high-level summary of each major component of the Asset Management Framework, as referenced in Figure 5-1. Specifically, this 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)
- Risk management

5.1 Quality, Safety, and the Environment

WELL is committed to delivering excellence in quality, safety, and environmental (QSE) outcomes. This commitment is underpinned by the following principles:

- Members of the public are not harmed by the operation, maintenance, or improvement of WELL's assets.
- Employees and contractors work in a safe environment and apply safe work practices at all times.
- The physical and mental well-being of staff and field workers is a key focus.

- Policies, plans, competencies, and other controls are effective in minimising environmental impacts.
- Audit, review, and assurance processes are in place to ensure consistently high-quality outcomes.
- Continuous improvement is embedded across all QSE activities.

To support these principles, WELL maintains a comprehensive set of policies and procedures for health and safety, environmental, and quality. These are integrated with the wider business policies and standards, which are routinely reviewed and updated to reflect changing risks, regulatory expectations, and best practice.

Consistent with WELL's mission, health and safety are treated as a core business value and given the highest priority. Oversight is provided through a dedicated Board Health and Safety Committee, which meets regularly to review performance metrics, workplace safety and initiatives, issues, and emerging issues, and to provide guidance to management. As illustrated in Figure 5-2, a formalised safety leadership structure operates across the organisation to ensure clear accountability, effective health, and safety leadership at all levels.

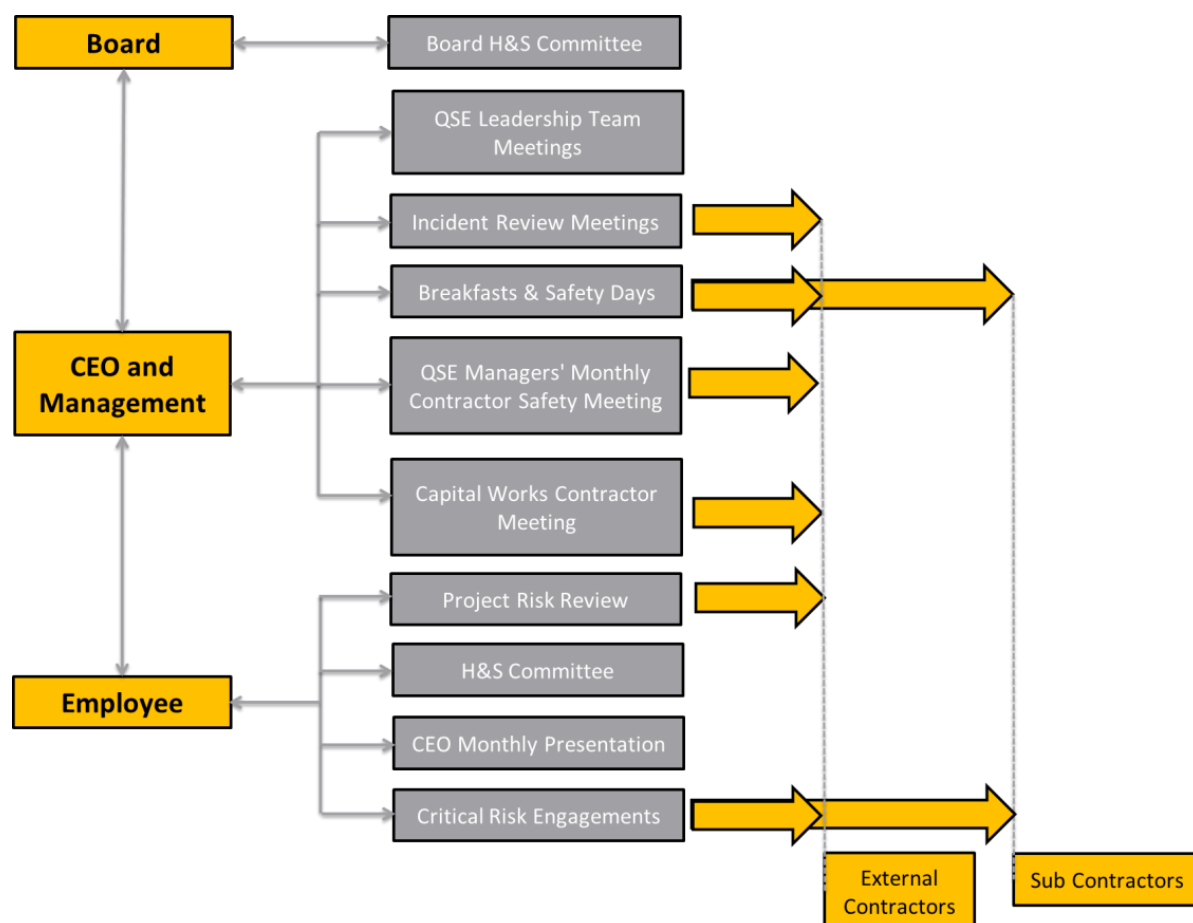


Figure 5-2 WELL's Safety Leadership Structure

WELL operates a monthly Safety Leadership Committee (QSE Leadership Team) meeting to monitor QSE performance, consider emerging trends or new issues, and track progress against key improvement initiatives. The QSE Leadership Team includes the Chief Executive and General Managers, ensuring senior leadership oversight and accountability.

Employees and contractors work collaboratively through structured processes of consultation, cooperation and coordination. These processes support the consistent application of safe work practices, appropriate use of plant, equipment, and personal protective equipment, and the ongoing review of control effectiveness. Incidents, near misses and hazard observations are actively reported and used to inform continuous improvement.

Quality and environmental outcomes are managed in a similar manner, with shared responsibility across employees and contractors. All personnel are required to:

- Take all reasonable steps to ensure that business activities minimise environmental impacts and support a sustainable environment for future generations.
- Ensure the delivery of goods, products and services meets acceptable standards and aligns with WELL's quality expectations.
- Identify and report any defects or non-conformances to enable improvement in the systems, processes, and performance.

WELL's QSE outcomes and supporting processes are discussed in more detail in the sections below. Associated performance objectives and measures are described in Section 6.1.

5.1.1 Safety Regulation

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

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

The Health and Safety at Work Act 2015 (HSW Act) came into effect in 2016 and introduced requirements for consultation, cooperation, and coordination in the management of health and safety duties. In response, WELL has continued to strengthen its relationships with other organisations and stakeholders where they interface with network assets.

These requirements have led to changes in how WELL conducts outsourced field activities, including a heightened focus on due diligence and governance at both the Board and operational levels, and across all parties in the supply chain. Under the HSW Act, all personnel involved in WELL's activities, including contractors and volunteers, are considered workers.

Protecting workers, the public, and property from harm remains the fundamental obligation. Effective planning, clear accountabilities, and strong communication are therefore central to WELL's approach to safe and effective work management.

5.1.2 Public Safety Management Systems (PSMS)

WELL operates a Public Safety Management System (PSMS) framework that is underpinned by documented policies, procedures, and guidelines for the safe design, operation, and management of network assets. The PSMS is designed to 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, as set out in Regulations 47 and 48 of the Electricity (Safety) Regulations 2010. It also meets the requirements of NZS 7901 Electricity and Gas Industries - Safety Management Systems for Public Safety.

WELL was last recertified WELL against NZS 7901 in 2024 by the certification body Telarc, which confirmed that the PSMS remains compliant with applicable regulatory and standard requirements. The next recertification audit is scheduled for 2027, with annual surveillance audits undertaken in the interim.

In addition to formal systems and assurance processes, WELL continues to invest in raising community awareness of the risks associated with living and working near electricity assets. Public safety information and guidance are provided through WELL's website www.welectricity.co.nz, which is designed to help the community stay safe around electricity. The site includes information on electrical shocks and fires, electromagnetic fields, appliance and power line safety, fault reporting, and links to relevant safety organisations and government safety agencies.

5.1.2.1 School Safety Programme

WELL delivers an electrical safety education programme for schools to improve children's awareness of electrical hazards. The Stay Safe programme is designed for primary school-aged students and delivered in schools across the Wellington region.

The programme includes a short educational video, a facilitated electrical safety discussion with visual props, and a Stay Safe Around Electricity workbook for each participating student. Additional information and resources are also available through the School Safety Programme section of WELL's website.

5.1.2.2 Media Advertising

WELL actively raises public awareness of the risks associated with living and working near network assets. This includes targeted radio safety campaigns that provide practical safety information on issues such as vegetation near overhead lines, cable identification and mark-outs, safety disconnects, and the use of surge protectors to protect sensitive appliances.

During 2025, WELL delivered radio safety campaigns focused on vegetation management, preparedness for major events, and safe behaviour in line-down situations.

5.1.2.3 Safety Seminars and Mail Outs

To reduce the risk of third-party contact with the network, WELL works closely with civil contracting companies and other organisations whose activities require operating in close proximity to network assets. Engagement typically occurs through early planning discussions and on-site safety briefings, which promote safe working practices when working around the network, particularly during excavation near existing underground infrastructure.

From time to time, WELL also issues targeted communications to contracting sectors, highlighting common safety infringements and reinforcing expectations for safe behaviour around network assets.

In addition, WELL works with Energy Safety to support safe interactions with the network and to ensure incidents are appropriately investigated where required.

5.1.2.4 Contractors' Safety Booklet

WELL has developed a safety publication targeted at civil contractors and others who work in proximity to, but do not directly access, the WELL network. This booklet, *"We* All Need to Work Safely"*, is distributed to participants attending safety workshops and is also included in targeted mailouts to contracting sectors that interface with the network.

5.1.2.5 Information Services

WELL provides an information service to reduce public safety risks and minimise incidents of damage to network assets or third-party property. The service is available through a 24-hour freephone number and supports safe planning and execution of works near the network.

These services include:

- Service Map requests
- Private and Strategic Cable Locations¹⁸
- Close Approach requests
- Stand overs
- High Load Permits
- High Load Escorts

5.1.3 Workplace Safety and Initiatives

WELL has implemented a range of workplace safety initiatives to support the effective management of health and safety risks and to promote safe work practices across all areas of the business.

5.1.3.1 Staff Health and Safety Committee

The Staff Health and Safety (H&S) Committee represents WELL's employees and meets bi-monthly to consider health and safety matters raised by Workgroup Representatives or reported through WELL's Health and Safety Management System (1FiCS). The Committee comprises seven volunteer members and addresses a broad range of issues, from emergency preparedness and response to the identification and remediation of faulty appliances requiring repair or replacement.

5.1.3.2 Safety Breakfasts

WELL regularly hosts safety breakfasts for all its external contractors to reinforce key safety messages and highlight areas for continuous improvement. The sessions also provide an opportunity to publicly recognise and celebrate examples of good safety behaviour and effective safety practice.

5.1.3.3 Annual Worker Safety Workshop

WELL holds an annual half-day safety seminar for its workers and closely associated PCBUs, together with their key workers. The seminar is designed to reinforce WELL's desired safety behaviours through direct

¹⁸ Other cable locations are now provided via a direct service by cable location companies.

engagement with keynote speakers and subject-matter experts. Attendance typically ranges between 350 and 400 participants.

5.1.3.4 Site Visits

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

5.1.3.5 Workplace Safety Training and Competence

WELL operates a Work Type Competency (WTC) framework that categorises network activities and defines the minimum qualifications, knowledge, and experience required for each work type. All operational personnel working in the field must hold the appropriate competency authorisation for the activities they undertake.

To ensure personnel remain trained and competent in safety matters, WELL provides a range of targeted training and refresher programmes, including:

- CPR and first aid refresher sessions annually
- Work Type Competency training
- Restricted area access training
- Defensive driving training
- Basic traffic control management training

5.1.3.6 Incident Review Meetings

WELL holds weekly internal meetings with outsourced service providers to review reported hazard observations, near misses, and incidents. The primary purpose of these meetings is to prevent incidents from occurring or recurring and to ensure lessons learnt are captured and applied to support continuous improvement.

5.1.3.7 Safety Alerts

When necessary, WELL issues Safety Alerts to all service providers to communicate identified safety concerns, outline the underlying causes or contributing factors, and specify the actions required to mitigate risk. Safety Alerts are used to ensure timely awareness, consistent implementation of corrective actions across the supply chain, and to support learning and continuous improvement.

5.1.4 Environmental, Social, and Governance

WELL's Board of Directors established an ESG Committee in 2022 that aims to support the Board in meeting its oversight responsibilities for environmental, social, and governance (ESG) matters. The Committee's role includes:

- Providing oversight of WELL's ESG strategy, including the development and evolution of policies, objectives, and strategic priorities as the external ESG environment continues to change.

- Ensuring appropriate targets, resources, and capabilities are in place to support the effective delivery of WELL's key ESG commitments.
- Overseeing the monitoring, reporting, and assurance of performance against ESG targets on a consolidated basis.
- Providing governance oversight of WELL's environmental and social policies and performance.

In February 2023, the Board approved WELL's first ESG Strategy. The strategy focuses on embedding sustainability into how WELL manages its impact on the economy, environment, and people, and is guided by the overarching objective of *"Empowering a resilient and sustainable future for Wellington."*

To support this objective, WELL has established targets across a range of priority areas, including emissions reduction, gender diversity, waste minimisation, community and staff ESG education, and initiatives to support the transition to, and intensification of, renewable energy.

5.2 Asset Management Framework

This section outlines WELL's Asset Management Framework, which provides a structured approach to planning, delivering, and managing assets to support the achievement of organisational objectives.

5.2.1 Corporate Objectives

WELL's corporate objectives are articulated through its mission and values and translated into clear performance expectations for the business. These objectives include the company's performance measures, such as annual key performance indicators (KPIs), and incorporate safety and quality targets, including SAIDI and SAIFI, as well as customer service outcomes.

5.2.2 Asset Management Policy

WELL's Asset Management Policy establishes the formal authority and governance framework for asset management across the business. The policy is aligned with 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."

The policy applies to all assets owned and operated by WELL for the provision of 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 further requires that WELL's electricity network be designed, constructed, operated, and maintained in a safe and efficient manner:

- Prioritises the safety of employees, contractors, and members of the public.
- Aligns with corporate objectives and business plans.

- Is based on customer service level expectations and engages stakeholders where appropriate on asset-related activities.
- Reflects the national and international asset management standards, trends, and best practices.
- Complies with all applicable regulatory and statutory requirements.
- Is consistent with WELL's risk management framework.
- Supports the ongoing development of staff capability and the effective engagement of external resources.
- Provides an appropriate 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 and provides a clear line of sight between corporate and asset management objectives. The Strategy translates high-level business goals into a focused set of asset management priorities and guiding objectives:

- Safety and Environment—protecting people, the public, and the environment
- Customers—delivering a high-quality service that meets customer needs and expectations
- Network Performance—providing a network that meets current requirements and supports future customer needs
- Cost—achieving long-term profitability driven by efficiency and innovation
- Capability—continuously developing asset management capability to support performance and efficiency improvements

The Asset Management Strategy summarises the objectives and strategic responses within each of these five priority areas. The first four priorities relate directly to WELL's performance, while the fifth focuses on building the asset management capability required to support and sustain those outcomes.

Sections 6 to 8 provide further detail on specific asset management objectives and strategies associated with each priority area.

5.2.4 Portfolio Strategies

Portfolio strategies translate the Asset Management Strategy into practical, portfolio-specific approaches. They link directly to the objectives set out in the Asset Management Strategy and identify any fleet-specific objectives and requirements.

These portfolio strategies cover asset fleet strategies, network development strategies, support systems, emerging technology, resilience, and customer-initiated projects and relocations. Each of these is discussed in detail in Sections 8 to 13, respectively.

The portfolio strategies inform the development of Network Standards, work plans, and delivery programmes. These, in turn, define the activities and budgets included in the 10-year AMP and the five-year business plan.

5.2.5 Investment Planning

WELL's investment plans are derived from the portfolio strategies and provide a structured basis for capital and operational expenditure decisions. The investment planning incorporates integration, prioritisation, and approval steps to ensure investments are prudent, well-governed, and align with strategic objectives. Investment planning is described in more detail in Section 5.3.

5.2.6 Delivery

Delivery comprises two complementary components:

- (i) The delivery of approved investment plans.
- (ii) The real-time management of the network.

The delivery of investment plans to achieve target customer service levels is discussed further in Section 5.3.

The objective of WELL's real-time network management is to operate the network safely and, in the event of outages, to restore supply as quickly and safely as practicable, while minimising impacts on customers.

5.2.7 Internal Feedback Loops

Key inputs to each component of the Asset Management Framework include asset condition information, network performance data, and customer feedback. Performance reporting is provided to those accountable for each component of the Framework, creating effective internal feedback loops. These feedback mechanisms enable strategies and plans to be refined and adjusted over time in response to performance outcomes and customer expectations.

5.2.8 Stakeholder and Customer Inputs

Customer feedback is key to ensuring WELL delivers services that meet customer expectations at the quality level they are willing to pay for. WELL regularly surveys customers to assess their satisfaction with current service quality and reliability.

In addition, WELL engages with community groups to test the balance between price and quality and to discuss topical issues that are relevant to customers. Feedback received to date indicates that customers support current service quality levels and do not want to fund further improvements. The Asset Management Framework reflects this preference by maintaining reliability performance at existing levels.

5.3 The Investment Selection Process

The investment selection process is a structured, multi-stage approach designed to ensure that investment decisions are aligned with WELL's strategic objectives, customer expectations, and risk appetite, and comprises five generalised stages, as illustrated in Figure 5-3.

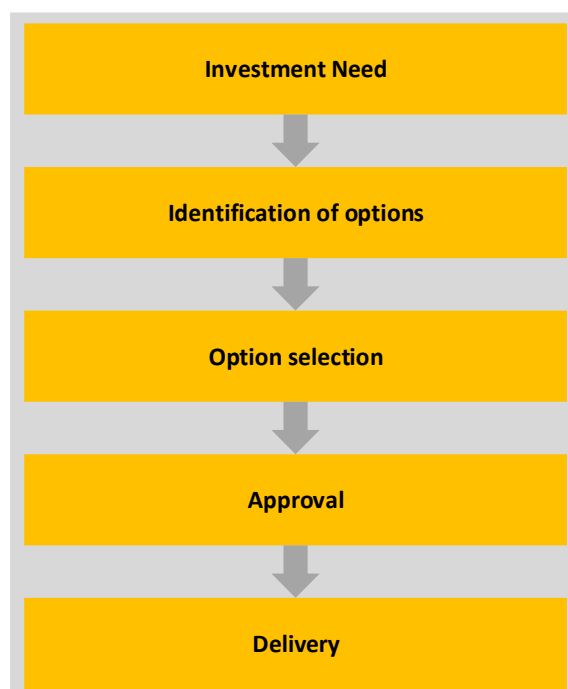


Figure 5-3 Investment Selection Process

The structured investment selection process ensures that safety, legal compliance, customer requirements, and risk mitigation remain the primary drivers of capital allocation decisions. When non-discretionary or safety-driven projects dominate the prioritisation hierarchy, the capacity to fund these interventions efficiently within a fixed, smoothed allowance framework may be constrained. In such circumstances, incremental deferral of lower-ranked projects may reduce near-term expenditure but can increase residual asset risk or defer economically efficient renewal activity. A CPP is likely to provide greater flexibility to align revenue allowances with the outcomes of the risk-based prioritisation framework, supporting the timely delivery of safety and compliance-driven investments while maintaining whole-of-life efficiency and long-term consumer benefit.

5.3.1 Investment Need

The need for investment is identified from a range of sources across the business. Asset replacement requirements are primarily informed by fleet strategies, which draw on asset condition assessments and detailed evaluations of asset health and criticality. In contrast, network development investment is driven by forecasts of peak load growth and by signals from developers indicating planned residential subdivisions or commercial investments.

5.3.1.1 Risk-based Approach

WELL adopts a risk-based approach to need identification, which underpins the network development, asset maintenance, refurbishment, and replacement programmes set out in this AMP. Effective risk management is central to determining where and when investment is required across the network.

Risks associated with network assets are managed through both proactive and reactive measures:

- Proactively—by reducing the likelihood of asset failure through compliance with security of supply criteria, targeted capital and maintenance programmes, enhanced work practices, and the development of fleet strategies. These strategies are informed by root-cause analysis of an expanding asset failure dataset and are used to predict future corrective maintenance requirements.

- Reactively—by reducing the consequences of asset failures through business continuity planning and the delivery of an efficient and effective fault response capability.

Asset failure risk is assessed as a function of both the likelihood of failure, largely driven by asset condition, and the consequences of failure. Consequences are evaluated based on factors such as safety impacts, the scale and duration of supply interruptions, environmental effects, repair or replacement timeframes, and any reduction in network operating security during restoration activities.

This risk assessment informs decisions on whether assets should be replaced through planned programmes or retained in service, with enhanced inspection and preventive maintenance.

5.3.1.2 Prioritisation of Projects

The AMP sets out WELL's investment view over a 10-year horizon and is reviewed and refined annually. Projects proposed for inclusion in each year's expenditure programme are subject to a top-down review and prioritised in accordance with the following sequence:

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
6. Commercial returns and investment recovery

Non-discretionary projects include:

- (i) HSE and Legal Compliance—operating a safe and reliable network is WELL's highest priority. Projects required to address safety risks and/or meet statutory and regulatory obligations are therefore given the highest priority.
- (ii) Customer-initiated Projects—where sufficient notice is provided, WELL prioritises the planning, design, and delivery of projects required to meet the direct needs of customers.

Under this prioritisation framework, safety, legal compliance, customer requirements, and risk mitigation are the primary drivers for including projects in the works programme.

5.3.2 Identification of options

A range of options is identified and assessed to address each investment need. These options include:

- Non-network solutions such as demand-side management (DSM), distributed generation (DG), or connection agreements incorporating operating envelopes that enable customers to optimise their use of available capacity without the need for significant investment in new capacity.
- Repair or refurbishment of existing distribution assets.
- Replacement of assets with new infrastructure.

- Extension or upgrade of the existing distribution network.

These options are evaluated to ensure that the service levels expected by stakeholders are met within the regulatory allowances, while appropriately balancing the price and quality. This approach seeks to align reliability outcomes with the long-term costs borne by customers.

5.3.3 Option Selection

The option selection process outlines how network investments progress from an initial list of feasible options through the selection of a preferred solution. Options are refined to a short list of practicable alternatives, analysed in detail, and the preferred option is documented in a business case for approval.

Approved investments are consolidated into the Works Plan, the central repository for all network investments for the year ahead. The Works Plan includes projects funded solely by WELL as well as customer-funded projects and is aligned with the first year of the AMP.

The option selection and approval process comprises the following steps:

1. Outputs from the option identification stage are developed into a business case that justifies the investment need and recommends a preferred option.
2. Approved recommendations are incorporated into the draft Works Plan and prioritised based on safety, customer requirements, budget constraints, delivery timelines, and network criticality.
3. Following final prioritisation, the resulting programme of works informs the annual budget, which is submitted for management approval and recommendation to the Board for approval.

5.3.4 Approval

Investment decisions are subject to WELL's Delegations for Authority (DFA) framework, which provides a structured and transparent approval process to ensure appropriate governance, accountability, and alignment with strategic and financial objectives, as described in Section 3.2.4.

5.3.5 Delivery

Approved investments are consolidated into the annual Works Plan and transitioned into delivery through WELL's established governance and project management framework. Clear accountabilities, procurement controls, contractor management arrangements, and structured performance reporting ensure projects are delivered safely, efficiently, and within approved scope and budget. The following section describes the delivery framework in more detail.

5.4 Asset Management Delivery

The Works Plan serves as the central repository for all network investment projects planned for delivery in the year ahead. It is the definitive document for tracking the delivery of network capital projects once approved. Responsibility for managing the Works Plan rests with the Service Delivery Team, with progress and performance reported regularly to the Executive and the Board.

5.4.1 Field Delivery

WELL operates an outsourced delivery model for field services and construction activities across the network. This model is used to deliver core operational, maintenance, and capital works in a way that supports safety, efficiency, and business value.



The primary service providers engaged by WELL for key field and network functions are:

- Fault response, maintenance, and minor capital works – Omexom
- Contestable capital works – Omexom, Connetics, Downer, and Ventia
- Vegetation management – Treescape
- Contact centre – Telnet

All outsourced agreements are required to comply with WELL's health and safety policies and management systems. Accountability for the effective management and performance of these field-based services rests with the General Manager – Service Delivery.

The scope and nature of these services are described in further detail in the sections below.

5.4.1.1 Fault Response, Maintenance and Minor Capital Works

Northpower Ltd was WELL's primary field service provider from 2011 to 2024, delivering fault response and maintenance services across the network. In 2024, WELL undertook a contestable procurement process for a new field services contract. Omexom New Zealand was appointed as the preferred provider and entered into a new Field Services Agreement (FSA) commencing on 1 January 2025. The FSA runs through to 31 December 2033, with provision of a one-year renewal and a further one-year extension.

The FSA delivers several strategic outcomes for WELL. It is structured to support alignment with WELL's asset management objectives and to improve the quality and integrity of the asset data in WELL's information systems. The scope of services under the FSA includes:

- Fault management – 24/7 response for fault restoration services.
- Preventative maintenance – asset inspection and condition monitoring, including the capture, storage, and reporting of asset condition data.
- Corrective maintenance – remedial maintenance on defective assets.
- Value-added services – safety disconnects and reconnects, critical cable stand-overs during excavation, and the provision of buried asset plans provided to third parties.
- Minor connection services and livening.
- 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, with incentives linked to high levels of achievement. Services are delivered on the basis of commercially tendered unit rates, and contract performance is managed through a structured programme of regular operational and governance meetings between WELL and Omexom.

5.4.1.2 Contestable Capital Works Projects

Contestable capital works comprise both customer-initiated and network-initiated projects, including:



- Customer-initiated works—new connections, subdivisions and substations, undergrounding, and relocations.
- Network-initiated works—asset replacement projects and cable or line reinforcement projects.

Contestable capital works projects are delivered through a competitive tendering process. Projects are undertaken under either independent contractor agreements (ICAs) or the FSA, depending on whether Omexom is the successful tenderer. These agreements define the commercial and performance requirements for delivery, including KPIs or KRAs, defect liability periods, insurance and liability provisions, and compliance with the HSW Act.

Each contract is managed on an individual basis and includes structured reporting, field auditing during construction, and close-out processes, including. In some instances, low-value works or situations where only a single supplier can deliver the required service may result in sole-source procurement. Where sole sourcing occurs, pricing is benchmarked against comparable market data.

Under WELL's project management framework, scopes of work are clearly defined, and robust controls are applied to manage variations to fixed-price work.

5.4.1.3 Vegetation Management

The vegetation management contract was competitively tendered in 2018, with Treescape appointed as the successful provider. The Vegetation Management Agreement with Treescape expired on 31 December 2025. WELL Management has approved a rollover agreement for a further two-year term.

The contract provides for vegetation management services in accordance with the Tree Regulations and includes initiatives to improve landowner awareness of tree-related hazards near the network.

Contract management reports to the General Manager – Service Delivery, and follows a governance model similar to the FSA, including regular performance meetings and the application of performance incentives.

5.4.1.4 Contact Centre

The Contact Centre provides a range of customer and retailer-facing services, including managing service requests, notifying retailers during outages, and handling general enquiries. Oversight and management of the Contact Centre contract rests with the Chief Financial Officer.

5.5 Asset Management Documentation and Control

WELL maintains a comprehensive suite of asset management documentation that supports the effective planning, delivery, and operation of the network. These documents include:

- High-level policy documents defining WELL's overarching approach to asset management.
- Asset fleet strategies setting out maintenance, lifecycle management, and renewal strategies across asset groups, ranging from subtransmission cables and power transformers to pole types and low-voltage installations.
- Network development and reinforcement plans providing a long-term, 30-year view of forecast load growth, potential network constraints, and mitigation strategies, aligned with asset renewal and reliability improvement programmes.

- Technical standards governing the procurement, construction, maintenance, and operation of network assets.
- Network guidelines providing direction on construction, maintenance, and operational procedures to achieve consistent and desired outcomes.
- Network instructions detailing specific requirements and procedures for network construction, maintenance, and operation.

All asset management documents, including policies, specifications, drawings, operations and maintenance standards, and guidelines, are subject to WELL's controlled document process. This includes formal review and approval requirements for new and substantially revised documents. Approved documents are made available to internal staff and external contractors and consultants through WELL's intranet and extranet systems.

Documents are generally reviewed on a three-year cycle, although review frequency may vary depending on their nature, regulatory requirements, or criticality to business operations.

5.6 Asset Management Maturity Assessment Tool

The Asset Management Maturity Assessment Tool (AMMAT) is a self-assessment questionnaire based on the PAS55 Assessment Methodology. It assesses organisational maturity across six key areas that relate to the management of processes and people:

- Asset strategy and delivery
- Communication and participation
- Competency and training
- Documentation, controls, and reviews
- Structure, capability and authority
- Systems, integration and information management

WELL's AMMAT results are provided in Appendix C.

The improvement areas identified through the AMMAT focus on enhancing the visibility of the multi-year work programme to contractors, supporting improved resourcing and delivery capability, and identifying any additional requirements for asset management information systems. These improvements represent a deliberate "lifting of the bar" to ensure WELL is positioned to deliver the Plan.

Progression beyond Maturity Level 3 for specific aspects of the AMMAT will be considered where there is a clear business need and where further investment is demonstrably cost-effective and justifiable.

Ongoing assessment and improvement of asset management maturity are important, given the increasing scale and coordination requirements of the forward work programmes. As investment needs become more concentrated across asset fleets and more closely aligned with external infrastructure programmes, organisational capability, systems integration, and multi-year planning discipline become critical to delivering efficiently. Continued progression in AMMAT maturity strengthens governance oversight, improves data quality, and enhances confidence in forward work planning.

In the context of a potential CPP application, demonstrable asset management capability provides assurance that forecast expenditure is prudent, efficiently structured, and realistically deliverable within prevailing organisational and market constraints.

5.7 Risk Management

WELL aligns its risk approach with its parent company by adopting the Enterprise Risk Management (ERM) – Integrated Framework: Risk Management – Principles and Guidelines. This framework provides a structured, robust approach to identifying, assessing, and managing risk across all business activities, including policy development and business planning. WELL's enterprise risk management framework is described in more detail 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 and oversight of the risk management framework. Day-to-day oversight of the risk management process is delegated to the Audit and Risk Management Committee, a sub-committee of the Board. As part of regular management reporting, the Committee is updated twice annually by the Chief Executive Officer, in line with the requirements of the risk management framework.

The Chief Executive Officer is accountable for the overall performance of the business and, accordingly, for the effectiveness of the controls employed to manage risk. While the Chief Executive Officer remains accountable to the Board, responsibility for implementing and managing controls is distributed across the management team. Controls are assigned to individual managers and are reviewed on a biannually basis to ensure they remain appropriate, effective, and responsive to changes in the risk environment.

Key controls within the risk management framework are outlined in Section 5.7.3.

5.7.2 Risk Management Framework

WELL's risk management approach is based on a structured framework that supports the identification, assessment, and management of risks across the business, as illustrated in Figure 5-4.

A structured risk management framework establishes defined tolerance thresholds and control requirements across safety, compliance, financial, operational, and resilience risk categories. Where assessed risks approach or exceed acceptable levels, intervention is required to reduce residual risk to within WELL's approved appetite. The effective timing of such interventions depends on funding aligned with risk-based triggers rather than fixed expenditure envelopes.

Under a constrained and smoothed allowance framework, the ability to respond to clustered or emerging risks may be limited, increasing reliance on deferral or reactive mitigation. In this context, a CPP is likely to provide greater flexibility to align revenue allowances with the timing of efficient risk mitigation, ensuring that safety, compliance, and resilience obligations are met in a manner consistent with prudent governance and long-term consumer benefit.

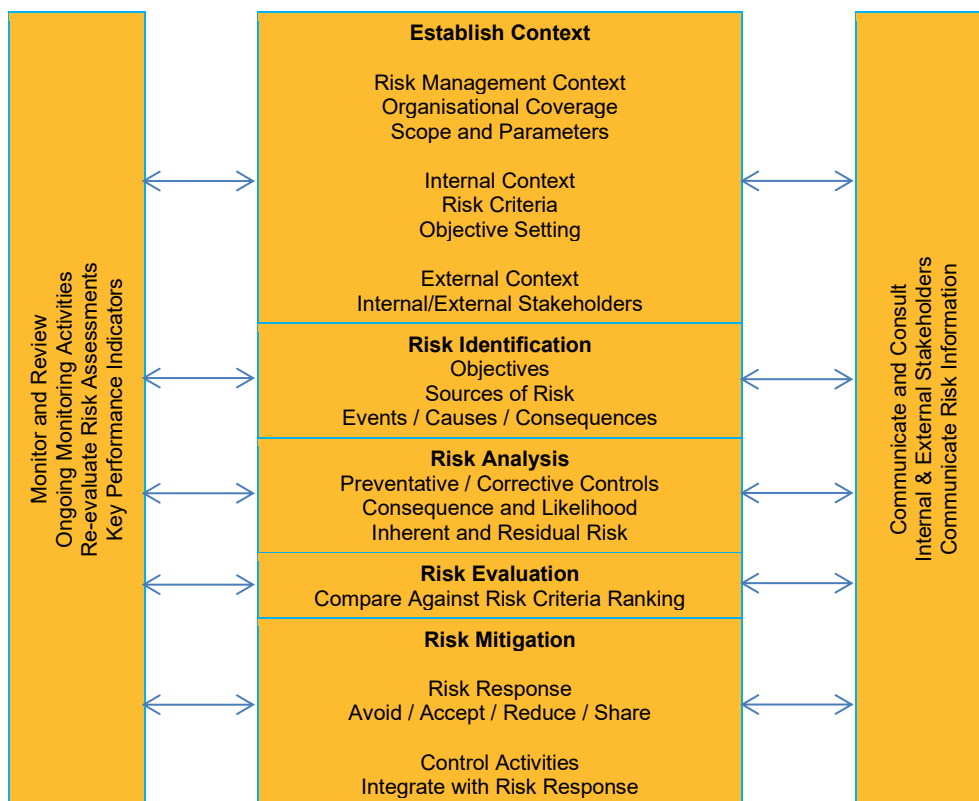


Figure 5-4 WELL's Risk Management Process

The risk management process, as illustrated above, comprises five key steps that provide a structured and consistent approach to managing risk across the business.

Step 1: Establish Context—this step considers WELL's objectives, the operating environment (discussed in Section 3.7), and the risk criteria used to assess and prioritise risks.

Step 2: Risk Identification—this step identifies risks through a range of operational and managerial processes grouped into the following seven categories:

- Health and safety – risks to employees, public, and service providers
- Environment – impacts on land, vegetation, waterways, and the atmosphere
- Financial – risks associated with cash flow and earnings
- Reputation – risks related to media coverage and stakeholder perceptions
- Compliance – risks arising from legislation, regulation and industry codes
- Customer service and reliability – risks affecting service quality and customer satisfaction

- Employee satisfaction – risks related to engagement, motivation, and morale

The controls used to mitigate these risks are described in Section 5.7.3.

Step 3: Risk Analysis—this step analyses the identified risks using both qualitative and quantitative measures and assesses them in terms of likelihood (the probability of the event occurring) and consequence (the impact should the event occur). Risks are plotted on a risk matrix, with likelihood on the y-axis and consequence on the x-axis. An example of the qualitative risk matrix is provided in Figure 5-5.

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

Step 4: Risk Evaluation—this step involves assessing the risk analysis outcomes to determine the significance of each risk, based on its likelihood and potential consequences. Risk evaluation is used to identify appropriate controls, prioritise risk treatment actions, and determine the level of management attention required.

Step 5: Risk Mitigation—this step focuses on applying controls to manage identified risks. Controls may include procedures and processes to eliminate or isolate risk sources: actions to reduce the likelihood and consequences of an event, risk transfer mechanisms such as contractual arrangements or insurance, or the acceptance of risk through informed decision-making. Applying these controls reduces the inherent risk to a residual risk level.

5.7.3 Key Business Risks and Controls

Risk event rankings and control effectiveness were reviewed and updated in December 2025. This assessment identified no extreme residual risks and a single risk rated high after controls were applied.

In total, WELL assessed 46 business risks. Table 5-1 presents the 10 highest-ranked risks, ordered first by residual risk ratings, then by inherent risk ratings.

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

Table 5-1 Summary of 10 Highest Business Risks

In total, WELL has identified over 225 distinct controls to mitigate the causes and consequences of the risks identified across the business. The 10 most commonly applied controls used to manage risk are:

- Insurance process, including engagement of qualified insurance brokers
- Board and Board Committees governance and reporting structures
- Contractor Management system and processes
- Internal and external auditing and compliance processes
- Management monitoring, reporting and review
- Purchasing and procurement policies and processes
- Asset management policies, strategies, standards, and plans
- Education, training and development policies and programs
- Delegations of Financial Authority
- Incident reporting and investigation processes and standards

5.7.3.1 Insurable Risks and Insurance Premiums

WELL insures approximately 15% of the estimated replacement value of its network assets. Insurance cover is limited to key strategic assets and is based on specialist advice to determine the maximum foreseeable loss for assets that can reasonably be insured.

The remaining 85% of the network, by replacement value, is uninsured. In the event of a significant event affecting these assets, WELL would need to apply for a Catastrophic Event CPP to align allowed revenue with the efficient costs of reinstatement, including any associated price-quality path adjustments. Consequently, customers retain the residual risk associated with the uninsured portion of the network.

WELL does not insure its subtransmission and distribution assets, such as poles, cables, and overhead lines, due to the limited availability and high cost of insurance coverage for these types of assets. Such cover is currently offered by only a small number of global reinsurers, carries high deductibles, is costly, and typically excludes windstorm-related damage.

By way of illustration, insuring poles, cables, and wire assets with a policy limit of \$500 million would require WELL to meet a deductible of \$50 million before any insurance proceeds were payable. In addition, the annual insurance premium for this level of cover is expected to exceed \$50 million and has increased in line with broader insurance market trends. This level of cost is not considered economic. Accordingly, ex post regulatory cost recovery is the primary mechanism for managing this risk.

The reliance on ex post regulatory recovery for a significant portion of uninsured network assets underscores the regulatory framework's structural role in managing low-probability, high-impact events. While insurance remains the preferred mitigation for certain strategic assets, market limitations and prohibitive premium levels mean that residual catastrophic risk is ultimately borne within the regulated funding model.

In this context, the CPP framework is not only a recovery mechanism following a material event but also an integral component of the sector's broader resilience architecture. It provides a transparent, established pathway to restore network capability when losses exceed insured limits, thereby supporting financial sustainability, prudent risk allocation between shareholders and consumers, and the continued delivery of essential services following a major disruption.

5.7.3.2 Insurance Cover

WELL renews its insurance across two tranches:

1. Industrial Special Risks (ISR) Insurance, which provides material damage and business interruption cover and is renewed annually as of 30 June.
2. General Products and Liability Insurance, which covers general, products, pollution, electromagnetic radiation, financial loss (failure to supply), and professional indemnity, and is renewed annually as of 30 September.

6 Service Levels

WELL is committed to operating a sustainably profitable electricity distribution business that delivers a safe, reliable, cost-effective, and high-quality energy supply to customers. This section sets out WELL's targeted service levels, which support the achievement of this objective.

The service measures and targets presented are derived directly from WELL's mission and Business Plan. This section also outlines the basis for measuring historic service-level performance and summarises WELL's performance to date.

Service levels have been established across four key areas:

- Safety Performance
- Reliability Performance
- Asset Efficiency
- Customer Experience

Performance targets within these areas include:

- Service levels applied by retailers on behalf of customers, as set out in current retailer agreements.
- Reliability targets established under the price-quality regulation framework under Part 4 of the Commerce Act 1986.
- WELL's internal service levels are used to measure performance against its mission and strategic objectives.

The service levels framework also reflects stakeholder feedback, as discussed in Section 3.6.

Maintaining these service commitments requires ongoing investment in asset renewal, network reinforcement, operational resilience, digital systems, and workforce capability. Reliability performance under the Commission's quality standards is influenced by asset condition, network complexity, integration of distributed energy resources, major weather events, and rising customer expectations for rapid restoration and timely communication. At the same time, stakeholder engagement confirms a continued tension between affordability and reliability; customers are reluctant to fund step increases in expenditure yet expect sustained service performance and safety outcomes. These dynamic underscores the importance of aligning expenditure efficiently with clearly defined service standards.

Under a constrained, smoothed allowance under DPP4, the ability to deliver the timing and scale of reliability, safety, or resilience-critical investments required to sustain these service levels is limited. This increases reliance on incremental deferral, short-term mitigation, and incremental interventions that may manage near-term affordability pressures but elevate medium to long-term service risk. As asset conditions and pressures intensify, sustaining compliance with regulatory quality limits and agreed service levels becomes increasingly dependent on timely investment.

In this context, a CPP is likely to provide greater flexibility to align revenue allowances with the efficient expenditure required to maintain defined safety, reliability, and customer service outcomes over time. This supports prudent risk management and regulatory compliance while preserving incentives for efficiency and ensuring that service levels are delivered in the long-term interests of consumers.

6.1 Safety Performance Service Levels

WELL continues to build on the foundations established through its past health and safety performance. It is an active member of the Electricity Engineers Association (EEA) and supports EEA-led initiatives that provide leadership, expertise, and guidance on technical, engineering, and safety matters across the New Zealand electricity industry.

Continuous improvement in health and safety management is a core focus for WELL and is supported by regular review of health and safety practices, systems and documentation.

Within this continuous improvement framework, WELL has adopted four primary measures to monitor health and safety performance:

- Incident, near miss, and hazard observation reporting
- Closure of corrective actions from site visits
- Lost Time Injury Frequency Rate (LTIFR)
- Total Notifiable Event Frequency Rate (TNEFR)

LTIFR and TNEFR are lagging indicators that reflect safety outcomes, while hazard observation reporting and workforce engagement through site visits are leading indicators. Together, these measures support the development of a strong safety culture and reinforce positive safety behaviours. Historical performance and targets for the planning period for each measure are presented in the following sections.

6.1.1 Lost Time Injury Frequency Rate

WELL's staff and contractors recorded three Lost Time Injuries (LTI) incidents in the industry reporting year ending June 2025. This equated to an LTIFR of 0.68 per 200,000 hours worked, with a two-year rolling average LTIFR of 1.03 per 200,000 hours worked. WELL's Lost Time Injury Frequency Rate, 24-month Moving Average, is shown in Figure 6-1.

WELL continues to actively monitor LTI trends. The incidents to date have predominantly been lower-severity, non-electrical, soft-tissue injuries, reflecting the impacts of an ageing workforce¹⁹ and the need for time away from work for recovery. WELL recognises the importance of maintaining an appropriate balance between managing critical network-related risks and addressing non-network-related health and safety risks and continues to work closely with service providers to ensure this balance is effectively managed.

¹⁹ A [State of a Thriving Nation report \(2025\)](#) highlights broader injury patterns in New Zealand, noting that while the overall number of injuries has declined, the duration of time off work per injury has substantially increased, influenced by factors including injury severity and comorbid health conditions; trends that are accentuated in older workers.

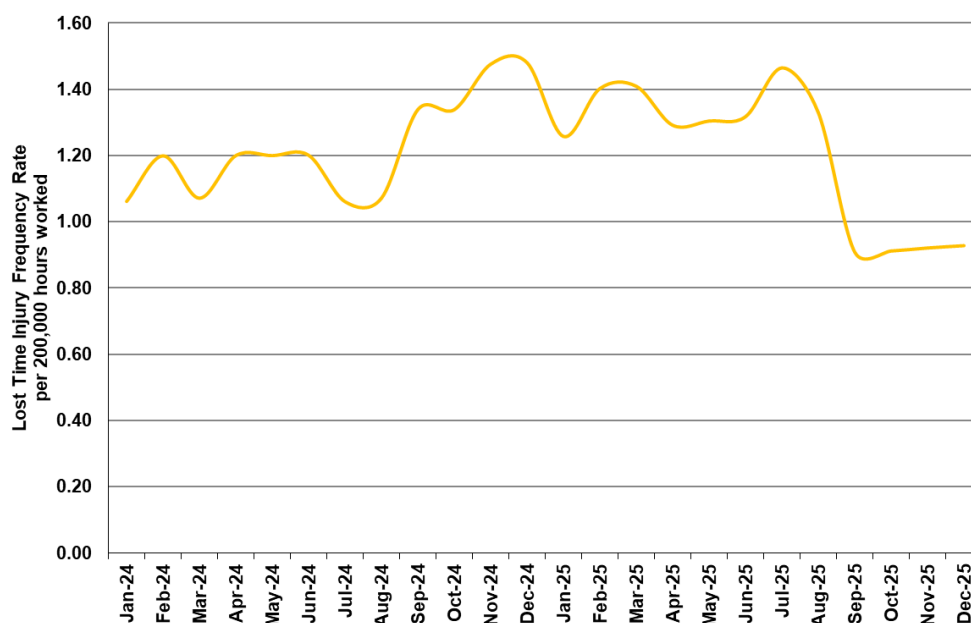


Figure 6-1 Lost Time Injury Frequency Rate (24-month Moving Average)

6.1.1.1 Planning Period Target

WELL's target for the planning period is to achieve and maintain an LTIFR of zero. This target is supported by a strong focus on leading indicators, including hazard and near-miss reporting, workforce engagement, and timely closure of corrective actions, to prevent incidents and support continuous improvement in health and safety performance.

6.1.2 Total Notifiable Event Frequency Rate

The HSW Act introduced the concept of "notifiable events", which include notifiable injuries, notifiable illnesses, notifiable incidents, and fatalities. In doing so, the reference to "serious harm" previously contained in Section 16 of the Electricity Act 1992 was replaced by Section 23 of the HSW Act with reference, which refers to "notifiable injury, illness or incident".

TNERF is a lagging indicator of health and safety performance. This measure has been reported since 2016 and is incorporated into the performance reporting requirements for all service providers.

In 2025, WELL's staff and contractors recorded one notifiable event. This resulted in a TNEFR of 0.37 per 200,000 hours worked for the year, with a two-year rolling average TNEFR of 0.59 per 200,000 hours worked.

6.1.2.1 Planning Period Target

WELL's target for the planning period is to achieve and maintain a TNEFR of zero. This target is supported by the same emphasis on proactive risk management, effective controls, workforce engagement, and continuous improvement to prevent notifiable events and reduce the likelihood and consequences of serious incidents.

6.1.3 Incident and Near Miss Reporting

In 2025, WELL continued to implement initiatives to increase hazard observation reporting and reduce near-miss events. Increased hazard observation reporting is an indicator of a mature safety culture and supports continuous improvement by enabling learning from low-consequence events, thereby reducing the likelihood of more serious events.

During 2025, a total of 388 events were reported. Of these, approximately 96.1% were classified as minor, 3.9% as moderate, and none were classified as serious. The total of 104 proactive reports received comprises five near-miss events and 99 hazard observation reports.

The collection and analysis of hazard observation data enable WELL to identify potential sources of harm to workers and the public and to detect emerging trends before harm occurs. It also provides assurance that outsourced service providers are actively assessing work sites under their control for unforeseen site-specific hazards that may not have been identified during the planning phase.

Near-miss reporting provides additional insight by identifying situations where harm could have occurred under slightly different circumstances. This information is used to test the effectiveness of critical controls and identify opportunities to strengthen risk management.

For reporting purposes, WELL defines a near miss as any unplanned event with a release of energy that could have caused adverse consequences to workers but did not. A hazard observation is similar in nature, in that potential for harm exists, but no release of energy has occurred.

6.1.3.1 Planning Period Target

WELL's expectation for the planning period is to maintain hazard observation reporting at approximately 100 addressed events per year. This is used as a leading indicator of safety performance and reflects a proactive safety culture focused on the early identification and mitigation of potential risks before harm occurs.

6.1.4 Corrective Actions from Filed Compliance Assessment Visits

WELL's Contractor Field and Completed Work Assessment Process provides a structured approach for categorising corrective actions identified during field compliance assessments of worksites by severity and for monitoring their timely close-out.

As shown in Figure 6-2, the ratio of corrective actions identified per assessment has decreased compared with 2021 levels. Ongoing monitoring supports the continuation of this improving trend. At the same time, WEL maintains a strong focus on compliance in higher-risk areas, including temporary traffic management requirements, adherence to network standards, and public safety around worksites.

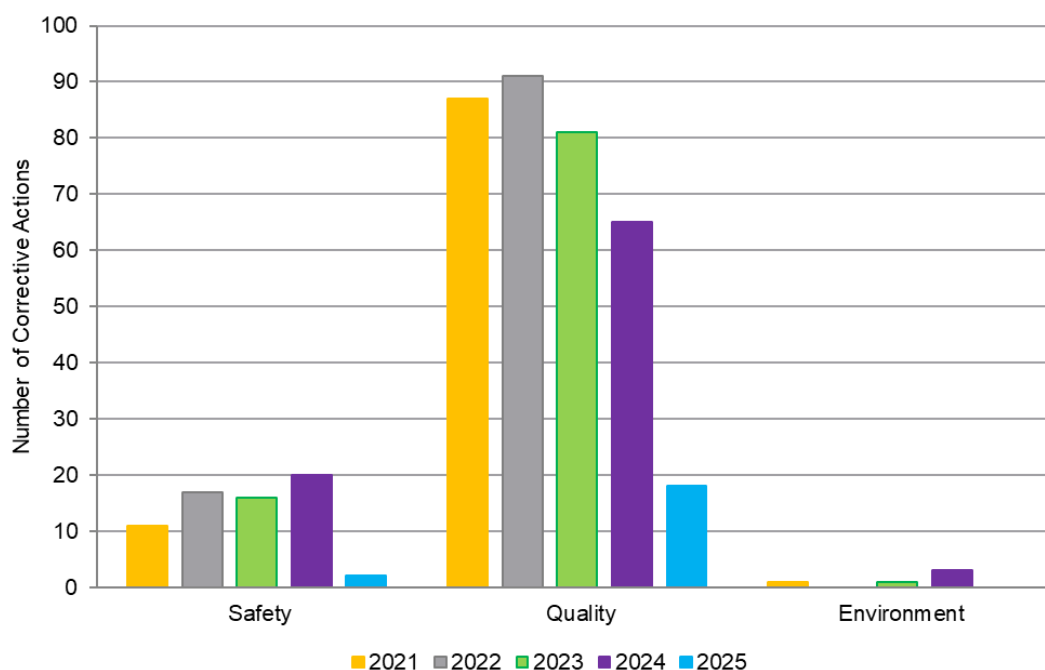


Figure 6-2 Corrective Actions Arising from Assessments 2021-2025

6.1.4.1 Planning Period Target

WELL's target for the planning period is to maintain the current level of field compliance activity at approximately 400 assessments per year. This activity serves as a leading indicator of safety and quality performance and is intended to support the ongoing reduction in corrective actions across all three severity categories by early identification of non-compliance and continuous improvement.

6.1.5 Health and Safety Initiatives

During 2026, WELL will focus on the following priority areas to further strengthen safety performance:

- Reinforcing collaboration with our new Field Service Provider.
- Strengthening WELL's "safer together" safety brand and its application across the business and supply chain.
- Increasing emphasis on the Te Whare Tapa Whā wellbeing framework, with targeted programmes and engagement to support the family, physical, mental, and spiritual wellbeing of staff and field workers.
- Maintaining the timely close-out of field assessments and associated corrective actions.
- Continuing the application of the risk management framework and expanding risk assessment processes, with a specific focus on critical risk and control management and effective principal-contractor communication.
- Maintain regular site visits to:
 - confirm workers have received and applied safety instructions

- engage with workers over workplace safety and verify effective management of WELL's critical risks
- ensure service provider personnel understand and apply all critical risk controls, particularly where these interface with WELL-owned risks
- Continuing to strengthen consultation, coordination, and cooperation where activities involve overlapping PCBU duties.
- Increasing strategic risk collaboration with contracted field service providers to develop practical and effective risk controls.

6.1.6 Safety Performance and Regulatory Obligations

The safety performance outcomes described above are supported by structured risk assessment, compliance monitoring, and timely intervention when hazards approach defined tolerance thresholds. Because safety obligations are statutory and non-discretionary, the ability to act at efficient intervention points is critical to maintaining acceptable risk levels.

Where safety-driven investment requirements cluster with or coincide with other renewal and reinforcement needs, a fixed, smoothed allowance framework may constrain the timing of efficient intervention. In such circumstances, incremental deferral or reliance on interim controls may increase residual risk or long-term cost. A CPP is likely to provide greater flexibility to align revenue allowances with safety-driven investment timing, supporting prudent governance, compliance with legal obligations, and the sustained delivery of safe network outcomes in the long-term interests of consumers.

6.2 Reliability Performance

The reliability targets described in this subsection are established under the price-quality regulatory framework in Part 4 of the Commerce Act 1986 and represent binding quality limits against which WELL's performance is assessed. Maintaining compliance with these limits requires timely investment in asset renewal, network reinforcement, fault response capability, and system resilience. As asset fleets age, network complexity increases, and exposure to severe weather events intensifies, reliability outcomes become increasingly sensitive to the timing of capital and operational expenditure.

Under a fixed and smoothed allowance framework, aligning funding with clustered, reliability-driven interventions may be constrained, increasing reliance on short-term mitigation or incremental deferral. In this context, a CPP is likely to provide greater flexibility to align revenue allowances with efficient reliability-supporting investment, reducing the risk of quality path breaches and supporting sustained delivery of service levels in the long-term interests of consumers.

6.2.1 Reliability Measures

Network reliability is measured using two internationally recognised performance indicators: SAIDI²⁰ and SAIFI.²¹ When considered together, these measures indicate the availability and continuity of electricity supply experienced by the average customer connected to the network.

²⁰ System Average Interruption Duration Index

²¹ System Average Interruption Frequency Index

- SAIDI measures the total duration, in minutes, that the electricity supply is unavailable to the average customer over the measurement period.
- SAIFI measures of the average number of supply interruptions experienced by a customer during the measurement period.

In accordance with the methodology established by the Commission, certain types of supply interruptions are excluded from the calculation of these performance indicators. These include:

- Interruptions caused by the unavailability of supply at a GXP, including automatic or manual load shedding directed by the transmission grid operator²² or other events external to the WELL network.
- Interruptions lasting less than one minute, which are typically restored automatically and are not recorded for performance measurement purposes; although WELL records these events for operational purposes and customer service planning.
- Interruptions resulting from outages of the low-voltage network.

SAIDI and SAIFI targets, together with WELL's historical performance, renormalised using the DPP4 methodology, are shown in Figure 6-3 to Figure 6-6.

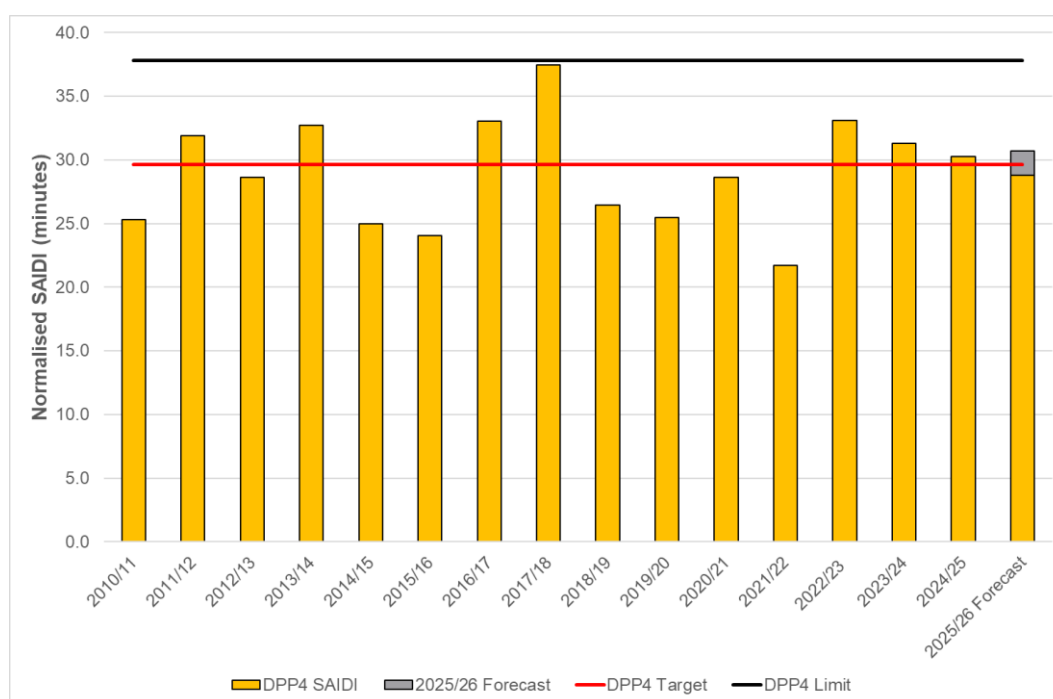


Figure 6-3 WELL Unplanned SAIDI Performance

²² 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.

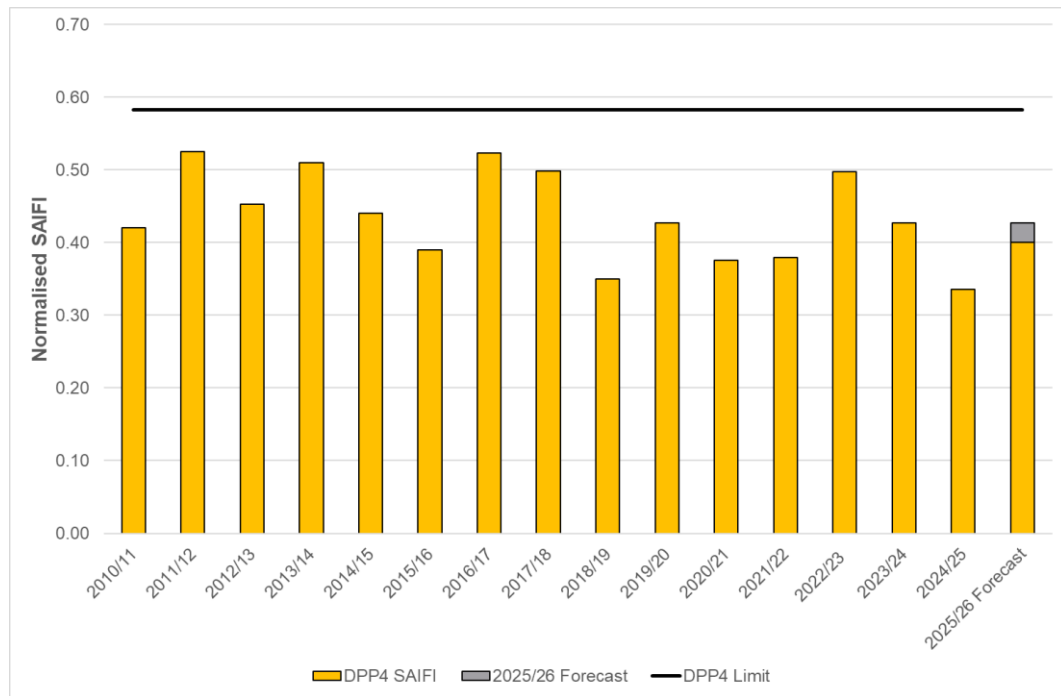


Figure 6-4 WELL Unplanned SAIFI Performance

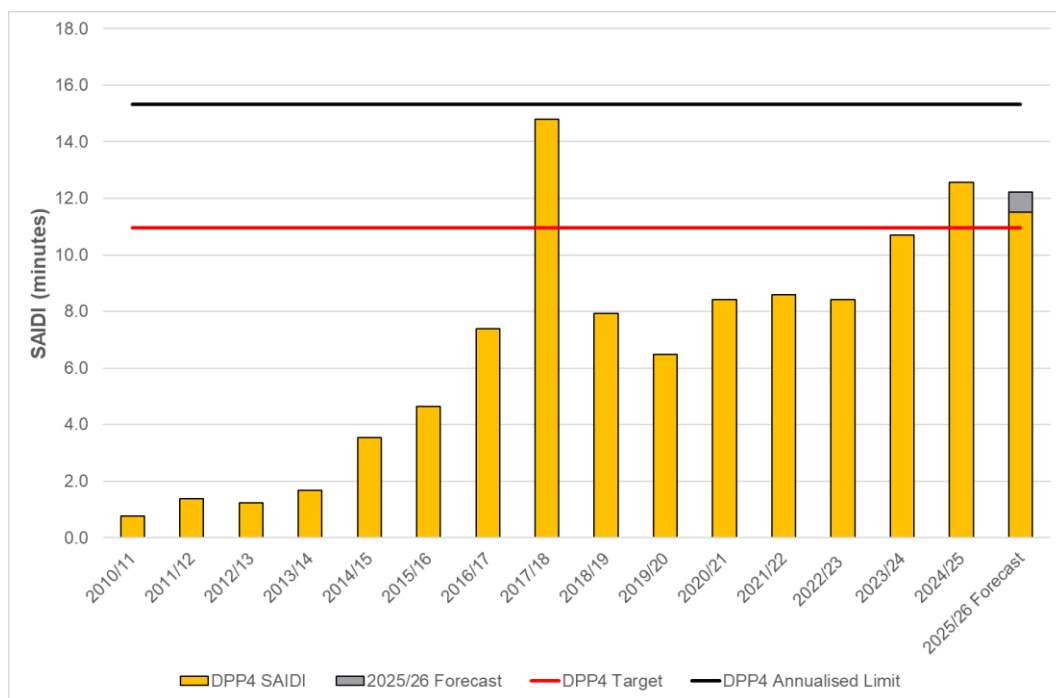


Figure 6-5 WELL Planned SAIDI Performance

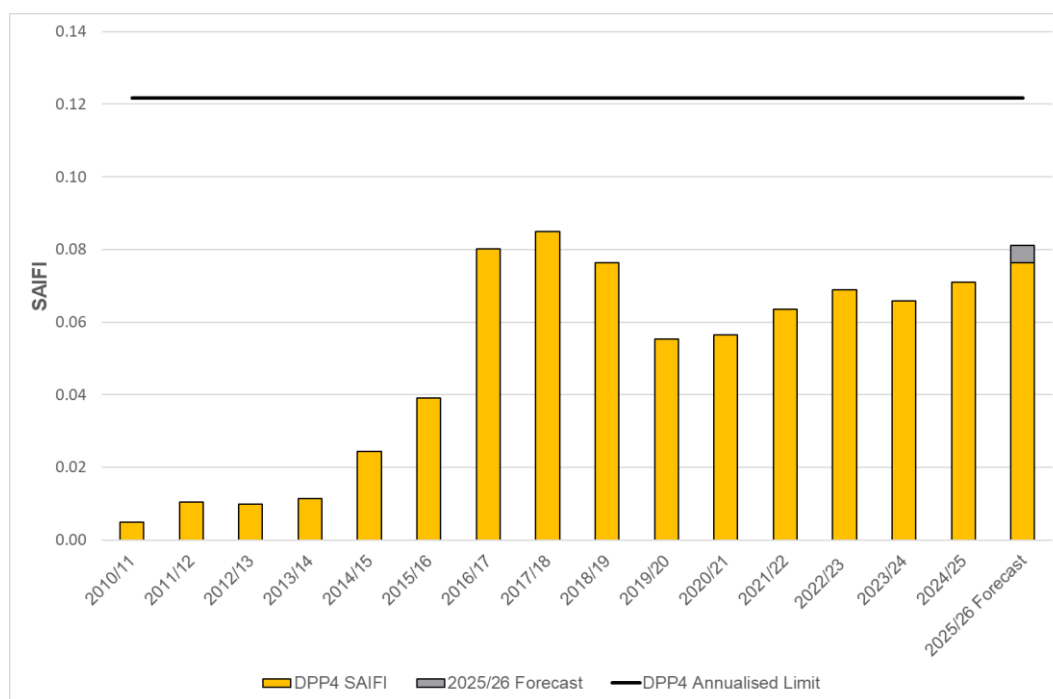


Figure 6-6 WELL Planned SAIFI Performance

WELL's reliability targets are aligned with its asset management objectives for network reliability and are intended to:

- Maintain overall network reliability at historically acceptable levels.
- Deliver the cost-quality trade-offs requested by customers.
- Meet regulatory standards for power quality, as discussed in Section 9.5.2.4.

6.2.2 Process for Measuring Reliability Performance

This section outlines the process used to record, validate, and assure reliability performance data, ensuring that reported outcomes are accurate, consistent, and aligned with regulatory requirements.

6.2.2.1 Outage Data Collection

WELL records SAIDI and SAIFI performance using the PowerOn Advantage (PoA) SCADA network management system. PoA is used for the real-time monitoring and control of the high-voltage network. Specifically, PoA provides visibility of the network status, including customer connection points and the operational state of devices such as circuit breakers and fuses.

PoA automatically captures outage information for all planned and unplanned outages on the 11 kV and above network. This includes outage duration, the number of customers affected, and other data required for SAIDI and SAIFI reporting. Outage data is subject to daily error checking and validation by the Network Operations Manager and an Asset Engineer before being recorded in the reliability reporting system.

For unplanned outages, PoA automatically identifies and logs faults, including a time-stamped record of when the outage occurred. Any subsequent switching operations undertaken to restore supply are also recorded and time-stamped within the system.

When faults occur on devices not directly monitored by PoA, outages are recorded from the time of the first customer call regarding the high-voltage fault. In these cases, switching operations are manually entered and time-stamped within the system.

6.2.2.2 Data Validation and Review

Once an outage is resolved, an outage report is generated, including notes recorded by the Network Controllers on duty. The reported information is then validated against the following parameters:

- Date and time outage started and ended
- Outage duration
- Number of customers affected
- Total customers' minutes lost (calculated from time-stamped switching operations)
- SAIDI for the outage
- SAIFI for the outage
- Fault type
- Fault cause

The data is reviewed for accuracy, with particular focus on non-system faults where information is manually entered by the Network Controllers. In contrast, system-generated faults are automatically captured and rarely have errors.

All faults are reviewed and approved daily by the Network Operations Manager. Following approval, the Asset Engineer consolidates the individual event reports into weekly and monthly network reliability reports. These reports form the basis for WELL's SAIDI and SAIFI performance reporting. The monthly reliability reports are then aggregated into the master database, which underpins WELL's regulatory quality reporting for Quality Path compliance and Information Disclosure.

6.2.2.3 Planned outages

For planned outages, the contractor submits a Network Access Request (NAR) electronically for the proposed work. Once the request has been assessed and approved, the Network Controller enters the planned switching operations into PoA ahead of the outage.

During the outage, PoA creates an incident, and the Network Controller time-stamps each switching operation as it occurs. Following completion of the work, the planned outage is validated by outage planners and Network Controllers using the relevant job documentation. This validation confirms the accuracy of the recorded information and assesses whether mitigation measures, such as low-voltage backfeeding or portable generation, were used to reduce the impact of the supply interruption.

6.2.3 Industry Comparison

WELL was one of the most reliable EDBs over the 2025 disclosure year, as illustrated in Figure 6-7 and Figure 6-8. This assessment is based on the annual Information Disclosures data publicly disclosed by EDBs in August 2025.

The benchmarking analysis demonstrates that WELL's system reliability performance is strong relative to its peer networks, including those with similar network profiles (predominantly urban and underground) and a comparable customer base.

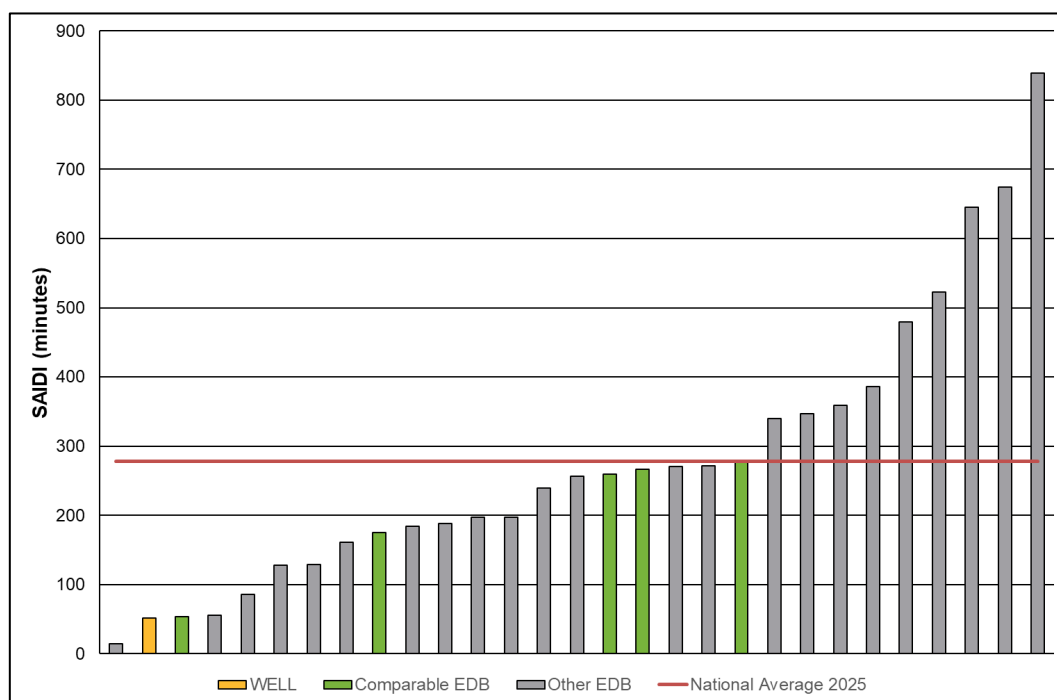


Figure 6-7 SAIDI by EDB for 2024/25

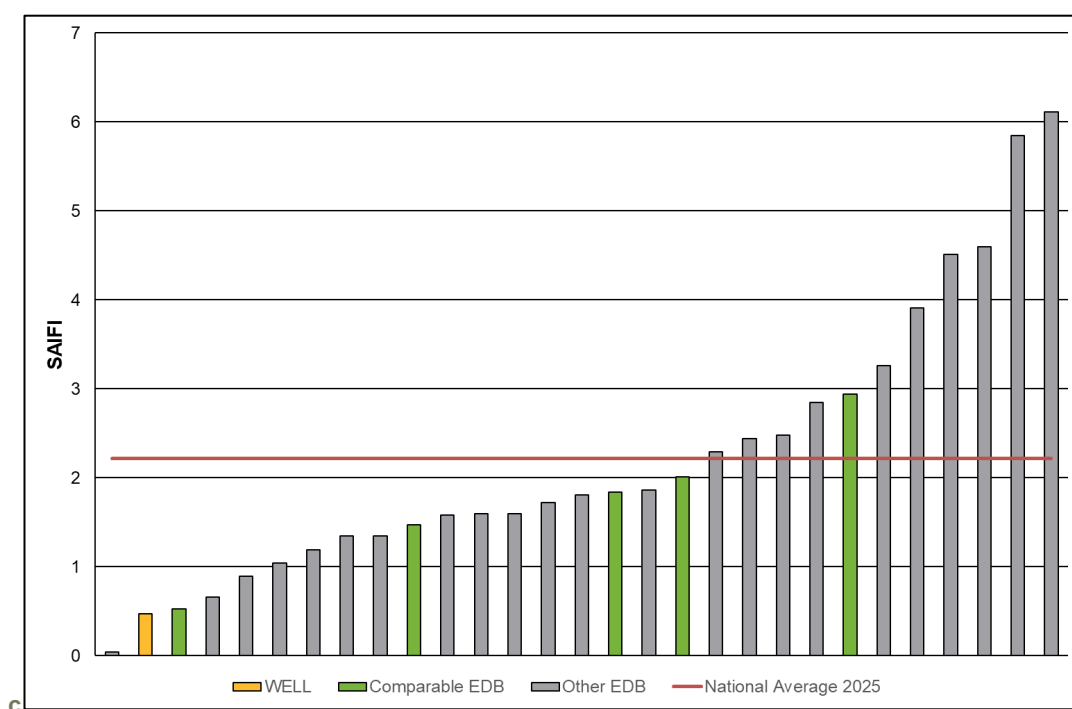


Figure 6-8 SAIFI by EDB for 2024/25

6.2.4 Reliability Performance forecast for the disclosure year beginning 1 April 2025

WELL's unplanned network performance for the 2025 disclosure year is forecast to remain below the annual regulatory limits of 37.82 minutes for SAIDI and 0.5829 interruptions for SAIFI.

The Wellington region experienced several major storms during the year, including two severe southerly storms in May 2025 and February 2026.

May 2025 Storm

The May 2025 storm was a strong southerly storm, with sustained gale-force winds exceeding 63 km/h recorded at Wellington Airport for 38 hours from 7 pm on 30 April to 9 am on 2 May, and gusts peaking at 118.5 km/h at 11 am on 1 May.

WELL's Major Event began at 9:30 am on 30 April 2025 and ended at 10:30 pm on 2 May 2025, encompassing 31 unplanned outages that affected 12,500 customers. Figure 6-9 presents the time series of wind gusts as recorded at Wellington Airport against the number of customers affected by HV outages on WELL's network for each half hour during the storm.

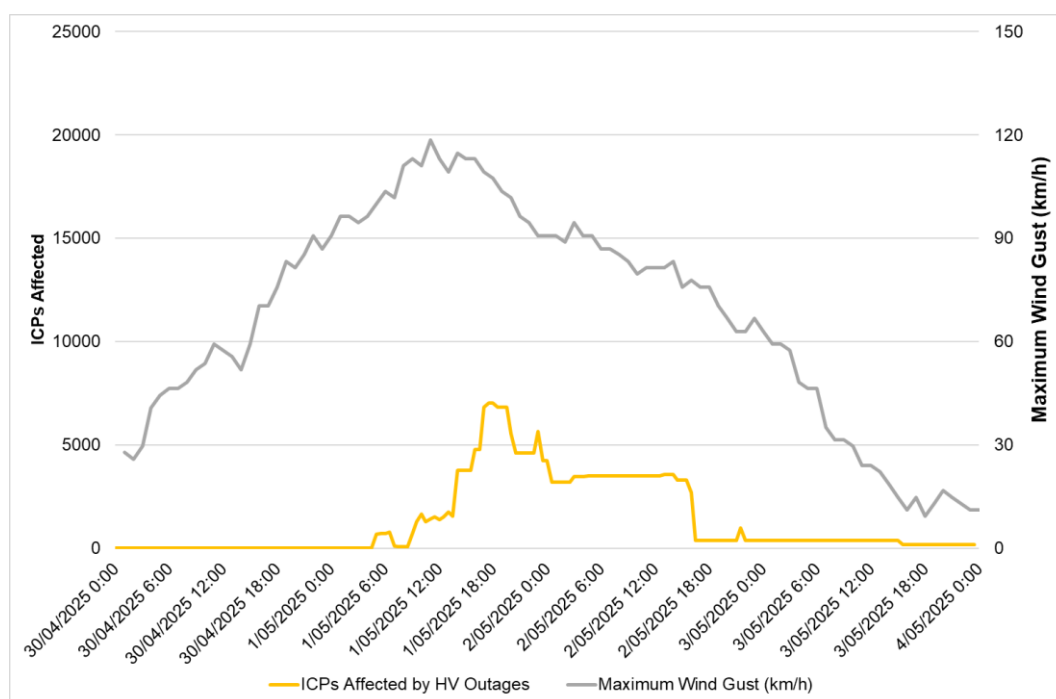


Figure 6-9 May 2025 Storm Wind Speed and Customer Impact

The raw SAIDI attributable to the May Major Event was approximately 9.0 SAIDI minutes, which reduced to 0.7 SAIDI minutes after normalisation to assess WELL's compliance with the DPP4 quality standards.

February 2026 Storm

The February 2026 storm was a strong southerly storm event associated with a subtropical low tracking down the east coast of the North Island. Sustained gale-force winds were recorded at Wellington Airport for 26 hours from 1 pm on 15 February to 3 pm on 16 February, with recorded gusts averaging above 120 km/h for 11 hours between 11 pm on 15 February and 10 am on 16 February.²³

The Major Event began at 7 pm on 14 February 2026 and ended at 4 pm on 20 February 2026. Over this period, 58 unplanned outages affected approximately 33,400 customers. Figure 6-10 presents the half-hourly wind gusts profile recorded at Wellington Airport alongside the number of customers affected by high-voltage outages across WELL's network during the storm.

²³ <https://www.stuff.co.nz/nz-news/360938876/pictures-storm-thats-walloping-north-island>

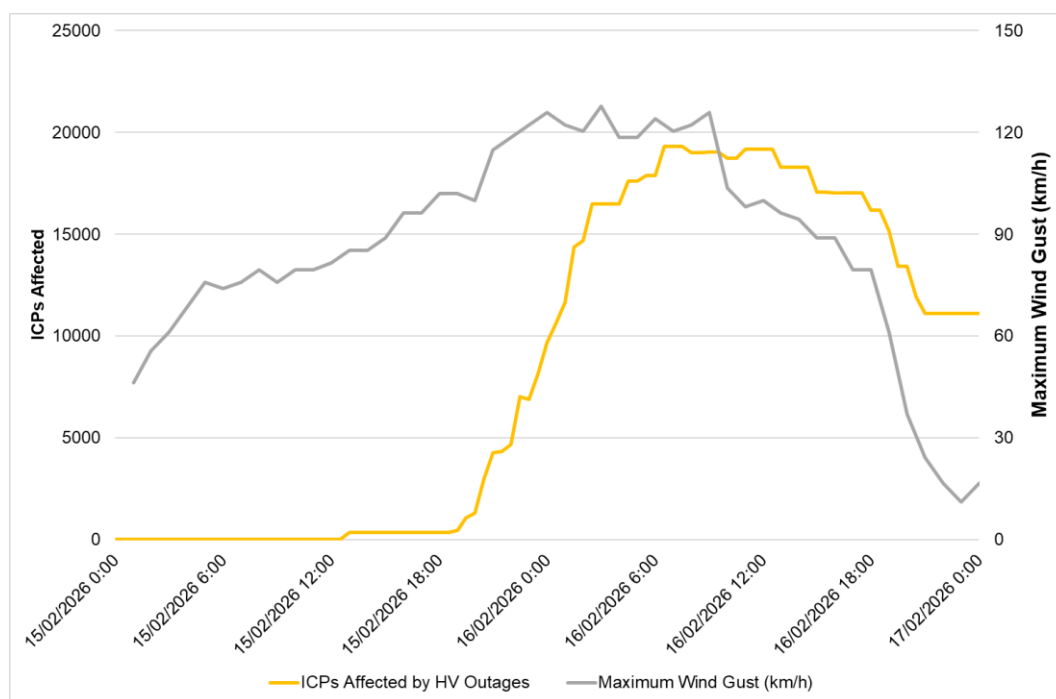


Figure 6-10 February 2026 Storm Wind Speed and Customer Impact

The raw SAIDI attributable to the February Major Event was approximately 82.7 SAIDI minutes, which reduced to approximately 1.17 minutes following normalisation for the purposes of assessing WELL's compliance with the DPP4 quality standards.

The February storm was the most significant weather event to affect the Wellington region since the June 2013 storm. Although peak wind speeds did not reach the same magnitude as those recorded in 2013, when a gust of 140.8 km/h was recorded at Wellington Airport, the February event involved a much longer duration of severe wind conditions, with gusts exceeding 120 km/h for 11 hours compared with approximately two hours in June 2013. Figure 6-10 shows that most customer interruptions occurred during this prolonged period of elevated wind gusts.

Forecast Performance for the disclosure year beginning 1 April 2025

Figure 6-13 presents a waterfall chart illustrating WELL's forecast SAIDI performance for the 2026 disclosure year, disaggregated by fault cause. The chart shows the relative contribution of each fault category to total unplanned SAIDI, with the following fault causes represented:

- Overhead network faults
- Underground network faults
- Substation faults
- Car versus pole faults
- Other third-party faults
- Major event days
- Other outage types

context, a CPP is likely to provide greater flexibility to align revenue allowances with the timing of efficient resilience and restoration investments, supporting compliance with regulatory quality limits and the sustained delivery of reliable service outcomes in the long-term interests of consumers.

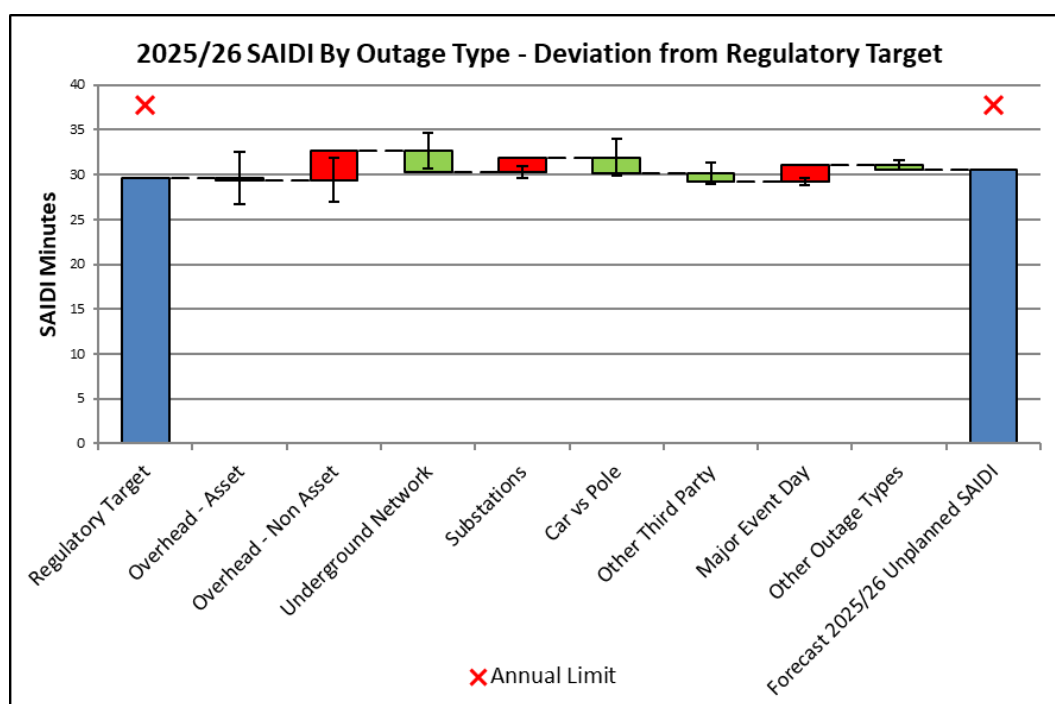


Figure 6-11 Waterfall Chart of 2025/26 SAIDI Performance by Outage Type

Overhead network faults have been further disaggregated into asset-failure and non-asset-failure events, with the latter outages caused by vegetation, lightning, and animals. Major event days are presented as a separate category to reflect the normalisation methodology applied under the quality standards.

For each category, the chart indicates whether its contribution is lower (green) or higher (red) than the average contribution over the reference period. The whiskers represent the standard deviation of the reference-period data.

Major event response and restoration performance are increasingly shaped by the frequency and severity of weather-related events, supply chain constraints, and the resilience of supporting systems and field resources. Maintaining rapid and coordinated restoration capability requires ongoing investment in network resilience, spares management, contractor capacity, operational technology, and communications systems. As climate volatility and event intensity increase, restoration performance becomes more sensitive to the condition and redundancy of core assets and the availability of pre-positioned capability.

Under the DPP4 allowances, funding constraints limit WELL's ability to progress resilience-driven upgrades and restoration capability requirements at the required scale and pace, particularly when these investments coincide with asset renewal and system replacement programmes. Where allowances are insufficient to support concurrent renewal, growth, and resilience initiatives, efficient sequencing becomes increasingly difficult, and reliance on deferral or interim mitigation measures may increase.

The equivalent waterfall chart for the 2025 disclosure year is presented in Figure 6-12, providing a comparative view of SAIDI performance by fault cause and enabling assessment of changes in the drivers of unplanned outages between the two years.

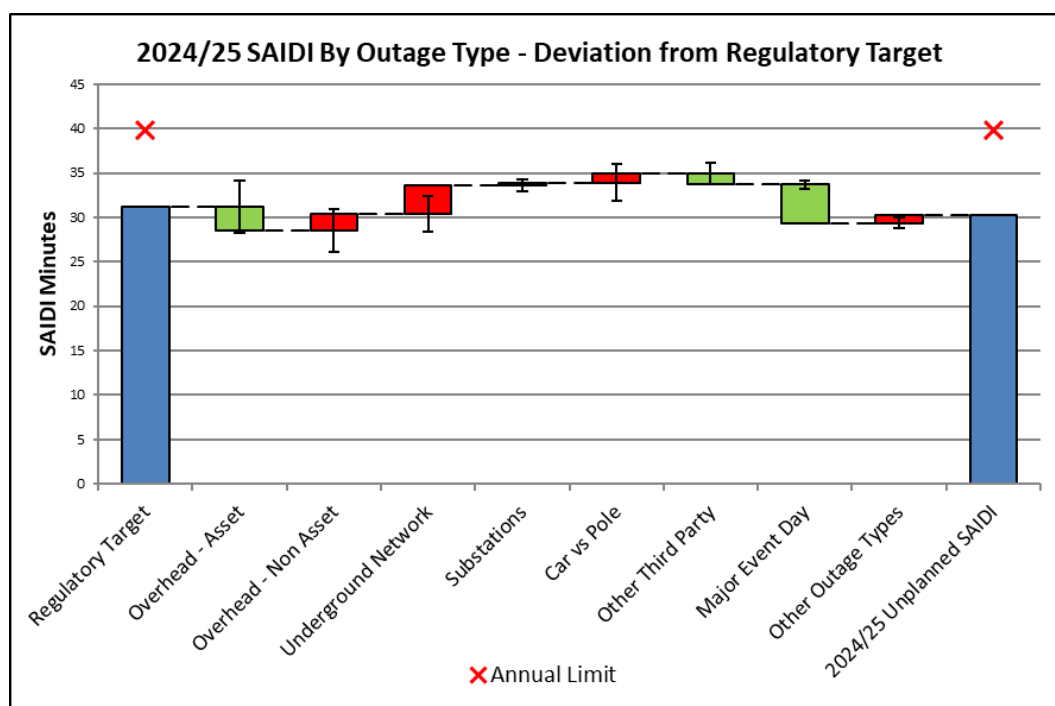


Figure 6-12 Waterfall Chart of 2024/25 SAIDI Performance by Outage Type

A comparison of the two years indicates that different fault categories were the primary drivers of unplanned outage performance in each year, with no discernible trend emerging across the period.

6.2.5 Reliability by Network Area

Figure 6-15 and Figure 6-16 present SAIDI and SAIFI performance by network area, excluding major event days, reflecting the availability of electricity supply experienced by the average customer in each region, rather than the total number of customers served.

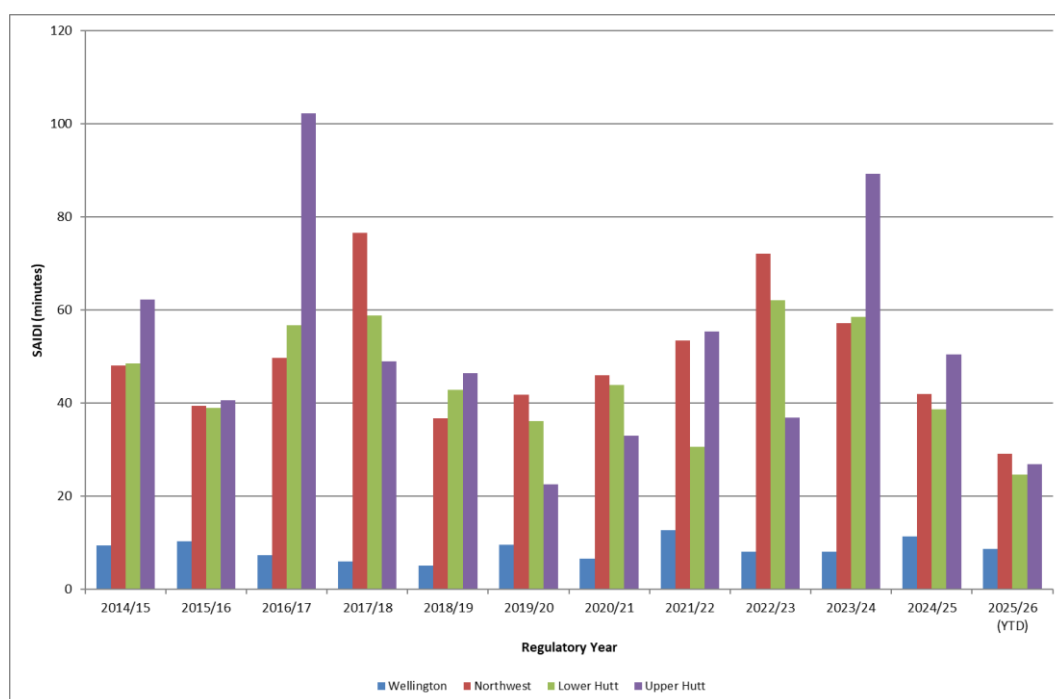


Figure 6-13 Unplanned SAIDI Performance by Network Area

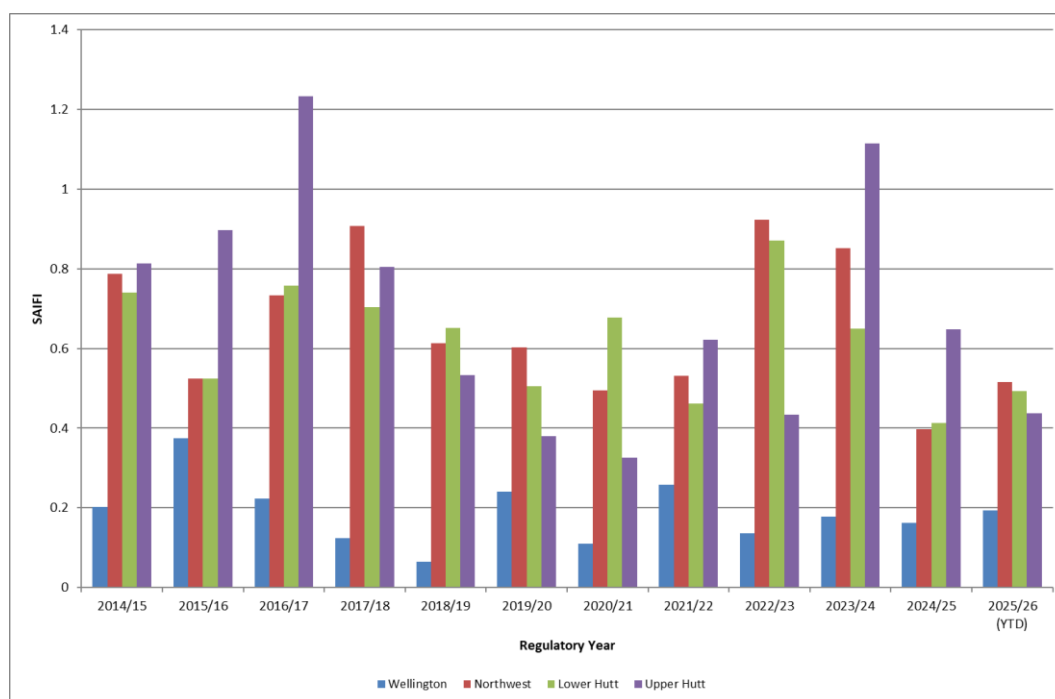


Figure 6-14 Unplanned SAIFI Performance by Network Area

These charts illustrate the variation in reliability across the network, highlighting the higher performance of Wellington city, which is predominantly underground, compared with the overhead networks supplying the Hutt Valley and Porirua regions.

6.3 Asset Efficiency Service Levels

The load factor, or utilisation, of an asset reflects a combination of customer demand profiles, regional geography, and historic network design and configuration decisions. WELL's predominantly urban network results in a higher-than-average utilisation and load density. These utilisation outcomes, in turn, indicate the performance and effectiveness of WELL's fixed distribution assets.

6.3.1 Planning Period Levels

WELL aims to maintain its high level of asset utilisation, consistent with other networks with similar characteristics. While WELL has a very high customer density, it also exhibits below-average energy intensity per ICP. Table 6-1 summarises performance against each utilisation measure over the planning period, alongside key network density metrics.²⁴

Overall, WELL's asset utilisation performance is expected to remain broadly stable over the planning period, reflecting the underlying characteristics of its network, customer density, and demand profile, and remaining consistent with networks exhibiting similar structural attributes.

²⁴ Values as per the PricewaterhouseCoopers (PwC) Electricity Line Business 2024 Information Disclosure Compendium.

	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 2025	59.1%	37.4%	4.8%	34.3	172.2	9.7	14,330
WELL 2025	52.2%	48.6%	4.9%	106.8	464.8	36.1	12,883
WELL Target 2026-2036	>50%	>40%	<5%	-	-	-	-

Table 6-1 WELL Asset Efficiency Levels

6.4 Consolidated Service Level Measures in Retailer Agreements

Section 6.5 of this AMP sets out WELL's service level targets, which retailers apply on behalf of their customers. These service levels are referenced in the Default Distributor Agreement (DDA), rather than being prescribed within the agreement itself.

The service levels are designed to:

- Provide clarity and transparency regarding the quality of service that WELL commits to delivering.
- Ensure service standards are aligned with WELL's regulatory quality obligations and remain achievable within approved regulatory allowances.
- Allow WELL to adjust and refine its service standards in response to changes in its price path or regulatory requirements.
- Transparently link the service standards to the work programmes, operational activities, and funding outlined in this AMP.

WELL's service levels operate within a broader consumer protection and regulatory framework, including the Consumer Guarantees Act, the Utilities Disputes framework, and price and quality regulation under Part 4 of the Commerce Act 1986. Together, these frameworks establish minimum service standards, provide customer remedies, and regulate the balance between price and quality outcomes.

The Commission's price-quality regulation ensures that service performance and funding are aligned over the regulatory period.

Customer complaints are managed through WELL's internal resolution process, with the Utilities Disputes scheme available as an independent escalation pathway where required.

6.5 Customer Experience Service Levels

WELL seeks to balance the level of services customers require with the value they place on those services, both now and over the long-term. To support this balance, WELL has established the following asset management objectives related to customer service levels:

- Understand customer needs and the value customers place on WELL's services.
- Deliver a high standard of customer service.

- Adjust the quality and type of services, including innovative offerings, to reflect changing customer needs.
- Reduce unit costs over time.
- Implement whole-of-life, least-cost solutions.

WELL uses the insights from its 'Voice of Customer' (VOC) programme to better understand customer priorities, perceptions of service quality, and areas of concern. These insights inform investment over the planning period. VOC inputs include customer survey responses, feedback received through community engagement events and trade shows, and interactions across WELL's customer contact channels.

6.5.1 Customer, stakeholder, and community engagement

In 2025, WELL undertook a range of customer, stakeholder, and community engagement initiatives to improve the overall customer experience and inform service delivery and investment decisions across the network. These initiatives are grouped below into key areas of focus, reflecting how WELL engages with customers, communities, and stakeholders to support continuous improvement in service outcomes.

6.5.1.1 Connections and Self-service Improvements

WELL replaced the portal used by its retailers to lodge and track service requests on behalf of their customers. The new platform provides improved information security and data quality, with retailers' feedback being overwhelmingly positive.

In addition, in 2025, a revised self-service application form for distributed generation applications was published on the WELL website. The updated form streamlines the application process, reducing customer effort and ensuring all required information is captured upfront, thereby minimising the associated costs with incomplete applications.

WELL is also reviewing its pricing policy for small to medium-sized network extensions to ensure that customer contributions remain fair, equitable, and proportionate to the costs of providing new connections. In parallel, WELL is monitoring changes signalled by the Authority that are expected to affect network connection and distributed generation processes. WELL will update its processes as required to remain aligned with evolving regulatory and market requirements.

6.5.1.2 Community Engagement

Electrify the Hutt was a community-led initiative to improve understanding of electrification opportunities and their implications for households and businesses. WELL sponsored the initiative, participated in the exhibition, delivered a seminar presentation, and administered a customer survey. The survey tested customers' understanding of cost and quality trade-offs, future network investment choices, and willingness to change energy-use behaviours, providing valuable insights to inform future planning and engagement.

6.5.1.3 Stakeholder Engagement

Significant storm events in May 2025 highlighted the importance of strong collaboration between WELL and the Wellington Region Emergency Management Office (WREMO). These events identified opportunities to improve collaboration during major events. Building on these lessons, WELL presented at a WREMO staff day to support our ongoing partnership arrangements and to enhance understanding of WELL's network, operational challenges, and the implications for coordinated emergency response.

6.5.2 Customer expectations are increasing

Customer experience outcomes are increasingly influenced by digital capabilities, system integration, workforce responsiveness, as well as the resilience of the underlying network and communications infrastructure. Customers consistently express a desire for price stability while expecting reliability and service standards to be maintained. At the same time, WELL faces an ageing asset fleet and the need to preserve N-1 security, which reduces available headroom to accommodate growth without augmentation. Delivering timely outage notifications, accurate restoration estimates, and transparent communication during planned and unplanned events depends on digital systems and operational processes. Investment in these areas competes with sustained investment in asset renewal, capacity, and resilience. This investment is needed to maintain service levels at a standard that customers have become accustomed to.

When digital and operational renewals coincide with asset replacement, growth, and reliability-driven investment requirements, the DPP4 allowances are insufficient to progress these programmes concurrently while maintaining established security standards. Under a fixed, smoothed allowance framework, constraints may limit WELL's ability to efficiently align expenditure with customer expectations. In this context, a CPP is likely to provide greater flexibility to align revenue allowances with the efficient delivery of asset renewal, system growth, and customer-support capabilities, ensuring reliability and service standards continue to reflect evolving customer expectations while maintaining long-term affordability and efficiency.

6.5.3 Complaint management and root cause analysis

WELL manages customer complaints through a structured internal process, with staff continuing to meet directly with customers who have raised concerns to better understand their experiences and identify underlying causes. This approach forms part of WELL's Root Cause Programme, which targets people, process, and system issues that contribute to customer dissatisfaction. Staff from WELL and its contractors meet regularly to review complaints and develop corrective actions jointly.

In previous years, WELL achieved a sustained reduction in customer complaints. In 2025, total complaint volume increased by approximately 12% compared with 2024, largely reflecting the impact of significant storm events in May and October, which resulted in prolonged and widespread outages. Complaint volumes are closely correlated with the frequency and duration of outages, resulting in increased customer contact and dissatisfaction.

When adjusted to remove the effects of these storm events and normal seasonal patterns, the underlying level of complaints in 2025 was broadly consistent with, and slightly lower than, 2024. Despite severe weather, WELL remains accountable for the customer experience and continues to focus on improving outage response, communications, and coordination during major events.

6.6 Forward programme

In 2026, WELL will continue to focus on improving customer experience through:

- Self-service improvements—further development of web-based self-service tools to enhance functionality and customer experience.
- Service improvements—ongoing analysis of complaint drivers, including direct engagement with customers who have reported poor service, to better understand their experiences and identify improvement opportunities.

- **Community and Stakeholder Engagement**—continued engagement with customers and representative organisations on matters influencing future network development and operation, including electrification-driven demand growth, asset renewal, and replacement needs, distributed generation integration, population growth, and changing customer expectations.

Engagement activities may include consultation on network planning approaches and the trade-offs between reliability, resilience, service levels, and cost. Engagement will be undertaken through a range of channels, including direct community engagement, representative organisations, trade and public events, community groups, and other relevant forums.

WELL will also continue engaging with communities most affected by outages as part of the worst-performing feeder programme. This programme provides customers with updates on network activities in their area and information on actions they can take to help improve reliability, such as vegetation management. WELL will continue to work closely with city councils on tree regulation matters and the issuing of trim-and-cut notices, as this remains an important contributor to maintaining network reliability.

Finally, WELL will continue to visit customers who have experienced perceived poor service, to better understand their experience and inform ongoing improvements to service delivery.

6.6.1 Customer Surveys

WELL conducts a regular customer survey to assess customer perceptions across a range of service and value dimensions. The survey includes questions designed to assess whether customers consider the price-quality trade-off in electricity delivery to be appropriately balanced. The survey sample, referred to as the Monthly Outage Sample, comprises customers who have recently experienced an outage. These customers are more likely to have well-formed views on reliability and value, having been directly impacted by a service interruption.

Figure 6-15 compares the results of two key price-quality trade-off questions.

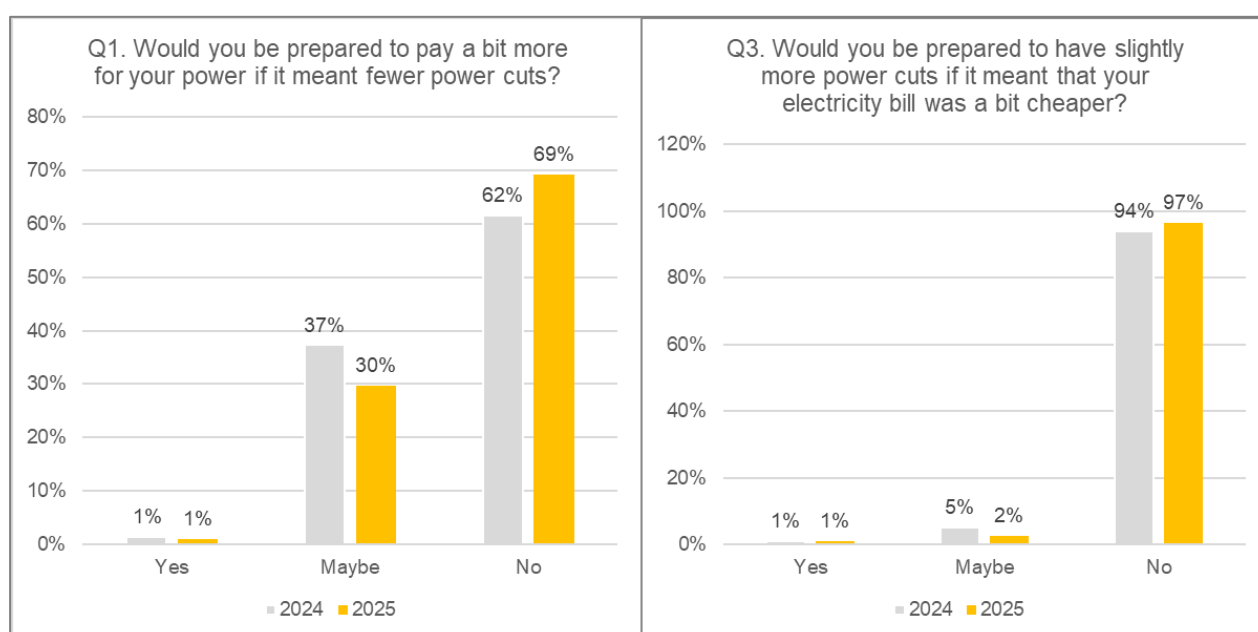


Figure 6-15 Sample of 2025 Customer Survey Results

For Q1, the proportion of customers willing to pay more for electricity in exchange for fewer outages has continued to decline from its 2024 level. Correspondingly, the share of customers unwilling to pay more for improved reliability has increased, likely reflecting ongoing cost-of-living pressures. These results reinforce the prioritisation of affordability in the current economic environment, a central consideration of this AMP.

The results for Q3 continue to indicate that customers remain unwilling to accept a reduction in reliability, even if doing so would lower their electricity costs. This finding highlights the enduring expectation of reliable supply as a baseline service outcome.

Taken together, the results for Q1 and Q3 demonstrate a clear tension in customer preferences. Customers value affordability and reliability highly and are unwilling to trade them off. This reinforces the need for WELL to carefully balance investment and operational decisions to maintain reliability outcomes while minimising cost pressures on customers.

6.6.2 Power Restoration Service Levels

WELL applies two power restoration service levels, Urban and Rural, reflecting differences in network characteristics and customer expectations across its service area. These service levels have been informed by customer feedback 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 defined as a network fault that results in a complete loss of supply to one or more points of connection within a rural area.

The geographical areas classified as urban and rural for the purposes of power restoration areas are illustrated in Figure 6-16.

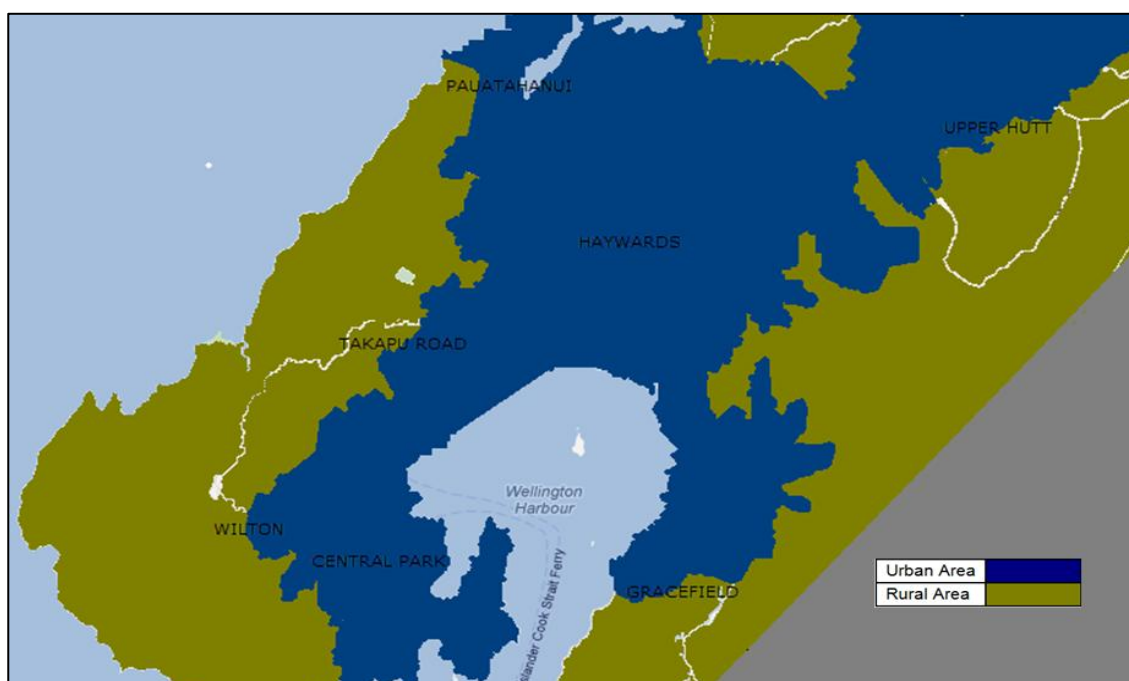


Figure 6-16 Geographical Map of Power Restoration Areas

6.6.2.1 Planning Period Targets

The power restoration service level targets are expected to remain unchanged over the planning period and are summarised in Table 6-2.

Power Restoration Service	Urban	Rural
Maximum time to restore power	3 hours	6 hours

Table 6-2 Standard Power Restoration Service Level Targets 2026-2036

6.6.3 Notification of Faults and Outages

In addition to reliability and affordability, customers increasingly expect accurate and timely information about their service and its status. Customer feedback indicates that most customers are willing to tolerate occasional outages, provided they are kept informed about restoration times following a fault. As a result, maintaining clear and effective information flows is a key component of delivering good customer service.

In support of this objective, WELL sets and monitors performance targets for its Contact Centre and incentivises its primary field service provider to ensure customers affected by prolonged outages receive accurate and timely status updates.

WELL publishes information on unplanned outages through its website and mobile app. However, the primary channel for outage communications is from WELL to retailers, who are then responsible for informing their customers. Accordingly, WELL's outage notification service levels focus on the timeliness of information provided to retailers. These notification service levels are set out in Table 6-3 for unplanned outages and Table 6-4 for planned outages.

Outage Type	Notification Action	Notification Service Level
Area Network Fault	Provide retailer(s), to the extent reasonably known at the time: - A description of the reason for the interruption - The area affected - 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 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

6.6.4 Notification of New Connections

Once WELL receives an application for a new connection, it provides the relevant connection details to the retailer, enabling the retailer to engage directly with the end customer. WELL's notification timeframes for new connections are set out in Table 6-5 provides.

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 to a site visit, and/or network expansion	3 working days

Table 6-5 New Connection Notification Timeframes

6.6.5 Connection, Disconnection, Capacity Change Timeframes

Table 6-6 sets out WELL's service-level timeframes for processing new connections, disconnections, and changes to connection capacity, providing transparency on expected response times for retailers and customers.

Activity	Requirements	Time to Action
Livening a new connection	Dependent on: - All necessary equipment in place - Network upgrades or extensions are not required - All other requirements met	10 working days
Temporary disconnections	If the retailer authorises it to do so. 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 the request is accepted and the requirements for the Point of Connection that must be met prior to the capacity change.	3 working days
Capacity change where only a fuse change is required	If the requested capacity change is likely to disrupt supply to other end customers, it may be delayed.	10 working days

Activity	Requirements	Time to Action
Vacant Site Disconnection	Provided that: - Access is available. - There is an accessible isolating device (fuse) that isolates only the requested Point of Connection. 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: - Access is available. - There is an accessible isolating device (fuse) that isolates only the requested Point of Connection. For complex decommissions where there is no accessible isolating device, therefore excavation, outages and/or capping of network cables are 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) that isolates only the requested Point of Connection.	3 working days

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

6.6.6 Supply Quality Investigations

WELL monitors voltage quality on its low-voltage network through customer reports of abnormal voltage conditions. This approach reflects current limitations in access to smart meter voltage data, which would otherwise enable more systematic and network-wide assessment of voltage performance.

When a retailer notifies WELL of a supply quality issue, WELL undertakes an investigation and responds to the retailer with details of the issue's nature and cause. The investigation of voltage quality issues is becoming increasingly complex due to the growing prevalence of CER, such as rooftop solar, batteries, and electric vehicle chargers, which introduce two-way power flows on the low-voltage network.

Table 6-7 sets out WELL's service-level response timeframes for investigating supply-quality issues.

Supply Quality Investigations	Time to Action
Investigate the problem and respond to the retailer, detailing the nature of the problem	7 working days
Where an 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 across the network has led to more customer queries about supply voltage. In many cases, the investigation confirms that the voltage at the point of supply is within the allowed range prescribed by the Electricity (Safety) Regulations 2010, and that the observed issues arise from a voltage rise within the customer's installation. EDBs are responsible for maintaining a 230V $\pm 10\%$ voltage at the point of supply. Where this requirement is met, the EDB is not responsible for the voltage experienced

by appliances within a customer's installation. As a result, public education is increasingly important to ensure customers understand that voltage readings taken at inverters or other smart appliances within the installation do not necessarily indicate a non-compliant network supply voltage.

Where a voltage-quality non-compliance is confirmed on the network, WELL takes appropriate corrective action. Responses may include adjusting distribution transformer tap settings, altering network open points, or implementing capital solutions such as installing larger distribution cables or additional transformers. These responses can require extended timeframes to complete, reflecting the need for detailed analysis, identification of the most cost-effective solution, and practical implementation. This is particularly relevant where solutions require planned outages and equipment procurement, both of which are subject to outage notification requirements and supply-chain lead times.

In addition, WELL must ensure that any corrective action resolves the identified voltage issue without creating unintended consequences for other customers. For example, reducing transformer tap settings to address high voltage during summer must be carefully assessed to avoid low-voltage issues during winter periods.

6.6.7 Customer Complaints

WELL receives customer complaints and enquiries through multiple channels, including its contact centre, website, and Customer Service email inbox²⁵. WELL has adopted the Utilities Disputes Code of Practice to manage complaints, ensuring a consistent and transparent approach to complaint handling.

All 'Times to Action', the timeframes within which WELL responds to complaints and enquiries, are aligned with the Utilities Disputes rules and protocols. These response timeframes are set out in Table 6-8.

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

Table 6-8 Complaint and Enquiry Response Timeframes

6.6.8 Contact Centre Service Levels to Customers

WELL measures the performance of its Contact Centre against a defined set of key performance indicators (KPIs). Customer feedback, call observation results, and regular operational reviews inform an ongoing programme of continuous improvement for the Contact Centre.

6.6.8.1 Contact Centre Targets

WELL monitors the performance of its Call Centre against four service-level measures. These measures are designed to assess call responsiveness, accessibility, and overall service quality, and are outlined below.

1. Grade of Service (GOS) (A1)—reflects the proportion of calls answered within a defined threshold of 30 seconds. The target is to answer 85% of calls within this timeframe.

²⁵ We_CustomerService@welectricity.co.nz

2. Call response (A2)—captures the average waiting time for calls to be answered. The target is an average wait time of 20 seconds. This benchmark reflects international standards for utility call centres and is informed by ongoing industry practice and customer survey results.
3. Missed calls (A3)—tracks the proportion of abandoned calls, where the caller disconnects before the call is answered. The target is an abandonment of 4% or less. This threshold target also aligns with international utility call centre standards and recognises that calls may be abandoned for reasons unrelated to call centre performance. However, sustained abandonment rates above 4% may indicate underlying service issues.
4. Call Quality (C1)—call quality is assessed through a monthly review of between 10 and 20 randomly selected call recordings. Calls are evaluated by both the Contact Centre and WELL against 16 quality criteria. Results are compared and discussed to identify opportunities for improvement, with a target quality score of 85% or higher.

6.6.8.2 Planning Period Targets

The Contact Centre service level targets are intended to deliver consistent performance over the planning period and are set out in Table 6-9. Reported performance in 2025 was materially affected by two severe storm events in May and October, which resulted in exceptionally high call volumes. In May, the Contact Centre received 5,332 calls, approximately 3,800 above the 2025 monthly average, while October recorded 2,124 calls, around 600 above average.

These short-term demand spikes adversely affected volume-sensitive measures, including Grade of Service, average wait time, and call abandonment rates. Notwithstanding these impacts, call quality performance remained above target throughout the year.

To provide a clearer view of underlying performance, a normalised results column has been added to Table 6-9. This adjustment recalculates the Grade of Service, Call Response, and Missed Calls metrics to reflect expected outcomes had call volumes in May and October aligned with typical seasonal patterns.

SL	Service Element	Measure	Target	2025 Performance	2025 Performance (normalised)
A1	Grade of Service	Average service level across all categories	$\geq 85\%$	77%	89.4%
A2	Call response	Average wait time across all categories	< 20 seconds	65.3 seconds	15.8 seconds
A3	Missed calls	Total missed/abandoned calls across all categories	$< 4\%$	6.3%	2%
C1	Call Quality	Agent performance against 16 key quality criteria for a random selection of calls	$\geq 85\%$	87.6%	87.6%

Table 6-9 Contact Centre Service Level Targets 2026-2036

On this normalised basis, 2025 performance was 89.4% for Grade of Service, an average wait time of 15.8 seconds, and a missed call rate of 2.0%. These results indicate stable underlying Contact Centre performance once storm-related impacts are excluded.

7 Reliability Performance

Electricity is an essential service for the community. While some level of interruption is unavoidable, and major disruptions may occur from time to time, customers reasonably expect the electricity supply to be restored without undue delay. Prolonged outages can adversely affect customer welfare and the regional economy.

Against this backdrop, WELL is committed to providing a consistent, reliable, and secure electricity supply under normal operating conditions. This commitment recognises that customers are generally willing to accept a reasonable level of supply interruption where this avoids significantly higher costs associated with mitigating infrequent or low-probability events.

This section describes WELL's approach to managing network reliability and is structured as follows:

- Reliability performance limits and targets
- Reliability strategies
- Reliability reporting and forecasting
- Reliability controls

The reliability framework described in this section establishes clear and binding performance limits under the price-quality regulation regime, including annual SAIDI and SAIFI limits and the Extreme Event compliance standard. These statutory obligations sit alongside WELL's broader risk management responsibilities and require coordinated asset fleet strategies, targeted renewal programmes, vegetation management, operational controls, and resilience investment. In particular, the condition and risk profile of critical assets, such as ageing gas-filled cables, must be actively managed to avoid low-probability but high-consequence failures that could materially affect reliability outcomes.

As noted, reliability performance is influenced by asset condition, network configuration, vegetation exposure, planned capital works, and the increasing frequency and severity of extreme weather events. The forecast increase in planned outages associated with the expanded capital works programme underscores the interdependency between renewal and reinforcement activity and short-term reliability metrics.

Efficiently managing these trade-offs requires aligning investment timing with reliability risk thresholds and operational constraints. Where funding constraints delay the proactive replacement of high-risk assets, including gas-filled cables, the risk of catastrophic failure and prolonged unplanned outages increases, placing additional pressure on compliance with regulatory quality standards.

A targeted example of this constraint is the renewal programme for ageing gas-filled cables. These assets present a low-probability but high-consequence failure risk: a catastrophic failure could result in significant asset damage, extended outages in dense urban areas, and complex, time-consuming restoration works. Given their location within constrained corridors and critical load zones, replacement is typically disruptive, technically complex, and costly.

Under a fixed and smoothed allowance framework, flexibility to fund clustered renewal of these assets may be limited. Incremental deferral to remain within allowance envelopes may preserve short-term affordability,

However it increases exposure to catastrophic failure risk, prolonged outages, and heightened safety and environmental consequences. Staging replacements purely to align with allowance smoothing may also increase whole-of-life costs and reduce the effectiveness of risk mitigation strategies.

In this context, a CPP is likely to provide greater flexibility to align revenue allowances with the efficient and coordinated replacement of gas-filled cables, along with associated reinforcement and resilience measures. This would support prudent risk management, sustained compliance with regulatory quality limits, and the continued delivery of reliable electricity supply in the long-term interests of consumers.

7.1 Reliability Performance Limits and Targets

The regulatory regime applying to WELL establishes annual reliability limits 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. WELL's applicable regulatory reliability limits are presented in Table 7-1.

Regulatory Period	1 April 2025 to 31 March 2030
Annual Unplanned SAIDI Limit	37.82
Annual Unplanned SAIFI Limit	0.5829
Period Planned SAIDI Limit	76.66
Period Planned SAIFI Limit	0.6089
Extreme Event Customer Minutes Limit	6 million

Table 7-1 WELL Regulatory Reliability Limits

WELL's SAIDI and SAIFI targets are set out in Table 7-2. These targets assume that unplanned SAIDI and SAIFI beyond 2030 will be calculated using the DPP4 determination methodology, including the treatment of Major Event Days, and that WELL will have met its unplanned reliability targets through to 2030.

Reliability Targets	Disclosure Year Beginning 1 April									
	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035
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	12.89	13.35	12.82	11.40	10.92	11.29	12.46	11.43	11.64	10.26
Planned SAIFI target	0.083	0.086	0.082	0.073	0.070	0.073	0.080	0.074	0.075	0.066

Table 7-2 Network Reliability Performance Targets

WELL expects planned outage targets to increase over the forecast period, reflecting an expanded capital works programme. While most of the increase in expenditure relates to sub-transmission and zone substation reinforcement projects, which can generally be delivered without customer outages, there is also a material increase in 11 kV reinforcement activity. This activity is expected to result in higher planned outage indices.

Figure 7-1 presents WELL's actual unplanned SAIDI performance over the past 15-year period, measured on a renormalised basis in accordance with the DPP4 methodology.

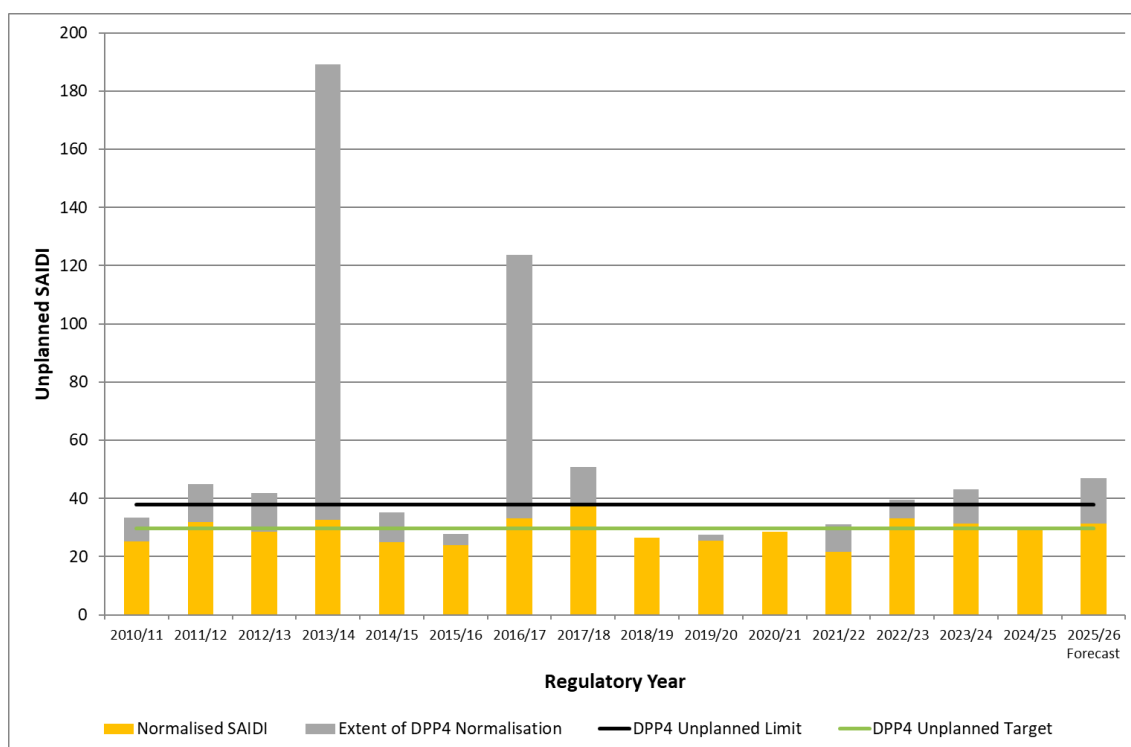


Figure 7-1 DPP3 Normalisation Applied to Historical Unplanned SAIDI Performance

The planned outage forecast is based on the following assumptions:

- Approximately 67% of recent planned SAIDI has been attributable to capital works, with the remainder attributable to maintenance activities.
- Maintenance-related SAIDI is assumed to remain constant over the forecast period, reflecting no material change in maintenance requirements for existing assets or in work practices, for example, increased generator usage or changes to live-work rules.
- Planned SAIDI arising from capital works is assumed to be proportional to the combined expenditure on growth, renewal, relocation, and quality of supply programmes, excluding expenditure on sub-transmission, zone substation, and distribution cable assets, as these projects can generally be delivered without requiring significant planned outages.
- Planned outage efficiency, measured as SAIDI per dollar of capital expenditure, is assumed to remain constant over the forecast period.
- Planned SAIFI is assumed to be proportional to planned SAIDI. Accordingly, planned CAIDI is assumed to remain constant, reflecting no material change in the nature or duration of planned outages.

The reliability limits outlined above are binding regulatory obligations under the price-quality framework and represent enforceable quality standards rather than aspirational targets. Sustained compliance requires the timely delivery of asset renewal, network reinforcement, vegetation management, and resilience measures that directly influence outage frequency and duration. As asset fleets age and exposure to severe weather events increases, reliability outcomes become more sensitive to the timing and scale of supporting investment.

Under a fixed and smoothed allowance framework, flexibility to respond to clustered reliability risks may be constrained, increasing reliance on short-term operational controls or incremental deferral of capital works. In this context, a CPP is likely to provide greater flexibility to align revenue allowances with the timing of efficient, reliability-supporting investment, reducing breach risk and supporting sustained compliance with regulatory quality limits in the long-term interests of consumers.

7.1.1 Extreme Event Compliance Standard

DPP4 includes an Extreme Event compliance standard intended to identify outage events with an exceptional impact on customers that would not otherwise be reflected in the standard quality measures due to normalisation for Major Event Day (MED). WELL's Extreme Event standard is set at 6,000,000 customer minutes, which currently equates to 33.8 SAIDI minutes. Outages caused by external factors, such as storms and third-party interference, are excluded from the standard.

WELL has reviewed the parts of its network that are most susceptible to extreme events. The outcomes of this assessment are summarised in Table 7-3.

The Extreme Event compliance standard recognises that certain high-impact events, while infrequent, can materially affect customer outcomes and network performance. Mitigating the consequences of such events requires targeted resilience investments, including redundancy enhancements, fire-suppression systems, mobile substations, improved network ties, and pre-established generation connection points. These measures are often capital-intensive and delivered as discrete projects aligned with risk assessments rather than smooth annual expenditure profiles.

Extreme Event	Outage Duration to Exceed Standard	Solutions to Reduce Consequences
33 kV Cable Fire at Central Park GXP	2 hours	- Cables within the switch room have intumescent coatings. - 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 switch room in 2021. - Mobile substation and generation connection points.
Loss of Karori Zone Substation	25 hours	- Pre-establish generation connection points. - Improve 11 kV ties to adjacent zone substations (Section 9.4.43).

Table 7-3 Top Three WELL Extreme Event Risks

Under a fixed and smoothed allowance framework, the ability to proactively implement resilience measures before risk thresholds are breached may be constrained, thereby increasing reliance on reactive restoration rather than pre-emptive mitigation. In this context, a CPP is likely to provide greater flexibility to align revenue allowances with the timing of efficient resilience investments, supporting prudent management of high-impact, low-probability risks and sustained compliance with the Extreme Event standard in the long-term interests of consumers.

7.2 Reliability Strategies

For reliability management, WELL categorises outages into three types: unplanned, planned, and high-impact low-probability (HILP). The strategies applicable to each outage type are summarised 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

WELL manages network reliability through a combination of asset and network development strategies, each addressing different drivers of outage risk and service performance.

Asset Fleet Strategies

Asset fleet strategies focus on the management of specific asset fleets and are discussed in Section 8. These strategies are predictive in nature and define the asset management actions required to achieve targeted future reliability levels. Each fleet strategy incorporates a risk-based assessment of the asset class, taking into account population characteristics, asset condition and health, and criticality indicators.

The outputs of fleet strategies are prioritised asset management actions that support expected asset performance and reliability. By driving improvements in asset condition and targeting investment toward higher-risk or higher-criticality assets, fleet strategies directly influence both the current and future likelihood of unplanned outages and the level of service customers experience. Asset fleet strategies also help manage outage consequences by directing investment toward assets whose failure would affect a larger number of customers or more critical parts of the network.

Fleet strategies include forecasting components that estimate future replacement rates across asset populations and form a key input to expenditure forecasts. The forecasting methodologies used are described in Section 8.2.

Secondary Asset Fleet Strategy

The secondary asset fleet strategy defines the protection and fault-indication requirements to effectively manage network security and limit the consequences of unplanned outages. This strategy is discussed in Section 8.5.9.

Network Development Strategies

Network development strategies complement asset fleet strategies by ensuring the network continues to operate at targeted security and capacity levels. These strategies support network integrity during outages and are discussed in Section 9.

7.2.2 High Impact Low Probability Outages

HILP events pose a distinct reliability challenge, as their consequences can be severe despite their infrequency. Managing HILP risk requires targeted resilience investment, including redundancy, physical hardening, improved interconnection, and enhanced restoration capability. These measures are typically driven by risk assessment rather than historic outage trends and often involve discrete, capital-intensive projects delivered ahead of potential events.

Under a fixed and smoothed allowance framework, the ability to proactively sequence resilience investments in line with evolving risk assessments may be constrained, thereby increasing reliance on reactive restoration rather than pre-emptive mitigation. A CPP is likely to provide greater flexibility to align funding with the timing of efficient resilience, thereby supporting prudent management of HILP exposure while maintaining sustainable reliability performance and regulatory compliance.

Resilience Strategy

A key portfolio-level strategy is WELL's Resiliency Strategy, which is discussed in Section 12. This strategy sets out the investment required to mitigate HILP events.

Stakeholder awareness of the region's major earthquake risk increased significantly following the 2016 Kaikōura earthquake, leading to a heightened focus on resilience and associated investments. While this investment is not directly reflected in standard reliability or quality metrics, it substantially enhances WELL's preparedness for major events and is valued by both its stakeholders and customers.

7.2.3 Planned Outages

Planned outages are an inherent component of delivering maintenance, renewal, and network reinforcement programmes and therefore represent a deliberate trade-off between short-term customer interruption and long-term reliability outcomes. The scale and sequencing of planned outages are closely linked to the timing of capital works and the efficiency with which projects can be bundled and delivered.

When capital investment is staged or fragmented to align with fixed-allowance smoothing, planned outage volumes and durations may increase due to repeated network reconfiguration or smaller work packages. Conversely, coordinated and efficiently timed delivery can minimise the cumulative impact on customers.

An inherent consequence of planned interruptions is a temporary increase in exposure to unplanned outages. On the WELL network, planned works are typically managed by operating the network at N rather than N-1 security while construction or maintenance activities are underway. Although this approach enables efficient delivery of renewal and reinforcement programmes, it reduces redundancy during the work window.

As a result, if an unplanned fault occurs while the network is operating without N-1 support, the likelihood of customer outages and the scale of impact may increase. These dynamic highlights the careful balance required between progressing essential capital works and maintaining reliability performance within regulatory limits. In this context, a CPP is likely to provide the flexibility to align funding with efficient capital sequencing, thereby supporting the effective management of planned-outage impacts while maintaining compliance with regulatory reliability standards.

Planned Outage Strategy

The planned outage strategy comprises guidelines and initiatives that govern the management of planned outages. The measures are designed to minimise the impact of planned outages on customers, manage the risks associated with network reconfiguration, and provide clear protocols for customer communication during planned outages.

7.3 Reliability Reporting and Forecasting

Figure 7-2 WELL's Reliability Reporting Structure illustrates WELL's reporting and governance framework for reliability performance management, including the regular meetings that support each level of oversight and the key reports provided.

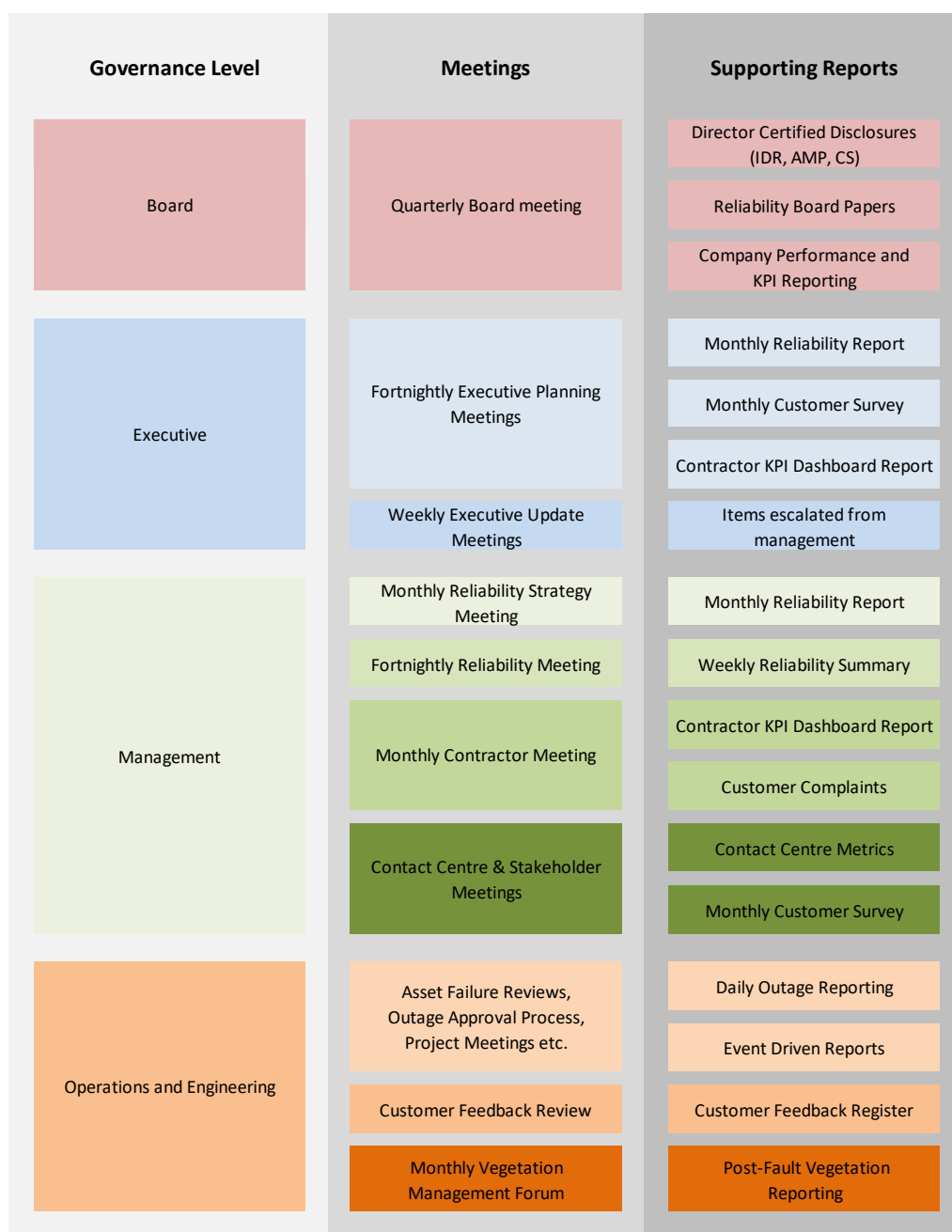


Figure 7-2 WELL's Reliability Reporting Structure

Reliability reporting typically includes progress against annual reliability targets. Where reports identify emerging issues or areas of concern, they also set out recommendations to adjust reliability controls. These recommendations are escalated to the appropriate governance or management level for assessment of any required trade-offs with other company performance objectives. Governance decisions arising from this process are formally documented through Board papers and meeting minutes.

WELL's reliability Board Papers and monthly reporting include forecasts of the year-end SAIDI and SAIFI outcomes for the current disclosure year, enabling ongoing assessment of the effectiveness of existing reliability controls.

7.3.1 SAIDI Forecast by Fault Type

Forecasts of SAIDI by outage type are derived using the historical monthly distribution of SAIDI by cause. The approach applies year-to-date SAIDI for each outage cause and scales it by the proportion of annual SAIDI that has historically occurred each month.

The results are presented using a waterfall chart, an example of which is shown in Figure 7-3. This presentation highlights the key drivers of year-end performance and clearly identifies any significant outliers relative to the reference period standard deviation. The chart also indicates the effectiveness of existing controls by outage type and serves as a trigger to investigate the need for additional controls where required.

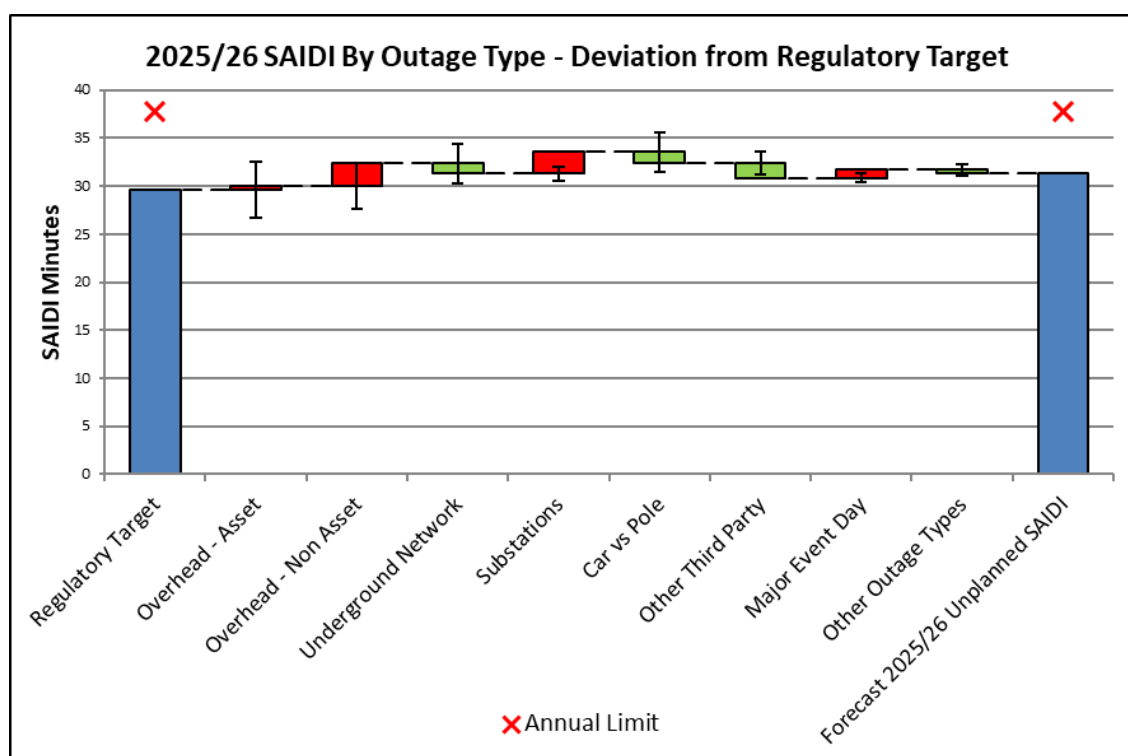


Figure 7-3 Waterfall Chart of 2025/26 SAIDI Performance by Outage Type

This forecasting methodology has been used since October 2017 and is included in monthly reports to the Executive and in network performance updates provided to the Board.

7.3.2 Reliability Trend Analysis

Detailed outage trend analysis is an important element in assuring that asset performance is not deteriorating over time. WELL's monthly reliability report to the Executive includes analysis of trends in monthly SAIDI by outage type.

Where material trends are identified, the relevant outage types are subject to further analysis. SAIDI is disaggregated into its components, outage frequency, outage duration, and the number of customers affected, and trends in each component are examined to identify the underlying drivers of the observed SAIDI trend. The results of this analysis are reviewed at the Reliability Strategy Meeting to determine whether additional or revised controls are required to address emerging trends. An example of this trend reporting is shown in Figure 7-4.

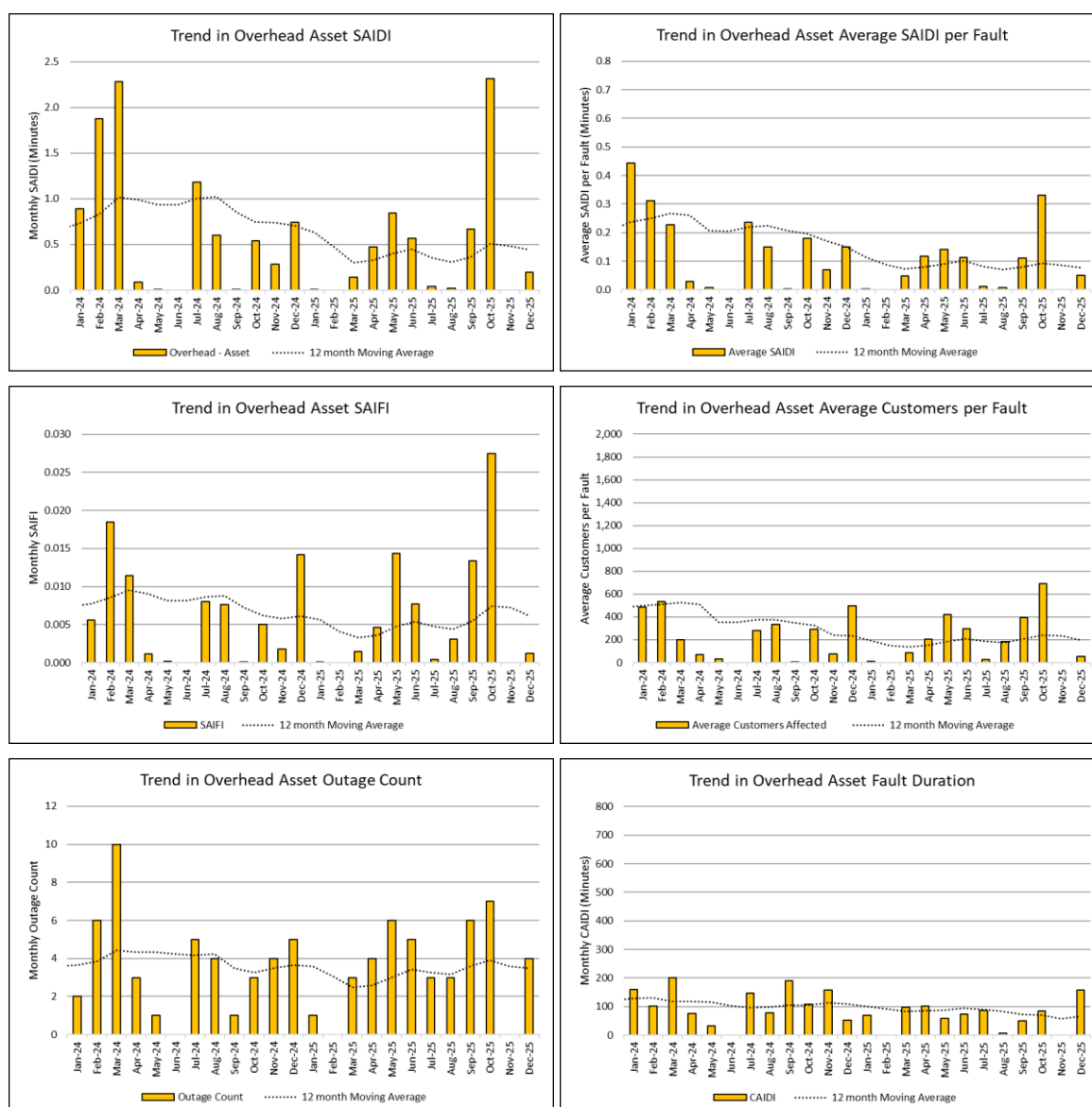


Figure 7-4 Example Trend Analysis from Monthly Reliability Report

7.3.3 Wind Effect Normalisation

The majority of unplanned SAIDI on WELL's network occurs on overhead assets, with monthly performance strongly influenced by weather conditions. To assess whether overhead network performance is better or

worse than expected for prevailing wind conditions, WELL normalises overhead outage count against the maximum daily wind gust speed. This approach enables proactive performance analysis. Where the overhead network underperforms at low or moderate wind speeds, potential underlying asset or vegetation issues can be identified and addressed in advance, rather than being discovered reactively following a severe wind event.

Two categories of overhead faults are included in this analysis:

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

Normalisation is based on the number of outages occurring on a given day relative to the maximum wind gust recorded on that day. Outage count is used in preference to SAIDI, as SAIDI outcomes are materially impacted by factors such as fault location and response time, which are not directly related to wind exposure.

Daily wind gust data is sourced from MetService weather stations at Kelburn, Porirua, and Upper Hutt. For simplicity, the model does not differentiate by wind direction. The baseline for the analysis is drawn from the reference period data used for the DPP4 regulatory period, with the relationship between the average outage frequency and daily wind gusts illustrated in Figure 7-5.

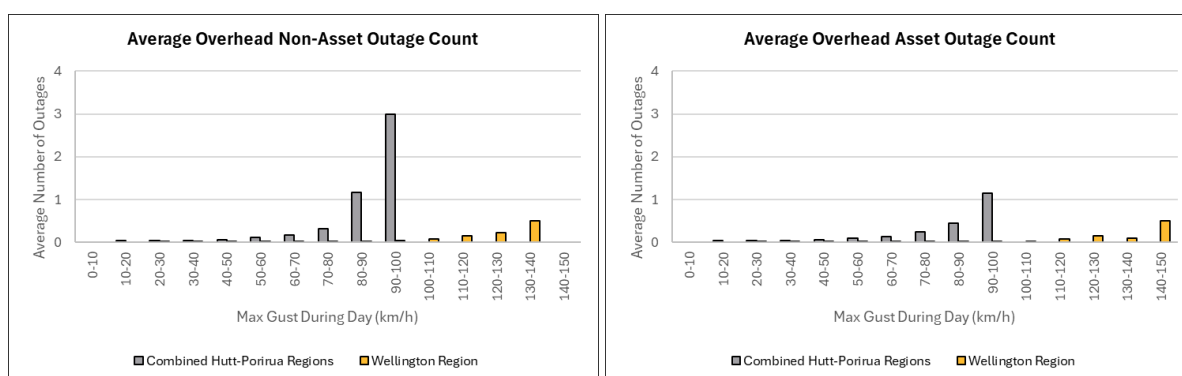
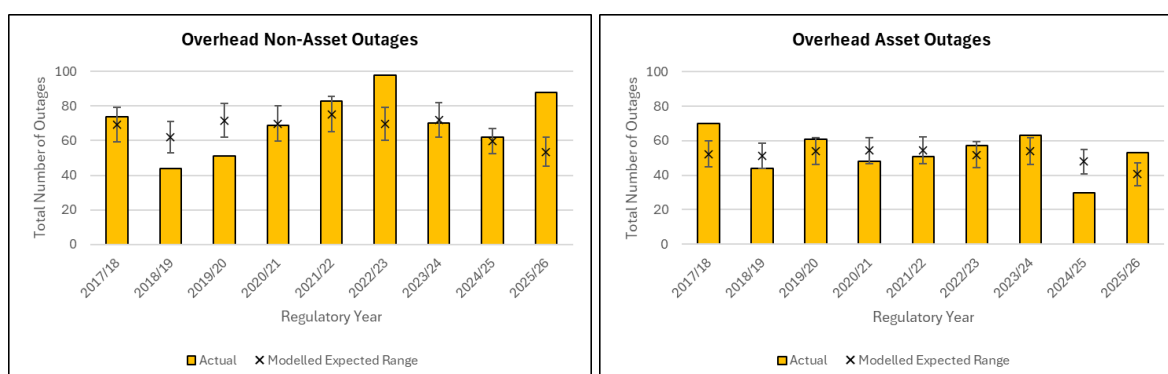


Figure 7-5 Overhead Outages by Maximum Daily Wind Gusts for DPP4 Reference Period

Applying these averages to the maximum daily wind gusts yields an expected annual number of outages that reflect the wind conditions experienced.

An example of this analysis is shown in Figure 7-6, where the expected range is presented as one standard deviation on either side of the expected average.



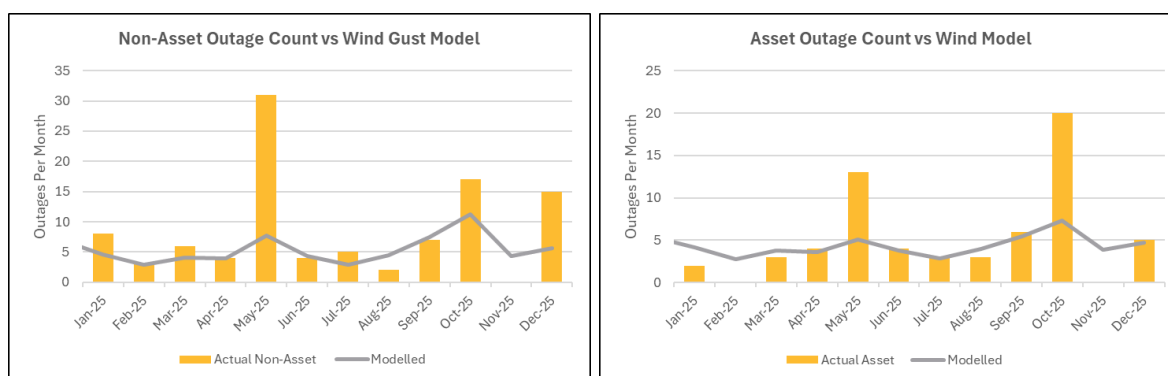


Figure 7-6 Example Overhead Outage Normalisation

These charts, presented in the monthly reporting to Management, indicate that overhead network performance in 2025 was broadly consistent with expected wind conditions, except for a small number of months affected by major events.

7.3.4 Monthly Feeder Performance Summaries

Identifying specific parts of the network experiencing clusters of outages is important for early detection of emerging reliability issues. To support this analysis, WELL's monthly reliability reporting includes feeder performance summaries, presented as pseudo-heatmaps.

These heatmaps show the number of outages by cause for each feeder, month by month. For large or complex feeders, the analysis is further refined by subdividing feeders into their major branches, enabling more precise identification of outage patterns that materially influence overall reliability performance. An example pseudo-heatmap reporting is shown 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 – Paekākāriki 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 produced for overhead asset failures, vegetation-related outages, no-fault-found outages, and all-cause outages. The analysis includes all feeders that have experienced at least two outages for a given cause over the preceding 12 months.

This approach provides a simplified, time-based view of the network, enabling rapid identification of poorly performing feeders and emerging trends that warrant more detailed analysis.

7.3.5 Low Voltage Reliability

Low-voltage outages are not included in either SAIDI or SAIFI performance indicators. WELL chooses to monitor low-voltage performance from both customer service and network-condition perspectives to identify emerging trends and inform corrective actions.

Analysis of fault types and locations has indicated that overhead low-voltage failures are concentrated in 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 low-voltage failures are most prevalent in Petone, while in Porirua, they are most concentrated in Titahi Bay. A commonality across these locations is proximity to the coast, coupled with high exposure to wind.

In response, WELL is developing a targeted low-voltage reliability intervention programme to improve performance in these poor-performing areas.

7.3.6 Reliability Reporting, Forecasting and Regulatory Oversight

The reporting and forecasting framework described above provides structured oversight of reliability performance and forward visibility of emerging breach risk. Where modelling indicates increasing exposure to quality limits, timely intervention through targeted renewal, vegetation management, network reinforcement, or operational measures may be required to mitigate that risk. The effectiveness of this governance framework depends not only on accurate data and transparent reporting, but also on aligning funding with identified reliability drivers.

Under a fixed and smoothed allowance framework, responsiveness to emerging reliability risks may be constrained if expenditure flexibility within the regulatory period is limited. A CPP is likely to provide greater flexibility to align revenue allowances with the reliability risk of forecasts, supporting proactive management of quality performance and reducing reliance on reactive or suboptimal mitigation strategies.

7.4 Reliability Controls

WELL applies a range of reliability controls to manage the frequency and impact of outages while enabling the safe and efficient delivery of maintenance and renewal programmes.

7.4.1 Planned Outages

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

Outage Peer Review

All requests for planned outages are subject to review by the WELL Network Operations team. Each proposed outage is assessed to confirm that all reasonably practicable and cost-effective measures have been taken to minimise customer impact.

Temporary Generation

WELL has used temporary diesel generation to support planned outages since 2018, initially funded through the DPP2 reliability incentive scheme. The reduction in incentive rates for DPP3 has reduced the economic viability of temporary generation for planned outages. As a result, temporary generation continues to be used where it delivers a clear customer benefit, but at a lower level than in earlier periods, as the cost of provision can exceed the value placed on planned outage reductions unless a large number of customers are affected.

WELL applies structured decision matrices to guide the use of temporary generation for both planned and unplanned outages. In parallel, WELL is actively exploring lower-emissions alternatives to diesel generation, consistent with its broader decarbonisation objectives.

7.4.2 Overhead Equipment

WELL applies targeted controls to manage the reliability performance of overhead equipment and to reduce the likelihood and impact of unplanned outages.

Outage Investigations

The WELL Asset Engineering Team investigates all unplanned outages exceeding 0.45 SAIDI minutes to identify root causes and recommend corrective actions. This process has previously identified recurring component failures, including specific types of overhead line connectors. Insights from these investigations have informed changes to work practices and network standards, which are expected to reduce the failure reliability impacts associated with these components.

7.4.3 Vegetation

Vegetation is a significant contributor to outages on overhead sections of the network, potentially materially affecting customer reliability. WELL implemented a range of controls to mitigate vegetation-related risks and reduce their impact on network performance.

Community Engagement

WELL engages with Community Boards in areas affected by vegetation-related outages to explain network performance and highlight actions local communities can take to improve the reliability through effective tree management. As part of this approach, WELL explores opportunities to coordinate vegetation work along entire lines, including aligning outages and traffic management requirements. This coordination can reduce the costs tree owners face in meeting their regulatory responsibilities.

Risk-based Vegetation Control

WELL, in partnership with Treescape, applies a risk-based approach to vegetation management. The types and frequencies of vegetation surveys undertaken are set out in Table 7-5. The annual vegetation management budget is informed by the surveys scheduled each year, along with allowances for customer liaison associated with cut or trim notices, and any first cuts that may be required.

Survey Type	Definition	Survey Frequency
Sub-transmission Feeder	33 kV circuit, with or without an underbuilt 11 kV or low voltage	2 years
Risk Feeder	Worst-performing 11 kV feeders	Annual
HV Survey	11 kV circuit, with or without an underbuilt low voltage	3 years
Low Voltage Survey	Low-voltage circuit	5 years
Rapid Response Survey	Out-of-cycle reactive survey	As required

Table 7-5 Vegetation Management Surveys

Routine surveys extend beyond the regulated clearance zones and include risk-based assessments of trees located outside those zones. All network components are assigned a potential reliability consequence, which determines the assessment level required for trees in each area. Individual out-of-zone trees are assessed for their likelihood of failure, with the depth of assessment scaled to the potential consequences of an outage.

Likelihood and consequence are then combined to determine the reliability risk posed by each tree and to assess the cost-effectiveness of cutting or trimming to reduce that risk. While the regulatory framework does not provide WELL with direct authority to manage vegetation outside the regulated zones, the risk-based approach provides a structured basis for engaging with tree owners about the potential impacts of their trees on power supply reliability.

Covered Conductors

Covered conductors have been installed in areas prone to vegetation-related outages since 2018. WELL has procured conductor covers that can be deployed as priority areas are identified. These installations have proven effective in eliminating the reliability impacts associated with wind-borne debris, such as branches and bark. No outages have been caused by vegetation where conductor covers have been installed, as shown in Figure 7-8.

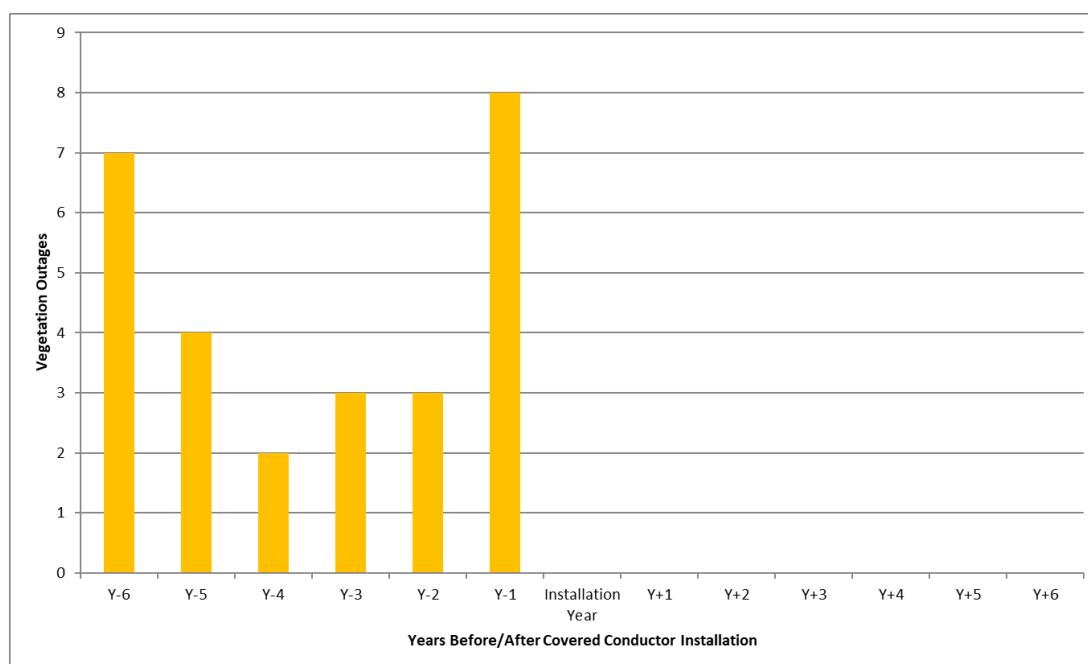


Figure 7-8 Aggregated Vegetation Outages in Covered Conductor Areas

7.4.4 Underground Equipment

WELL has been trialling a range of cable testing technologies on poorly performing underground cables using multiple diagnostic tools. The purpose of this proactive trial is to build a robust understanding of the outputs from these tools and to correlate test results with observable cable performance. This will provide confidence in the suitability of these technologies as a condition assessment tool to:

- Determine whether a tested cable needs to be proactively replaced, either in full or for targeted sections.
- Support the development of a predictive model of cable condition.
- Inform forecast future cable replacement requirements.

Further details of underground cable modelling are provided in Section 8.5.4.

7.4.5 Car versus Pole Incidents

WELL's approach to car-versus-pole incidents prioritises rapid site stabilisation to support emergency services and minimise impacts on customers.

8 Asset Lifecycle Management

This section provides an overview of WELL's assets and the maintenance, refurbishment, and replacement strategies applied over the planning period. The strategies are designed to optimise operational expenditure and capital investment in asset replacement and renewal, while ensuring the network continues to meet service-level targets and effectively manages the risks inherent in operating an electricity distribution network.

Specifically, this section covers:

- An overview of the asset fleet
- Risk-based asset lifecycle planning
- Asset health and criticality assessment
- Maintenance practices
- Asset maintenance and renewal programmes
- A summary of asset replacement and renewal activities

The asset lifecycle investment requirements set out in this section represent a sustained and material increase in renewal and replacement expenditure that cannot be efficiently accommodated within the current DPP allowances. Future investment is driven by the convergence of asset ageing across multiple high-criticality asset classes, the increasing complexity of renewal in an urban environment, and the need to maintain safety, reliability, and environmental performance in line with regulated quality standards

From an efficiency perspective, the DPP constrains WELL's ability to align expenditure with the efficient timing of asset replacement. The smoothing of allowances and limited flexibility to respond to clustered end-of-life drivers increase the risk that replacement is deferred beyond the economically optimal point. Such deferral may reduce short-term expenditure but leads to higher whole-of-life costs through increased corrective maintenance, higher failure rates, and the eventual need for reactive or emergency replacement.

The investment programme described in this section is expected to deliver long-term benefits to consumers by reducing the likelihood and impact of unplanned outages in high-criticality parts of the network, managing safety and environmental risks associated with ageing subtransmission and substation assets, and avoiding inefficient boom-and-bust investment cycles arising from deferred renewal. By enabling timely and coordinated replacement of end-of-life assets, the programme supports stable and predictable network performance outcomes over time and reduces the risk of higher whole-of-life costs associated with reactive maintenance and emergency replacement

8.1 Fleet Summary

This section summarises the asset population for each category prescribed by each Information Disclosure Requirement (ID), with a detailed breakdown in Table 8-1.

IDR Category	Asset Class	Section	Measurement Unit	Quantity
Subtransmission	Subtransmission Cables	8.5.1	km	140.7
	Subtransmission Lines	8.5.6	km	53.8
Zone Substations	Zone Substation Transformers	8.5.2	number	52
	Zone Substation Circuit Breakers	8.5.3	number	380
	Zone Substation Buildings	8.5.4	number	32
Distribution and LV Lines	Distribution and LV Lines	8.5.5	km	1,651.7
	Streetlight Lines	8.5.7	km	817.6
	Distribution and LV Poles	8.5.5	number	40,153
Distribution and LV Cables	Distribution and LV Cables	8.5.8	km	3,045.9
	Streetlight Cables	8.5.8	km	1,158.4
Distribution Substations and Transformers	Distribution Transformers	8.5.9	number	4,554
	Distribution Substations	8.5.9	number	4,011
Distribution Switchgear	Distribution Circuit Breakers	8.5.10	number	1,237
	Distribution Reclosers and Line Circuit Breakers	8.5.12	number	27
	Distribution Switchgear - Overhead	8.5.13	number	2,680
	Distribution Switchgear - Ground Mounted/Ring Main Units	8.5.10	number	2,366
Other Network Assets	Low Voltage Pits, Pillars, and Cabinets	8.5.11	number	23,668
	Protection Relays	8.5.15	number	1,484
	Load Control Plant	8.5.17	number	25

Table 8-1 Asset Population Summary

8.2 Risk-Based Asset Lifecycle Planning

Risk-based asset lifecycle planning at WELL encompasses the full life of an asset, from design and commissioning through to maintenance, renewal, and replacement. This approach comprises the following key elements:

- Design, construction, and commissioning in accordance with network standards, including the use of standardised designs and equipment where appropriate.
- Condition-based risk assessments informed by asset performance and history.

- Routine inspections, condition assessments, and servicing of in-service assets.
- Evaluation of inspection outcomes against public and worker safety, customer service levels, performance expectations, and risk control requirements.
- Identification of maintenance requirements and equipment specifications to address known issues.
- Repair, refurbishment or replacement of assets where required.

At every stage of the asset lifecycle, public and worker safety is the highest priority.

8.2.1 Preventative and Corrective Maintenance Strategy

WELL applies a risk-based approach to asset lifecycle planning, underpinned by a preventative maintenance programme. Preventive maintenance tasks are assigned to defined cycles based on known asset reliability histories and are refined over time as condition data and performance trends across each asset fleet are observed.

Corrective maintenance identified during inspections is prioritised based on defect severity and the associated risk to public and worker safety, network performance, and customer service levels. This risk-based prioritisation ensures that resources are directed to areas of highest need while maintaining efficiency across the wider network.

8.2.2 Standardisation and Asset Design Philosophy

Standardised designs are applied to high-volume asset classes, including overhead and underground network construction, distribution substations, and distribution switchgear. This approach delivers a number of benefits, including:

- Improved safety and operational efficiency through contractor familiarity with standard equipment and configurations.
- Procurement efficiencies through reduced lead times and improved availability of spares.
- Economic benefits, as standardised assets generally have a lower unit cost than customised alternatives.

For high-value, low-volume assets, such as subtransmission cables and zone substation equipment, designs are tailored to meet the specific requirements of the relevant network standards.

8.2.3 Replacement Decision-Making and Whole-of-Life Efficiency

Electricity distribution assets have a long but finite service life and ultimately require replacement. Replacing assets prematurely is inefficient because the remaining service life is not fully utilised. Conversely, deferring replacement beyond an asset's effective life increases the risk of safety incidents and supply interruptions.

Asset replacement planning, therefore, involves balancing the costs of ongoing maintenance against the increasing risk of asset failure, impacts on public and contractor safety, and declining supply reliability. These decisions are informed by asset health, criticality, and observed performance trends across each fleet.

8.2.4 Consideration of Non-Traditional Solutions

Non-traditional solutions may, over time, create opportunities to defer or avoid asset replacement by enabling the decommissioning of end-of-life assets at materially lower cost. However, these solutions have not yet

reached the scale and reliability required for EDBs to rely on them for core network planning decisions, particularly given the potential consequences of breaching the quality path if third-party solutions underperform. As a result, non-traditional solutions are not currently considered a viable input to WELL's asset lifecycle planning.

8.2.5 Regulatory Context and Application of the Framework

WELL's risk-based asset lifecycle planning framework is designed to optimise whole-of-life outcomes by aligning maintenance, renewal, and replacement decisions with asset condition, criticality, and the consequences of failure. Effective application of this framework requires intervening when asset risk reaches an efficient threshold, rather than deferring action due to short-term funding constraints.

While the DPP has historically supported prudent prioritisation, the increasing concentration of end-of-life risk across multiple asset classes reduces the scope to defer replacement without compromising efficiency or increasing long-term costs. In this context, a CPP is likely to provide regulatory flexibility that better aligns expenditure with risk-based replacement timing, which would support the efficient application of WELL's asset lifecycle planning approach.

8.3 Asset Health and Criticality Analysis

WELL assesses the condition of assets using the EEA Asset Health Indicator Guide (2019). This methodology defines a set of health indices for each asset class scored on a scale from H5 to H1. The scale represents distinct asset life-cycle phases, each associated with different levels of intervention need and replacement benefit and influenced by identified end-of-life drivers. The health index scale is shown in Table 8-2.²⁶

Health Indicator	EEA Definition
H5	As-new condition. No drivers for replacement.
H4	Normal in-service deterioration. No drivers for replacement.
H3	End-of-life drivers for replacement are present. Onset of unreliability.
H2	End-of-life drivers for replacement are present. The probability of failure is the maximum that would normally be tolerated in service.
H1	Replacement/renewal recommended.

Table 8-2 AHI Categories and Definitions

For each asset, the poorest-performing health index determines the overall Asset Health Indicator (AHI), with the overall score further moderated where multiple indices fall below H4.

In parallel, WELL applies asset criticality indicators (ACI) in accordance with the EEA Asset Criticality Guide (2019). Asset criticality is assessed across public and worker safety, customer impact, and environmental consequences. Each dimension is scored on a scale of C4 (minor impact) to C1 (high impact), based on the credible consequences of asset failure after mitigation is applied. The criticality scale is shown in Table 8-3.²⁷

²⁶ Asset Health Indicator Guide, EEA, 2019

²⁷ Asset Criticality Guide, EEA, 2019

Criticality Indicator	EEA Definition
C4	Credible consequences of failure are broadly tolerable.
C3	Asset failure would cause some disruption and inconvenience, but systems are in place to anticipate and manage the outcomes.
C2	Asset failure could cause harm to people, assets, the business, or the environment. The consequences are tolerable but should be avoided or mitigated where practicable.
C1	Credible consequences of failure would generally be intolerable.

Table 8-3 ACI Categories and Definitions

The combined assessment of asset health and criticality produces a health-criticality matrix for each major asset class. An asset's position within the matrix indicates its relative risk profile, with each cell showing the number of assets, expressed as units or circuit kilometres, depending on asset type, within that health and criticality combination. Matrix locations are assigned Risk Grades that inform asset prioritisation and investment decision-making, as illustrated in Figure 8-1 and summarised in Table 8-4.

		Best Health		Asset Health		Worst Health	
		H5	H4	H3	H2	H1	
Asset Criticality	Lowest Impact	C4	Grade 5	Grade 5	Grade 5	Grade 4	Grade 2
		C3	Grade 5	Grade 5	Grade 4	Grade 3	Grade 1
		C2	Grade 5	Grade 4	Grade 3	Grade 2	Grade 1
	Highest Impact	C1	Grade 4	Grade 3	Grade 2	Grade 1	Grade 1

Figure 8-1 Example Health-Criticality Matrix

Risk Grade	Definition
Risk Grade 5	Low relative consequences of failure. Monitor and maintain.
Risk Grade 4	Typical asset, in useful life phase. Monitor and maintain. Interventions would likely be justified on efficiency or cost/benefit considerations alone.
Risk Grade 3	Healthy but highly critical assets. Consider interventions that reduce criticality.
Risk Grade 2	A combination of criticality and health indicates an elevated risk. Appropriate intervention measures should be devised and timetabled, and current risks prudently managed in the interim.
Risk Grade 1	A combination of high consequences of failure and reduced health indicates a high risk. Intervention required.

Table 8-4 Fleet Risk Reporting Grades

The approach to asset risk forecasting varies by asset fleet, reflecting the differences in asset value, volume and the availability of condition and performance data.

Low-volume, high-value assets, such as power transformers, are subject to extensive monitoring, with a wide range of condition information available through the maintenance programme. This data supports unit-level decision-making. The Asset Health-Criticality matrix is used to identify assets with elevated risk profiles, enabling a detailed assessment of individual units to better understand risk drivers and determine appropriate management responses.

For high-volume low-value assets, such as poles and distribution transformers, extensive diagnostic testing at an individual asset level is not cost-effective. These assets are typically replaced once they reach defined condition-based replacement criteria. Replacement requirements for these fleets are forecast using survival curve modelling based on historical condition assessments and replacement data. This approach estimates the overall future replacement profile rather than the specific assets to be replaced in a given year.

High-volume linear assets, such as cables and conductors, are generally repaired following failure, with replacement decisions driven by reliability analysis, as described in Section 7. The performance of these assets is modelled using fault-per-kilometre rates to forecast future replacement and renewal needs.

Short-life assets, such as batteries, are replaced on a fixed cycle without asset modelling. Preventative maintenance activities are used to confirm that assets are not failing prematurely and to validate that the replacement frequency remains appropriate.

8.4 Maintenance Practices

WELL's maintenance practices are based on a risk-informed framework that prioritises safety, reliability, and asset condition while supporting efficient whole-of-life asset management.

8.4.1 Maintenance Standards

WELL delivers its network maintenance programme under a Field Services Agreement with Omexom as its field services provider. Maintenance activities across all asset classes are undertaken in accordance with WELL's approved standards and specifications.

Condition-based risk management is supported by a structured condition assessment and defect-identification process embedded within planned inspection and maintenance activities. Condition data collected by the field services provider is entered into the SAP PM maintenance management system and assessed alongside other key network data. This approach enables WELL to prioritise field findings, optimise asset replacement and renewal decisions and maintain visibility of maintenance activities and task completion in the field.

Vegetation management services are provided by Treescape and are delivered in accordance with WELL's policies and the Electricity (Hazards from Trees) Regulations 2003 as amended in 2024.

8.4.2 Maintenance Categories

Maintenance activities are grouped into the following categories:

- Service interruptions and emergencies—work undertaken in response to network faults, third-party incidents, and equipment failures or damage. This category includes the contractor management

overhead required to retain and mobilise resources to ensure an appropriate response to unplanned events.

- Vegetation management—planned and reactive vegetation control activities undertaken to manage safety and reliability risks. WELL's vegetation management approach is discussed further in Section 7.4.3.
- Routine and corrective maintenance and inspection—activities that support the ongoing condition assessment and performance of the network, comprising:
 - Preventative maintenance works—routine inspections and maintenance, servicing, and condition assessment undertaken across the network. Outputs from planned activities inform corrective maintenance and renewal activities.
 - Corrective maintenance works—work undertaken to address defects identified through planned inspection and maintenance activities.
 - Value-added services—customer and third-party support services, including high-load escorts, standover services for third-party contractors, and the provision of asset information for the 'B4Udig' programme to reduce the risk of third-party damage.
- Asset replacement and renewal—reactive asset replacements that do not meet the criteria for capitalisation.

Forecast maintenance expenditure for the planning period is summarised by asset class throughout this section.

8.5 Asset Maintenance and Renewal Programmes

WELL's approach to preventive maintenance and inspections across the network is outlined in this section, along with the maintenance activities performed for each asset class. Commentary is also provided on renewal and refurbishment policies, criteria, and known systematic issues.

The Information Disclosure Requirement categories, together with their associated asset classes, covered in this section are:

- Subtransmission cables
- Zone substation—Transformers, Switchboards and Circuit Breakers, and Buildings and Equipment
- Distribution and Low-voltage lines—Poles, Subtransmission Lines, and Conductors
- Distribution and Low-voltage cables
- Distribution substations and transformers
- Distribution switchgear—Ground Mounted, Low Voltage Pits and Pillars, Reclosers and Line Circuit Breakers, and Overhead Switches, Links and Fuses
- Other network assets—Substation DC Systems, Protection Devices, Load Control Equipment, and General

8.5.1 Subtransmission Cables

Subtransmission cables are critical to network security, safety, and reliability, supplying power from GXPs to zone substations that serve large customer populations and high-criticality loads. This asset class is characterised by long service lives, high replacement costs, and renewal projects that are typically discrete, location-specific, and driven by asset condition and external coordination opportunities rather than incremental investment profiles. As deterioration accelerates, the scope to defer replacement becomes limited without increasing safety, environmental, or reliability risk. These characteristics have implications for the efficient timing and funding of investment in subtransmission cables under the prevailing regulatory framework, as discussed later in this subsection.

8.5.1.1 Fleet Overview

WELL owns approximately 141 km of subtransmission cables, comprising 50 circuits that connect Transpower GXPs to WELL's zone substations. Approximately 34 km of the subtransmission network is constructed using XLPE cable, which generally requires minimal maintenance. The remaining assets are paper-insulated, with a significant portion filled with fluid or gas.

This class includes a section of subtransmission circuits between Central Park GXP and the 33 kV bus at Evans Bay, comprising oil-filled paper-insulated aluminium-sheathed (PIAS) cables. These cables are rated to 110 kV but operate at 33 kV. In addition, two 33 kV cables operating at 11 kV are treated as subtransmission assets, as they supply the Titahi Bay substation.

The total lengths and age profile of the subtransmission cable fleet are presented in Table 8-5 and Figure 8-2.

Construction	Design Voltage	Percentage	Quantity
Paper Insulated, Oil Pressurised	33 kV	29%	41.4 km
Paper Insulated, Gas Pressurised	33 kV	28%	39.2 km
Paper Insulated	33 kV	5%	7.5 km
XLPE Insulated	33 kV	25%	35.0 km
Paper Insulated, Oil Pressurised	110 kV	6%	8.9 km
Paper Insulated, Oil Pressurised	11 kV	6%	8.6 km
Total			140.7 km

Table 8-5 Summary of Subtransmission Cables

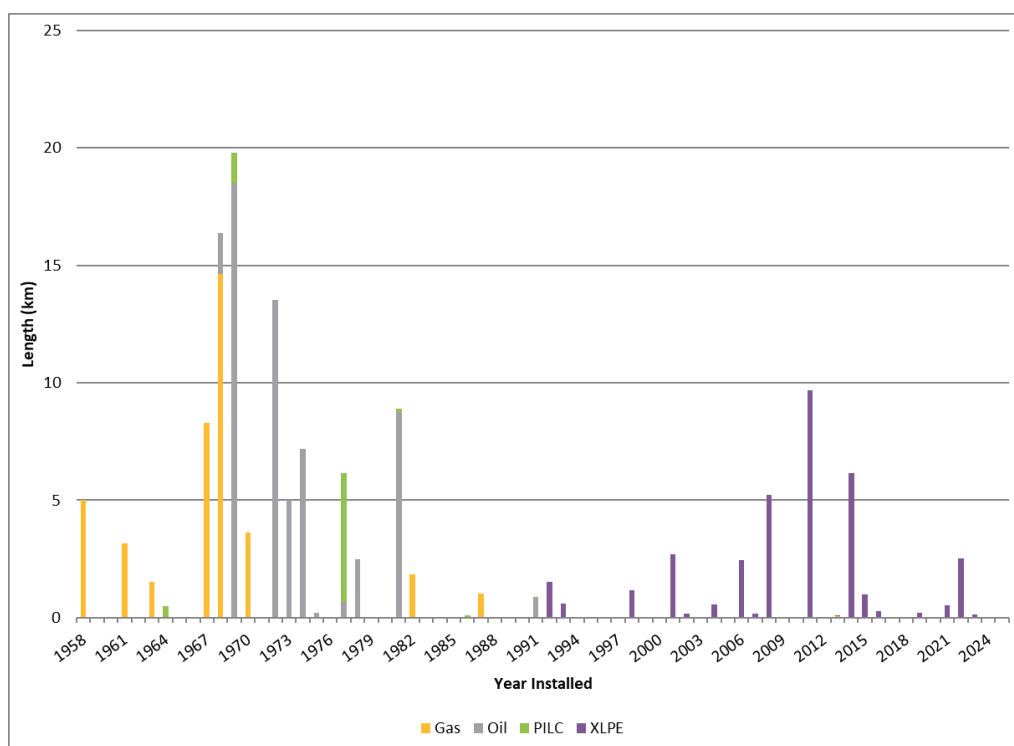


Figure 8-2 Age Profile of Subtransmission Cables

8.5.1.2 Fleet Objectives

In addition to WELL's overarching asset management objectives, Table 8-6 lists the fleet-specific objectives defined for the subtransmission cable fleet to address the critical role in network security, safety, and reliability.

Priority Area	Objective
Safety and Environment	No injuries resulting from working on and around subtransmission cables. Manage the environmental impact of fluid lost from fluid-filled cables.
Customer	Mitigate the risk of service disruption or price shocks from subtransmission cable replacement.
Network Performance	Avoid incurring SAIDI and SAIFI due to tripped 33 kV cables.
Capability	Maintaining access to a workforce competent to repair and maintain gas and fluid-filled cables until these cables are retired from service.

Table 8-6 Fleet-Specific Objectives for Subtransmission Cable Fleet

8.5.1.3 Maintenance Activities

Table 8-7 outlines the routine inspection, testing, and maintenance activities undertaken for the subtransmission cables fleet in accordance with WELL's risk-based asset lifecycle management approach.

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, and identify any third-party works that may be putting cables at risk.	Weekly

Table 8-7 Inspection and Routine Maintenance Schedule for Subtransmission Cables

In addition to the routine maintenance programme, all fluid-filled subtransmission cables are continuously monitored for pressure through the centralised SCADA system, with Management oversight provided via a monthly reporting process. This monitoring enables early detection of fluid leakage and allows prompt investigation of unexpected pressure changes.

Objective condition assessment of pressurised cables is largely limited to leakage-rate analysis, as many conventional cable condition assessment techniques, such as partial discharge testing, are not applicable to fluid-filled cable designs. The primary failure modes for these assets are stress-induced joint and sheath failures, which typically manifest as fluid leaks and localised low-pressure zones along the cable length. These conditions can generally be detected and repaired before the cable's electrical insulation properties are compromised.

Historical fault performance data is used to assess and prioritise cable replacement needs and to inform decisions on the level and type of strategic spares required to support the subtransmission cable fleet. Details of the strategic spares held are summarised in Table 8-8.

Strategic Spares	
Medium lengths of cable	Medium-length, fluid-filled cables are stored to enable replacement of short sections after damage and to allow repairs without requiring termination or 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 enable 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 19 km of emergency overhead 33 kV lines.

Table 8-8 Spares for Subtransmission Cables

8.5.1.4 Cable Condition and Failure Modes

The condition and failure modes of cables across WELL's network are described in this subsection, providing context for assessing asset risk, reliability performance, and renewal strategies.

Gas-filled cables

Gas-filled subtransmission cables are pressurised with nitrogen and have been in use internationally since the 1940s. However, they have largely been phased out in favour of fluid-filled and solid-insulated cable technologies.

WELL is currently the only EDB in New Zealand with gas-filled cables still in service, although limited installations remain in Australia. As such, the availability of expertise to repair such cables within New Zealand and Australia is now very limited and continues to decline. This is a significant risk to the continued operation of gas cables.

Given their age and design characteristics, gas-filled cables require close performance monitoring to manage deterioration and mitigate the associated risk of declining service levels. Several of these cables have been repaired following third-party damage or detection of a gas leak. We have also seen cascade failures of gas-filled cables as they were loaded following a fault on single circuits.

The trend in gas leakage from WELL's gas-filled cables for the 12 months to 28 February 2026 is presented in Figure 8-3.

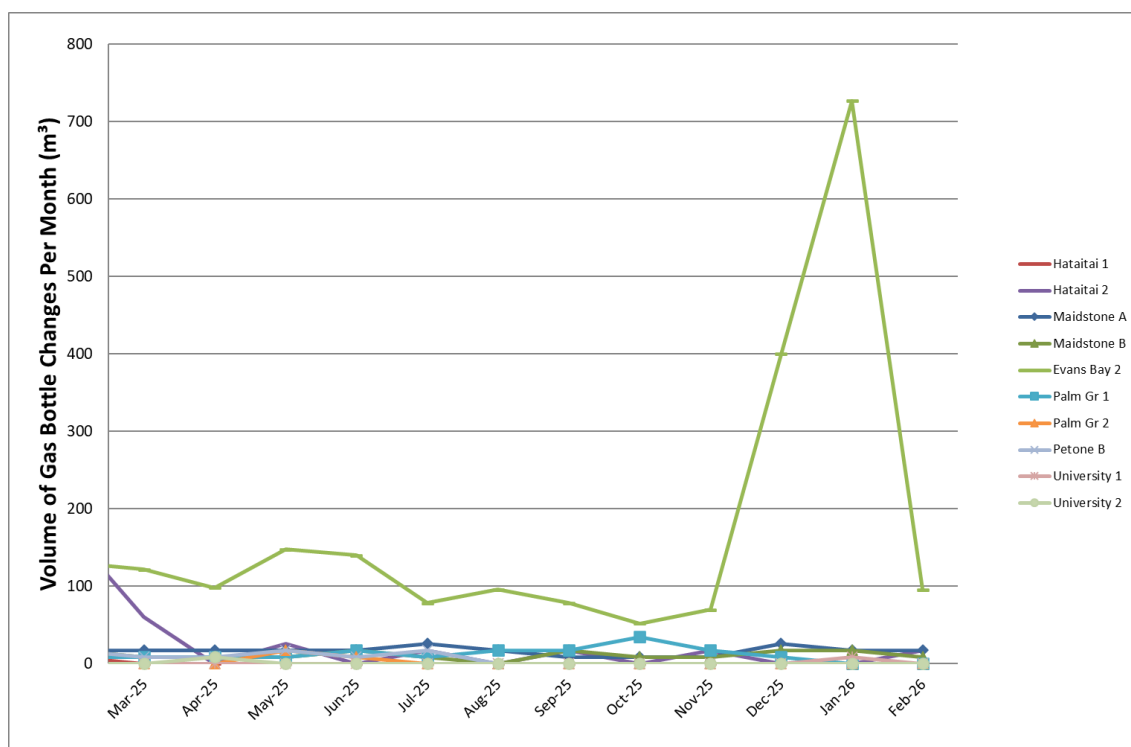


Figure 8-3 Monthly Gas-Filled Cable Leakage

The replacement of fluid and gas-filled subtransmission cables addresses a clearly identified single-point-of-failure risk with significant restoration and environmental consequences in the event of rupture following a seismic or major fault event. These assets represent legacy technology with heightened fragility exposure and increasing maintenance complexity, and their failure could materially extend outage duration for the critical load. Replacement programmes of this nature are high-value, location-specific, and delivered within defined construction windows rather than as incremental annual upgrades. Deferral beyond efficient risk thresholds would increase exposure to prolonged outages and environmental remediation risk.

Under a fixed, smoothed allowance framework, aligning funding with optimal replacement timing for these clustered high-risk assets may be constrained. In this context, a CPP is likely to provide greater flexibility to sequence gas-filled cable replacement in line with resilience priorities, supporting prudent risk mitigation and improved long-term reliability outcomes for consumers and the wider region.

Fluid-filled Cables

Fluid-filled subtransmission cables were installed across the WELL network from the mid-1960s through to 1991. While some circuits have experienced fluid leaks, the fleet has generally remained in good condition relative to its age. The potential environmental impacts of fluid leaks are mitigated by using biodegradable cable fluid.

Figure 8-4 illustrates the trend in fluid top-ups from WELL's fluid-filled cables for the 12 months to 28 February 2026. Fluid top-ups are performed to replace fluid lost to leaks and to compensate for fluid contraction at lower ambient temperatures, particularly during the winter period.

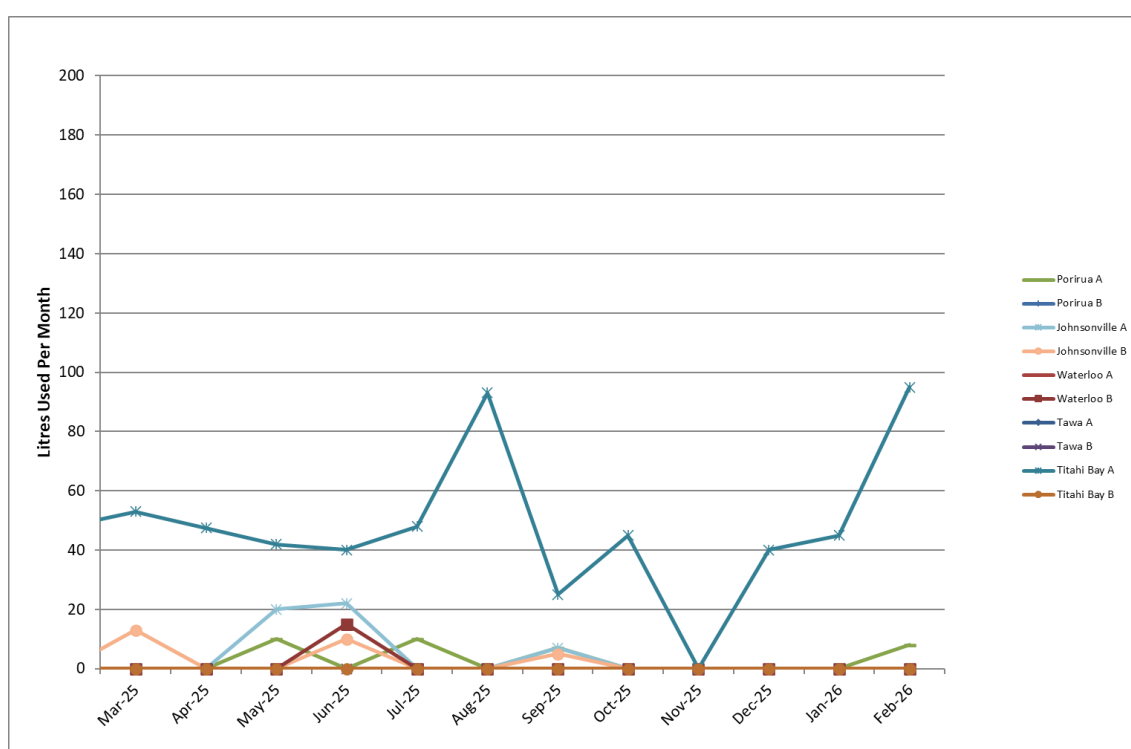


Figure 8-4 Monthly Fluid-Filled Cable Leakage

Paper and Polymeric Cables

Approximately 30% of WELL's subtransmission cable fleet comprises solid-insulation cables, including oil-impregnated paper and XLPE constructions. These assets are generally newer than the fluid-filled installations and, in most cases, are in good condition, except for the University circuits, which are discussed further below.

8.5.1.5 Forecast Future Condition

The current condition of the subtransmission cable fleet is assessed using Asset Health and Criticality Analysis of individual circuits. This analysis categorises circuits by risk and identifies those with elevated risk profiles for more detailed assessment and targeted investigation.

Future health is forecast using age-based deterioration curves, applying the ageing parameters set out in the EEA Asset Health Indicator Guide. The suitability of this modelling approach is supported by the observed performance of the subtransmission cable fleet, which remains consistent with the EEA parameters.

8.5.1.6 Subtransmission Asset Health and Criticality Analysis

The Asset Health and Criticality Analysis produces a health-criticality matrix presented in Figure 8-5, with individual circuit scores and risk ratings summarised in Table 8-9. We note that the health presented here reflects only the core health and does not account for risks related to the availability of skills or the potential for cascade failures, including the impact of higher loading on older cables.

		Asset Health				
		Best Health				Worst Health
		H5	H4	H3	H2	H1
Asset Criticality	Lowest Impact	C4				
		C3	0.9	3.0	62.5	26.0
		C2	2.6	20.7	21.5	3.6
	Highest Impact	C1				

Figure 8-5 Subtransmission Cable Circuit Health-Criticality Matrix (km)

Under WELL's asset lifecycle management framework, health ratings (H5–H1) reflect the assessed health of an asset, from good to end-of-life, while criticality ratings (C1–C4) represent the consequence of failure; movements between these categories signal changes in asset risk profile and help prioritise renewal and intervention decisions.

Where a circuit comprises multiple cable types; for example, a predominantly gas-filled cable circuit that includes sections of XLPE cable, health indices are assessed separately for each cable type, with the lowest health score determining the overall AHI for the circuit.

Subtransmission Circuit	Length (km)	Primary Type	AHI	ACI	Risk Grade
University 1 & 2	1.8/1.8	Gas and XLPE	2.0	C2	
Evans Bay 2	5.0	Gas	1.9	C3	
Hataitai 2	2.4	Gas	2.0	C3	
Titahi Bay A & B (11kV)	4.3/4.3	Fluid	2.0	C3	
Maidstone A & B	5.0/5.0	Gas	2.0	C3	
Trentham A & B	2.1/0.8	Fluid	2.3	C2	
Porirua A & B	2.7/2.7	Fluid	2.6	C2	
Seaview A & B	1.4/1.4	PILC	2.7	C2	
Kenepuru A & B	0.8/0.8	Fluid	2.8	C2	
Evans Bay 3 & 4 (110kV)	4.4/4.4	Fluid	2.9	C2	
Ira Street 1 & 2	2.5/2.5	Gas	2.2	C3	
Karori 1 & 2	4.9/4.9	Gas	2.3	C3	
Brown Owl A & B	0.9/0.9	Fluid	2.4	C3	
Hataitai 1	2.4	Gas	2.4	C3	

Subtransmission Circuit	Length (km)	Primary Type	AHI	ACI	Risk Grade
Johnsonville A & B	5.1/5.2	Fluid	2.5	C3	
Waikowhai Street A & B	1.8/1.8	Gas	2.5	C3	
Waitangirua A & B	1.6/1.4	Fluid	2.5	C3	
Naenae A & B	3.8/3.8	Fluid	2.5	C3	
Korokoro A & B	5.3/5.3	Fluid	2.6	C3	
Waterloo A & B	2.6/2.6	Fluid	2.6	C3	
Tawa A & B	1.5/1.5	Fluid	3.0	C3	
Palm Grove 1 & 2	3.2/3.2	XLPE	4.0	C2	
The Terrace 1 & 2	2.2/2.2	XLPE	4.0	C2	
Moore Street 1 & 2	5.2/5.2	XLPE	4.0	C2	
Mana	2.0	XLPE	3.1	C3	
Plimmerton	0.2	XLPE	3.1	C3	
Ngauranga A & B	0.3/0.3	XLPE	3.2	C3	
Frederick Street 1 & 2	1.6/1.6	XLPE	4.8	C2	
Wainuiomata A & B	0.1/0.5	XLPE	4.8	C3	
Gracefield A & B	0.1/0.1	XLPE	4.8	C3	

Table 8-9 Health Criticality Scores for Subtransmission Cable Circuits

Outcome of Asset Health and Criticality Analysis

Based on the outcomes of the asset health and criticality assessment, the highest-priority subtransmission cable circuits, together with any material changes since the 2025 AMP are discussed below. As noted above, the discussion below only reflects the core health of cables and does not reflect either the risks around the availability of skills or the potential for cascade failures, nor the impact of older cables seeing higher loading over time, which has previously led to increased and sudden cable failures.

University

The gas-filled University subtransmission cable circuits were largely replaced in 2006. However, approximately 500 metres of gas-filled cable remains in each circuit. These residual sections are considered highly critical, as the University zone substation supplies part of the Wellington CBD.

In 2015, both circuits experienced faults within their XLPE sections. Subsequent laboratory analysis of cable samples identified premature ageing due to thermal degradation. Based on this analysis, full replacement of both the remaining gas-filled sections and the associated XLPE cables was assessed as being required within approximately 10 years. Accordingly, replacement of these circuits is planned for 2027.

Titahi Bay

The two fluid-filled Titahi Bay subtransmission circuits have experienced multiple fluid leaks since August 2021. The pattern and frequency of these leaks over the past five years indicate that the cables are approaching the end of their life. Accordingly, replacement of both circuits has commenced and is being delivered in conjunction with a Porirua City Council urban cycleway project.

Evans Bay

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

Evans Bay Circuit 1 was retired from service in September 2024 due to its deteriorating condition. To maintain supply security, a 33 kV bus has been established at Evans Bay, supplied by the Evans Bay Circuit 2 and the two 110 kV-rated fluid-filled cables from Ira Street. These cables run from Central Park to the Evans Bay substation compound and are now designed as Evans Bay Circuits 3 and 4. This configuration forms a subtransmission ring that provides sufficient capacity to supply both the Evans Bay and Ira Street zone substations with N-1 security, while reducing the criticality of the remaining Evans Bay gas-filled circuit.

A leak appeared on Evans Bay Circuit 2 in December 2025, with the repair completed in February 2026.

Over the longer term, WELL plans to install new subtransmission cables to Evans Bay within the next 10 years, preferably aligned with planned transport infrastructure projects, as discussed in Section 9.8.2.6.

Hataitai 2

Gas-filled Hataitai Circuit 2 developed a leak at the end of 2023, which progressively worsened throughout 2024. The leak location was identified in December 2024, and repairs were completed in March 2025. Since the repair, the cable's performance has remained stable, and the AHL for Circuit 2 is expected to increase in 2026 if this trend continues.

8.5.1.7 Renewal and Refurbishment

A limited number of cost-effective options are available for refurbishing or extending the service life of subtransmission cables following major leaks, electrical discharges, or insulation failures. However, in most cases, the high cost and complexity of gas-to-fluid transition joints make full end-to-end cable replacement the most cost-effective solution.

Significant subtransmission cable renewal projects planned for delivery over the next 12 months are summarised in Table 8-10.

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

Table 8-10 Subtransmission Cable Projects for the Disclosure Year Beginning 1 April 2026

8.5.1.8 Implications of the Price-Quality Path for Subtransmission Cable Investment

The scale, criticality, and timing of the subtransmission cable renewal programme highlight the limitations of the DPP4 allowances in accommodating large, discrete replacement projects. Subtransmission cable investments are typically high-value, location-specific, and driven by asset condition, significant asset and operational risks, and external coordination opportunities rather than smooth, incremental expenditure profiles. Deferring replacement beyond efficient thresholds in response to DPP constraints would increase exposure to safety, environmental, and reliability risks, while advancing or fragmenting delivery would be inefficient.

In this context, greater regulatory flexibility to align expenditure with the efficient timing of renewal, particularly where delivery can be coordinated with third-party infrastructure works, would support better whole-of-life outcomes and reduce the risk of reactive or emergency replacement. These characteristics reinforce the relevance of considering a Customised Price-Quality Path framework for this asset class.

8.5.1.9 Expenditure Summary for Subtransmission Cables

Table 8-11 presents the expected expenditure on subtransmission cables by disclosure year. As noted above, this does not reflect the risks to skill availability or the potential for cascade failures, nor the impact of older cables experiencing higher loading over time. As such, changes to this investment schedule are likely to follow further investigation. Some cables identified for replacement are included in the System Growth expenditure outlined in Section 9.

Expenditure Type	Disclosure Year Beginning 1 April									
	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035
Titahi Bay Cable Replacement	10,973	-	-	-	-	-	-	-	-	-
University Cable Replacement	2,455	-	-	-	-	-	-	-	-	-
Karori Cable Replacement	-	-	-	-	-	6,808	15,656	-	-	-
Maidstone Cable Replacement	-	-	9,034	8,908	-	-	-	-	-	-
Waterloo Cable Replacement	-	-	-	-	-	-	-	4,239	4,411	4,310
Capital Expenditure Total	13,427	-	9,034	8,908	-	6,808	15,656	4,239	4,411	4,310
Preventative Maintenance	108	109	109	108	108	111	112	114	115	118
Corrective Maintenance	589	594	597	599	601	614	626	638	651	674
Operational Expenditure Total	697	703	706	707	710	724	738	752	766	791

Table 8-11 Expenditure on Subtransmission Cables
(\$K in constant prices)

8.5.2 Zone Substation Transformers

Zone substation transformers are among the most critical assets on WELL's network, providing the sole point of voltage transformation between the subtransmission and distribution systems for large customer populations. This asset class is characterised by very long service lives, high unit replacement costs, and limited redundancy at individual sites. Investment decisions for transformers are primarily driven by asset condition, criticality, and capacity requirements, with failure consequences that can be severe in terms of safety, service continuity, and customer impact. As transformers approach the end of their effective service lives, the scope to defer replacement becomes increasingly constrained without materially increasing operational and reliability risk. These characteristics have implications for the efficient timing and funding of transformer investment under the prevailing regulatory framework.

The composition, condition, and management of zone substation transformers and tap changers across WELL's network are described in this subsection, supporting the assessment of maintenance, renewal, and investment requirements.

8.5.2.1 Fleet Overview

WELL operates 52 33/11 kV power transformers across its network, supported by one spare unit. While the power transformer fleet is relatively mature, most transformers remain in very good condition. This is largely due to their indoor installation and relatively low utilisation, with most units operating at less than 50% of their nameplate rating.

The age profile of the zone substation transformers is shown in Figure 8-6. The mean age of the transformer fleet is 53 years.

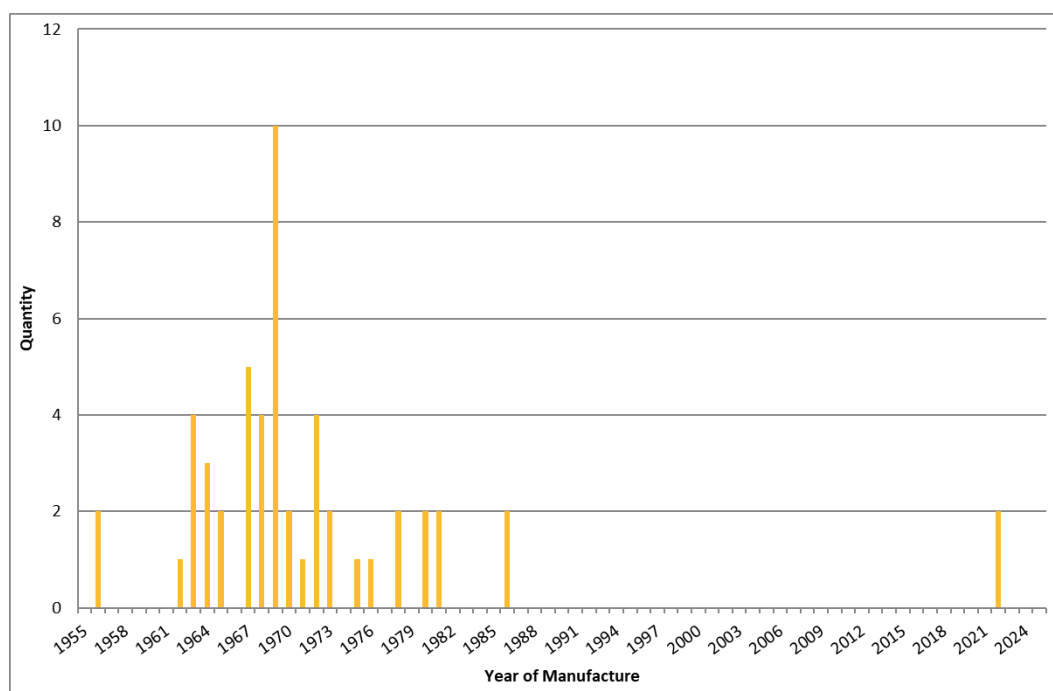


Figure 8-6 Age Profile of Zone Substation Transformers

8.5.2.2 Fleet Objectives

In addition to network-wide asset management objectives, WELL has established fleet-specific objectives for its power transformer fleet. These objectives are set out in Table 8-12.

Priority Area	Objective
Safety and Environment	No injuries resulting from working on and around power transformers. No public safety risk due to power transformers.
Customer	Mitigate the risk of service disruption or price shock from unplanned power transformer replacements.
Network Performance	Avoid incurring SAIDI and SAIFI due to power transformer unavailability.

Table 8-12 Fleet-Specific Objectives for Power Transformer Fleet

8.5.2.3 Maintenance Activities

Routine planned inspection, testing and maintenance activities are undertaken for zone substation power transformers, as outlined in Table 8-13.

Activity	Description	Frequency
Routine inspection	Visual, thermal, and partial discharge survey of the transformer and fittings.	3 monthly
Transformer main tank oil test	Dissolved gas analysis testing of transformer main tank oil, including furan analysis.	Annually
Transformer tap changer oil test	Dissolved gas analysis 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 Buchholz. Testing of the temperature gauge and probe. Confirmation of correct alarms. Test the AVR and ensure correct operation and indications.	4-yearly
OLTC maintenance	Programmed maintenance of OLTC.	4-yearly

Table 8-13 Inspection and Routine Maintenance Schedule for Zone Substation Transformers

8.5.2.4 Strategic Spares

WELL maintains critical spares for the power transformers and tap changers, as detailed in Table 8-14.

Strategic Spares	
Tap changer fittings	WELL holds several 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 the corresponding tap changer model. Spares are still available for most models on the network, and, if necessary, they can be remanufactured by third-party suppliers.
Transformer misc. fittings	Various other transformer fittings have been identified and retained for sites where leaving a transformer out of service for an extended period is unacceptable. Fittings include Buchholz relays, high-voltage bushings, and related components. If major repairs are needed, the unit will be replaced.
Spare transformers	One spare power transformer is located at the Petone Zone Substation. This unit was refurbished in 2018. Should additional spare transformers be required, one will be taken from any of several lightly loaded substations with sufficient distribution network backfeed options.
Mobile Substations	WELL owns two mobile substations comprising trailer-mounted 10 MVA 33/11 kV transformers and containerised 33 kV and 11 kV switchgear.

Table 8-14 Spares Held for Zone Substation Transformers

8.5.2.5 Transformer Condition

All zone substation transformers are operated within their rated capacities, subject to regular testing, and supported by routine condition assessments. Where evidence of heating is identified, corrective maintenance is undertaken where economically feasible. This may include tightening or renewing external connections outside the core or performing targeted maintenance on tap changers.

The most common issues observed are mechanical deterioration in moving components. Typical examples include wear of tap changer mechanisms and contacts. External condition issues can include leaking

gaskets, fan and cooling-system faults, and, for outdoor installations, corrosion and weathering of transformer tanks, particularly on tank tops, where water can accumulate.

Deterioration of barrier boards on Fuller tap changers has begun to emerge on some older units in service. This condition can cause oil to migrate between the tap changer and the main tank. Oil migration levels are being actively monitored through ongoing oil sampling and dissolved gas analysis (DGA).

8.5.2.6 Forecasting Future Condition

The future condition of the power transformer fleet is modelled using asset health and criticality analysis at an individual transformer level. This analysis categorises transformers based on risk, enabling targeted investigation and further assessment of assets with the highest risk profiles.

Future asset health is modelled using age-based deterioration curves, applying ageing parameters from the EEA Asset Health Indicator Guide. The suitability of this modelling approach is supported by the fleet's current performance, which remains consistent with the EEA parameters. However, we note that the analysis presented in this AMP does not incorporate circumstances where the loading changes significantly on older transformers. Experience has shown that changes in the loading of older transformers significantly affect asset life and increase the probability of failure. As such, further consideration of the health of the power transformer asset fleet is ongoing.

8.5.2.7 Transformer Asset Health and Criticality Analysis

The results of our current Asset Health and Criticality Analysis are presented in the health–criticality matrix shown in Figure 8-7, with individual transformer scores and ratings detailed in Table 8-15.

		Asset Health				
		Best Health			Worst Health	
		H5	H4	H3	H2	H1
Asset Criticality	Lowest Impact	C4				
		C3	2	19	3	2
		C2		21	5	
	Highest Impact	C1				

Figure 8-7 Power Transformer Health-Criticality Matrix

Transformer	AHI	ACI	Rating
Ngauranga B	1.0	C3	
Mana	1.0	C3	
Kenepuru A	1.7	C2	
Tawa B	1.9	C2	
Palm Grove T1 & T2	2.0	C2	
Frederick Street T1	2.0	C2	
Ngauranga A	1.9	C3	
Waikowhai Street T1	2.0	C3	
Plimmerton	2.0	C3	
Tawa A	2.1	C2	

Transformer	AHI	ACI	Rating
Seaview A & B	2.1	C2	
Moore Street T1 & T2	2.1	C2	
Frederick Street T2	2.2	C2	
Kenepuru B	2.2	C2	
Porirua A & B	2.2	C2	
Gracefield A & B	2.3	C2	
Trentham A & B	2.3	C2	
The Terrace T1 & T2	2.3	C2	
Wainuiomata B	2.3	C2	
Maidstone A & B	2.3	C2	
Wainuiomata A	2.4	C2	
University T1 & T2	3.0	C2	
Karori T1 & T2	2.0	C3	
Johnsonville A & B	2.1	C3	
Waterloo A & B	2.1	C3	
Brown Owl A & B	2.1	C3	
Korokoro A & B	2.1	C3	
Waitangirua A & B	2.2	C3	
Naenae A & B	2.2	C3	
Waikowhai Street T2	2.3	C3	
Hataitai T1 & T2	2.3	C3	
Ira Street T1 & T2	2.3	C3	
Evans Bay T1 & T2	5.0	C3	

Table 8-15 Health Criticality Scores for Power Transformers

8.5.2.8 Outcome of Asset Health and Criticality Analysis

Overall, many power transformers appear to be in better condition than would typically be expected for their age. This reflects several contributing factors, particularly the high proportion of units installed indoors, which reduces exposure to corrosion, and the practice of operating transformers at less than 50% of nameplate rating for security-of-supply reasons. However, we consider that significant operational risks arise as the loading of the old transformers increases. As noted above, these risks are not incorporated in the analysis shown here. The notable exceptions to the general condition profile are outlined below.

Ngauranga

Ngauranga has the oldest power transformers on WELL's network. While these units have generally performed reliably, they have had historical issues with tap-changer diverter switches. These issues continue to be monitored, with corrective maintenance undertaken as required. On a condition basis, replacement would typically be expected toward the end of the planning period. However, as discussed in Section 9.10.2 replacement of the Ngauranga transformers is planned for 2027 to address capacity constraints.

Mana

The Mana transformer is a South Wales unit manufactured in 1963 and has an estimated degree of polymerisation (DP) of approximately 400 based on furan analysis. Dissolved gas analysis (DGA) indicates

no concerning levels of combustible gases, carbon monoxide, or carbon dioxide. Online monitoring has been installed to provide improved visibility of the transformer's condition and end-of-life trajectory. Based on this information, replacement is expected to be required within the period covered by this AMP.

Kenepuru

The Kenepuru transformers are Brush units manufactured in 1971. Kenepuru A has exhibited a lower estimated DP value. Records show that both transformers underwent mid-life refurbishment between 1998 and 2002, during which it was identified that Kenepuru A had lower paper quality than comparable transformers of similar age and design. DGA results do not indicate any concerning gas levels. The condition of both units will continue to be monitored through routine maintenance, with replacement of the two transformers planned as a paired project within the AMP period.

8.5.2.9 Renewal and Refurbishment

With a large proportion of the transformer fleet approaching the end of its technical life, refurbishment is no longer considered a feasible or cost-effective option. Instead, transformers are prioritised for replacement based on risk and are replaced as they near the end-of-life.

The following activities and projects are provided for within the asset maintenance and replacement forecasts for the planning period:

- Ongoing preventive maintenance, including routine testing and inspections.
- Replacement of power transformers at the Kenepuru and Mana zone substations.

Transformer replacement projects driven primarily by capacity constraints, rather than asset health and criticality, such as those at Ngauranga and Porirua, are addressed separately in Section 9.5.

Significant subtransmission cable renewal projects planned for delivery over the next 12 months are summarised in Table 8-17.

Project	Description
Kenepuru	Detailed design and procurement to be completed during the 1 April 2026 disclosure year, ahead of replacement next disclosure year.

Table 8-16 Power Transformer Projects for the Disclosure Year Beginning 1 April 2026

8.5.2.10 Implications of the Price-Quality Path for Zone Substation Transformer Investment

The timing and scale of zone substation transformer replacement projects highlight the limitations of DPP4 allowances in accommodating high-value, discrete investments driven by asset condition rather than smooth expenditure profiles. Transformer replacements are typically delivered as site-specific projects with limited opportunity for staging or deferral once risk thresholds are reached. As noted above, the analysis presented in this AMP does not account for circumstances in which transformer loading changes significantly. Accordingly, we consider risks associated with our transformer fleet that should be addressed. Deferring replacement to manage the constraints from the DPP4 allowances increases exposure to unplanned outages, emergency replacement, and potential safety and environmental risks, while advancing replacement prematurely would be inefficient. In this context, greater regulatory flexibility to better align revenue allowances with the optimal timing of transformer replacement would support whole-of-life efficiency

and prudent risk management, reinforcing the case for considering a CPP application to fund long-term investment in zone substation transformers.

8.5.2.11 Expenditure Summary for Power Transformers

Table 8-17 sets out the expected expenditure on power transformers by disclosure year. Transformers for which replacement is driven by capacity requirements rather than asset condition are included in the System Growth expenditure described in Section 9.

Expenditure Type	Disclosure Year Beginning 1 April									
	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035
Mana Transformer Replacement	-	-	-	5,292	-	-	-	-	-	-
Kenepuru Transformer Replacement	44	5,407	-	-	-	-	-	-	-	-
Capital Expenditure Total	44	5,407	-	5,292	-	-	-	-	-	-
Preventative Maintenance	141	142	143	144	144	147	150	154	157	163
Corrective Maintenance	49	50	50	50	50	51	52	53	55	57
Operational Expenditure Total	190	192	193	194	195	198	202	207	211	219

Table 8-17 Expenditure on Power Transformers
(\$K in constant prices)

8.5.3 Zone Substation Switchboards and Circuit Breakers

Zone substation circuit breakers are critical components of the network's switching and protection systems, enabling safe and reliable operation of zone substations and the controlled supply of electricity to the distribution network. This asset class is characterised by long service lives, a mix of legacy and modern technologies, and a high degree of co-location with other critical assets within individual substations.

Investment decisions for circuit breakers are primarily driven by asset condition, operational performance, and the consequences of failure, particularly where faults may result in loss of supply to large customer groups or compromise the protection of associated plant. As circuit breakers age, the scope for managing risk through maintenance alone becomes increasingly constrained, with implications for the optimal timing of renewal and replacement.

8.5.3.1 Fleet Overview

Circuit breakers are used at zone substations to control the injection of power into the 11 kV distribution network. WELL operates 380 circuit breakers across its zone substations. The most prevalent type is the Reyrolle Pacific LMT circuit breaker. The age profile of the zone substation circuit breaker fleet is shown in Figure 8-8.

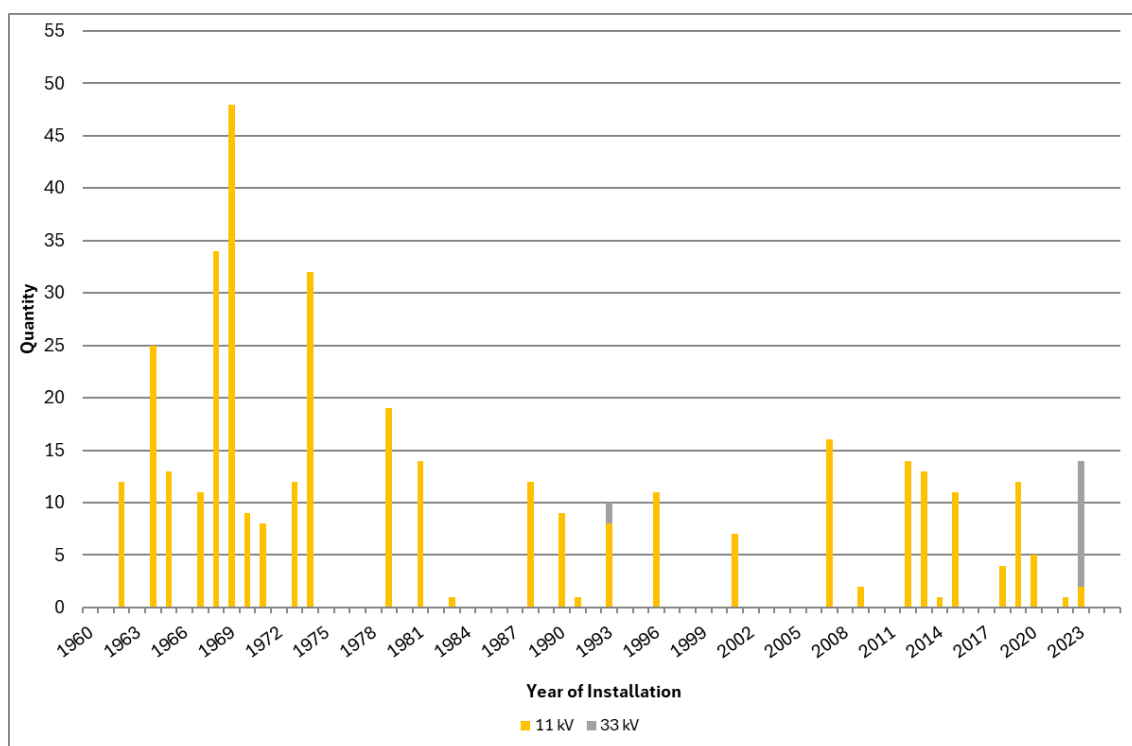


Figure 8-8 Age Profile for Zone Substation Circuit Breakers

The average age of zone substation circuit breakers on the Wellington network is approximately 42 years, with individual units ranging from relatively new to more than 60 years old. The mix of circuit breaker technologies reflects this age profile, with older units being oil-filled and newer installations using vacuum interrupters. Much of the fleet remains oil-filled, which generally requires more intensive maintenance regimes.

In 2024, a new 33 kV switching station was commissioned at Evans Bay. The installation comprises 11 circuit breakers, including a bus coupler, and has been delivered as a modular, prefabricated unit. A summary of the zone substation circuit breakers is provided at Table 8-18. The switching station is located on a raised platform to reduce the risk of flood-related damage to equipment.

Category	Quantity
33 kV Circuit Breakers	13
11 kV Circuit Breakers	367
Total	380

Table 8-18 Summary of Zone Substation Circuit Breakers

At Ngauranga, there are two 33 kV Nissin KOR oil circuit breakers that have been in service for approximately 33 years. Originally manufactured in 1964, these breakers were installed in 1993 during the substation's construction. A summary of the zone substation circuit breakers by manufacturer is provided at Table 8-19.

The units are planned for decommissioning when the transformers are replaced in 2027, as discussed in Section 9.10.2.2. In the interim, a spare unit has been sourced from Transpower to support operational resilience.

Manufacturer	Interrupter Type	Bus Insulation	Quantity
Nissin (33 kV)	Oil	N/A	2
Eaton (33 kV)	Vacuum	SF ₆	11
Reyrolle/RPS	Oil	Air	251
	Vacuum	Air	100
Siemens	Vacuum	SF ₆	16
Total			380

Table 8-19 Summary of Zone Substation Circuit Breakers by Manufacturer

8.5.3.2 Fleet Objectives

In addition to the asset management objectives that apply across the network as a whole, Table 8-20 sets out WELL's established fleet-specific objective for the zone substation circuit breaker fleet.

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

Table 8-20 Fleet-Specific Objectives for Zone Substation Circuit Breaker Fleet

8.5.3.3 Maintenance Activities

Table 8-21 sets out the routine planned inspection, testing and maintenance activities that 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, and return to service. Trip timing test before and after service.	4-yearly
11 kV Circuit Breaker Maintenance (Oil)	Withdraw and drain OCB, ensure correct mechanical operation, dress or replace contacts as required, undertake minor repairs, refill with clean oil, 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

Activity	Description	Frequency
11 kV Switchboard Major Maintenance	Full or bus section shutdown, removal of all busbars, 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.	Triggered by Inspection Results
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	An external specialist will undertake the partial discharge location service.	Annually

Table 8-21 Inspection and Routine Maintenance Schedule for Zone Substation Circuit Breakers

8.5.3.4 Strategic Spares

Given the large number of circuit breakers in service across the WELL network, maintaining an adequate level of strategic spares is essential to ensure timely defect repair and support network reliability. The most common circuit breaker type on the network is the Reyrolle Pacific LMT, which is predominantly installed at zone substations. WELL therefore holds a substantial number of spares for this fleet.

In addition, the RPS (formerly Reyrolle Pacific) switchgear factory is in Petone, enabling access to additional spares within short timeframes when required for LMT-type switchgear. An overview of the strategic circuit breaker spares held by WELL is provided in Table 8-22.

Strategic Spares	
Circuit breaker trucks	At least one circuit breaker truck of each rating (or the maximum rating where it is a universal fitment) is held for each type of withdrawable circuit breaker on the network.
Trip/Close coils	Spare coils are held for each circuit breaker type and all operating voltages.
Spring charge motors	Spare spring charge motors are held for each voltage and 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 partial-discharge issue.
33 kV Nissin KOR Circuit Breaker	One complete unit is held as a spare for the Ngauranga 33 kV circuit breakers
Mobile switchboard	WELL owns a containerised 11 kV mobile switchboard.

Table 8-22 Spare Parts Held for Circuit Breakers

8.5.3.5 Switchgear Condition and Failure Modes

Switchgear installed on the WELL network is generally in very good condition. Most equipment is installed indoors, has not been exposed to extreme operating conditions, and has undergone regular, effective maintenance.

Instances of poorer condition are typically associated with identifiable issues, such as partial discharge (particularly in cast-resin components), corrosion, external compound leaks, slow or worn operating

mechanisms, and unacceptable contact wear. Many of these defects can be readily detected and addressed through corrective maintenance programmes.

The future condition of the zone substation circuit breaker fleet is modelled using asset health and criticality analysis at the switchboard level. This analysis categorises switchboards based on risk, enabling targeted investigation and further assessment of higher-risk assets.

Based on the outcomes of condition assessments undertaken as part of routine preventive maintenance, assets are either identified for replacement or managed through targeted inspection and maintenance programmes until replacement is required. Many older circuit breakers remain in service and continue to perform well due to ongoing maintenance throughout their operating lives.

8.5.3.6 Reyrolle LMT - Partial Discharge

Reyrolle LMT circuit breakers have been installed on the WELL network since the late 1960s, with more than 600 units currently in service across both zone substations and distribution substations.

Older LMT circuit breakers can be susceptible to partial discharge in resin current transformers and bushings. These issues can generally be addressed cost-effectively through refurbishment using retrofit kits. As part of routine maintenance, all circuit breakers are surveyed annually using handheld partial discharge detection equipment. In addition, zone substation circuit breakers receive a comprehensive partial-discharge survey each year, undertaken by an industry specialist.

When elevated partial-discharge levels are identified, corrective maintenance is performed. At present, no other material condition issues have been identified with the LMT circuit breaker fleet.

8.5.3.7 Circuit Breaker Asset Health and Criticality Analysis

The results of the Asset Health and Criticality Analysis are presented in the health–criticality matrix shown in Figure 8-9 with individual switchboard scores and ratings detailed in Table 8-23.

		Asset Health				
		Best Health				Worst Health
		H5	H4	H3	H2	H1
Lowest Impact	C4					
	C3	2		6	13	
	C2	2	1	3	5	
Highest Impact	C1					

Figure 8-9 Zone Substation Switchboard Health-Criticality Matrix

Switchboard	Model	AHI	ACI	Rating
Wainuiomata	LMT	1.6	C2	
Seaview	LM23T	1.8	C2	
Frederick Street	LM23T	2.0	C2	
Kenepuru	LM23T	2.0	C2	
Moore Street	LM23T	2.0	C2	
Porirua	LM23T	1.4	C3	
Tawa	LM23T	1.5	C3	
Trentham	LM23T	1.5	C3	
Maidstone	LM23T	1.7	C3	
Hataitai	LM23T	1.7	C3	
Petone	LM23T	1.7	C3	
Brown Owl	LM23T	1.7	C3	
Johnsonville	LM23T	1.8	C3	
Naenae	LM23T	1.8	C3	
Waitangirua	LM23T	1.8	C3	
Ira Street	LM23T	1.9	C3	
Titahi Bay	LMT	1.9	C3	
Mana	LM23T	2.0	C3	
Nairn Street	LMT	2.5	C2	
University	LMT	2.9	C2	
Kaiwharawhara	LMVP	3.0	C2	
Waterloo	LMT	2.0	C3	
Waikowhai Street	LMT	2.1	C3	
Plimmerton	LM23T	2.1	C3	
Korokoro	LM23T	2.1	C3	
Evans Bay	LMVP	3.0	C3	
Ngauranga	LMT	3.0	C3	
Terrace	NX-PLUS	4.0	C2	
Palm Grove	LMVP	4.3	C2	
Evans Bay 33 kV	XGIS	4.9	C2	
Karori	LMVP	4.4	C3	
Gracefield	LMVP	4.7	C3	

Table 8-23 Health-Criticality Scores for Zone Substation Switchboards

8.5.3.8 Outcome of the Asset Health Analysis

The Asset Health and Criticality Analysis has identified a small number of switchboards and circuit breakers that warrant targeted monitoring or corrective maintenance. The outcomes for these assets are summarised below.

Wainuiomata and Seaview

The Reyrolle switchboards at Wainuiomata and Seaview have low health scores due primarily to their age, having been installed in 1965 and 1969, respectively, and high criticality because of their locations on the network. Despite this, the switchboards are otherwise in good condition, with no partial discharge detected, and are not currently planned for replacement.

Frederick Street

The Reyrolle LMT switchboard at Frederick Street has undergone several stages of partial discharge mitigation since 2015. Subsequent testing indicates that this work has been effective. However, testing has also identified adjacent circuit breakers with elevated partial discharge levels that were previously masked. Further mitigation work is planned for these breakers.

Kenepuru

Partial discharge mitigation work at Kenepuru is in progress on two circuit breakers.

Moore Street

Partial discharge has been identified on three circuit breakers at Moore Street. This is being addressed by installing retrofit components.

8.5.3.9 Renewal and Refurbishment

WELL's fleet of zone substation circuit breakers are generally in good condition. Provided the ongoing programme of partial discharge mitigation continues to be effective, no zone substation circuit breakers are expected to require replacement for condition-related reasons over the next five years.

The most likely driver for circuit breaker replacement is the renewal of associated power transformers, which require increased 11 kV busbar ratings. Switchboard replacement projects driven by capacity constraints rather than asset health and criticality, including those at Ira Street and Porirua, are addressed in Section 9.

Significant zone substation circuit breaker renewal projects planned for delivery over the next 12 months are summarised in Table 8-24.

Project	Description
Frederick Street	Partial discharge mitigation
Moore Street	Partial discharge mitigation
Kenepuru	Partial discharge migration
Kaiwharawhara	LMVP truck replacement
Hataitai	Partial discharge mitigation

Table 8-24 Zone Substation Circuit Breaker Projects for the Disclosure Year Beginning 1 April 2026

8.5.3.10 Price-Quality Path Implications for Zone Substation Assets

The timing and delivery of zone substation circuit breaker renewal programmes highlight the limitations of the DPP4 allowances in accommodating condition-driven replacement across clustered assets at individual sites. While maintenance and targeted refurbishment can extend asset life, replacement requirements often

emerge in groups as switchboards age or as associated plant is renewed, resulting in lumpy investment profiles rather than smooth annual expenditure.

Deferring renewal in response to DPP constraints can increase exposure to protection failures, unplanned outages, and safety risks, whereas prematurely advancing replacement would be inefficient. In this context, greater regulatory flexibility to better align expenditure with optimal renewal timing would support prudent risk management and whole-of-life efficiency, reinforcing the case for a CPP application to fund long-term investments in zone substation switchboards and circuit breakers.

8.5.3.11 Expenditure Summary for Zone Substation Circuit Breakers

Table 8-25 sets out the expected expenditure on zone substation circuit breakers by disclosure year.

Expenditure Type	Disclosure Year Beginning 1 April									
	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035
Partial Discharge Mitigation	-	350	378	363	317	315	314	264	317	330
Capital Expenditure Total	-	350	378	363	317	315	314	264	317	330
Preventative Maintenance	138	139	140	141	141	144	147	150	153	159
Corrective Maintenance	28	28	28	28	28	29	29	30	31	32
Operational Expenditure Total	165	167	168	169	169	173	176	180	184	191

Table 8-25 Expenditure on Zone Substation Circuit Breakers
(\$K in constant prices)

8.5.4 Zone Substation Buildings and Equipment

8.5.4.1 Fleet Overview

WELL operates 27 zone substations and three major 11 kV switching stations that perform zone substation functions. Most sites comprise a single building. Evans Bay is an exception, with separate buildings housing the 11 kV switchgear, 33 kV switchgear, and power transformers. Substation buildings are generally standalone, although some CBD sites are located close to adjacent buildings or, in the case of The Terrace, are situated within a larger customer-owned building.

All WELL zone substation buildings have been assessed as achieving at least 67% of the New Building Standard (NBS) at Importance Level 4.

The age profile of major substation buildings is shown in Figure 8-10. The average age of the building fleet is 51 years. At five locations, WELL does not own the underlying land and instead operates under long-term lease arrangements with the landowners.

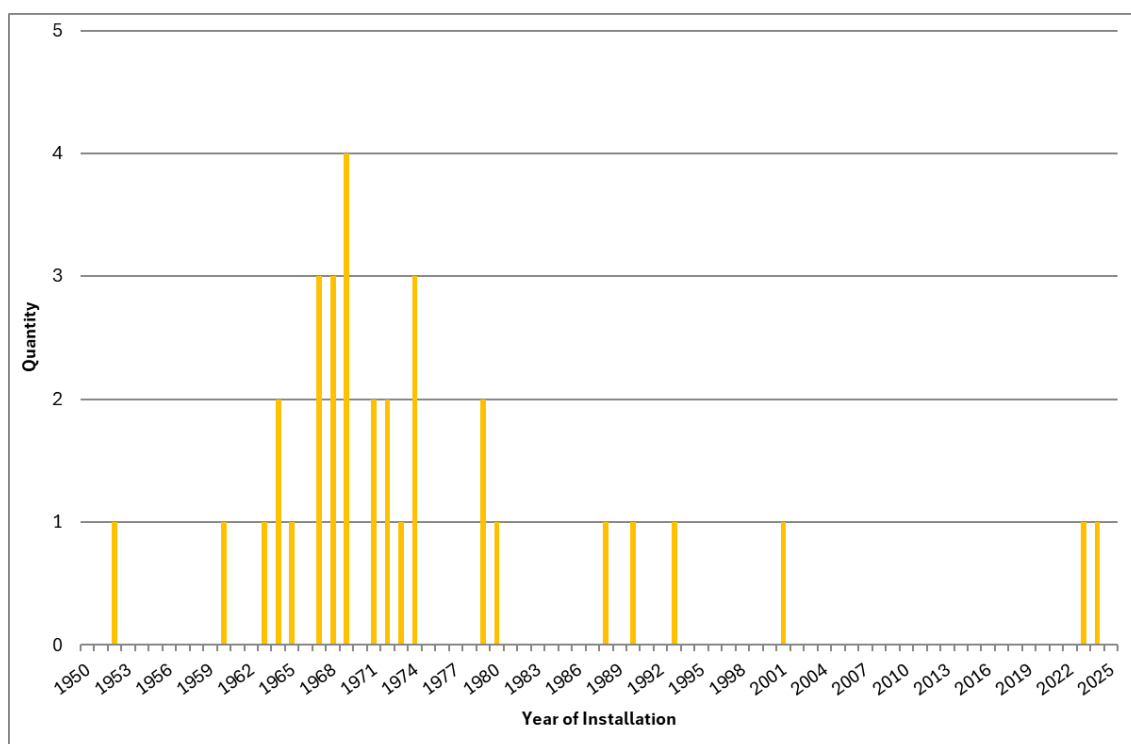


Figure 8-10 Age Profile of Major Substation Buildings

8.5.4.2 Fleet Objectives

In addition to the asset management objectives that apply across the network, WELL has established the following fleet-specific objectives for zone substation buildings as set out in Table 8-26.

Priority Area	Objective
Safety and Environment	No zone substations to be classified as Earthquake Risk Buildings.
Network Performance	Ensure weather tightness to prevent damage to internal equipment.

Table 8-26 Fleet-Specific Objectives for Zone Substation Buildings

8.5.4.3 Maintenance Activities

Routine inspections of zone substation buildings and associated assets are conducted quarterly. This includes: lighting, fire protection systems, security systems, fans, heaters, and safety equipment. Substation grounds and ripple-injection spaces are maintained to ensure continued access, security, asset condition, and safe operation.

Where required, annual Building Warrant of Fitness (BWOFF) inspections are completed, and any identified defects are addressed. Building maintenance requirements vary by site, with minor defects rectified as they are identified.

The routine inspection, testing, and maintenance activities for zone substation buildings and related equipment are set out in Table 8-27.

Activity	Description	Frequency
Zone Substation - Routine Inspection	Routine visual inspection of the zone substation to ensure asset integrity, safety and security. Record and report defects. Undertake minor repairs as required. Thermal inspection of all equipment, handheld PD and ultrasonic scan. Inspect and maintain oil containment systems. Inspect and test transformer pumps and fans.	3-monthly
Grounds maintenance	General programme of grounds and building maintenance for zone substations.	Ongoing
Fire Suppression System Inspection	Inspect and test the fire suppression system (Inergen/gas flood).	Monthly
Fire Suppression System Maintenance	Maintain fire suppression systems	12 monthly
Fire Alarm Test	Inspect and test passive fire alarm systems.	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 8-27 Inspection and Routine Maintenance Schedule for Zone Substations and Equipment

8.5.4.4 Renewal and Refurbishment

The zone substation building refurbishment programme includes activities such as roof replacement, exterior and interior painting, security, and fencing upgrades. These works are undertaken on an as-needed basis to maintain buildings in a serviceable condition.

Given the average age of the substation building fleet, WELL is entering a period of increased expenditure to replace doors, roofs, and other building components. Where deterioration from exposure to natural elements makes ongoing maintenance uneconomic, particularly in relation to weather-tightness, components are replaced in full. This work is critical to maintaining the reliability of the electrical plant housed within the buildings.

WELL also considers environmental factors, such as heating, cooling, and ventilation, to ensure that network assets operate within acceptable temperature and humidity limits. Where required, improvements are implemented to control the operating environment within substations.

Significant zone substation building renewal projects planned for delivery within the next 12 months are listed in Table 8-28.

Project	Description
Ngauranga Seismic Upgrade	Seismic upgrade of transformer rooms to support new power transformer installation.

Table 8-28 Zone Substation Building Projects for the Disclosure Year Beginning 1 April 2026

8.5.4.5 Expenditure Summary for Zone Substation Buildings

Table 8-29 sets out the expected expenditure on zone substation buildings by disclosure year.

Expenditure Type	Disclosure Year Beginning 1 April									
	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035
Asset Replacement and Renewal Capex	198	216	215	212	213	210	207	207	205	214
Capital Expenditure Total	198	216	215	212	213	210	207	207	205	214
Preventative Maintenance	169	171	171	172	173	176	180	183	187	193
Corrective Maintenance	517	521	522	524	527	537	548	558	569	588
Operational Expenditure Total	686	691	693	696	699	714	728	741	755	780

Table 8-29 Expenditure on Zone Substation Buildings
(\$K in constant prices)

8.5.5 Distribution and Low-voltage Lines—Poles

WELL owns 40,153 poles across its subtransmission, distribution, and low-voltage networks. Of these, approximately 17% are wooden poles, 82% are concrete poles, and the remaining 1% are fibreglass or steel poles.

In addition, 16,937 poles, including crossarms and conductors, are owned by third parties and carry WELL assets. Including telecommunications poles owned by Chorus and Wellington City Council. A summary of poles either owned by WELL or carrying WELL assets is provided in Table 8-30.

Pole Owner	Wood	Concrete/Other	Total
WELL	7,001	33,152	40,153
Customer	6,091	603	6,694
Chorus	7,446	354	7,800
Councils	1,370	1,073	2,443
Total	21,908	35,182	57,090

Table 8-30 Summary of Poles

The average age of concrete and other non-wooden poles is approximately 31 years. While the standard asset life for concrete poles is 60 years, a number of these poles have been in service for longer than this benchmark. The average age of wooden poles is approximately 40 years. Crossarms are predominantly constructed from hardwood.

As WELL does not own customer service lines or customer-owned poles, ongoing engagement is required to ensure customers understand their responsibilities for these privately owned assets. Where defects or hazards are identified on customer-owned poles or service lines, the relevant owners are notified so that appropriate action can be taken.

The age profile of poles owned by WELL is shown in Figure 8-11.

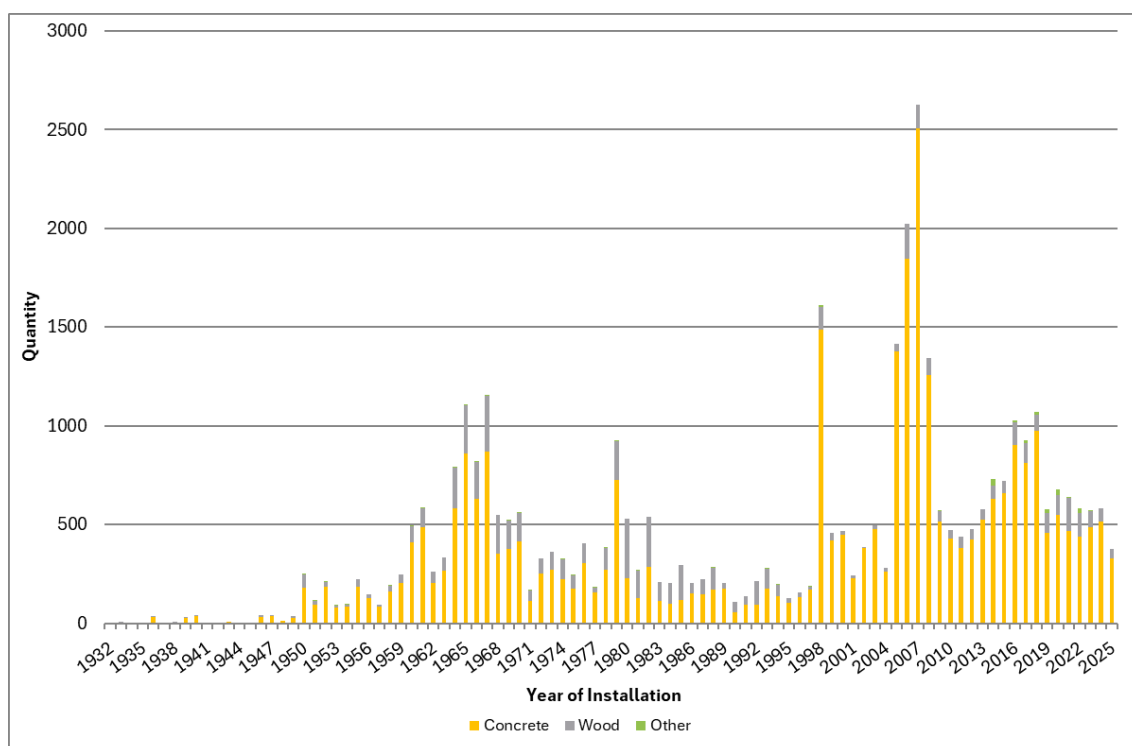


Figure 8-11 Age Profile of Poles

WELL does, however, have an interest in certain customer poles that are classified as “works” under the Electricity Act 1992. An example includes poles supplying multiple customers along a private right-of-way. In some cases, and by agreement with the original pole owner, WELL replaces these customer or private poles and subsequently assumes responsibility for their ongoing testing and maintenance.

In addition to electricity distribution services, WELL’s poles are also utilised by other service providers, including Chorus, One NZ, and Vital, to support telecommunications, cable television, and ultra-fast broadband (UFB) services.

8.5.6 Distribution and LV Lines—Subtransmission Lines

WELL operates approximately 53.8 km of 33 kV subtransmission overhead lines, predominantly constructed with AAC conductors installed on a combination of wooden and concrete poles. Overhead construction is primarily used in the Hutt Valley and Porirua areas, with the network transitioning to underground cable at the urban boundary.

Subtransmission overhead lines are generally located in rural or sparsely developed areas. In some locations, overhead construction has also been retained where challenging access or site conditions would have made underground cable installation impractical.

A summary of the subtransmission overhead line assets, together with their age profile, is presented in Table 8-31 and Figure 8-12.

Category	Quantity
33 kV Overhead Line	53.8 km

Table 8-31 Summary of Subtransmission Lines

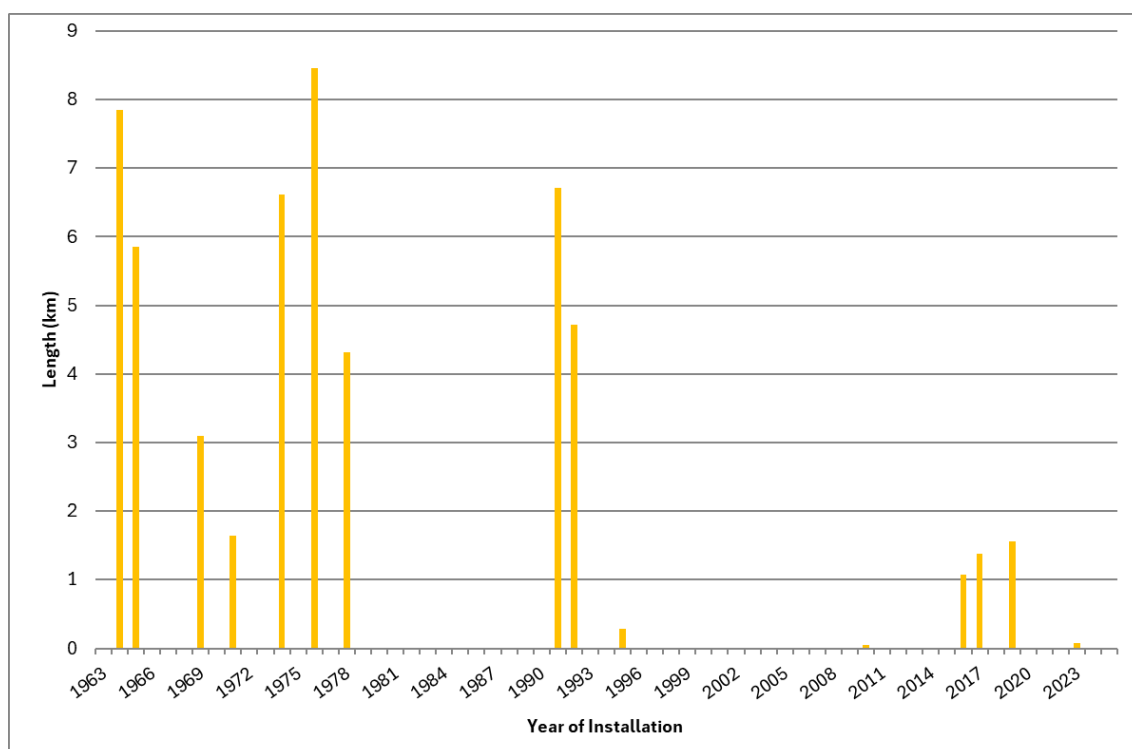


Figure 8-12 Age Profile of Subtransmission Line Conductors

8.5.7 Distribution and Low Voltage Lines—Conductors

Overhead conductors on the WELL network are predominantly all aluminium conductor (AAC), with older sections of the network utilising copper conductors. In some areas, aluminium conductor steel reinforced (ACSR) has been installed, with aluminised steel cores providing improved corrosion resistance compared with standard ACSR using galvanised steel cores.

New overhead line construction utilises all aluminium alloy conductor (AAAC). In locations with a history of outages caused by windborne debris, limited lengths of covered conductor (CCT) have been installed. Most low-voltage conductors are PVC-covered, and low-voltage aerial bundled conductors (LV ABC) have been deployed in a small number of locations with significant tree encroachment, subject to District Plan requirements.

A summary of the overhead line conductor fleet is provided in Table 8-32, with the corresponding age profile shown in Figure 8-13.

Category	Quantity
11 kV Line	587 km
Low Voltage Line	1,065 km
Streetlight Conductor	818 km

Table 8-32 Summary of Distribution Overhead Lines

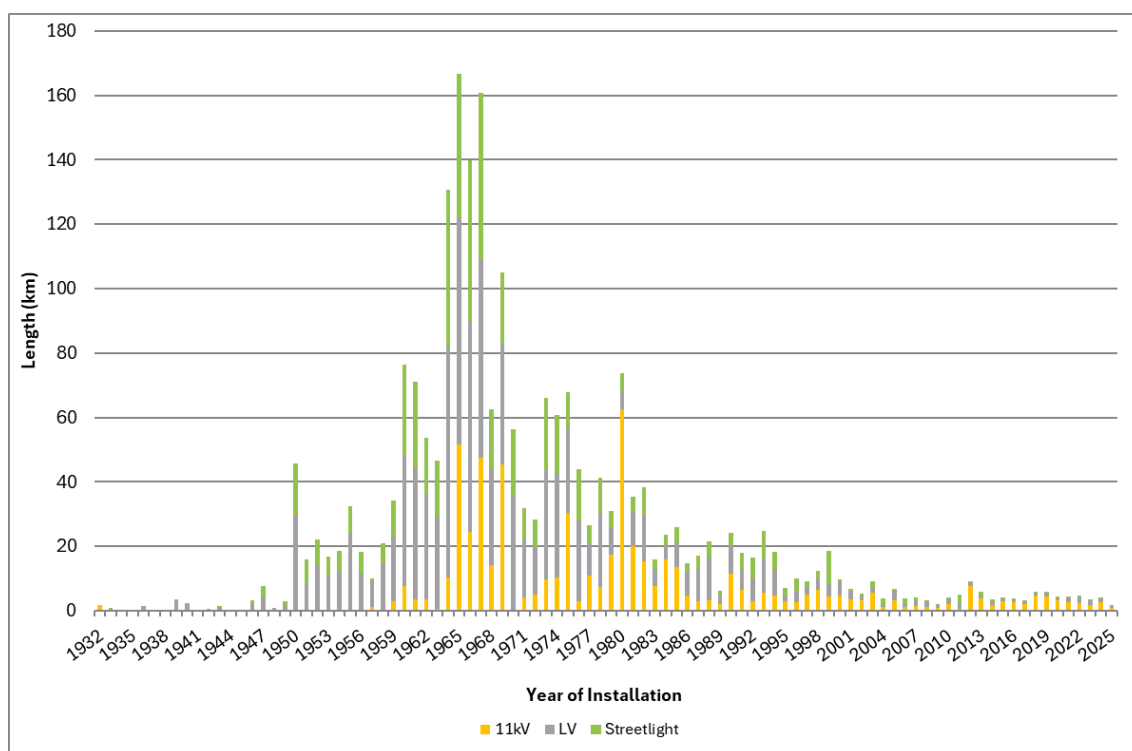


Figure 8-13 Age Profile of Distribution Overhead Line Conductors

8.5.7.1 Fleet Objectives

In addition to the asset management objectives that apply across the network, WELL has established fleet-specific objectives for the pole and overhead line fleets, as set out in Table 8-33.

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

Table 8-33 Fleet-Specific Objectives for Pole and Overhead Line Fleets

8.5.7.2 Maintenance Activities

All overhead lines are subject to an annual visual inspection programme to identify readily observable issues, including the condition of conductors, crossarms, and insulators, as well as potential vegetation encroachments and safety risks. In addition, all connectors within the current-carrying path are thermally scanned to detect high-resistance joints that may fail due to overheating.

These inspection activities account for a significant proportion of overhead corrective maintenance work and inform targeted asset replacement programmes, particularly for insulators and crossarms.

The routine inspection, testing, and maintenance activities for poles and overhead lines are set out in Table 8-34.

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 the pole, tagging and reporting of results.	5-yearly
Wooden pole inspections and testing (Deuar)	Visual inspection of the pole, testing and analysis of the pole using the 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 the line fault passage indicator, testing in accordance with the manufacturer's 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 8-34 Inspection and Routine Maintenance Schedule for Poles and Overhead Lines

Decisions to replace overhead conductors are based on the length of conductor identified as having deteriorated to defined replacement criteria through annual inspections and analysis. Historically, this assessment has relied on visual condition indicators and historical failure rates. WELL is transitioning to a condition-based replacement approach, supported by a predictive deterioration model that is currently under development.

8.5.7.3 Condition Assessments

Poles

Since 2011, WELL has used the Deuar MPT40 to test its wooden pole population. This testing programme identifies structural issues along the full length of the pole, including below ground level, and provides indicators of remaining service life and the pole's suitability to support the applied mechanical loading. Approximately 1,400 poles are tested annually using the Deuar methodology.

Approximately 83% of poles installed across the Wellington network are concrete, which are generally durable when properly maintained. Most of the remaining poles are timber, which are tested and replaced in accordance with their Deuar serviceability index results or where visible structural defects are identified.

Common issues affecting timber poles include loss of strength from internal or external decay. Poles that are leaning, exhibit head splits, or have sustained third-party damage may require remediation or replacement. For concrete poles, typical condition issues include cracking, spalling (loss of concrete mass due to corrosion of reinforcing steel), leaning, and third-party damage.

Third-party attachments are a significant contributor to poles leaning on the Wellington network. WELL has established agreements with One NZ and Chorus for the attachment of telecommunications infrastructure to network poles and maintains a standard governing third-party attachment. This standard ensures that future telecommunications connections meet WELL's requirements and do not adversely affect pole service life, network integrity, or the safety of contractors and members of the public. When additional attachments increase loading beyond acceptable limits, third-party operators must contribute to pole upgrades.

The health–criticality matrix for WELL’s pole fleet is shown in Figure 8-14. Pole asset health is determined primarily by condition and age, while asset criticality reflects the voltage of the lines supported and the number of customers supplied.

		Asset Health				
		Best Health				Worst Health
		H5	H4	H3	H2	H1
Asset Criticality	Lowest Impact	C4				
		C3	9,580	9,326	9,633	151
		C2	4,075	2,778	3,231	74
	Highest Impact	C1	429	147	330	11

Figure 8-14 Pole Health-Criticality Matrix

The future condition of the pole fleet is forecast using survival curve modelling. For poles, survival curves are derived from the age at which poles are tagged for replacement. At present, there is insufficient data to reliably forecast the expected end-of-life for concrete poles.

Survival curves for crossarms are developed based on the age at which a crossarm is identified as having a defect that necessitates replacement.

Overhead Lines

Pin-type insulators are no longer used for new 33 kV or 11 kV line construction, as they can develop reliability issues later in their service life. These issues include cracking caused by pin corrosion and bending moments on the pin, which can lead to wear of the crossarm mounting hole. There is no programme to proactively replace existing pin-type insulators. Instead, replacements are undertaken when defects are identified, when crossarms require replacement, or as part of feeder reliability improvement projects. All new installations use solid-core post insulators, which exhibit different failure modes and offer improved reliability, particularly in polluted environments and lightning-prone areas.

High wind loadings can also contribute to fatigue-related failures of line hardware on older AAC conductors historically used on the Wellington network. Affected components may include binders, compression sleeves, line guards, and armour rods. In addition, several Fargo sleeve-type automatic line splices have failed in service. These sleeves were intended for temporary repair only, and their failure is likely vibration-related, which can cause feeder faults under high-vibration conditions. Fargo sleeves are no longer used on the network and are replaced with full-tension compression sleeves as they are identified. Where joint locations are unsuitable for replacement, the affected span is reconducted.

The future condition of the overhead line conductor and connector fleet is forecast using a model based on failures per kilometre of conductor installed.

8.5.7.4 Renewal and Refurbishment

Poles

Wooden poles that undergo Deuar testing and fail the serviceability assessment are categorised as red, yellow, or blue-tagged based on the severity of the defect and residual capacity.

- Red-tagged poles have a serviceability index of less than 0.5 or exhibit major structural defects and are programmed for replacement within three months.
- Yellow-tagged poles have a serviceability index between 0.5 and 1.0, or display moderate structural defects, and are programmed for replacement within 12 months.
- Blue-tagged poles have a serviceability index greater than 1.0 but a reduced ability to support design loads. These poles are reassessed after 2.5 years rather than the standard five-year inspection cycle.

For all tag categories, climbing of tagged poles by contractors or third parties is prohibited.

Concrete poles are replaced following an unsatisfactory visual inspection. Replacement criteria include the presence of large cracks, structural defects, spalling, or loss of concrete mass. The severity of the defect determines whether a pole is assigned a red or yellow tag, triggering replacement within three to 12 months, respectively.

All replacement poles are concrete, except where site-specific constraints require the use of timber or composite poles. These exceptions typically arise due to weight limitations, access constraints, or loading design requirements. Poles located on walkways or in hard-to-reach areas are typically replaced with lightweight softwood or composite poles that can be installed manually. Cranes are used where practicable, although their reach is limited in some parts of Wellington. WELL does not generally use helicopters for pole installation due to the high cost and the need to evacuate residents in the vicinity of the worksite.

The annual requirement for pole replacements is forecast by applying survival curves to the pole population to estimate the number of assets reaching the end-of-life each year. Replacement volumes are expected to decline through 2035 as timber poles are progressively replaced with concrete poles, then increase as older concrete poles reach the end of their service lives. As noted earlier, there is uncertainty in forecasting the life of concrete poles, and these projections will continue to be refined as additional condition and performance data become available.

Overhead Lines

Since 2009, WELL has invested in the renewal of overhead lines in areas exhibiting relatively high SAIDI and SAIFI performance, as well as in locations where public safety concerns have been identified. This programme has included the progressive reconductoring of feeders in areas such as Newlands, Johnsonville, Karori, Wainuiomata, and Korokoro. As part of these projects, all line hardware, crossarms, and poles in poor condition have been replaced. These feeders have demonstrated a material improvement in reliability performance following completion of the renewal works.

A comparatively high number of failures observed in the 5 to 20-year age bracket has been attributed to corrosion of Ampact wedge connectors. This corrosion can result in failure of the connector itself or of the jumper or conductor at the point of connection. To address this issue, WELL now requires Gelpact covers to be installed on any exposed Ampact connectors during planned work on poles.

Significant overhead line renewal projects planned for delivery over the next 12 months are summarised in Table 8-35.

Project	Description
Brown Owl Feeders	Refurbishment of Brown Owl 3 and 13
Wainuiomata Feeders	Refurbishment of Wainuiomata 13
Maidstone Feeders	Further refurbishment stages of Maidstone 10

Table 8-35 Overhead Line Projects for the Disclosure Year Beginning 1 April 2026

8.5.7.5 Expenditure Summary for Overhead Lines

Table 8-36 sets out the expected expenditure on overhead lines by disclosure year.

Expenditure Type	Disclosure Year Beginning 1 April									
	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035
Feeder Reliability Projects	-	1,113	1,261	1,079	1,037	1,036	1,037	1,049	1,052	949
Pole Replacement Programme	4,887	5,742	5,325	4,544	4,410	4,130	3,875	3,678	3,467	3,128
Reactive Capital Expenditure	2,384	1,179	1,137	1,126	1,137	1,109	1,084	1,072	1,053	951
Capital Expenditure Total	7,271	8,035	7,723	6,748	6,584	6,275	5,996	5,799	5,572	5,027
Preventative Maintenance	720	720	716	720	726	743	755	764	773	793
Corrective Maintenance	1,047	1,057	1,062	1,066	1,070	1,091	1,113	1,135	1,158	1,198
Operational Expenditure Total	1,767	1,777	1,778	1,786	1,796	1,834	1,868	1,899	1,931	1,991

Table 8-36 Expenditure on Overhead Lines
(\$K in constant prices)

8.5.8 Distribution and Low-voltage Cables

This subsection describes the composition, extent, and management of distribution and low-voltage underground cable assets across WELL's network, providing context for the condition, performance, and renewal strategies that follow.

8.5.8.1 Fleet Overview

WELL's network includes a high proportion of underground cables. This configuration has historically delivered strong reliability during weather-related events, but it also increases exposure to third-party damage, particularly during underground construction.

The 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 utilises automatically operated circuit breakers and differential protection on cables between distribution substations, rather than manually operated ring main switches between switching zones. A summary of the distribution cables serving the Wellington CBD is provided in Table 8-37.

Category	Quantity
11 kV cable (incl. risers)	1,231 km
Low Voltage cable (incl. risers)	1,815 km
Streetlight cable	1,158 km

Table 8-37 Summary of Distribution Cables

This arrangement results in higher reliability because cable faults affect smaller segments of the network. However, due to the constrained urban environment, repairs to the distribution system within the CBD typically take longer than standard replacement times and incur higher costs, particularly for traffic management and road or pavement reinstatement.

The age profile of distribution cables at both voltage levels is shown in Figure 8-15.

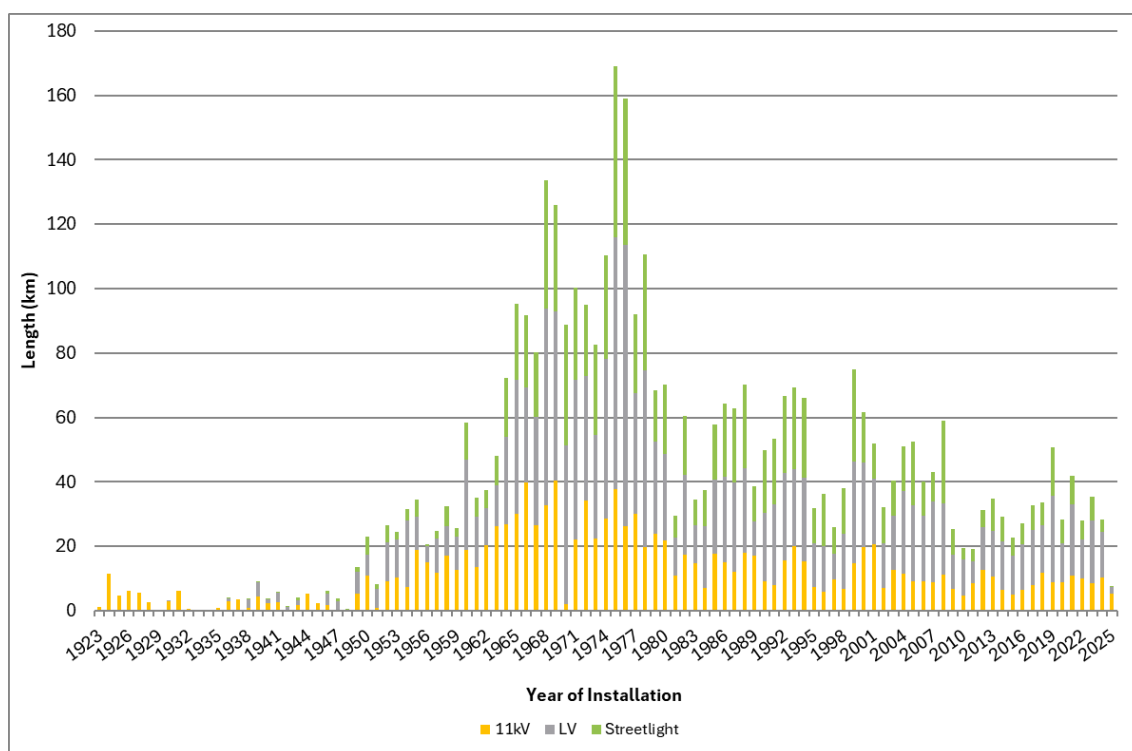


Figure 8-15 Age Profile of Distribution Cables

Outside the Wellington CBD, the 11 kV underground distribution network is generally configured with normally open interconnections between radial feeders. Feeders are segmented into smaller switching zones using locally operated ring main switches. In the event of a cable fault, the affected section can be isolated and the supply to downstream customers restored by transferring load to neighbouring feeders.

Approximately 85% of the underground 11 kV cable fleet comprises PILC and PIAS cables, with the remaining 15% consisting of XLPE-insulated cables installed since around 2000. Most low-voltage cables are PILC or PVC insulated, with a smaller proportion of newer XLPE insulated cables.

8.5.8.2 Fleet Objectives

In addition to the asset management objectives that apply across the network, Table 8-38 sets out WELL's 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 low-voltage cables.
Customer	Mitigate the risk of service-quality decline or a price shock from an incorrect cable replacement forecast. Avoid repeat 11 kV outages due to cable condition.
Cost	Reduce cable replacement costs.

Table 8-38 Fleet-Specific Objectives for Distribution Cable Fleets

8.5.8.3 Maintenance Activities

Maintenance of the underground distribution cable network is largely limited to visual inspection and thermal imaging of cable terminations. In parallel, WELL has been trialling a range of cable testing technologies to assess poorly performing cables using various diagnostic tools. The purpose of these trials is to build confidence in the suitability of the tools as condition assessment methods by correlating test results with actual cable performance. This work is intended to:

- Determine whether a cable requires proactive replacement, either in full or for targeted sections
- Support the development of a predictive condition model
- Improve forecasting of future cable replacement requirements

8.5.8.4 Distribution Cable Condition

Underground cables generally have long service lives and high reliability, as they are not exposed to the same environmental hazards as overhead assets. However, cable performance can deteriorate as assets age. External factors such as third-party strikes, inadvertent overloading, or rapid increases in load beyond normal ratings can also accelerate the reduction in a cable's service life.

Some cable failures are attributable to workmanship issues associated with newer joints and terminations, which can be addressed through targeted training and education. Other failures arise from age-related deterioration, environmental factors, or external damage. The health–criticality matrix for WELL's 11 kV cable fleet, presented by cable length, is shown in Figure 8-16.

		Best Health		Asset Health		Worst Health	
		H5	H4	H3	H2	H1	
Lowest Impact	C4	19.4	33.0	11.7	1.4	0.2	
Asset Criticality	C3	149.5	266.2	228.9	53.3	0.7	
	C2	107.6	223.0	131.0	4.9	0.3	
	Highest Impact	C1					

Figure 8-16 11 kV Cable Health-Criticality Matrix (km)

The future condition of the distribution cable fleet is forecast using a failure-rate model based on failures per unit installed. For this purpose, a cable unit is defined as the network-average segment length of 150 metres, enabling direct comparison of failure rates between cables and associated accessories.

Failure rates for cables, joints, and terminations are shown in Figure 8-17.

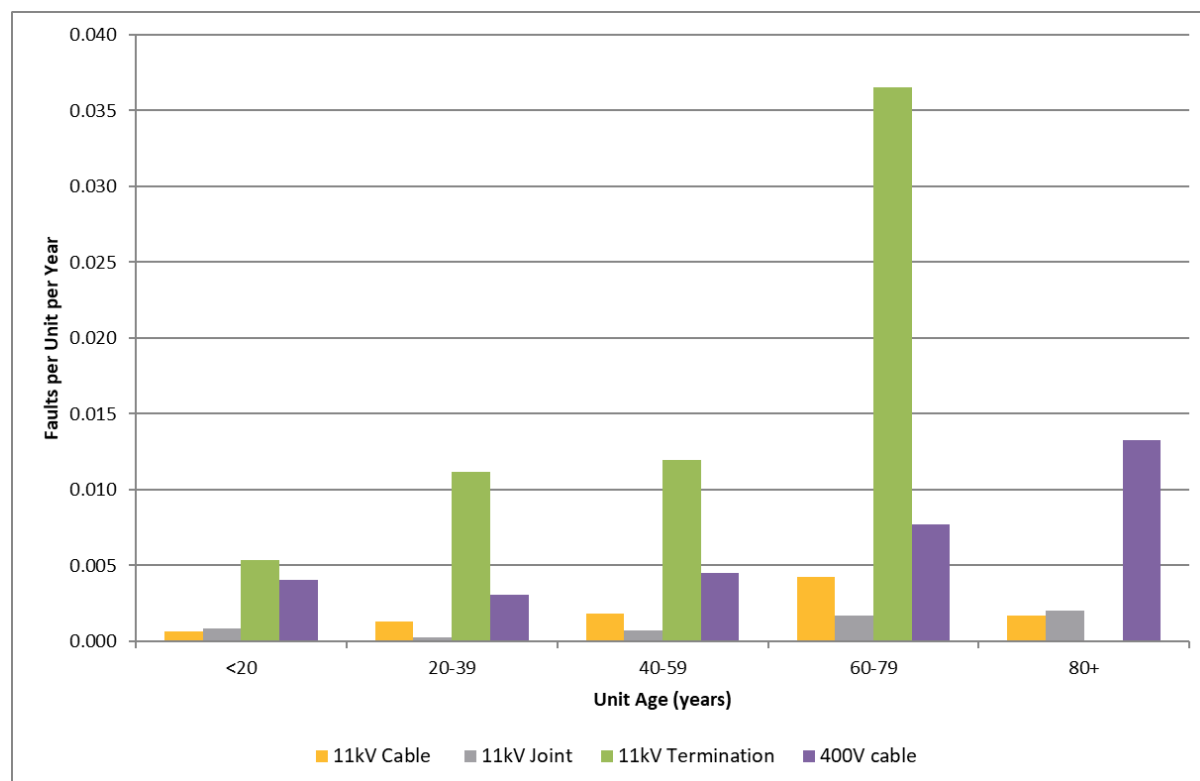


Figure 8-17 Cable Failure Rate by Age

Failure-rate analysis indicates that outdoor terminations are the weakest component of the 11 kV cable system, exhibiting higher failure rates across all ages and a marked increase in failures beyond 60 years of service.

Applying average failure rates across the fleet, together with estimates of customer impact for each potential failure, enables forecasting of the underlying trend in future performance due to cable condition in the absence of intervention. This forecast is presented in Figure 8-18.

The actions proposed to manage this trend and maintain performance at current levels are described in the following section on renewal and refurbishment.

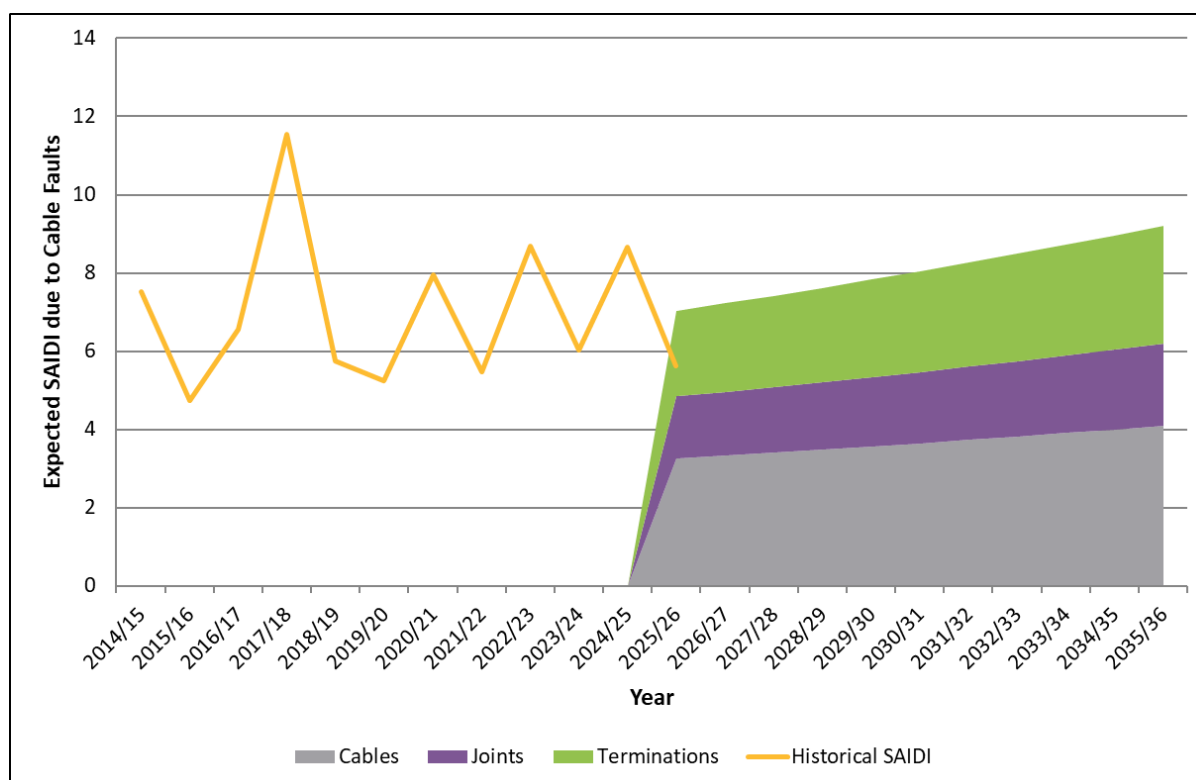


Figure 8-18 Forecast 11 kV Cable Fleet Performance Trend without Intervention

8.5.8.5 Renewal and Refurbishment

The scale of the underground cable fleet, combined with the high unit cost of replacement, makes distribution cables a significant risk area for WELL. Allowing the fleet to operate to failure would result in a gradual deterioration in the quality of supply. Conversely, large-scale proactive replacement would impose substantial costs without necessarily guaranteeing commensurate performance improvements. In response, WELL has adopted a cable fleet management strategy that seeks to minimise impacts on customers in terms of both reliability and affordability.

The cable fleet strategy outlined below targets specific drivers of forecast future performance to maintain reliability at current levels:

- Cable terminations—represent a relatively accessible and cost-effective intervention point. A targeted condition assessment programme is used to identify deteriorating terminations and enable replacement before failure occurs.
- Cable diagnostics—continued investment in modern diagnostic equipment improves understanding of cable condition and supports targeted replacement of the highest-risk cable sections.
- Network automation—increasing the number of circuit breakers and remote-controlled switches on the underground network reduces the customer impact of individual cable faults (refer to Section 8.5.16.3).
- Workmanship and fittings—early failures of cable fittings, particularly those less than 20 years old, are being managed through enhanced training, competency requirements for cable jointers, and close collaboration with suppliers to investigate failure causes.

- Technology review—cable fitting technologies are subject to ongoing review to ensure that approved joints and terminations remain suitable for Wellington's operating conditions.

Over the longer term, WELL will need to commence a substantial programme of distribution cable renewals. For the period covered by this AMP, WELL's preferred approach is to apply the strategies outlined above to manage customer impacts and defer the start of a large-scale renewal programme. This approach supports customer affordability by avoiding overlap between significant distribution cable renewal costs and network reinforcement investment driven by decarbonisation-related load growth.

Cable fleet performance will continue to be closely monitored to confirm that this strategy remains appropriate and delivers optimal long-term outcomes for customers. Significant distribution cable renewal projects are listed in Table 8-39.

Project	Description
Haywards Feeder Replacement under SH2	A multi-year project that requires multiple cable relocations, moving into the construction phase.

Table 8-39 Distribution Cable Projects for the Disclosure Year Beginning 1 April 2026

8.5.8.6 Expenditure Summary for Distribution and Low Voltage Cable

Table 8-40 sets out the expected expenditure on distribution and low-voltage cable by disclosure year.

Expenditure Type	Disclosure Year Beginning 1 April									
	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035
Asset Replacement and Renewal Capex	2,330	2,727	1,062	1,204	3,383	3,329	3,285	3,281	3,255	3,032
Reactive Capital Expenditure	1,494	3,319	3,294	3,248	3,272	3,220	3,177	3,173	3,148	2,933
Capital Expenditure Total	3,824	6,046	4,356	4,453	6,654	6,549	6,462	6,454	6,403	5,965
Preventative Maintenance	-	-	-	-	-	-	-	-	-	-
Corrective Maintenance	106	107	108	108	108	111	113	115	117	121
Operational Expenditure Total	106	107	108	108	108	111	113	115	117	121

Table 8-40 Expenditure on Distribution and Low Voltage Cable
(\$K in constant prices)

8.5.9 Distribution Substations and Transformers

The composition, deployment, condition, and management of distribution substations and transformers across WELL's network are described in this subsection, providing context for the associated maintenance, renewal, and investment strategies.

8.5.9.1 Fleet Overview

Approximately 60% of WELL's distribution transformers are ground-mounted, with the remaining 40% pole-mounted. Pole-mounted transformers are installed on single and double-pole structures and are predominantly three-phase units rated between 10 kVA and 200 kVA. Ground-mounted transformers are also three-phase units, with capacities typically ranging from 100 kVA to 2,000 kVA.

WELL maintains a range of spare distribution transformers to enable rapid replacement in the event of an in-service failure. The standard design life of a distribution transformer is 45 years, although units installed in indoor environments may achieve longer service lives. Conversely, transformers installed in exposed outdoor environments, particularly in coastal locations, may experience reduced service life due to corrosion.

The age profile of the distribution transformer fleet is shown in Figure 8-19.

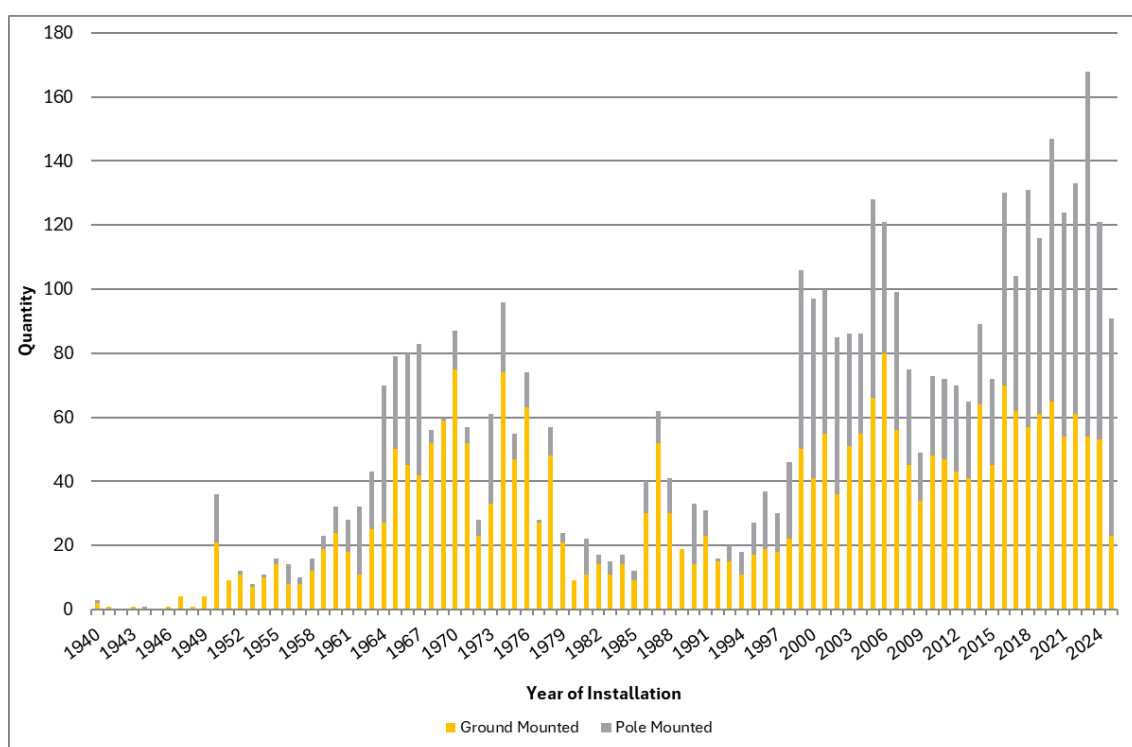


Figure 8-19 Age Profile of Distribution Transformers

In addition to pole-mounted and integral pad-mount berm substations, WELL owns 526 indoor substation kiosks and operates a further 659 customer-owned sites, which are typically masonry or block structures or outdoor enclosures. A summary of WELL's distribution transformers and substations is provided in Table 8-41.

Category	Quantity
Distribution transformers	4,554
Distribution transformers – Total	4,554
WELL owned substations	4,011
Customer-owned substations containing WELL owned equipment	659
Distribution substations – Total	4,670

Table 8-41 Summary of Distribution Transformers and Substations

8.5.9.2 Fleet Objectives

In addition to the asset management objectives that apply across the network, Table 8-42 sets out WELL's fleet-specific objectives for distribution transformers and substations.

Priority Area	Objective
Safety and Environment	No distribution substations are prone to earthquakes. Substations located in road reserves are not to be a risk to public safety. Compliance with asbestos regulations is maintained.
Customer	Meet customer needs by providing information on the transformers installed inside their buildings.
Network Performance	Ensure weather tightness to prevent damage to internal equipment.

Table 8-42 Fleet-Specific Objectives for Distribution Transformers and Substations

8.5.9.3 Maintenance Activities

The routine planned inspection and maintenance activities undertaken on distribution substations and associated equipment are set out in Table 8-43.

Activity	Description	Frequency
Inspection of Distribution Substations	Routine inspection of distribution substations to ensure asset integrity, security and safety. Record and report defects. Undertake minor repairs as required. Record MDIs where fitted.	Annually
Grounds maintenance	General programme of ground and building maintenance for distribution substations.	Ongoing
Fire Alarm Test	Inspect and test passive fire alarm systems.	Monthly
Visual Inspection and Thermal Image (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 (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 8-43 Inspection and Routine Maintenance Schedule for Distribution Transformers

The key condition, performance, and risk issues identified for the distribution transformer fleet are outlined below.

Internal Bushing Transformers

Ground-mounted transformers manufactured by Bonar Long, Bryce and ASEA were installed between 1946 and 1999. Thirty-four 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 8-20 presents the health–criticality matrix for WELL’s distribution transformer fleet, covering both pole-mounted and ground-mounted units. Asset health reflects a combination of transformer-type-specific issues and the assessed condition of each unit, while asset criticality is determined by the number and type of customers served by the transformer.

		Best Health		Asset Health		Worst Health
		H5	H4	H3	H2	H1
Asset Criticality	Lowest Impact	C4	167	721	847	13
		C3	173	1,015	1,188	12
		C2	6	124	182	
	Highest Impact	C1	1	29	72	4

Figure 8-20 Distribution Transformer Health-Criticality Matrix

The future condition of the distribution transformer fleet is forecast using survival curve modelling. These curves are derived from the age at which transformers are identified as having defects that are most appropriately addressed through replacement. The modelling highlights the material benefit of housing transformers under cover, with these units, representing approximately 53% of WELL’s distribution transformer fleet, exhibiting significantly longer service lives. It also shows broadly similar performance between pole-mounted and outdoor ground-mounted transformers, with the earlier replacement profile for pole-mounted units reflecting their greater exposure to lightning and more limited accessibility for repair.

To further enhance understanding of transformer performance and utilisation, WELL is installing monitoring equipment on 50 transformers identified by the modelling as potentially constrained, as discussed in Section 11.2.2.3. In addition to providing safety-related functions, such as broken neutral and stolen-earth detection, these monitors will improve visibility into fleet performance and loading, with insights extrapolated across the wider distribution transformer population.

8.5.9.4 Renewal and Refurbishment

Where a distribution transformer is found to be in unsatisfactory condition during routine inspection, it is programmed for corrective maintenance or replacement. In-service transformer failures are investigated to identify the root cause, with each unit assessed to determine whether repair, refurbishment, or scrapping is the most appropriate option based on cost and remaining service life. Typical condition issues include corrosion, significant insulating-fluid leaks, and internal faults. Minor issues, such as paint deterioration, localised surface rust, or small oil leaks, are addressed through repair, and the transformer is returned to service. Refurbishment and replacement of distribution transformers are part of an ongoing, condition-driven programme included in the asset maintenance and replacement forecasts.

In addition to the transformer units themselves, associated substation structures and fittings are routinely inspected and as required, renewed. These include distribution earthing systems, substation canopies, and kiosk building components, including improvements in weather-tightness. Some renewal activities can be complex and costly, particularly when berm substations are integral units manufactured in the 1970s and 1980s, such as those produced by Tolley Industries in the Hutt Valley. Replacement of these substations typically requires complete foundation renewal and extensive cable works. While the development of a compatible replacement design was investigated and a prototype installed, the potential civil cost savings were offset by the higher cost of procuring specialised transformers rather than standard designs.

Historically, WELL has preferred canopy-type substations, in which the transformer, high-voltage switchgear, and low-voltage switchgear are housed in a single enclosure, for new installations where practicable. However, increasing space constraints and rising unit costs have driven a shift towards standalone transformers and separate ring main units, except where canopy substations are required for public safety or technical reasons.

8.5.9.5 Expenditure Summary for Distribution Substations

Table 8-44 details the expected expenditure on distribution substations by disclosure year.

Expenditure Type	Disclosure Year Beginning 1 April									
	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035
Seismic Strengthening	-	457	-	-	-	-	-	-	-	-
Asset Replacement and Renewal Capex	8,620	4,920	3,256	3,855	5,350	5,550	5,563	5,556	5,512	5,134
Reactive Capital Expenditure	3,337	2,798	2,942	2,901	2,922	2,876	2,837	2,834	2,812	2,619
Capital Expenditure Total	11,957	8,175	6,198	6,756	8,272	8,425	8,401	8,390	8,323	7,753
Preventative Maintenance	807	815	819	822	825	841	858	875	893	924
Corrective Maintenance	799	806	810	813	816	833	849	866	884	914
Operational Expenditure Total	1,606	1,621	1,629	1,635	1,641	1,674	1,708	1,742	1,776	1,838

Table 8-44 Expenditure on Distribution Substations
(\$K in constant prices)

8.5.10 Distribution Switchgear—Ground Mounted

The composition, extent, and management of ground-mounted distribution switchgear across WELL's network are described in this subsection, providing context for the condition, performance, and renewal strategies discussed in the sections that follow.

8.5.10.1 Fleet Overview

This section describes the composition, deployment, and management of ring main units (RMUs) and other ground-mounted switching equipment installed across the distribution network. Zone substation circuit breakers are excluded from this discussion and are addressed separately in Section 8.5.3.

The age profiles of the distribution circuit breaker fleet and other ground-mounted switchgear are shown in Figure 8-21 and Figure 8-22.

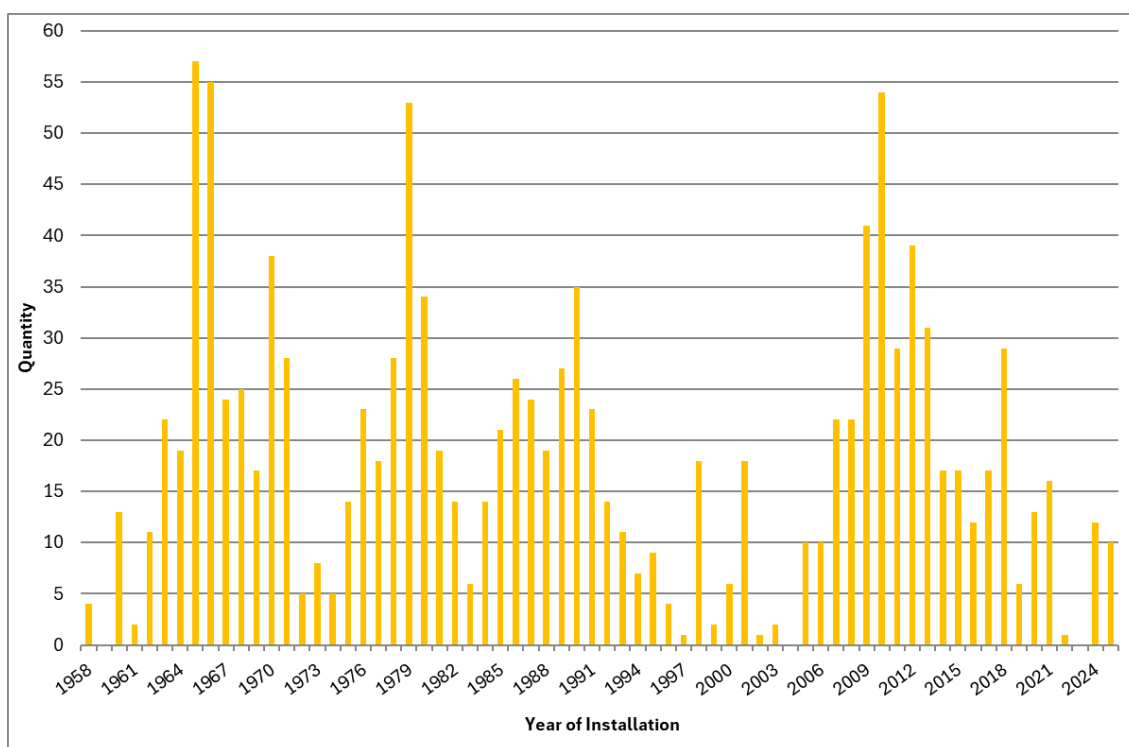


Figure 8-21 Age Profile for Distribution Circuit Breakers

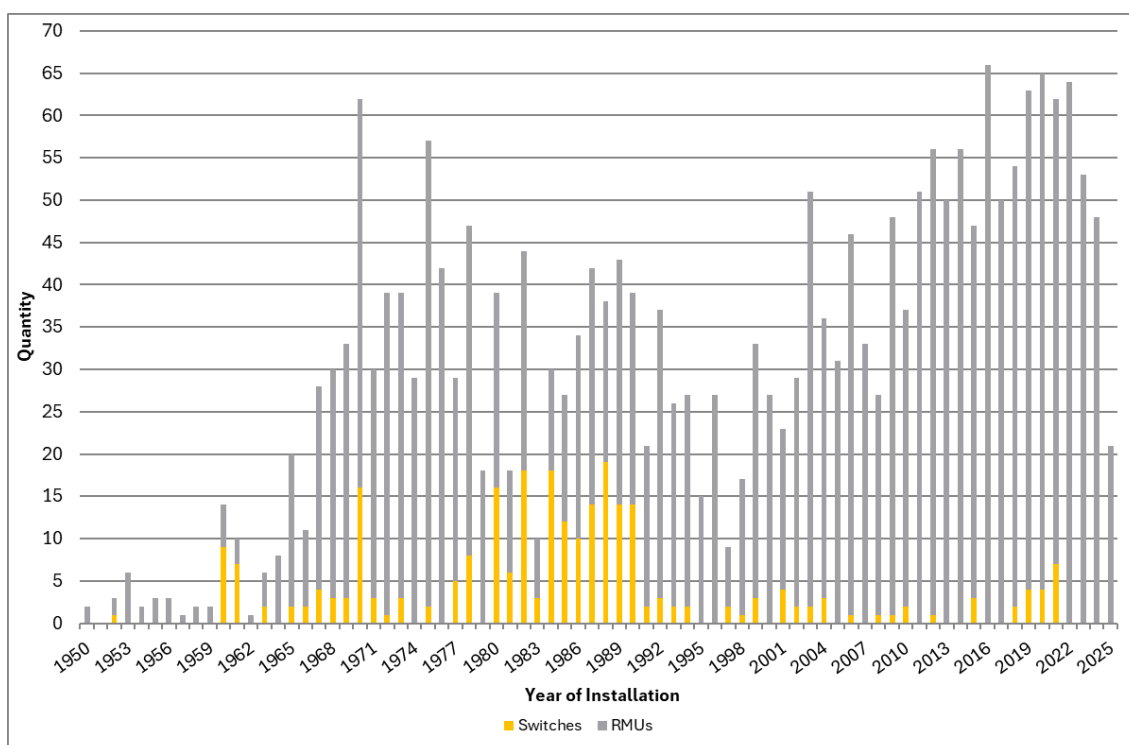


Figure 8-22 Age Profile of Other Ground-Mounted Distribution Switchgear

In total, the WELL network includes 1,237 distribution circuit breakers and 2,366 other ground-mounted switching devices. WELL deploys 11 kV circuit breakers within the distribution network to enhance supply

reliability in priority areas, including the CBD, and to protect larger transformers rated at 750 kVA and above. Other ground-mounted switching equipment includes fuse switches to protect distribution transformers and load-break switches to enable isolation and reconfiguration of network components. These functions are often combined within a single ring main unit.

The average age of distribution circuit breakers on the network is approximately 35 years, while the average age of ring main units is around 27 years. A summary of distribution circuit breakers and other ground-mounted distribution switchgear, including both stand-alone units and ring main units, is provided in Table 8-45 and Table 8-46.

Category	Quantity
Distribution Circuit Breakers	1,237
Oil Insulated Switches	238
Oil Insulated RMUs	136
SF ₆ Insulated Switches	12
SF ₆ Insulated RMUs	1,030
Resin Insulated Switches	17
Resin Insulated RMUs	933

Table 8-45 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	59
Hawker Siddeley/FKI	Vacuum	21
Merlin Gerin/Schneider	SF ₆	314
Reyrolle	Oil	579
	Vacuum	60
South Wales	SF ₆	38
Statter	Oil	14
Total		1,237

Table 8-46 Summary of Distribution Circuit Breakers by Manufacturer

8.5.10.2 Fleet Objectives

In addition to the asset management objectives that apply across the network, WELL has established fleet-specific objectives for ground-mounted distribution switchgear, as set out in Table 8-47.

Priority Area	Objective
Safety and Environment	No injuries resulting from working on and around distribution switchgear. Only use SF₆-filled equipment when no technically suitable and cost-effective non-SF₆ alternatives exist. Minimise SF₆ emissions into the environment.
Network Performance	Distribution switchgear to be safe to operate live, to minimise customer impact during switching.

Table 8-47 Fleet-Specific Objectives for Ground-Mounted Distribution Switchgear

8.5.10.3 Maintenance Activities

The routine planned inspection and maintenance activities undertaken on ground-mounted distribution switchgear and associated equipment are set out in Table 8-48.

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 the 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.	Triggered by Inspection Results

Table 8-48 Inspection and Routine Maintenance Schedule for Distribution Switchgear

Ground-mounted distribution switchgear installed across the WELL network is generally in good condition. Routine maintenance addresses most minor defects, with assets programmed for replacement once their

condition deteriorates to a point where repair is no longer cost-effective. Common condition issues include mechanical wear of enclosures and operating mechanisms, partial discharge, and degraded oil condition or insulation performance.

The health–criticality matrix for WELL’s ground-mounted distribution switchgear fleet is shown in Figure 8-23. Asset health reflects a combination of equipment type–related issues and assessed condition, while asset criticality is determined by the importance of the 11 kV feeder to which each unit is connected.

		Best Health		Asset Health		Worst Health
		H5	H4	H3	H2	H1
Lowest Impact	C4	45	118	703	476	96
Asset Criticality	C3	24	116	438	333	104
	C2	12	31	636	328	147
Highest Impact	C1					

Figure 8-23 Distribution Switchgear Health-Criticality Matrix

Ringmaster

Several gas depressurisation events have occurred on Ringmaster switchgear, with the first loss of gas recorded in 2011, approximately 10 years after the affected units entered service. These events have been limited to Ringmaster ring main units (RMUs) and have not affected circuit breakers. The impacted RMUs were manufactured between 2000 and 2005, with 88 units currently in service on the network.

Loss of gas does not result in immediate electrical failure of the unit. However, depressurised RMUs are subject to operational restrictions and cannot be operated live until they are replaced. As a result, enhanced monitoring of gas pressure prior to switching operations has been reinforced with switching staff. The manufacturer has advised that the most likely cause of these failures is stress fracturing of the resin gas tank moulding, driven by temperature cycling and the higher gas pressures used in RMUs manufactured during this period. The issue is not considered to be related to the underlying switchgear design, and Ringmaster switchgear remains approved for installation on the WELL network.

Solid Insulation Magnefix

Maintenance requirements for Magnefix switchgear are generally minimal, typically limited to cleaning and verification that contacts remain in good condition. In-service failures are rare, with historical issues largely attributable to cable terminations or switching operations rather than to the switchgear units themselves. This indicates that when a Magnefix unit is operating correctly and remains in good condition, it can remain in service without requiring intrusive maintenance.

An investigation into the Magnefix fleet has confirmed that maintenance requirements can be reliably predicted using visual inspections, thermal imaging, and partial-discharge testing, rather than relying on a purely time-based approach. This condition-based methodology reduces the need for switching outages and enables maintenance resources to be prioritised towards higher-risk oil-filled switchgear.

Some older Magnefix units are fitted with grease-filled termination boxes. Thermal cycling can cause grease migration into the cable, potentially compromising phase-to-phase insulation within the termination. These

units are identified through the routine inspection programme and are subject to operational restrictions that prohibit live operation until outages can be arranged to replenish grease levels as required.

In addition, WELL operates 13 sites with Krone KES 10 solid-insulated switchgear. These units are replaced when their condition deteriorates to the point that repair or maintenance is no longer cost-effective.

Long and Crawford

One Long and Crawford ring main unit remains in service on the network. Replacement of this unit is currently on hold pending the customer's decision regarding future power supply requirements. In the interim, operational controls prohibit the switchgear from being operated live.

Statter

As of October 2025, WELL operates Statter switchgear at 32 sites, comprising 78 units, including circuit breakers, oil switches, and fuse switches. These assets were installed between 1960 and 1990. There have been historical instances in which Statter switchgear has failed to operate as intended, necessitating operational restrictions prohibiting live operation until the unit is repaired or replaced. The fleet is approaching the end of its useful service life and is increasingly difficult to maintain due to the limited availability of spare parts.

Most Statter installations do not have protection functions enabled or remote-control capability on circuit breakers and can therefore be replaced with conventional ring main units without adversely affecting network reliability. In a small number of cases, where units have full protection and control and are located on feeders supplying many customers, replacement will be undertaken using modular secondary-class circuit breakers to maintain reliability levels.

WELL has an ongoing programme to replace Statter switchgear, with completion planned by 2029.

8.5.10.4 Renewal and Refurbishment

This subsection describes WELL's approach to the renewal and refurbishment of ground-mounted distribution switchgear, including the drivers for investment and the planned interventions over the planning period.

HV Distribution Switchgear (Ground Mounted)

As noted above, this section excludes zone substation circuit breakers, which are addressed separately in Section 8.5.3. Minor defects and routine maintenance issues are typically rectified on site during inspections and may include tasks such as topping up oil reservoirs, replacing bolts, treating corrosion, and undertaking paint repairs. More significant issues that cannot be addressed on-site generally require replacement of the affected device. In addition to the targeted replacement programmes for specific switchgear types described above, WELL maintains an ongoing refurbishment and replacement programme for the wider ground-mounted distribution switchgear fleet.

In the relatively rare event of a switchgear failure, the incident is investigated, and a cost-benefit assessment is undertaken to determine whether repair, refurbishment, replacement, or decommissioning is the most appropriate course of action. Where failures identify systemic issues, maintenance policies for other assets of the same type are reviewed. As outlined earlier, several types of ring main units have known age- or condition-related issues and are being progressively replaced based on asset risk assessments. Oil-insulated switchgear is no longer installed on the network, with vacuum or gas-insulated (SF₆) equipment now used for new installations. WELL intends to phase out the use of SF₆ for new distribution switchgear due to its

contribution to climate change. At present, there are no SF₆ free ring main units available in the New Zealand market that meet WELL's technical and operational requirements. Significant projects for the renewal of ground-mounted distribution switchgear over the next 12 months are listed in Table 8-49.

Project	Description
Normandale Bridge	Completion of Statter switchgear replacement
Lever Bros	Statter switchgear replacement
Military Road	JB Switchgear replacement
St John Street	JB Switchgear replacement
Elizabeth Street	JB Switchgear replacement

Table 8-49 Ground Mounted Switchgear Projects for the Disclosure Year Beginning 1 April 2026

Low Voltage Distribution Switchgear (Substation)

Low-voltage distribution switchgear and fusing are maintained as part of routine substation maintenance, with any issues identified during inspection addressed at that time. Overall, the performance of low-voltage distribution switchgear and fusing is satisfactory, and no specific replacement programmes are currently required for this equipment.

8.5.10.5 Expenditure Summary for Ground-mounted Switchgear

Table 8-50 details the forecast expenditure on ground-mounted distribution switchgear over the planning period, with costs presented by disclosure year.

Expenditure Type	Disclosure Year Beginning 1 April									
	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035
Statter Replacement Programme	235	2,607	1,689	-	-	-	-	-	-	-
Partial Discharge Mitigation	974	521	353	249	229	222	215	210	205	192
Other Asset Replacement and Renewal Capex	2,052	3,437	4,528	6,547	2,918	2,827	2,777	2,623	2,665	2,503
Reactive Capital Expenditure	-	549	572	550	517	510	504	503	501	471
Capital Expenditure Total	3,260	7,113	7,142	7,347	3,664	3,558	3,496	3,336	3,370	3,166
Preventative Maintenance	819	730	911	1,033	969	825	649	728	783	715
Corrective Maintenance	517	432	460	469	478	359	396	391	382	417
Operational Expenditure Total	1,337	1,162	1,371	1,502	1,447	1,184	1,045	1,119	1,165	1,133

**Table 8-50 Expenditure on Ground-Mounted Switchgear
(\$K in constant prices)**

8.5.11 Distribution Switchgear—Low Voltage Pits and Pillars

The composition, deployment, condition, and management of low-voltage pits and pillars across WELL's network are described in this subsection.

8.5.11.1 Fleet Overview

A high-level breakdown of low-voltage unit types is provided in Table 8-51.

Type	Quantity
Customer service pillar	17,353
Customer service pit	4,538
Link pillars, pits and cabinets	1,777
Total	23,668

Table 8-51 Summary of Low-voltage Units

Figure 8-24 presents the age profile of WELL's low-voltage units, which informs the assessment of asset condition, maintenance requirements, and future renewal planning.²⁸

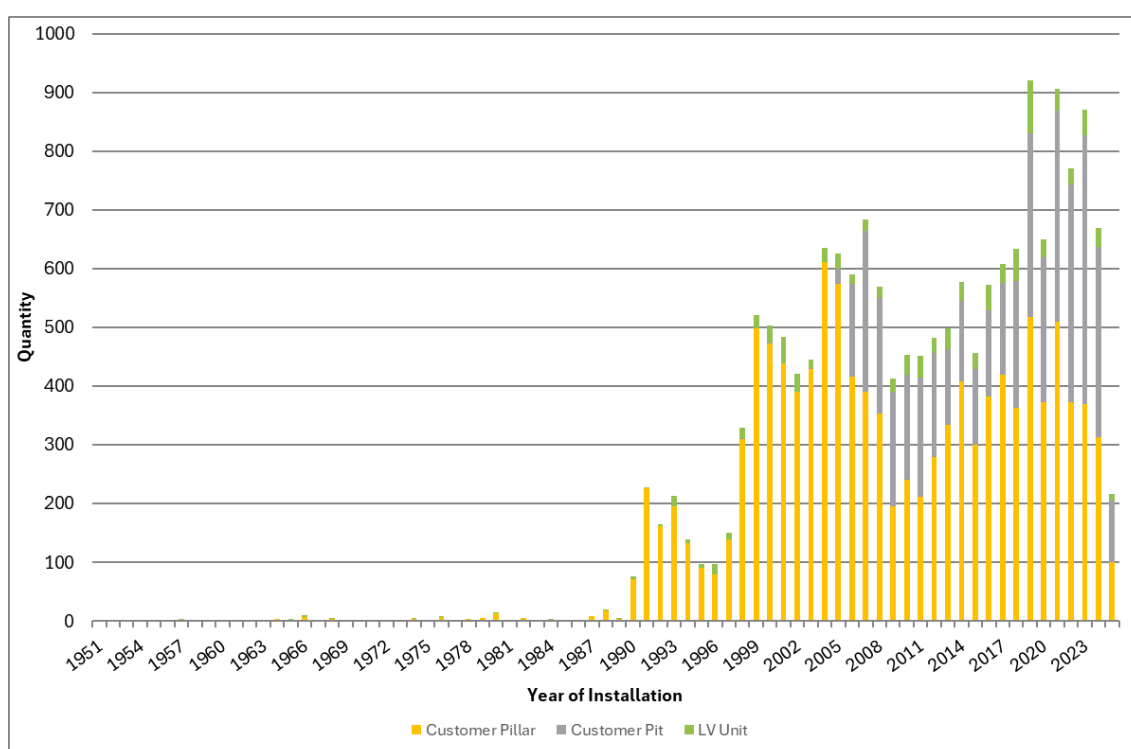


Figure 8-24 Age Profile of Pillars, Pits and Cabinets

Pillars and pits provide connection points between customer service cables and WELL's underground low-voltage reticulation and contain the fusing required to isolate individual service cables from the network. Pits are manufactured from polyethylene, as are most newer pillars, while earlier-generation pillars were constructed from concrete pipe, steel, or aluminium. In total, WELL operates 23,668 low-voltage units, including link pillars, pits, cabinets, under-veranda boxes, and boards. These assets are used to parallel

²⁸ There are 6,401 low voltage pillars, pits, cabinets and low voltage boards that have unknown installation dates, and these have not been included in the age profile.

adjacent low-voltage circuits to enable backfeeding during outages and to sectionalise larger low-voltage circuits for operational flexibility.

8.5.11.2 Fleet Objectives

In addition to the asset management objectives that apply across the network, WELL has established fleet-specific objectives for low-voltage equipment, as set out in Table 8-52.

Priority Area	Objective
Safety and Environment	No injuries resulting from working on and around low-voltage units. Low-voltage units located in the road reserve are not to be a risk to public safety.

Table 8-52 Fleet-Specific Objectives for Low-voltage Equipment

8.5.11.3 Maintenance Activities

The routine planned inspection and maintenance activities undertaken on low-voltage pits and pillars, including those used for customer service connections, fusing, and low-voltage network linking, are set out in Table 8-53.

Activity	Description	Frequency
Inspection of Service Pillars	Visual inspection and condition assessment of the service pillar and minor repairs to the lid as required.	5-yearly
Inspection of Service Pits	Visual inspection and condition assessment of the service pit and 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 the link box, thermal imaging and minor repairs as required.	5-yearly

Table 8-53 Inspection and Routine Maintenance Schedule for Low-voltage Pits and Pillars

Where practicable, WELL includes a loop impedance test to check the condition of the connections from the fuses to the source in its underground pillar's inspection regime.

8.5.11.4 Pit and Pillar Condition

Figure 8-25 presents the health–criticality matrix for WELL's low-voltage pits and pillars. Asset health reflects the assessed condition of each unit, including age-related deterioration and recorded defects, while asset criticality is determined by the asset's type and location within the network.

		Best Health		Asset Health		Worst Health	
		H5	H4	H3	H2	H1	
Asset Criticality	Lowest Impact	C4	4,157	3,917	11,208	378	14
		C3	138	254	1,169	2,142	5
		C2			258	26	2
	Highest Impact	C1					

Figure 8-25 Low Voltage Asset Health-Criticality Matrix

8.5.11.5 Renewal and Refurbishment

Pillars are generally replaced in response to fault or damage reports. Where pillars are assessed as having a high likelihood of future vehicle impact, they are replaced with pits. Older pillar types, including concrete and “mushroom” designs, are replaced when identified in poor overall condition, as repair is typically impractical or uneconomic.

Several variants of service connection pillars remain in service across the network and are being progressively replaced in small batches, particularly under-veranda service connection boxes located in older commercial areas.

In addition, WELL maintains an ongoing condition-based replacement programme for underground link boxes across Wellington City. Where link boxes are no longer required for network operation, they are jointed through; otherwise, they are replaced to retain the same functionality. Replacement is triggered by unsatisfactory inspection results, with fewer than 10 link boxes expected to require replacement each year.

8.5.11.6 Expenditure Summary for Low Voltage Pits and Pillars

Table 8-54 details the forecast capital expenditure on low-voltage pits and pillars over the planning period, with costs presented by disclosure year.

Expenditure Type	Disclosure Year Beginning 1 April									
	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035
Asset Replacement and Renewal Capex	4,898	434	441	414	382	376	372	371	370	348
Reactive Capital Expenditure	342	2,017	2,102	2,023	1,900	1,873	1,852	1,848	1,841	1,730
Capital Expenditure Total	5,240	2,452	2,543	2,437	2,282	2,249	2,225	2,220	2,211	2,077
Preventative Maintenance	245	343	296	335	300	461	413	446	485	465
Corrective Maintenance	147	205	177	200	180	276	247	267	290	278
Operational Expenditure Total	392	549	473	535	480	738	661	712	776	743

Table 8-54 Expenditure on Low Voltage Pits and Pillars
(\$K in constant prices)

8.5.12 Distribution Switchgear—Reclosers and Line Circuit Breakers

The composition, deployment, condition, and management of reclosers and line circuit breakers across WELL’s network are described in this subsection, providing context for the maintenance, reliability, and renewal strategies discussed below.

8.5.12.1 Fleet Overview

Automatic circuit reclosers are pole-mounted circuit breakers used to protect the rural 11 kV overhead network. On these feeders, reclosers are employed to minimise customer impacts from transient faults commonly associated with overhead lines. The same equipment type is also installed on urban overhead feeders, with the reclosing function disabled, where it is used to automatically sectionalise the network.

All reclosers installed on the WELL network are modern vacuum-interruption units fitted with electronic controllers. The recloser types currently in service are summarised in Table 8-55.

Manufacturer	Insulation	Model	Quantity
G&W	Solid/Vacuum	Viper-S	27
Total			27

Table 8-55 Summary of Recloser Types

Figure 8-26 presents the age profile of WELL's recloser fleet, which informs the assessment of asset condition, maintenance requirements, and renewal timing discussed in the sections that follow.

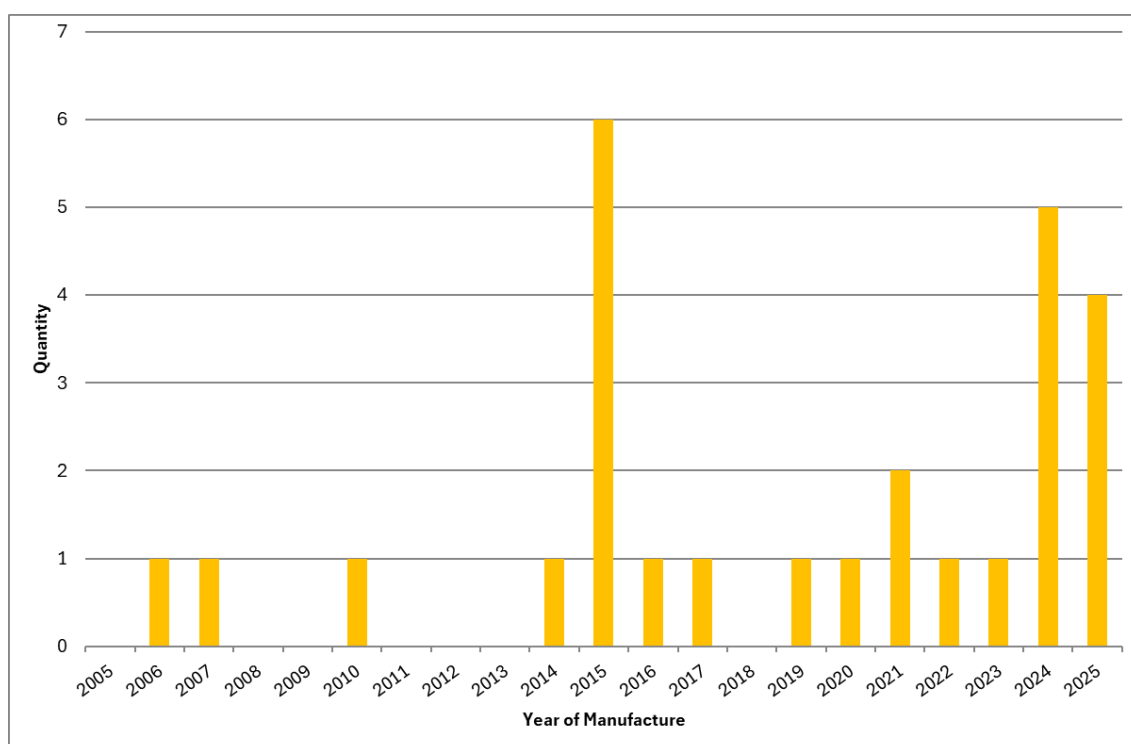


Figure 8-26 Age Profile of Reclosers and Line Circuit Breakers

8.5.12.2 Fleet Objectives

In addition to the asset management objectives that apply across the network as a whole, WELL has established fleet-specific objectives for reclosers, as set out in Table 8-56.

Priority Area	Objective
Safety and Environment	Ensure the use of reclosing complies with best industry practices to minimise public safety and wildfire risk.
Customer	Ensure reclosers are functioning correctly to minimise customer disruption.

Table 8-56 Fleet-Specific Objectives for Reclosers

8.5.12.3 Maintenance Activities

The routine planned inspection, testing, and maintenance activities undertaken on reclosers are set out 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
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 and proving 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 8-57 Inspection and Routine Maintenance Schedule for Auto Reclosers

8.5.12.4 Renewal and Refurbishment

Reliable and appropriately located reclosers are a key contributor to network performance in rural areas. The reclosers currently in service are modern vacuum-interruption units, are in good condition, and are performing as expected.

In addition, WELL plans to install further line circuit breakers on urban overhead feeders to reduce the customer impact of outages on these feeders.

8.5.12.5 Expenditure Summary for Reclosers

Table 8-58 details the forecast capital expenditure on reclosers over the planning period, with costs presented by disclosure year.

Expenditure Type	Disclosure Year Beginning 1 April									
	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035
Feeder Reliability Projects– Switchgear	-	1,196	689	956	1,068	1,033	1,002	979	957	899
Capital Expenditure Total	-	1,196	689	956	1,068	1,033	1,002	979	957	899
Preventative Maintenance	53	127	126	82	110	207	182	192	205	193
Corrective Maintenance	48	105	105	63	78	138	121	128	137	129
Operational Expenditure Total	100	232	231	145	188	345	303	321	342	322

Table 8-58 Expenditure on Reclosers
(\$K in constant prices)

8.5.13 Distribution Switchgear—Overhead Switches, Links and Fuses

The composition, deployment, condition, and management of overhead switches, links, and fuses across WELL's network are described in this subsection, providing context for the maintenance, reliability, and renewal strategies discussed below.

8.5.13.1 Fleet Overview

Overhead switchgear is used to sectionalise the overhead network and to provide protection for pole-mounted distribution transformers and cables at overhead-to-underground transition points. A summary of the quantities of the various categories of overhead switches is provided in Table 8-59.

Category	Quantity
Gas Switches	70
Air Break Switches	326
Knife Links	41
Dropout Fuses	2,232
Dropout Sectionalisers	11
Total	2,680

Table 8-59 Summary of Pole-Mounted Distribution Switchgear

Figure 8-27 presents the age profiles of overhead switches, links, and fuses, which inform the assessment of asset condition, maintenance requirements, and renewal planning discussed in the sections that follow.

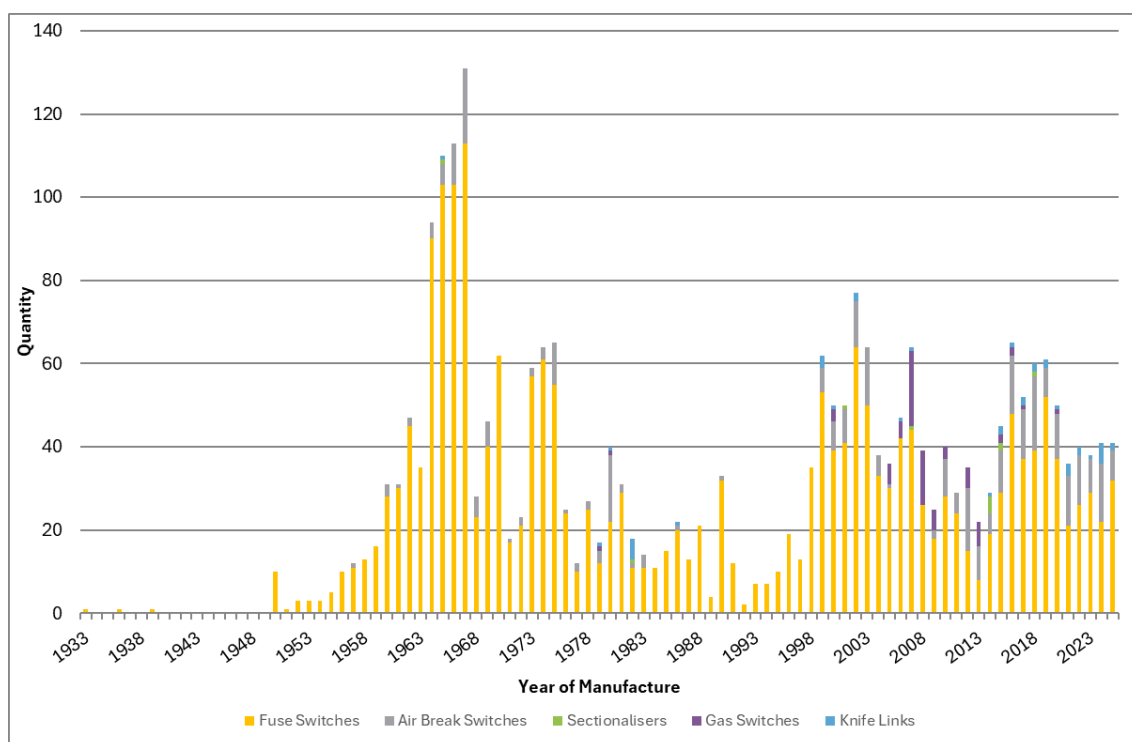


Figure 8-27 Age Profile of Overhead Switchgear and Devices

8.5.13.2 Fleet Objectives

In addition to the asset management objectives that apply across the network, WELL has established fleet-specific objectives for pole-mounted switchgear, as set out in Table 8-60.

Priority Area	Objective
Safety and Environment	No injuries resulting from working on and around overhead switchgear. Overhead switchgear located in the road reserve must not pose a risk to public safety.

Table 8-60 Fleet-Specific Objectives for Pole-Mounted Switchgear

8.5.13.3 Maintenance Activities

The routine planned inspection, testing, and maintenance activities undertaken on overhead switches, links, and fuses are set out in Table 8-61.

All overhead switches and links are managed under a common preventative maintenance programme, as outlined above. Overhead high-voltage fuses are visually inspected as part of the annual overhead line survey. Given the large population of fuses and their relatively low risk profile, a standalone inspection and maintenance programme is not considered justified.

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, cleaned and adjusted contacts, and checked 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 8-61 Inspection and Routine Maintenance Schedule for Overhead Switch Equipment

8.5.13.4 Condition of Overhead Switches, Links and Fuses

Overall, the condition of overhead equipment across the network is generally good. However, exposure to wind, salt spray, pollution, and windborne debris results in a small number of asset failures each year. Common deterioration mechanisms include corrosion of steel frame components and operating handles, mechanical damage to insulators, and corrosion or electrical welding of contacts.

The coastal environment around Wellington accelerates the corrosion of galvanised overhead equipment. Where practicable, stainless-steel fittings are used in place of galvanised components, as they have demonstrated improved durability and a more cost-effective whole-of-life solution.

The forecast future condition of the overhead switch fleet is modelled using survival curves derived from the age at which switches have been replaced.

8.5.13.5 Renewal and Refurbishment

Standard inspection cycles inform renewal activity for these assets, with maintenance and replacement actions triggered by the identification of corrective works. As a result of the extensive pole and crossarm replacement programmes undertaken in recent years, a significant number of overhead switches have already been renewed. Further replacement typically occurs either as reactive capital expenditure following an unsatisfactory condition assessment during routine inspections, or opportunistically during pole or crossarm replacement when the switch condition warrants renewal.

The forecast number of overhead switch replacements each year is estimated by modelling the asset population through the survival curve.

8.5.13.6 Expenditure Summary for Overhead Switchgear

Table 8-62 details the forecast capital expenditure on overhead switchgear over the planning period, with costs presented by disclosure year.

Expenditure Type	Disclosure Year Beginning 1 April									
	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035
Reactive Capital Expenditure	94	157	164	157	148	146	144	144	143	135
Capital Expenditure Total	94	157	164	157	148	146	144	144	143	135
Preventative Maintenance	65	21	27	31	28	43	39	42	45	44
Corrective Maintenance	7	2	3	3	3	5	4	4	5	5
Operational Expenditure Total	72	24	30	34	31	48	43	46	50	48

Table 8-62 Expenditure on Overhead Switchgear
(\$K in constant prices)

8.5.14 Other System Fixed Assets—Substation DC Systems

This subsection describes the composition, condition, and management of substation DC systems across WELL's network, providing context for the maintenance, renewal, and investment approaches applied to these critical support systems.

8.5.14.1 Fleet Overview

DC auxiliary systems supply power to substation protection, control, metering, monitoring, automation, and communication systems, as well as to circuit breaker tripping and closing mechanisms. A standard DC auxiliary system comprises batteries, battery chargers, DC/DC converters, and a battery monitoring system.

Historically, WELL's substations have operated a range of DC system voltages, including 24 V, 30 V, 36 V, 48 V, and 110 V. To improve standardisation, reliability, and maintainability, 24 V has been adopted as the standard voltage for all new installations and replacement DC systems.

8.5.14.2 Maintenance Activities

The routine inspection, testing, and maintenance activities for substation DC supply systems (battery banks) are set out in Table 8-63.

Activity	Description	Frequency
Inspection and monitoring of battery & charger condition	Routine visual inspection of batteries, chargers and associated equipment. Voltage checks on batteries and the 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 8-63 Inspection and Routine Maintenance Schedule for Zone Substation Battery Banks

Valve-regulated lead-acid batteries are now the standard battery type used across the network, with maintenance undertaken in accordance with IEEE 1188 (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 fleet is very good, and battery chargers are also generally in good condition. Many DC systems are monitored via Supervisory Control and Data Acquisition (SCADA), enabling the Network Control Room to be promptly notified of charger failures. Given that repair costs for battery chargers are often higher than replacement costs, chargers are repaired only when this is economically justified.

Battery Replacement

WELL operates 557 battery banks across 301 sites. While batteries are critical to substation operation, they are relatively low-cost assets. Accordingly, WELL's policy is to replace all batteries at approximately 80% of their design life rather than rely on an extensive testing regime.

At sites with higher amp-hour demand, 10-year design-life batteries are installed, while smaller sites and communications systems with lower demand typically use 5-year design-life batteries. In parallel, WELL is standardising the voltages used for switchgear and communications equipment as part of the primary plant replacement programme.

8.5.14.3 Expenditure Summary for Substation Batteries

Table 8-64 details the forecast capital expenditure on substation batteries over the planning period, with costs presented by disclosure year.

Expenditure Type	Disclosure Year Beginning 1 April									
	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035
Asset Replacement and Renewal Capex	418	382	378	372	376	370	365	364	361	334
Capital Expenditure Total	418	382	378	372	376	370	365	364	361	334
Preventative Maintenance	80	81	81	81	82	83	85	87	88	91
Corrective Maintenance	11	11	11	11	11	11	11	11	12	12
Operational Expenditure Total	90	91	92	92	92	94	96	98	100	103

Table 8-64 Expenditure on Substation Batteries
(\$K in constant prices)

8.5.15 Other Network Assets—Protection Devices

The composition, condition, and management of protection devices across WELL's network are described in this subsection, outlining their role in ensuring the safe, reliable, and secure operation of the electricity system.

8.5.15.1 Fleet Overview

Protection devices are assets that automatically detect abnormal operating conditions and indicate potential primary plant faults. Their operation helps ensure the electricity system remains safe and stable, minimises damage to network equipment, and maximises asset service life. Protection devices also play a key role in

limiting the number of customers affected by equipment failures by enabling faults to be isolated quickly and selectively.

Across the high-voltage network, WELL operates 1,484 protection devices. The majority of these are electromechanical units, with the remainder utilising solid-state electronic or microprocessor-based technology. Protection devices are typically installed on substation switchboards, although some are housed within dedicated protection panels.

To support asset management planning and expenditure forecasting, WELL has adopted a tiered classification of the distribution network, as shown in Figure 8-28. This tier system reflects varying security and reliability requirements across the network and informs the selection and application of protection device types appropriate to the level of risk and the consequences of a supply interruption.

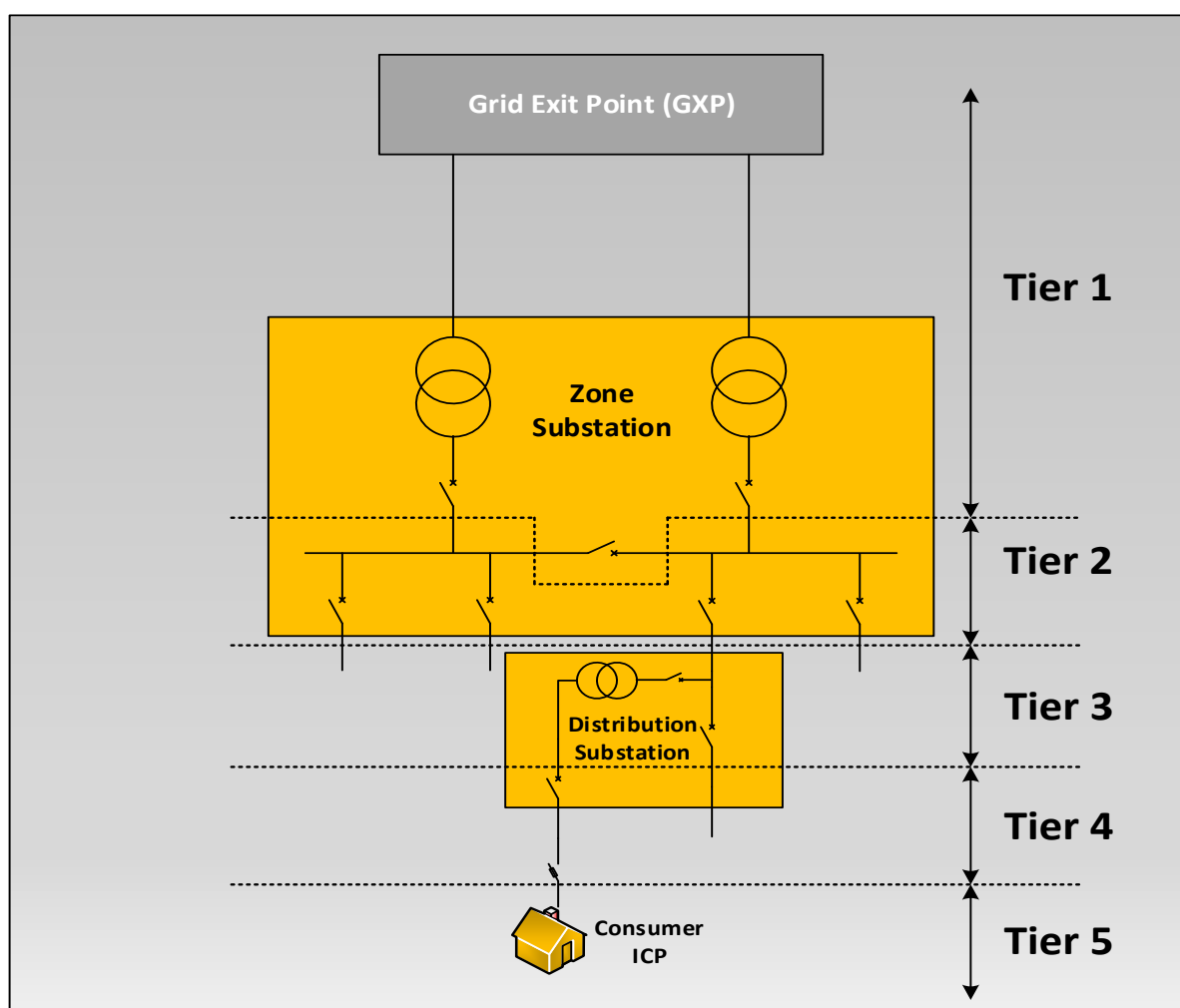


Figure 8-28 WELL Protection Tier System

Differential protection is applied to all Tier 1 systems across the network and is also widely used on Tier 2 systems in the Southern Area. This approach provides an optimal level of protection for operating a closed-ring network topology. Overcurrent and earth-fault (OC/EF) protection is used as the primary protection where differential protection is not required, such as on radial feeders with normally open points, and as backup protection on circuits that are differentially protected.

Outside the Southern Area, Tier 2 networks are generally protected using OC/EF relays, supplemented by auto-reclosers on rural feeders and fuses on rural spur lines. Fuses are used to protect 11 kV distribution transformers up to 1 MVA, while larger transformers are protected using OC/EF relays. On the low-voltage network, fuses are typically used to protect cables and low-voltage equipment. However, low-voltage circuit breakers are installed where larger transformers increase arc-flash risk or where specific operating requirements apply, such as bi-directional power flow.

Automatic Under-Frequency Load Shedding (AUFLS) relays are installed at 17 zone substations and are configured to trip feeders if system frequency falls below predefined thresholds, in accordance with System Operator requirements.

Figure 8-29 presents the age profiles of WELL's protection devices, which inform the assessment of asset condition, maintenance requirements, and renewal planning discussed in the sections that follow.

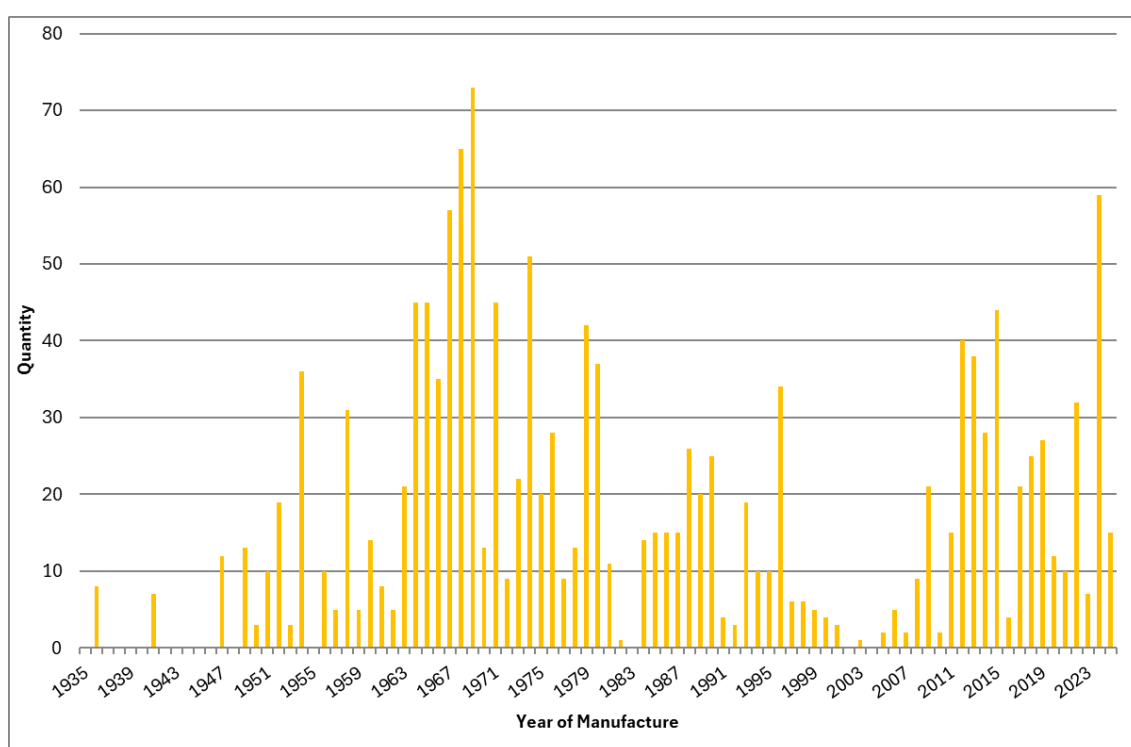


Figure 8-29 Age Profile of Protection Relays

8.5.15.2 Maintenance Activities

Table 8-65 outlines the routine planned testing and maintenance activities undertaken on protection relays, which support the safe, reliable, and compliant operation of the network.

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

Table 8-65 Inspection and Routine Maintenance Schedule for Protection Relays

Testing of differential protection also verifies the integrity of the copper pilot cables between substations. Where a test failure occurs, the condition of the pilot cable is assessed against the requirements of the specific protection scheme. Depending on the outcome, the protection service may be transferred to healthy conductors within the pilot cable, or the cable may be flagged for repair.

Some early pilot cables are now experiencing outer-sheath deterioration, leading to moisture ingress and a consequent reduction in insulation quality. These issues are managed through a combination of rerouting pilot cable paths, targeted repairs, or full cable replacement, as appropriate.

8.5.15.3 Renewal and Replacement

WELL adopts a risk-based approach to replacing protection devices. Electromechanical protection devices generally have long service lives, and the fleet remains in good overall condition. In-service failures of these devices are rare, with deterioration typically identified through routine maintenance testing. Numerical protection devices, while offering enhanced functionality, have shorter service lives and may fail in service. However, their self-diagnostic features provide early warning through alarms when degradation is detected.

Where a protection device is identified as unable to perform its primary function, it is replaced immediately using a critical spare. Devices that remain operational but show signs of deterioration are scheduled for inclusion in planned replacement programmes. These programmes are prioritised based on device condition, functionality, and network risk, and replacement is often coordinated with other projects, particularly those involving associated switchgear or transformers.

Tier 1 protection assets are the most critical and require the highest level of security; accordingly, they are assigned the highest replacement priority. Where primary equipment is replaced, associated protection schemes are reviewed and, where appropriate, upgraded to meet current standards.

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

- Ongoing replacement of devices with identified risk
- Annual preventative maintenance programme
- Tier 1, 2, and 3 replacement programmes

In addition to these replacement programmes, WELL maintains a continuous improvement focus by regularly reviewing and refining protection management processes, developing application guides, and testing and commissioning documentation.

8.5.15.4 Expenditure Summary for Protection Relays

Table 8-66 details the forecast capital expenditure on over the planning period, with costs presented by disclosure year.

Expenditure Type	Disclosure Year Beginning 1 April									
	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035
Tier 1 Replacement Programme	-	938	911	876	875	861	849	848	841	778
Tier 2 Replacement Programme	-	703	729	701	693	669	647	634	616	569
Tier 3 Replacement Programme	-	470	271	261	258	249	241	235	229	211
Capital Expenditure Total	-	2,111	1,911	1,838	1,827	1,779	1,737	1,717	1,686	1,558
Preventative Maintenance	172	174	175	175	176	180	183	187	191	197
Corrective Maintenance	11	11	11	11	11	11	11	11	12	12
Standards / Process	49	49	48	47	46	46	46	46	47	47
Operational Expenditure Total	232	233	233	233	233	237	240	244	249	256

Table 8-66 Expenditure on Protection Relays
(\$K in constant prices)

8.5.16 Other Network Assets—SCADA and Communications Assets

The composition, condition, and management of SCADA and communications assets across WELL's network are described in this subsection, outlining their role in supporting network monitoring, control, protection, and operational decision-making.

8.5.16.1 Fleet Overview

WELL's SCADA comprises a hierarchy of communication and control assets distributed across the network and interconnected through multiple communications platforms. The system is structured with a central Master Station at the top of the topology, supported by a range of intermediate components that extend down to the field level, where Remote Terminal Units (RTUs) interface directly with network assets.

SCADA enables real-time monitoring and remote operation of the electricity network, providing operators with visibility of system status and the ability to control field equipment from a central control room. In practice, the SCADA system is used to:

- Monitor the operation of the high-voltage network by remotely indicating key parameters, such as voltage and current, at critical locations;
- Enable real-time remote control of selected field equipment
- Graphically display outages and switching states on a dynamic network schematic
- Transmit alarms from field devices to the control room for prompt investigation and response.

Operational data is collected by RTUs installed at remote locations and transmitted to the SCADA Master Station via dedicated communication links. Control commands are issued from the Master Station and conveyed back to field devices over the same communications pathways.

Figure 8-30 presents the age profile of WELL's SCADA RTU fleet, providing context for assessing asset condition, ongoing supportability, and future renewal planning.

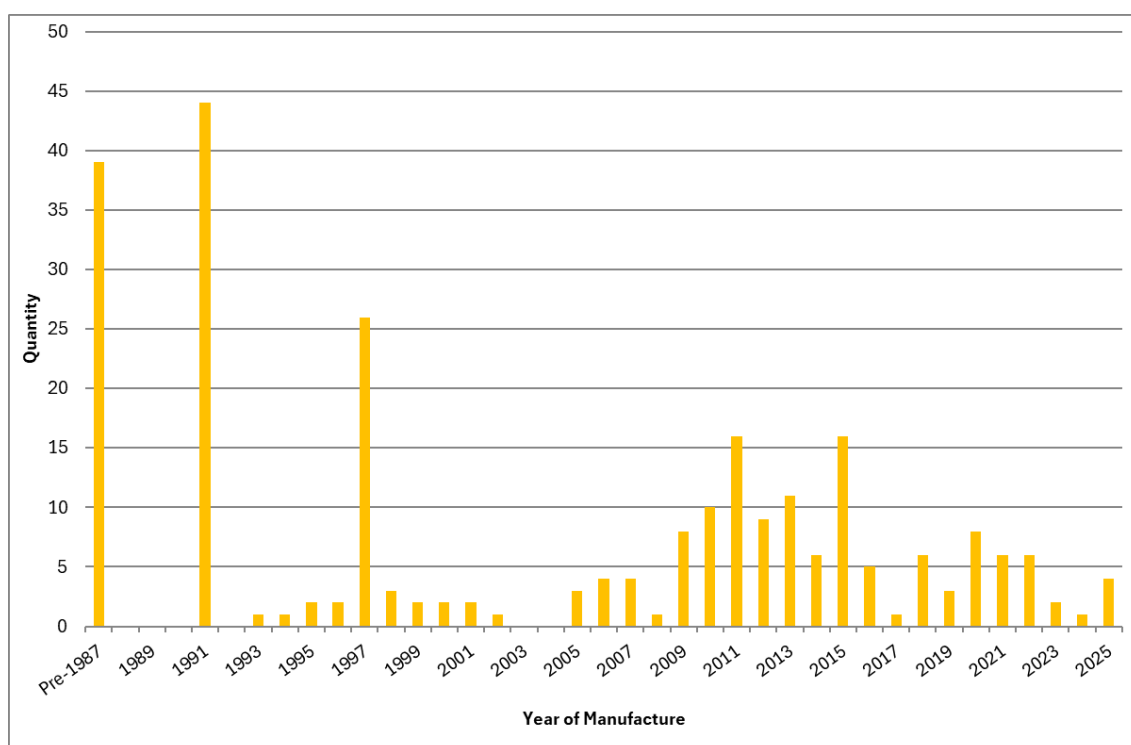


Figure 8-30 Age Profile of SCADA RTUs

The most common communication links used on the network are copper pilot cables and fibre-optic cables, with WELL owning approximately 750 km of communications cabling in total. In addition, WELL leases several fibre links from third-party providers where this is operationally or economically efficient. The age profile of WELL owned communications cables is shown in Figure 8-31.

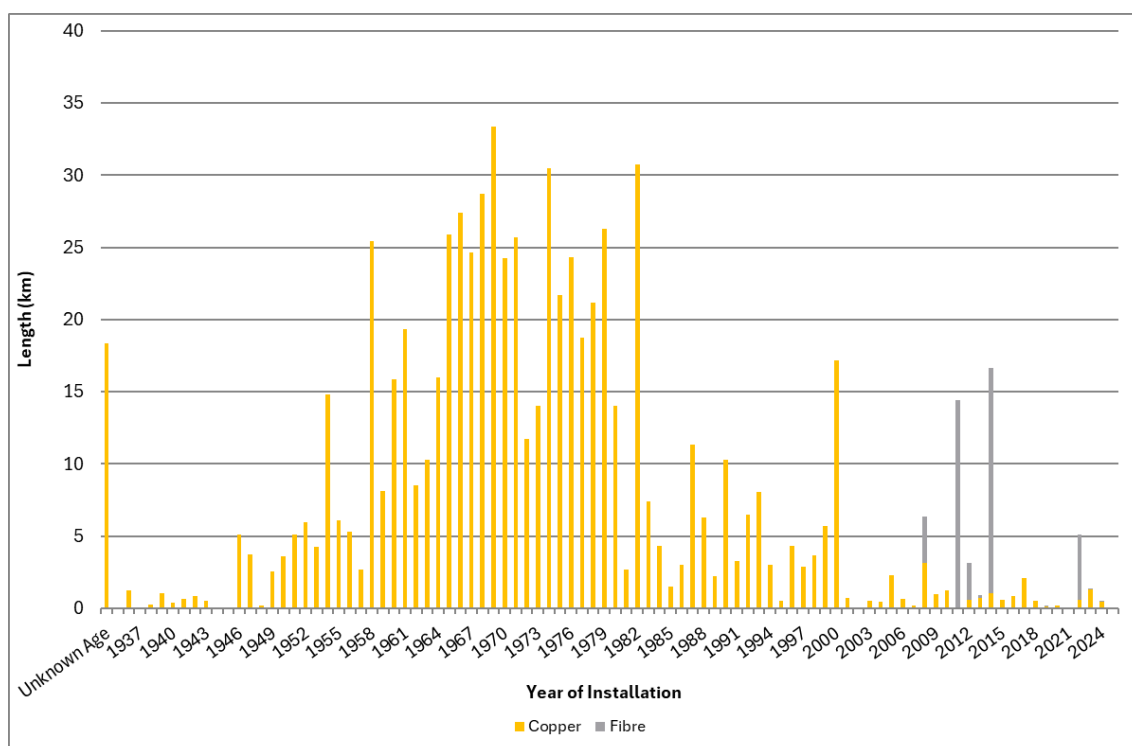


Figure 8-31 Age Profile of Communication Cables

8.5.16.2 Maintenance Activities

The SCADA system is largely self-monitoring, and preventative maintenance requirements are limited. Routine activities are primarily focused on planned server, hardware, and software upgrades and replacements. Maintenance responsibilities are broadly divided into two categories:

- Hardware support, which is provided on an as-required basis by Wellington-based maintenance contractors.
- Software maintenance and support, which is provided by external service providers.

First-line maintenance of SCADA field equipment is undertaken by the Field Service Provider within the scope of its substation maintenance contracts. The substation-level IP network is monitored and supported by its IP network infrastructure providers.

SCADA front-end processors are supported by Uninterruptible Power Supply (UPS) systems to provide backup power, with an additional UPS supplying operator terminals in the Network Control Room (NCR). These systems are maintained under a supplier-provided maintenance programme and incorporate remote self-diagnostics and dual redundancy of converters and batteries, providing a high level of supply security in the event of component failure.

Communication cables that support protection schemes are tested in conjunction with the protection relays that operate over those circuits. Cables used for SCADA communications are tested when associated SCADA equipment is replaced or where circuit performance is identified as degraded.

8.5.16.3 SCADA System Component Challenges

Key challenges associated with SCADA system components are addressed in this subsection, including lifecycle management, supportability, cybersecurity, and the implications for network reliability and operational resilience.

SCADA Radio

WELL continues to use analogue radio communications at a small number of non-critical sites. However, the age of this equipment, the limited availability of spare parts, and inherent system constraints constrain its continued use. These limitations include a restricted address range, the absence of timestamping, and a diminishing ability to interface with modern devices.

All new sites requiring radio-based communications are implemented using public cellular infrastructure operating on a private Access Point Name (APN), providing improved functionality, scalability, and long-term supportability.

Legacy Remote Terminal Units (RTUs)

Several legacy RTUs remain in service across the network. These devices are no longer manufactured and have limited repair support; accordingly, they are progressively replaced with modern alternatives as failures occur.

Common Alarms

Common Alarm units remain in service across the network. These custom-built devices are installed at non-critical, ringed distribution substations to provide the Network Control Room with basic indication of substation events. The units offer limited functionality, are not economically viable to repair, and are therefore being progressively replaced under an active programme with modern RTUs.

8.5.16.4 Renewal and Refurbishment

When substation sites are upgraded or redeveloped, and IP network connectivity is available, the station RTU is upgraded and migrated to the substation TCP/IP network using the DNP3.0 protocol. Similarly, where an RTU at a zone substation or major switching point is located adjacent to existing TCP/IP infrastructure, consideration is given to upgrading the equipment to enable IP-based communications and improve overall system reliability. This infrastructure also supports the future deployment of additional non-SCADA substation-based equipment.

The prioritisation of the RTU replacement programme aligns with that of other secondary asset replacement programmes. RTU replacements are scheduled where specific risks are identified and are often coordinated with other works, such as switchgear upgrades. In these cases, RTU replacement is incorporated into the broader project scope and assessed on a case-by-case basis.

As part of WELL's strategy to manage the customer impact of 11 kV underground cable faults (refer to Section 8.5.7), the number of circuit breakers and remotely controlled switches on the underground network will continue to increase. To support this, WELL intends to implement a programme to retrofit ring main units with motor drives and RTUs, with units prioritised based on their potential impact on network reliability.

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

- Zone RTU Replacement Programme
- Common Alarm Replacement Programme
- Distribution RTU Replacement Programme
- Substation Data Network Renewal, including Conitel replacement
- Retrofitting SCADA control to existing automation-enabled switchgear
- End-of-life RTU Replacement (reactive)

WELL does not currently operate an active renewal programme for communications cables. New fibre-optic cables are installed alongside 33 kV cable replacement projects to support communications and protection signalling and to enable future condition-assessment technologies, such as distributed temperature sensing (DTS). Existing communications cables are maintained reactively as performance degrades.

8.5.16.5 Expenditure Summary for SCADA and Communications Assets

Table 8-67 details the forecast capital expenditure on SCADA and communications assets over the planning period, with costs presented by disclosure year.

Expenditure Type	Disclosure Year Beginning 1 April									
	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035
Zone RTU Replacement Programme	536	732	725	714	721	709	700	698	693	641
Common Alarm Replacement Programme	345	523	518	510	515	507	500	499	495	458
Distribution RTU Replacement Programme	354	234	272	233	206	203	200	200	198	183
Substation Data Network	-	314	311	306	309	304	300	299	297	275
SCADA control retrofits	-	209	207	204	206	203	200	200	198	183
Reactive Capital Expenditure	-	145	144	142	143	141	139	139	138	127
Capital Expenditure Total	1,236	2,157	2,176	2,108	2,099	2,066	2,038	2,035	2,018	1,866
Corrective Maintenance	-	-	-	-	-	-	-	-	-	-
Preventative Maintenance	21	21	21	21	21	22	22	23	23	24
Operational Expenditure Total	21	21	21	21	21	22	22	23	23	24

Table 8-67 Expenditure on SCADA and Communications Assets
(\$K in constant prices)

8.5.17 Other network assets—Load Control Equipment

This subsection describes the composition, function, and management of load control equipment across WELL's network, outlining its role in supporting system security, demand management, and regulatory compliance.

8.5.17.1 Fleet Overview

WELL operates a ripple injection load control system that injects 475 Hz and 1050 Hz signals into the network to control selected customer loads. This includes water heating and storage heaters, operating street lighting, and providing legacy tariff signalling on behalf of retailers. Ripple injection is normally controlled automatically via a Catapult master station, with manual control available at injection plants during emergencies.

Figure 8-32 presents the age profile of WELL's ripple injection plant fleet, providing context for ongoing maintenance, supportability, and future renewal considerations for this critical load-control system.

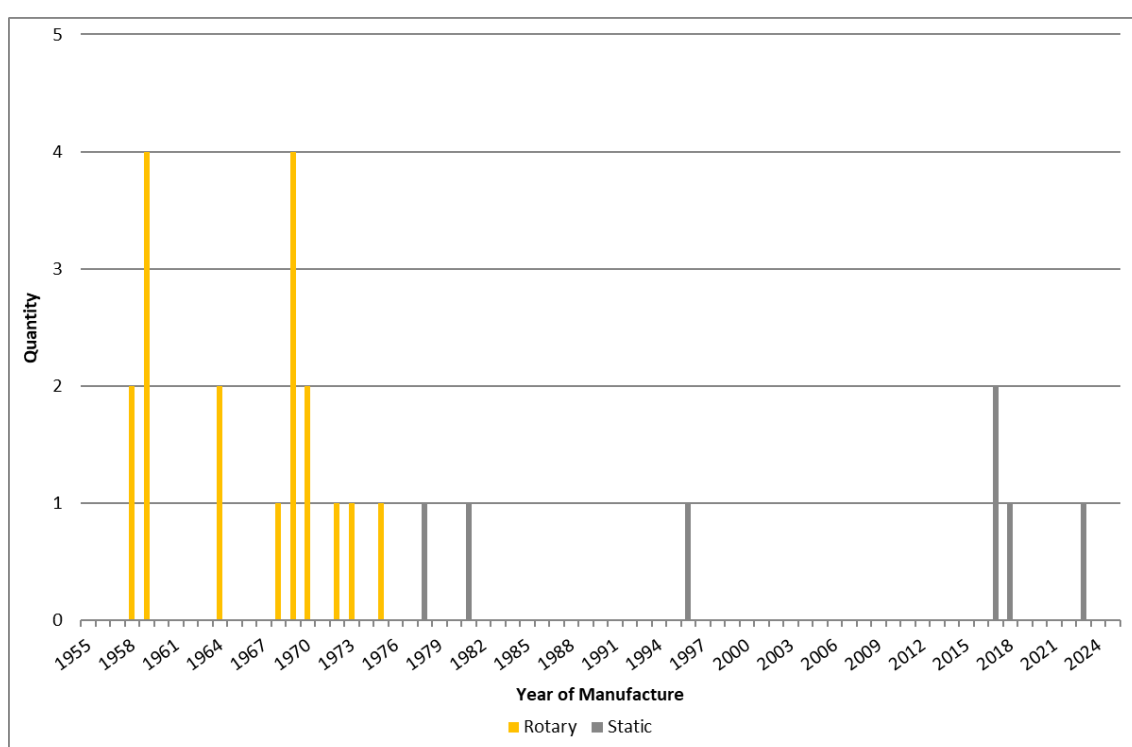


Figure 8-32 Age Profile of Ripple Plant

There are 25 ripple injection plants installed across the network, predominantly located at GXPs and zone substations. In the Southern Area, a 475 Hz signal is injected into the 33 kV network via two static plants at the Wilton and Central Park GXPs, and two additional plants injecting at the Kaiwharawhara 11 kV point of supply. In the Northeast and Northwest Areas, a nominal 1050 Hz signal is injected at 11 kV at each zone substation.

The 1050 Hz signals are generated using motor-generator sets. Due to a slip in the induction motor, the operating frequency is slightly lower than the nominal 1050 Hz. At full load, the design slip is approximately 0.7%, resulting in a signalling frequency range of 1042–1050 Hz under varying load conditions. The standard receivers installed in the Northeast and Northwest Areas are tuned to 1042 Hz to accommodate this variation.

WELL intends to continue operating the ripple injection system for the foreseeable future. This reflects concerns about the reliability, resilience, and response speed of alternative load-control technologies that rely on public cellular networks, which may not be capable of delivering the rapid demand response required to support network operations and Grid Emergency events.

8.5.17.2 Maintenance Activities

The routine inspection, testing, and maintenance activities for load control equipment are set out in Table 8-68. WELL owns and maintains the ripple injection plants located at substations and the blocking cells at GXPs, while customer receivers are owned by retailers or customers.

Activity	Description	Frequency
General Inspection	Check the output signal, visual inspection, thermal image, partial discharge scan, and motor generator test run.	6-monthly
Maintain Ripple Injection Plant	Clean and inspect all equipment; maintain motor generator sets; conduct coupling cell tests and inspections.	Annually
Blocking Cell Testing and Maintenance	Visual inspection, cleaning and maintenance of blocking cells at GXPs as required.	5-yearly

Table 8-68 Inspection and Routine Maintenance Schedule for Ripple Plant

Strategic Spares

Table 8-69 summarises the strategic spares held for the load control plant, which are maintained to support the ongoing reliability, operability, and timely restoration of the ripple injection system following equipment failure.

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

Table 8-69 Spares Held for Load Control Plant

8.5.17.3 Renewal and Refurbishment

WELL's approach to the renewal and refurbishment of primary equipment and load control programmable logic controllers (PLCs) is outlined in this subsection, with a focus on managing end-of-life risk, maintaining operational resilience, and sequencing replacements to minimise impacts on customers and the wider power system.

Primary Equipment

The rotary injection fleet is progressively transitioning to static units, driven by end-of-life considerations and capacity constraints.

Load Control Programmable Logic Controller

The Load Control PLCs are housed at the ripple injection sites and coordinate the local operation of the ripple plant. These PLCs are at or near the end of their technical lives. While some spare parts remain available, units will be replaced either as part of planned ripple plant replacement projects or on a reactive basis as failures occur and existing spares are exhausted.

8.5.17.4 Expenditure Summary for Other Network Assets

Table 8-70 summarises the forecast capital expenditure on other network assets over the planning period, disaggregated by disclosure year, and reflects the timing of planned renewal, refurbishment, and replacement activities required to manage asset condition, obsolescence, and operational risk.

Expenditure Type	Disclosure Year Beginning 1 April									
	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035
Ripple Injection Plant Renewal	1,262	943	911	876	1,300	1,254	1,213	1,187	1,154	1,067
Reactive Capital Expenditure	-	436	432	425	429	422	417	416	413	382
AVRR Replacement Programme	293	283	-	-	-	-	-	-	-	-
Capital Expenditure Total	1,555	1,662	1,342	1,301	1,730	1,677	1,630	1,604	1,567	1,449
Preventative Maintenance	71	72	72	73	73	74	76	78	79	82
Corrective Maintenance	105	106	107	107	107	110	112	114	116	120
Operational Expenditure Total	177	178	179	180	180	184	188	191	195	202

Table 8-70 Expenditure on Other Network Assets
(\$K in constant prices)

8.5.18 Other Network Assets—General

This subsection describes other network assets that support the operation, safety, and performance of WELL's electricity network and are not captured within the primary asset categories outlined in the preceding sections.

8.5.18.1 Metering

WELL does not own metering assets located on customer premises; these are owned and maintained by retailers and metering service providers. WELL owned check meters are installed at GXPs and provide data to support WELL's load control system, as described in Section 8.5.9.4. Replacement of legacy electronic check meters is required at five GXPs to meet enhanced regulatory reporting requirements for the Automatic Under-Frequency Load Shedding (AUFLS) scheme, with completion scheduled for 2025. This replacement programme will also be extended to the remaining four GXPs that are not directly required for AUFLS reporting, as these units have reached the end-of-life. This approach will standardise the check meter fleet and align it under a common maintenance regime.

Maximum Demand Indicator (MDI) meters are installed at most distribution substations, predominantly those supplying street lighting and low-voltage networks. These meters are used for operational and planning purposes only and are treated as part of the distribution substation asset base.

8.5.18.2 Generators and Mobile Substations

WELL owns six mobile generators and a fixed-site generator that supports the disaster recovery control room. One mobile generator is deployed at the corporate office, two at disaster recovery data centres, and the remaining units are available to mitigate customer impact during network outages. In addition, WELL owns two 33/11 kV, 10 MVA mobile substations and one 11 kV mobile switchboard to support network restoration and contingency operations.

Additional generation capacity is provided by the works contractor as required to support network operations and outage mitigation.

8.5.18.3 Voltage Regulation

Voltage is regulated at zone substations using Automatic Voltage Regulator Relays (AVRRs) to control power transformer tap changers. Several sites have AVRRs that are no longer supported by suppliers, increasing the risk of failure. These relays are being progressively replaced as part of the ongoing asset renewal programme.

8.5.19 Assets Located at Bulk Electricity Supply Points Owned by Others

WELL owns and maintains a range of network assets installed at Transpower-owned and operated GXPs. While these assets are included within the relevant asset categories described above, this subsection provides additional context on their location, role, and management considerations, reflecting the shared-site environment and associated operational, access, and coordination requirements.

8.5.19.1 33 kV and 11 kV Lines, Poles, and Cables

WELL owns the lines, poles, cables, and associated support structures at all GXPs from which it takes supply. In the Wellington City area, these connections are fully underground, while in the Hutt Valley and Porirua areas, a significant proportion of circuits connect to GXPs via overhead lines.

8.5.19.2 11 kV Switchgear

WELL owns the 11 kV switchgear located at Kaiwharawhara GXP. At all other GXPs where supply is provided at 11 kV, the 11 kV switchboards are owned by Transpower.

8.5.19.3 Protection Relays and Metering

WELL owns the 33 kV line differential and inter-tripping protection relays at all GXPs, except Kaiwharawhara GXP. At Kaiwharawhara, WELL owns the protection relays associated with the 11 kV switchgear, with the exception of the incomer relays, which are owned by Transpower. WELL also owns check metering at all GXPs, which provides data to support the load control system and AUFLS reporting requirements.

8.5.19.4 SCADA, RTUs, and Communications Equipment

WELL owns and maintains the SCADA RTUs and associated communications equipment at all GXPs, enabling real-time monitoring, control, and integration of GXP assets into WELL's network operations and control systems.

8.5.19.5 DC Power Supplies and Battery Banks

WELL owns and maintains the battery banks and associated DC supply equipment at all GXPs, providing secure auxiliary power for protection, control, communications, and operational systems in the event of loss of normal supply.

8.5.19.6 Load Control Equipment

WELL owns and operates a load control injection plant at the Haywards and Melling GXPs and has ripple-blocking circuits installed on the 33 kV buses at Takapu Road, Melling, Gracefield, and Upper Hutt GXPs to manage signal propagation across the transmission–distribution interface.

8.6 Asset Replacement and Renewal Summary for 2026–2036

The total projected capital budget for asset replacement and renewal over the 2026–2036 period is presented in Table 8-71. This forecast includes allowances for asset replacements arising from in-year faults and condition-based assessment programmes.

Asset Category	Disclosure Year Beginning 1 April									
	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035
Subtransmission	13,427	-	9,034	8,908	-	6,808	15,656	4,239	4,411	4,310
Zone Substations	242	5,974	592	5,867	530	525	521	470	522	544
Distribution Poles and Lines	7,271	8,035	7,723	6,748	6,584	6,275	5,996	5,799	5,572	5,027
Distribution Cables	3,824	6,046	4,356	4,453	6,654	6,549	6,462	6,454	6,403	5,965
Distribution Substations	11,957	8,175	6,198	6,756	8,272	8,425	8,401	8,390	8,323	7,753
Distribution Switchgear	8,595	10,918	10,538	10,897	7,163	6,986	6,866	6,679	6,682	6,277
Other Network Assets	3,209	6,312	5,807	5,620	6,032	5,891	5,769	5,720	5,632	5,207
Total	48,526	45,459	44,248	49,248	35,235	41,458	49,671	37,751	37,545	35,084

Table 8-71 System Asset Replacement and Renewal Capital Expenditure Forecast
(\$K in constant prices)

Projections for the later years of the planning horizon are inherently less certain and will be refined through the annual AMP update process. The timing and progression of individual renewal projects will be influenced by changes in asset condition, the assessed risk to the network, and their relative priority compared with other replacement needs. Where the consequence of failure increases, or assets deteriorate more rapidly than forecast, renewal may need to be brought forward. Conversely, if risk levels reduce or alternative mitigation measures become available, projects may be deferred to later in the planning period or replaced with lower-cost solutions.

A breakdown of forecast preventative maintenance expenditure by asset category is presented in Table 8-72. This expenditure profile remains relatively stable over the planning horizon, reflecting the application of established asset strategies and maintenance standards that define the scope, frequency, and nature of inspection and maintenance activities across the network.

Forecast Asset Replacement and Renewal expenditure for corrective and preventative maintenance, by asset category, is summarised in Table 8-73 and Table 8-74 respectively. The forecast excludes capitalised maintenance, is informed by historical expenditure trends and expected asset replacement profiles.

Year-to-year variation across asset categories is expected, reflecting the timing, scale, and nature of maintenance activities each year.

Asset Category	Disclosure Year Beginning 1 April									
	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035
Subtransmission	108	109	109	108	108	111	112	114	115	118
Zone Substations	448	452	455	457	458	467	477	487	497	515
Distribution Poles and Lines	720	720	716	720	726	743	755	764	773	793
Distribution Cables	-	-	-	-	-	-	-	-	-	-
Distribution Substations	807	815	819	822	825	841	858	875	893	924
Distribution Switchgear	1,182	1,222	1,360	1,481	1,407	1,537	1,283	1,408	1,519	1,417
Other Network Assets	324	327	328	330	331	337	344	351	358	370
Total	3,590	3,645	3,787	3,917	3,856	4,037	3,829	3,999	4,155	4,136

Table 8-72 Preventive Maintenance by Asset Category
(\$K in constant prices)

Asset Category	Disclosure Year Beginning 1 April									
	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035
Subtransmission	589	594	597	599	601	614	626	638	651	674
Zone Substations	593	598	600	603	605	617	630	642	654	676
Distribution Poles and Lines	1,047	1,057	1,062	1,066	1,070	1,091	1,113	1,135	1,158	1,198
Distribution Cables	106	107	108	108	108	111	113	115	117	121
Distribution Substations	799	806	810	813	816	833	849	866	884	914
Distribution Switchgear	719	745	745	735	739	778	768	791	814	829
Other Network Assets	147	149	149	150	150	153	156	160	163	168
Total	4,000	4,056	4,071	4,074	4,090	4,196	4,256	4,347	4,441	4,580

Table 8-73 Corrective Maintenance by Asset Category
(\$K in constant prices)

8.6.1 Reliability, Safety and Environmental Programmes for 2026–2036

Asset management expenditure that is not directly driven by asset health is categorised as quality of supply and other reliability, safety, and environmental expenditure. Quality of supply projects are targeted at the worst-performing feeders, while other reliability, safety, and environmental initiatives include programmes such as routine substation seismic strengthening. The total projected capital budget for these expenditure categories is presented in Table 8-74.

Programme	Disclosure Year Beginning 1 April									
	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035
Feeder Reliability Projects – Lines	1,058	1,219	1,429	1,232	1,170	1,197	1,223	1,248	1,271	1,286
Feeder Reliability Projects – Switchgear	1,505	1,267	699	1,006	1,195	1,169	1,144	1,119	1,095	1,065
Switchgear SCADA Control Retrofit	204	204	204	203	203	202	202	202	201	199
Total Quality of Supply	2,768	2,690	2,332	2,441	2,568	2,569	2,570	2,569	2,567	2,551
AUFLS Relay Replacement	-	-	-	-	-	-	-	-	-	-
Total Legislative and Regulatory	-	-	-	-	-	-	-	-	-	-
Asset Readiness Expenditure (See Section 12)	472	457	-	-	-	-	-	-	-	-
Total Other Reliability, Safety and Environment	472	457	-	-	-	-	-	-	-	-

Table 8-74 Reliability, Safety and Environmental Capital Expenditure
(\$K in constant prices)

8.6.2 Asset Management Expenditure

The consolidated forecast for total capital expenditure is presented in Table 8-75.

Category	Disclosure Year Beginning 1 April									
	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035
Asset Replacement & Renewal	48,526	45,459	44,248	49,248	35,235	41,458	49,671	37,751	37,545	35,084
Quality of Supply	2,768	2,690	2,332	2,441	2,568	2,569	2,570	2,569	2,567	2,551
Legislative and Regulatory	-	-	-	-	-	-	-	-	-	-
Other Reliability, Safety & Environment	472	457	-	-	-	-	-	-	-	-
Total Capital Expenditure on Asset Replacement Safety and Quality	51,765	48,606	46,580	51,690	37,802	44,026	52,240	40,320	40,112	37,635

Table 8-75 Asset Management Capital Expenditure Forecast
(\$K in constant prices)

The consolidated forecast for total operating expenditure is presented in Table 8-76.

Category	Disclosure Year Beginning 1 April									
	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035
Service interruptions & emergency maintenance	5,668	5,793	5,908	6,027	6,147	6,270	6,395	6,523	6,654	7,047
Vegetation management	2,467	2,521	2,572	2,623	2,676	2,729	2,784	2,839	2,896	2,826
Routine & corrective maintenance and inspection maintenance	11,342	11,591	11,823	12,060	12,301	12,547	12,798	13,054	13,315	13,561
Asset replacement & renewal maintenance	1,913	1,955	1,994	2,034	2,075	2,117	2,159	2,202	2,246	2,537
Total Network Operational Expenditure	21,390	21,860	22,298	22,744	23,198	23,662	24,136	24,618	25,111	25,971

Table 8-76 Network Operational Expenditure Forecast
(\$K in constant prices)

The operational expenditure forecast is limited to maintenance-related activities and excludes non-maintenance operational costs. Expenditure associated with service interruptions and emergency maintenance cannot be reliably attributed to individual asset categories and is therefore forecast and reported at the system level only, reflecting the structure of the Field Services Agreement, which defines fault response rates on an aggregated basis rather than by asset class.

9 System Growth and Reinforcement

Section 9 outlines WELL's 10-year network development plan, which is designed to deliver the capacity and security of supply required to meet the service levels and performance standards described in Sections 6 and 7. The plan responds to forecast changes in electricity demand while ensuring that investment is timed and delivered efficiently to support long-term network performance.

As discussed in Section 3 for planning and operational purposes, WELL's network is structured into three areas:

- Southern Area - supplied by the Wilton, Central Park, and Kaiwharawhara GXP
- Northwestern Area - supplied by the Takapu Road and Pauatahanui GXP
- Northeastern Area - supplied by the Upper Hutt, Haywards, Melling, and Gracefield GXP

Within the Network Development and Reinforcement Plan (NDRP), these areas are further disaggregated into smaller planning regions. Each region faces distinct load growth, capacity and resilience challenges, and this regionalisation enables WELL to identify targeted needs, options and investment pathways. The characteristics and development strategies for each region are described in Section 9.7.

9.1 Timing of decarbonisation demand growth is now less certain

New Zealand's First Emissions Reduction Plan (ERP1), published in May 2022, established a suite of decarbonisation programmes to support New Zealand's commitment to achieving net-zero emissions by 2050. The second reduction-emission plan (ERP2), published in December 2024, reaffirmed this long-term target while signalling changes to the pace, sequencing, and policy settings supporting electrification.

Due to the uncertainty in the timing of customer-driven transitions, WELL's 2025 AMP demand forecasts did not include assumptions for commercial or industrial decarbonisation-related load growth. For the 2026 AMP demand forecasts, again, WELL have not included decarbonisation growth assumptions. In addition to customer uncertainties, recent changes in central government policy have reduced certainty about the timing and pace of electrification, including the removal of incentives for electric-vehicle uptake, delays to major public-transport electrification projects, the rescoping of customer-led decarbonisation initiatives, and a broader softening of economic conditions. In light of this increased uncertainty, decarbonisation-driven demand has excluded commercial and industrial customers from the 2026 forecasts.

WELL will continue to actively monitor developments across key electricity demand drivers, including government decarbonisation policy, electrification incentives, transport and industrial transition programmes, distributed energy uptake, and broader economic conditions. Demand forecasts and associated investment plans will be updated as part of WELL's regular AMP review cycle, or earlier where material changes in demand outlook emerge. This adaptive approach ensures that network planning remains aligned with evolving customer requirements and policy settings, while avoiding premature investment ahead of confirmed need.

9.2 Electrification is expected to displace gas in transition pathways

Recent policy direction and market signals indicate that natural gas is unlikely to play a sustained role as a transition fuel in New Zealand's energy system, with decarbonisation pathways increasingly predicated on

direct electrification of transport, process heat, and building energy use. As gas availability tightens and long-term supply becomes more uncertain, electrification is expected to proceed more rapidly and at a greater scale than previously assumed, particularly where customers face asset replacement or fuel-switch decision points. This creates the potential for step changes in electricity demand within relatively short timeframes and concentrated locations, rather than gradual uptake. For electricity distribution networks, this reinforces the need for timely augmentation and reinforcement to maintain security standards and enable customer decarbonisation.

This dynamic is illustrated in the education sector. As school gas boilers reach the end of their life, they are expected to be replaced with electric alternatives rather than renewed on gas. While the timing of individual conversions remains uncertain and is likely to align with asset replacement cycles and funding decisions, the total thermal capacity expected to transition is approximately 31 MW, as summarised in Table 9-1.

Measurement	Expected Transition from Gas Boilers to Electric				
	Within 0–5 years	Within 5–10 years	Within 10–15 years	Over 15 years	Total
Number of schools	50	16	10	3	79
Thermal Output (MW)	21	7	2	1	31

Table 9-1 Gas thermal output to be replaced by electrification

The pace and scale of residential transition away from natural gas remain uncertain, reflecting variability in household economics, policy settings, fuel availability, and customer preferences. While electrification of space and water heating is expected to increase over time as gas appliances reach the end-of-life, there is currently no established demand trend or committed programme from which to derive a reliable baseline forecast. Residential electrification growth is therefore treated as a forward-looking scenario rather than a continuation of observed demand, and its timing and uptake are inherently uncertain. WELL will continue to monitor indicators such as appliance replacement cycles, gas market developments, technology costs, and policy direction, and will incorporate residential electrification load into future forecasts as clearer evidence of sustained transition emerges.

A similar transition dynamic is evident among industrial customers currently reliant on gas for process heat. Within WELL's network, approximately 70 industrial customers have been identified with an estimated 76 MW of gas-based thermal load that may require electrification over time. As with other sectors, the timing and scale of conversion remain uncertain and are expected to be driven primarily by asset replacement cycles, site-specific economics, and future fuel availability. Electrification uptake is therefore unlikely to follow a smooth trend, but rather to occur in step changes associated with individual plant transitions. While these conversions are not yet committed and are not forecast from an established demand base, they represent a material source of potential future load that may emerge within relatively short timeframes and concentrated locations, reinforcing the need for adaptable network planning and timely augmentation aligned to confirmed demand.

9.3 Build Early vs Build Late Dilemma

In practice, the risk asymmetry is material. Delivering reinforcement several years ahead of demand may result in a period of underutilised capacity, whereas even a short delay in delivery can leave WELL with no feasible interim solution other than deferring or declining new connections where capacity is constrained. As greater certainty emerges on the timing, location, and scale of electrification demand, decarbonisation-related load growth will be progressively incorporated into forecasts and long-term network development

plans. In this context, the regulatory framework will need to support timely and anticipatory augmentation aligned to confirmed need.

Accommodating electrification at the pace and scale anticipated is unlikely to be achievable within the constraints of DPP4 allowances alone, strengthening the case for a CPP-based approach to align funding with the efficient delivery of decarbonisation-driven network investment. WELL recognises that the DPP4 framework does not provide sufficient headroom to fund the level of augmentation required to accommodate sustained growth in electrification load while maintaining N-1 security standards.

Planning network reinforcement to support decarbonisation must be undertaken in an environment of material uncertainty about where and when load will emerge, combined with the long lead times required to plan, consent to, and deliver major assets. Investment decisions, therefore, require careful balancing of the risk of premature augmentation, where customers fund capacity ahead of utilisation, against the risk of deferring, which may constrain electrification uptake, reduce network security, or delay customer connections.

While the DPP4 allowances provide a stable funding path for managing incremental growth, they are insufficient to fund the scale and timing of investment needed to meet WELL's emerging electrification-driven investment needs while maintaining N-1 security standards. The fixed and smoothed allowance profile constrains WELL's ability to efficiently stage and scale reinforcement as decarbonisation demand becomes clearer. A CPP is likely to provide WELL a more appropriate mechanism to align revenue allowances with the efficient timing and scale of network augmentation required to support electrification, particularly where reinforcement is contingent on emerging demand closely linked to asset renewal opportunities, all while maintaining customer expectations of retaining N-1 security.

9.4 Demand forecasts assume New Zealand will achieve net-zero by 2050

Against this changing policy and economic backdrop, the updated demand forecasts in the 2026 AMP continue to be developed on the assumption that New Zealand will achieve net-zero by 2050. While the 2050 target has been reaffirmed in the October 2024 Government Policy Statement on Electricity, the policy actions and delivery pathways supporting the target are being recalibrated to reflect current economic conditions.

Given the uncertainty in future demand growth and the long lead times associated with delivering new capacity, WELL's investment plan will manage this risk by:

- Continuing to apply Time-of-Use pricing to shift discretionary demand away from peak periods, while also exploring additional innovative pricing mechanisms to encourage demand flexibility.
- Coordinating capacity investments with end-of-life asset renewals to maximise efficiency and minimise disruption.
- Monitoring gas exit by residential customers and promoting heat pump over electric element hot water heaters to manage peak demand growth.
- Promote & educate EV charging times outside of peak demand periods.
- Promote increased solar utilisation by aligning hot water heating and EV charging demand with peak summer daytime generation and expanded storage capacity.

- Developing and consenting interventions early, so projects are 'build-ready', should demand materialise sooner than forecast.
- Installing cable ducting in advance of cable installation, in conjunction with other infrastructure providers' works, to reduce future construction timeframes and disruption.
- Extending the application of the 'Readiness Spares' concept, previously used for earthquake preparedness, to reinforcement projects in order to minimise equipment procurement and delivery lead times.

It is important to note that, while the revised forecasts indicate lower network-level demand growth, this aggregation still reflects how demand is evolving at the subtransmission and zone substation levels. Although fewer zone substations are now expected to exceed the loading limits defined in WELL's security of supply policy over the next 10 years compared with the 2024 forecast, localised 33 kV constraints are still expected to emerge and will require targeted solutions, even under these lower growth assumptions.

9.4.1 Zone substation +10-year maximum demand

Figure 9-1 shows the change in +10-year maximum demand at WELL's zone substations relative to their rated capacity between the 2025 and updated 2026 forecast. Illustrating the networks where changes in decarbonisation trajectories have deferred the need for capacity-triggered investment, as well as those areas where capacity reinforcement is still required, even under slower electrification scenarios, due to limited existing headroom.

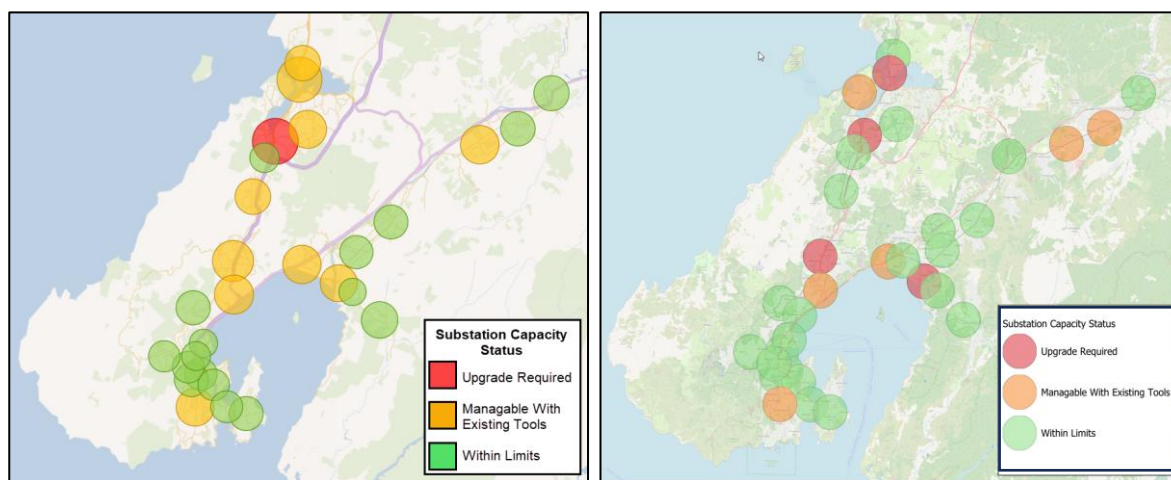


Figure 9-1 Change in +10 Year Zone Substation Demand vs Capacity Without Intervention from 2025 AMP (Left) to 2026 AMP (Right)

WELL must invest in new capacity to address emerging network constraints while carefully managing timing risk to avoid investing too early, where customers would fund assets before they are required, or too late, which could result in quality risks or delays to customer connection requests. These capacity investments have strong natural synergies with renewing major asset fleets, such as power transformers and subtransmission cables, as they approach the end of their useful lives.

Coordinating capacity reinforcement with end-of-life asset renewal enables WELL to minimise duplication of works, reduce construction disruption, and improve whole-of-life efficiency by addressing multiple investment drivers through a single, integrated delivery programme. In practice, achieving this coordination requires

flexibility in the timing and sequencing of expenditure, as renewal and capacity drivers frequently converge in discrete, high-value projects rather than aligning with smooth annual investment profiles.

The constraints inherent in the DPP4 allowances limit WELL's ability to deliver these coordinated investments efficiently, increasing the risk of inefficient deferral, fragmented delivery, or rework. In this context, a CPP is likely to better support the efficient alignment of funding with coordinated renewal and reinforcement activity, reducing long-term costs and delivering improved outcomes for consumers while maintaining required security and service standards.

WELL is also aware that some commercial and industrial customers are considering transitioning from gas to electricity. However, customers have not yet provided WELL with confirmed transition timelines or the expected magnitude of additional electrical demand. As a result, these potential transitions have not been included in the AMP allowances at this stage. Once customers provide confirmed transition values and implementation timeframes, WELL will treat these as step changes in demand and incorporate them into future forecasts and AMP allowances, as appropriate. These transitions may also create new network constraints or accelerate existing ones, requiring further investigation and, where necessary, additional investment to maintain security of supply and service standards.

Figure 9-1 shows the potential locations where a transition may occur and the locations where potential commercial and industrial gas-to-electricity transitions have been identified based on currently available information. This indicates where future step changes may emerge and where additional demand could materially affect capacity headroom and the timing of network reinforcement.

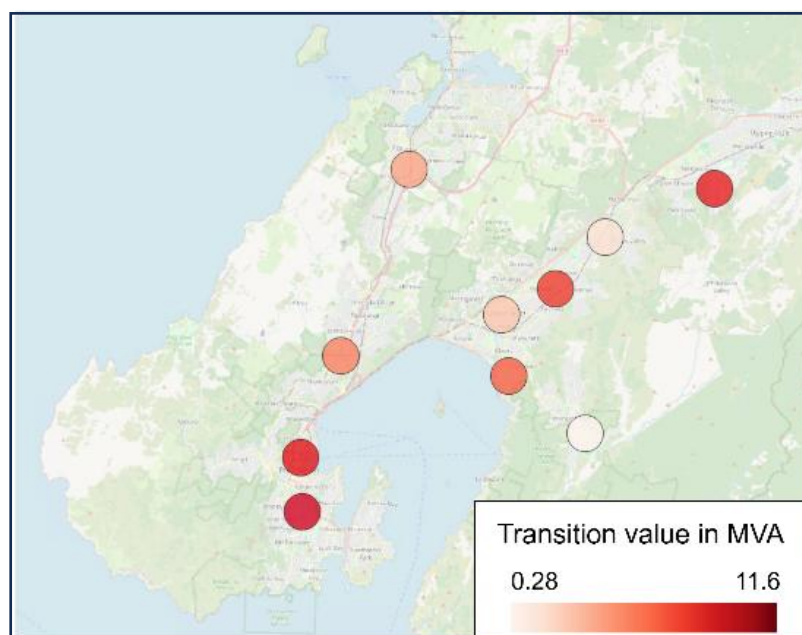


Figure 9-2 Potential Commercial and Industrial Gas Transition

Given this uncertainty, WELL's network development approach focuses on maintaining optionality and avoiding irreversible investment decisions until demand drivers become clearer, while still ensuring that emerging constraints can be managed in a timely manner. This includes accommodating customer-specific connection preferences, such as requests for security levels below standard, where these do not create undue risk for other network users or compromise overall network performance; where they do, WELL requires connections consistent with standard security arrangements.

However, this uncertainty, combined with long asset lead times and the potential for step changes in demand, highlights the limitations of a fixed, smoothed allowance framework for efficiently responding to evolving network needs.

In this context, the ability to more closely align investment timing with emerging demand signals while maintaining appropriate security standards is a relevant consideration in assessing whether a CPP would better support prudent risk management and long-term consumer outcomes. The security criteria described in Section 9.5.1 below provide the technical framework for determining when intervention is required as these uncertainties resolve.

9.5 Network Planning Policies and Standards

WELL's approach to system reinforcement is underpinned by a suite of policies and technical standards that address the following areas:

- Security criteria—defining the network capacity and redundancy requirements necessary to maintain the required reliability levels.
- Technical standards—specifying voltage, power factor, and harmonic limits to ensure the network remains safe and secure while minimising whole-of-network costs.
- Standardised designs—reducing design efforts and spare equipment holdings, leading to lower overall project and maintenance costs.
- Non-network solutions—incorporating alternative solutions within the planning and investment assessment process;
- Impact of Distributed Energy Resources—considering the effects of distributed and embedded generation on network planning and operation.
- Planning capacity definitions—defining the asset capacity used for network planning and investment decisions.
- Demand forecasting policies and methodologies—establishing the approaches used to forecast future network demand.

9.5.1 Security Criteria

The design of WELL's network is based on the security criteria. Subtransmission criteria is shown in Table 9-2 and the distribution criteria is shown in Table 9-3. The criterion is consistent with good industry practice and are designed to:²⁹

- Align security of supply with customer requirements
- Optimise capital and operational expenditure without materially increasing supply risks
- Increase asset utilisation and reduce system losses
- Mitigate credible risks to the network

²⁹ *Guide for Security of Supply*, Electricity Engineers' Association, August 2013.

The security criteria recognise a small residual risk of supply interruption if a fault occurs during peak demand and backfeeding is not available. This reflects a deliberate balance between risk and cost, and is considered a prudent approach compared with increasing customer costs to eliminate this low-probability risk altogether.

9.5.1.1 Subtransmission

Subtransmission constraints are assessed by evaluating the duration of potential overload against the security criteria using a load-duration curve. Forecast constraints are then quantified by identifying the years in which the risk of overload is likely to occur, based on forecast peak demand levels.

Building on the application of security criteria at the subtransmission level, WELL groups zone substations into four 'Security Classes' and two levels of security are considered:

1. First-event security—all zone substations are designed to maintain continuity of supply following the loss of any single system component. This represents N-1 continuous security.
2. Second-event security—for zone substations supplied by fluid-filled cables, or where dual-circuit outages are considered relatively likely or would have a high impact, additional redundancy must be available through the neighbouring 11 kV network to meet customer service levels. This represents N-2 switched security and applies only to selected zone substations.

Table 9-2 summarises the applicable security criteria for the subtransmission network.

Security Class	Description	First Event Security Criteria	Second Event Security Criteria
ZS 1	CBD zone substations that are deemed vulnerable to double circuit outages.	No interruption to supply for 99.5% of the year. At other times, loading is managed post-contingently within 3 hours.	All customers restored via the 11 kV network within 3 hours
ZS 2	Zone substations in other areas that are deemed vulnerable to double circuit outages.	No interruption to supply for 98% of the year. At other times, loading is managed post-contingently within 3 hours.	All customers restored via the 11 kV network within 3 hours
ZS 3	CBD zone substations that are not deemed vulnerable to double circuit outages.	No interruption to supply for 99.5% of the year. At other times, loading is managed post-contingently within 3 hours.	N/A
ZS 4	Zone substations in other areas that are not deemed vulnerable to double circuit outages	No interruption to supply for 98% of the year. At other times, loading is managed post-contingently within 3 hours.	N/A

Table 9-2 Security Criteria for the Subtransmission Network

Zone substations with similar characteristics, such as customer profiles and supply configurations, are assigned to the same security class, ensuring a consistent approach to reliability planning. Each security class is governed by specific security criteria that define the required performance of the zone substation during outage conditions.

For each security class, WELL defines the proportion of time (expressed as a percentage) during which the subtransmission network may not meet security criteria. Peak demand at a zone substation is calculated in

accordance with the applicable security criteria. This differs from the anytime maximum demand, which is measured over 30 minutes and may reflect abnormal or atypical system operations.

Consistent with the security criteria described above, WELL's subtransmission network is configured primarily as a series of radial 33 kV circuits from Transpower's GXPs to the zone substations. These circuits generally connect directly to the high-voltage terminals of the 33/11 kV power transformers, except at Evans Bay, where three subtransmission circuits connect to a 33 kV bus.

In the Southern Area, the 11 kV bus is normally operated open to limit fault levels, whereas in the Northwestern and Northeastern areas, it is operated closed. At zone substations where the 11 kV bus is normally operated open, a customer interruption of less than five minutes will occur following a subtransmission, transformer, or incomer cable fault, while the bus tie is closed to restore supply. This operating arrangement meets the N-1 security criteria.

At the subtransmission level, WELL plans to maintain N-1 capacity down to the 11 kV incomer level, based on equipment maximum continuous branch rating (MCBR), with typical subtransmission circuits configured as follows:

- 33 kV cabling to zone substation supply transformers—typically configured as a double-circuit arrangement terminating on separate supply transformers. These cables are operated at cyclic rating, with the magnitude of the rating determined by the ambient temperature (winter and summer) and a pre-event loading assumption of 50%.
- Zone substation 33 kV/11 kV supply transformers—generally rated between 20 and 30 MVA, and fitted with oil circulation pumps and cooling fans where required to achieve higher cyclic rating.
- 11 kV cabling between transformer bushings and switchboard incomers—forming part of the subtransmission circuit and therefore must be sized to carry full circuit load under N-1 conditions; where undersized, it can constrain the firm capacity of the circuit following the outage of a parallel asset.

9.5.1.2 Distribution Feeders

Distribution feeders 11 kV are grouped into security classes based on their configuration, closed ring, radial meshed, or radial spurs without backfeed, and the proportion of time during for which each feeder is required to meet its defined security standard.

Table 9-3 summarises the applicable security criteria for the distribution network.

Security Class	Description of Circuit	Security Criteria
F 1	Closed ring circuits in the CBD	N-1 continuous (no interruption to supply) for 99.5% of the year. At other times, loading is managed post-contingently within 3 hours.
F 2	Closed ring circuits originating from zone substations other than the CBD	N-1 continuous (no interruption to supply) for 98% of the year. At other times, loading is managed post-contingently within 3 hours.

Security Class	Description of Circuit	Security Criteria
F 3	Radial feeders originating from the CBD with multiple backfeeds.	N-1 switched security for 99.5% of the year. Short interruption to customers while supply is restored by reconfiguring the 11 kV network. At other times, the load is restored within 3 hours.
F 4	Radial feeders originating from zone substations other than the CBD with multiple backfeeds.	N-1 switched security for 98% of the year. Short interruption to customers while supply is restored by reconfiguring the 11 kV network. At other times, the load is restored within 3 hours.
F 5	Radial feeders originating from the CBD with only one backfeed possibility.	N-1 switched security for 99.5% of the year. Short interruption to customers while supply is restored by reconfiguring the 11 kV network. At other times, the load is restored within 3 hours.
F 6	Radial feeders originating from zone substations other than the CBD, with only one backfeed possibility.	N-1 switched security for 98% of the year. Short interruption to customers while supply is restored by reconfiguring the 11 kV network. At other times, the load is restored within 3 hours.
F 7	Radial feeders originating from the CBD that do not have a backfeed option.	N security for 99.5% of the year. Loss of supply upon failure. The load is restored within the repair time.
F 8	Radial feeders originating from zone substations other than the CBD, which do not have a backfeed option (typically in rural areas).	N security for 98% of the year. Loss of supply upon failure. The load is restored within the repair time.

Table 9-3 Security Criteria for the Distribution Network

To enable network reconfiguration following a fault, 11 kV distribution feeders are not operated at their full thermal rating under normal system operating conditions. The maximum feeder utilisation factor applied by WELL during both normal and contingency operations is set out in Table 9-4.

Security Class	Pre-Contingent Loading	Post-Contingent Loading
F 1 and F 2	-	100%
F 3 and F 4	67%	100%
F 5 and F 6	50%	100%
F 7 and F 8	100%	-

Table 9-4 11 kV Feeder Utilisation during Normal and Contingency Operation

Pre-contingent loading is the primary method for identifying distribution feeder constraints. Feeders identified as constrained are then subject to post-contingent analysis to determine whether they can be managed using existing network tools. Feeders that cannot be effectively managed and therefore present a risk of not meeting the security of supply criteria outlined in Table 9-3, are classified as high-priority. Due to the expenditure limitations under the DPP4 allowances, only high-priority constraints are included within WELL's network development plans.

Within the Wellington CBD, parts of the surrounding suburbs, and the Porirua commercial centre, most 11 kV feeders 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 supply

reliability. Outside these areas, the urban 11 kV network generally comprises radial feeders equipped with mid-feeder switchboards and normally open interconnectors, enabling customer supply to be restored from neighbouring feeders following equipment failure.

WELL's distribution network is not designed to eliminate all supply interruptions, as doing so would be neither practical nor economic. Instead, it is designed to limit the duration and the extent of outages following a single unplanned equipment failure. This approach recognises that network demand varies by time of day and season, and that maximum-demand conditions occur only for short periods.

9.5.1.3 Distribution Transformers and Low-voltage Network

The security criteria described above apply to the planning and operation of the subtransmission and high-voltage distribution networks, but do not extend to faults on distribution transformers, the low-voltage network, or to failures of connection assets used to supply individual customers. These assets are typically designed for 'N' security, meaning that interruptions will remain in place until repairs are completed.

To manage risk on radial spur sections of the 11 kV network, WELL limits the maximum installed transformer capacity to 1 MVA for overhead spurs and 400 kVA for underground spurs. When these thresholds are exceeded, an 11 kV backfeed path is required.

The security criteria do not apply when multiple equipment outages affect the same part of the network, or during major storms and other severe events with high system impact. While WELL maintains emergency plans to prioritise restoration activities in such circumstances (as discussed in Section 12), longer supply interruptions than those indicated in the security tables may occur.

In some cases, customers may require security levels above or below those provided by a standard connection. Where this occurs, WELL undertakes a site risk assessment to confirm that the proposed security standards do not pose reputational risk. Where risks are identified, these are mitigated through measures such as dedicated or duplicated supply arrangements, capacity or protection upgrades, operational constraints, or customer-funded augmentation to maintain overall network performance and equity between customers.

9.5.2 Technical standards

9.5.2.1 Asset Capacity Definition

Primary assets in the WELL network are classified into a hierarchy of categories, with the planning criteria and operational requirements for each asset type shown in Table 9-5.

In alignment with WELL's Security of Supply Policy, 11 kV and 33 kV network planning uses maximum continuous ratings to define asset capacity. Cyclic ratings apply to planned operational activities, while emergency overload ratings apply to unplanned contingency events.

Asset capacity is further defined as follows:

- Transformer loading limits—aligned to industry thermal criteria based on permissible hot-spot winding temperature and cyclic (BS-type) emergency overload capability, followed by an appropriate thermal relaxation period to restore normal loading without accelerating insulation ageing.

Primary Asset Categories	Asset Boundary	Security Planning Criteria
Tier 0—Upstream Asset	Transpower owned GXP Feeder CB Cable Termination and above	National Grid Planning Criteria
Tier 1—Subtransmission and Zone Substation	From GXP CB Cable Termination to Zone Substation 11 kV Bus before Feeder CB	Subtransmission Security Criteria, Maximum Continuous Branch Rating (MCBR)
Tier 2—High-voltage Feeder Distribution	From ZS Feeder CB to Distribution Substation, High-voltage Distribution Substation Ring Switch, before the connection to High-voltage Load switch	Distribution Security Criteria, MCBR
Tier 3—Distribution Substation	From the Distribution Substation High-voltage switch to the Substation Low-voltage Bus	Distribution Security Criteria, MCBR
Tier 4—Low-voltage Feeders	From the Low-voltage Feeder switch to the customer demarcation point	Distribution Security Criteria, Peak demand and After Diversity Maximum Demand (ADMD), MCBR
Tier 5—Customer Assets (High-voltage direct or Low-voltage)	From the network demarcation point	Peak demand, customer-provided equipment rating

Table 9-5 Asset Categories

- Subtransmission cables and lines—thermal conductor capacity is determined using CYMCAP modelling to IEC 60853 and IEC 60287, which accounts for soil thermal resistivity, load profile and resulting thermal inertia, mutual heating due to adjacent conductors, and installation configuration. Seasonal variations in soil and ambient temperature are incorporated to establish normal, cyclic and emergency ratings.
- Maximum Continuous Branch Rating—the MCBR is defined by the lowest-rated component within a circuit. For example, a transformer may be rated at 24 MVA while the supplying cable may be limited to 21 MVA in winter and 17 MVA in summer. In such cases, the effective MCBR is set by the seasonal rating of the limiting component.
- Low-voltage distribution transformers and circuits—Capacity in this category is largely driven by the customer usage patterns and demand response behaviour. Section 11 outlines WELL's development plans and trial projects that directly interface with low-voltage connections.

The capacity of all high-voltage network elements is entered in the DigSILENT PowerFactory network model, which assesses the network loading against the applicable security standard.

9.5.2.2 Voltage Levels

Consistent with WELL's network planning policies and technical standards, the subtransmission network operates at a nominal voltage of 33 kV, reflecting the source voltage at the supplying GXP. Distribution networks operate at a nominal voltage of 11 kV, while the low-voltage network supplies most customers at nominal voltages of 230 V single-phase or 400 V three-phase. By agreement, customers may also be supplied at 11 kV or 33 kV, depending on their load requirements and connection arrangements.

In accordance with Regulation 28 of the Electricity (Safety) Regulations 2010³⁰, standard supply voltages at both high and low voltage must be kept within +/-10% of the nominal supply voltage calculated at the point of supply, except for momentary fluctuations. WELL's network planning and design standards incorporate these requirements.

Network design explicitly accounts for voltage variability arising from changes in loading conditions and the integration of embedded generation under both normal and contingency operating scenarios. 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 are typically equipped with off-load tap changers that are set at the time of installation but can be manually adjusted if necessary.

9.5.2.3 Fault Levels

Consistent with WELL's network planning policies and technical standards, the 11 kV network is operated to limit the maximum prospective fault level to 13 kA, ensuring the fault rating of several legacy switchgears is not exceeded. Fault-level control is achieved by operating all zone substations supplied by the Central Park and Wilton GXPs with split 11 kV bus configurations, in which each zone substation transformer supplies an independent bus section. At all other zone substations, prospective fault levels are inherently below 13 kA.

In accordance with WELL's asset and design standards, new switchgear is typically specified with fault ratings of 25 kA for use in zone substations and 21 kA for distribution network installations.

Distributed generation, predominantly rooftop solar, is connected at low voltage and does not materially influence 11 kV fault levels under current connection arrangements and penetration levels.

9.5.2.4 Power Factor

Consistent with WELL's network planning policies, pricing schedules, and connection standards, all connected customers are responsible for ensuring that their reactive power demand remains within the prescribed limits and that their power factor limits comply with the requirements specified in WELL's pricing schedule and connection requirements. The power factor of a customer's load, measured at the metering point, must not fall below 0.95 lagging at all times. If a customer's power factor falls below this threshold, WELL may require corrective action to restore compliance.

9.5.2.5 Acceptable Harmonic Distortion

Consistent with WELL's network planning policies and power-quality standards, harmonic distortion is actively managed to ensure safe and reliable network operation. Harmonic currents arise from the normal operation of nonlinear voltage-source devices connected to the power system and produce voltage distortion through nonlinear voltage drops across network components. Harmonic distortion is defined by the magnitude and phase angle of individual harmonic components, and elevated distortion levels can adversely affect customer power quality and reduce available transformer capacity.

To provide a practical measure of distortion, Total Harmonic Distortion (THD) is used as a composite indicator of harmonic magnitude. In accordance with the Electrical Safety Regulations 2010 and WELL's connection standards, both current and voltage harmonic levels at the point of supply must remain within the prescribed 5% THD limit.

³⁰ Amended from +/-6% by the Electricity (Safety) Amendment Regulations 2025.

9.5.3 Standardised Designs

Consistent with WELL's network planning policies and design standards, standardised designs are applied across common development and connection activities to improve safety by design, reduce design and review effort, and deliver consistent construction and operational outcomes. The use of standardised designs significantly reduces design costs and eliminates the need for repeated assessments for routine installations. It also promotes consistency in installation, commissioning, and maintenance practices, improving familiarity among field staff and reducing whole-of-life implementation costs.

Standardised designs are currently applied to a range of installation specifications, including protection design, zone substation and distribution-level earthing, and low-voltage reticulation.

High-voltage network augmentation is not standardised, as these works depend heavily on the specific technical and operational requirements of individual customer projects.

9.5.3.1 Standardised Cost Model

Consistent with WELL's network planning and investment policies and the Wellington Electricity Pricing Methodology, a standardised cost model is used to support efficient, consistent project cost estimation. WELL is currently updating this model using actual costs from recently completed projects to inform forecasts for future work. This standardised cost model has been applied to estimate the costs of the network growth projects described in this section.

The model is subject to continual improvement, with completed projects regularly incorporated to update unit rates for building-block cost items to maintain alignment with prevailing market conditions. This ensures that growth-related cost estimates remain consistent with the cost-allocation and pricing principles set out in the Wellington Electricity Pricing Methodology.

9.5.3.2 Energy Efficiency

Consistent with WELL's network planning, asset management, and operational standards, WELL applies a range of processes and strategies to promote the energy efficiency of the network, including:

- Network planning—designing network configurations that minimise technical losses and inefficient distribution, through the selection of appropriate conductor types and operating voltages to minimise total life-cycle costs, including the cost of losses.
- Equipment procurement—specifying and approving equipment that meets recognised efficiency standards, including the selection of distribution transformers that comply with relevant AS/NZS efficiency standards.
- Network Operations—operating the network in the most efficient manner practicable within existing constraints, including the use of load management systems to optimise network loading and improve overall efficiency.

9.5.4 Non-Traditional Solutions

Consistent with WELL's network planning policies and investment standards, WELL applies a structured, non-traditional solutions framework to identify, evaluate, and implement market-led alternatives that substitute for or complement traditional network reinforcement and lifecycle asset investment. This framework ensures that non-traditional solutions are fully assessed before committing to capital-intensive network upgrades.

WELL currently applies established non-network solutions, including cost-reflective pricing, demand-side management, network reconfiguration, load operating envelopes, and ripple-controlled hot-water load. Time-of-use pricing is used to incentivise customers to shift energy use away from peak periods, while ongoing refinement of pricing structures and innovative commercial mechanisms, for example, dynamic and differential pricing (see Section 11.2.3) provide clearer locational signals of available network capacity.³¹ These mechanisms shape demand growth, delay capacity reinforcement, and reduce reliance on higher-cost demand-side interventions.

WELL's load control system reduces maximum network demand by shifting hot-water load to low-demand periods during periods of constraint. The demand forecasts that underpin WELL's network reinforcement programme assume that hot water control will continue in line with current practice. Any material change in WELL's ability to shape peak demand through load control, either an increase or a reduction, may affect the timing and scale of future network reinforcement investment.

Network reconfiguration options are also assessed to optimise the use of existing capacity prior to committing to new infrastructure. These typically include:

- Open-point adjustments using existing infrastructure to relieve loading on highly loaded feeders.
- Operational changes to improve utilisation of existing network capacity in preference to constructing redundant assets.
- Evaluation of demand-side management solutions to address localised network constraints where they are cost-effective.

Non-network solutions are evaluated before any network reinforcement is committed. WELL continuously monitors feeder loading via SCADA-based thermal- and voltage-alarm systems to detect emerging overload conditions and maintain voltage within acceptable limits. Where there is a risk of thermal limits being exceeded due to equipment failures or localised constraints, network controllers can:

- Initiate hot water load shedding to shift demand away from peak periods.
- Adjust network open points to optimise feeder loading and the number of customers supplied by individual feeders.

WELL also recognises the uncertainty associated with rapidly evolving flexibility technologies. Its structured approach to assessing emerging solutions is outlined in Section 11. Experience from the Resi-Flex project (discussed in Section 11.2.3.3) indicates that while third-party non-network service providers are developing capabilities, they are not yet able to deliver solutions at the scale and reliability required to fully replace traditional network-based reinforcement for WELL's capacity needs.

Within this strategic framework, WELL has defined a suite of future non-network solutions and corresponding implementation pathways to support a more flexible, market-led approach to managing emerging network constraints. These include low-voltage constraint mapping, locational pricing, DER-enabled load control, and network battery energy storage. While WELL supports the development and integration of flexibility services as an important component of efficient network management, it does not consider flexibility to be a standalone substitute for conventional augmentation. In many locations, sustained load growth and security

³¹ <https://www.welectricity.co.nz/disclosures/pricing/future-pricing>

requirements will still necessitate physical reinforcement, with non-network solutions playing a complementary role in deferring, optimising, or staging investment rather than replacing it.

WELL is refining its low-voltage constraint maps and intends to publish them. These maps will provide customers and retailers with visibility into both winter peak-demand constraints and summer injection or voltage constraints associated with high solar photovoltaic injections, and will serve as the foundation for introducing locational pricing. Locational pricing communicates time and location-specific network constraints through tariff signals, enabling retailers to leverage their customer relationships to deliver demand response and manage peak demand in winter-constrained areas, and moderate export or injection levels in locations experiencing high distributed generation during summer periods.

To support more targeted and responsive demand management, WELL is evaluating the adoption of internet-based protocols, such as OpenADR and IEEE 2030.5. These protocols enable secure two-way communication with DERs and support flexibility mechanisms, including dynamic operating envelopes and flexible export limits aligned to forecast network constraints.

Network-owned battery energy storage is also recognised as a valuable interim tool for maintaining voltage compliance on constrained circuits. WELL will develop the capability to assess and, where appropriate, deploy network batteries to manage voltage and capacity between the identification of emerging constraints, signalled through locational pricing, and the delivery of permanent network reinforcement.

9.5.5 Impact of Distributed Energy Resources

Consistent with WELL's network planning policies and investment standards, the currently installed capacity of DER on the WELL network remains relatively low,³² despite increasing availability of distributed generation, energy storage, and flexible demand technologies. Network modelling indicates that a shift in typical residential solar system size from around 5 kW to 10 kW would materially increase low-voltage network utilisation, with hosting capacity in many feeders becoming constrained at approximately 30% ICP penetration under 10 kW export conditions. As a result, new or upgraded installations above 5 kW, including applications to increase export capacity from 5 kW to 10 kW, are expected to require an operating-envelope arrangement. This would enable export to be reduced during periods of network constraint or, alternatively, require sufficient on-site or feeder-level storage to absorb surplus generation and maintain network limits.

Given the intermittent nature of many DERs and the uncertainty associated with proposed DER projects, WELL applies a conservative planning approach when assessing their impact on network performance and capacity requirements. Investment decisions are therefore based on worst-case operating scenarios and consider only DER resources assessed as reliable and supported by a high level of project certainty.

9.5.5.1 Connection Policy

WELL welcomes enquiries from third parties seeking to install embedded generation or storage capacity on its network. WELL maintains a Distribution Code and Network Connection Standard that sets out the procedures for assessing and connecting distributed generation in accordance with Part 6 of the Cod.

For each third-party proposal, WELL undertakes a structured risk assessment of the proposed connection. The location, timing, and scale of the scheme are evaluated using network planning tools to identify the potential risks and benefits to the network. This assessment also quantifies the level of uncertainty associated

³² Installed capacity, excluding standby generation and Mill Creek (connected at 33 kV), is 3% of the system maximum demand.

with future step changes in demand or generation. WELL's approach to quantifying such uncertainty is described in Section 9.13.3.

Where a third-party scheme is identified as having the potential to defer the need for capital investment on the network, WELL will assess the extent to which the proposal satisfies the following requirements when developing a technical and commercial solution with stakeholders:

- Availability at peak demand—the extent to which generation is available during peak demand periods, which determines its effectiveness in offsetting network investment.
- Technical compliance—compliance with relevant technical codes and assurance that the scheme will not adversely affect other customers.
- Service-based payments—any payments to third parties must be directly linked to the delivery of services that achieve the required technical and commercial outcomes.
- Commercial alignment—commercial arrangements must be consistent with avoided cost principles.
- Network visibility—the ability to provide visibility of local network conditions where the provider manages DER.

Where these requirements can be met, and generation dispatch can be coordinated with system peaks or local network constraints, the use of distributed generation as part of a demand-side management programme can deliver benefits for both WELL and its customers.

9.5.5.2 Information Sharing with Potential Distributed Generation Providers

To support transparent engagement, WELL publishes a network-constraint map on its website identifying areas of the low-voltage network subject to distributed export constraints. This map will be updated throughout 2026 to incorporate low-voltage hosting capacity modelling (see Section 11.2.2.2). WELL also provides prospective customers with access to relevant GIS network data upon request, subject to agreed terms and conditions of use. Further information on connecting distributed generation is available on the WELL website – www.welectricity.co.nz or by calling 0800 248 148.

9.5.6 Demand Forecast 2026—2036

Growth in peak demand drives system constraints and the need for additional investment, either in the network or in alternative capacity provision or management methods. This section describes WELL's methodology and assumptions for forecasting the network's peak demand.

While the overall WELL load has traditionally been winter-peaking, recent trends indicate that the Moore Street zone substation in the Wellington CBD is now summer-peaking. This indicates that near-term demand growth is increasingly being driven by existing customers increasing their electricity use through appliance electrification, cooling load, and progressive decarbonisation, rather than by connection growth alone. In future planning periods, as electrification becomes more widespread across transport, heating, and other end users, contention between loads is expected to increase, and demand profiles are likely to become less diverse.

The timing and scale of this transition remain uncertain, however, as customer decisions, technology adoption rates, fuel substitution pathways, and behavioural responses to pricing signals may materially alter both peak demand growth and coincidence. WELL's forecasts are therefore expected to continue changing over time as better information becomes available and actual network behaviour reveals how these drivers are emerging in practice.

9.5.6.1 Demand Forecast Methodology

WELL's maximum network demand typically occurs on the coldest winter weekdays, reflecting a negative correlation between demand and ambient temperature, while the ratings of certain network assets, such as cables, also vary with temperature. To reflect these characteristics, WELL develops separate winter and summer demand forecasts based on historical peak-demand trends, incorporating confirmed future step changes. For each zone substation, historical winter and summer demand trends are analysed to establish an average peak demand growth rate, derived in accordance with the subtransmission security criteria defined in Table 9-2 (i.e. 99.5th percentile for CBD zone substations and the 98th percentile for all other zone substations).

At the subtransmission level, WELL uses a planning-demand metric known as the Likely Peak Demand (LPD), defined as the 60th percentile of the range between the high and low winter and summer peak-demand forecasts. This percentile provides an appropriate margin for forecast uncertainty given the load at risk and the scale of augmentation typically required when substation constraints are identified. LPD values are assessed against the applicable N-1 subtransmission security criteria to determine the security-of-supply requirements.

Growth scenarios are aggregated 'bottom-up' from feeder level to provide GXP, regional, and system-wide demand forecasts, with diversity factors applied at each level. This modelling framework is used to determine when subtransmission and feeder-level constraints are likely to occur and to establish annual maximum demand for load-flow modelling. An overview of the demand forecast methodology is shown in Figure 9-3.

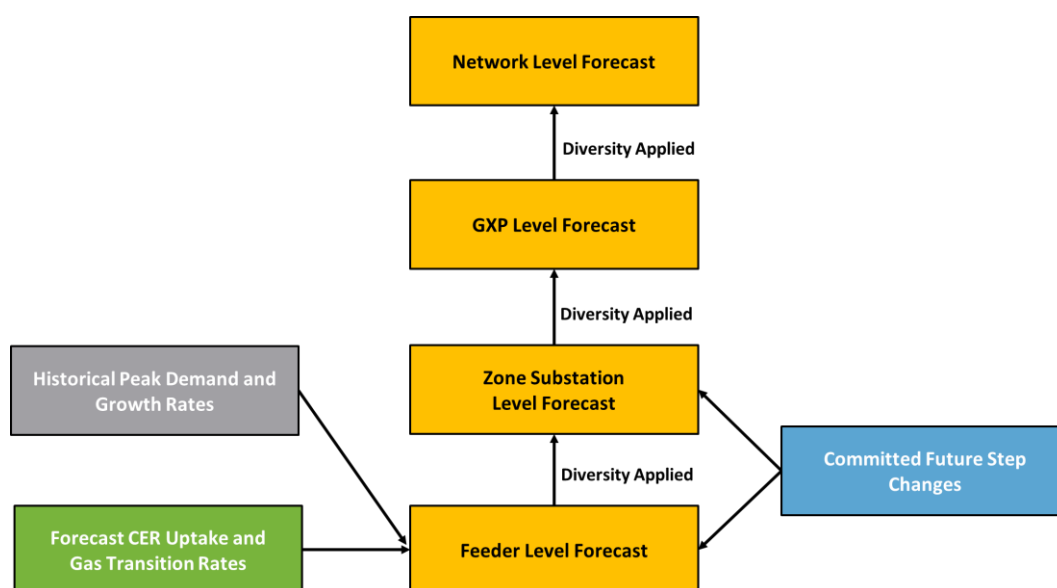


Figure 9-3 Demand Forecasting Methodology

9.5.6.2 Forecasting Inputs

Consistent with the forecasting methodology and planning metrics described above, the peak demand forecasts for the current planning period are developed using the following core assumptions:

- Load control—is assumed to continue in line with current operating practice.
- No allowance is made for abnormal operating conditions—including for major weather events or unforeseen network outages.

- High-resolution demand data—is used with 5-minute interval data per zone substation feeder captured by SCADA and GXP demand metered through time-of-use revenue metering.
- The historic events that may distort the underlying load forecast trend have been excluded.

Peak demand forecasts are derived using these assumptions and the following information sources:

- Confirmed step-change loads—based on approved customer connection requests.
- Forecast impacts of electric vehicle—uptake and gas-to-electricity transitions.
- Diversity factors³³—calculated from historical data to determine coincident demand.
- Typical demand profiles—based on the predominant load type at each zone substation.
- Historical zone substation demand data.

These assumptions, datasets, and trend analyses are reviewed annually, and any material changes are incorporated into the demand forecast to ensure it remains aligned with prevailing network conditions and planning requirements.

9.5.6.3 Step Change Loads

Consistent with the peak demand forecasting methodology described above, confirmed step change loads are explicitly incorporated into WELL's load forecasts. These step changes represent material changes in demand that can significantly influence the timing and scale of network investment and may arise from:

- Major developments—introducing large new loads to the network, typically 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.
- Load reductions—resulting from the relocation or closure of businesses.

To reflect differing levels of certainty, known step-change loads are categorised into three confidence classes:

- C1—connection offers signed by the developer.
- C2—development identified through local authority planning assessments or signalled by the developer as highly likely to proceed, but where no formal connection application has yet been received.
- C3—speculative developments based on emerging trends.

For the purposes of this AMP, only the C1 step changes are incorporated into constraint identification and network reinforcement planning. WELL's approach recognises the uncertainty associated with less certain developments and assumes that any C2 or C3 step changes that ultimately require significant investment in new capacity would be addressed through future price path reopeners.

Step-change demand is reflected in the network peak demand profile, though the actual outcomes remain inherently uncertain and difficult to estimate more than 12 months in advance.

³³ Diversity factors represent the difference in times of peak demand between different sites.

9.6 Typical Load Profiles

Typical annual demand profiles for the CBD and residential loads are shown in Figure 9-4 and Figure 9-5 respectively. The CBD load profile remains relatively flat throughout the year, with a modest summer peak driven by air-conditioning load. In contrast, residential loads exhibit a pronounced winter peak, largely attributable to domestic space heating.

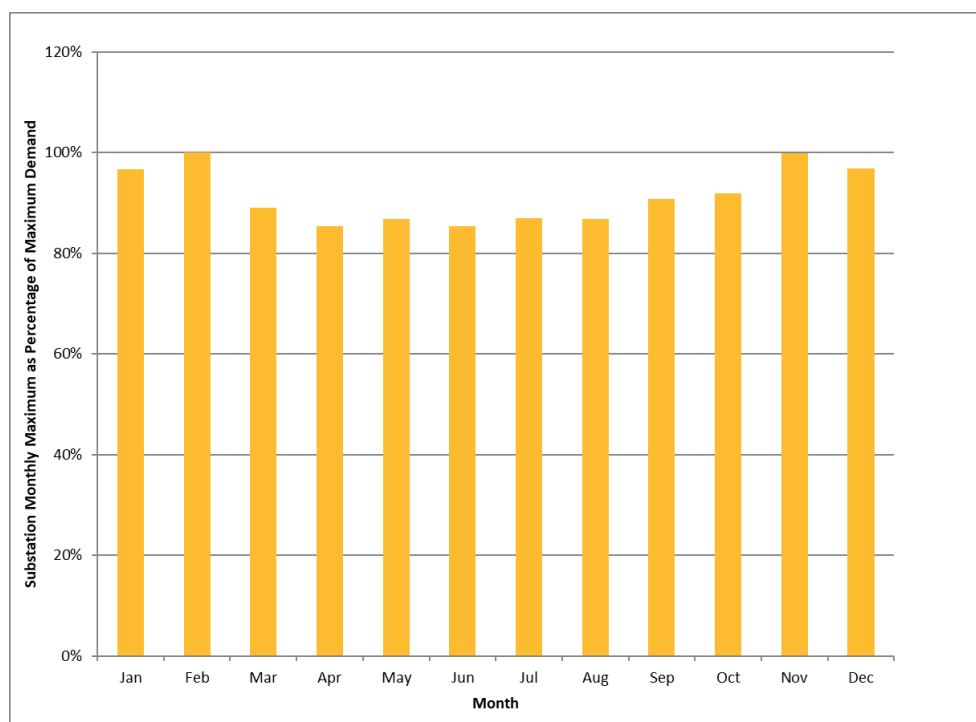


Figure 9-4 Typical CBD Commercial Area Monthly Peak Load Profile

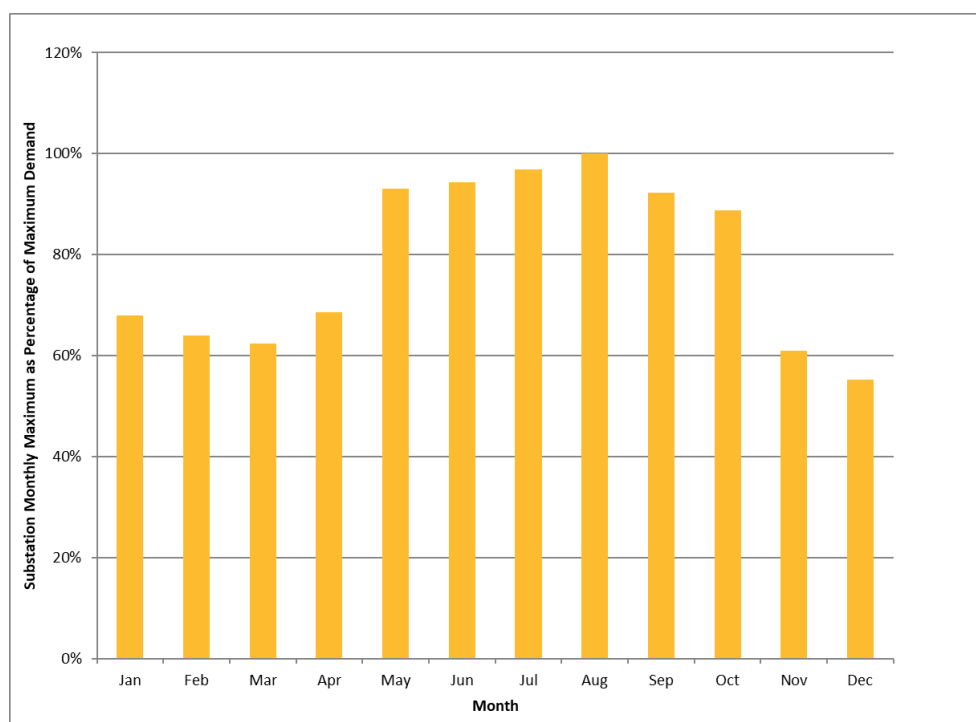


Figure 9-5 Typical Residential Monthly Peak Load Profile

Building on these trends, typical daily demand profiles for CBD and residential loads are shown in Figure 9-6 and Figure 9-7 respectively. The CBD profile rises to a daytime peak and then remains relatively flat through business hours, whereas residential load exhibits distinct morning and early-evening peaks, particularly in winter. These profiles are expected to evolve as the uptake of electric vehicles and demand-management technologies increases.

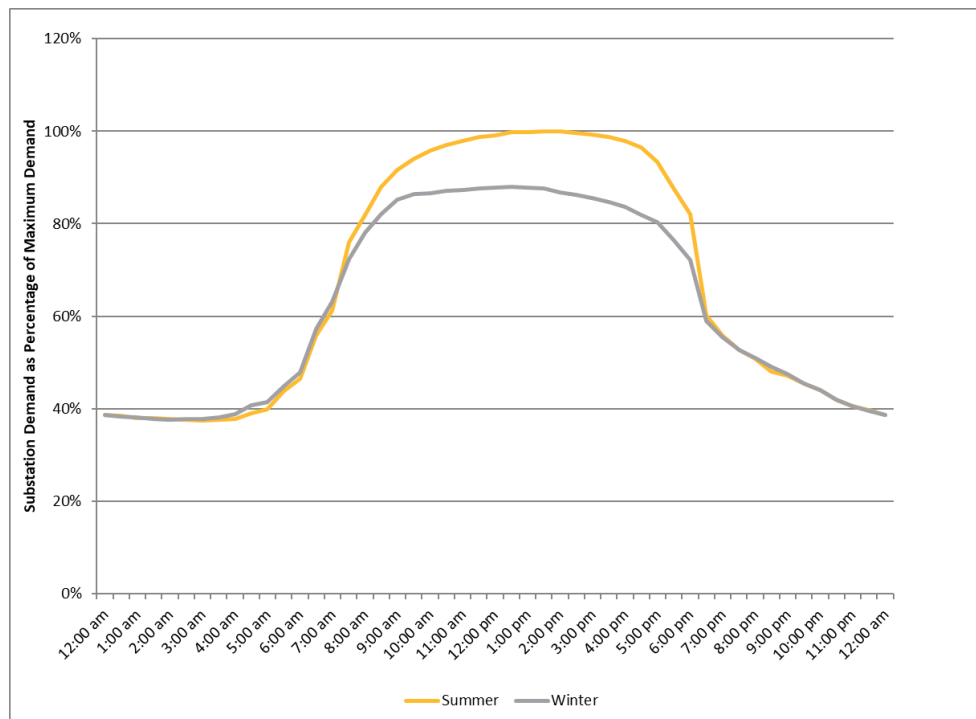


Figure 9-6 Typical CBD Commercial Area Zone Substation Daily Load Profile

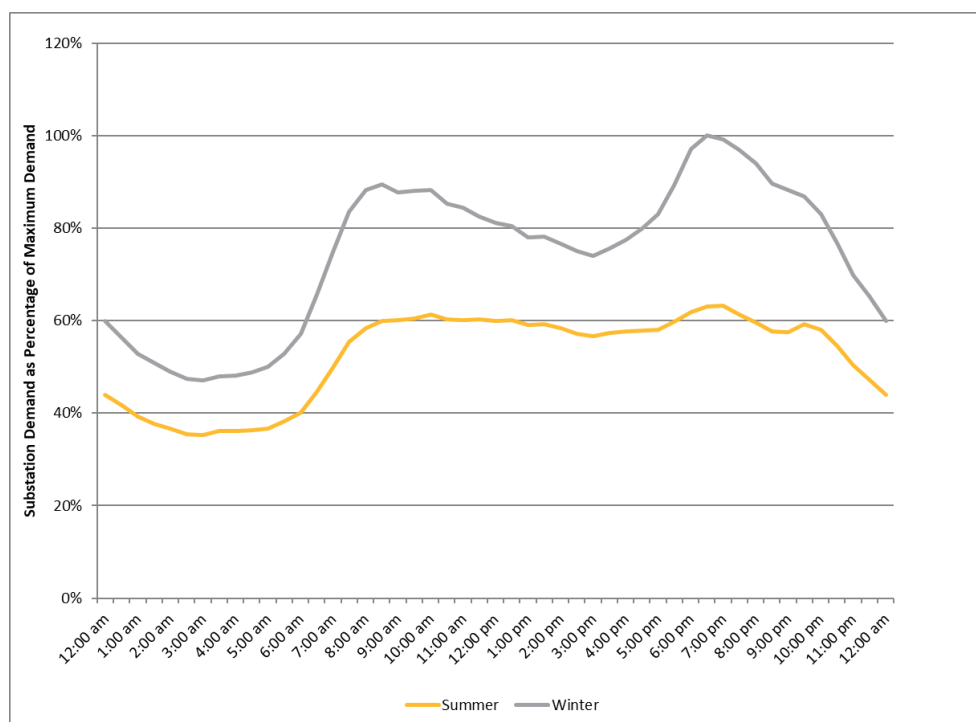


Figure 9-7 Typical Residential Zone Substation Daily Load Profile

9.6.1 Wellington Network Maximum Demand Forecast

Table 9-6 shows the network maximum-demand forecast through 2035, assuming an average winter.

Network	Maximum Demand (MW) by Calendar Year										
	2025 Actual	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035
Total System Maximum Demand (MW)	531	551	558	561	563	565	569	573	578	585	593

Table 9-6 Forecast Network Maximum Demand

In practice, the actual maximum demand will be influenced by the pace of transport and heating decarbonisation, customer electric-vehicle charging behaviours, and seasonal weather variability, particularly whether winters are milder or colder than average.³⁴

WELL is conducting a detailed review of load-forecasting drivers and enhancing its load-forecasting tool to improve forecasting accuracy.

Table 9-7 shows the contribution of each GXP and major DG to the 2025 winter maximum demand.

Location	2025 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)	152	62	37	23	59	20	99	32	-13	57	1	2	1	0	531

Table 9-7 2025 Coincident Maximum Demand

9.6.2 GXP and Zone Level Demand Forecasts

The following tables present the GXP and zone-substation-level demand forecasts for each area within the Wellington network. Table 9-8 sets out the GXP level forecast and Table 9-9 provides the corresponding zone-substation level forecast.

³⁴ For consistency, load forecasts are presented on a calendar-year basis.

Area	GXP	Winter N-1 Capacity	Actual and Forecast Peak Demand ³⁵ (MVA) by Calendar Year										
			2025 Actual	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035
Southern	Central Park 33 kV	224	152	159	162	162	162	162	163	164	165	166	168
	Central Park 11 kV	30	21	22	23	23	23	23	23	23	23	24	24
	Wilton 33 kV ³⁶	110	45	47	47	47	48	48	48	48	48	49	49
	Kaiwharawhara 11 kV	38	27	27	27	27	27	27	27	27	28	28	28
Northwestern	Pauatahanui 33 kV	24	20	20	20	20	20	21	21	21	21	21	22
	Takapu Road 33 kV	116	99	102	103	103	103	104	104	105	106	107	109
Northeastern	Gracefield 33 kV	80	62	63	63	63	63	64	64	65	65	66	67
	Haywards 33 kV	25	21	25	26	27	28	29	29	30	31	32	33
	Melling 33 kV	65	35	36	36	36	36	36	36	37	37	37	38
	Upper Hutt 33 kV	53	32	33	34	34	34	35	35	35	36	36	37
	Haywards 11 kV	30	19	19	20	20	20	20	20	21	21	21	22
	Melling 11 kV	34	25	26	26	26	26	26	26	26	27	27	27

Table 9-8 GXP Level Forecast

In both tables, totals represent non-coincident peak demand values. Years in which forecast demand exceeds the site's current firm N-1 capacity, excluding available 11 kV backfeeds from neighbouring substations and future capacity upgrades, are highlighted in red and are addressed in the detailed regional analysis in Sections 9.8 to 9.13.

³⁵ Forecast values are for the normal growth average seasonal temperature case correspond to the 60th percentile deduced from the peak demand range and include step-change loading due to planned load transfer or confirmed customer connections.

³⁶ 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) by Calendar Year										
			2025 Actual	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035
Southern	8 Ira Street	20	15.8	18.1	19.3	19.4	19.4	19.5	19.6	19.7	19.9	20.1	20.3
	Evans Bay	24	12.3	13.0	13.0	13.0	13.1	13.1	13.2	13.3	13.4	13.6	13.8
	Frederick Street	30	23.7	24.7	25.4	25.4	25.4	25.5	25.6	25.7	25.9	26.1	26.4
	Hataitai	18.1	14.8	14.8	14.8	14.8	14.8	14.9	14.9	14.9	15.0	15.1	15.2
	Palm Grove	20	22.3	22.4	22.4	22.5	22.5	22.6	22.7	22.8	23.0	23.3	23.6
	Terrace	30	19.8	20.3	20.3	20.3	20.4	20.4	20.5	20.6	20.8	21.0	21.3
	University	20	16.6	17.2	17.2	17.2	17.3	17.3	17.3	17.4	17.4	17.5	17.6
	Nairn Street	22	19.5	20.4	21.1	21.1	21.2	21.2	21.2	21.3	21.4	21.5	21.7
	Karori	18.9	13.9	15.3	15.3	15.4	15.4	15.4	15.5	15.6	15.7	15.9	16.1
	Moore Street	30	17.3	17.7	18.5	18.5	18.5	18.6	18.6	18.7	18.8	19.0	19.2
	Waikowhai Street	15	13.0	13.0	13.0	13.0	13.0	13.1	13.1	13.2	13.3	13.4	13.5
Northwestern	Mana	7	10.9	10.9	10.9	10.9	10.9	10.9	11.0	11.0	11.1	11.2	11.3
	Plimmerton	7	5.9	6.3	6.3	6.4	6.4	6.5	6.6	6.7	6.8	7.0	7.2
	Johnsonville	16	20.1	20.1	20.1	20.2	20.2	20.3	20.4	20.5	20.7	21.0	21.3
	Kenepuru	18.4	11.2	11.7	11.7	11.7	11.7	11.7	11.8	11.8	11.9	11.9	12.1
	Ngauranga	10	10.4	10.9	10.9	10.9	11.0	11.0	11.1	11.2	11.3	11.5	11.7
	Porirua	16	20.8	21.1	21.2	21.2	21.3	21.4	21.5	21.7	21.9	22.1	22.5
	Tawa	16	13.9	14.8	15.0	15.1	15.1	15.2	15.3	15.4	15.5	15.7	16.0
	Waitangirua	16	13.4	14.2	14.3	14.3	14.4	14.5	14.6	14.8	15.0	15.3	15.6
Northeastern	Gracefield	18.4	9.7	9.8	9.8	9.8	9.9	9.9	10.0	10.1	10.3	10.5	10.7
	Korokoro	15.5	17.4	17.4	17.4	17.4	17.5	17.5	17.5	17.6	17.7	17.8	17.9
	Seaview	13.7	13.8	14.5	14.4	14.4	14.3	14.2	14.2	14.2	14.2	14.2	14.3
	Wainuiomata	16	17.4	17.5	17.7	17.9	18.1	18.3	18.5	18.8	19.0	19.4	19.8
	Trentham	19.1	16.8	19.7	20.8	21.9	22.4	22.9	23.5	24.1	24.7	25.4	26.2
	Naenae	18.3	15.3	15.6	15.8	15.9	16.1	16.3	16.5	16.7	16.9	17.2	17.5
	Waterloo	18.4	15.4	15.8	15.8	15.7	15.7	15.7	15.7	15.7	15.8	15.9	16.0
	Brown Owl	18.4	15.5	15.6	16.1	16.5	16.6	16.7	16.9	17.1	17.3	17.5	17.7
	Maidstone	17.6	13.8	14.7	14.7	14.8	14.8	14.9	15.0	15.1	15.2	15.3	15.6

Table 9-9 Zone Substation Level Forecast

9.7 Overview of the Network Development and Reinforcement Plan

The following section outlines the Network Development and Reinforcement Plan (NDRP), which defines the identified needs, assessed options, and proposed investment pathways for the network over the next ten years. While previous AMPs structured development planning across three broad network areas, the 2026 AMP introduces a finer regionalisation within these areas through NDRP regions. This reflects increasing spatial variability in load growth, capacity, and resilience drivers across the network. Although each area and region faces distinct challenges, planning across the NDRP continues to follow a consistent, structured methodology.

9.7.1 Introducing Network Development and Reinforcement Plan Regions

To support efficient and coordinated system planning, WELL has adopted an area-based approach that assesses the subtransmission and distribution network across a group of zone substations rather than on an individual basis. Accordingly, the three 'traditional' planning regions, Southern, Northwestern, and Northeastern, have been reconfigured into six NDRP regions. These NDRP regions are defined by GXP supply areas, city council jurisdictions, and geographic proximity. These resulting regions are illustrated in Figure 9-8 and are described below.

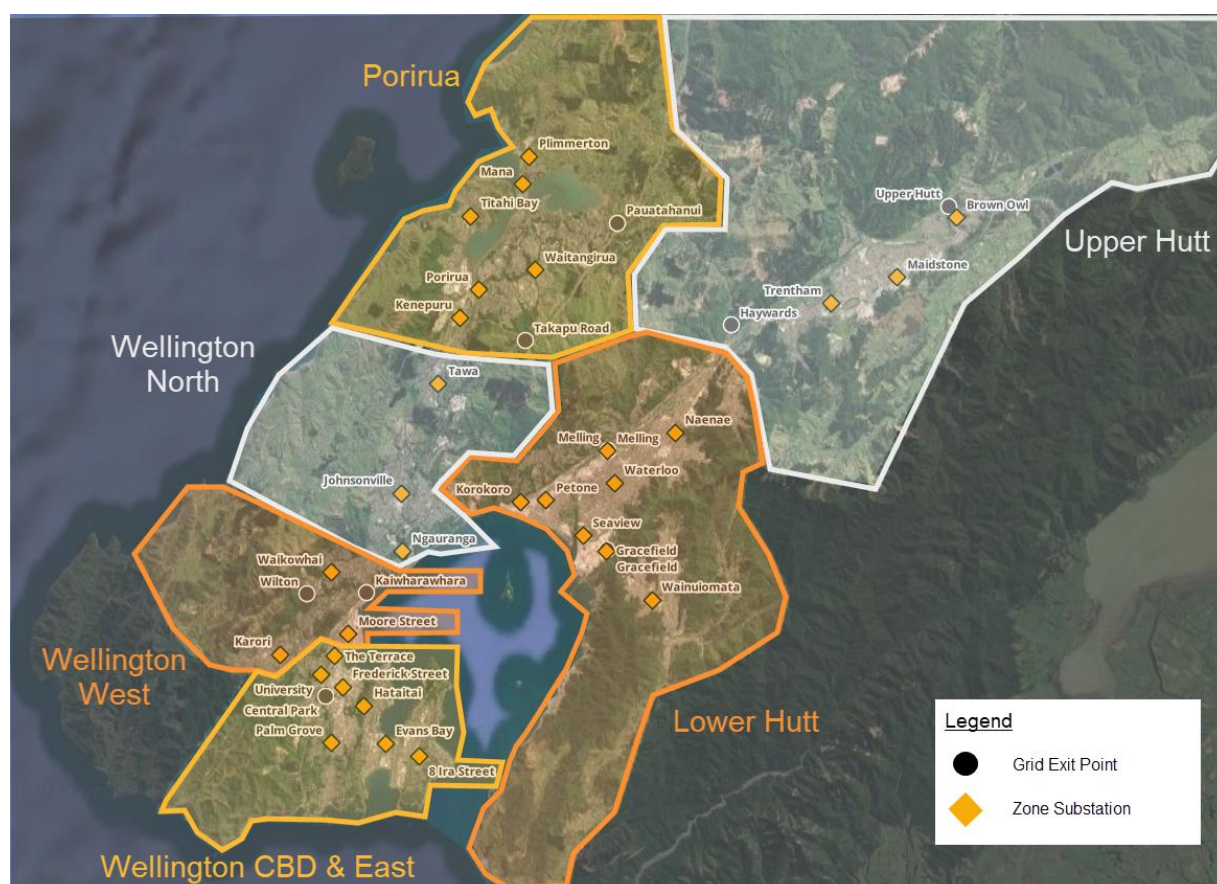


Figure 9-8 NDRP Regions

- i) Wellington CBD and East – the Southern network area supplied by Central Park GXP and located entirely within the Wellington City Council jurisdiction.
- ii) Wellington West – the Southern network area supplied by Wilton and Kaiwharawhara GXPs and located entirely within the Wellington City Council jurisdiction.

- iii) Wellington North – the Northwestern network area located within the Wellington City Council and supplied from Takapu Rd GXP.
- iv) Porirua – the Northwestern network area located within the Porirua City Council jurisdiction and supplied by the Takapu Rd and Pauatahanui GXPs.
- v) Lower Hutt – the Northeastern network area that is supplied by the Gracefield and Melling GXPs and corresponds to the Hutt City Council jurisdiction.
- vi) Upper Hutt – the Northeastern network area supplied by the Haywards and Upper Hutt GXPs and corresponds to the Upper Hutt City Council jurisdiction.

Following the release of the second Emissions Reduction Plan in December 2024, the forecast system growth trajectory shifts from declining to broadly flat. While the Plan reaffirmed New Zealand's long-term commitment to achieving net-zero emissions by 2050, it also signalled changes in the timing, sequencing, and policy support for decarbonisation initiatives. In particular, the removal or deferral of incentives for electric-vehicle uptake, delays to large-scale public-transport electrification, and the rescoping of some customer-led decarbonisation programmes reduced near- to medium-term demand-growth expectations.

At the same time, broader economic conditions tempered investment in discretionary electrification. Collectively, these factors moderated previously anticipated load growth, resulting in a stabilisation of forecast system demand rather than a continued decline. Wellington Electricity analyses the network against forecast load growth over the coming years to identify existing and emerging network constraints. WELL are currently working on validating the assumptions underpinning this analysis.

9.8 Wellington CBD and East NDRP

The following section presents the NDRP for the Wellington CBD and East region.

9.8.1 GXP Development Plans

The Wellington CBD and East NDRP region is supplied by two Transpower-owned transformers at the Central Park GXP. The transformer capacity and peak system demand are summarised in Table 9-10.³⁷

GXP	Continuous Capacity (MVA)	Cyclic Summer / Winter Capacity (MVA)	Peak Demand (MVA)	
			2025	2035
Central Park 33 kV	2x100 1x120	2 x 108/112 1 x 146/147	152	168
Central Park 11 kV	2x25	29/30	21	24

Table 9-10 Wellington CBD and East GXP Capacities

The Central Park GXP recorded a peak demand of 152 MVA in 2025. Under normal operating conditions, the 33 kV bus at Central Park is operated closed and supplies eight zone substations via double 33 kV subtransmission circuits and two 33/11 kV transformers.

³⁷ Please note that the forecasts presented reflect only committed developments.

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.
- Nairn Street at 11 kV.

Each zone substation is supplied from two separate 33 kV bus sections to provide N-1 security of supply.

To further enhance the resilience of the CBD supply, WELL and Transpower have been jointly investigating site-diversity options for Central Park GXP. The preferred option involves establishing a parallel GXP at a site adjacent to the existing Central Park GXP, including relocating one 110/33 kV transformer, associated 33 kV switchgear, and protection systems. This is discussed further in Section 12.

9.8.2 Subtransmission Network Development Needs

Many zone substations in the Wellington CBD and East are exhibiting approximately flat or slightly increasing trends in maximum demand. Generally, this is driven by local customer step changes and observed trends in CBD building occupancy.

A summary of supply capacity and demand for each zone substation is provided in Table 9-11. The Evans Bay 33 kV 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 Dec 2025
				2025	2035	
Palm Grove	Winter	20.0	Transformer	22.3	23.6	10,769
	Summer	20.0	Transformer	15.5	16.8	
8 Ira Street	Winter	20.0	Transformer	15.8	20.3	5,059
	Summer	15.0	33 kV Cables	11.8	15.3	
Frederick Street	Winter	30.0	Transformer	23.7	26.4	7,805
	Summer	30.0	Transformer	19.6	22.4	
Nairn Street	Winter	22.0	11 kV Incomer	19.5	21.7	7,887
	Summer	22.0	11 kV Incomer	14.3	16.4	
University	Winter	20.0	Transformer	16.6	17.6	6,315
	Summer	20.0	Transformer	11.8	12.8	
Evans Bay	Winter	24.0	Transformer	12.3	13.8	4,835
	Summer	24.0	Transformer	8.8	10.3	
Hataitai	Winter	18.1	33 kV Cables	14.8	15.2	7,390
	Summer	9.8	33 kV Cables	9.7	10.2	
The Terrace	Winter	30.0	Transformer	19.8	21.3	1,881
	Summer	30.0	Transformer	18.9	20.4	
Evans Bay 33 kV Bus	Winter	33.0	33 kV Cables	26.4	32.0	9,894
	Summer	26.4	33 kV Cables	20.6	25.5	

Table 9-11 Wellington CBD and East Zone Substation Capacities

The subtransmission-level development needs for the Wellington CBD and East region are outlined in the following sub-sections.

9.8.2.1 Palm Grove

Winter peak demand supplied by the Palm Grove zone substation currently exceeds the N-1 capacity of the transformers, as summarised in Table 9-12.

Circuit	Season	Constraining N-1 branch rating (MVA)	Peak Demand @ 2025 (MVA)	Minimum offload for N-1 @ 2025 peak (MVA)
Palm Grove	Winter	20.0	22.3	2.3
	Summer	20.0	15.5	0.0

Table 9-12 Current Palm Grove Subtransmission Constraints

Based on the estimated growth scenarios, planned developments, and step-charge allowances applied over the planning period, the load at the Palm Grove zone substation is forecast to grow as shown in Figure 9-9.

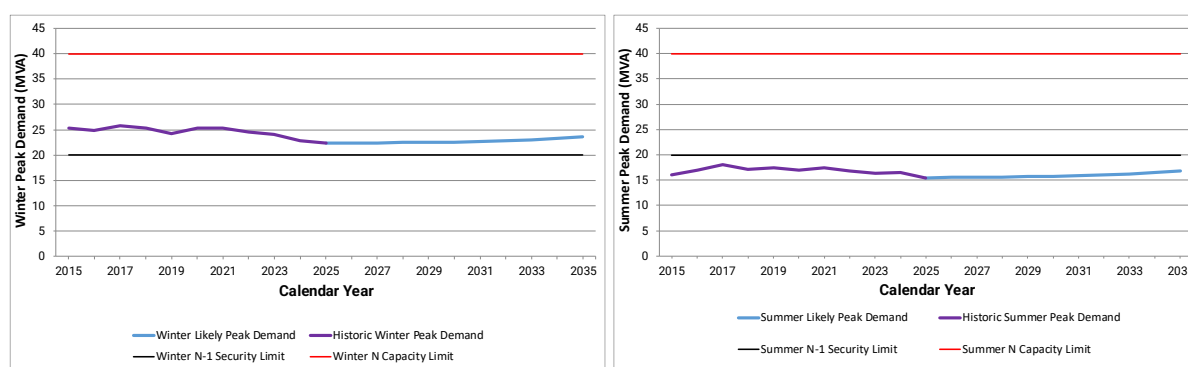


Figure 9-9 Palm Grove Demand Forecast

Peak demand at the Palm Grove zone substation currently exceeds the winter subtransmission N-1 capacity. This security constraint is currently managed through post-contingent offloads through the 11 kV network to adjacent zone substations. Planned projects to address the subtransmission constraint are provided in Section 9.8.2.1.

A major customer decarbonisation development has been proposed in the Newtown area, on a scale that would require the establishment of a new zone substation. This would transfer a substantial proportion of the load away from the Palm Grove zone substation and resolve the current subtransmission security constraint. However, the project remains in early-stage discussions between WELL and the customer, and its timing and deliverability are not yet confirmed.

In parallel, WELL and Transpower are progressing Central Park GXP site-diversity and capacity initiatives to support the future growth of critical loads, including the Wellington Hospital precinct. These developments will improve supply resilience and create additional upstream capacity, providing flexibility to accommodate hospital load growth and broader increases in decarbonisation-driven demand within the CBD and East region.

Should the Newtown customer project not proceed, the alternative option would be to upgrade the 33/11 kV transformers at Palm Grove. The preferred investment pathway will be confirmed once the customer's intentions are clarified.

9.8.2.2 8 Ira Street

Peak demand supplied by the 8 Ira Street zone substation currently remains within the N-1 capacity of the subtransmission circuits and is getting slightly closer to the limit in the coming years. Table 9-13 summarises the seasonal constraint levels and the corresponding minimum offload requirements on each circuit.

Circuit	Season	Constraining N-1 branch rating (MVA)	Peak Demand @ 2025 (MVA)	Minimum offload for N-1 @ 2025 peak (MVA)
8 Ira Street	Winter	20.0	15.8	0.0
	Summer	15.0	11.8	0.0

Table 9-13 Current 8 Ira Street Subtransmission Constraints

Based on the estimated growth scenarios and step-change allowances applied over the planning period, the load at 8 Ira Street zone substation is forecast to evolve as shown in Figure 9-10. The corresponding subtransmission capacity constraints are overlaid for comparison.

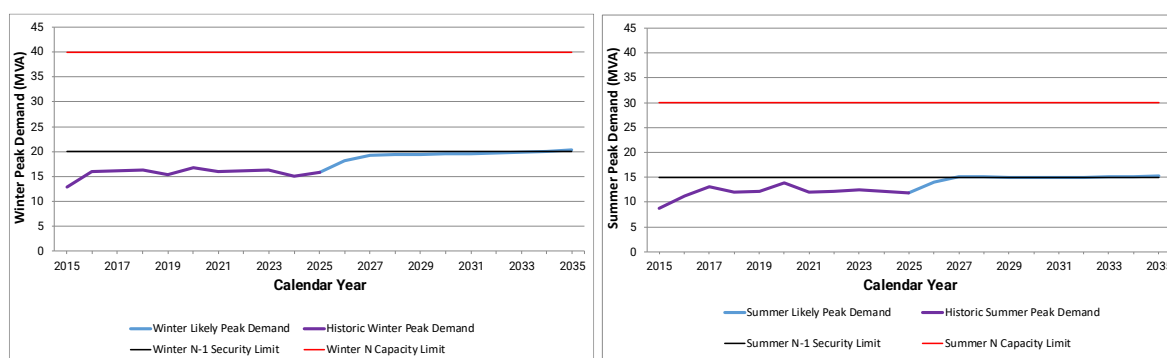


Figure 9-10 8 Ira Street Demand Forecast

Peak demand at 8 Ira Street zone substation has remained stable since 2016. However, major customer projects currently underway are expected to increase load to levels that may exceed the winter and summer N-1 subtransmission limits from 2027 onwards. Planned projects to address these emerging subtransmission constraints are outlined in Section 9.8.2.2.

9.8.2.3 Frederick Street

Peak demand supplied by the Frederick Street zone substation currently remains within the N-1 capacity of the subtransmission circuits. Table 9-14 summarises the seasonal constraint levels and the corresponding minimum offload requirements on each circuit.

Circuit	Season	Constraining N-1 branch rating (MVA)	Peak Demand @ 2025 (MVA)	Minimum offload for N-1 @ 2025 peak (MVA)
Frederick Street	Winter	30.0	23.7	0.0
	Summer	30.0	19.6	0.0

Table 9-14 Current Frederick Street Subtransmission Constraints

Based on the estimated growth scenarios and step-change allowances applied over the planning period, the load at the Frederick Street zone substation is forecast to change as shown in Figure 9-11. The corresponding subtransmission capacity constraints are plotted for comparison.

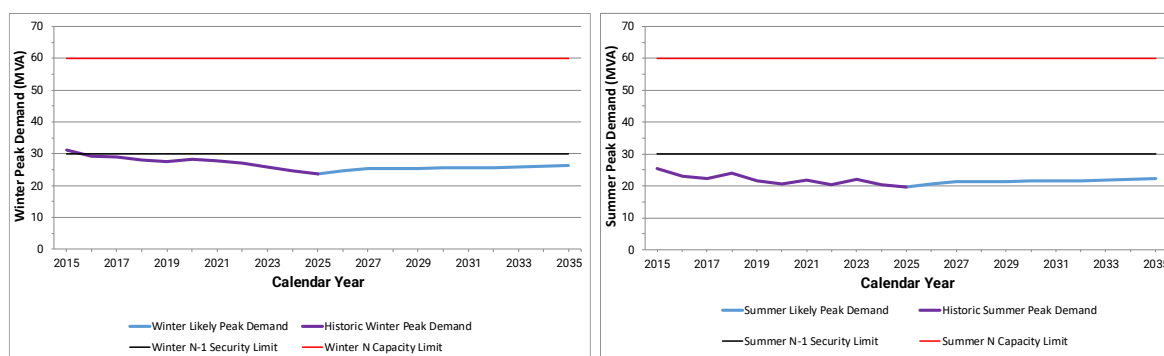


Figure 9-11 Frederick Street Demand Forecast

Peak demand at the Frederick Street zone substation is forecast to remain within the winter and summer subtransmission N-1 capacity for the duration of this planning period.

9.8.2.4 Nairn Street

Peak demand supplied by the Nairn Street zone substation currently remains within the N-1 rating of the 11 kV incomer cables. Table 9-15 summarises the seasonal constraint levels and the corresponding minimum offload requirements on each circuit.

Circuit	Season	Constraining N-1 branch rating (MVA)	Peak Demand @ 2025 (MVA)	Minimum offload for N-1 @ 2025 peak (MVA)
Nairn Street	Winter	22.0	19.5	0.0
	Summer	22.0	14.3	0.0

Table 9-15 Current Nairn Street Subtransmission Constraints

Based on the estimated growth scenarios and step-change growth allowances applied over the planning period, the load at the Nairn Street zone substation is forecast to evolve as shown in Figure 9-12. The corresponding subtransmission capacity constraints are overlaid for comparison.

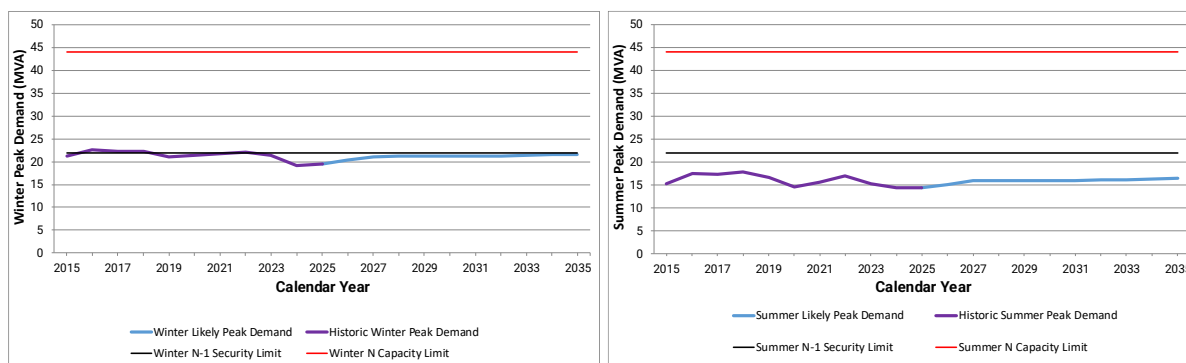


Figure 9-12 Nairn Street Demand Forecast

Peak demand at the Nairn Street zone substation has been steady and is forecast to remain within the winter and summer subtransmission N-1 capacity for the duration of this plan. However, the load here is closely monitored because of its proximity to N-1 capacity limit.

9.8.2.5 University

Peak demand supplied by the University zone substation currently remains within the N-1 capacity of the subtransmission circuits. Table 9-16 summarises the seasonal constraint levels and the corresponding minimum offload requirements on each circuit.

Circuit	Season	Constraining N-1 branch rating (MVA)	Peak Demand @ 2025 (MVA)	Minimum offload for N-1 @ 2025 peak (MVA)
University	Winter	20.0	16.6	0.0
	Summer	20.0	11.8	0.0

Table 9-16 Current University Subtransmission Constraints

Based on the estimated growth scenarios and step-change growth allowances applied over the planning period, the load at the University zone substation is forecast to change as shown in Figure 9-13. The corresponding subtransmission capacity constraints are overlaid for comparison.

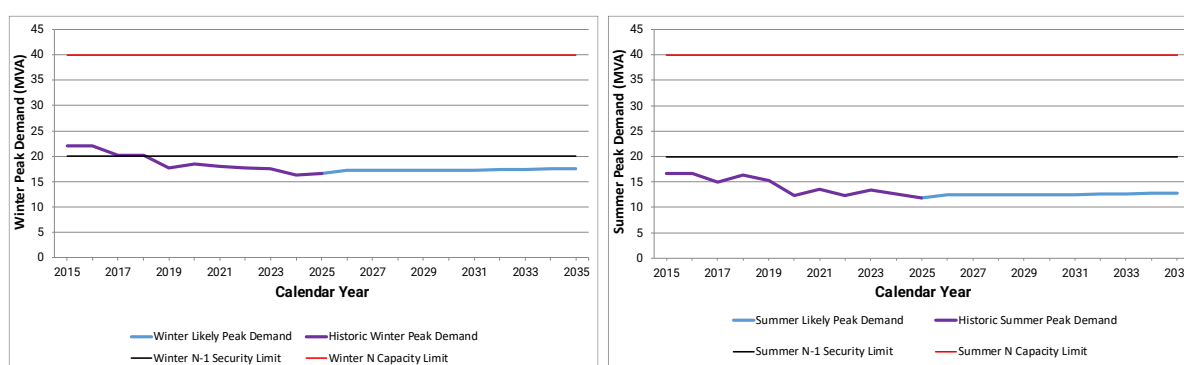


Figure 9-13 University Demand Forecast

Peak demand at the University zone substation has previously declined and is now stabilising. It is forecast to remain within both the winter and summer subtransmission N-1 capacity for the duration of this planning period. Planned projects are underway to replace the University subtransmission cables due to asset condition, as detailed in Section 8.

9.8.2.6 Evans Bay

Peak demand supplied by the Evans Bay zone substation currently remains within the N-1 capacity of the subtransmission circuits. Table 9-17 summarises the seasonal constraint levels and the corresponding minimum offload requirements on each circuit.

Circuit	Season	Constraining N-1 branch rating (MVA)	Peak Demand @ 2025 (MVA)	Minimum offload for N-1 @ 2025 peak (MVA)
Evans Bay	Winter	24.0	12.3	0.0
	Summer	24.0	8.8	0.0

Table 9-17 Current Evans Bay Subtransmission Constraints

Based on the estimated growth scenarios and step-change allowances applied over the planning period, the load at the Evans Bay zone substation is forecast to evolve as shown in Figure 9-14. The corresponding subtransmission capacity constraints are overlaid for comparison.

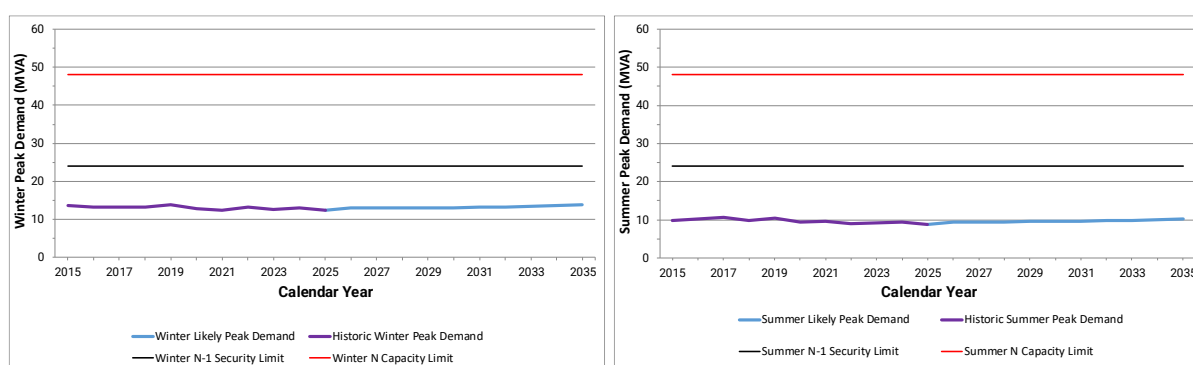


Figure 9-14 Evans Bay Demand Forecast

Peak demand at the Evans Bay zone substation has remained stable since 2014 and is forecast to remain within both winter and summer subtransmission N-1 capacity limits throughout this planning period. Plans to manage the fluid-filled cables supplying the Evans Bay bus are provided in Section 9.8.2.6.

9.8.2.7 Hataitai

Peak demand supplied by the Hataitai zone substation currently remains within the N-1 capacity of the subtransmission circuits. Table 9-18 summarises the seasonal constraint levels and the corresponding minimum offload requirements on each circuit.

Circuit	Season	Constraining N-1 branch rating (MVA)	Peak Demand @ 2025 (MVA)	Minimum offload for N-1 @ 2025 peak (MVA)
Hataitai	Winter	18.1	14.8	0.0
	Summer	9.8	9.7	0.0

Table 9-18 Current Hataitai Subtransmission Constraints

Based on the estimated growth scenarios and step-change allowances applied over the planning period, the load at the Hataitai zone substation is forecast to evolve as shown in Figure 9-15. The corresponding subtransmission capacity constraints are overlaid for comparison.

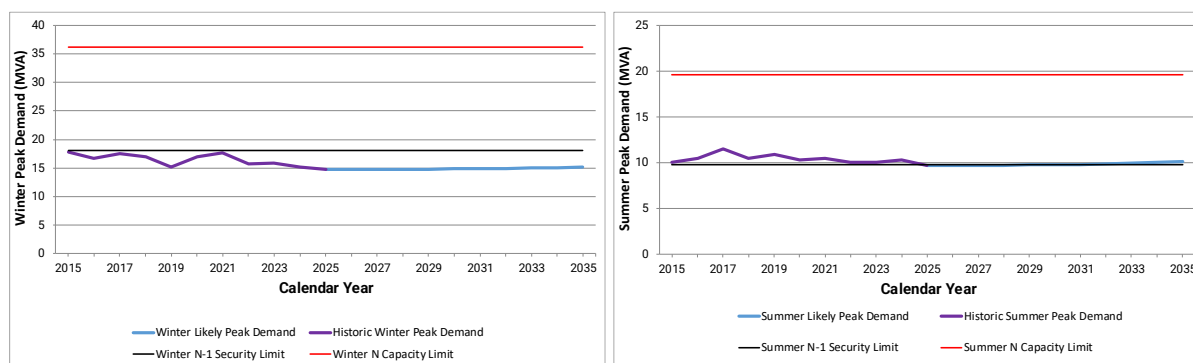


Figure 9-15 Hataitai Demand Forecast

Peak demand at the Hataitai zone substation has remained stable since 2014 and is forecast to remain within both the winter and summer subtransmission N-1 capacity limits throughout this planning period. Plans to manage the criticality of the gas cables at the zone substation are provided in Section 9.8.2.7.

9.8.2.8 The Terrace

Peak demand supplied by The Terrace zone substation is currently within the N-1 capacity of the subtransmission circuits. Table 9-19 summarises the seasonal constraint levels and the corresponding minimum offload requirements on each circuit.

Circuit	Season	Constraining N-1 branch rating (MVA)	Peak Demand @ 2025 (MVA)	Minimum offload for N-1 @ 2025 peak (MVA)
The Terrace	Winter	30.0	19.8	0.0
	Summer	30.0	18.9	0.0

Table 9-19 Current The Terrace Subtransmission Constraints

Based on the estimated growth scenarios and step-change allowances applied over the planning period, the load at The Terrace zone substation is forecast to evolve as shown in Figure 9-16. The corresponding subtransmission capacity constraints are overlaid for comparison.

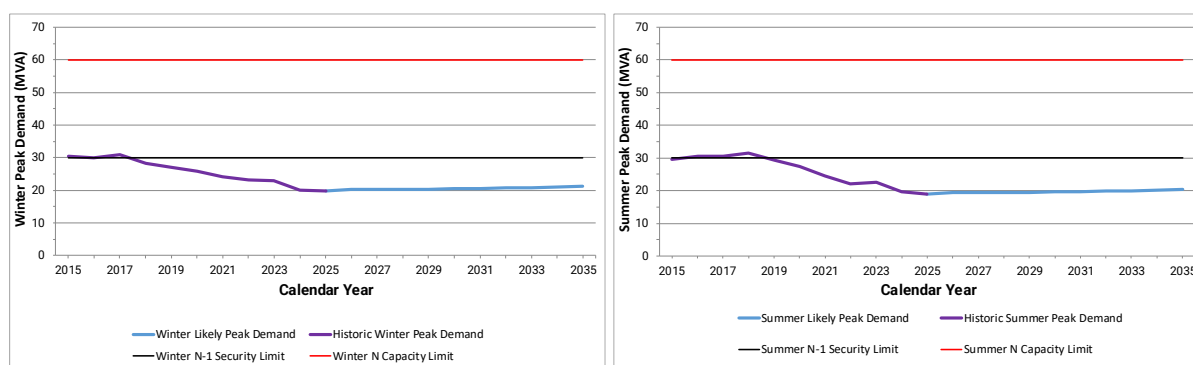


Figure 9-16 The Terrace Demand Forecast

The reduction in peak demand at The Terrace zone substation between 2018 and 2024 primarily reflects changes in occupancy across several large commercial buildings following seismic assessments and associated strengthening requirements after the Wellington earthquakes. With a number of these buildings progressively returning to service as strengthening works are completed, demand has recently stabilised and is expected to recover toward historical levels, potentially exceeding them as full occupancy resumes. On this basis, peak demand is forecast to remain within both the winter and summer subtransmission N-1 capacity limits throughout this planning period.

9.8.3 Distribution Network Development Needs

The Wellington CBD and East distribution network is a highly meshed system with overlapping supply boundaries and a high degree of interdependency between zone substations. This meshed configuration provides operational flexibility and resilience but also means that development options must be assessed at a network-wide level rather than on a feeder-by-feeder basis, as constraints and solutions at one site can materially affect neighbouring supply areas.

Each zone substation supplies an interconnected 11 kV distribution network, and most substations are linked via normally open points that enable post-contingent load transfer between zones. The most critical distribution-level risks arise from:

- meshed ring feeders supplying a high concentration of customers
- inter-zone links that are relied upon to transfer load following a contingency

Feeder protection settings are designed to protect breaker and cable thermal limits while allowing short-duration overloads to support post-contingent load transfer. In practice, the loss of a single feeder within a meshed ring can cause a rapid redistribution of load onto adjacent feeders. The loading figures assessed are conservative worst-case conditions, as in most scenarios the faulted feeder section will isolate part of the load, thereby reducing the load transferred to the remaining feeders.

WELL is also aware of several potential future step-change loads arising from customer connection requests, district plan developments, and engagement with councils, developers, and large customers. While some of these developments may introduce significant new load demand in different areas. Given the uncertainty surrounding the timing and magnitude of these potential changes, they have not been incorporated into the forecast assessment. WELL will continue to monitor these developments and will implement timely network solutions as projects become confirmed.

Distribution-level constraints are assessed initially by comparing feeder loading against pre-contingent trigger thresholds (as defined in Table 9-4). Feeders exceeding these thresholds are then subject to post-contingent analysis to determine whether the constraint can be managed through network reconfiguration and load transfer. Feeders that cannot be managed post-contingency are treated as high priority and require network augmentation or permanent reconfiguration. Feeders that can be managed through post-contingent reconfiguration are assigned lower priority and monitored before any investment is committed.

Table 9-20 summarises the constrained distribution feeders within the planning period and identifies the corresponding management approach and required actions.

Constrained Feeder	Constraint Year	Required Action	
		First Step	Second Step
8 Ira St 6	Existing	Monitor Load	
8 Ira St 8/9	Existing	Ira Street Eastern 11kV Cable and Moa Point ongoing projects	
8 Ira St 11	Existing	Monitor Load	
Evans Bay 2/4	Existing	Northern Miramar 11 kV Reinforcement project	
Frederick St 13/14	Existing	Network Reconfiguration ³⁸	
Palm Grove 2/3/6	Existing	Network Reconfiguration	
Palm Grove 8/10/12	Existing	Network Reconfiguration	
University 8/10	Existing	Network Reconfiguration	
University 12	Existing	Monitor Load	

Table 9-20 Distribution Network Needs – Wellington CBD and East

Details for each of the projects can be found in Table 9-21 and the projects to address existing distribution-level constraints are summarised in Section 9.8.4.3.

9.8.4 Summary of Network Development Plan

This sub-section summarises the development options available to address the network needs identified above. Given that the Wellington CBD and East distribution network is highly meshed and characterised by significant interdependency between sites, development options comprise a coordinated suite of individual solutions rather than standalone projects. These options are not mutually exclusive, as several investments can address multiple network needs simultaneously.

9.8.4.1 Non-network Solutions

Before any investment in network infrastructure is considered, non-network solutions are first evaluated as potential deferral options, as discussed in Section 9.13.4.1.

9.8.4.2 Major Projects for the Disclosure Year Beginning 1 April 2026

Table 9-21 summarises major projects that are either currently under construction or planned to commence construction within the next 12 months. Feasibility and design activities are excluded from this summary.

Project	Description
Ira Street Switchboard	Replacement of the 11 kV switchboard at 8 Ira Street to allow the connection of a major customer project at Moa Point.
Moa Point	Reinforcement of the 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 9-21 Wellington CBD & East Area Major Projects for the Disclosure Year Beginning 1 April 2026

³⁸ Reconfiguration of the 11 kV network refers to changing the position of normally open points of interconnection between adjacent distribution feeders. This redistributes the loading between feeders to enable more effective post-contingent management.

The Ira Street Switchboard and Moa Point projects have been initiated to meet the capacity requirements of a major customer operating under an accelerated delivery timeframe. WELL's DPP4 capital expenditure allowances do not fund these works, and WELL therefore intends to apply to the Commission to reopen its DPP4 price path under an unforeseen large-project reopener application. However, the urgency and regional significance of the customer's project have required WELL to commence investment before the reopener is submitted. This is discussed further in Section 13.6.

9.8.4.3 Development Plan Summary

Table 9-22 summarises the development plan for each area and sets out the preferred solutions for existing and forecast network constraints.

Project	Description	Constraint Relieved	Target Completion	Constraint Type	Investment
Subtransmission Constraints					
Ira Street Switchboard	Replace 8 Ira Street 11 kV Switchboard	Ira Street 11 kV feeder capacity supporting customer and other network projects.	2026	Capacity	\$5.4M
Hataitai 33 kV Bus	Install 33 kV Bus at Hataitai, cut in Hataitai and Evans Bay cables	Evans Bay and Hataitai 33 kV cables' health and criticality	2030	Security	\$11.4M
Hataitai-Evans Bay 33 kV Cable Upgrade	Run new 33 kV cables from the proposed Hataitai 33 kV Bus to the Evans Bay 33 kV Bus	Evans Bay 33 kV gas cable health and criticality	2030	Security	\$11.0M
Ira Street 33kV Cables	Replace Ira Street 33 kV gas cables	Ira Street 33 kV cable health and criticality	2031	Security	\$8.7M
Hataitai 33 kV Cables	Replace 33 kV gas-filled cables from Central Park to Hataitai	Hataitai 33 kV cables' health and criticality	2032	Security	\$18.3M
Newtown Zone Substation ³⁹	Build new zone substation in Newtown to relieve Palm Grove transformers	Palm Grove Transformers	2033	Capacity	\$42M
Distribution Constraints					
Ira Street Eastern 11kV Cable	Reinforce the 11 kV network between 8 Ira Street, Moa Point and the Airport	Ira Street 8/9, Ira Street 6	2026	Security	\$4.6M
Moa Point	Upgrade the Moa Point switchboard.	Ira Street 8/9	2026	Security	\$8.5M
Northern Miramar 11 kV Reinforcement	Run a new feeder(s) from Ira St to Devonshire Rd, reconfigure the network.	Evans Bay 2/4, Ira Street 11	2028	Security	\$1.8M
Ira Street Western 11 kV Cable Stage 1	Reinforce the 11 kV network between 8 Ira St and the Airport	Ira Street 8/9, Evans Bay 8	2028	Security	\$6.2M
Ira Street Western 11 kV Cable Stage 2	Reinforce the 11 kV network between 8 Ira St, the Airport, and Moa Point	Ira Street 8/9	Customer Driven	Security	\$13.0M

Table 9-22 Wellington CBD & East Area Development Summary

³⁹ The estimated increase in capacity of 24 MVA includes the potential for 10 MVA to accommodate a customer driven connection.

The plan excludes reinforcement associated with major customer-initiated projects that have not yet been contractually committed. System Growth expenditure that is conditional on customer delivery is summarised in Section 13.6. Detailed project planning and option engineering will be undertaken as part of the project scoping and approval process.

9.9 Wellington West NDRP

The following section presents the NDRP for Wellington West.

9.9.1 GXP Development Plans

The Wellington West network is supplied by two GXPs at Wilton and Kaiwharawhara, owned by Transpower. The transformer capacity and peak system demand are summarised in Table 9-23⁴⁰.

GXP	Continuous Capacity (MVA)	Cyclic Summer / Winter Capacity (MVA)	Peak Demand (MVA)	
			2025	2035
Wilton 33 kV ⁴¹	2x100	103/110	45	49
Kaiwharawhara 11 kV	2x30	38/38	27	28

Table 9-23 Southern Area GXP Capacities

The development needs at each GXP are discussed below.

9.9.1.1 Wilton GXP

In 2025, peak demand at the Wilton GXP, excluding injection from the Mill Creek wind farm, was 45 MVA. Wilton supplies the Karori, Moore Street, and Waikowhai Street zone substations, each via double 33 kV subtransmission circuits. The Wilton 110 kV bus comprises three sections providing supply diversity and resilience by terminating each of the Central Park circuits on separate bus sections. In addition, Transpower has undertaken a risk assessment of potential loss-of-asset scenarios at Wilton, including the complete loss of the 220 kV or 110 kV bus structures, and has developed concept bypass arrangements to enable restoration of supply within short timeframes should such events occur.

9.9.1.2 Kaiwharawhara GXP

In 2025, peak demand at the Kaiwharawhara GXP was 27 MVA. The GXP supplies the Kaiwharawhara zone substation directly via the low-voltage circuit breakers of its 110/11 kV transformer. Based on the estimated growth scenarios and potential step-change allowances applied over the planning period, the Kaiwharawhara load is forecast to evolve as shown in Figure 9-17, with the corresponding subtransmission capacity constraints overlaid for comparison.

⁴⁰ The forecast presented reflects only committed developments.

⁴¹ Wilton 33 kV peak demand excluding injection from Mill Creek generation.

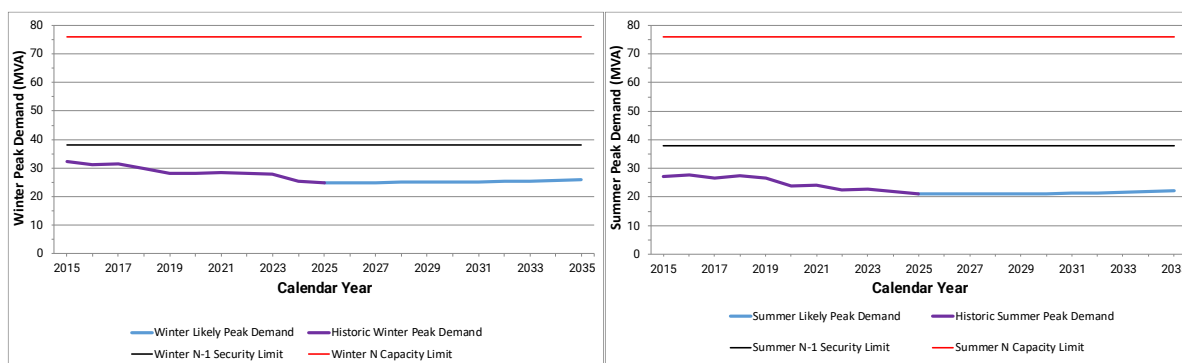


Figure 9-17 Kaiwharawhara Demand Forecast

The investment needs identified at Transpower GXPs are detailed in Transpower's Transmission Planning Report. At this stage, no capacity upgrades are planned for either the Wilton or Kaiwharawhara GXPs.

9.9.2 Subtransmission Network Development Needs

Security-of-supply constraints and associated development needs have been identified across the Wellington West subtransmission network, with zone substations in the area exhibiting flat trends in maximum demand. An overview of the supply capacity and demand for each zone substation is listed in Table 9-24.

Zone Substation	Season	Subtransmission N-1 branch rating (MVA)	Constraining Branch	Peak Demand C1 (MVA)		ICP Count Dec 2025
				2025	2035	
Karori	Winter	18.9	33 kV Cables	13.9	16.1	6,304
	Summer	10.1	33 kV Cables	8.9	11	
Moore Street	Winter	30.0	Transformer	17.3	19.2	924
	Summer	30.0	Transformer	18.4	20.3	
Waikowhai Street	Winter	15.0	Transformer	13.0	13.5	5,891
	Summer	15.0	Transformer	8.2	8.7	

Table 9-24 Wellington West Area Zone Substation Capacities

Subtransmission-level development needs for the Wellington West region are outlined in the sub-sections below.

9.9.2.1 Karori

Peak demand supplied by Karori zone substation currently remains within the N-1 capacity of the subtransmission circuits. Table 9-25 summarises the seasonal constraint levels and the corresponding minimum offload requirements on each circuit.

Circuit	Season	Constraining N-1 branch rating (MVA)	Peak Demand @ 2025 (MVA)	Minimum offload for N-1 @ 2025 peak (MVA)
Karori	Winter	18.9	13.9	0.0
	Summer	10.1	8.9	0.0

Table 9-25 Current Karori Subtransmission Constraints

Based on the estimated growth scenarios and step-change growth allowances applied over the planning period, the load at the Karori zone substation is forecast to change as shown in Figure 9-18. The corresponding subtransmission capacity constraints are overlaid for comparison.

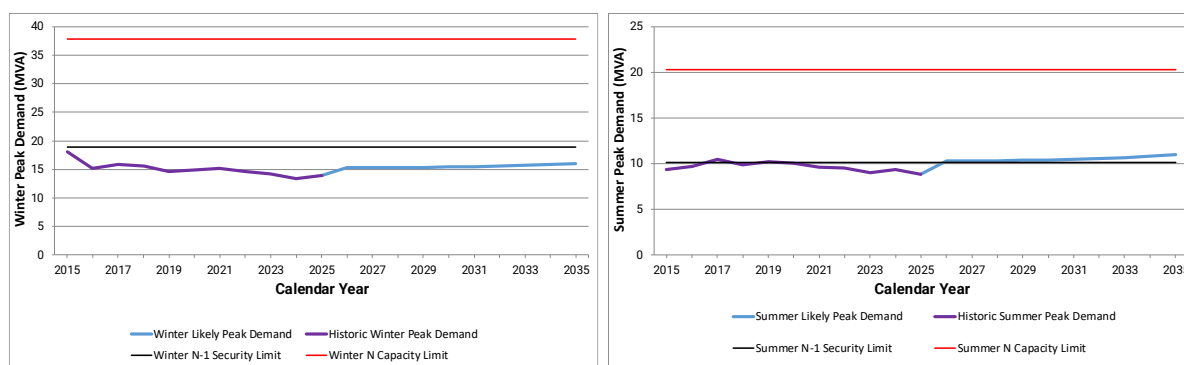


Figure 9-18 Karori Demand Forecast

Peak demand at the Karori zone substation has remained stable since 2016 and is forecast to remain within both the winter and summer subtransmission N-1 capacity limits throughout this planning period. Replacement of the gas-filled subtransmission cables to Karori is discussed in Section 8.

9.9.2.2 Moore Street

Peak demand supplied by the Moore Street zone substation is currently within the N-1 capacity of the subtransmission circuits. Table 9-26 summarises the seasonal constraint levels and the corresponding minimum offload requirements on each circuit.

Circuit	Season	Constraining N-1 branch rating (MVA)	Peak Demand @ 2025 (MVA)	Minimum offload for N-1 @ 2025 peak (MVA)
Moore Street	Winter	30.0	17.3	0.0
	Summer	30.0	18.4	0.0

Table 9-26 Current Moore Street Subtransmission Constraints

Based on the estimated growth scenarios and step-change growth allowances applied over the planning period, the load at the Moore Street zone substation is forecast to evolve as shown in Figure 9-19. The corresponding subtransmission capacity constraints are overlaid for comparison.

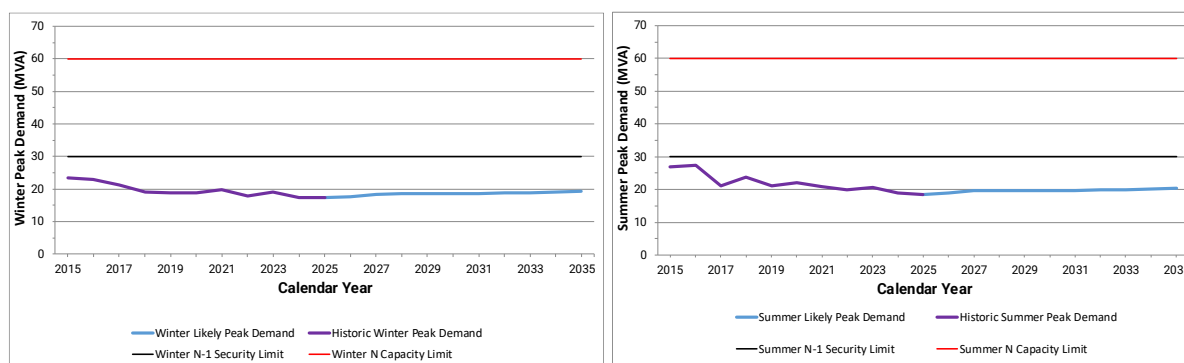


Figure 9-19 Moore Street Demand Forecast

Peak demand at the Moore Street zone substation is approximately steady over the years and is forecast to remain within the winter and summer subtransmission N-1 capacity limits for the duration of this planning period.

9.9.2.3 Waikowhai Street

Peak demand supplied by the Waikowhai Street zone substation currently remains within the N-1 capacity of the subtransmission circuits. Table 9-27 summarises the seasonal constraint levels and the corresponding minimum offload requirements on each circuit.

Circuit	Season	Constraining N-1 branch rating (MVA)	Peak Demand @ 2025 (MVA)	Minimum offload for N-1 @ 2025 peak (MVA)
Waikowhai Street	Winter	15.0	13.0	0.0
	Summer	15.0	8.2	0.0

Table 9-27 Current Waikowhai Street Subtransmission Constraints

Based on the estimated growth scenarios and step-change allowances applied over the planning period, the load at Waikowhai Street zone substation is forecast to evolve as shown in Figure 9-20. The corresponding subtransmission capacity constraints are overlaid for comparison.

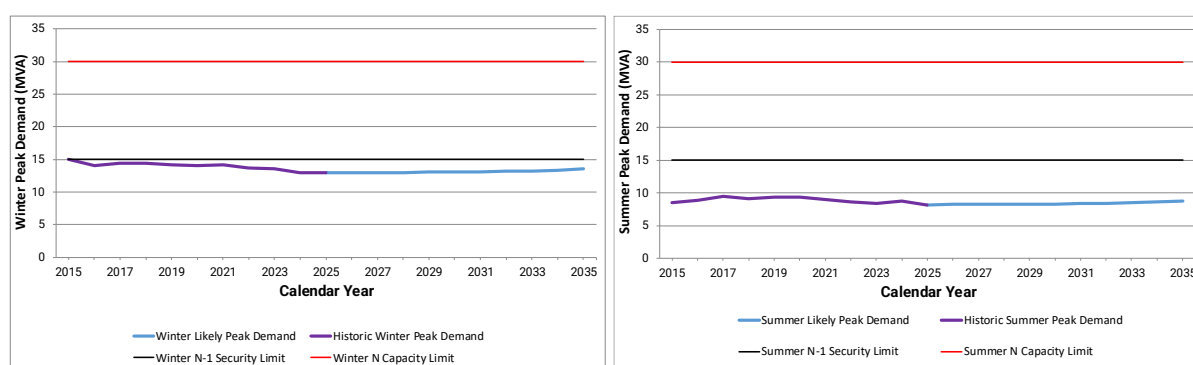


Figure 9-20 Waikowhai Street Demand Forecast

Peak demand at Waikowhai Street zone substation has remained stable since 2014 and is forecast to remain within both the winter and summer subtransmission N-1 capacity limits for the duration of this planning period. Replacement of the gas-filled subtransmission cables to Waikowhai Street is discussed in Section 8.

9.9.3 Distribution Network Development Needs

The Wellington West distribution network shares the same highly meshed, interdependent configuration as the Wellington CBD and Eastern Region. Accordingly, development options must be considered in the context of network-wide interdependencies rather than on a feeder-by-feeder basis.

Distribution-level constraints are assessed using the same pre- and post-contingent methodology described in Section 9.9.3 with feeders exceeding their pre-contingent trigger thresholds (defined in Table 9-4) subject to post-contingent analysis to determine whether constraints can be managed through load transfer and network reconfiguration. Feeders that cannot be managed post-contingency are treated as high priority and require network augmentation or permanent reconfiguration, whereas manageable feeders are monitored before committing to investment.

A summary of the 11 kV constraint assessment for the Wellington West region is presented in Table 9-28, which identifies constrained feeders within the planning period and summarises the assessment outcomes and required actions.

Constrained Feeder	Constraint Year	Required Action	
		First Step	Second Step
Kaiwharawhara 6/7/9/10	Existing	Abattoirs 11 kV feeder project	
Karori 3/6	Existing	Karori West 11 kV Reinforcement project	
Karori 8/10	2027	Network Reconfiguration	

Table 9-28 Distribution Network Needs – Wellington West

Details for each of the projects can be found in Table 9-28 and the projects to address existing distribution-level constraints are summarised in Section 9.9.4.3.

9.9.4 Summary of Network Development Plan

This sub-section summarises the development options available to address the network needs identified above. Given the highly meshed and interdependent configuration of the Wellington West distribution network, these options comprise a coordinated suite of individual solutions rather than standalone projects. The options are not mutually exclusive, as several investments can address multiple network needs simultaneously.

9.9.4.1 Non-network Solutions

Before any investment in network infrastructure is considered, non-network solutions are first evaluated as potential deferral options, as discussed in Section 9.5.4.

9.9.4.2 Major Projects for the Disclosure Year Beginning 1 April 2026

Table 9-29 summarises major projects that are currently under construction or planned to commence construction over the next 12 months.

Project	Description
Abattoirs 11 kV feeder	Upgrade the short section of cable on Kaiwharawhara 6/7/9/10 to relieve constraint on the radial sub-feeder of the ring

Table 9-29 Southern Area Projects for the Disclosure Year Beginning 1 April 2026

9.9.4.3 Development Plan Summary

Table 9-30 summarises the development plan for Wellington West and sets out the preferred solutions for existing and forecast distribution network constraints. The plan excludes reinforcement associated with potential major customer-initiated projects that have not yet been contractually committed. System Growth expenditure that is conditional on customer delivery is summarised in Section 13.6. Detailed project planning and option engineering will be undertaken as part of the project scoping and approval process.

Project	Description	Constraint Relieved	Target Completion	Constraint Type	Investment
Distribution Constraints					
Abattoirs 11 kV feeder	Upgrade the short section of cable on Kaiwharawhara 6/7/9/10	Kaiwharawhara 6/7/9/10	2026	Capacity	\$1.2m
Karori West 11 kV Reinforcement	New sub-feeder from 9 Parkvale Road to near Burrows Ave	Karori 3/6	2027	Security	\$3.1m

Table 9-30 Wellington West Area Development Summary

9.10 Wellington North NDRP

The following section presents the NDRP for the Wellington North region.

9.10.1 GXP Development Plans

The Wellington North region is supplied from the Takapu Rd GXP, which is shared with the Porirua region (refer to Section 9.10). Transpower owns the supply transformers at this GXP. Installed transformer capacity and peak system demand are summarised in Table 9-31, with the forecast reflecting only committed developments. For simplicity, the GXP loading is presented on a combined basis for both Wellington North and Porirua regions.

GXP	Continuous Capacity (MVA)	Transformer Cyclic Summer / Winter Capacity (MVA)	Peak Demand (MVA)	
			2025	2035
Takapu Road 33 kV	2x90	111/116	99	109

Table 9-31 Wellington North Area GXP Capacities

The investment needs identified at Transpower GXPs are detailed in Transpower's Transmission Planning Report. The development needs at the Takapu Rd GXP are outlined in the sub-sections below.

9.10.1.1 Takapu Road

Takapu Road supplies the Waitangirua, Porirua, Kenepuru, Tawa, Ngauranga, and Johnsonville zone substations, each via double 33 kV subtransmission circuits. The Ngauranga subtransmission circuits are carried on a 110 kV-rated double-circuit transmission tower line owned and maintained by Transpower. The GXP comprises two parallel 110/33 kV transformers, each nominally rated at 90 MVA, providing a winter N-1 cyclic capacity of 116 MVA. In 2025, maximum demand at Takapu Rd GXP was 99 MVA. WELL will continue to monitor GXP loading and will engage with Transpower on potential upgrade requirements, having regard to Transpower's plans at the Pauatahanui GXP, as discussed in Section 9.11.

9.10.2 Subtransmission Network Development Needs

The Wellington North subtransmission network has several identified security-of-supply constraints and associated development needs, and comprises three zone substations: Ngauranga, Johnsonville, and Tawa. Increasing trends in maximum demands are driven by residential and commercial growth.

Ngauranga zone substation is supplied via a 110 kV double-circuit transmission tower line, owned and operated by Transpower and energised at 33 kV. A combination of overhead circuits and oil-filled cables

supplies the Johnsonville zone substation. The Tawa zone substation is supplied by an overhead circuit shared with the Kenepuru zone substation, together with dedicated oil-filled cables. A summary of the loading for each zone substation is provided in Table 9-32.

Zone Substation	Season	Subtransmission N-1 branch rating (MVA)	Constraining Branch	Peak Demand C1 (MVA)		ICP Count Dec 2025
				2025	2035	
Johnsonville	Winter	16.0	33 kV Cables	20.1	21.3	9,252
	Summer	11.0	33 kV Cables	14.8	18.8	
Ngauranga	Winter	10.0	Transformer	10.4	11.7	4,644
	Summer	10.0	Transformer	7.3	8.6	
Tawa	Winter	16.0	Transformer	13.9	16	5,632
	Summer	14.6	33 kV Cables	9.8	11.8	

Table 9-32 Wellington North Area Zone Substation Capacities

Subtransmission-level development needs for the Wellington North region are outlined in the sub-sections below.

9.10.2.1 Johnsonville

Peak demand supplied by the Johnsonville zone substation currently exceeds the N-1 capacity of the subtransmission circuits. Operational risk is managed through a combination of load control and post-contingent load transfer from adjacent zone substations to high-voltage feeders. Table 9-33 summarises the seasonal constraint levels and the corresponding minimum offload requirements.

Zone substation	Season	Subtransmission N-1 Constraining N-1 branch rating (MVA)rating (MVA)	Peak Demand @ 2025 (MVA)	Minimum offload for N-1 @ 2025 peak (MVA)
Johnsonville	Winter	16.0	20.1	4.1
	Summer	11.0	14.8	3.8

Table 9-33 Current Johnsonville Subtransmission Constraints

Based on the estimated growth scenarios, development, and step-change growth allowances over the planning period, the load at the Johnsonville zone substation is forecast to evolve as shown in Figure 9-21. The corresponding subtransmission capacity constraints are overlaid for comparison.

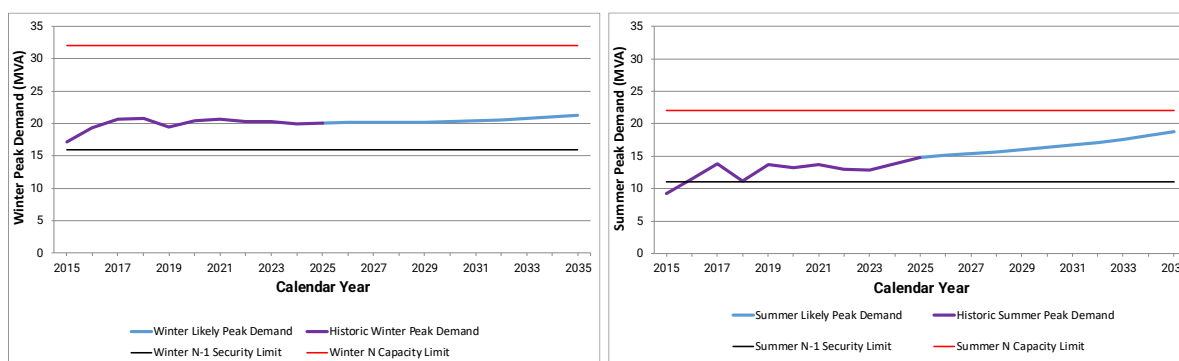


Figure 9-21 Johnsonville Demand Forecast

Peak demand at the Johnsonville zone substation is forecast to increase significantly, particularly during summer. This is driven by sustained residential growth.

WELL's preferred development option is to transfer the load from the Johnsonville zone substation to a proposed new Grenada zone substation and the existing Ngauranga zone substation. While an alternative would be to increase capacity at Johnsonville by replacing the 33 kV cables and transformers, an upgrade that will ultimately be required for asset health reasons, the Grenada substation is preferred as an initial step in the regional development plan. This option provides broader security benefits for the Tawa and Ngauranga zone substations, in addition to Johnsonville, and therefore represents the most cost-effective solution.

Replacement of the oil-filled subtransmission cables to Johnsonville is discussed in Section 8.

9.10.2.2 Ngauranga

Winter peak demand supplied by the Ngauranga zone substation currently exceeds the N-1 capacity of the subtransmission circuits. Operational risk is managed through load control and post-contingent load transfer from adjacent zone substations to high-voltage feeders. Table 9-34 summarises the seasonal constraint levels and the corresponding minimum offload requirements.

Circuit	Season	Constraining N-1 branch rating (MVA)	Peak Demand @ 2025 (MVA)	Minimum offload for N-1 @ 2025 peak (MVA)
Ngauranga	Winter	10.0	10.4	0.4
	Summer	10.0	7.3	0.0

Table 9-34 Current Ngauranga Subtransmission Constraints

Based on the estimated growth scenarios, development, and step-change growth allowances over the planning period, the load at the Ngauranga zone substation is forecast to evolve as shown in Figure 9-22. The corresponding subtransmission capacity constraints are overlaid for comparison.

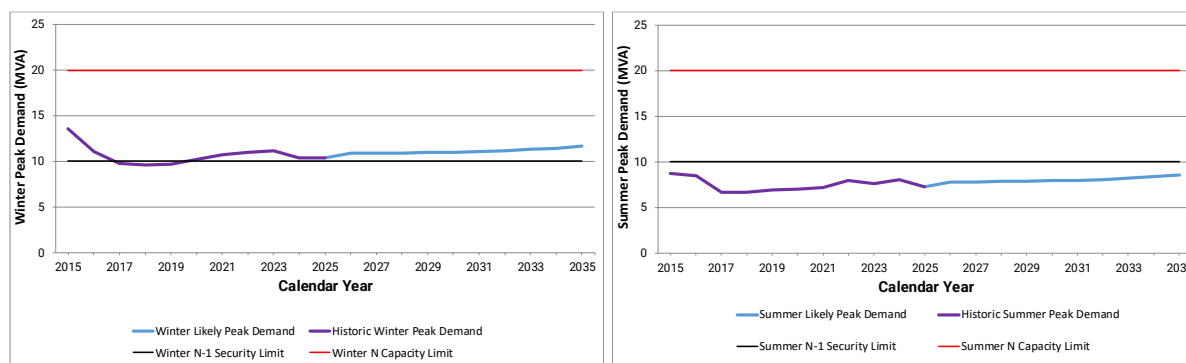


Figure 9-22 Ngauranga Demand Forecast

Peak demand at the Ngauranga zone substation presently exceeds the winter subtransmission N-1 capacity limits. WELL plans to address this constraint by replacing the existing transformers with higher-capacity units. As the transformers are approaching the end of their useful life, this replacement represents a cost-effective and timely solution. The upgrade will provide sufficient capacity for the foreseeable future, with interim security managed operationally through 11 kV connections to the adjacent zone substation.

9.10.2.3 Tawa

Peak demand supplied by the Tawa zone substation currently remains within the N-1 capacity of the subtransmission circuits. Table 9-35 summarises the seasonal constraint levels and the corresponding minimum offload requirements.

Circuit	Season	Constraining N-1 branch rating (MVA)	Peak Demand @ 2025 (MVA)	Minimum offload for N-1 @ 2025 peak (MVA)
Tawa	Winter	16.0	13.9	0.0
	Summer	14.6	9.8	0.0

Table 9-35 Current Tawa Subtransmission Constraints

Based on the estimated growth scenarios, development, and step-change allowances applied over the planning period, the load at the Tawa zone substation is forecast to evolve as shown in Figure 9-23. The corresponding subtransmission capacity constraints are overlaid for comparison.

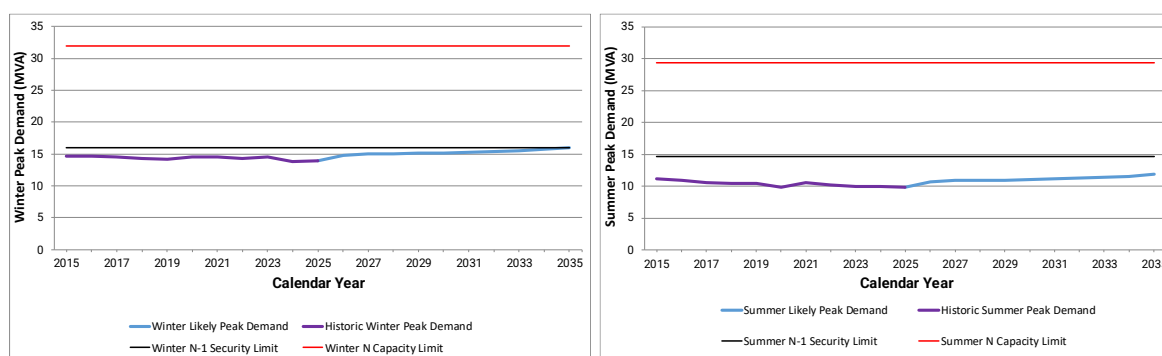


Figure 9-23 Tawa Demand Forecast

Peak demand at the Tawa zone substation has remained stable since 2014 and is forecast to remain within both winter and summer subtransmission N-1 capacity limits for the duration of this planning period. Load will be monitored closely, as it is in proximity to the N-1 limit in Winter. Plans to replace the oil-filled subtransmission cables to Tawa are discussed in Section 8.

9.10.3 Distribution Level Development Needs

WELL is aware of several potential future step-change load increases identified through customer connection requests, local council District Plans, and ongoing consultation with city councils, developers, and large customers. Several property developers and businesses have also signalled prospective developments that may introduce new loads to the network. The timing, scale, and certainty of these potential step-change demands remain uncertain and difficult to quantify; accordingly, they have not been included in the assessment above. WELL will continue to monitor these developments and will progress timely network solutions as individual projects become sufficiently defined and confirmed.

Development options for the Wellington North area comprise a combination of individual network solutions required to address specific constraints. These solutions are not mutually exclusive; in some cases, a single investment may address multiple needs across the network.

Distribution-level constraints are first assessed by comparing feeder loading against pre-contingent 'trigger' values (defined in Table 9-4). Feeders exceeding these trigger values are subject to post-contingent analysis. Feeders that cannot be effectively managed via post-contingent offload to adjacent feeders are classified as high priority. Proposed solutions for these feeders typically include network augmentation (such as cable upgrades) or reconfiguration of the existing network to rebalance load and enable post-contingent operation.

Feeders that can be adequately managed through post-contingent network reconfiguration are assigned a lower priority. For these feeders, WELL will continue to monitor loading trends before committing capital to solutions.

A summary of the 11 kV constraint analysis for the Wellington North region is provided in Table 9-36. This table identifies pre-contingent constrained feeders, presents the outcomes of post-contingent assessments and specifies the required actions for each case.

Constrained Feeder	Constraint Year	Required Action	
		First Step	Second Step
Johnsonville 2	Existing	Johnsonville 11 kV Reinforcement project	
Johnsonville 6	Existing	Monitor Load	
Johnsonville 11	Existing	Johnsonville 11 kV Reinforcement project	
Ngauranga 4	Existing	Monitor Load	
Ngauranga 7	Existing	Monitor Load	
Ngauranga 9	Existing	Monitor Load	
Tawa 8	Existing	Tawa 8 LV Separation project	
Tawa 13	Existing	Monitor Load	
Tawa 11	2025	Monitor Load	
Johnsonville 12	2029	Monitor Load	

Table 9-36 Distribution Network Needs – Wellington North

Details for each of the projects can be found in Table 9-37 and the projects to address existing distribution-level constraints are summarised in Section 9.10.4.3. While the constraint on Tawa 8 can be managed through post-contingent switching under normal network conditions, existing limitations in the local low-voltage network reduce the effectiveness of reconfiguration. To mitigate these limitations and improve post-contingency operability, a project has been proposed to remove low-voltage transformer ties in the area.

9.10.4 Summary of Network Development Plan

This sub-section summarises the development options available to address the network needs identified above.

9.10.4.1 Non-network Solutions

Before any investment in network infrastructure is considered, non-network solutions are first evaluated as potential deferral options, as discussed in Section 9.5.4.

9.10.4.2 Major Projects for the Disclosure Year Beginning 1 April 2026

There are no major projects currently underway, nor are any planned to commence within the next 12 months, in the Wellington North area.

9.10.4.3 Development Plan Summary

Table 9-37 summarises the development plan for Wellington North and sets out the preferred solutions for existing and forecast network constraints, excluding any reinforcement associated with potential major customer-initiated projects that have not yet been contractually committed. System Growth expenditure that is contingent on customer work is summarised in Section 13.6. Detailed project scoping and option engineering will be undertaken as part of the project development and approval stage.

Project	Description	Constraint Relieved	Target Completion	Constraint Type	Investment
Subtransmission					
Grenada zone substation – Stage 1	Stage 1 of establishing a new zone substation at Grenada	Johnsonville zone substation	2028	Security	\$7.4 M
Ngauranga transformer upgrade	Replace Ngauranga transformers	Ngauranga transformers	2028	Security	\$9.0M
Distribution					
Johnsonville 11 kV Reinforcement	Upgrade cable sections and split low-voltage ties across transformers	Johnsonville 11, Johnsonville 2	2027	Security	\$4.7M
Tawa 8 LV Separation	Separate low voltage ties on 11 kV feeder Tawa 8 and offload to Tawa 13	Tawa 8	2028	Security	\$0.9M

Table 9-37 Wellington North Area Development Summary

9.11 Porirua NDRP

The following section presents the NDRP for the Porirua Region.

9.11.1 GXP Development Plans

The Porirua region is supplied from two GXPs: Takapu Road and Pauatahanui. As outlined in Section 9.11 the Takapu Road GXP supplies both the Porirua and Wellington North regions. Transpower owns and operates the supply transformers at these GXPs. The installed transformer capacities and the peak system demand are presented in Table 9-38, with the forecast reflecting only committed developments.

GXP	Continuous Capacity (MVA)	Transformer Cyclic Summer / Winter Capacity (MVA)	Peak Demand (MVA)	
			2025	2035
Takapu Road 33 kV	2x90	111/116	99	109
Pauatahanui 33 kV	2x20	22/24	20	22

Table 9-38 Northwestern Area GXP Capacities

The investment needs identified at Transpower GXPs are detailed in Transpower's Transmission Planning Report. The development needs at the Takapu Road and Pauatahanui GXP are outlined in the sub-sections below.

9.11.1.1 Takapu Road

Takapu Road supplies zone substations at Waitangirua, Porirua, and Kenepuru. Waitangirua and Porirua are each served by double 33 kV circuits, while Kenepuru is supplied in a 'tee' arrangement with Tawa.

The GXP comprises two parallel 110/33 kV transformers, each nominally rated at 90 MVA, providing a winter N-1 cyclic capacity of 116 MVA. The maximum demand on the Takapu Road GXP in 2025 was 96 MVA.

9.11.1.2 Pauatahanui

Takapu Road GXP supplies Pauatahanui GXP via two 110 kV circuits. It comprises two parallel 110/33 kV transformers rated at 20 MVA, providing a winter cyclic N-1 capacity of 24 MVA. The maximum demand on the Pauatahanui GXP in 2025 was 20 MVA.

Pauatahanui GXP supplies the Mana and Plimmerton zone substations via single 33 kV overhead circuits to each substation. The Mana and Plimmerton zone substations are interconnected via a normally closed 11 kV bus-tie cable, providing operational redundancy in the event that one of the 33 kV connections is unavailable.

Transpower has identified that the Pauatahanui supply transformers are approaching end-of-life and will require renewal or replacement within the next five to ten years. WELL is currently working with Transpower to assess options to mitigate flood risk at the Pauatahanui site. This programme of work is discussed further in Section 12.

9.11.2 Subtransmission Network Development Needs

The Porirua region subtransmission network has several security-of-supply constraints and associated development needs. Increasing growth trends are driven by large residential subdivision developments and step changes in industrial customers.

The Porirua network comprises five zone substations. As with Wellington North, each zone substation supplies the 11 kV distribution network, with interconnection to adjacent zones provided through switched open points. All 11 kV feeders are operated radially from the zone substations, except for the meshed ring feeders supplying the Porirua CBD and Titahi Bay substation. A summary of the loading at each zone substation is provided in Table 9-39.

Zone Substation	Season	Subtransmission N-1 branch rating (MVA)	Constraining Branch	Peak Demand C1 (MVA)		ICP Count Dec 2025
				2025	2035	
Mana	Winter	7.0	11 kV Intertie	10.9	11.3	4,894
	Summer	5.9	11 kV Intertie	6.9	7.4	
Porirua	Winter	16	Transformer	20.8	22.5	4,145
	Summer	14.3	33 kV Cables	15.2	16.7	
Plimmerton	Winter	7.0	11 kV Intertie	5.9	7.2	2,537
	Summer	5.9	11 kV Intertie	4.1	5.6	
Kenepuru	Winter	18.3	33 kV Cables	11.2	12.1	2,551
	Summer	13.7	33 kV Cables	8.6	10.1	
Waitangirua	Winter	16.0	Transformer	13.4	15.6	6,394
	Summer	15.2	33 kV Cables	8.3	13.0	

Table 9-39 Northwestern Area Zone Substation Capacities

Subtransmission-level development needs for the Porirua region are outlined in the sub-sections below.

9.11.2.1 Mana

Mana zone substation is supplied via a single subtransmission circuit comprising a single 33/11 kV transformer and a single 33 kV circuit from Pauatahanui GXP. Peak demand at Mana remains within the capacity of this single subtransmission circuit.

The 11 kV buses at the Mana and Plimmerton zone substations are connected via an 11 kV bus-tie cable, providing up to 7 MVA of transfer capacity between the two zone substations. In the event that the single 33 kV circuit supplying Mana is out of service, the amount of Mana load that can be supported via the bus-tie is limited to the lesser of the:

- 7 MVA capacity of the 11 kV bus-tie cable; or
- requirement that the combined Mana and Plimmerton load does not exceed the 14 MVA capacity of the single subtransmission circuit supplying Plimmerton.

Where these limits are exceeded, it may be necessary to transfer the Mana load to adjacent zone substations, as summarised in Table 9-40.

Circuit	Season	Maximum Mana-Plimmerton Bus-tie capacity (MVA)	Peak Demand @ 2025 (MVA)	Minimum offload for N-1 @ 2025 peak (MVA)
Mana	Winter	7.0	10.9	3.9
	Summer	5.9	6.9	1

Table 9-40 Current Mana Subtransmission Constraints

Based on the estimated growth scenarios, development, and step-change growth allowances over the planning period, the load at the Mana zone substation is forecast to evolve as shown in Figure 9-24. The corresponding subtransmission capacity constraints are overlaid for comparison.

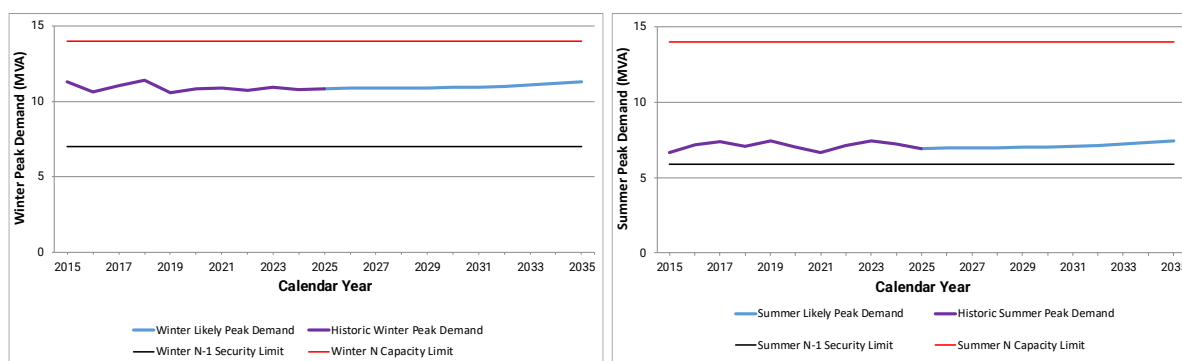


Figure 9-24 Mana Demand Forecast

Peak demand at the Mana zone substation currently exceeds the winter and summer subtransmission N-1 capacity limits, although maximum demand has remained stable since 2014. To address this existing subtransmission constraint, WELL plans to upgrade the 11 kV bus-tie between Mana and Plimmerton. The planned replacement of the Mana transformer is outlined in Section 8.

9.11.2.2 Porirua

Peak demand supplied by the Porirua zone substation exceeds the N-1 subtransmission branch ratings in both winter and summer. Following a subtransmission contingency, load is offloaded from Porirua to adjacent zone substations to maintain network security. Table 9-41 summarises the seasonal constraint levels and the corresponding minimum offload requirements.

Circuit	Season	Constraining N-1 branch rating (MVA)	Peak Demand @ 2025 (MVA)	Minimum offload for N-1 @ 2025 peak (MVA)
Porirua	Winter	16	20.8	4.8
	Summer	14.2	15.2	1.0

Table 9-41 Current Porirua Subtransmission Constraints

Based on the estimated growth scenarios, development, and step-change allowances over the planning period, the load at the Porirua zone substation is forecast to evolve as shown in Figure 9-25. The corresponding subtransmission capacity constraints are overlaid for comparison.

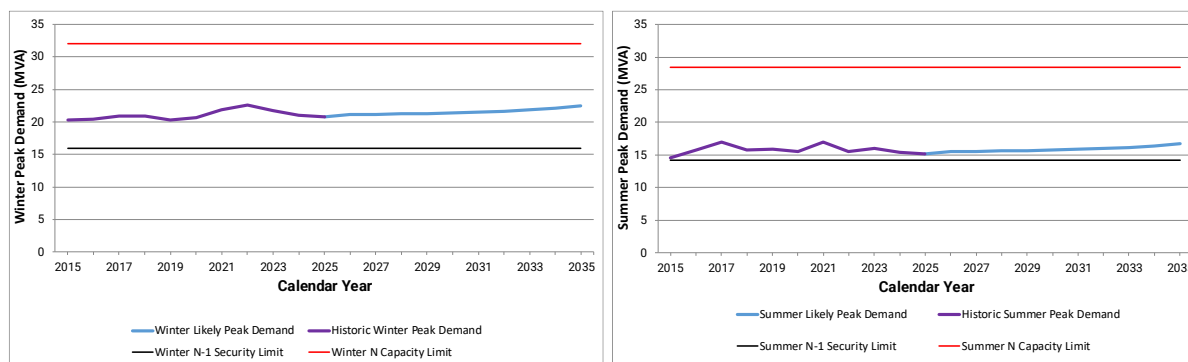


Figure 9-25 Porirua Demand Forecast

Peak demand at the Porirua zone substation exceeds the winter and summer subtransmission N-1 capacity limits, while demand has been modest to date, further increases are projected due to residential redevelopment in Porirua East.

In the short term, WELL plans to transfer load from Porirua to Kenepuru in 2026 by constructing new 11 kV feeders from Kenepuru. This investment will strengthen the interconnection between the two zone substations and improve WELL's ability to manage the existing Porirua subtransmission constraint under contingency conditions. WELL is also aware of potential future customer-driven step-change demands that may alter the load characteristics in the area and will continue to investigate longer-term solutions to address the underlying subtransmission constraint at this zone substation.

9.11.2.3 Plimmerton

The Plimmerton zone substation is supplied via a single subtransmission circuit comprising a single 33/11 kV transformer and a single 33 kV circuit from Pauatahanui GXP. Peak demand at Plimmerton remains within the capacity of this single subtransmission circuit.

The 11 kV buses at the Mana and Plimmerton zone substations are interconnected via an 11 kV bus-tie cable, providing up to 7 MVA of transfer capacity between the two zone substations. In the event that the

single 33 kV circuit supplying Plimmerton is out of service, the amount of Plimmerton load that can be supported via the bus-tie is limited to the lesser of the:

- 7 MVA capacity of the 11 kV bus-tie cabler
- Requirements that the combined Mana and Plimmerton load does not exceed the 14 MVA capacity of the single subtransmission circuit supplying Mana

Where these limits are exceeded, it may be necessary to transfer load to other zone substations, as summarised in Table 9-42.

Circuit	Season	Maximum Mana-Plimmerton Bus-tie capacity (MVA)	Peak Demand @ 2025 (MVA)	Minimum offload for N-1 @ 2025 peak (MVA)
Plimmerton	Winter	7.0	5.9	0.0
	Summer	5.9	4.1	0.0

Table 9-42 Current Plimmerton Subtransmission Constraints

Based on the estimated growth scenarios, development, and step-change growth allowances over the planning period, the load at the Plimmerton zone substation is forecast to evolve as shown in Figure 9-26. The corresponding subtransmission capacity constraints are overlaid for comparison.

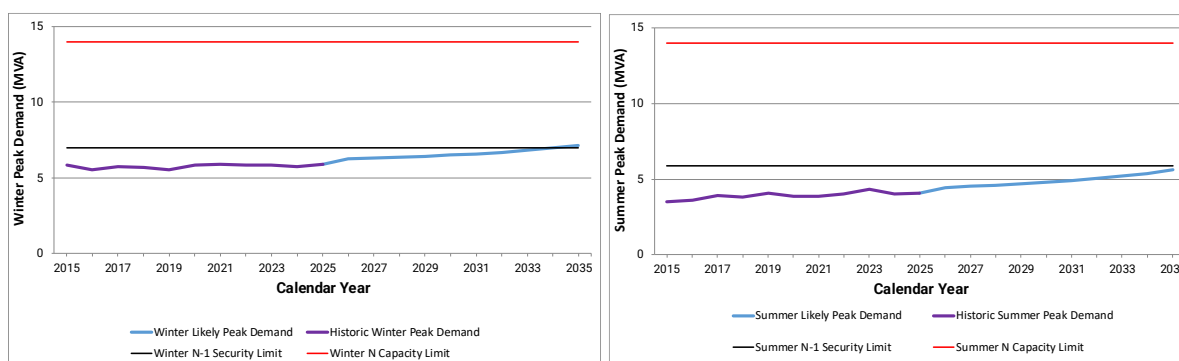


Figure 9-26 Plimmerton Demand Forecast

Peak demand at the Plimmerton zone substation is forecasted to increase significantly due to residential growth, reaching the N-1 capacity at the end of the period.

Several major residential and commercial developments are currently progressing through the Fast Track Consenting process in the area north of Plimmerton. If these developments attain consent, WELL would propose constructing a new zone substation north of Plimmerton to support the associated demand growth, subject to the Commission approving a price-path reopener for the work.

9.11.2.4 Kenepuru

Maximum demand at the Kenepuru zone substation remains within the available N-1 subtransmission capacity. Table 9-43 summarises the seasonal constraint levels and the corresponding minimum offload requirements.

Circuit	Season	Constraining N-1 branch rating (MVA)	Peak Demand @ 2025 (MVA)	Minimum offload for N-1 @ 2025 peak (MVA)
Kenepuru	Winter	18.3	11.2	0.0
	Summer	13.7	8.6	0.0

Table 9-43 Current Kenepuru Subtransmission Constraints

Based on the estimated growth scenarios, development, and step-change growth allowances over the planning period, the load at the Kenepuru zone substation is forecast to evolve as shown in Figure 9-27. The corresponding subtransmission capacity constraints are overlaid for comparison.

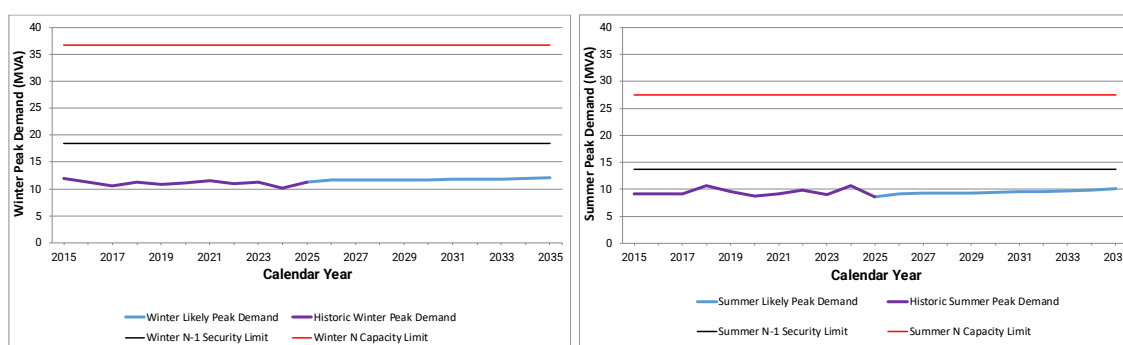


Figure 9-27 Kenepuru Demand Forecast

Peak demand at the Kenepuru zone substation has remained stable since 2014 and is forecast to remain within both the winter and summer subtransmission N-1 capacity for the duration of this planning period. WELL plans to install a new feeder from Kenepuru to the Elsdon industrial area to transfer load from the Porirua zone substation. It will continue to monitor load growth and investigate options to mitigate system constraints if any future step load growth is confirmed.

9.11.2.5 Waitangirua

Peak demand supplied by the Waitangirua zone substation remains within the N-1 branch rating of the subtransmission circuits. Table 9-44 summarises the seasonal constraint levels and the corresponding minimum offload requirements.

Zone substation	Season	Constraining N-1 branch rating (MVA)	Peak Demand @ 2025 (MVA)	Minimum offload for N-1 @ 2025 peak (MVA)
Waitangirua	Winter	16.0	13.4	0.0
	Summer	15.2	8.3	0.0

Table 9-44 Current Waitangirua Subtransmission Constraints

Based on the estimated growth scenarios, development, and step-change allowances applied over the planning period, the load at the Waitangirua zone substation is forecast to evolve as shown in Figure 9-28. The corresponding subtransmission capacity constraints are overlaid for comparison.

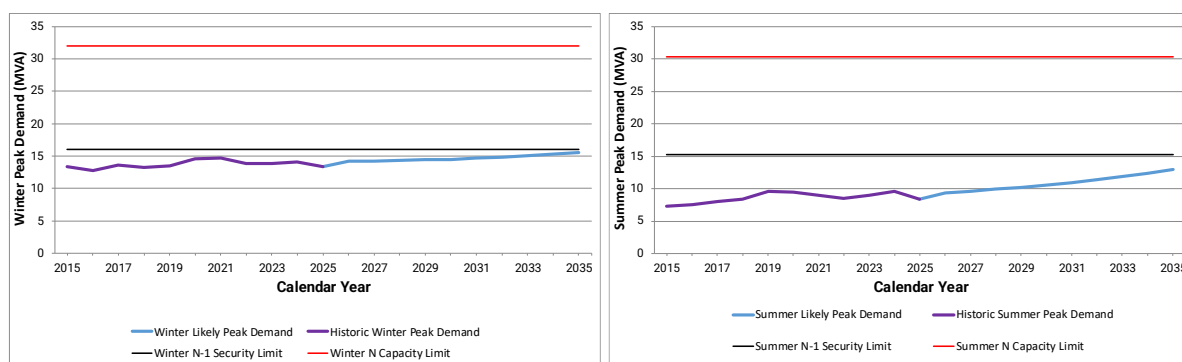


Figure 9-28 Waitangirua Demand Forecast

Peak demand at the Waitangirua zone substation is forecasted to increase, driven by new residential subdivisions in the Whitby area. Loading is expected to remain within the subtransmission N-1 capacity limits for the duration of this planning period.

9.11.3 Distribution Level Development Needs

The most critical distribution-level constraints in the Porirua area are associated with meshed ring feeders supplying a high number of customers, and with inter-zone links used for load transfer.

WELL is aware of several potential future step-change load increases identified through customer connection requests, local council District Plans, and ongoing consultation with city councils, developers, and large customers. Several property developers and businesses have also flagged developments that may introduce new loads to the network. The timing, scale, and certainty of these potential step-change demands remain uncertain and difficult to quantify; therefore, they have not been included in the assessment above. WELL will continue to monitor these developments and progress timely network solutions as individual projects become sufficiently defined and confirmed.

Distribution-level issues are initially assessed by comparing feeder loading against pre-contingent trigger values (defined in Table 9-4). Feeders exceeding these trigger values are subject to post-contingent analysis. Feeders that cannot be effectively managed via post-contingent offload to adjacent feeders are considered high-priority. Proposed solutions for these feeders typically include network augmentation (such as cable upgrades) or reconfiguration of the existing network to rebalance load and enable post-contingent operation.

Feeders that can be adequately managed through post-contingent network reconfiguration are assigned lower priority. For these feeders, WELL will continue to monitor loading trends before committing to a solution.

A summary of the 11 kV constraint analysis for the Porirua region is provided in Table 9-45. This Table identifies the pre-contingent constrained feeders, presents the outcomes of post-contingent assessments and specifies the required actions for each case.

Constrained Feeder	Constraint Year	Required Action	
		First Step	Second Step
Mana 2	Existing	Whitby cable replacement project until 2034	Mana 2 Feeder Reinforcement project
Waitangirua 11	Existing	Whitby cable replacement project	
Waitangirua 5	Existing	Monitor Load until 2027	Whitby cable replacement and Mana 2 Feeder Reinforcement projects
Porirua 12	Existing	Eastern Porirua 11 kV Reinforcement project	
Porirua 4/5	2028	Network Reconfiguration	

Table 9-45 Distribution Network Needs – Porirua

Details for each of the projects can be found in Table 9-47 and the projects to resolve existing distribution-level constraints are summarised in Section 9.11.4.3.

9.11.4 Summary of Network Development Plan

This sub-section summarises the development options available to address the network needs identified above. The development options for the Porirua region comprise a combination of individual solutions required to meet each identified need, noting that these solutions are not mutually exclusive, as in some cases a single investment may address multiple network needs.

9.11.4.1 Non-network Solutions

Before any investment in network infrastructure is considered, non-network solutions are first evaluated as potential deferral options, as discussed in Section 9.5.4.

9.11.4.2 Major Projects for the Disclosure Year Beginning 1 April 2026

Table 9-46 summarises major projects that are currently under construction or planned to commence construction over the next 12 months.

Project	Description
Kenepuru Feeders	New 11 kV feeders from the Kenepuru zone substation to Elsdon, to offload demand from the Porirua zone substation.

Table 9-46 Porirua Area Projects for the Disclosure Year Beginning 1 April 2026

9.11.4.3 Development Plan Summary

Table 9-47 summarises the development plan for the Porirua region and sets out the preferred solutions for existing and forecast network constraints. It excludes any reinforcement associated with potential major customer-initiated projects that have not yet been contractually committed. System Growth expenditure that is contingent on customer-driven work is summarised in Section 13.6. Detailed project scoping and option engineering will be undertaken as part of the project development and approval process.

Project	Description	Constraint Relieved	Target Completion	Constraint Type	Investment
Subtransmission					
Mana-Plimmerton Bus Tie	Upgrade of 11 kV bus tie between Mana and Plimmerton	Mana-Plimmerton 11 kV bus tie	2030	Security	\$5.6m
Porirua Zone substation	Upgrade of zone substation	Upgrade of zone substation	2031	Security	\$23.1m
Distribution					
New Kenepuru feeders	New 2x11 kV feeders to the Mohuia Cr to offload Porirua Zone Substation	Porirua Zone Substation, Porirua 6, Kenepuru 9	2026	Security	\$7.8m
Eastern Porirua 11 kV Reinforcement	Offload Porirua 9 and 12 to Waitangirua 6 and 10, upgrade cable sections	Porirua 12	2027	Security	\$1.7m
Whitby cable replacement	Replace strategic cable sections and split transformer low-voltage ties on Waitangirua 5 and 11	Waitangirua 5 and 11	2027	Security	\$4.7m
Mana 2 Feeder Reinforcement	New feeder link from Mana 2 to Waitangirua 3	Mana 2, Waitangirua 5	2029	Security	\$2.1m

Table 9-47 Porirua Area Development Summary

9.12 Lower Hutt NDRP

The following section presents the NDRP for the Lower Hutt region.

9.12.1 GXP Development Plan

The Lower Hutt region is supplied from the Gracefield and Melling GXPs. Gracefield provides subtransmission supply at 33 kV, while Melling supplies both at 33 kV and 11 kV. Transpower owns and operates all supply transformers and associated switchgear at these GXPs. The installed transformer capacity and the peak system demand are presented in Table 9-48, with the forecast reflecting only committed developments.

GXP	Continuous Capacity (MVA)	Transformer Cyclic Summer / Winter Capacity (MVA)	Peak Demand (MVA)	
			2025	2035
Gracefield 33 kV	1x60 + 1x85	76/80	62	67
Melling 33 kV	2x50	64/65	35	38
Melling 11 kV	2x25	32/34	25	27

Table 9-48 Lower Hutt Area GXP Capacities

The subtransmission-level development needs for the Lower Hutt region are outlined in the following sub-sections.

9.12.1.1 Gracefield

The Gracefield GXP comprises two parallel 110/33 kV transformers, nominally rated at 60 MVA and 85 MVA, providing winter N-1 cyclic capacities of 80 MVA and 113 MVA, respectively. The maximum demand on the Gracefield GXP was 62 MVA in 2025. The GXP supplies the Wainuiomata, Gracefield, Seaview, and Korokoro zone substations.

9.12.1.2 Melling

Melling comprises both a 33 kV and an 11 kV GXP. The Melling 33 kV GXP comprises two parallel 110/33 kV transformers, each nominally rated at 50 MVA, providing a winter N-1 cyclic capacity of 65 MVA. The maximum demand at the Melling 33 kV GXP in 2025 was 35 MVA. This GXP supplies the Naenae and Waterloo zone substations via double 33 kV circuits.

The Melling 11 kV GXP comprises two parallel 110/11 kV transformers, each nominally rated at 25 MVA, providing a winter N-1 cyclic capacity of 33 MVA. The maximum demand on the Melling 11 kV GXP in 2025 was 25 MVA. This GXP supplies the WELL network directly through a Transpower-owned 11 kV switchboard.

9.12.2 Subtransmission Network Development Needs

Security-of-supply constraints and associated development needs have been identified across the Lower Hutt subtransmission network. The Lower Hutt network consists of twelve 33 kV subtransmission circuits supplying six zone substations. Each supplies the 11 kV distribution network and is interconnected with adjacent zones via switched open points. The Melling 11 kV switchboard also feeds directly into the distribution network. A summary of the characteristics of each zone substation is provided in Table 9-49.

Zone Substation	Season	Subtransmission N-1 branch rating (MVA)	Constraining Branch	Peak Demand C1 (MVA)		ICP Count Dec 2025
				2025	2035	
Korokoro	Winter	15.5	33 kV Cables	17.4	17.9	3,963
	Summer	12	33 kV Cables	12.9	13.4	
Seaview	Winter	13.8	33 kV Cables	13.8	14.3	3,833
	Summer	10.6	33 kV Cables	11.0	11.2	
Waterloo	Winter	18.4	Transformer	15.4	16.0	6,483
	Summer	12.0	33 kV Cables	10.9	12.8	
Gracefield	Winter	18.4	Transformer	9.7	10.7	2,852
	Summer	18.4	Transformer	7.2	8.0	
Naenae	Winter	18.3	33 kV Cables	15.3	17.5	6,981
	Summer	13.9	33 kV Cables	9.1	9.6	
Wainuiomata	Winter	16	Transformer	17.4	19.8	7,808
	Summer	16	Transformer	10.7	11.6	

Table 9-49 Northeastern Area Zone Substation Capacities

The Lower Hutt area is characterised by a mix of established industrial areas with flat or increasing demand, older suburbs experiencing high levels of infill housing, and increased residential intensification near key public transport corridors. The subtransmission-level development needs for the Lower Hutt region are outlined in the following sub-sections.

9.12.2.1 Korokoro

Peak demand at the Korokoro zone substation currently exceeds the N-1 capacity of subtransmission circuits. Table 9-50 summarises the seasonal constraint levels and the corresponding minimum offload requirements on each circuit.

Zone substation	Season	Constraining N-1 branch rating (MVA)	Peak Demand @ 2025 (MVA)	Minimum offload for N-1 @ 2025 peak (MVA)
Korokoro	Winter	15.5	17.4	1.9
	Summer	12	12.9	0.9

Table 9-50 Current Korokoro Subtransmission Constraints

Based on the estimated growth scenarios, development, and step-change allowances applied over the planning period, the load at the Korokoro zone substation is forecast to evolve as shown in Figure 9-29. The corresponding subtransmission capacity constraints are overlaid for comparison.

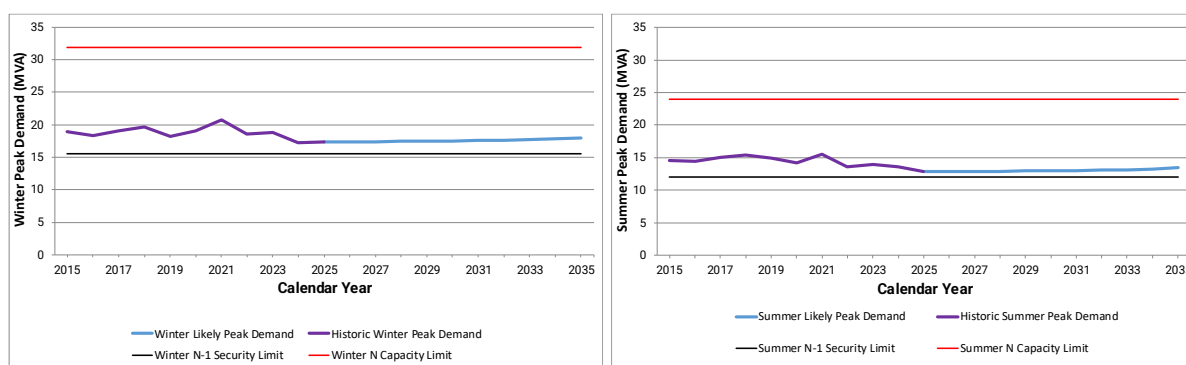


Figure 9-29 Korokoro Load Forecast

Peak demand at the Korokoro zone substation presently exceeds both winter and summer subtransmission N-1 capacity limits. WELL plans to transfer load from Korokoro, and until then will continue monitoring load growth and manage the overloading risk through operational control by shifting load to adjacent zone substations to relieve overloads.

Options for addressing the Korokoro zone substation constraint include:

- Relocating 11 kV cables away from the Korokoro subtransmission cables outside Seaview zone substation to remove a thermal pinch point.
- Redeveloping the Petone zone substation to transfer load from Korokoro across the 11 kV network.
- Replacing and upgrading the 33 kV cables and power transformers at Korokoro.

9.12.2.2 Seaview

Peak demand supplied by the Seaview zone substation currently exceeds the N-1 capacity of the subtransmission circuits in winter and summer. Table 9-51 summarises the seasonal constraint levels and the corresponding minimum offload requirements.

Zone substation	Season	Constraining N-1 branch rating (MVA)	Peak Demand @ 2025 (MVA)	Minimum offload for N-1 @ 2025 peak (MVA)
Seaview	Winter	13.8	13.8	0
	Summer	10.6	11.0	0.4

Table 9-51 Current Seaview Subtransmission Constraints

Based on the estimated growth scenarios and development within the planning period, the load at the Seaview zone substation is forecast to evolve as shown in Figure 9-30. The corresponding subtransmission capacity constraints are plotted for comparison.

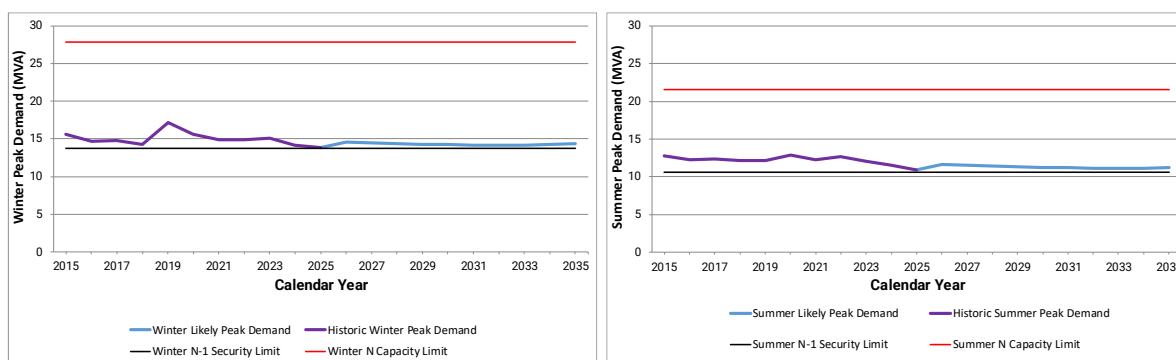


Figure 9-30 Seaview Demand Forecast

Peak demand at the Seaview zone substation currently exceeds the winter and summer subtransmission N-1 capacity limits. WELL will continue to monitor loading at the site and can manage security of supply operationally by shifting load to adjacent zone substations through the 11 kV network until any future load growth is confirmed.

9.12.2.3 Waterloo

Peak demand supplied by the Waterloo zone substation currently remains within the winter but exceeds the summer N-1 capacity of the subtransmission circuits at the end of the duration. Table 9-52 summarises the seasonal constraint levels and the corresponding minimum offload requirements.

Zone substation	Season	Constraining N-1 branch rating (MVA)	Peak Demand @ 2025 (MVA)	Minimum offload for N-1 @ 2025 peak (MVA)
Waterloo	Winter	18.4	15.4	0.0
	Summer	12.0	10.9	0.0

Table 9-52 Current Waterloo Subtransmission Constraints

Based on the estimated growth scenarios and development within the planning period, the load at Waterloo is forecast to evolve as shown in Figure 9-30. The corresponding subtransmission capacity constraints are overlaid for comparison.

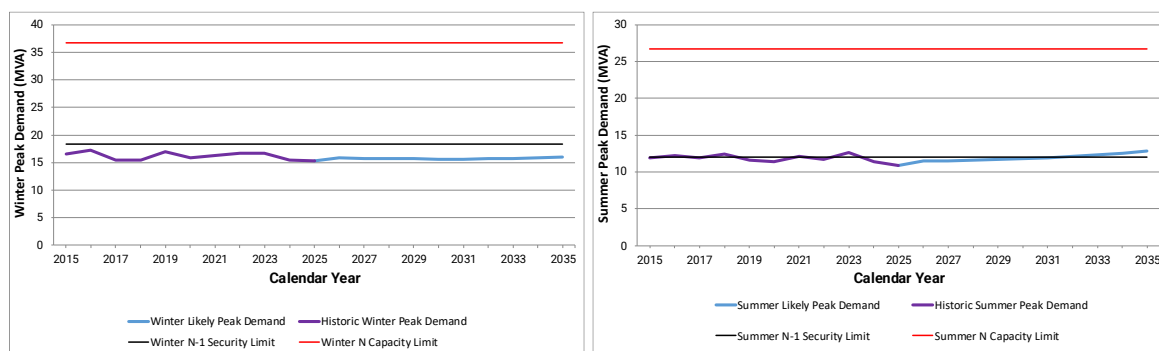


Figure 9-31 Waterloo Demand Forecast

Peak demand at the Waterloo zone substation is currently exceeding summer N-1 security limits at sub-transmission level. WELL will continue to monitor load growth and manage security of supply through targeted upgrades to increase the 11 kV transfer capacity to neighbouring zone substations, until the constraining fluid-filled 33 kV cables are replaced as part of its asset health programmes outlined in Section 8.

9.12.2.4 Gracefield

Peak demand supplied by the Gracefield zone substation currently remains within the N-1 capacity of the subtransmission circuits. Table 9-53 summarises the seasonal constraint levels and the corresponding minimum offload requirements.

Zone substation	Season	Constraining N-1 branch rating (MVA)	Peak Demand @ 2025 (MVA)	Minimum offload for N-1 @ 2025 peak (MVA)
Gracefield	Winter	18.4	9.7	0.0
	Summer	18.4	7.2	0.0

Table 9-53 Current Gracefield Subtransmission Constraints

Based on the estimated growth scenarios, development, and step-change allowances applied over the planning period, the load at the Gracefield zone substation is forecast to evolve as shown in Figure 9-32. The corresponding subtransmission capacity constraints are overlaid for comparison.

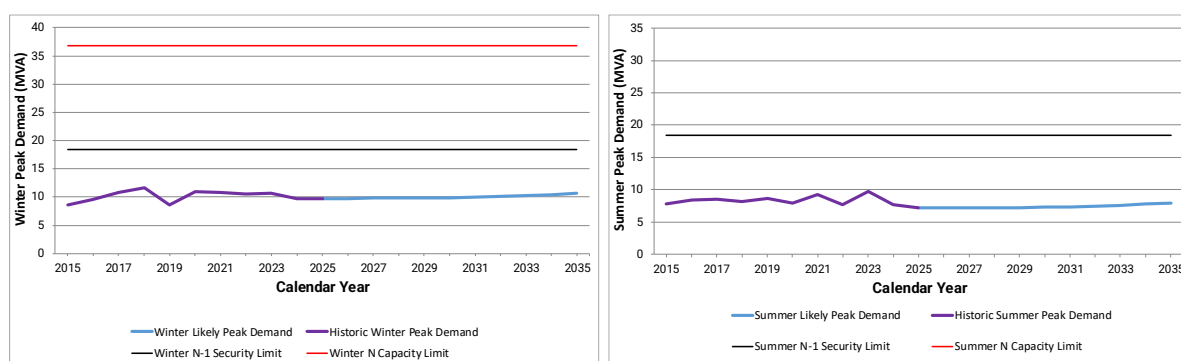


Figure 9-32 Gracefield Demand Forecast

Peak demand at the Gracefield zone substation has remained stable since 2015 and is forecast to remain within the winter and summer subtransmission N-1 capacity limits throughout this planning period.

9.12.2.5 Melling

Peak demand supplied by the Melling zone substation currently remains within the N-1 capacity of the Transpower point-of-supply. Table 9-54 summarises the seasonal constraint levels and the corresponding minimum offload requirements on each circuit.

Zone substation	Season	Constraining N-1 branch rating (MVA)	Peak Demand @ 2025 (MVA)	Minimum offload for N-1 @ 2025 peak (MVA)
Melling	Winter	34.0	21.9	0.0
	Summer	32.0	15.2	0.0

Table 9-54 Current Melling Subtransmission Constraints

Based on the estimated growth scenarios, development, and step-change allowances applied over the planning period, the load at the Melling zone substation is forecast to evolve as shown in Figure 9-33. The corresponding subtransmission capacity constraints are overlaid for comparison.

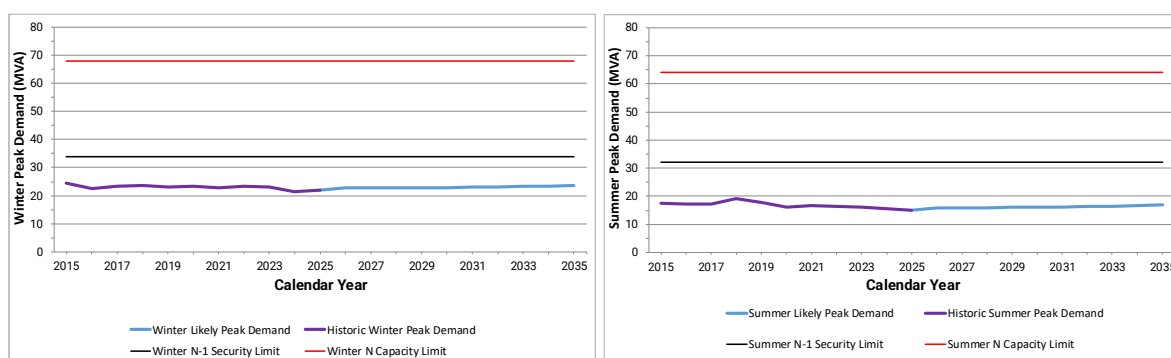


Figure 9-33 Melling Demand Forecast

Peak demand at the Melling zone substation has remained stable since 2014 and is forecast to remain within both the winter and summer subtransmission N-1 capacity limits for the duration of this planning period.

9.12.2.6 Naenae

Peak demand supplied by the Naenae zone substation currently remains within the N-1 capacity of the subtransmission circuits. Table 9-55 summarises the seasonal constraint levels and the corresponding minimum offload requirements.

Zone substation	Season	Constraining N-1 branch rating (MVA)	Peak Demand @ 2025 (MVA)	Minimum offload for N-1 @ 2025 peak (MVA)
Naenae	Winter	18.3	15.3	0.0
	Summer	13.9	9.1	0.0

Table 9-55 Current Naenae Subtransmission Constraints

Based on the estimated growth scenarios, development, and step-change allowances applied over the planning period, the load at the Naenae zone substation is forecast to evolve as shown in Figure 9-34. The corresponding subtransmission capacity constraints are overlaid for comparison.

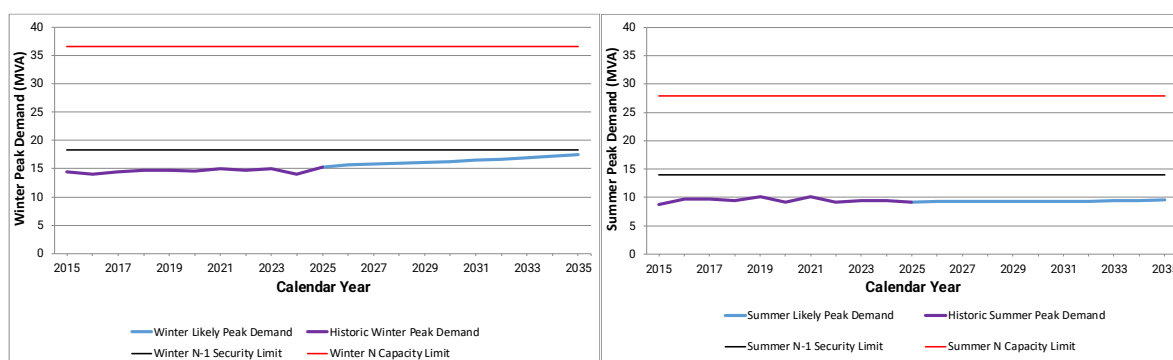


Figure 9-34 Naenae Demand Forecast

We have observed an increase in load and the forecast remains within both winter and summer subtransmission N-1 capacity limits for the duration of this planning period. Plans for the replacement of the oil-filled cables are described in Section 8.

9.12.2.7 Wainuiomata

Peak demand supplied by the Wainuiomata zone substation currently remains within the N-1 capacity of the subtransmission circuits. Table 9-56 summarises the seasonal constraint levels and the corresponding minimum offload requirements.

Zone substation	Season	Constraining N-1 branch rating (MVA)	Peak Demand @ 2025 (MVA)	Minimum offload for N-1 @ 2025 peak (MVA)
Wainuiomata	Winter	16	17.4	0.9
	Summer	16	10.7	0.0

Table 9-56 Current Wainuiomata Subtransmission Constraints

Based on the estimated growth scenarios and development within the planning period, the load at the Wainuiomata zone substation is forecast to evolve as shown in Figure 9-35. The corresponding subtransmission capacity constraints are overlaid for comparison.

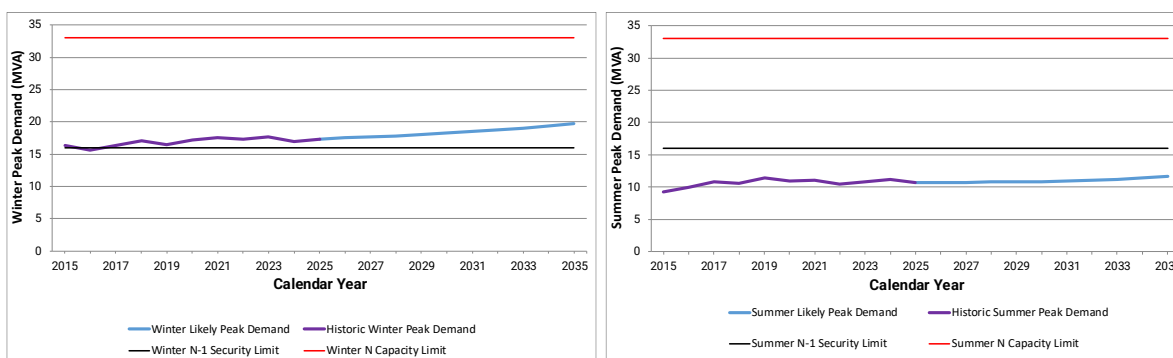


Figure 9-35 Wainuiomata Demand Forecast

Peak demand at the Wainuiomata zone substation is currently exceeding the winter subtransmission N-1 limit, with some further growth expected within the planning period. Planned projects to alleviate the subtransmission constraint are outlined in Section 9.12.4.3.

9.12.3 Distribution Level Development Needs

There are no closed-ring feeders in the Lower Hutt Area. Existing constraints are currently managed operationally through post-contingent off-loading to adjacent 11 kV feeders in the event of an outage. Over the longer term, these constraints will be addressed with targeted network upgrades. Additional feeder reinforcement projects are outlined in Section 9.12.4.2.

Development options for the Lower Hutt region comprise a combination of individual solutions required to address each identified network need. These solutions are not mutually exclusive; in some cases, a single investment may address multiple requirements across the network.

WELL is aware of several potential future step-change load increases identified through customer connection requests, local council District Plans, and ongoing consultation with City Councils, developers, and large customers. Several property developers and businesses have also signalled prospective developments that may impose additional load on the network. The timing, scale, and certainty of these potential step-change demands remain uncertain and difficult to quantify; therefore, they have not been included in the assessment above. WELL will continue to monitor these developments and progress timely solutions as individual projects become sufficiently defined and confirmed.

Distribution-level constraints are initially assessed by comparing feeder loading against their pre-contingent trigger value (as defined in Table 9-4). Feeders exceeding these trigger values are subject to post-contingent analysis. Feeders that cannot be effectively managed by post-contingent offloading to adjacent feeders are classified as high priority. Proposed solutions for these feeders typically include network augmentation (such as cable upgrades) or reconfiguration of the existing network to rebalance load and enable post-contingent operation. Feeders that can be adequately managed through post-contingent network reconfiguration are assigned a lower priority, with loading trends monitored before committing to a solution.

A summary of the 11 kV constraint analysis for the Northeastern region is provided in Table 9-57. This Table identifies constrained feeders, presents the outcomes of post-contingent assessments and specifies the required actions for each case.

Constrained Feeder	Constraint Year	Required Action	
		First Step	Second Step
Gracefield 3	Existing	Gracefield 3 reinforcement project 11 kV	
Melling 3	Existing	Monitor Load	
Waterloo 5	Existing	Malone Road and Godley Street Link project	
Waterloo 6	Existing	Waterloo 11 kV Feeder Reconfiguration project	
Wainuiomata 6	2028	Monitor Load	

Table 9-57 Distribution Network Needs – Lower Hutt

Details for each of the projects can be found in Table 9-58 and the projects to address existing distribution-level constraints are summarised in Section 9.12.4.3. While the constraints on Waterloo 5 and 6 can be managed through post-contingent network reconfiguration, there are existing low-voltage network and reliability issues in both areas. Accordingly, targeted projects have been proposed to address these issues and improve overall network resilience.

9.12.4 Summary of Network Development Plan

This sub-section summarises the development options available to address the network needs identified above.

9.12.4.1 Non-network Solutions

Before any investment in network infrastructure is considered, non-network solutions are first evaluated as potential deferral options, as discussed in Section 9.5.4

9.12.4.2 Major Projects for the Disclosure Year Beginning 1 April 2026

There are no major projects currently underway, nor are any planned to commence within the next 12 months in the Lower Hutt area. Details of projects to relocate WELL assets associated with the Riverlink project are outlined in Section 12.

9.12.4.3 Development Plan Summary

Table 9-58 summarises the development plan for Lower Hutt and sets out the preferred solutions for existing and forecast network constraints, excluding any reinforcement associated with potential major customer-initiated projects that have not yet been contractually committed. System Growth expenditure that is conditional on customer work is summarised in Section 13.6. Detailed project scoping and option engineering will be undertaken at the project development and approval stage.

Project	Description	Constraint Relieved	Target Completion	Constraint Type	Investment
Subtransmission Constraints					
Wainuiomata transformers	Replace the transformers with higher capacity units	Wainuiomata transformers	2030	Security	\$7.1m
Distribution Constraints					
Waterloo 11 kV Feeder Reconfiguration	Offload onto Melling 3 and Waterloo 11. Split low-voltage ties.	Waterloo 6	2027	Security	\$1.8m
Malone Road and Godley Street Link	Link 17 Godley Street with the Malone Street spur	Waterloo 5, Seaview 12	2027	Security	\$2.1m
Gracefield 3 11 kV reinforcement	Upgrade strategic cable sections	Gracefield 3	2028	Security	\$0.4m

Table 9-58 Lower Hutt Area Development Summary

9.13 Upper Hutt NDRP

The following section presents the NDRP for the Upper Hutt Region.

9.13.1 GXP Development Plan

The Upper Hutt region is supplied from two GXPs: Upper Hutt and Haywards. Upper Hutt GXP provides subtransmission supply at 33 kV, while Haywards supplies at both 33 kV and 11 kV. Transpower owns and operates all supply transformers and associated switchgear at these GXPs. The installed transformer capacities and the peak system demand are set out in Table 9-59, with the forecast reflecting only committed developments.

GXP	Continuous Capacity (MVA)	Transformer Cyclic Summer / Winter Capacity (MVA)	Peak Demand (MVA)	
			2025	2035
Upper Hutt 33 kV	2x40	51/53	32	37
Haywards 33 kV	2x25	25/25	21	33
Haywards 11 kV	2x30	30/30	19	22

Table 9-59 Upper Hutt Area GXP Capacities

9.13.1.1 Haywards

Haywards GXP comprises two parallel three-winding 110/33/11 kV transformers, each rated at 60/25/30 MVA, providing N-1 security of supply to the Trentham zone substation via two 33 kV circuits and to the Haywards 11 kV switchboard. The maximum demand in 2025 was 21 MVA at the Haywards 33 kV GXP and 19 MVA on the Haywards 11 kV GXP.

9.13.1.2 Upper Hutt

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 2025 was 32 MVA. The GXP supplies the Brown Owl and Maidstone zone substations via double 33 kV circuits.

9.13.2 Subtransmission Network Development Needs

The Upper Hutt subtransmission network has several identified security-of-supply constraints and associated development needs.

The Upper Hutt network consists of six subtransmission 33 kV circuits supplying three zone substations. Each zone substation supplies the 11 kV distribution network and is interconnected with adjacent zones via switched open points. The Haywards 11 kV switchboard also feeds directly into the distribution network. A summary of the characteristics of each zone substation is provided in Table 9-60.

Zone Substation	Season	Subtransmission N-1 branch rating (MVA)	Constraining Branch	Peak Demand C1 (MVA)		ICP Count Dec 2025
				2025	2035	
Brown Owl	Winter	18.4	Transformer	15.5	17.7	7,091
	Summer	12.9	33 kV Cables	9.9	12.5	
Maidstone	Winter	17.6	33 kV Cables	13.8	15.6	4,655
	Summer	10.2	33 kV Cables	9.5	9.9	
Trentham	Winter	19.1	33 kV Cables	16.8	26.2	6,614
	Summer	14.7	33 kV Cables	10.2	15.6	

Table 9-60 Upper Hutt Zone Substation Capacities

Upper Hutt region is characterised by a mix of industrial areas, established suburbs experiencing significant infill housing developments, and expanding residential subdivisions. The zone substations forecast to become constrained over the planning period are outlined below.

9.13.2.1 Brown Owl

Peak demand supplied by the Brown Owl zone substation remains within the N-1 capacity of the zone substation. Table 9-61 summarises the seasonal constraint levels and the corresponding minimum offload requirements.

Zone substation	Season	Subtransmission N-1 branch rating (MVA)	Peak Demand @ 2025 (MVA)	Minimum offload for N-1 @ 2025 peak (MVA)
Brown Owl	Winter	18.4	15.5	0.0
	Summer	12.9	9.9	0.0

Table 9-61 Current Brown Owl Subtransmission Constraints

Based on the estimated growth scenarios, development, and step-change growth allowances over the planning period, the load at the Brown Owl zone substation is forecast to evolve as shown in Figure 9-36. The corresponding subtransmission capacity constraints are overlaid for comparison.

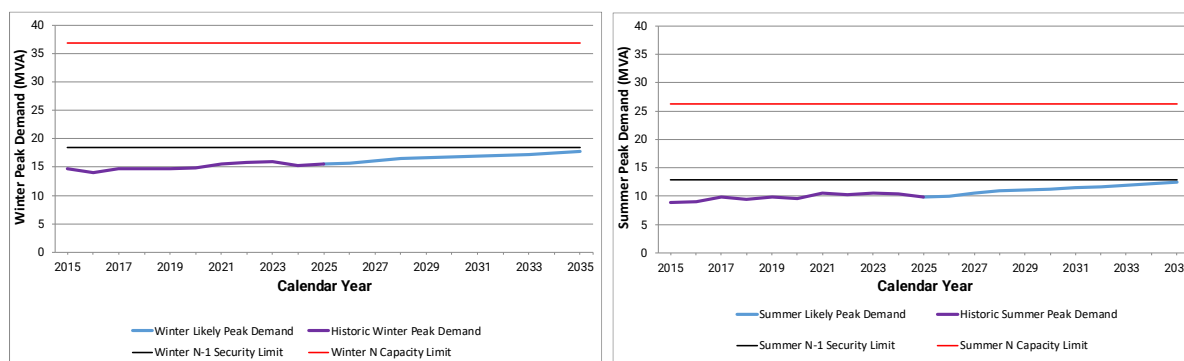


Figure 9-36 Brown Owl Demand Forecast

Peak demand at the Brown Owl zone substation is forecast to remain within subtransmission N-1 capacity throughout the planning period, but it is approaching that capacity by the end of this planning period; therefore, it requires continuous monitoring.

9.13.2.2 Maidstone

Peak demand supplied by the Maidstone zone substation currently reaches the N-1 capacity of subtransmission circuits during summer. Table 9-62 summarises the seasonal constraint levels and the corresponding minimum offload requirements on each circuit.

Zone substation	Season	Constraining N-1 branch rating (MVA)	Peak Demand @ 2025 (MVA)	Minimum offload for N-1 @ 2025 peak (MVA)
Maidstone	Winter	17.6	13.8	0.0
	Summer	10.2	9.5	0.0

Table 9-62 Current Maidstone Subtransmission Constraints

Based on the estimated growth scenarios, development, and step-change allowances applied during the planning period, the load at the Maidstone zone substation is forecast to evolve as shown in Figure 9-37. The corresponding subtransmission capacity constraints are overlaid for comparison.

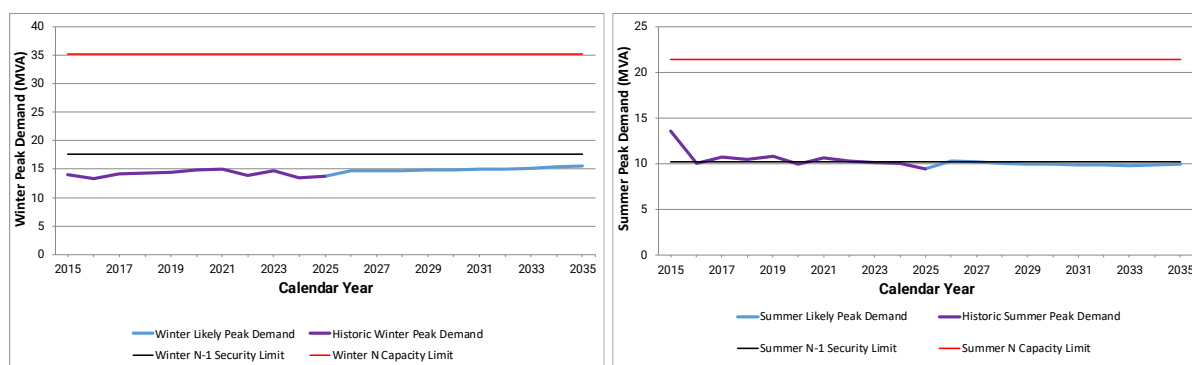


Figure 9-37 Maidstone Demand Forecast

Peak demand at the Maidstone zone substation is currently at the summer subtransmission N-1 capacity, and demand has been stable since 2016. The constraining 33 kV cables are scheduled for replacement due to asset health considerations, as outlined in Section 8.5.1. In the interim, security of supply will be managed operationally through load transfers to adjacent substations.

9.13.2.3 Haywards

Peak demand supplied by the Haywards zone substation currently remains within the N-1 11 kV capacity of the Transpower transformers. Table 9-63 summarises the seasonal constraint levels and the corresponding minimum offload requirements.

Zone substation	Season	Constraining N-1 branch rating (MVA)	Peak Demand @ 2025 (MVA)	Minimum offload for N-1 @ 2025 peak (MVA)
Haywards	Winter	30.0	17.1	0.0
	Summer	30.0	11.0	0.0

Table 9-63 Current Haywards Subtransmission Constraints

Based on the estimated growth scenarios, development, and step-change allowances applied over the planning period, the load at the Haywards zone substation is forecast to evolve as shown in Figure 9-38. The corresponding subtransmission capacity constraints are plotted for comparison.

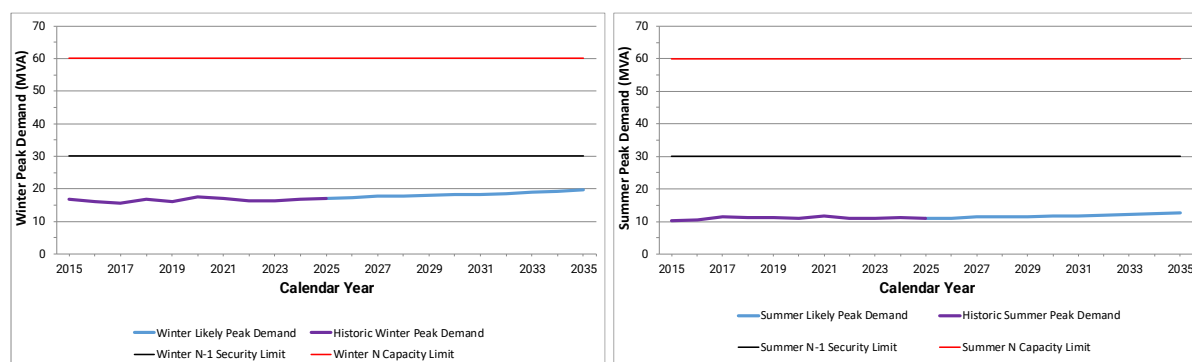


Figure 9-38 Haywards Demand Forecast

Peak demand at the Haywards zone substation has remained stable since 2014 and is forecast to remain within both winter and summer subtransmission N-1 capacity limits throughout this planning period.

9.13.2.4 Trentham

Peak demand supplied by the Trentham zone substation currently remains within the N-1 capacity of the subtransmission circuits at present but is forecast to exceed the available N-1 capacity over the planning period. Table 9-64 summarises the seasonal constraint levels and the corresponding minimum offload requirements.

Zone substation	Season	Constraining N-1 branch rating (MVA)	Peak Demand @ 2025 (MVA)	Minimum offload for N-1 @ 2025 peak (MVA)
Trentham	Winter	19.1	16.8	0.0
	Summer	14.7	10.2	0.0

Table 9-64 Current Trentham Subtransmission Constraints

Based on the estimated growth scenarios, development, and step-change allowances applied over the planning period, the load at the Trentham zone substation is forecast to evolve as shown in Figure 9-38. The corresponding subtransmission capacity constraints are plotted for comparison.

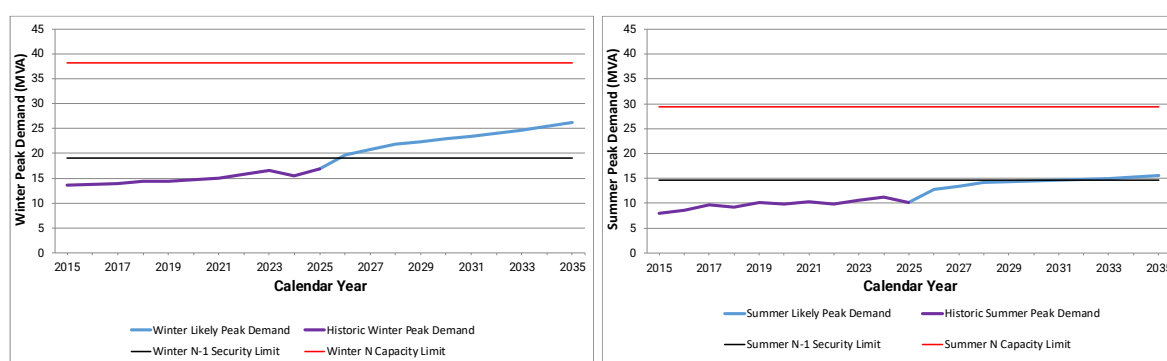


Figure 9-39 Trentham Demand Forecast

Demand at the Trentham zone substation has been increasing since 2014, driven by residential development in the area. Peak demand is forecast to exceed both winter and summer subtransmission N-1 capacity limits in the coming year. WELL proposes to replace the constraining fluid-filled 33 kV cables and will closely monitor demand growth in the interim, noting that the zone substation's ultimate capacity is limited by the 30 MVA transformer windings at the Haywards GXP.

9.13.3 Distribution Level Development Needs

There are no closed-ring feeders in the Upper Hutt Area; all feeders are operated radially in accordance with the applicable security criterion in Section 9.5.1. Existing constraints are managed operationally by post-contingent offloading of customers to adjacent 11 kV feeders in the event of an outage. Over the longer term, these constraints will be addressed through targeted reinforcement projects, with additional proposed feeder upgrades listed in Section 9.13.4.2.

WELL is aware of several possible future step-load changes arising from customer connection requests, local council District Plans, and ongoing consultation with City Councils, developers, and large customers. Several

property developers and businesses have also signalled developments that may introduce new loads to the network. At this stage, the timing and magnitude of potential step-changes remain uncertain and have therefore not been included in the assessment above. WELL will continue to monitor these prospective developments and implement timely network solutions as requirements are confirmed.

Distribution-level constraints are initially assessed by comparing feeder loading against the pre-contingent trigger value (defined in Table 9-4). Feeders exceeding these thresholds are progressed to post-contingent analysis. Feeders that cannot be adequately managed through post-contingent offload to adjacent feeders are classified as high priority, with proposed solutions typically involving network augmentation (such as targeted cable upgrades) or reconfiguration of the existing network to rebalance load between feeders and enable secure operation. Feeders that can be managed through post-contingent network reconfiguration are assigned a lower priority and will continue to be monitored before any capital solutions are committed.

Table 9-65 identifies constrained distribution feeders within the forecasted period and summarises the assessment outcomes and required actions.

Constrained Feeder	Constraint Year	Required Action	
		First Step	Second Step
Brown Owl 8	Existing	Brown Owl 8 Low-voltage Separation project	
Haywards 2822	Existing	Haywards 2822 - ongoing project	
Trentham 5	Existing	Monitor Load	
Maidstone 10	2032	Monitor Load	
Brown Owl 2	2030	Monitor Load	
Trentham 12	2028	Monitor Load	

Table 9-65 Distribution Network Needs – Upper Hutt

Details for each of the projects can be found in Table 9-67 and the projects to address existing distribution-level constraints are summarised in Section 9.13.4.3. The constraint on Trentham 12 is assessed as not manageable under post-contingent conditions. However, it only emerges at the very end of the planning period and is of limited severity. Accordingly, WELL has elected to continue monitoring feeder loading before committing to a capital solution.

In contrast, while the constraint on Brown Owl 8 is technically manageable through post-contingent switching, existing issues in the local low-voltage network constrain the effectiveness of reconfiguration. As a result, a targeted project has been proposed to remove low-voltage transformer ties in the area to improve operability and effectiveness of post-contingent switching.

9.13.4 Summary of Network Development Plan

This sub-section summarises the development options available to address the network needs identified above, which comprise a combination of individual solutions that are not mutually exclusive, as several options address multiple needs through a single investment.

9.13.4.1 Non-network Solutions

Before any investment in network infrastructure is considered, non-network solutions are first evaluated as potential deferral options, as discussed in Section 9.5.4.

9.13.4.2 Major Projects for the Disclosure Year Beginning 1 April 2026

Table 9-66 summarises major projects that are currently under construction or planned to commence construction over the next 12 months.

Project	Description
Haywards 2822	Overlay of a section of 11 kV cable along State Highway 58 on Haywards 2822 to relieve a constraint in the Moonshine Hill area.

Table 9-66 Upper Hutt Area Projects for the Disclosure Year Beginning 1 April 2026

9.13.4.3 Development Plan Summary

Table 9-67 summarises the development plan for Upper Hutt and sets out the preferred solutions for existing and forecast distribution network constraints. The plan excludes reinforcement associated with potential major customer-initiated projects that have not yet been contractually committed. System Growth expenditure that is conditional on customer delivery is summarised in Section 13.6. Detailed project planning and option engineering will be undertaken during the project scoping and approval stage.

Project	Description	Constraint Relieved	Target Completion	Constraint Type	Investment
Subtransmission Constraints					
Trentham 33 kV Cables	Replace the Trentham fluid-filled 33 kV cable	Trentham 33 kV cables	2027	Security	\$4.7m
Trentham-Maidstone Inter-tie Reinforcement	Upgrade strategic sections of cable and overhead line between Trentham and Maidstone zone substation, and add the open points to SCADA	Trentham transformers	2028	Security	\$6.4m
Distribution Constraints					
Haywards 2822	Upgrade constraining lengths of 11 kV cable	Haywards 2822	2026	Security	\$1.3m
Brown Owl 8 LV Separation	Separate low voltage ties on 11 kV feeder Brown Owl 8	Brown Owl 8	2027	Security	\$0.9m

Table 9-67 Upper Hutt Area Development Summary

9.14 Low Voltage Reinforcement

Historically, low-voltage capacity has been largely invisible to distribution network planners. This has constrained low-voltage network growth capital expenditure, as networks have not been funded to establish the tools and processes needed to provide low-voltage visibility, manage the connection of large new customer devices, or incorporate flexibility into network planning.

In response to the rapid demand growth forecast for Wellington (refer to Section 4), WELL commissioned ANSA to provide a low-voltage constraint risk tool that:

1. Establishes the hosting capacity of each low-voltage asset across residential networks.
2. Applies forecast demand to those assets.
3. Identifies the point at which each asset becomes capacity constrained.

4. Applies a standard cost model to assets requiring reinforcement.
5. Aggregates those costs to generate a 50-year low-voltage network growth capital expenditure forecast.

As DPP3 allowances did not provide funding for this work, WELL submitted an Innovation Project Allowance application and was required to fund the remaining 50% through savings from other areas of the business. Data access and data quality posed additional challenges, necessitating one-off data requests from retailers to avoid prohibitive data purchase costs and applying statistical methods to infer missing data.

Looking ahead, networks will require sustained funding to develop tools and processes that provide ongoing visibility into low-voltage networks. WELL is incorporating the ANSA solution into business-as-usual network planning processes. In parallel, it will be necessary to develop complementary capabilities, including near-real-time monitoring of capacity constraints, targeting to those assets identified by the tool as being at risk of constraint.

9.14.1 Methodology

The ANSA tool constructs a spatial model of the low-voltage network, incorporating customer ICPs, the distribution transformers supplying those connections, and the associated conductors. This model enables a range of power-flow scenarios to be applied to each low-voltage network, testing whether individual assets have the capacity to accommodate changes in electricity demand.

The model then applies alternative demand growth scenarios using Monte Carlo simulation to assess the impact on low-voltage asset capacity across the different combinations of:

- Electric vehicle uptake rates
- Gas-to-electricity transition rates
- Photovoltaic uptake rates
- Average electric vehicle charger size (1.8 kW, 3.7 kW, 7.4 kW)
- Electric vehicle charging patterns, including the proportion of electric vehicles charging at 6 pm, 9 pm, 12 am, and 3 am

The simulation produces, for each asset, the probability of exceeding its capacity threshold. Standardised reinforcement costs are then applied to those constrained assets, and the aggregated reinforcement costs inform the low-voltage growth capital expenditure forecast.

9.14.2 Study Scope

The Wellington network is a winter evening-peaking network, with residential customers driving peak demand. Accordingly, the study focused on residential low-voltage networks. A total of 1,860 residential-urban low-voltage networks were assessed, representing the majority of residential customers. Rural networks below 100 kVA were excluded, as they typically supply fewer customers, exhibit higher design after diversity maximum demand and are less likely to have reticulated gas connections. Commercial and industrial low-voltage networks were also excluded, as they are unlikely to contribute materially to winter evening peak demand. In these networks, demand growth is more likely to trigger customer-initiated projects, enabling constraints to be identified and addressed ahead of any capacity shortfall.

WELL's 2024 AMP model has been updated and enhanced to:

- Utilise significant improvements in low-voltage GIS data quality arising from the previous study, including modelling of low-voltage ties between transformers.
- Incorporate photovoltaic hosting capacity results into the capital expenditure forecast.
- Update electric vehicle and gas-to-electricity transition uptake rates to reflect the material reductions observed over the past 12 months.
- Reflect regional variation in electric vehicle uptake (see Section 4.2.1.1).
- Apply WELL's standards for cyclic winter-peak rating of assets relative to their nameplate ratings.

9.14.3 Assumptions and Limitations

The following assumptions and limitations apply to the study:

1. Asset replacement may be driven by factors other than capacity constraints, including asset age and condition. This study considers only reinforcement required due to load growth.
2. It is assumed that no mechanical constraints exist when upgrading conductors. In practice, upgrades may be limited by wind loading and other structural conditions.
3. The identification of customers with gas connections, the estimation of gas-related demand, and the assignment of that demand within the modelling are subject to limitations arising from imperfect information regarding gas consumers status, end-use appliances (for example, water heating, cooking, and space heating), and the technologies that may replace those uses (such as conventional electric hot water cylinders, heat pump cylinders, or continuous electric flow heating).
4. The capital expenditure forecast used for this AMP reflects the expenditure required to address those constraints assessed by the model as having a 50% probability of occurring. The capital contribution of each constraint has been adjusted accordingly, such that, on average, only half of the modelled constraints are expected to materialise.

9.14.4 Results

The study tested a range of electric vehicle charging behaviours and demand growth scenarios, as summarised in Table 9-68. These scenarios reflect varying assumptions regarding electric vehicle uptake, gas-to-electricity transition rates, and photovoltaic adoption across the Wellington network.

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 9-68 Uptake Rates Applied to ANSA Low Voltage Growth Scenario

Figure 9-40 presents the cumulative low-voltage capital expenditure to 2050 for the four scenarios, including the scenario presented in the 2025 AMP. There has been a material reduction in the forecast capital expenditure over the period relative to the 2025 AMP, reflecting the impact of the increase in the upper voltage limit from +6% to +10% implemented through the Electricity (Safety) Amendment Regulations 2025, allowing significantly more PV to be accommodated within the existing low voltage network capacity.

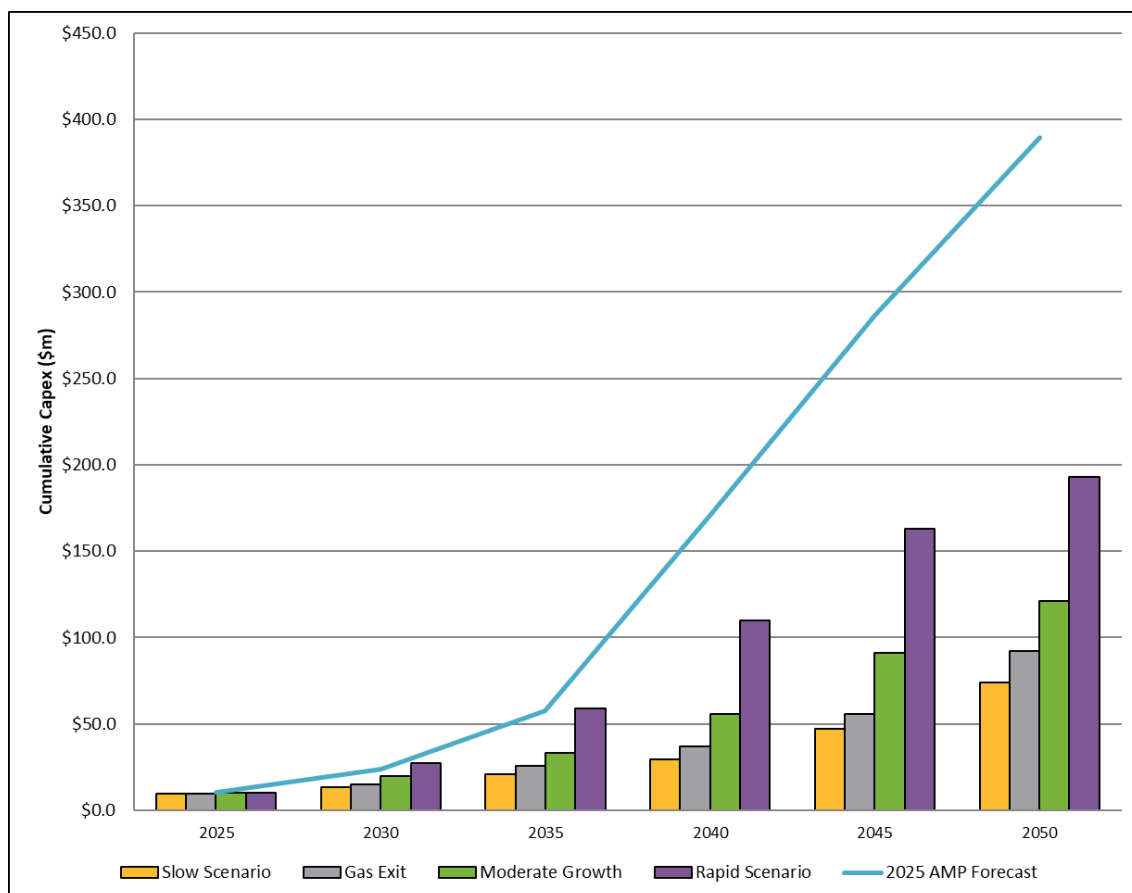


Figure 9-40 Cumulative ANSA Low Voltage Reinforcement Capex by Regulatory Period and Growth Scenario

The modelling framework enables sensitivity testing of key assumptions within the forecast. Figure 9-41 compares the present value of the low-voltage reinforcement capital expenditure over the 50-year study period under the “Moderate Growth” scenario, focusing on networks assessed as fully constrained within the study horizon.

The comparison examines two average electric vehicle charger sizes and two charging behaviours: a base case in which 50% of electric vehicle charging occurs at 6 pm, and an alternative, shifted charging profile that moves the majority of charging outside of the evening peak. The result illustrates the material influence that charging behaviour can have on the network’s capacity to accommodate electric vehicle uptake and, consequently, on the long-term cost to customers.

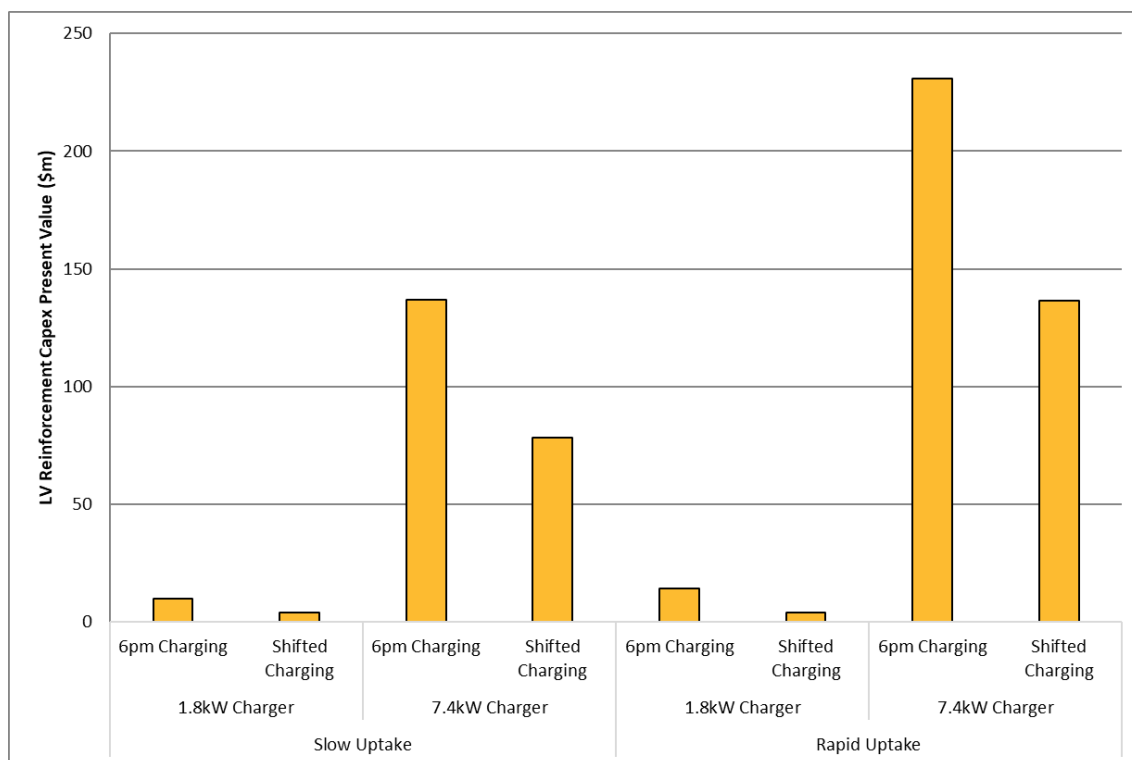


Figure 9-41 Residential EV Charging Scenario Impact on ANSA Low Voltage Reinforcement Capex

9.14.4.1 AMP Scenario

The base scenario applied to the ANSA low-voltage reinforcement forecast in this AMP is founded on the following assumptions:

- Seasonal winter transformer ratings are applied at 120% of nameplate capacity.
- An average electric vehicle charger size of 3.7 kW is assumed.
- A 6 pm electric vehicle charging profile with 50% charging diversity is adopted. This provides a benchmark against which the benefits of shifting electric vehicle charging outside the evening peak can be assessed.
- An average photovoltaic inverter size of 5 kW is assumed, with Volt-VAR control not mandated and an upper voltage limit of +10%.
- A slow gas-to-electricity transition is assumed, under which biogas replaces fossil gas for customers remaining connected to the gas network, alongside moderate electric vehicle uptake and moderate photovoltaic adoption. The resulting penetration rates are summarised in Table 9-69.

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 9-69 Penetration Rates Used in Base AMP Low Voltage Reinforcement Scenario

Figure 9-42 presents the ANSA forecast of the capital expenditure required to address the constraints identified under the base AMP scenario through to 2050. The total from the 2025 modelling undertaken with an upper voltage limit of 6% is included for comparison, showing the benefit of the increase of the upper voltage limit to +10%.

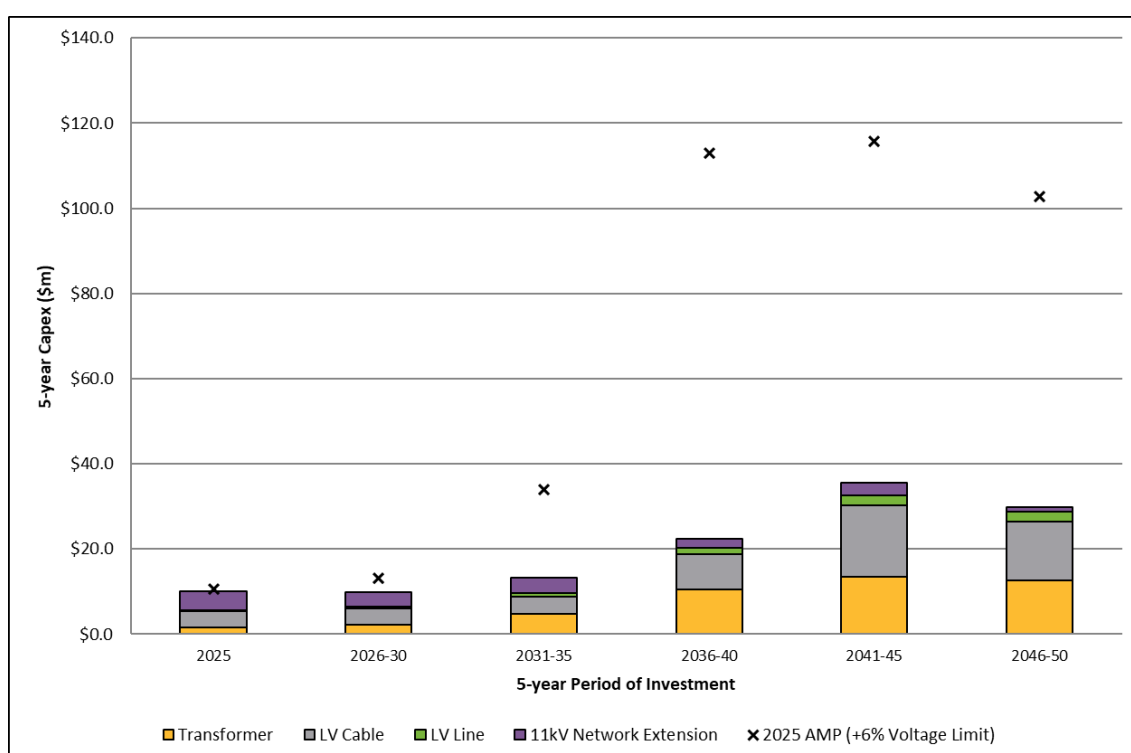


Figure 9-42 Forecast Low Voltage Reinforcement Capex to 2050 for Base AMP Scenario

As the ANSA model is probabilistic, its outputs do not directly trigger investment. Rather, the results are used to generate a heat map identifying areas where capacity constraints are likely to emerge, as illustrated in Figure 9-43. This heat map is then used to target further investigation to confirm whether investment is required. This targeted approach avoids the cost of installing monitoring equipment on all transformers or procuring network-wide coverage of smart metering data, instead focusing expenditure on those areas most likely to require reinforcement. Further detail is provided in Section 11.2.2.

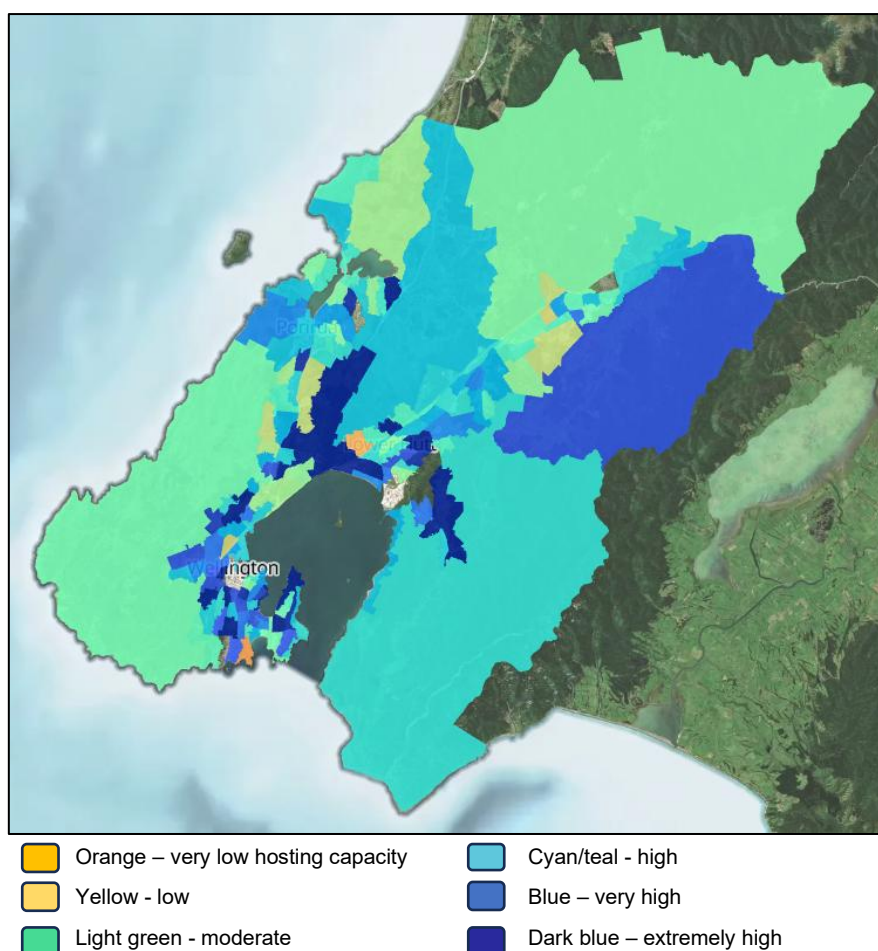


Figure 9-43 Example ANSA Heat Map
(Median 6 pm EV Hosting Capacity at SA2 Level) Image © ANSA® 2025

9.15 Regulatory Considerations for Network Development and Reinforcement

The network development and reinforcement requirements outlined in this section demonstrate that network development over the next ten years is shaped not only by forecast demand growth, but also by uncertainty regarding the pace and location of electrification, the potential for step-change loads, and the long lead times required to deliver major reinforcement projects. Efficient planning in this environment requires maintaining optionality, progressing build-ready solutions, and carefully sequencing investment so that capacity is delivered when required, neither prematurely nor reactively.

The investment profile that emerges from this approach is inherently uneven, with reinforcement needs arising in discrete locations and often converging with end-of-life asset renewal. These characteristics do not always align well with the DPP's fixed and smoothed allowance structure. While the DPP framework supports incremental growth and routine reinforcement, it provides limited flexibility to efficiently stage or coordinate larger, condition-driven and demand-contingent investments across planning periods.

Taken together, the drivers identified in this section indicate that a more flexible regulatory framework is likely required to deliver the network development programme efficiently over the medium term. A CPP is likely to better align revenue with efficient investment timing, support coordinated renewal and reinforcement activities, and provide a durable mechanism for managing uncertainty while maintaining security-of-supply and service-quality obligations. In this way, revenue allowances can support the prudent and efficient delivery of network development outcomes that are in the long-term interests of consumers

9.16 System Growth and Reinforcement Summary for 2026-2036

Based on the details in the sections above, WELL's forecast total capital expenditure for system growth and security of supply over the planning period is summarised by asset category in Table 9-70.

Asset Category	Disclosure Year Beginning 1 April									
	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035
Subtransmission	5,710	348	6,447	7,124	22,358	21,415	10,567	7,031	-	-
Zone Substations	11,945	9,564	5,217	6,277	19,690	11,052	335	10,059	7,473	9,437
Distribution Poles and Lines	253	-	-	-	-	-	-	-	9,463	-
Distribution Cables	30,257	24,642	19,486	7,830	1,405	10,343	29,916	17,541	14,683	20,892
Distribution Substations	670	-	-	-	-	-	-	-	-	-
Distribution Switchgear	-	-	-	-	-	-	-	-	-	-
Other Network Assets	-	-	-	-	-	-	-	-	-	-
Total	48,835	34,553	31,151	21,231	43,453	42,810	40,818	34,631	31,620	30,328

Table 9-70 Capital Expenditure Forecast by Asset Type
(\$K in constant prices)

10 Support Systems

This section describes WELL's support system assets and their role in enabling the safe, reliable, and efficient operation of the electricity distribution network. While these assets are not directly part of the network itself, they are critical to supporting core network activities, including asset management, network operations, field service delivery, customer service, and regulatory compliance.

Since its acquisition by Vector, WELL has been transitioning toward a more digitally enabled operating model, in which operational technology (OT) and data-driven insights play a greater role in network management and decision-making. At the time of acquisition, WELL inherited limited internal IT capability and relatively few operational systems, reflecting the outsourced IT arrangements in place and the fact that many of Vector's supporting systems did not transfer with the network. As a result, WELL's early operating environment focused primarily on maintaining real-time operational control and core fleet and asset maintenance records, with limited capability to capture, store, and analyse operational data trends over time.

WELL is now working to address these gaps by developing the systems, processes, and specialist capabilities needed to support a more integrated, data-driven asset management framework. This includes strengthening internal digital capability, improving the integration of operational systems, and building the analytical tools needed to extract greater value from real-time network data. This transition represents an important step in enabling more proactive planning, operational optimisation, and informed decision-making as the network evolves.

The following categories of operational and supporting assets underpin this transition and WELL's ability to manage and operate the network effectively:

- Information and communications technology (ICT) systems, including ICT programmes, applications
- ICT hardware
- Data-Driven Operations
- Real-Time Analytics Capability
- Plant and machinery
- Land and buildings

The support systems described in this section are critical enablers of safe network operations, regulatory compliance, asset management, customer service, and financial control. While not directly part of the electricity network, these systems underpin SCADA monitoring, outage management, maintenance planning, billing accuracy, cybersecurity defence, and enterprise risk management. As the network becomes more digitalised and increasingly reliant on real-time data, the resilience, security, and capability of these systems assume greater operational and safety significance.

Several core platforms, including enterprise resource planning (ERP), billing, geographic information system (GIS), and asset management systems, are approaching vendor support limits or require significant uplift to address cybersecurity, data governance, and integration requirements. These investments are largely non-discretionary and driven by system obsolescence, regulatory expectations, and increasing exposure to cyber

risk, rather than by incremental service enhancements. In addition, system replacements tend to be high-value, discrete projects delivered within defined windows rather than smooth annual expenditure profiles.

Under a fixed, smoothed allowance framework, the ability to efficiently align funding with system replacement cycles may be constrained, particularly when multiple core platforms require renewal within the same regulatory period. Incremental deferral of such investments increases operational risk, cybersecurity exposure, data integrity risk, and the likelihood of unplanned system failure or vendor support withdrawal. Conversely, prematurely staging replacements to fit within constrained allowances may increase whole-of-life costs and integration risk.

In this context, a CPP is likely to provide greater flexibility to align revenue allowances with the efficient timing of major system renewals, cybersecurity enhancements, and resilience upgrades. This would support prudent risk management, maintain compliance and operational integrity, and ensure that WELL's digital and enterprise platforms remain fit for purpose as the network transitions to a more complex and data-intensive operating environment.

10.1 WELL Information and Communications Technology

ICT systems are a core enabler of efficient network operations and prudent asset management. This section provides an overview of the primary ICT systems used by WELL and describes the planned renewal and replacement activities over the life of the AMP to ensure these systems remain fit for purpose and cost-effective.

10.1.1 Asset Management

Historically, WELL's operational focus has been on 11 kV and higher-voltage networks, where visibility and control have been sufficient to manage network security and performance. Real-time management of the low-voltage network was not previously required, as demand patterns were relatively predictable and largely unidirectional. However, this is changing as customers increasingly install CER, including solar generation, battery storage, electric vehicles, and other electrified loads. These technologies enable customers to both generate and consume electricity in new ways, placing pressures on parts of the low-voltage network that were not originally designed to accommodate two-way power flows or highly variable demand.

In response, WELL expects that greater low-voltage monitoring, analytics, and operational capability will be required in the future to maintain network security and performance. This will support more active management of emerging constraints and enable the development of pricing structures that better reflect network conditions. Improved low-voltage visibility and cost-reflective pricing signals will help ensure that the costs associated with managing increased electrification and CER integration are allocated fairly, reducing the risk of cross-subsidies between early adopters of behind-the-meter technologies and customers without these capabilities. At the same time, these mechanisms will help guide CER behaviour, through tariffs and other price signals, so that customer actions support efficient network utilisation and reduce unnecessary network investment.

The subsections that follow outline the key IT systems and digital platforms that support WELL's asset management, operational decision-making, and evolving network management capabilities.

10.1.1.1 SCADA

WELL uses the GE PowerOn Advantage supervisory control and data acquisition (SCADA) system to manage the 11kV network in real time. SCADA provides monitoring, control, and operational visibility across the 11 kV and 33 kV networks.

Currently, the low-voltage network (400 V or below) is not monitored via SCADA. WELL is investigating opportunities to introduce low-voltage telemetry as distribution substations are upgraded or replaced, to improve network visibility and support future operational requirements. Congestion from CER will require SCADA functionality at low voltage (SAPN)

WELL receives customer outage reports primarily from retailers via email and phone, as well as directly from customers contacting the WELL Contact Centre. All reported outages are recorded in the GE PowerOn Call Taker system, which supports the Contact Centre's outage management process. During storms or other major events, additional Contact Centre staff are deployed and use the Contact Suite to ensure customer reports and updates are promptly entered into the Call Taker system, maintaining accurate and timely outage records. Call Taker interfaces with the contracted field service provider's dispatch system to enable the timely allocation of field crews for fault response. Once work is completed, job status and closure information are electronically fed back into the Call Taker system.

The WELL contact centre uses this information to update outage details for publication on the WELL website and outage application, ensuring customers receive timely and accurate information about network interruptions.

The SCADA platform is critical to real-time network monitoring and control and underpins safe switching, outage management, and operational security. As operational technology becomes increasingly interconnected and cyber exposure grows, maintaining a resilient, supportable, and secure SCADA environment is essential to managing safety and reliability risks. SCADA upgrades and platform transitions are typically high-value, discrete investments delivered within defined implementation windows to manage risks related to system integration, data migration, and operational continuity. Deferring renewal or security uplift beyond the efficient timing thresholds increases exposure to operational failures, cybersecurity compromises, and reduced visibility across the network.

While WELL's current operational technology environment provides strong visibility and control across the high and medium-voltage levels, limitations remain at the low-voltage level. As distributed and customer energy resources continue to increase, gaps in low-voltage network observability, real-time congestion management, and end-to-end system integration are becoming more pronounced. In particular, the absence of SCADA-enabled low-voltage telemetry constrains proactive fault detection, voltage management, and timely response to emerging congestion and operational complexity at the network edge.

To address these gaps, WELL plans to progressively integrate low-voltage monitoring and control capabilities, expand telemetry deployment, and closer integration between SCADA and other systems.

However, the scale and timing of this investment must be assessed in light of the constrained allowances under DPP4. The framework provides limited flexibility to fund step changes in digital capability, telemetry expansion, and enabling systems alongside core renewal and resilience programmes. As low-voltage visibility and control become increasingly critical to maintaining reliability and accommodating distributed energy resources, the required expenditure is likely to exceed what can be efficiently delivered within the existing allowance envelope.

In this context, WELL considers it likely that a CPP will better align revenue with the efficient level and timing of investment. A CPP would provide a more appropriate mechanism to fund the necessary step change in operational technology capability, while maintaining service standards and supporting the long-term interests of consumers.

10.1.1.2 Planned Outage Management

EDNAR is used to manage network access requests and planned outages. All planned outage requests are submitted electronically to EDNAR by the contracted field service providers and reviewed by WELL's outage planning team before switching instructions are prepared in PowerOn Advantage.

EDNAR provides automated notification of planned outages to retailers and publishes notices of intended interruptions on WELL's website, supporting timely communication with stakeholders and customers and enabling planned outages to be identified, managed, and communicated.

While EDNAR provides a robust platform for managing planned outages and network access requests, further enhancements are required to support increasing network complexity and rising customer expectations. Current constraints include limited integration with real-time network status, restricted automation of outage impact assessments, and a continued reliance on manual coordination between EDNAR and SCADA.

To address these gaps, WELL plans to progressively enhance EDNAR's functionality by improving integration with PowerOn Advantage and SCADA, increasing automation where feasible, and enhancing the management of alternative dates for planned outages to provide greater flexibility and transparency for customers.

10.1.1.3 Load Management System

The Catapult load management system (LMS) manages hot-water load control and the switching of streetlights and other controllable loads through WELL's ripple control system, supporting peak-demand management and the efficient operation of the network.

10.1.1.4 Geographic Information System

The GIS provides a spatial representation of WELL's fixed network assets overlaid on a map of the supply area. WELL uses the GE Electric Office GIS application to support the planning, design, and operation of the distribution network, and it serves as the primary repository of network asset information.

The GIS interfaces with the maintenance management system (SAP PM), the billing system⁴², the contracted field service provider's works management system, and the B4UDig underground asset location platform. These integrations support the sharing of network asset and connectivity information across operational, planning, and customer service functions.

Looking ahead, further development of the GIS will be required to better support single-premise fault identification and wire-down response coordination. Enhancing GIS connectivity and integration with operational systems will enable more accurate identification of affected customers and assets, improve the coordination of field responses, and support faster restoration following network faults. Strengthening these

⁴² Currently, Gentrack is to be replaced by August 2026.

capabilities will help ensure that operational teams and service providers have access to consistent, location-specific network information when responding to customer outages and safety-related incidents.

WELL routinely shares its GIS data with external parties, subject to appropriate data usage agreements. Over the past 12 months, this has included the Wellington underground asset register,⁴³ other infrastructure providers, and organisations investigating opportunities for embedded generation.

WELL's GIS platform lacks SCADA integration and offers only limited manual integration with the billing system, resulting in manual workflows, inconsistent asset data, and increased operational risk, particularly during outages and storm responses. Gaps in data quality and naming standards currently constrain the ability to automate network models and enable GIS-driven SCADA operations. WELL intends to address these gaps by standardising data models and asset conventions, strengthening change-capture processes, and ensuring close integration with GIS, billing, and SCADA systems. These initiatives will reduce technology risk, improve data integrity, and enable a more integrated, efficient, and resilient operational technology environment over time.

The GIS platform underpins asset data integrity, network planning, outage management, regulatory reporting, and coordination with external infrastructure providers. As integration requirements increase and reliance on accurate spatial and connectivity data grows, maintaining a resilient, supportable GIS platform becomes critical to safe and efficient network operations. Replacement or a major upgrade of the GIS system is typically a high-value, discrete investment, delivered within defined implementation windows, to manage data migration, system integration, and operational continuity risks. Deferring such investment beyond the efficient timing thresholds increases exposure to data integrity risks, integration failures, and operational inefficiencies.

Under a fixed, smoothed allowance framework, aligning funding with externally driven system lifecycle requirements may be constrained. In this context, a CPP is likely to provide greater flexibility to align revenue allowances with the efficient timing of GIS renewal, supporting prudent risk management, whole-of-life efficiency, and the continued delivery of reliable network services.

10.1.1.5 Drawing Management System

WELL stores all GXP, substation, and system drawings, together with historical asset information diagrams, in M-Files, which serves as WELL's drawing management system (DMS), in both PDF and CAD formats. The DMS supports controlled access and approval workflows, ensuring field staff and contractors can reliably access current, approved drawings to support safe and efficient work on the network.

10.1.1.6 Power System Modelling

DIgSILENT PowerFactory is used to model and simulate the electricity distribution network, supporting load flow analysis for development planning, contingency planning, and protection studies. The PowerFactory database contains detailed connectivity and asset rating information.

To maintain model accuracy, the database is manually updated quarterly to incorporate recently commissioned assets and network augmentations. Updated models are regularly distributed to design consultants to ensure consistency across commissioned studies.

⁴³ <https://nzuar.org/>

10.1.1.7 Cable Rating Modelling

CYMCAP is used as WELL's cable rating model to determine the thermal ratings of underground cables across all voltage levels, informing network capacity assessments, contingency analysis, and replacement planning for existing assets and proposed developments.

10.1.1.8 Low-voltage Drop Modelling

LVDrop is used to model low-voltage electrical networks to assess voltage drop and conductor and transformer loading under forecast demand conditions. The model incorporates cable, conductor, transformer, and after-diversity maximum demand ADMD data and ratings, supporting efficient low-voltage network design.

LVDrop is used for new subdivision reticulation designs and is integral to WELL's customer connection and network planning process.

WELL recognises that LVDrop is not currently being utilised to its full potential and intends to evolve its role into a dynamic forecasting tool. By integrating transformer (TX) data and leveraging AI-driven analytics, LVDrop could proactively predict emerging network constraints and forecast periods where network capacity is limited. This capability would enable the development of clearer, more timely pricing signals that reflect the underlying cost of network utilisation across different times and locations.

Over time, these signals could help guide customer behaviour and connection decisions, encouraging flexible demand, such as EV charging or controllable loads, to shift away from constrained periods or locations. In doing so, pricing signals would support more efficient use of existing network capacity, reduce the need for premature reinforcement, and improve the alignment between customer choices and the costs of providing network capacity. This would ultimately support more responsive and cost-effective planning and connection outcomes as the network continues to evolve.

10.1.1.9 Protection Relay Configuration Management Database

DlgSILENT StationWare is used as a centralised protection-setting database and device management tool, storing relay and device information, parameters and settings files that support the safe and reliable operation of the network's protection systems.

As part of WELL's digital roadmap, developing an automated workflow for controlled access and approval of protection settings is being considered. This would include migrating the StationWare database to a secure cloud-based repository, strengthening cybersecurity, improving system resilience, and enhancing governance and auditability of protection configuration management.

10.1.1.10 Maintenance Management System

WELL uses the SAP Plant Maintenance (SAP PM) module as its core maintenance management system (MMS) to plan and manage maintenance activities and to capture asset condition data for both preventative and corrective work. The system issues maintenance work packs electronically to service providers, supporting efficient, consistent field delivery.

Maintenance outcomes are returned electronically, either through an integration module for high-volume tasks or via a web interface for lower-volume activities. Asset data in is synchronised with the GIS, enabling maintenance activities to be grouped spatially and improving operational efficiency.

SAP PM is hosted in Melbourne by WELL's sister company in the CK Infrastructure Holdings Limited group. WELL is evaluating options for the future replacement of the SAP PM system to ensure long-term sustainability, resilience, and alignment with evolving operational and information requirements.

10.1.1.11 Supplier Management

WELL has implemented State of Flux as its supplier management tool. For project consolidation, key reporting areas, financial reporting across contracts, and improving visibility of supplier performance and expenditure. Further work is underway to extend the platform's capability to support the full lifecycle management of network projects, including enhanced contract oversight, performance tracking, and integration with broader project delivery processes.

Delivering these additional capabilities will require further system configuration, integration with other enterprise platforms, and ongoing process development, as well as access to personnel with specialist skills in digital systems, data integration, and supplier performance management. Under the DPP4 allowances, funding for such step changes in digital capability is limited, particularly where they coincide with other operational technology and system upgrade programmes.

In this context, a CPP provides a mechanism to align revenue allowances with the efficient timing and scale of these investments, supporting improved supplier management, stronger project governance, and more effective delivery of WELL's capital programme in the long-term interests of consumers.

10.1.1.12 Service Request Portal

WELL has implemented a customer connection portal using Microsoft, enabling retailers to submit requests for new connections and changes to existing connections through a standardised digital interface. This has improved customer service outcomes by reducing manual processing and increasing the efficiency and consistency of connection request management.

WELL intends to continue developing the portal in line with emerging best practice, including approaches used by UK Power Networks (UKPN), where approval processes draw on multiple datasets to enable faster confirmations. Future enhancements may also include functionality to automate elements of the approval workflow, such as signalling when a required customer deposit has been received and triggering progression to the next stage of the design process. These improvements are intended to further streamline connection processes while maintaining appropriate governance and control.

Despite the progress made, gaps remain in WELL's current digital and workflow solutions, particularly in automation, integration, and the speed of customer connection approval processes. WELL recognises the need to further develop its systems in line with best practices, enabling the integration of multiple datasets to support faster confirmation and approval of connection requests.

As part of its future roadmap, WELL is considering implementing a tool that can not only automate approval steps and provide real-time status updates, such as signalling when a customer deposit has been received, thereby triggering the next stage of the design process. This more integrated approach would streamline internal workflows, reduce processing timeframes for customers, and ensure that governance, auditability, and security standards are upheld throughout the approval and connection lifecycle.

10.1.1.13 Billing System

Gentrack is used to manage ICP and revenue data, reconcile GXP information, and deliver billing and connection services. The system is populated from and synchronised with the central national ICP registry to ensure data accuracy and consistency.

Gentrack interfaces with the GIS and PowerOn Advantage systems to provide visibility of customers affected by planned and unplanned network outages. It also interfaces with WELL's SAP financial system to support billing and financial processing.

The Gentrack system is currently hosted in Melbourne by WELL's sister company within the CK Infrastructure Holdings Limited group. As part of WELL's forward-investment planning and risk-mitigation strategy, the billing system is being replaced. This change is to better align the billing platform and ICP management with WELL's operational and regulatory requirements. The replacement system is expected to be fully operational by August 2026.

In addition to enhanced billing capabilities, WELL recognises the need for a solution that extends beyond traditional revenue management. The proposed system would integrate congestion forecasting and billing functionality, enabling the signalling of Time-of-Use (TOU) periods or operating envelope periods against congestion-period and dynamic pricing. This integration would enable customers to receive pricing signals that more accurately reflect underlying network conditions, providing clearer information about when and where capacity constraints exist while supporting more efficient network utilisation.

As part of the new system implementation, WELL also plans to integrate the billing and ICP management platforms, GIS, and SCADA. This will ensure that consistent, accurate information on ICPs and their network connectivity is maintained across all platforms. By harmonising data flows and connectivity records, WELL will improve operational visibility, streamline processes, and support more informed decision-making across planning, operations, and customer service functions.

10.1.1.14 Financial system and Enterprise Resource Planning

SAP version 7.0 is used as WELL's core financial and accounting system and operates as WELL's primary commercial management platform. The system supports billing, fixed asset registers, accounts payable, and general ledger functions, with asset management integrated to effectively provide an enterprise resource planning (ERP) capability for WELL.

Human resources functions are managed separately using the ELMO app. No standalone accounting systems are used outside of SAP.

SAP version 7.0 is hosted in Melbourne by a sister company within the CK Infrastructure Holdings Limited group. WELL is currently assessing options to replace the existing ERP system, as the software vendor has advised that support for version 7.0 will cease within the next four years. This presents an increasing risk to system resilience, cybersecurity, and long-term operational supportability.

The planned replacement of the existing ERP platform is driven primarily by vendor end-of-support timelines, increasing cybersecurity risk, and the need to maintain system resilience and integration capability across core financial and asset management processes. These drivers are largely non-discretionary and time-bound, with limited scope for deferral without increasing operational, compliance, and data-integrity risks. ERP replacement is also a high-value, discrete investment that must be delivered within defined

implementation windows to ensure continuity of financial control, regulatory reporting, and asset management integration.

Under a fixed, smoothed allowance framework, the ability to efficiently align funding with externally driven replacement cycles may be constrained. In this context, a CPP is likely to provide greater flexibility to align revenue allowances with the efficient timing of ERP replacement, supporting prudent risk management, system resilience, and the continued delivery of safe and reliable network services.

10.1.1.15 System Upgrades

WELL, is required to keep its system up to date to support business continuity and address emerging risks. and improve operational efficiency. A summary of these upgrades is provided in Table 10-1.

System	Upgrade Policy	Last Upgrade / Replacement	Next Planned Upgrade	Planned Enhancements
GIS	Lifecycle and support-based	2024	2029	Data improvement and integration with other systems
HR/payroll	Software as a Service	2022	N/A	Additional modules and automation
Billing	Replacement system planned to be SaaS	2017	2026	Overhaul of the billing system
SCADA	Lifecycle and support-based	2023	2027	Data improvement and integration with other systems, decision-making capability improvement
Load management	Lifecycle and support-based	2025	2028	Data and Decision-making capability improvement
Planned outage management	Lifecycle and support-based	2023	2029	Tight integration and capability improvement
Supplier management	Software as a Service	2024	N/A	An additional module and better utilisation of the tool
Network resilience risk analysis	As per the requirements	2025	Ongoing	Further enhancement to network resiliency
ICT Hardware Infrastructure	Lifecycle and support-based	2025	2029	To maintain capacity and support business continuity
SCADA Hardware Infrastructure	Lifecycle and support-based	2022-23	2026-27	To maintain capacity and support business continuity

Table 10-1 Summary of System Upgrades

10.2 Cybersecurity

WELL operates in an increasingly complex cybersecurity threat environment, consistent with the experience of other electricity distribution businesses and critical infrastructure providers. The energy sector remains a recognised target for cyber threats, and this risk is expected to increase as network operations and asset management systems become more digitalised and interconnected.

Cybersecurity incidents can materially affect the safe and reliable operation of the electricity network, including through improper switching, system overloads, or disruptions to customer supply. As such, cybersecurity is treated as a core operational and safety risk within WELL's risk management and asset management frameworks.

WELL works closely with the National Cyber Security Centre (NCSC) to strengthen the security of its IT and operational technology (OT) environments, with particular focus on systems that directly support network monitoring and control. WELL's cybersecurity approach is risk-based and proportionate, targeting controls and capabilities where they deliver the greatest risk reduction.

The escalating cybersecurity threat environment described above materially affects the risk profile of WELL's operational technology (OT) and information technology (IT) systems. As digitalisation increases and network control systems become more interconnected, cybersecurity investment is driven by evolving threat intelligence, regulatory expectations, and system integration requirements rather than by discretionary enhancement. Effective risk mitigation requires continuous control uplift, periodic platform upgrades, and, in some cases, discrete system replacements delivered within defined timeframes.

Under a fixed and smoothed allowance framework, the ability to align funding with rapidly evolving cyber risk and externally driven system requirements may be constrained. In this context, a CPP is likely to provide greater flexibility to align revenue allowances with the timing of efficient cybersecurity investments, supporting prudent risk management, operational resilience, and the protection of critical infrastructure in the long-term interests of consumers.

10.3 Data Quality

Over the past 12 months, WELL has improved aspects of its asset data quality, particularly regarding low-voltage connectivity, through the delivery of the ANSA low-voltage constraint risk modelling project (see Section 11.2.2.2). This work has helped address several data gaps by improving the consistency and coverage of low-voltage connectivity information, enabling better identification of potential constraints and informing planning and operational assessments at the low-voltage level.

While these improvements represent an important step forward, gaps remain in the completeness, timeliness, and integration of low-voltage asset data. These limitations constrain full network visibility and restrict the ability to support more advanced operational and analytical use cases. Further investment is therefore required to strengthen data governance and standards, as well as improve integration between key systems such as GIS, SCADA, billing, and planning systems. WELL intends to address these gaps through targeted data remediation, process improvements, and system enhancements, enabling more reliable, scalable, and data-driven planning and operational decision-making as low-voltage complexity and customer energy resources continue to increase.

At the same time, WELL is increasingly utilising data from external sources, including small samples of smart metering data (see Section 11.3.2.6). However, WELL has elected not to purchase detailed low-voltage smart

meter data due to the associated cost and the limited incremental value compared with aggregated, anonymised datasets currently available. Instead, WELL relies on these aggregated data sources to support network analysis and planning. This approach underscores the importance of robust data governance, data quality assurance, and system resilience to manage dependencies, ensure access continuity, and maintain confidence in asset and network information.

10.4 Plant and machinery

Vehicles are replaced in accordance with WELL's fleet replacement policy, with the fleet primarily maintained through leased arrangements rather than owned assets. Other plant, test equipment, and tools, such as power-quality measurement devices and partial-discharge test sets, are replaced as required, based on condition and operational needs. No other material investments in plant and machinery are currently planned.

10.5 Relocating head office and primary control room

WELL is relocating its head office from Petone, which is in a tsunami evacuation zone⁴⁴, to Upper Hutt. Occupation of the Upper Hutt site is planned for March 2026. As part of this relocation, the primary network control room will also be transferred to Upper Hutt. The new facility has been constructed to a high seismic performance standard, improving organisational resilience and business continuity.

10.6 Non-Network Asset Expenditure Forecast

Based on the asset strategies, system requirements, and investment drivers outlined above, WELL's forecast non-network expenditure is summarised in Table 10-2.

Taken together, the ERP, GIS, SCADA and cybersecurity programmes described in this section represent a series of major IT and operational technology system renewals that are critical to maintaining safe and reliable network operations. These investments are largely driven by external factors, including step-changes in vendor support cycles, evolving cyber threats, integration requirements, and increasing reliance on digital platforms to manage network operations, customer connections, and financial processes. As a result, they tend to involve discrete, high-value implementation projects delivered within defined timeframes, rather than incremental upgrades that can be easily accommodated within smoothed annual expenditure profiles.

Under the DPP4 allowances, the ability to efficiently sequence and coordinate this clustered system's renewals is limited, increasing the risk of deferral beyond optimal replacement timing or fragmented implementation across platforms. In this context, a CPP is likely provide greater flexibility to align revenue allowances with the timing and scale of efficient IT and operational technology system investments. Thereby supporting timely system replacement, maintaining cybersecurity and operational resilience, and ensuring that the digital capabilities required to operate an increasingly sophisticated network are delivered in the long-term interests of consumers.

⁴⁴ <https://www.huttcity.govt.nz/services/emergency-management/useful-information/maps>

Expenditure Type	Disclosure Year Beginning 1 April									
	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035
GIS	153	363	106	139	403	149	181	130	140	159
SCADA	-	-	-	-	-	711	-	-	-	-
Load Management	16	48	14	19	54	20	24	17	19	21
Operational IT Infrastructure	57	220	42	55	161	60	72	78	56	63
Cyber Security	82	242	70	93	269	100	120	87	93	106
Mobile Operations Tools	82	242	70	93	269	100	120	87	93	106
Outage Management	126	48	14	19	54	20	24	17	19	21
Asset Management	493	472	137	181	525	194	235	169	182	207
Engineering Tools	16	48	14	19	54	20	24	17	19	21
Other Systems (e.g. Billing, Financial, Website)	519	774	561	297	861	319	385	277	738	840
IT Infrastructure	720	459	1,353	489	511	189	229	1,655	495	563
Safety	8	24	7	9	27	10	12	9	9	11
Future Services	-	-	-	-	-	-	-	-	-	-
Buildings	-	-	-	-	-	-	-	-	-	-
Capitalised Leases	1,655	561	646	145	1,338	492	590	421	451	517
Total Non-network Capital Expenditure	3,930	3,503	3,034	1,557	4,526	2,383	2,017	2,964	2,313	2,636
System Operations and Network Support	11,681	11,938	12,177	12,421	12,669	12,922	13,181	13,444	13,713	14,519
Business Support	17,344	16,417	15,125	15,611	16,120	16,653	17,210	17,795	18,409	19,545
Non-network solutions provided by a related party or third party	-	-	-	-	-	-	-	-	-	-
Total Non-network Operational Expenditure	29,025	28,355	27,302	28,032	28,789	29,575	30,391	31,240	32,122	34,063

Table 10-2 Non-network Expenditure Forecast
(\$K in constant prices)

11 Enabling the Future Network

This section looks beyond traditional network investments to identify the tools and capabilities WELL requires to manage its network efficiently and cost-effectively. In doing so, it reflects WELL's objective of enabling the business to deliver a future-ready network, while continuing to invest in the network underpinning customer expectations of service reliability.

WELL is planning for an uncertain future, in which the timing and scale of the transition from gas to electricity, and the resulting electrification of heating, cooking, and transport, remain uncertain. Within WELL's geographically constrained network footprint, this uncertainty raises important investment timing questions: whether to build capacity ahead of demand so the network is ready when load materialises, or to defer investment until demand is confirmed, risking insufficient capacity if electrification accelerates. While building incrementally and earlier can reduce the marginal cost of expansion and improve readiness for a highly electrified future, it also increases the risk of asset stranding if demand emerges more slowly than anticipated.

As the electricity system evolves and customers increasingly adopt CER, WELL is progressively developing its systems, data, and operational capabilities needed to understand and manage emerging network impacts, including the identification and valuation of cost-of-constraint effects. Developing low-voltage visibility, flexibility procurement capability, tariff reform, and market-integrated solutions requires sustained investment in digital systems, analytical tools, commercial frameworks, and specialist capability over multiple years.

While distributed resources such as solar generation contribute to the evolving energy system, their ability to mitigate winter peak demand and other network constraints remains limited in many cases. Accordingly, WELL's approach recognises the need to progress both enabling capabilities and timely infrastructure investment to ensure network reliability and avoid the risk that delays in market or technology development result in infrastructure shortfalls.

Rather than remaining in extended trial phases, WELL is advancing these capabilities through a least-regrets investment approach that builds the foundational systems needed to operate an increasingly complex, customer-driven network. This includes enabling the business to respond to emerging constraints while maintaining the ability to invest in network infrastructure where non-network alternatives are uncertain, slow to commercialise, or insufficient to address system needs.

Existing regulatory settings were largely designed around conventional network investment, where capital expenditure and asset life are clearly defined. As noted throughout this section, current incentives may favour traditional augmentation even when non-network solutions or flexibility services could deliver lower whole-of-life costs. Without appropriate recognition of development costs, data acquisition requirements, and the operational expenditure associated with flexibility markets, the ability to scale these alternatives efficiently may be constrained.

Delivering a future-ready network requires upfront investment in the systems, visibility, and operational capabilities needed to manage a more dynamic and electrified distribution system. These investments must be progressed alongside ongoing asset renewal, resilience improvements, and digital system replacement programmes that sustain current service performance. At the same time, WELL must balance infrastructure investment timing in an environment where the pace of electrification and the transition away from gas remain uncertain.

The fixed and smoothed allowance under DPP4 constrains the efficient sequencing of capability development and infrastructure investment, either delaying preparation for future demand or increasing the risk of stranded capacity. In this context, a CPP is likely to provide greater flexibility to align revenue allowances with the

transitional investment required to enable low-voltage visibility, flexibility services, and tariff reform at scale, while also supporting efficient management of demand uncertainty, reducing long-term augmentation requirements, and ensuring that emerging non-network solutions are treated as credible alternatives to traditional investment in the long-term interests of consumers.

11.1 Innovation Practices

WELL's innovation workstreams aim to unlock the value of CER in supporting peak-demand management, improving network utilisation, helping to defer capital investment and moderate electricity price increases for its customers.

Success for these innovation practices is defined by their ability to demonstrably meet a specific network use case, be commercially attractive for participants, and deliver a lower lifecycle cost than traditional network investment. Where these approaches can consistently deliver outcomes comparable to infrastructure investment, they may be adopted as part of WELL's operational toolkit, subject to regulatory allowances that enable their implementation. Where they cannot deliver this level of efficacy, or where development and commercialisation are too slow to address emerging network needs, WELL will proceed with the necessary infrastructure investment to maintain network performance and reliability.

Collaboration is a core element of WELL's innovation approach. WELL works with other organisations through industry forums, including leading EV Connect (see Section 11.2.3.1), participating in sector working groups, and engaging directly with other EDBs and companies through ongoing commercial trials (see Section 11.2.1.1). This includes initiatives such as the Sharing the Sun project, which explores ways to extend the benefits of distributed solar generation beyond households that can install rooftop systems, enabling non-solar customers to share in the value created by local renewable generation. WELL considers collaboration across the electricity supply chain essential to realising the full benefits of innovation, with shared learning driving efficiencies and delivering greater value for customers.

A key focus of WELL's innovation activities is developing tools to acquire and analyse data to identify and predict emerging network constraints and better understand low-voltage network performance. The targeted application of innovation practices to known or emerging constraints will be critical to meeting the defined success criteria. Information will be sourced in a coordinated and efficient manner once a workstream is established to explore a specific use case.

11.2 Development Programmes

11.2.1 Supporting Regulatory Changes

Electricity distribution services are regulated. Economic regulation is overseen by the Commission, which sets funding allowances and quality targets, and market regulation is overseen by the Authority, which sets the rules for participation in the electricity market. The Authority's regulatory framework has historically focused on promoting competition and market-led solutions across the electricity supply chain. While this approach supports efficient price discovery and innovation in competitive market segments, it does not always fully recognise the operational realities and physical constraints of distribution networks, where infrastructure investment, system visibility, and reliability obligations must often be addressed ahead of clear market signals. As a result, reliance on market-led development of services such as flexibility may not always occur at the pace or scale required to support network security and the transition to a more electrified energy system.

EDBs are also influenced by indirect regulation from entities such as the Energy Efficiency and Conservation Authority (EECA), which sets standards for the operation of customer appliances, and the Ministry of Business, Innovation and Employment (MBIE), which administers electricity legislation and associated regulations.

As decarbonisation accelerates, this regulatory framework must evolve to better align EDB incentives with outcomes that efficiently manage uncertainty and reduce long-term system costs. Existing settings tend to favour traditional capital investment, even where non-network solutions or flexibility services could defer or avoid expenditure at a lower whole-of-life cost. While innovation and non-network solutions offer potential benefits, the threshold for relying on them is high given the expectation that network infrastructure must be available and reliable at all times. In many cases, these solutions are not yet sufficiently mature, scalable, or commercially developed to consistently replace or supplement physical infrastructure.

At the same time, current regulatory settings do not support commercial arrangements such as take-or-pay structures that could provide the certainty required to underpin flexibility markets, and neither regulatory framework fully addresses the investment risk faced by EDBs when planning infrastructure ahead of uncertain demand. Without appropriate regulatory recognition and funding mechanisms, EDBs face a limited ability to adopt these alternatives at scale while continuing to meet their reliability obligations.

The Government Policy Statement on Electricity in October 2024 signalled the Government's expectation that the electricity sector prepares for a more electrified economy, including increased demand from electric vehicles, industrial electrification, and the gradual displacement of fossil fuels such as gas. In this context, the GPS highlighted the potential role of flexibility services and demand-side participation in helping manage changing demand patterns and improving the utilisation of existing infrastructure.

However, these mechanisms are still emerging and not yet sufficiently developed to reliably replace network infrastructure or deliver affordability and reliability outcomes at scale. Translating the policy intent of the GPS into practical application will therefore require targeted amendments to the Code and supporting regulatory settings, including clearer pathways for the procurement, valuation, and cost recovery of flexibility services alongside conventional network investment.

For WELL, these changes are critical to enabling efficient investment decisions under uncertainty. WELL currently cannot treat emerging flexibility solutions as credible alternatives to traditional network augmentation, ensuring that customers benefit from lower long-term costs while maintaining supply security. Government Policy needs to be developed to support the new CER, so that it becomes certain and dependable, as if infrastructure had been provided.

11.2.1.1 Code Changes to Support the Uptake of Electric Vehicles

Targeted changes to the Code are required to enable secure, efficient connections for large-scale electric-vehicle charging infrastructure. The rapid growth of high-capacity public charging hubs, fleet depots, and commercial charging facilities will introduce concentrated new loads onto distribution networks. As the scale and clustering of these installations increase, consistent national requirements will be critical to maintaining network security, avoiding unnecessary barriers to customer connections, and supporting the timely electrification of transport.

In particular, the Code should require all large electric vehicle charging installations above a defined capacity threshold to apply for connection to the local distribution network. A standardised application and assessment process could be largely automated for typical installations, enabling timely connection while

providing early visibility to EDBs where proposed charging loads may exceed available network capacity. This approach would allow straightforward connections to proceed efficiently, while ensuring that sites with potentially material network impacts are identified early and subject to more detailed technical review.

Technical standards are also required to ensure that large electric vehicle chargers can be remotely monitored and, where appropriate, managed within agreed operational parameters. Providing EDBs with secure visibility of charging loads and the ability to implement temporary operational controls during periods of network constraint would improve the utilisation of existing network capacity and reduce the risk of unmanaged peak demand growth. Such capabilities would also support the future development of flexibility services and demand response arrangements.

However, a workable and competitive market for flexibility services has not yet emerged at the scale required to manage distribution network constraints. While flexibility is often identified as a potential mechanism for managing peak demand, the commercial frameworks, participant incentives, and operational platforms required to deliver these services consistently are still developing. As a result, EDBs cannot rely on flexible markets alone to manage peak demand growth associated with electrification.

Accordingly, while enabling flexibility and controllability of large charging loads is an important step toward a more active and efficient distribution system, it must be complemented by timely investment in network capacity where required. Establishing appropriate Code requirements now will allow networks to support the continued rollout of electric vehicle infrastructure while maintaining system security and ensuring that both non-network solutions and traditional network investment can be deployed efficiently as the market evolves.

11.2.1.2 Code Changes to Support Flexibility Services

Further amendments to the Code are required to enable the effective development and operation of fully flexible services at scale. These changes are necessary to ensure that flexibility can be integrated into network operations in an efficient, equitable manner while maintaining system security.

First, EDBs require streamlined, timely access to smart meter data, including consumption and power-quality data, as well as reliable information on the location and operating characteristics of large CERs. This data must be provided in accordance with clearly defined, mandated quality standards, as it is a critical input to systems used to identify, forecast, and manage congestion on the low-voltage network. Initiatives such as the Ara Ake data access project⁴⁵ are exploring frameworks to improve the accessibility and interoperability of electricity data across the sector, which could help address some of these challenges. However, ensuring that EDBs can access the data they need to operate and plan their networks efficiently will require clear regulatory standards and consistent data standards.

Because the collection and provision of metering data exhibit monopolistic characteristics, appropriate price-quality regulation is required to ensure that the cost of supplying this data to interested parties is reasonable. This is particularly important given that customers have already borne the cost of the initial collection of this data through their retailer-appointed Meter Equipment Provider (MEP) and should not incur inefficient duplication of those costs.

Second, the Code need to establish an industry-wide hierarchy of needs that preserves network operators' ability to maintain a secure electricity system. Network operators, including EDBs and Transpower, have historically relied on priority access to hot-water ripple control during emergency events requiring direct

⁴⁵ More information about Ara Kae projects can be found on their website at <https://www.araake.co.nz/projects>

intervention to maintain supply. While such events are rare and would have limited impact on competing flexibility services, this priority access is fundamental because flexibility services cannot operate without a secure, stable underlying system.

This hierarchy should be retained as the highest element of the flexibility value stack and expanded beyond traditional hot-water control to include new controllable devices, including those managed by third-party flexibility providers that are not currently captured within the Code. Extending this capability will ensure that networks retain the tools needed to maintain system security and provide a stable platform for building competitive, customer-focused flexibility services.

Lastly, regulatory policy will need to ensure that price signals originating from the wholesale market and local network conditions are transparently and consistently passed through to consumers in a form that influences behaviour. Without this alignment, the incentives needed to support a workable, competitive flexibility market will not materialise. In practice, this means establishing regulatory settings that enable cost-reflective retail and distribution pricing structures so that consumers and third-party service providers can respond to real network and system conditions.

Clear direction from the Authority will be required to ensure that retailers and market participants transmit these signals in ways that encourage demand response, flexible consumption, and efficient use of network capacity. In effect, the Authority must ensure that the policy intent of enabling flexible demand is translated into operational market signals, i.e., “getting the arrow to the target” so that EDBs can rely on customer behaviour responding to price signals rather than defaulting to infrastructure investment to maintain system performance.

11.2.1.3 Other Regulatory Changes

In all cases, regulatory changes must be carefully designed to avoid unintended cross-subsidisation. In particular, settings should not exacerbate energy hardship by requiring customers who cannot afford CER, or renters who cannot install technologies such as rooftop PV, to subsidise wealthier customers who can afford CER.

At the same time, EDBs must retain the ability to actively manage operational network security to meet the regulatory obligations they are accountable for. These obligations include quality standards imposed under Part 4 of the Commerce Act 1986, such as SAIDI and SAIFI targets, power quality requirements under the Electricity (Safety) Regulations and the Code, including compliance with the permitted voltage ranges, and liability under the Consumer Guarantees Act for damage to customer appliances arising from power quality issues.

11.2.2 Low-voltage Management

WELL’s immediate focus for low-voltage management is improving network visibility by integrating GIS spatial data with ICP-level consumption and voltage data, along with transformer monitoring information. This enhanced visibility underpins WELL’s broader low-voltage management approach. Based on developing a series of foundational concepts as building blocks through targeted trials and pilot programmes that leverage prior work and build toward the goal of enabling the market to manage low-voltage constraints in real time.

These building blocks leverage prior work and are designed to progressively enable market-led management of low-voltage constraints in near-real time. The individual components and their interrelationships are illustrated in Figure 11-1.

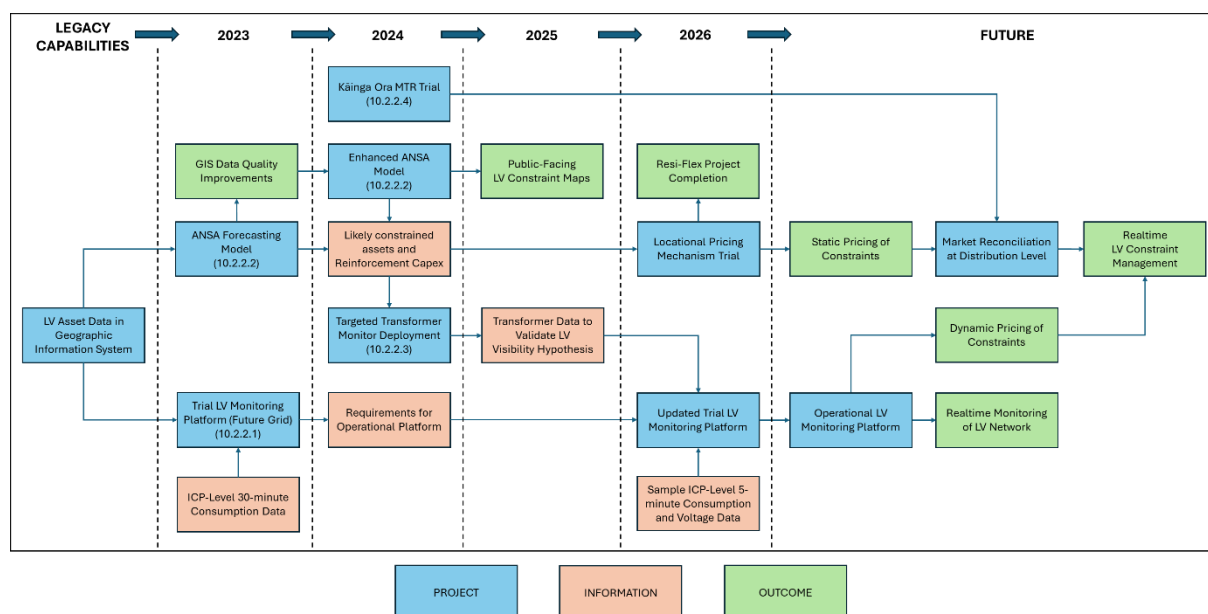


Figure 11-1 Key Low Voltage Visibility Building Blocks

11.2.2.1 Future Grid Pilot

In 2022, WELL participated alongside seven other EDBs in Ara Ake's EDB Challenge. The Challenge focused on identifying domestic and international solutions to incorporate flexibility into EDB's asset management processes.

As electrification accelerates and CER deployment increases, improved visibility into the low-voltage network is becoming increasingly important for both long-term planning and real-time operations. Enhanced low-voltage visibility enables EDBs to identify emerging network constraints, proactively detect and resolve power-quality issues, and provides a foundational capability for any future market for flexibility services. Collectively, these use cases deliver tangible benefits to customers by improving reliability, efficiency, and value for money.

As an outcome result of the Challenge, WELL selected Future Grid as a preferred partner. Future Grid provides a low-voltage network visibility and management platform that is already in use by several WELL's Australian sister companies. WELL identified the platform as a strong fit for addressing low-voltage information gaps, including constraint mapping and modelling the operational impact of flexibility services on network operations.

A pilot of Future Grid's Compass software was undertaken in 2023.⁴⁶ The key findings from the pilot were that:

1. Third-party ICP consumption data and WELL's spatial data could be successfully incorporated into the tool.
2. Half-hour consumption data provided useful asset management insights, making cost-effective access to voltage data critical for the majority of intended use cases.

⁴⁶ <https://www.araake.co.nz/projects/edb-challenge/>

3. Ongoing regulatory support is required to enable sustained funding for software, data acquisition, and the specialist capability needed to operate and maintain the platform.

WELL will use the insights from the Future Grid pilot to inform the development of requirements for procuring a network-wide low-voltage management platform. In addition to improving visibility into low-voltage constraints, such a platform would provide significant value by enabling the proactive identification of abnormal network conditions with potential public safety implications, including deteriorating neutral connections.⁴⁷

11.2.2.2 ANSA Low Voltage Constraint Risk Modelling

In 2023, WELL commissioned ANSA to develop a forecasting tool to assess low-voltage constraint risk and associated capital investment. The tool analysed WELL's residential low-voltage network by integrating GIS spatial data, consumption data, decarbonisation-driven load growth forecasts, and standard cost inputs to project low-voltage constraints and the capital investment required to address them over a 50-year horizon.

The output of this model was incorporated into WELL's System Growth Capex forecast presented in the 2024 AMP, used to set the DPP4 expenditure allowances. The model has also been used to guide subsequent stages of WELL's low-voltage management strategy and to identify opportunities to improve the completeness and accuracy of the low-voltage asset data held within WELL's GIS.

The model was updated in late 2024 to reflect improved GIS data, revised decarbonisation scenarios, and updated PV hosting capacity forecasts. The results of this modelling are presented in Section 9.14.

Over time, this capability is expected to inform the development of locational pricing signals that assign a transparent value to network constraints, thereby incentivising their effective management.

11.2.2.3 Piloting Transformer Monitoring Equipment

WELL is evaluating the most effective and efficient data sources to improve visibility into the low-voltage network. The current hypothesis is that aggregating ICP-level consumption and power quality data at a five-minute resolution, focused on areas identified by the probabilistic ANSA model as likely to experience constraints, will provide sufficient insight into low-voltage network performance. On this basis, WELL considers that procuring 100% smart meter data coverage or undertaking a wide-scale rollout of transformer monitoring equipment is unlikely to deliver sufficient marginal benefit to justify the additional cost.

This hypothesis is being tested by deploying 50 transformer monitors in suburbs identified by the ANSA model as likely to be congested. These suburbs have been selected to span a range of socioeconomic and decarbonisation characteristics, as shown in Table 11-1.

⁴⁷ See "Leveraging Meter Data", Page 287, WELL Asset Management Plan 2022.

Suburb	Socioeconomic Decile (1 = low deprivation, 10 = high deprivation)	Electric Vehicle 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

Figure 11-2 shows the alignment between the pilot suburbs selected for transformer monitoring and the areas identified by the 2023 ANSA study as most likely to experience low voltage network constraints, demonstrating that the pilot has been targeted at locations with the highest forecast risk.

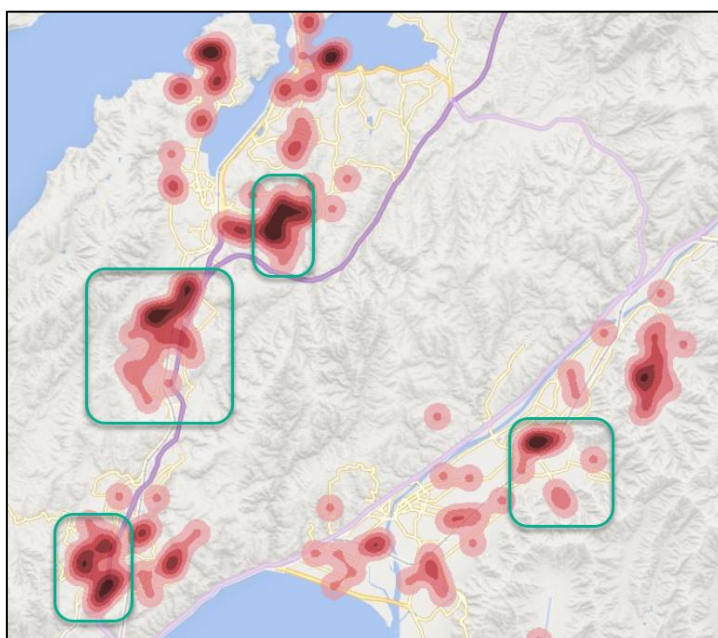


Figure 11-2 Alignment of Transformer Monitor Study Locations to Constraint Model Heatmap

This project is designed to test WELL's low-voltage network visibility approach and assess the value of targeted transformer monitoring in improving operational insight, network planning, and safety outcomes. The objectives of the project are to:

1. Allow testing of the low-voltage visibility hypothesis through the trial deployment of a limited number of transformer monitors, with the results compared against the insights achievable using ICP-level data only.
2. Further test the Future Grid Compass low-voltage monitoring platform through the ingestion and analysis of transformer monitor data.
3. Validate the ANSA model outputs for the transformers, including those in the monitoring programme.

4. Review the safety-related functions of the transformer monitors, including broken neutral, stolen earth, and 11 kV conductor down detection, to assess how these capabilities could be integrated into day-to-day operational practices.
5. Improve WELL's understanding of distribution transformer fleet performance and utilisation, including voltage, current, and transformer temperature, by extrapolating insights from the monitored transformers.

The development of low-voltage visibility capability is a foundational investment that enables identifying constraint locations, quantifying network impacts from CER uptake, and supporting efficient non-network decision-making. These systems must be established in advance of widespread flexibility deployment, and their benefits are realised progressively through improved planning and deferred augmentation rather than immediate reliability metrics. As such, they involve upfront digital and analytical investment before full network cost offsets are achieved.

Under a fixed and smoothed allowance framework, funding these enabling capabilities alongside asset renewal and resilience priorities may constrain efficient sequencing. A CPP is likely to provide greater flexibility to align revenue allowances with the development of transitional digital capabilities, supporting whole-of-life efficiency and more credible use of non-network alternatives.

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 trial Multiple Trading Relationships,⁴⁸ with the aim of exploring new market arrangements that better enable the sharing of CER benefits. Kāinga Ora's challenge was to maximise the value of excess electricity generated by PV systems installed on its properties, while ensuring that tenants could continue to benefit from on-site-self-consumption and retain the freedom to purchase electricity from the retailer of their choice.

The trial went live in May 2024 and is currently ongoing. To date, it has involved 180 Kāinga Ora-connected residential properties connected to WELL's network. The Authority granted Code exemptions to allow these installations to operate with separate ICPs for consumption and export, with the consumption ICP registered to the tenant's chosen retailer and the export ICP registered to Kāinga Ora's retailer. This arrangement has enabled Kāinga Ora to monetise excess solar generation and redistribute the value to a broader group of tenants, including those without PV installations, while preserving tenants' consumer rights.

The Multiple Trading Trial was recognised as Energy Project of the Year prize at the 2024 New Zealand Energy Excellence Awards.⁴⁹

The project provides valuable insight into how the benefits of CER can be shared with customers experiencing energy hardship and highlights the market changes required to fully realise the value of flexibility services. From a network perspective, transitioning from GXP-level to low-voltage market reconciliation will be critical to efficiently valuing and managing low-voltage constraints, and the Multiple Trading Trial is an important step toward understanding how such arrangements could be implemented in practice.

⁴⁸ https://kaingaora.govt.nz/en_NZ/about-us/sustainability-at-kainga-ora/solar-innovation/

⁴⁹ <https://www.araake.co.nz/news/kainga-ora-solar-programme-awarded-for-breaking-new-ground>

11.2.2.5 Developing Access to Data

Access to ICP-level data is fundamental to the effective use of the models and tools outlined in this section. It is neither cost-effective nor in customers' long-term interests for EDBs to invest in duplicate infrastructure to collect and store data already captured by the existing smart meter fleet.

To enable efficient use of this data, changes to the Code are required to provide EDBs with streamlined, consistent access to smart meter data on consumption and power quality. The collection and provision of metering data exhibit monopolistic characteristics and therefore require careful regulatory oversight to ensure that the costs charged to interested persons, and ultimately borne by customers, despite the data having already been paid for at the point of its initial collection, are reasonable and proportionate.

WELL's pilot of the Future Grid platform has focused on assessing its ability to integrate multiple data sources and determining whether those sources provide sufficient quality and granularity to support low-voltage network planning and operational decision-making. This has required developing new data agreements and managing large third-party datasets.

As part of the pilot, WELL engaged with a MEP to obtain voltage data for the Future Grid trial. However, voltage data were ultimately excluded from the project scope due to cost constraints and limited coverage, with data available for only 1,000 ICPs, approximately 6% of the trial sample. The lack of ready access to five-minute voltage data remains a significant barrier to the widespread deployment of tools identifying and managing low-voltage network constraints.

In addition to confirming the importance of five-minute data, the pilot reinforced WELL's view that EDBs do not need to store or directly interact with the large volumes of raw metering data generated by networks of this scale. Instead, WELL's requirements are for the insights derived from that data, such as identifying potential safety issues, assessing asset utilisation, and locating network constraints. These insights can be generated by algorithms operating on third-party data, avoiding the need for large-scale data transfers and the inefficient duplication of digital storage infrastructure across multiple organisations.

11.2.2.6 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 Distribution System Operator (DSO) capability over the past seven years. Their programmes have demonstrated both the complexity of establishing DSO functionality and the time required to develop the supporting data, systems, and operating tools. WELL is drawing on this experience to inform the design and sequencing of its own research and development activities.

Key lessons emerging from the Australia experience that are directly relevant to New Zealand include:

1. The need for extensive data correction and cleansing—the deployment of low-voltage management platforms in Australia, including tools such as Future Grid, exposed material issues in the underlying GIS and ICP data. In 2023, WELL provided United Energy with a sample of ICP data from its network for analysis using United Energy's tools. This exercise identified that, at the time, the quality and consistency of metering data available in New Zealand were insufficient to support operational low-voltage management use cases.
2. The requirement for a multiple-year development horizon—integrating low-voltage visibility and management into core network planning and operational processes is inherently complex and cannot

be delivered as a single-step change. The Australian experience indicates that functionality must be progressively developed, tested, and embedded over multiple years.

11.2.3 The Development of Flexibility Services

WELL supports the development of third-party demand management and flexibility services on its network to deliver improved customer outcomes. Enabling customers to realise a financial return on their investment in CER encourages greater uptake of CER and supports aggregation at a scale that provides WELL with access to reliable non-wires alternatives to traditional investments in new network capacity, ultimately benefiting customers in the long term.

However, for these services to be a credible alternative to infrastructure investment, they must be dispatched reliably and consistently, with appropriate mechanisms in place to reduce demand when dispatch signals are not delivered as expected. Experience from international and Australian trials, including initiatives such as the GreenSync⁵⁰ flexibility trials on the Mornington Peninsula, demonstrates the importance of ensuring that aggregated demand response can be delivered with sufficient certainty to support network operations. Where these conditions can be met, flexibility services have the potential to complement traditional network investment and deliver long-term benefits for customers.

To realise these long-term benefits, it must operate within defined technical limits to ensure that its deployment does not adversely affect network reliability or power quality, and to contribute to the secure operation of the electricity system during network emergencies. Maintaining a stable and resilient network is a prerequisite for effective flexibility markets; without this foundation, the efficient use of CER and demand management services cannot be sustained.

11.2.3.1 Electric Vehicle Connect Roadmap

The Electric Vehicle Connect Roadmap formed part of the EECA Low Emissions Vehicle Contestable Fund (LEVCF) funded EC Connect project, which sought to identify how electric vehicle adoption could be supported while maintaining the security and performance of the existing electricity network.

As part of EV Connect, WELL collaborated with its technology partner, GreenSync, to develop a roadmap outlining the industry, regulatory, and technical changes required to support the adoption of electric vehicles and the introduction of managed charging flexibility services. Input was gathered from more than 50 key stakeholders through a series of workshops and consultations, including policy advisors from MBIE, other EDBs, Transpower as the national grid operator, regulators (i.e., the Commission and the Authority), electricity retailers, consumer advocates, and electric vehicle user groups.

The EV Connect Roadmap identifies a range of recommended changes, including regulations and policy settings that actively support the efficient connection of electric vehicles and ensure that network operators are appropriately funded to manage the associated impacts. The roadmap also highlights the importance of flexible regulations that enable stakeholders to trial and develop new services without creating unnecessary barriers or delays. For example, appropriate regulation is required to ensure customer devices meet the technical specifications necessary to participate in the future flexibility services.

A summary of the EV Connect Roadmap is provided in Figure 11-3.⁵¹

⁵⁰ More information about GreenSync can be found on its website at <https://greensync.com/about-us>

⁵¹ <https://www.welectricity.co.nz/about-us/major-projects/ev-connect/>

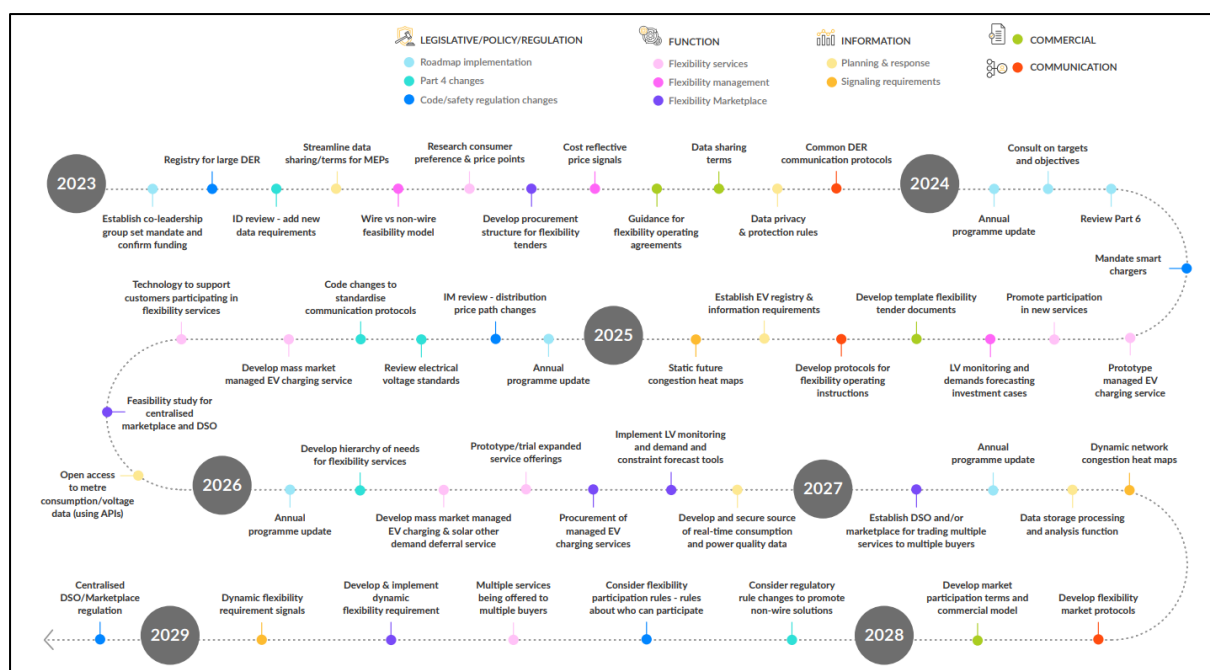


Figure 11-3 EV Connect Roadmap

11.2.3.2 FlexForum

The FlexForum is a cross-industry collaboration established in February 2022 to identify and progress the actions needed to integrate CER into New Zealand's electricity system and markets in a way that maximises system-wide benefits. The groups are 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”.*⁵²

The FlexForum represents the natural progression of WELL's EV Connect programme and has been established to implement the actions identified through that work. WELL is an active participant in, and supporter of, the FlexForum and its programme of activities.

A key near-term outcome of the FlexForum is the development of trials that can be scaled into operational solutions. These trials are being developed collaboratively by FlexForum members, with participation from flexibility providers with access to controllable customer devices, retailers capable of developing scalable customer products, and flexibility service users, including EDBs and Transpower, who are adapting their internal systems and processes to utilise these services. In August 2025, the FlexForum released an update on progress toward its Flexibility Plan. Further information about the Flexibility Plan is available on the FlexForum website at <https://flexforum.nz/>.



⁵² FlexForum, Flexibility Plan 2.0, <https://flexforum.nz/flexibility-plan/>

While progress is being made in developing flexibility services in the electricity sector, significant gaps remain in the value stack required to support a functioning and scalable flexibility market. The most critical gap is the absence of routine and reliable price signals that incentivise customers or aggregators to deliver dependable flexible responses to real-time network and system conditions. Without these signals, flexibility cannot yet operate as a routine operational or risk management tool for network and system operators.

FlexForum analysis highlights several structural barriers that must be addressed to close these gaps. These include establishing clear methods for measuring and verifying flexibility performance to determine payments, simplifying how flexibility bids and offers are made, standardising flexibility products through clearly defined use cases, and ensuring the digital connectivity required for market participants to send and respond to operational signals. Together, these elements are necessary to allow flexibility services to be transacted in a consistent and scalable manner across the electricity system.

FlexForum members also emphasise that price-based signals alone, such as those created through time-of-use pricing, are unlikely to deliver the timely and reliable responses required to manage real-time network and system events. Instead, many distributors are exploring contracted flexibility arrangements and platform-based solutions that provide clearer incentives and operational certainty when flexibility is required to manage network constraints.

While initiatives such as the Electricity Competition Taskforce's proposal for an emergency reserve scheme may help strengthen incentives for flexible responses during unexpected supply shortages, further work is required to address the broader absence of routine cash signals across the system. In particular, FlexForum identifies the need to understand and address the current hesitancy among network operators and electricity retailers to create the external cash signals necessary for flexibility to become a dependable and widely used operational tool. Until these gaps are resolved, flexibility is likely to remain supplementary to traditional network investment rather than a consistent substitute.

11.2.3.3 Resi-Flex

Resi-Flex is a collaboration initiative between WELL and the Christchurch EDB Orion, established to develop and trial commercial mechanisms that enable and support residential demand flexibility. The objective of the project is to design and develop a simple, attractive customer proposition that rewards customers for shifting their electricity consumption to meet network needs.

Delivering the trial collaboratively offers several advantages, including increased scale, pooling resources and expertise to enable faster implementation, and developing a more consistent approach to residential flexibility across participating EDBs. A summary of the Resi-Flex trial steps is provided in Figure 11-4.

The User Requirements phase of the project was completed in 2023, with the results presented at the 2023 Electricity Engineers' Association conference and subsequently published in the project's first public report.⁵³ This phase established a shared understanding of the functional and commercial requirements needed to support residential flexibility.

⁵³ <https://www.welectricity.co.nz/news/document/323>

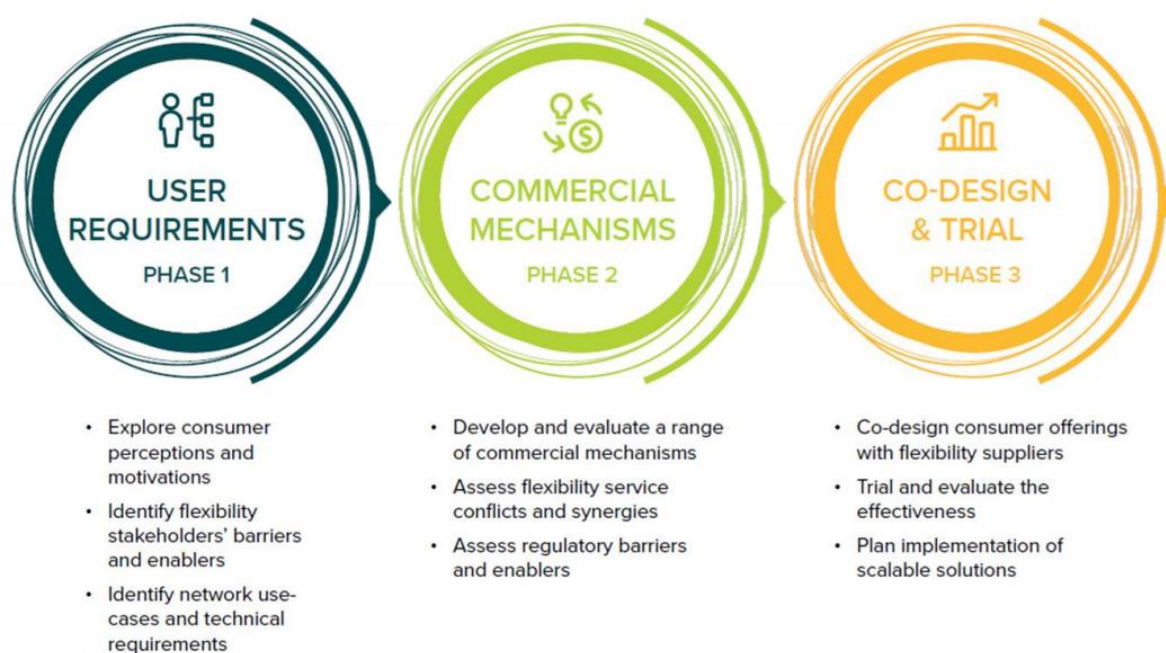


Figure 11-4 Resi-Flex Project Stages

The second phase of the project focused on developing commercial incentives and culminated in the creation of a commercial framework. This framework was designed to create three commercial mechanisms, which were trialled in phase three (Co-design and Trial). The Commercial Framework has also been provided to the Electricity Networks Aotearoa Future Network Forum, where it will inform the workstream on commercial flexibility.

Resi-Flex has now progressed into Phase 3 (Co-design and Trial), with residential flexibility trials underway across the WELL and Orion networks. Phase 3a has been completed, including co-designing trial specifications and customer propositions with participating flexibility stakeholders and recruiting residential customers. Trials are being delivered in partnership with electricity retailers, including Octopus Energy and Ecotricity, and are testing a range of commercial mechanisms developed through the project's Commercial Framework.

Phase 3b is underway and includes expanded trial activity and data collection to assess customer participation, responsiveness, and the effectiveness of different incentive structures. Orion published early findings from Phase 3 in February 2026,⁵⁴ with ongoing work expected to inform future industry approaches to residential flexibility, support scalability considerations, and contribute to broader regulatory and innovation discussions.

11.2.3.4 Flexibility Commercial Framework

As part of the Resi-Flex project, WELL and Orion have developed a commercial framework to support the procurement and use of flexibility services. The framework establishes a structured approach for assessing when flexibility services can provide a viable alternative to traditional network solutions and for determining how the EDB could price and procure these services. It also outlines a range of commercial models that EDBs could offer to flexibility providers.

⁵⁴ <https://www.oriongroup.co.nz/assets/Your-energy-future/Resi-Flex-Phase-3-Report-Feb-2026.pdf>

The framework includes methodologies for calculating and setting flexibility price signals, supported by a calculator to determine the value of flexibility payments. In addition, it incorporates a selection of commercial mechanisms that reflect different approaches to trading flexibility. Figure 11-5 summarises these mechanisms and classifies them according to the three recognised methods for trading flexibility.



Figure 11-5 Flexibility Commercial Mechanisms

11.2.3.5 Flexibility is needed within the regulatory framework

Scaling flexibility services from pilot activity to operational deployment requires investment in commercial frameworks, data systems, performance verification tools, and operational integration processes. These capability-building activities are inherently iterative and require upfront expenditure before measurable augmentation, deferral, or benefit. When regulatory settings predominantly recognise traditional capital solutions, incentives may unintentionally favour conventional network reinforcement over the development of flexibility.

A further constraint is that price signals originating from distribution networks are not consistently passed through to customers by retailers. Without these signals reaching end users, many flexibility initiatives remain theoretical rather than practical, as customers lack the incentives needed to modify consumption during periods of network congestion. Addressing this gap will be important to enabling flexibility to operate as an effective operational tool. International approaches, such as those being implemented in New South Wales, Australia,⁵⁵ provide examples of stronger market frameworks that support the transmission of network price signals and the coordination of customer responses to local constraints.

In this context, WELL will continue to develop price-signal frameworks that provide retailers with clearer, stronger signals to manage customer demand during congestion periods. Providing greater flexibility within

⁵⁵ Australian Renewable Energy Agency (ARENA), *Flexible Demand – The Current State of Play in Australia*, May 2024, <https://arena.gov.au/assets/2024/06/UTS-Flexible-Demand-State-of-Play-in-Aust-Report.pdf>

the regulatory framework to fund transitional capability development would support the efficient integration of these non-network solutions alongside traditional investment, reducing long-term augmentation requirements and benefiting consumers.

11.2.4 Tariff Pricing Reform

WELL is revising its tariff structure to provide stronger, clearer price signals that incentivise customers to shift electricity use away from peak-demand periods. The pricing framework underpinning WELL's new tariffs is also designed to support the future introduction of flexibility services, including managed services. Further details on these reforms are set out in WELL's Pricing Roadmap found on its website.⁵⁶

The key pricing changes being implemented to support network-wide flexibility include:

- Progressively simplification of WELL's price structures, with the intended phasing out of the off-peak price signals and retaining a single peak-period price signal. This approach provides a clearer indication of the value of flexibility while ensuring customers are not penalised for using the network when it is unconstrained. Fixed network costs will continue to be fully recovered through the fixed-price component.
- Development of a revised long-run marginal cost methodology to more accurately calculate the strength and location-specific nature of price signals.
- Introduction of new prices, including exploration of differential pricing in areas experiencing network congested areas.
- Continuing to promote time-of-use (ToU) prices as a key enabler of the future flexibility market. With approximately 95% of residential customers already on ToU pricing at the start of the 2026 AMP period, WELL has established a strong foundation for introducing more advanced flexibility and managed services.
- Retailers cooperating with congestion price signals from the distributor to shift customer demand or operate demand-shedding devices.
- Expansion of operating envelopes, enabling customers to connect to the network at a lower cost where the timing of their demand can be flexed to operate within available network capacity.

Tariff reform and cost-reflective pricing are critical enablers of efficient network utilisation and flexibility participation. Implementing dynamic or time-varying pricing structures requires investment in billing systems, data integration, analytical capabilities, customer engagement, and regulatory coordination before behavioural and network-efficiency benefits are fully realised.

These transitional costs are incurred ahead of demand response outcomes and may not align neatly with smoothed allowance profiles. Collectively, these changes are intended to strengthen price signals, support the efficient use of the existing network, and create an environment that enables the scalable use of flexibility services. Greater regulatory flexibility to align revenue allowances with the efficient implementation of tariff reform would improve demand management outcomes, reduce long-term augmentation requirements, and deliver long-term benefits for consumers.

⁵⁶ <https://www.welectricity.co.nz/disclosures/pricing/future-pricing/>.

12 Resilience and High-Impact Low-Probability Events

The resilience framework and investment initiatives described in this section reflect WELL's statutory obligations as a lifeline utility and the Wellington region's increasing exposure to seismic, climatic, and other high-impact risks. While significant progress was made under the 2018 Readiness CPP to strengthen emergency readiness capability, spares strategy, seismic reinforcement, and communications resilience, the analysis undertaken through the Wellington Lifelines Regional Resilience Project⁵⁷ demonstrates that further targeted network reinforcement and supply diversification are required to materially reduce restoration timeframes and regional economic disruption.

Many of the resilience initiatives identified, including subtransmission ring construction, gas-filled cable replacement, Central Park supply diversification, and coordinated flood mitigation, are capital-intensive, discrete projects undelivered rather than built through smooth annual expenditure profiles. Their timing is driven by risk assessments, interdependency modelling, and regional coordination rather than incremental service enhancement. Deferring these investments beyond efficient risk thresholds would increase exposure to prolonged outages following a major event, with material consequences for public safety, economic continuity, and the operation of critical infrastructure.

Under the DPP4 fixed and smoothed allowance settings, available funding is insufficient to support the efficient sequencing and delivery of clustered resilience investments, particularly where multiple high-risk assets require intervention within the same regulatory period. Although reactive restoration capability has improved, resilience modelling indicates that restoration timeframes following a major seismic event are likely to exceed acceptable durations without additional targeted reinforcement. This gap reflects a structural shortfall in DPP4 allowances relative to WELL's long-term resilience investment needs.

In this context, a CPP provides the appropriate mechanisms to realign revenue with the timing and scale of efficient resilience investment, enabling prudent risk management, compliance with lifeline obligations under the CDEM Act, and improved long-term outcomes for consumers. As demonstrated by the previous Readiness CPP, the CPP framework is specifically designed to address step-change resilience requirements that cannot be accommodated within standard DPP allowance smoothing.

12.1 WELL's Resilience Framework

This section outlines WELL's approach to resilience and its associated investment plan, with a focus on managing and mitigating the impacts of events that occur outside normal operating conditions, including emergency situations. The programme is concerned not only with asset robustness, but also with preparedness, response, and recovery following disruptive events.

12.1.1 Lifeline Utility Obligations

As a lifeline utility under the Civil Defence Emergency Management (CDEM) Act 2002, WELL is required to ensure it can continue to function during and after an emergency, even if at a reduced level of service. These events may include severe storms, earthquakes, or significant equipment failures. Meeting these obligations requires both appropriate investment in assets and robust operational and contingency planning. The 2017 Government Policy Statement on Resilience of Electricity Services in the Wellington Region⁵⁸ clarified that a price-quality regulated lifeline utility's reasonable costs of meeting its obligations under the CDEM Act are

⁵⁷ MERIT Model, Program Business Case, spend \$3 billion to avoid a \$6 billion exposure

⁵⁸ www.gazette.govt.nz/notice/id/2017-go4910

recoverable under Part 4 of the Commerce Act. This was supported by the inclusion of resilience Capex as a price path reopener in the 2023 amendment to the Input Methodologies.

12.1.2 Practical Limits to Network Resilience

There are practical limits to the extent to which electricity networks can be hardened against all risks. While targeted investments can reduce vulnerability and improve response capability, networks cannot be made fully resilient to every potential threat.

Overhead networks will always remain vulnerable during severe storms, as they cannot be economically designed to withstand the shock loading caused by large windborne debris. Similarly, underground networks remain exposed to geotechnical risks, including landslides and liquefaction. WELL's resilience approach, therefore, balances targeted asset hardening with preparedness and recovery capabilities.

12.1.3 The Importance of Coordinated Community Resilience

Improving community resilience requires coordinated action across Civil Defence, Local Authorities, lifeline utilities, and other agencies. Integrated solutions can deliver more effective and lower-cost protection than isolated interventions by individual organisations. For example, coordinated flood protection measures, such as stopbanks, can better protect communities and critical infrastructure more efficiently than standalone asset hardening.

Community hubs will also play a critical role in post-event recovery, providing welfare support, access to standalone power, and distribution points for food and water.

12.1.4 Decarbonisation and Emerging Resilience Considerations

Decarbonisation introduces additional elements to resilience considerations. As households transition transportation and heating away from petrol and gas, outages will have a more significant impact on daily life than in the past. At the same time, new technologies such as electric vehicles offer opportunities to enhance resilience, for example, through vehicle-to-load (V2L) capability that allows EV batteries to supply critical household loads during outages.

12.1.5 Technology Adoption and Resilience Risk

Any new technologies must be assessed through a resilience lens before being adopted on the distribution network. Systems that play a critical role in network security and emergency recovery, such as the hot-water control systems used for emergency load shedding, must remain functional during major events.

Transitioning critical control or communication systems reliant on cellular networks introduces resilience risk. Cellular networks are prone to congestion following major events and typically have limited battery backup at cell sites. These vulnerabilities have been demonstrated by the Christchurch and Kaikoura earthquakes and Cyclone Gabrielle. It is therefore essential that telecommunications providers, as operators of critical infrastructure, align their contingency planning with the prolonged electricity outages that can occur during major events, rather than optimising solely for business-as-usual operation.

12.1.6 Resilience Framework and Programme Structure

WELL's resilience framework is structured in this AMP across the following areas:

- Climate change
- Emergency response and contingency planning

- High impact, low-probability (HILP) events
- Future resilience initiatives, including the WeLG Regional Resilience Project

12.1.7 Building on Previous Investment and Future Priorities

In 2018, significant work was undertaken to improve earthquake readiness under WELL's Readiness CPP. Delivery of the Readiness CPP substantially improved WELL's emergency response capability and primarily addressed the Readiness component of the 4Rs resilience framework.

While these improvements materially enhanced resilience, further work is required to strengthen the network's ability to withstand a major seismic event. Section 12.6 outlines additional resilience investments, including reducing 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 result in rising sea levels and changing weather patterns, leading to more frequent and severe weather events than historically experienced. These changes will affect temperature, rainfall, wind patterns, and storm intensity across the Wellington region, with direct implications for the performance and resilience of the electricity network.

12.2.1 Changes in Temperature, Rainfall, and Wind

Forecasts from the National Institute of Water and Atmospheric Research (NIWA) indicate that Wellington's climate will continue to change over the foreseeable future.⁵⁹ Average regional temperatures are expected to increase by approximately 0.75-1.25°C by 2040, resulting in fewer cold days and more hot days. This shift is likely to alter electricity demand patterns.

Rainfall events are expected to become more frequent and intense, increasing the risk of flooding and landslides. In addition, an increase in high-wind days is anticipated, underscoring the need for continued investment in overhead line resilience and vegetation management. Wellington already experiences some of the highest wind conditions in New Zealand due to its location on the Cook Strait and between the mountain ranges of the North and South Islands.

In mid-February 2026, a deep low-pressure system of subtropical origin moved across the North Island, bringing a period of intense rainfall and strong winds to the Wellington region. The storm delivered sustained heavy rain and gusty southerlies, resulting in localised flooding, surface water on roads, and numerous slips across the region's steep terrain. Strong winds brought down trees and damaged buildings and transport infrastructure, while saturated ground conditions increased the risk of landslides and access disruptions. The event caused widespread power outages as falling vegetation and storm damage affected overhead lines and other network assets, necessitating extensive restoration efforts. Figure 12-1 shows the low-pressure systems over the North Island and Upper South Island on Monday, 16 February 2026.

⁵⁹ Climate change projections for west of Wellington's Tararua and Remutaka Ranges" NIWA, September 2022.

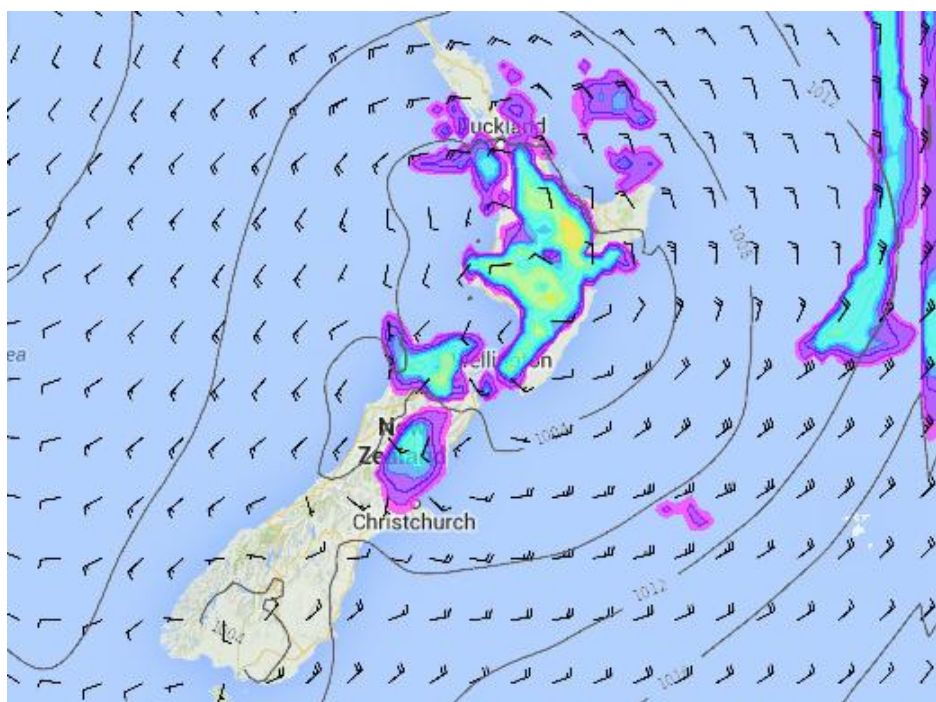


Figure 12-1 Low-pressure system 16 February 2026, WeatherWatch – New Zealand

12.2.2 Sea-level Rise and Coastal Storm Surge Risk

Sea-level rise presents a particular risk in central Wellington, where several substations serving the CBD are located in basements. Between 1961 and 2019, sea level at Wellington rose at an average rate of 2.82 mm per year, driven by a combination of climate-related sea-level rise and seismic subsidence, with the rate continuing to accelerate.⁶⁰

While sea-level rise is a long-term challenge with significant uncertainties across future scenarios, its impacts may be realised earlier through more severe storm events. Warmer sea temperatures are expected to increase storm surge heights, compounding the effects of rising sea levels. This risk has already been demonstrated during Cyclone Dovi in 2022 and the major storm surges that caused damage along Wellington's south coast in April 2020 and June 2021. This increase in coastal risk was one factor in WELL's decision to relocate its head office from Petone to Upper Hutt in 2026.

12.2.3 Coordinated Response and Policy Alignment

Responding effectively to climate-related risks requires a coordinated approach between local authorities, lifeline utilities and other agencies. WELL is updating its policies and technical standards to better protect network assets exposed to climate change impacts. For example, WELL's Inundation Zones Policy will, over time, improve the identification and management of assets at risk of storm inundation and sea-level rise.

To be effective, these changes cannot be implemented in isolation. Ongoing collaboration with local authorities is required to understand wider flood and coastal defence strategies and to influence District Plan updates. This will help to ensure that WELL's policies and standards are aligned with a coherent, region-wide resilience approach across the Lifelines Group.

⁶⁰ Update on sea-level rise projections for Wellington City" NIWA, March 2021.

12.3 Emergency Response and Contingency Planning

WELL adopts the 4Rs framework for hazard and emergency management, as set out by the National Emergency Management Agency (NEMA).⁶¹ In the context of EDBs, the 4Rs framework is described in the EEA Resilience Guide⁶² as encompassing the following four components:

- Reduction—identify and mitigate network vulnerability risks
- Readiness—pre-event contingency planning and training
- Response—immediate actions undertaken following an event
- Recovery—long-term reinstatement of the network

WELL's approach to mitigating the impacts of emergency events is supported by a range of plans, policies, and initiatives implemented across the business, which are described in the sections that follow.

12.3.1 Civil Defence

NEMA is responsible for national emergency management. Emergency management in New Zealand is governed by the Civil Defence Emergency (CDEM) Act, which sets out the roles and responsibilities of resilience groups, including local emergency management groups, lifeline utilities, and emergency services. The Act also provides for the development and maintenance of the national components of New Zealand's 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 responsible for coordinating civil defence and emergency management services on behalf of the councils in the Wellington region. Outside emergency response periods, WREMO focuses on identifying local hazards, implementing risk-reduction measures, promoting awareness of those risks, and providing support to other regional emergency management groups upon request.

12.3.3 Wellington Lifelines Group

The Wellington Lifelines Group (WeLG) is a collaborative working group comprising the lifeline utilities operating in the region, together with representatives from local and regional government. The group provides a forum for coordination, information sharing, and joint planning to improve regional resilience and recovery following major events.

WELL's participation in the Wellington Lifelines Group reflects the increasing importance of coordinated cross-sector resilience planning across electricity, water, transport, and telecommunications networks. Because lifeline utilities are highly interdependent, the sequencing of resilience investments in one sector can materially affect restoration outcomes in others. Effective participation, therefore, requires not only alignment of technical planning and risk assessment but also alignment of funding timeframes with regionally coordinated resilience priorities.

Where infrastructure partners operate under different regulatory or funding frameworks, fixed and smoothed allowance settings may constrain the efficient timing of cross-sector initiatives. In this context, a CPP is likely

⁶¹ <https://www.civildefence.govt.nz/cdem-sector/the-4rs/>

⁶² <https://eea.co.nz/publication/resilience-guide-pdf/>

to provide the flexibility needed to align revenue allowances with regionally coordinated resilience programmes, thereby supporting whole-of-system efficiency, prudent risk management, and improved long-term outcomes for the Wellington region.

12.3.3.1 Lifeline Utilities Under the CDEM Act

The CDEM Act defines lifeline utilities as organisations that provide 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
- Telecommunications network providers

WELL is classified as a lifeline utility under the CDEM Act.

12.3.3.2 WELL's Responsibilities as a Lifeline Utility

As a lifeline utility, WELL has specific statutory responsibilities, including:

- Ensuring it can fully function, during and after an emergency, albeit potentially at a reduced level of service
- Maintaining plans for operating during and after an emergency
- Participating in CDEM strategic planning processes
- Providing technical advice to CDEM organisations where required

The CDEM Amendment Act 2016 places increased emphasis on continuity of operations where lifeline support is essential for emergency response activities.

12.3.3.3 Earthquake Restoration Planning and Regional Constraints

In March 2013, WeLG published a report on the likely restoration timeframes for lifeline utilities under a magnitude 7.5 earthquake scenario on the Wellington fault, centred in the harbour area.⁶³ The report was developed in response to questions raised following the Christchurch earthquakes regarding how Wellington might perform in a similar seismic event.

The report identified the expected time required for each lifeline utility to restore services to a defined level across the region. A key distinction between the Canterbury and Wellington regions was Wellington's limited number of transport access routes and their vulnerability, which led to long anticipated recovery times. This risk has been partially mitigated by the development of the Transmission Gully route, as demonstrated in 2022 when State Highway 59 was closed for six weeks following a landslide.⁶⁴

⁶³ <https://www.wremo.nz/assets/Library/Reports/Lifeline-Utilities-Restoration-Times.pdf>

⁶⁴ <https://www.rnz.co.nz/news/national/474617/sh59-to-reopen-after-being-closed-for-weeks>

12.3.3.4 Interdependencies and Recovery Modelling

During 2018 and 2019, WeLG undertook a regional disaster response and recovery project, as discussed further in Section 12.5. A central focus of this work was understanding the interdependencies between lifeline utilities and how failures in one network could affect restoration across others.

The project involved detailed modelling of likely damage to lifeline utility networks using fault rupture and regional geography modelling undertaken by GNS, as well as assessment of the broader economic impacts of a major earthquake on the Wellington region. This work has informed regional resilience planning and continues to underpin WeLG's coordinated recovery approach.

12.3.4 Resilience Explorer

WELL has implemented the Resilience Explorer tool developed by Urban Intelligence to support a more consistent and systematic assessment of climate and environmental risks to the network. This online platform overlays WELL's GIS asset data with a range of environmental hazard datasets, providing an integrated view of network exposure across different risk types, as illustrated in Figure 12-2.

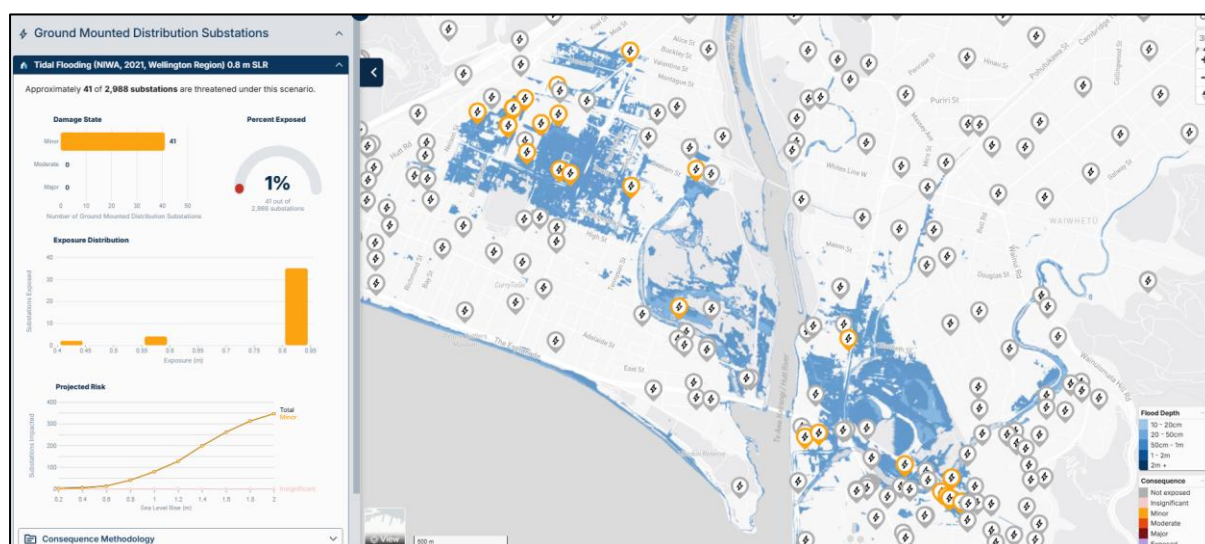


Figure 12-2 WELL's Resilience Explorer Tool

WELL is undertaking a detailed analysis using this tool, commencing with flood risk. The outcomes of this work will inform the scope, prioritisation and timing of future resilience and climate adaptation investments where additional mitigation is required.

12.3.5 WELL Contingency Plans

To meet its responsibilities as a lifeline utility under the CDEM Act, WELL has developed a suite of plans that set out how the organisation will prepare for, respond to, and recover from a range of emergency and disruption scenarios.

12.3.5.1 Emergency Response Plans

As part of the Business Continuity Framework Policy, WELL has developed a suite of Emergency Response Plans (ERPs) to address a range of emergency and high-impact business scenarios. These plans define roles, responsibilities, and response procedures and are supported by regular simulation exercises that test their effectiveness and identify opportunities for continuous improvement.

All ERPs are subject to periodic review and revision to ensure that they remain current and fit for purpose. Learnings from major natural disaster events in New Zealand, including the Christchurch and Kaikōura earthquakes and the June 2013 Wellington storm, have been incorporated into these plans to strengthen WELL's preparedness and response capability.

12.3.5.2 Civil Defence and Emergency Management Plan

WELL has developed the CDEM Plan to meet the relevant requirements of the CDEM Act. The plan outlines the arrangements and actions required to protect life, alleviate distress, and restore the electricity supply during and following a civil defence emergency.

The CDEM Plan is structured around the four 'Rs' framework for hazard management: reduction, readiness, response, and recovery, providing a consistent and integrated approach to managing events that could give rise to a civil defence emergency.

12.3.5.3 Crisis Management Plan

The Crisis Management Plan (CMP) defines the Crisis Management Team structure and outlines staff roles and responsibilities during a crisis. It also includes detailed contact information for key internal and external stakeholders who may be involved in or affected by a crisis, supporting timely coordination and effective communication.

12.3.5.4 Major Event Management Plan

The Major Event Management Plan (MEMP) defines a major event and outlines the required actions and the roles and responsibilities of staff during it. A focus of the MEMP is how the internal and external communications are managed. It includes 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

The Business Recovery Management Plan (BRMP) addresses events that disrupt occupancy of WELL's corporate offices in Upper Hutt and outlines how business operations will be recovered and, where necessary, escalated to a crisis response. This includes mobilising the Business Recovery Event Centre at the WELL Disaster Recovery site in Tawa.

The plan was activated following the November 2016 earthquake, which rendered the Petone office unsafe and required all corporate functions to relocate to the Haywards Disaster Recovery site. WELL successfully operated from that location until business-as-usual arrangements were restored in January 2017, demonstrating the effectiveness of the BRMP.

Since that time, WELL has further strengthened its business continuity by relocating its head office from Petone to Upper Hutt to eliminate tsunami risk, and its primary disaster recovery site, including the primary data centre, backup control room, and essential business continuity functions, from Transpower's Haywards substation to a purpose-built facility in Tawa. The new sites offer significantly improved resilience from the

previous sites, being housed in fully seismically rated buildings (100% New Zealand Building Standard at Importance Level 4) and located in different “islands” to each other.⁶⁵

In addition, WELL has installed Starlink connections across all its backup data centres and control rooms to provide resilient emergency communications. This enhancement reflects lessons learnt from Cyclone Gabrielle, where the loss of terrestrial communication materially constrained response and recovery efforts.

12.3.5.6 Information Technology Recovery Plan

The Information Technology Recovery Plan (ITRP) is in place to ensure that WELL’s critical IT systems can be restored quickly within defined timeframes following a major business interruption. Recovery objectives have been established through business impact assessments to ensure restoration priorities align with operational and regulatory requirements.

12.3.5.7 Major Event Field Response Plan

The Major Event Field Response Plan (MEFRP) sets out how WELL’s field contractors are prepared to respond to high-impact, low-probability events. The plan defines the roles and responsibilities of WELL and its field contractors during an event and specifies the actions required to coordinate an effective field response.

The MEFRP has a strong focus on field systems and both internal and external communications required to support the safe and timely restoration of supply. Where the scale or complexity of an event increases, a major event field response may be escalated to the MEMP.

12.3.5.8 Emergency Evacuation Plan

The Emergency Evacuation Plan (EEP) is designed to ensure the Network Control Room can respond effectively to incidents requiring short- or long-term evacuation of the facility and the rapid re-establishment of control room operations at the designated disaster recovery site.

The plan was activated following the November 2016 earthquake, which rendered the corporate office in Petone unsafe and necessitated relocating Network Control Room operations and broader corporate functions to the Haywards site.

12.3.5.9 Earthquake Response Plan

The Earthquake Response Plan is designed to ensure WELL is prepared to respond safely and effectively to earthquakes that affect the electricity network, including scenarios in which parts of the network may be isolated from one another.

The plan provides clear guidance on when and how to activate associated emergency and event management plans and sets out arrangements for the use of the disaster recovery sites. It also includes specific procedures for accessing and deploying earthquake-related resources and systems, including:

- Safe building entry process

⁶⁵ 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 the Hutt Valley.

- Locations and access arrangements for emergency spares
- The deployment of mobile substations and data centres

12.3.5.10 Pandemic Preparedness Plan

The Pandemic Preparedness Plan is designed to manage the impacts of a pandemic-related event by protecting employees from the spread of disease, maintaining a safe working environment, and ensuring the continuity of essential business functions, including under conditions of reduced staffing levels, where containment is not possible.

The plan was updated in early 2020 as it became clear that COVID-19 would significantly impact WELL's operations. It was subsequently reviewed and refined throughout the pandemic in response to evolving government guidance and to incorporate best-practice insights from WELL's sister companies overseas.

To reduce operational risk, WELL implemented split control room operations, with two control rooms in separate locations, and shifts alternating between the main control room and the disaster recovery site to minimise the crossover between controllers. This approach enabled control room operations to be maintained at a low risk level throughout all stages of the pandemic.

The plan also outlines the working arrangements for each alert level, including assigning staff across multiple sites to limit workplace exposure. During elevated alert levels, WELL transitioned to widespread remote working, with only the network control room and a small number of senior management staff operating from the two designated operational sites.

12.3.5.11 Other Emergency Response Plans

In addition to the core emergency and business continuity plans, WELL maintains a range of supporting emergency response plans and procedures to address specific operational scenarios. These include:

- 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, a requirement under Code
- Call Centre Continuance Plan

Where required, WELL also develops contingency plans for major or critical customers, outlining tailored arrangements to manage specific risks and service requirements during emergencies.

12.4 High Impact Low Probability Events

The WELL network is designed with appropriate security and reliability to handle isolated equipment failures and recurring adverse events. However, like all infrastructure, it remains exposed to potential HILP events, which could result in a major unplanned outage over an extended period.

Due to its geography and weather patterns, the Wellington region is exposed to both severe storms and seismic events, with earthquakes presenting the greatest risk of widespread damage. Other possible HILP events include upstream supply failures, communications outages, and cyber or information security breaches. These risks are managed through a combination of network design, operational controls, and IT security policies.

WELL works closely with the National Cyber Security Centre (NCSC) to ensure that its IT systems, particularly those associated with the direct control of the electricity network, are as secure as practicable. As cyber threats continue to evolve, WELL is required to make ongoing investments in training, systems, and processes to strengthen cyber security monitoring, detection, and response capabilities.

HILP events are inherently unpredictable, largely uncontrollable, and, in many cases, prohibitively expensive to fully mitigate. WELL's network design standards align with industry best practices and explicitly consider the region's typical weather and seismic conditions. However, these design standards do not extend to events that exceed what is considered 'normal' for the region.

Accordingly, WELL's approach to managing unforeseen events is structured around two complementary elements:

- Proactive risk mitigation through network planning, design, and asset maintenance.
- Effective response and recovery during and after an event, with a focus on restoring supply as quickly as possible without compromising contractor or public safety.

12.4.1 Identification and Planning for High-Impact Low-Probability Events

WELL employs a range of complementary processes to identify HILP events across its network and operating environment. These include:

- Transmission risk reviews—participation in the Connection Asset Risk Review projects undertaken jointly with Transpower every three to four years. These reviews identify risks associated with transmission circuits and substations and support the development of appropriate mitigation measures.
- Distribution risk reviews—as part of the network planning process, WELL identifies potential HILP events affecting the distribution network. Examples include the simultaneous loss of subtransmission circuits resulting in a complete loss of supply to a zone substation or the destruction of a zone substation. Contingency response plans are developed to mitigate the impacts of such events.
- Environmental risk reviews—WELL assesses the risk posed by natural disasters, including earthquakes, tsunamis, and severe storms. Seismic risk studies have been undertaken by GNS, and external specialists have supported the development of WELL's Storm Inundation Policy. WELL also utilises the Resilience Explorer Tool (refer to Section 12.3.4) to identify and assess flooding risks across the network.

WELL undertakes a range of complementary processes to identify and assess HILP events across its network and operating environment, including transmission risk reviews undertaken jointly with Transpower, internal distribution network risk assessments, and environmental risk studies covering hazards such as earthquakes, tsunamis and severe storms. These processes support the identification of credible extreme events and the development of contingency response plans and mitigation strategies. Identifying and planning for HILP events often reveals the need for targeted resilience investments that are difficult to

accommodate within the fixed and smoothed allowances available under DPP4. Many resilience initiatives involve step-changes in expenditure, cross-asset coordination, or investment in capability ahead of a clearly defined failure risk. In this context, a CPP is likely to provide the flexibility required to align funding with the scale and timing of resilience investments needed to address HILP risks, ensuring that WELL can implement appropriate mitigation measures and maintain network security in the long-term interests of consumers.

12.4.2 Strategies to Mitigate the Impact of HILP Events

The following section outlines WELL's assessment of HILP events that could materially affect network performance and security of supply. These include:

- Major storm events
- High-impact asset failure
- Upstream supply failure
- Major earthquake
- Flooding and inundation
- Wildfire

12.4.2.1 Major Storm Events

The Wellington region is exposed to high winds and severe storms, which present a significant risk to the overhead electricity network. In response, WELL applies higher wind-loading standards to the design of overhead lines compared with many other network companies. This exposure has also contributed to the relatively high proportion of the Wellington network constructed with underground cables.

A key outage risk for overhead sections of the network is contact with vegetation and wind-blown debris. This risk is managed through WELL's vegetation management programme, which, as outlined in Section 7.4.3, has been effective in supporting network reliability. However, severe storm conditions can result in strong wind gusts, causing vegetation that would not normally encroach on lines to make contact, or debris to be blown into lines before a patrol can be completed.

The Wellington region experienced a significant storm event in June 2013, comparable in magnitude to the 1968 Wahine storm. Wind gusts remained above 100 km/h for approximately 24 hours, peaking at over 200 km/h. The storm caused extensive damage across the WELL network and, at its peak, left approximately 30,000 homes and businesses without electricity. Damage was concentrated primarily on the low-voltage assets across both rural and urban areas, with uprooted trees and airborne debris damaging poles and conductors.

Outages were widespread and restoration times were extended due to hazardous conditions that limited access for patrols and repair crews. Blocked roads and traffic congestion further delayed response times. To manage the scale of the event, WELL deployed approximately 150 additional personnel from other regions to support restoration efforts.

Since the 2013 storm, WELL has implemented a range of improvements, including enhancements to vegetation management practices, field crew fatigue management, SCADA system capacity, and the ability to rapidly scale emergency resourcing for major events.

More recently, the February 2026 New Zealand storms were a series of severe weather events between 12 and 17 February 2026, a deep low-pressure system of subtropical origin moved across much of the North Island before affecting parts of the South Island. The storms produced widespread heavy rainfall, flash flooding, landslides and damaging winds across several regions. Multiple local states of emergency were declared, including in Ōtorohanga, Waipā, Taranaki, Manawātū, Rangitīkei and Manawātū–Whanganui, as rivers flooded and roads were closed.

In the Wellington region, the storm caused significant disruption, including the cancellation of ferry services, trains and flights, while strong winds brought down trees and power lines, leaving around 30,000 properties without electricity across Wellington and Manawātū–Whanganui. Extreme weather conditions were recorded, including rainfall totals of 121 mm in Wellington, and wind gusts reached 193 km/h at Mount Kaukau. Flooding also destroyed infrastructure such as bridges and isolated several communities in southern Wairarapa. The event caused widespread infrastructure disruption across transport and electricity networks.

EDBs' response plans to major storms are predicated on being able to scale up field resources through mutual aid agreements with other EDBs. The geographical extent of the damage in February 2026 impacted this approach, as all of the neighbouring EDBs that would usually be able to provide field crews to support WELL's response were fully committed responding to significant damage on their own networks. WELL received mutual aid from several South Island EDBs that were unaffected by the storm, however this was hampered by a lack of available vehicle capacity on the interisland ferry routes, leaving some of these EDBs unable to send vehicles with their personnel.

Severe weather events such as the February 2026 storms highlight the importance of building resilience into both the physical network and the operational capability of an electricity distribution business. These events reinforce the need for robust asset design standards, proactive vegetation management, and careful design of the network to reduce the consequences of windborne debris. They also demonstrate the importance of operational preparedness, including the ability to rapidly mobilise additional field crews, manage workforce fatigue over the course of a multi-day response, maintain effective communication with customers and emergency services, and utilise network visibility and control systems to support safe and efficient restoration.

12.4.2.2 High-Impact Asset Failure

WELL's system security standard is designed to provide N-1 security at the zone substation level, meaning that each zone can continue to operate at full capacity after the failure of a single asset. This is typically achieved through dual subtransmission circuits and multiple power transformers. Resilience within the 11 kV network is further supported by meshed ring configurations or tie points between radial feeders, which reduce the impact of equipment failures and improve restoration after an event.

Despite these design standards, the constrained nature of many WELL sites and shared subtransmission corridors means that a single event can affect multiple assets simultaneously, potentially resulting in a site-wide outage. Mitigation measures vary by asset type and include physical separation or barriers between transformers, spatial separation of overhead lines where practicable, and consideration of route diversity when selecting new subtransmission cable routes. WELL's fleet of mobile substations provides an additional option to restore a limited supply following a major asset failure.

In the event of a total loss of supply at a zone substation, it is often possible to restore a significant proportion of the load through network switching to supply the affected area from a neighbouring zone substation. However, this capability is not universal. It may be constrained by damage to the distribution network or

adjacent substations during a major event, by seasonal peak loading, or by the location of substations at the extremities of the network, where there are strong ties to other zones.

These limitations are expected to become more pronounced as decarbonisation accelerates. The electrification of loads previously supplied by fossil fuels will increase demand and reduce available capacity headroom, further constraining the ability to resupply areas following a zone substation outage.

Areas most affected by these constraints tend to be located at the outer edges of the network, including Wainuiomata, Karori, Mana-Plimmerton, and areas north of Upper Hutt. Two of these substations also supply major water treatment and pumping facilities at Te Marua and Wainuiomata, which provide potable water to the wider region. While both facilities are equipped with backup generation to meet emergency requirements, a full network supply is required to operate at normal capacity.

12.4.2.3 Upstream Supply Failure

WELL receives electricity supply from Transpower at GXP substations. There are nine GXPs across the Wellington region supplying WELL's network at either 33 kV or 11 kV, with some GXPs supplying at both voltage levels. The number of Installation Control Points (ICPs) supplied by each GXP is summarised in Table 12-1.

GXP	ICP Count (as of Dec 2025)
Central Park	49,818
Takapu Road	34,988
Melling	21,334
Gracefield	20,266
Haywards	13,569
Wilton	12,884
Upper Hutt	11,485
Pauatahanui	7,256
Kaiwharawhara	5,560
Total	177,022

Table 12-1 ICP Numbers per Transpower GXP

Central Park

While the loss of any of these GXPs would result in supply interruptions to one or more zone substations and a significant number of customers, the Central Park GXP represents the single highest upstream supply risk on the WELL network. A failure at Central Park would result in the greatest loss of load and customers without supply. The site supplies seven zone substations and one switching station, serving approximately 50,000 customer connections with a maximum demand of approximately 150 MVA.

The ability to transfer load away from Central Park is limited. Only approximately 17 MVA can be shifted to the Wilton GXP to support the Moore Street, Kaiwharawhara, and Karori zone substations. The area supplied

by Central Park includes much of Wellington's CBD and several nationally and regionally significant sites, including government facilities, Wellington Regional Hospital, Wellington International Airport, and the Moa Point Wastewater Treatment Plant.

The Central Park site, shown in Figure 12-3, is constrained by its small geographic footprint, having been established in its current location around 1944. Electrical assets are located in close proximity, creating multiple security-of-supply vulnerabilities. By comparison, larger transmission substations such as Penrose or Haywards are typically 300-400m across, whereas Central Park spans little more than 50 meters. The site has no fire separation between the two transformers or between bus sections within the 33 kV switchroom, further increasing the potential impact of a major asset failure.



Figure 12-3 Central Park Substation

Central Park supplies a substantial proportion of the load across central Wellington, and there is currently no upstream supply point in the event of a fire resulting in a site failure. The potential loss of supply at Central Park, therefore, represents an unacceptable risk to network security and the continuity of supply to critical customers.

Accordingly, WELL is working closely with Transpower to expand the site and improve upstream supply diversity. These initiatives are discussed further in Section 12.5.1.

Melling

Melling GXP supplies three WELL zone substations and approximately 21,000 customer connections, serving the primary commercial and residential areas of Lower Hutt, New Zealand's sixth most populous city.

Melling, shown in Figure 12-4 is located within the Hutt River's stopbanks, which expose the site to flooding and erosion risks. While the switchgear is housed in an elevated switchroom above the expected flood level,

there remains a risk that scouring or debris could damage the 110/33 kV transformers and 110 kV within the yard.

Transpower has undertaken flood risk assessments for the site. WELL is currently engaging with Transpower and Greater Wellington Regional Council about on options to relocate the GXP in conjunction with the RiverLink flood protection programme (see Section 12.4.2.5). However, this work is not currently funded.



Figure 12-4 Melling Substation (Hutt River stop bank location shown in blue)

The primary WELL costs associated with relocating Melling GXP relate to the oil-filled 33 kV cables supplying the Waterloo and Naenae zone substations. These cables are already proposed for replacement on asset health grounds during DPP5. Additional costs would also be incurred to replace the load control plant currently housed in a WELL-owned building located on the Transpower site.

In the event of a flood that interrupts supply from Melling GXP, WELL would seek to transfer the load to the Haywards and Gracefield GXPs. This transfer capability is estimated at approximately 54% of the winter peak demand and 67% of the summer peak demand. Customers unable to be supplied under this arrangement will remain without electricity until the supply is restored by Transpower.

If a Transpower outage were to be prolonged, WELL would deploy its earthquake-readiness spares (refer to Section 12.4.2.4) to establish a temporary overhead 33 kV connection from alternative GXPs to affected zone substations, enabling partial restoration of supply while permanent repairs are undertaken.

Pauatahanui

Pauatahanui GXP is located north of Porirua City and supplies approximately 7,000 customers through WELL's Plimmerton and Mana substations.

The site is situated within a 1-in-10-year flood zone.⁶⁶ The most recent significant flooding event occurred in 2016, when around 0.6m of water inundated the site, resulting in damage to WELL's batteries and communications equipment.

Transpower is currently investigating options to upgrade or relocate Pauatahanui GXP to address the identified flood risk. In parallel, WELL is assessing options for relocating or protecting its own equipment as part of any future site works.

Flooding at Pauatahanui is unlikely to result in a loss of supply to WELL's substations. Based on events such as the 2016 flood, the more likely consequences for WELL are the loss of SCADA connection to the site and the loss of battery-backed protection inter-tripping to the Mana and Plimmerton zone substations. These impacts can be managed through established operational procedures and do not pose a material risk to overall network security.

12.4.2.4 Major Earthquake

The Wellington region is intersected by multiple active fault lines capable of producing severe ground shaking. The three most well-studied faults are the Wellington, Ohariu, and Wairarapa fault lines, as shown in Figure 12-5, a regional fault map prepared by GNS Science.⁶⁷

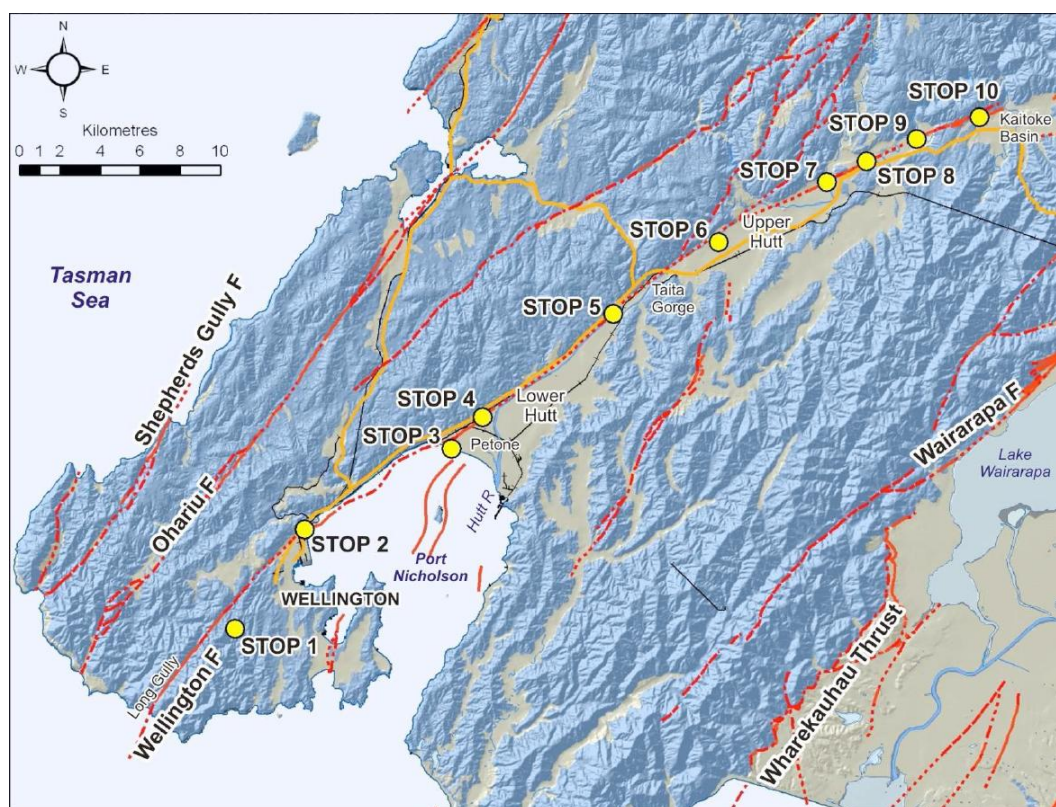


Figure 12-5 Wellington Region Fault Lines

⁶⁶ <https://porirua.govt.nz/your-council/city-planning-and-reporting/district-plan/proposed-district-plan/past-consultations/porirua-flood-mapping/>

⁶⁷ 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).

The Wellington Fault extends from Long Gully through Thorndon, along the edge of Wellington Harbour, and broadly follows 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 follows the Remutaka Ranges and last ruptured in 1855, generating an estimated magnitude 8.2 earthquake, the largest recorded in New Zealand.

In addition to these local fault lines, the Hikurangi Subduction Zone east of the North Island has been assessed as having a 25% probability of producing a magnitude 8 or greater earthquake within the next 50 years.⁶⁸

Expected earthquake impacts

A rupture of any of these faults would lead to a severe earthquake in the Wellington region, with impacts comparable to or greater than those experienced during the February 2011 Christchurch earthquake. In such an event, large sections of the electricity network are expected to be without power immediately following the earthquake.

Significant damage to transport infrastructure is also anticipated, with road access between Wellington and the Hutt Valley potentially unavailable for several weeks, materially constraining restoration activities.⁶⁹

Network damage modelling and restoration constraints

To identify potential resilience improvements, WELL has modelled the likely damage to its network arising from a major earthquake in the Wellington region. Under normal operating conditions, outages caused by equipment failure can often be mitigated by supplying affected areas from adjacent feeders or zone substations. However, the damage modelling indicates that following a major earthquake, this level of network redundancy would no longer be available. Damage would be widespread, preventing supply from adjacent feeders and resulting in extended outages across much of the network. Restoration would be further slowed by restricted access into and within the region.

Restoration time estimates were separated into the time required to bring the region to readiness and the time needed to physically repair the damaged assets. These assessments are consistent with earlier studies indicating that full restoration could take more than 90 days.

Earthquake readiness and CPP investment

The 2016 Kaikōura Earthquake reinforced the likelihood that a major seismic event in the Wellington region would cause prolonged electricity outages that would be unacceptable, even under extreme event assumptions. To address this risk, WELL applied for a CPP focused on improving earthquake readiness, which was approved in 2018.

The Readiness CPP was delivered through five dedicated workstreams:

1. Spares—this workstream was delivered through three projects covering overhead line spares, cable and jointing spares, and the procurement of a mobile 11 kV switchboard. It also included establishing distributed storage locations across the network to reduce reliance on external supply chains and enable restoration work to commence despite severed transport links.

⁶⁸ <https://www.eastcoastlab.org.nz/home/article/216/>

⁶⁹ *Restoring Wellington's Transport Links after a Major Earthquake*, WeLG/WREMO, March 2013.

2. Data Centres—three data centres were constructed and installed within the network to provide access to critical operating systems and data in the event that communications to the Network Control Room are disrupted.
3. Mobile Substations—two mobile 33 kV/11 kV substations were constructed to enable supply restoration where permanent substations are severely damaged. These substations are modular, with transformers mounted on trailers and switchgear and control equipment housed in standard 20-foot shipping containers. This arrangement is due to transport considerations. This configuration improves transportability under constrained access conditions and provides flexibility in site layout and connection arrangements.
4. Radio and Phones—a modern digital radio system was deployed to improve communications coverage and reduce reliance on cellular networks, which are unlikely to be operational following a major earthquake. A Voice over Internet Protocol (VoIP) telephone system was also installed to enhance connectivity between the Network Control Room and zone substations.
5. Seismic Reinforcement—WELL has maintained an ongoing programme to strengthen pre-1976 buildings assessed as having less than 34% of the New Building Standard (NBS). Under the CPP, this programme was expanded to strengthen 91 significant substations to a minimum of 67% of NBS.

Tsunami risk considerations

A major earthquake also presents a secondary tsunami risk to parts of the Wellington region. To mitigate this exposure, WELL has relocated its head office to Upper Hutt, outside the Petone tsunami evacuation zone.⁷⁰

12.4.2.5 Flooding and Storm Inundation

In addition to causing widespread damage to the overhead network, major storm events can also trigger flooding and landslides across parts of the region. While these secondary impacts typically do not cause the same level of direct damage, they can significantly delay restoration by blocking roads and restricting access to affected areas. Flooding can also cause long-term degradation of network assets by damaging secondary systems, such as protection and control equipment, and accelerating the corrosion of metallic components, thereby increasing the risk of subsequent failures.

To better understand and manage these risks, WELL will undertake modelling of flood exposure across its distribution network in 2025, using the Resilience Explorer tool discussed in Section 12.3.4.

Porirua Zone Substation

Porirua Zone Substation supplies approximately 7,000 customers across Porirua City, Cannons Creek, Aotea, and Titahi Bay. Parts of the site, including the transformer yard and the 11 kV switchroom, have been identified as being at risk of stormwater ponding during severe weather events. To mitigate this risk, the 11 kV switchroom is currently planned to be relocated and rebuilt in a lower-risk area within the site in 2031. Further details on this project are provided in Section 9.11.2.2.

⁷⁰ <https://www.huttcity.govt.nz/services/emergency-management/useful-information/maps>

Riverlink

RiverLink is a Greater Wellington Regional Council-led programme to strengthen Lower Hutt's flood defences along the Hutt River. WELL has several critical network assets within the project area that will benefit from the enhanced stopbanks.

Providing flood protection through a coordinated, region-wide approach is significantly more cost-effective and more resilient than having individual asset owners implement standalone mitigation measures. The cost to WELL of independently protecting each asset would be substantially higher and would deliver less secure outcomes. This has been reinforced by lessons from Cyclone Gabrielle, where stopbanks were overtopped, resulting in infrastructure failures that they were intended to protect.

As part of the RiverLink project, the 33 kV subtransmission cables between Melling GXP and Petone Zone Substation, along with several distribution substations, are being relocated to allow for the construction of the new stopbanks. Further details on this project are provided in Section 13.5.

12.4.2.6 Wildfire

The Wellington region has not historically been considered highly susceptible to wildfire. However, engagement with the Greater Wellington Regional Council has identified several areas with elevated wildfire risk. The extent and number of these areas are expected to increase over time as climate change influences vegetation growth patterns, temperature, and rainfall.

One area of particular concern is East Harbour Regional Park, where a coastal environment characterised by high winds and low rainfall can create a combination of highly flammable vegetation and an increased risk of electrical tracking. This risk is exacerbated by salt deposition on insulators, which can degrade insulation performance under dry conditions. To inform its response, WELL has engaged with its Australian sister companies to understand their approaches to managing bushfire risk. Drawing on this experience, WELL has developed a wildfire mitigation policy tailored to local conditions. The policy includes enhanced design standards for assets in wildfire-prone areas, targeted protection and control measures, such as disabling auto-reclose during elevated risk periods, and clear communication protocols with relevant emergency management agencies.

12.4.3 Summary of Primary Resilience Risks

Table 12-2 summarises WELL's key network resilience risks and the actions underway to manage and mitigate them.

Risk	Risk Type	Action
Major Earthquake	Seismic	Readiness CPP completed in 2021, including procurement of spares and substation strengthening (Section 12.4.2.4). Replacement of gas-filled 33 kV cables (Section 12.5.2).
Tsunami	Flooding	Relocation of WELL head office completed (Section 10.6).
Central Park GXP	Fire	Transpower project to extend the site by 2027 (Section 12.5.1).
Melling GXP	Flooding	Transpower's 2025 Transmission Planning Report addresses Wellington's regional transmission capacity.
Pauatahanui GXP	Flooding	
Porirua Zone Substation	Flooding	11 kV switchboard relocation planned for 2031 (Section 9.11.2.2).
Flood or Storm Surge Event	Flooding	Undertake distribution network flood risk assessment during 2025 using Resilience Explorer (Section 12.3.4). Engagement with Greater Wellington's ongoing Riverlink project (Section 12.4.2.5). Trialling submersible low-voltage pillars on Wellington's south coast.
Wildfire	Fire	Engagement with Greater Wellington to identify high-fire-risk areas. Engagement with Australian sister companies to understand their bushfire risk reduction strategies. Wildfire Risk Reduction Policy.

Table 12-2 Summary of Primary Resilience Risks

12.5 Future resilience initiatives—WeLG Regional Resilience Project

The Wellington Lifelines Regional Resilience Project (WeLG RRP) was initiated by Wellington Lifelines Group in the aftermath of the 2016 Kaikōura Earthquake. The project sought to assess the resilience of critical lifeline services across the region and to develop a coordinated, evidence-based business case for targeted resilience investment. The final report was published in October 2019.

Economic modelling undertaken as part of the project indicated that a single magnitude 7.5 earthquake on the Wellington Fault could reduce national GDP by approximately \$16.7 billion over a five-year period. Hazard and damage-state modelling was carried out using RiskScape, a multi-hazard risk assessment tool developed by GNS Science and NIWA. Lifeline utilities were engaged to inform asset fragility curves and restoration timeframes.

The broader economic impacts were assessed using MERIT (Modelling the Economics of Resilient Infrastructure Tool), which captures not only the direct costs of physical damage but also longer-term economic disruption arising from service outages.

A range of resilience investment options was then tested through the same modelling framework. This analysis identified a preferred programme of approximately \$3.9 billion in resilience expenditure, which was estimated to reduce the GDP impact of a major earthquake by \$6.16 billion.

The findings of the WeLG RRP demonstrate that electricity network resilience is foundational to the recovery of water, transport, telecommunications, and other essential services across the region. Delivering the preferred resilience pathway requires targeted, capital-intensive interventions at defined network locations,

aligned with wider regional infrastructure programmes. These investments are inherently discrete and risk-driven rather than incremental, and their efficient sequencing is determined by hazard-exposure and interdependency modelling rather than by smooth annual expenditure profiles. In this context, aligning funding with regionally coordinated resilience priorities is an important consideration in determining the most appropriate regulatory framework for delivering the step-change improvements identified through the WeLG RRP.

The preferred investment package included \$205 million of targeted investment in regional electricity infrastructure and comprised three targeted initiatives to improve the resilience of electricity networks across the Wellington region, as summarised in Table 12-3.⁷¹

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 33 kV 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

The first addressed the region's most vulnerable assets, fluid- and gas-filled subtransmission cables, by replacing them with more resilient ring configurations. The second initiative targeted the single point of failure at the Central Park Substation, which supplies much of Wellington City. The third initiative involved replacing the Central Park-to-Frederick Street cable, which was considered separately from the wider seismic cable upgrade programme because it was already scheduled for replacement due to capacity constraints.

These WeLG RRP initiatives were not included in WELL's Readiness CPP, as discussed in Section 12.4.2.4 which was intentionally focused on the rapid implementation of earthquake-preparedness measures. As a result, the longer-term network reinforcement works identified through the WeLG RRP were outside the scope of that CPP, and the required investment scale exceeded what could be accommodated within DPP2 allowances at that time.

While the readiness initiatives already implemented will materially improve restoration capability following a major earthquake, they do not eliminate the risk of widespread and prolonged outages across the network. The extent of customer impact will continue to depend on the scale and location of any seismic event, which underpins the potential need for additional resilience investments identified through the WeLG RRP.

12.5.1 Central Park

The secondary substation will be constructed, owned, and operated by Transpower, funded under a new customer connection contract and recovered as a pass-through cost to end consumers. WELL will be required to facilitate the reconfiguration and connection of its 33 kV subtransmission system.

As outlined in Section 12.4.2.3, there is a significant risk of supply loss at the Central Park GXP due to its limited supply diversity and its critical role in serving central Wellington.

⁷¹ Sourced from Wellington Lifelines Project Report, 2019.

WELL has been working with Transpower since 2009 to address this risk. In 2018, Transpower initiated a system planning analysis to assess a long list of options and determine the load that could be supplied following a high-impact, low-probability (HILP) event, such as a major earthquake or fire. This analysis was followed by a Grid Reliability Standards assessment and a Grid Investment Test to evaluate the costs and benefits of the shortlisted solutions. The preferred option passed the Grid Investment Test in 2021, following engagement with the Commission and the Authority.

A Solution Study Report commissioned by Transpower on behalf of WELL was completed in October 2024. This study defined the preferred option and the required investment scope to materially improve supply diversity in central Wellington and its southern and eastern suburbs.

The most effective way to reduce this risk is to construct a secondary substation at a nearby location and operate it as a physically separate extension of the existing Central Park GXP. This configuration will enable WELL to transfer approximately half of the Central Park 33 kV feeders, one per zone substation, onto an independent supply. This materially improves operational flexibility and maximises the amount of load that can be restored to the city in the event of a loss of supply at Central Park. Transpower's current delivery programme targets commissioning of the secondary substation in 2027.

The secondary substation will be constructed, owned, and operated by Transpower. Transpower's investment will be funded through a new customer connection contract with WELL, and recovered as a pass-through cost to WELL's customers.

WELL is responsible for facilitating the associated reconfiguration and connection of its 33 kV subtransmission network to enable the project's benefits to be realised. WELL has applied to the Commission to reopen its price path to fund this work.

12.5.2 Fluid-Filled Subtransmission Cables

While the condition and asset health management of WELL's subtransmission cables are addressed in Section 8.5.1, their performance under major seismic events presents a distinct and material resilience risk. Fluid-pressurised subtransmission cables are vulnerable to earthquake damage and are expensive and time-consuming to repair, requiring specialist skills that are not readily available within the region.

A significant earthquake could cause cable damage that does not immediately trigger an electrical fault, such as fluid leaks or sheath damage, but would nonetheless degrade network reliability. Locating fluid leaks in the absence of a fault can be challenging and time-consuming, leading to high investigation and repair costs and ongoing losses while fluid continues to escape. Once damage is identified, repairs typically require specialist crews to be mobilised from outside the region. Given these constraints, repairing fluid-filled subtransmission cables after a major seismic event may not be viable or timely.

To address this risk in the immediate aftermath of a major earthquake, the earthquake readiness programme included procuring spare equipment to enable the construction of temporary overhead lines in the most severely affected areas.

Longer-term resilience can be materially improved by replacing fluid-filled cables with modern cables installed in ducts, which are less susceptible to this type of damage and do not face the same labour resourcing constraints. Resilience can also be enhanced by diversifying cable routes to zone substations and increasing interconnection between Transpower GXPs. Route diversification reduces the likelihood that localised cable

damage will cause a complete loss of supply, compared with the current configuration, in which multiple circuits often share the same physical route.

The Wellington Lifelines Regional Resilience Project assessed the impact of subtransmission upgrades on restoration timeframes using earthquake damage modelling undertaken by GNS Science. For this analysis, the proposed works were grouped into three initiatives:

- Construction of a subtransmission ring through Wellington's eastern suburbs
- Construction of a subtransmission ring in Lower Hutt
- Seismic upgrading of other vulnerable subtransmission cables

The modelling identified constructing two subtransmission rings as the preferred option to improve the resilience of electricity distribution in the Wellington region. These rings would enable greater load transfer between zone substations and GXPs, while associated cable replacement would also provide improved route diversity. The installation of the new 33 kV bus at Evans Bay, discussed in Section 9.8.2.6, represents the first step toward establishing the eastern suburbs subtransmission ring.

Replacement of gas-filled subtransmission cables is planned as set out in Table 12-4.

Subtransmission Circuits	Cable Type	Project Completion Timeframe	Project Driver
University	Nitrogen	2027	Condition
Maidstone	Nitrogen	2029	Condition
Evans Bay	Nitrogen	2030	Condition
Ira Street	Nitrogen	2031	Criticality
Hataitai	Nitrogen	2032	Condition
Karori	Nitrogen	2033	Criticality
Waikowhai Street	Nitrogen	2035	Condition

Table 12-4 Timeframe for Gas-Filled Cable Replacement

12.5.3 Subtransmission Ring and Supply Diversification Initiatives

The subtransmission ring and supply diversification initiatives described above represent targeted, high-value interventions designed to materially reduce restoration timeframes and single-point-of-failure exposure in the event of a major seismic or regional disruption. These projects are driven by resilience modelling and network interdependency analysis rather than incremental load growth, and their benefits are realised primarily through reduced consequence rather than day-to-day reliability metrics. As such, they are typically delivered as discrete capital programmes aligned with defined risk thresholds rather than smooth annual expenditure profiles.

Under a fixed and smoothed allowance framework, the ability to efficiently sequence these step-change resilience investments may be constrained, particularly where multiple high-risk assets require intervention within the same regulatory period.

12.6 Resilience Investment and Regulatory Flexibility

Taken together, the resilience and HILP initiatives described in this section represent targeted, risk-driven investments intended to materially reduce restoration timeframes, mitigate single-point-of-failure exposure, and strengthen the Wellington region's ability to recover from major disruptive events. These projects are capital-intensive, location-specific, and sequenced based on hazard modelling and interdependency analysis rather than incremental demand growth. Their efficient delivery often requires coordinated timing across asset fleets and infrastructure sectors and does not align neatly with smoothed annual expenditure profiles.

While previous resilience investments under the Readiness CPP have strengthened emergency response capabilities, the scale and clustering of the remaining resilience priorities exceed what can be sustainably accommodated within fixed DPP4 allowances. In this context, a CPP is likely to provide greater flexibility to align revenue allowances with efficient resilience sequencing, support prudent risk management, ensure compliance with lifeline obligations, and improve long-term outcomes for consumers and the wider regional economy.

13 Customer Initiated Projects and Relocations

This section outlines customer-initiated projects and network relocations planned for WELL's network over the next 10 years. New connections and changes to existing connections arising from customer-led projects directly influence WELL's long-term network planning and development strategy. In addition, the increasing adoption of new technologies, such as energy storage systems and demand response programmes, will affect how WELL manages supply quality, network capacity, and overall system performance over the planning period.

Customer-initiated projects are inherently uncertain in timing, scope, and scale, yet they can require substantial, concentrated network investment as they proceed. Large substation connections, industrial electrification, major residential developments, infrastructure relocations, and critical public-sector projects can each trigger high-value, location-specific augmentation that exceeds typical annual investment levels. While customer capital contributions appropriately allocate direct costs, significant shared network reinforcement and capacity upgrades may still be required to accommodate these developments efficiently.

As demonstrated by the Moa Point wastewater treatment plant upgrade and the portfolio of major potential projects summarised in this section, the scale of contingent investment relative to WELL's base DPP4 allowances is material. These projects are externally driven and time-bound, often aligned with statutory delivery deadlines or government infrastructure programmes. Their timing cannot always be staged to align with smoothed regulatory allowances without risking delay to critical regional infrastructure or introducing inefficient sequencing of works

The current regulatory framework provides reopener mechanisms to address large or unforeseen connection projects. However, reliance on multiple project-specific reopeners may fragment investment planning, introduce regulatory lag, and reduce flexibility to coordinate work efficiently across asset classes. Where several major customer-driven projects proceed within the same regulatory period, the cumulative scale may exceed what can be sustainably managed through incremental reopener mechanisms alone.

In this context, a CPP is likely to provide greater flexibility to align revenue allowances with the efficient delivery of customer-driven network augmentation at scale. It would support coordinated sequencing, maintain financial viability, and ensure that regionally significant projects can proceed without distorting base investment programmes. This approach would better align the regulatory framework with the realities of externally driven network growth, technological change, and infrastructure interdependency in the long-term interests of consumers.

13.1 Connection Application Process

Applications for connections are submitted through WELL's website, allowing customers to register their request for new or modified connections.⁷² Applications are broadly categorised as residential or business connections, with fuse sizing requirements of 60A, 100A, or greater than 100A. The complexity of the connection determines the approach to customer communication and project management. For standard residential new connections, the customer's retailer acts as WELL's primary point of contact. Service levels for communication with retailers are defined in the Code and the DDA and are set out in Section 6.5.1.

⁷² <https://www.welectricity.co.nz/getting-connected/new-online-forms-holder/get-connected/>

Projects that require network extensions are managed directly by WELL's Service Delivery team in conjunction with the customer or their nominated representative. Communication related to the living process is undertaken directly between WELL's Field Service Provider and the customer's electrician. A key aspect of effective customer communication is setting clear expectations early in the process, including indicative timeframes and customer responsibilities. Current lead times for new connections requiring a new point of supply are published on the new connections' portal on WELL's website.

Simple new connections, typically residential customers, can usually be completed within three months using standard designs and pricing. WELL also undertakes regular surveys of customers and electricians to monitor performance and identify opportunities for further improvement. For larger or more complex connections that require network extensions, timeframes are developed collaboratively as WELL works with the customer to assess available network capacity and determine the scope of work required to meet the customer's needs.

Delays can arise from both the network and customer-related factors. Network-related delays may result from contractor availability, variability in work volume, or lead times for major materials such as transformers. Customer-related delays can occur where incomplete information is provided, installations are not ready for connection at the agreed date, or required documentation, such as certificates of compliance, has not been completed.

Throughout the new connection process, WELL seeks to minimise costs for customers by using standardised designs and materials, competitive tendering across multiple contractors, and applying a customer contributions policy that promotes fairness among existing, new, and future customers. WELL's customer contributions policy is discussed further in Section 13.7.

13.2 New Connections and ICPs

Figure 13-1 illustrates the trend in new dwellings consented over the past nine years.⁷³

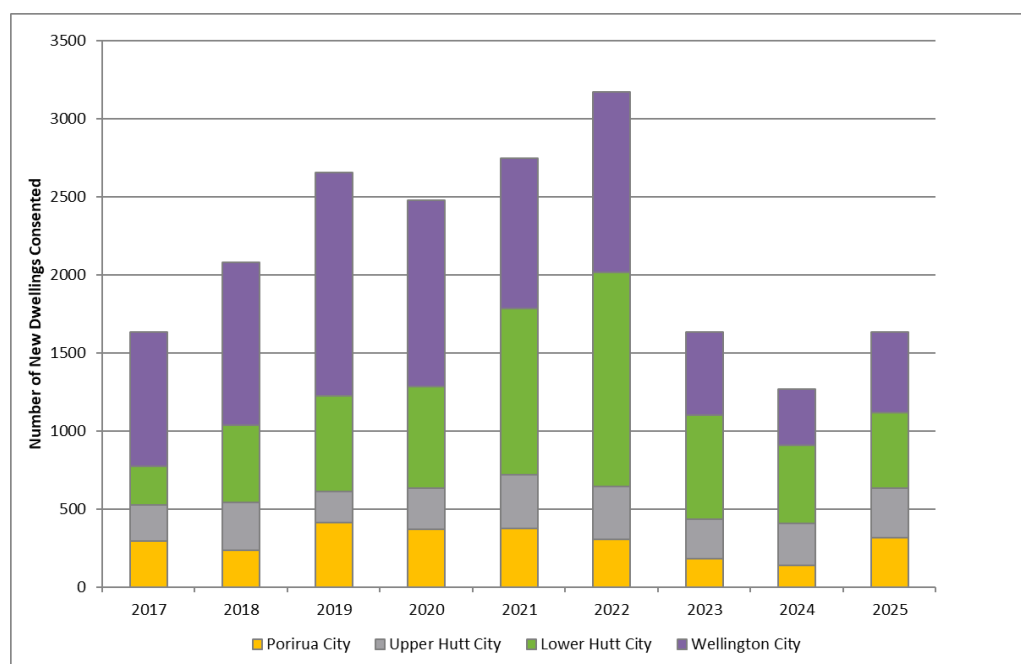


Figure 13-1 Number of New Dwellings Consented in the Wellington Region

⁷³ <https://www.stats.govt.nz/information-releases/building-consents-issued-december-2025/>

Figure 13-2 illustrates the trend in the types of dwellings being consented in the Wellington Region. The data shows a clear shift toward multi-unit development, including apartments, retirement villages, and townhouses, indicating that recent residential growth in Wellington has primarily been driven by housing intensification.⁷⁴

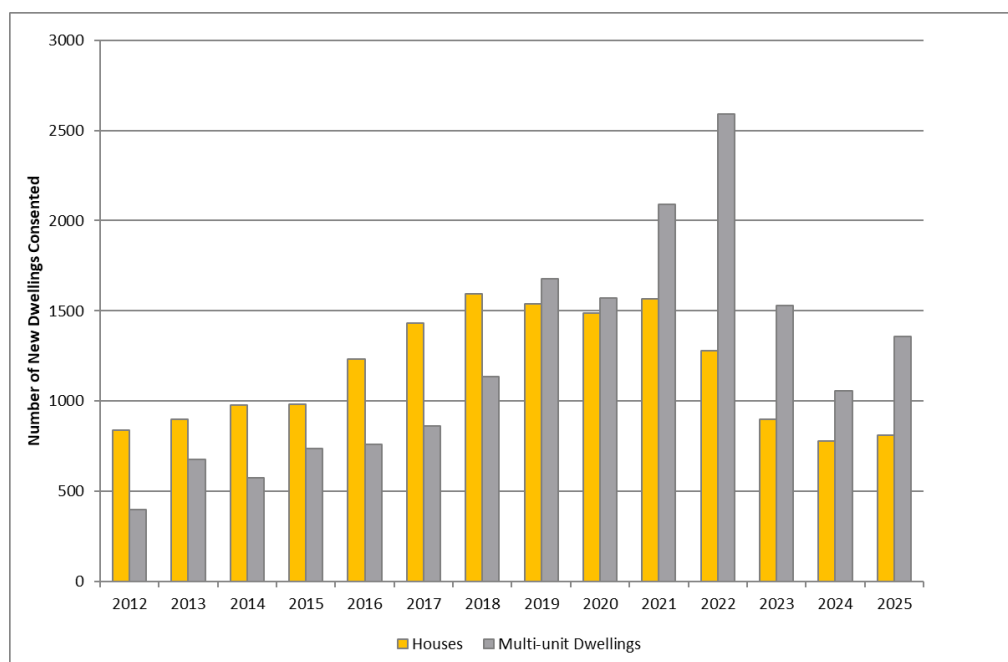


Figure 13-2 Types of New Dwellings Consented in the Wellington Region

Figure 13-3 presents the number of new connections added to the Wellington network since 2019, along with forecasted new connections over the next five years.

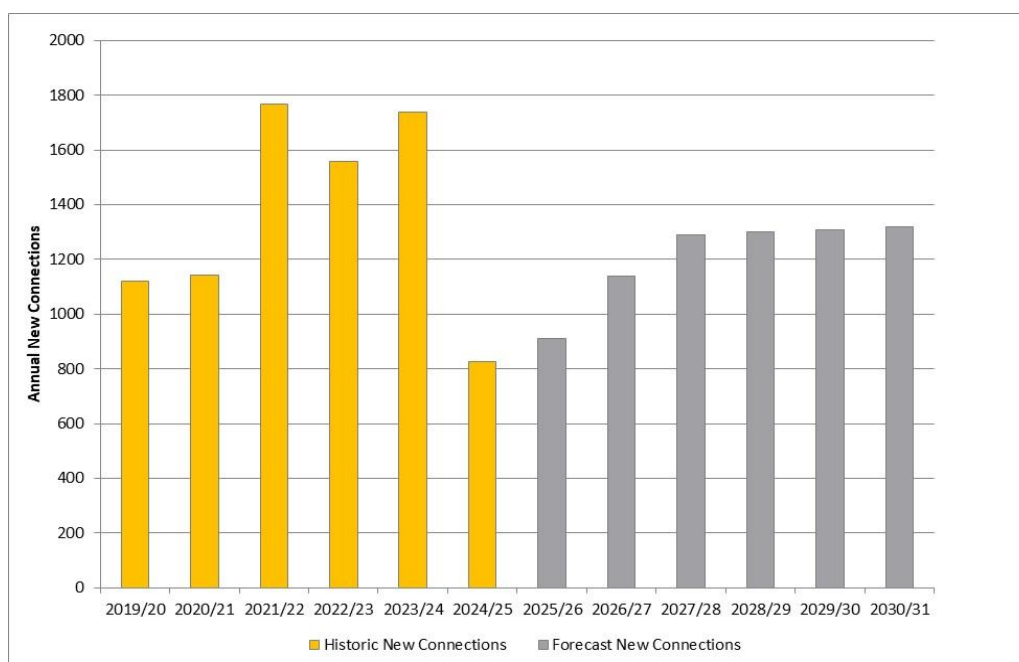


Figure 13-3 New Connections in the Wellington Region

⁷⁴ <https://www.stats.govt.nz/information-releases/building-consents-issued-december-2025/>

The number of new dwellings consented annually across the Wellington Region, within the four local authority areas served by WELL's network, peaked in 2022. Consent activity declined markedly in 2023 and again in 2024 and has started to recover.

New ICP connection volumes do not exactly align with building consent activity, reflecting the lag between consent approval and network connection, but do follow a similar trend. In addition, a single ICP connection may supply multiple dwellings within multiple-unit developments, further contributing to the divergence between consent and connection trends.

Based on the 2025 recovery in dwelling consents shown in Figure 13-1, WELL expects that new connection volumes will recover from the low levels seen in 2025/26 and quickly return to 2024/25 levels. This outlook is supported by WELL's forward work programme, which indicates that development activity within previously consented large subdivisions is continuing.

13.3 Substations and Subdivisions

Substation projects typically involve installing new transformers and high-voltage connections and are often required to meet the capacity needs of new or expanding businesses. Demand for large substation connections has remained broadly consistent over recent years. The forecast has therefore been set conservatively, reflecting uncertainty about the timing and likelihood of individual projects proceeding.

13.3.1 Industrial and Commercial Gas Conversions

The substation connection forecast also incorporates commercial and industrial gas-to-electricity conversions. In 2023, DETA Consulting surveyed major gas users in the Wellington region, identifying potential demand for up to 40 MW of additional electricity capacity across 34 entities. These findings were incorporated into WELL's 2024 AMP customer substation capital expenditure forecast.

Subsequent engagement with major gas users since the completion of the DETA survey indicates that many customers have since deferred their electrification plans. As a result, WELL will continue to refine its forecast as project-specific information becomes available and conversion timeframes become clearer.

Accordingly, and consistent with the 2026 AMP base case, no material changes have been made to the forecasts or associated capital allowances in this section, with existing assumptions retained pending greater certainty on the timing and commitment of customer-initiated projects.

13.3.2 Subdivisions

Despite the recent downturn in residential consenting discussed in Section 13.2, a number of significant new residential developments have been proposed on land to the north of the Porirua and Upper Hutt regions. Several of these developments have been designated as listed projects under the Fast-track Approvals Act 2024.

While the staged release of sections within these developments is expected to occur over an extended period, substantial enabling infrastructure will be required from the outset to support their ultimate build-out. This includes installing 11 kV feeders and zone substation assets sized to meet the capacity requirements of the developments at full completion.

Given the evolving scope, timing, and delivery pathways for these projects, WELL anticipates that the required investment will be progressed through applications for price-path reopeners, rather than included in the base forecast.

13.3.3 Public EV Charge Points

In 2025, DETA Consulting undertook an analysis for Electricity Networks Aotearoa (ENA)⁷⁵ regarding future demand for public journey charging infrastructure in the North Island. This report identified that the forecast demand for 2030 in the WELL network area could be met by three additional 50 kW chargers in Porirua and up to eight additional 50 kW chargers in Upper Hutt. No additional journey charging was forecast to be required for Wellington City or Lower Hutt, as there is sufficient capacity in the existing public chargers to meet the forecast demand in 2030.

WELL's preferred approach to connecting public electric-vehicle charging-points is to offer operators an operating envelope at their chosen location, rather than requiring extensive 11 kV network reinforcement prior to connection. This approach enables public electric-vehicle charging infrastructure to connect cost-effectively by utilising existing network capacity, while appropriately pricing the impact of network constraints during peak demand periods.

By providing operating envelopes, electric vehicle operators and customers can make informed decisions about charging locations and available charge rates, selecting the price and quality outcomes that best meet their needs across the public electric vehicle charging network.

13.4 Capacity Changes

Expenditure associated with transformer upgrades or downgrades is included in the customer substation component of the customer connection forecasts, reflecting the role these assets play in meeting changing customer capacity requirements driven by new connections, load growth, or load reductions.

13.5 Relocations

Relocation projects are commonly initiated by the New Zealand Transport Agency Waka Kotahi, or local authorities, although some relocations may also be driven by private customer requirements. Projects associated with State Highway works and local authority road safety improvements make up a significant proportion of this category.

WELL is currently engaging with the Greater Wellington Regional Council-led Riverlink project,⁷⁶ which aims to strengthen Lower Hutt's flood defences protection along the Hutt River and deliver a new bridge and interchange on State Highway 2 at Melling. The project requires relocating 33 kV and 11 kV cables, as well as distribution substations, to be funded by the customer.

13.6 Reopeners for Large New Connections

The DPP regulatory framework provides mechanisms for network operators to apply for additional allowances when unforeseen new connections, network reinforcement, or relocations arise outside the five-year regulatory allowance determination period. Given the scale of network investment that can be required to support large connection projects relative to WELL's base network-initiated programme, and the inherent uncertainty surrounding customer scope, timing, and commitment, material augmentation associated with such projects would typically be funded through price path reopeners or via Large Connection Contracts once projects are sufficiently defined and confirmed.

⁷⁵ DETA, The ENA and associated South Island EDBs, South Island EV Journey Charging Project – Report, Final Report 8 May 2025, <https://www.ena.org.nz/our-work/publications/document/1547>

⁷⁶ <https://teawakairangi.co.nz/>

Major customer projects can also introduce significant and time-critical step changes in network investment requirements. These projects are externally driven, often aligned with statutory delivery deadlines or government infrastructure programmes, and may require coordinated augmentation across multiple asset classes. Their timing cannot always be scheduled to align with smoothed regulatory allowances without causing delays or inefficient work sequencing. While capital contributions appropriately allocate direct project costs to the initiating customer, shared upstream reinforcement and capacity upgrades may still be required to maintain overall network integrity and reliability.

Table 13-1 summarises some of the potential large customer projects and the indicative associated scale of the expenditure. This expenditure quoted is indicative only as the scope, the capacity requirements, and the subsequent investment for these projects are yet to be defined. The timing of these projects along with whether some will even proceed creates further uncertainty. As these projects remain uncertain and are not currently included in the base expenditure forecasts in this AMP. Should these projects proceed, WELL would seek to reopen its price path to recover the associated efficient costs.

Major Customer Project	Indicative Related Expenditure
KiwiRail Network Capacity Upgrade ⁷⁷	\$100m
Hospital Electrification ⁷⁸	\$50m
Fast Track Residential Development North of Porirua ⁷⁹	\$40m
Total	\$190m

**Table 13-1 Possible Large Customer Projects
(Gross of Customer Contributions)**

Where there is uncertainty in the project scope and timing, efficient delivery depends on aligning funding with externally driven project timelines while maintaining continuity of base renewal and resilience programmes. This cumulative exposure is therefore an important consideration in assessing the most appropriate regulatory framework for managing contingent, customer-driven growth over the planning horizon.

In addition to these projects WELL has recently submitted reopener applications for Central Park, and Moa Point. In these circumstances, efficient delivery depends on aligning funding with externally driven project timelines while maintaining continuity of base renewal and resilience programmes. This cumulative exposure is therefore an important consideration in assessing the most appropriate regulatory framework for managing contingent, customer-driven growth over the planning horizon.

The reopener mechanisms within the DPP framework provide an important, well-established pathway for addressing large or unforeseen customer-connection projects. They allow cost recovery where qualifying thresholds are met and provide regulatory certainty once project scope and timing are confirmed. However, reopeners are typically assessed on a project-by-project basis and are therefore most effective for discrete isolated events. When multiple material projects proceed in parallel, reliance on successive reopeners may introduce regulatory lag, reduce flexibility to coordinate work efficiently across asset classes, and fragment funding alignment across the broader investment programme. In such circumstances, a more

⁷⁷ Expected to require capacity upgrades for Petone and Tawa zone substations.

⁷⁸ Expected to require a new zone substation in Newtown.

⁷⁹ Expected to require a capacity upgrade and relocation for the Plimmerton zone substation.

holistic approach to aligning revenue allowances with externally driven investment timing may support more efficient sequencing and improved long-term outcomes for consumers.

13.6.1 Moa Point Sewerage Treatment Plant

Wellington City Council is currently upgrading its Moa Point wastewater treatment plant,⁸⁰ which is critical regional infrastructure. The upgrade requires a significant increase in the site's electrical capacity, including the construction of a new 11 kV switching station and two new 11 kV feeders from WELL's Ira Street zone substation. To accommodate these additional feeders, the existing 11 kV switchboard at the Ira Street zone substation must also be replaced to provide the necessary circuit breaker capacity.

The scale of this investment exceeds what WELL can reasonably accommodate within its DPP4 capital expenditure allowances. Accordingly, WELL has applied to reopen its DPP4 price path to recover the associated costs. However, given the project's criticality and Wellington City Council's delivery timeframe for commissioning the upgraded plant, WELL commenced the required investment in advance of the additional allowances being approved.

13.7 Capital Contributions

The cost of connecting to the network, or altering an existing service, comprises the capital cost associated with designing and installing new connection assets, as well as any additional assets required to modify a customer's existing connection. These costs relate to assets that primarily benefit the connected customer and are therefore funded through a combination of annual line charges and upfront customer capital contributions.

A customer capital contribution is a one-off payment made at the commencement of a project to directly fund the required capital works. Under the Input Methodologies, customer capital contributions must be excluded from the calculation of an EDB's ongoing regulatory allowances. This indicates that some or all of the capital costs have been funded by the customer rather than by the EDB. As a result, these costs are also excluded from line charges, ensuring the assets funded directly by customers are not recovered twice.

Customer capital contributions are excluded from allowances by being deducted from the value of assets added to the Regulatory Asset Base (RAB). The RAB records the value of assets invested by the EDB and forms the basis for calculating allowable revenue, including depreciation and returns on investment. Excluding customer-funded assets from the RAB ensures that customers' contributions are not included in target revenue and, therefore, excluded from prices.

WELL calculates customer capital contributions as the incremental cost of a new connection or a change to an existing connection, plus a contribution towards shared network costs, less the incremental revenue associated with the connection or service change, as shown in Figure 13-4.



Figure 13-4 Customer Capital Contribution Calculation

This approach ensures that the connecting customer receives the direct benefits of the investment and bears the full costs of connecting to, or augmenting, their existing connection over the life of the assets that primarily

⁸⁰ <https://wellington.govt.nz/your-council/projects/moa-point-sludge-minimisation-facility>

benefit them. These costs are met through a combination of upfront capital contributions and annual line charges. At the same time, the approach avoids cross-subsidisation by existing customers, while ensuring that costs associated with shared network assets are appropriately allocated to all customers who benefit from them.

13.8 Customer Connections Summary for 2026-2036

WELL's forecast customer connection capital expenditure over the planning period, reflecting expected investment to support new connections, capacity upgrades, and customer-initiated network changes, with the total forecast expenditure presented in Table 13-2.

Customer Type	Disclosure Year Beginning 1 April									
	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035
Substation	12,334	12,350	12,386	12,425	12,401	12,377	12,353	12,328	12,304	12,228
Subdivision	6,576	6,584	6,603	6,624	6,611	6,598	6,586	6,573	6,560	6,519
High Voltage Connection	-	-	-	-	-	-	-	-	-	-
Residential and Commercial (low voltage) Customers	1,713	1,715	1,720	1,726	1,722	1,719	1,715	1,712	1,709	1,698
Public Lighting	-	-	-	-	-	-	-	-	-	-
Total Gross	20,622	20,649	20,709	20,775	20,735	20,694	20,654	20,613	20,573	20,445

Table 13-2 Customer Connection Capital Expenditure Forecast
(\$K in constant prices)

13.9 Asset Relocations Summary for 2026-2036

WELL's forecast asset relocation capital expenditure⁸¹ over the planning period, which is primarily driven by roading projects and the undergrounding of existing overhead networks associated with subdivision development, is presented in Table 13-3.

Programme	Disclosure Year Beginning 1 April									
	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035
Asset Relocations	1,957	1,960	1,965	1,972	1,968	1,964	1,960	1,956	1,953	1,945
Total Gross	1,957	1,960	1,965	1,972	1,968	1,964	1,960	1,956	1,953	1,945

Table 13-3 Asset Relocation Capital Expenditure Forecast
(\$K in constant prices)

⁸¹ Please note that this forecast excludes potential major customer-initiated relocations outlined in Section 13.7 that have not yet been contracted for delivery.

14 Expenditure Summary

This section provides an overview of WELL's forecast capital and operational expenditure over the planning period to implement this AMP.

14.1 Capital Expenditure 2026-2036

14.1.1 Customer Connections

The total forecast customer connection capital expenditure for the planning period, as discussed in Section 13, is presented in Table 14-1.

Customer Type	Disclosure Year Beginning 1 April									
	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035
Substation	12,334	12,350	12,386	12,425	12,401	12,377	12,353	12,328	12,304	12,228
Subdivision	6,576	6,584	6,603	6,624	6,611	6,598	6,586	6,573	6,560	6,519
High Voltage Connection	-	-	-	-	-	-	-	-	-	-
Residential and Commercial (low voltage) Customers	1,713	1,715	1,720	1,726	1,722	1,719	1,715	1,712	1,709	1,698
Public Lighting	-	-	-	-	-	-	-	-	-	-
Total	20,622	20,649	20,709	20,775	20,735	20,694	20,654	20,613	20,573	20,445

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 the planning period is presented in Table 14-2.

Asset Category	Disclosure Year Beginning 1 April									
	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035
Subtransmission	5,710	348	6,447	7,124	22,358	21,415	10,567	7,031	-	-
Zone Substations	11,945	9,564	5,217	6,277	19,690	11,052	335	10,059	7,473	9,437
Distribution Poles and Lines	253	-	-	-	-	-	-	-	9,463	-
Distribution Cables	30,257	24,642	19,486	7,830	1,405	10,343	29,916	17,541	14,683	20,892
Distribution Substations	670	-	-	-	-	-	-	-	-	-
Distribution Switchgear	-	-	-	-	-	-	-	-	-	-
Other Network Assets	-	-	-	-	-	-	-	-	-	-
Total	48,835	34,553	31,151	21,231	43,453	42,810	40,818	34,631	31,620	30,328

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 the planning period, 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	Disclosure Year Beginning 1 April									
	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035
Subtransmission	13,427	-	9,034	8,908	-	6,808	15,656	4,239	4,411	4,310
Zone Substations	242	5,974	592	5,867	530	525	521	470	522	544
Distribution Poles and Lines	7,271	8,035	7,723	6,748	6,584	6,275	5,996	5,799	5,572	5,027
Distribution Cables	3,824	6,046	4,356	4,453	6,654	6,549	6,462	6,454	6,403	5,965
Distribution Substations	11,957	8,175	6,198	6,756	8,272	8,425	8,401	8,390	8,323	7,753
Distribution Switchgear	8,595	10,918	10,538	10,897	7,163	6,986	6,866	6,679	6,682	6,277
Other Network Assets	3,209	6,312	5,807	5,620	6,032	5,891	5,769	5,720	5,632	5,207
Total	48,526	45,459	44,248	49,248	35,235	41,458	49,671	37,751	37,545	35,084

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, for the planning period, is presented in Table 14-4.

Programme	Disclosure Year Beginning 1 April									
	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035
Pole Replacement	1,162	1,163	1,167	1,170	1,168	1,166	1,164	1,161	1,159	1,154
OH to UG Conversions	795	796	799	801	800	798	797	795	794	790
Total	1,957	1,960	1,965	1,972	1,968	1,964	1,960	1,956	1,953	1,945

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 attributable to asset health drivers is categorised as quality of supply and other reliability, safety and environmental expenditure. Quality of supply projects targets poorly performing feeders. Other reliability, safety and environmental projects include the seismic programme and other resilience work. The total forecast capital expenditure by category for the planning period is presented in Table 14-5.

Programme	Disclosure Year Beginning 1 April									
	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035
Feeder Reliability Projects – Lines	1,058	1,219	1,429	1,232	1,170	1,197	1,223	1,248	1,271	1,286
Feeder Reliability Projects – Switchgear	1,505	1,267	699	1,006	1,195	1,169	1,144	1,119	1,095	1,065
Switchgear SCADA Control Retrofit	204	204	204	203	203	202	202	202	201	199
Total Quality of Supply	2,768	2,690	2,332	2,441	2,568	2,569	2,570	2,569	2,567	2,551
AUFLS Relay Replacement	-	-	-	-	-	-	-	-	-	-
Total Legislative and Regulatory	-	-	-	-	-	-	-	-	-	-
Seismic Strengthening	472	457	-	-	-	-	-	-	-	-
Total Other Reliability, Safety and Environment	472	457	-	-	-	-	-	-	-	-

Table 14-5 Reliability, Safety and Environmental Capital Expenditure
(\$K in constant prices)

14.1.6 Non-network Assets

The forecast non-network asset capital expenditure for the planning period is presented in Table 14-6.

Routine Expenditure	Disclosure Year Beginning 1 April									
	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035
Software and Licenses	1,497	2,262	993	868	2,516	1,642	1,126	810	1,311	1,492
IT Infrastructure	720	459	1,353	489	511	189	229	1,655	495	563
Capitalised Leases	1,655	561	646	145	1,338	492	590	421	451	517
All other projects or programmes - routine expenditure	57	220	42	55	161	60	72	78	56	63
Total Non-network Assets	3,930	3,503	3,034	1,557	4,526	2,383	2,017	2,964	2,313	2,636

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 for the planning period is presented in Table 14-7.

Category	Disclosure Year Beginning 1 April									
	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035
Customer Connection	20,622	20,649	20,709	20,775	20,735	20,694	20,654	20,613	20,573	20,445
System Growth	48,835	34,553	31,151	21,231	43,453	42,810	40,818	34,631	31,620	30,328
Asset Replacement & Renewal	48,526	45,459	44,248	49,248	35,235	41,458	49,671	37,751	37,545	35,084
Asset Relocations	1,957	1,960	1,965	1,972	1,968	1,964	1,960	1,956	1,953	1,945
Quality of Supply	2,768	2,690	2,332	2,441	2,568	2,569	2,570	2,569	2,567	2,551
Legislative and Regulatory	-	-	-	-	-	-	-	-	-	-
Other Reliability, Safety & Environment	472	457	-	-	-	-	-	-	-	-
Subtotal – Network Capital Expenditure	123,180	105,768	100,406	95,668	103,957	109,495	115,672	97,521	94,257	90,352
Non-Network Assets	3,930	3,503	3,034	1,557	4,526	2,383	2,017	2,964	2,313	2,636
Total – Capital Expenditure on Assets	127,110	109,271	103,440	97,225	108,483	111,877	117,689	100,484	96,570	92,988

Table 14-7 Capital Expenditure Forecast
(\$K in constant prices)

14.2 Operational Expenditure 2026-2036

The total forecast operational expenditure for the planning period is shown in Table 14-8.

Category	Disclosure Year Beginning 1 April									
	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035
Service interruptions & emergencies maintenance	5,668	5,793	5,908	6,027	6,147	6,270	6,395	6,523	6,654	7,047
Vegetation management	2,467	2,521	2,572	2,623	2,676	2,729	2,784	2,839	2,896	2,826
Routine & corrective maintenance and inspection	11,342	11,591	11,823	12,060	12,301	12,547	12,798	13,054	13,315	13,561
Asset replacement & renewal maintenance	1,913	1,955	1,994	2,034	2,075	2,117	2,159	2,202	2,246	2,537
Subtotal – Network Operational Expenditure	21,390	21,860	22,298	22,744	23,198	23,662	24,136	24,618	25,111	25,971
System Operations and Network Support	11,681	11,938	12,177	12,421	12,669	12,922	13,181	13,444	13,713	14,519
Business Support	17,344	16,417	15,125	15,611	16,120	16,653	17,210	17,795	18,409	19,545
Non-network solutions provided by a related party or third party	-	-	-	-	-	-	-	-	-	-
Subtotal – Non-network Operational Expenditure	29,025	28,355	27,302	28,032	28,789	29,575	30,391	31,240	32,122	34,063
Total – Operational Expenditure	50,415	50,216	49,600	50,775	51,987	53,237	54,527	55,858	57,233	60,034

Table 14-8 Operational Expenditure Forecast
(\$K in constant prices)

Appendix A Assumptions

Area	Assumption	Reasoning	Impact
The Energy Trilemma ⁸²	Customer affordability remains the primary focus under DPP4, while the pace and extent of decarbonisation support will continue to be shaped by affordability constraints, customer uptake, and evolving network requirements.	The Commission's DPP4 Determination prioritises short-term customer affordability, indicating that coordinated programmes of decarbonisation investment may require a more comprehensive level of scrutiny and justification than is typically achievable within the DPP framework.	WELL's prior planning approach emphasised cost-effective long-term investment that could efficiently support both decarbonisation and future network demand. Under the DPP4 settings, this AMP places greater focus on incremental reinforcement, delivering smaller near-term capacity increases while deferring larger projects that would otherwise provide longer-duration network benefits through a single coordinated investment.
Government Policy - Decarbonisation	It is assumed that the broader policy commitment to the Emissions Reduction Plan remains in place throughout this AMP, while recognising that specific programmes and implementation pathways may be adjusted over time.	New Zealand's net-zero carbon target by 2050 continues to be supported across successive governments, with recent policy signals, such as the October 2024 Government Policy Statement on Electricity, indicating a continued commitment to electrification as a key pathway to emissions reduction.	Policy uncertainty may result in a slower or more uneven pace of decarbonisation, creating uncertainty in when and where demand emerges and therefore affecting the timing, scale, and coordination of reinforcement investment across the 10-year plan.
Gas Transition	WELL assumes that natural gas will continue to be available to act as a transition fuel during the planning period, with significant residential electrification of heating and cooking loads expected to occur mainly beyond the 10-year horizon of this AMP.	Past fuel transitions in the residential sector have generally taken place over extended periods, rather than through rapid step changes. Current indications similarly suggest that hydrogen is more likely to emerge first in heavy transport and industrial applications than as a near-term alternative within residential gas networks. Industries transitioning from gas will free up gas supply for residential customers, along with customers having the option to transition their reticulated gas supply to bottled LPG instead of electricity. Economic conditions and the cost of replacing appliances will constrain the rate at which households can transition.	Higher gas prices, arising from supply constraints or rising network costs, may encourage customers to electrify heating and cooking earlier than expected. Alternatively, future governments could introduce policies that incentivise the residential gas transition. Either of these would result in electricity demand growing faster than forecast and requiring reinforcement sooner in affected areas.

⁸² <https://www.worldenergy.org/transition-toolkit/world-energy-trilemma-framework>

Area	Assumption	Reasoning	Impact
Demand and Consumption	This AMP assumes that while electrification-related demand growth will continue to emerge over the planning period, a significant acceleration in peak demand and electricity consumption associated with decarbonisation is more likely to occur beyond 2030.	Although New Zealand's long-term emissions reduction pathway remains dependent on increased electrification, WELL's major customers currently signal limited near-term decarbonisation investment, with most significant projects expected after 2030. The removal of support mechanisms, such as GIDI funding, has contributed to the delayed timing. Section 9.6.2 sets out how these revised assumptions have been reflected in demand forecasting.	Growth above forecast demand levels may require reinforcement projects to be brought forward or re-sequenced across the planning period. When asset lead times, outages, or delivery constraints limit timely implementation, the risk of quality standards being harder to maintain increases.
Demand-side Management and Flexibility Markets	This AMP assumes that cost-reflective pricing and retailer-led customer responses will increasingly influence discretionary demand, but that market-based flexibility services will remain insufficiently mature over the planning period to provide a reliable alternative to planned network reinforcement. Network stability and security remain the primary operational requirements, supported by continued EDB-controlled hot water ripple control, a proven mechanism for immediate, coordinated demand response during peak and emergency events.	The current regulatory framework means WELL does not assume direct reliance on competitive flexibility procurement by an EDB. Near-term growth in flexible demand has also been lower than previously expected, reflecting slower uptake of electric vehicles and rooftop PV. Customer engagement continues to indicate limited demand response participation, and smart meter control of hot water has not yet demonstrated the operational speed and reliability needed to support network security during peak or emergency events.	Given uncertainty in the scale and reliability of flexibility services, WELL's approach is to develop pricing signals that expose network constraints while maintaining operational guardrails for quality of supply. This provides a clearer basis for determining when reinforcement investment is required to maintain secure and efficient network performance.
Inflation	The financial information disclosed in the forecast capital expenditure and forecast operational expenditure schedules is presented in nominal New Zealand dollars and has been prepared using the assumptions set out in Schedule 14a.	Capex and Opex inflation have been forecast using the Reserve Bank of New Zealand's February 2026 projections to ensure a transparent and repeatable basis for nominal expenditure disclosure. CPI is used as a general inflation measure, recognising current volatility and the limited benefits of adopting alternative inflation indices.	The principal impact of this assumption is to ensure forecast Capex and Opex appropriately reflect current cost levels. WELL recognises that inflation forecasts are inherently uncertain and that the regulatory model provides partial protection against forecast divergence, so forecasts are used primarily to signal expenditure trends rather than define project-specific nominal allowances. Section 4.4.3 addresses the impact of cost escalation in more detail.

Area	Assumption	Reasoning	Impact
Operational Expenditure	Forecast operational expenditure is expected to remain above DPP4 allowances, and this funding gap is an important factor in WELL's ongoing assessment that a CPP may provide a more appropriate way to align funding with efficient long-term service delivery.	Higher forecast operational expenditure is primarily driven by: - Updated field service contract costs reflecting sector-specific inflation above CPI - Additional systems, data, and analytical capability required to support active low-voltage network management - The progressive development of asset data maturity and operational technology capability needed to support efficient planning, real-time operations, and future network security - Increasing insurance costs as climate-related events continue to influence global insurance pricing.	If operational expenditure allowances under the regulatory framework remain below forecast levels, WELL may need to reprioritise both support activities and capital delivery to remain within funding constraints. Where actual costs increase faster than forecast, programme timing and scope would need to be adjusted, further indicating that a CPP may provide a more appropriate mechanism for aligning expenditure with delivery requirements.
Insurance Costs	This AMP assumes insurance costs will increase by 7% in 2026, and 5% in each of the subsequent six years.	If insurance costs increase faster than forecast, operational expenditure pressure will increase and may require reprioritisation of expenditure within available funding. Where additional insurance costs cannot be fully absorbed, customers ultimately remain exposed through either higher future prices or the financial consequences of uninsured or partially insured network risk.	Higher-than-forecast insurance premium increases would place additional pressure on operational expenditure, requiring WELL to reprioritise spending or identify further efficiencies elsewhere in the business. This may also increase the extent to which customers are exposed to trade-offs between affordability, service delivery, and retained risk.
Unplanned Outage Quality Standard	This AMP assumes that the methodology used to set future quality targets remains broadly consistent with the Commission's 2024 determination for the 2025-2030 regulatory period.	Alignment with the Commission's 2024 quality targets reflects WELL's planning assumption that network reliability will be maintained at broadly current levels through continued investment in assets, operations, and resilience.	If future quality settings change, including new low-voltage quality measures or revised assessment methods, additional investment may be required in systems, monitoring, and network capability to support compliance and maintain service outcomes.

Area	Assumption	Reasoning	Impact
Planned Outage Quality Standard	It is assumed that the Planned Outage Quality Standards will remain compatible with the outage access needed to deliver the planned programme of renewal, reinforcement, and customer-driven capacity works, despite increasing customer expectations that planned interruptions be minimised in duration, frequency, and impact.	Safety is the overriding requirement for all planned work. Although WELL undertakes live-line work where feasible and uses switching arrangements to minimise customer impact, many renewal and reinforcement activities require planned interruptions to ensure safe access and maintain system security. The assumptions supporting planned outage targets are detailed in Section 7.1.	A planned outage quality standard that does not align with the volume of outage access required may force reprioritisation or deferral of planned works, creating trade-offs between regulatory compliance, timely capacity delivery, and customer service expectations.
Transmission Network	This AMP assumes that the transmission grid and associated GXPs will continue to be developed in line with future demand and decarbonisation needs, with Transpower maintaining appropriate resilience standards. Because transmission upgrades involve long lead times for investigation, approval, procurement, and construction, WELL's ability to sequence distribution investment efficiently depends on timely transmission delivery. It is therefore assumed that required transmission projects can be agreed, funded, and completed without materially constraining customer connections or planned network reinforcement.	WELL is engaging with Transpower on the transmission requirements identified in Sections 9 and 12.4.2.3, recognising that early coordination is necessary given the long lead times associated with transmission planning and delivery	Where transmission investment is delayed, re-scoped, or prioritised toward generation integration, WELL may need to accelerate or expand distribution investment to manage capacity and security risks that would otherwise have been addressed through grid capability.
Public Safety	This AMP assumes that public safety compliance requirements will not materially increase intervention on existing public-domain assets, and that significant works by other utilities will not materially increase third-party damage or delivery disruption. It also assumes that growing urban coordination complexity. This includes constrained road corridors, overlapping utility programmes, and increasing permitting requirements, which can be managed without materially affecting delivery efficiency or network risk.	This assumption is supported by WELL's implementation of a public safety management system, including compliance with NZS 7901 and ongoing efforts to embed consistent incident reporting, safety awareness, and proactive risk management across the business.	A higher level of intervention arising from public safety compliance could increase both operational and capital programme requirements, particularly where existing public-domain assets require earlier treatment or modified design standards.

Area	Assumption	Reasoning	Impact
Technology – Low-voltage Monitoring	It is assumed that low-voltage monitoring will continue to be selectively deployed, with priority given to locations where modelling and emerging demand patterns indicate the highest uncertainty or likelihood of future constraint.	At current market prices, universal access to smart meter data is not considered cost-effective, as customers would effectively pay twice for metering-related services. This supports a targeted monitoring approach focused on areas where better visibility is most likely to improve network decisions.	If smart meter data were available at closer to incremental cost, WELL could extend monitoring into more areas where constraints are uncertain or emerging. Even under lower-cost settings, selective deployment would remain necessary to avoid customers' funding data acquisition when network benefits are unlikely.
Resource Management Regulation	This AMP assumes that future resource management changes will not retrospectively affect the compliance status of existing lawful assets, thereby avoiding unplanned intervention or additional programme cost.	This assumption is supported by the historical treatment of existing lawful land use under changing resource management rules, which has generally avoided retrospective intervention for established infrastructure.	Changes requiring intervention in existing assets could increase both operational and capital expenditures, particularly when assets must be relocated or redesigned to remain compliant. A shift in legal responsibility for relocation costs associated with other utilities' programmes would similarly create unfunded cost pressure that may affect WELL's ability to deliver planned works within current allowances.
Climate Change Adaptation – Coastal Environments	Insurance market responses, including rising premiums, reduced coverage, or withdrawal from high-risk locations, are increasingly likely to influence when coastal adaptation or retreat decisions occur, often ahead of formal infrastructure or planning interventions.	WELL has a continuing obligation to supply existing customers and therefore cannot assume withdrawal of network assets from potential inundation areas while those locations remain occupied. At present, there are no clear territorial local authority signals that any part of WELL's network will be subject to managed retreat within the planning period.	Any decision to defend or retreat from vulnerable coastal areas may require significant changes to network configuration, including asset relocation, removal, or redesign. The timing and form of those decisions will materially influence whether WELL needs to invest in inundation-tolerant solutions or alternative asset arrangements in affected locations.
High Impact, Low Probability Events	WELL's resilience planning and emergency preparedness are intended to reduce the consequences of major events but cannot eliminate the potential for a high-impact low-probability event to materially disrupt programme delivery if one occurs.	Extreme disruptive events can be prepared for but not predicted. WELL considers that its existing resilience measures, including contingency planning, mutual aid agreements, strategic spares, and readiness investments, provide an appropriate basis for responding to more routine major events such as storms and moderate earthquakes. If a more severe event occurs, the Input Methodologies provide a mechanism to recover immediate response costs and, where necessary, to seek a different price path to fund recovery.	An extreme disruptive event affecting significant parts of WELL's network would require revisions to elements of this AMP, including changes to programme sequencing, expenditure priorities, and recovery-related investment.

Appendix B Update from the 2025 Plan

Material Changes Since the Previous Asset Management Plan

Relative to the 2025 AMP, the principal material changes reflected in this 2026 AMP relate to updated treatment of future network capability requirements, increased emphasis on uncertainty in future demand pathways, and expanded consideration of resilience and enabling systems within the existing expenditure framework.

Asset Management

The 2026 AMP places greater emphasis on future network capability requirements than did the 2025 AMP, particularly at the low-voltage level, where increasing customer energy resources are expected to change operational requirements over time. This includes expanded consideration of low-voltage observability, telemetry, and monitoring to support future network security and performance as distributed generation, battery storage, and electric vehicle charging increase.

This AMP expanded the discussion of digital capabilities as enablers of asset management and network operations, including operational technology, system integration, data availability, and real-time analytics required to support future operational decision-making.

Expenditure

The reduced investment profile established in the 2025 AMP is maintained to remain consistent with DPP4 allowance settings. The 2026 AMP more clearly identifies the increasing interaction between renewal, resilience, and capability-driven expenditure requirements over the planning period. Greater emphasis is also placed on the limitations of sequencing multiple investment drivers within a fixed, smoothed allowance framework, particularly when clustered interventions may be required within the same regulatory period.

Forecasts

Forecasting assumptions have been updated to reflect increased uncertainty in future demand pathways, including the effects of electrification, distributed energy resources, and changing customer load behaviour. Compared with the 2025 AMP, greater weight is placed on the influence of customer behaviour and pricing signals on future network utilisation, recognising that reinforcement timing will depend not only on connection growth but also on how and when electricity is used across the network.

Risk and Uncertainty

The 2026 AMP strengthens resilience planning, placing greater emphasis on Wellington's severe wind environment, seismic exposure, and restoration requirements. Lessons from recent storm events, restoration assessments, and resilience modelling are more explicitly reflected in planning assumptions.

This AMP also places greater emphasis on preserving investment optionality under uncertainty, including avoiding premature capital commitment until demand drivers become clearer, while maintaining the ability to respond to emerging constraints.

Funding under CPP is likely to more effectively support WELL's long-term investment needs

Throughout the 2026 AMP, WELL has identified the circumstances that may support submission of a CPP application. The AMP provides context for the growing tension between WELL's long-term investment requirements and the expenditure flexibility afforded by DPP4 allowances.

While the AMP maintains the reduced investment profile established under DPP4, it identifies areas where the timing, scale, and interplay of renewal, resilience, network capability, and enabling system investments are increasingly difficult to accommodate efficiently within a fixed, smoothed allowance framework. This is particularly relevant when multiple asset risks or service drivers arise concurrently, when investment lead times are long, or when deferral increases longer-term costs, service risk, or the likelihood of less efficient future intervention.

The 2026 AMP does not present the submission of a CPP application as a predetermined outcome but recognises that a CPP is likely to provide greater flexibility to align revenue allowances with efficient expenditure when future investment requirements materially exceed current settings. This would support prudent risk management, the continued delivery of resilience and reliability outcomes, and the development of future network capabilities in the long-term interests of consumers.

Summary of progress and material changes

Over the past year, WELL has continued reviewing its asset management strategy and practices. Progress against the gaps identified in the 2025 AMP, along with progress and material changes to network development projects and lifecycle asset management plans, are shown in Table B-1.

2026 AMP Section	Item	Description
1.6	Capability to Deliver	Update: Created a Project Management Office (PMO) to support the delivery of WELL's investment programme.
3.2.5	Responsibilities	Update: Responsibility for environmental, social and governance (ESG) has moved to the Chief Financial Officer
4.1	Changes from the 2025 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 reaffirmed its position on flexibility services as a market-led approach to valuing and clearing constraints, with the EDB providing guardrails based on the network's current and voltage limits.
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.
8.3	Asset Health and Criticality Analysis	Update: WELL has updated its Health-Criticality framework to improve its forecasting of future asset health and to better align with the industry-standard EEA guidelines. Whereas the previous framework was dependent on observed asset condition, this updated framework includes an assessment of age-based probability of failure, resulting in a step change in asset health indicators compared to previous AMPs.
8.5.1.6	Outcome of Asset Health and Criticality Analysis	Update: A leak appeared on Evans Bay Circuit 2 in December 2025, with the repair completed in February 2026.
9.6.1	Wellington Network Maximum Demand Forecast	Update: This section details the forecast of maximum demand in the Wellington Electricity network for the planning period.

2026 AMP Section	Item	Description
9.8.4.2	Ira Street zone substation capacity	2025 AMP: This stepwise approach is continuing, there have been minor adjustments to the expected timing of component upgrades. The switchboard is committed for replacement in the 2026 disclosure year 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.
		Update: The project continues in accordance with the approach outlined in the 2025 AMP, with no material changes identified.
9.8.4.3	Evans Bay zone substation capacity.	2025 AMP: The 33 kV bus and power transformer replacement at Evans Bay was completed. 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 later, ideally coordinated with a proposed NZTA redevelopment of State Highway 1 at the Basin Reserve and Mount Victoria Tunnel.
		Update: The project continues in accordance with the approach outlined in the 2025 AMP, with no material changes identified.
9.8.4.3	Palm Grove zone substation capacity	2025 AMP: Changes in customer intentions made it unclear whether a new zone substation will be constructed. Declining demand at Palm Grove and the availability of 11 kV backfeeds allow WELL to wait for the customer's situation to be resolved before deciding whether to invest in additional capacity at Palm Grove.
		Update: A major customer-led decarbonisation development has been proposed in the Newtown area at a scale that would necessitate the establishment of a new zone substation. At the same time, WELL and Transpower are advancing site-diversity and capacity initiatives at Central Park Substation to support anticipated growth in critical loads, including those associated with the Wellington Regional Hospital precinct. These initiatives are expected to strengthen supply resilience and increase upstream capacity, creating greater optionality to accommodate both hospital demand growth and wider decarbonisation-driven increases in load across the CBD and eastern network.
9.11.2.2	Porirua zone substation capacity	2025 AMP: Capacity at Porirua is to 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.
		Update: The project continues in accordance with the approach outlined in the 2025 AMP, with no material changes identified.
9.13.2.4	Trentham zone substation capacity	2025 AMP: The Trentham 33 kV fluid-filled cables are to be replaced to maximise use of the available 33 kV capacity from Haywards GXP. The interconnectivity between Trentham and Maidstone will be improved through upgrades to cable and overhead line sections.
		Update: The project continues in accordance with the approach outlined in the 2025 AMP, with no material changes identified.
9.14	Low-voltage reinforcement	Update: WELL has updated its low-voltage reinforcement Capex forecast based on updated modelling and revised residential decarbonisation load growth forecasts.
11.3.2	Low-voltage Management Projects	Update: WELL's low-voltage network management innovation projects are underway.
12.4.3	Resilience Risks	Update: WELL has provided an update of its primary network resilience risks and the actions underway to address them.



2026 AMP Section	Item	Description
Schedule 11b	Insurance Costs	Update: WELL has revised these assumed increases to 7% in 2026 and 5% over the subsequent five years.
Schedule 12c	Customer Connections	Update: WELL has changed its approach to recognising new connections, using a living date rather than a restoration date.
Schedule 13	Asset Management Maturity Assessment	Update: WELL has increased its AMMAT score on question #27 from 2 to 3 following the completion of the project to formalise and control asset management strategies within WELL's document framework, and to provide contractors with improved forward visibility of the multi-year work programme.

Table B-1 Material Changes in the 2026 AMP

Comparison of Current Year Expenditure Forecasts to the previous AMP

Comparisons between forecast operating expenditure for the Current Year (i.e. the disclosure year beginning 1 April 2025) in this AMP and the same period in the prior AMP are shown below in Table B-2.

Expenditure Category	Current Year Forecast from 2025 AMP	Current Year Forecast from 2026 AMP	Variation	
Service Interruptions and Emergencies	4,691	3,489	(1,202)	-26%
Vegetation Management	1,872	2,305	434	23%
Routine and Corrective Maintenance and Inspection	10,904	9,419	(1,484)	-14%
Asset Replacement and Renewal	1,704	1,568	(136)	-8%
System Operations and Network Support	10,901	9,439	(1,462)	-13%
Business Support	14,149	13,274	(875)	-6%
Non-network solutions provided by a related party or third party	-	-	-	0%
Operational Expenditure	44,220	39,494	(4,726)	-11%

Table B-2 Comparison of Operational Expenditure against 2025 AMP Forecasts (\$K, forecast in nominal dollars)

Overall operating expenditure for the Current Year is forecast to decrease by \$4.7 million (11%) compared with the forecasts for the same period in the 2025 AMP. This reduction primarily reflects lower forecast expenditure across service interruptions and emergencies, routine and corrective maintenance, system operations and network support, and business support. The lower forecast expenditure primarily reflects the transition to a new contractor agreement, which delayed delivery of some work programmes by approximately six months during the Current Year, rather than any reduction in the underlying operational demands facing the network.



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together

These reductions are partly offset by increased vegetation management expenditure, reflecting continued prioritisation of vegetation-related risk mitigation in response to Wellington's exposure to severe wind events and the importance of maintaining reliability across overhead network areas.

Although the Current Year forecast is lower overall, the underlying drivers of operating expenditure remain consistent with those identified throughout this AMP: ageing assets, increasing resilience expectations, growing system complexity, and the need to progressively strengthen operational technology, data capability, and specialist support.

The revised forecast, therefore, reflects short-term programme and timing adjustments within the current regulatory period, rather than any easing of the longer-term operational pressures that continue to shape WELL's expenditure outlook and reinforce the increasing challenge of sustaining service outcomes efficiently within fixed DPP4 allowance settings.

Comparisons between forecast capital expenditure for the Current Year (the disclosure year beginning, i.e. April 2025) in this AMP and the same period in the prior AMP are shown below in Table B-3.

Expenditure Category	Current Year Forecast from 2025 AMP	Current Year Forecast from 2026 AMP	Variation	
Customer Connection	17,695	17,415	(280)	-2%
System Growth	16,652	14,946	(1,706)	-10%
Asset Replacement and Renewal	42,044	48,710	6,666	16%
Asset Relocations	1,913	1,417	(495)	-26%
Reliability, Safety and Environment	6,814	4,494	(2,320)	-34%
Expenditure on Non-network Assets	24,561	22,507	(2,054)	-8%
Gross Capital Expenditure	109,679	109,490	(189)	0%
Customer Contributions	14,028	14,915	887	6%
Net Capital Expenditure	95,651	94,576	(1,076)	-1%

Table B-3 Comparison of Capital Expenditure against 2025 AMP Forecasts
(\$K, forecast in nominal dollars)

The overall capital expenditure forecast for the Current Year remains materially consistent between the 2025 AMP and the 2026 AMP, with gross capital expenditure reducing by \$0.2 million (0%) and net capital expenditure by \$1.1 million (1%). This immaterial variation reflects continued sequencing and reprioritisation of expenditure within the constraints of the DPP4 allowances, rather than any reduction in underlying investment need.

Movements between expenditure categories reflect adjustments to project timing and scope to align expenditure with available allowances. The increase in asset replacement and renewal expenditure reflects updated prioritisation of condition-driven interventions, while lower forecast expenditure in system growth,

reliability and safety, and non-network assets largely reflects expenditure being deferred or rescheduled where timing flexibility remains available.

While this approach preserves short-term expenditure stability and maintains optionality when future drivers remain uncertain, it increasingly requires balancing competing investment priorities within the fixed and smoothed DPP4 allowance. These allowances are unlikely to support efficient delivery when multiple renewal, resilience, network capability, and enabling system requirements emerge concurrently. As investment lead times lengthen and the potential for step changes in expenditure increases, the scope to continue managing future needs through reprioritisation alone becomes increasingly limited. WELL considers that a CPP application is increasingly likely to provide the regulatory flexibility needed to better align revenue allowances with the timing and scale of efficient long-term investment.



	Current Year CY	CY+1	CY+2	CY+3	CY+4	CY+5	CY+6	CY+7	CY+8	CY+9	CY+10
\$000 (in constant prices)											
Consumer connection	17,415	20,622	20,649	20,709	20,775	20,735	20,694	20,654	20,613	20,573	20,445
System growth	14,946	48,835	34,553	31,151	21,231	43,453	42,810	40,818	34,631	31,620	30,328
Asset replacement and renewal	48,710	48,526	45,459	44,248	49,248	35,235	41,458	49,671	37,751	37,545	35,084
Asset relocations	1,417	1,957	1,960	1,965	1,972	1,968	1,964	1,960	1,956	1,953	1,945
Reliability, safety and environment:											
Quality of supply	2,525	2,768	2,690	2,332	2,441	2,568	2,569	2,570	2,569	2,567	2,551
Legislative and regulatory	1,550	-	-	-	-	-	-	-	-	-	-
Other reliability, safety and environment	419	472	457	-	-	-	-	-	-	-	-
Total reliability, safety and environment	4,494	3,240	3,147	2,332	2,441	2,568	2,569	2,570	2,569	2,567	2,551
Expenditure on network assets	86,983	123,180	105,768	100,406	95,668	103,957	109,495	115,672	97,521	94,257	90,352
Expenditure on non-network assets	22,507	3,930	3,503	3,034	1,557	4,526	2,383	2,017	2,964	2,313	2,636
Expenditure on assets	109,490	127,110	109,271	103,440	97,225	108,483	111,877	117,689	100,484	96,570	92,988
Subcomponents of expenditure on assets (where known)											
Energy efficiency and demand side management, reduction of energy losses											
Overhead to underground conversion											
Research and development											
Difference between nominal and constant price forecasts											
\$000											
Consumer connection	-	454	919	1,397	1,889	2,383	2,886	3,398	3,920	4,451	4,970
System growth	-	1,074	1,537	2,102	1,931	4,995	5,971	6,716	6,586	6,841	7,373
Asset replacement and renewal	-	1,068	2,022	2,985	4,479	4,050	5,782	8,173	7,179	8,123	8,529
Asset relocations	-	43	87	133	179	226	274	323	372	422	473
Reliability, safety and environment:											
Quality of supply	-	61	120	157	222	295	358	423	488	555	620
Legislative and regulatory	-	-	-	-	-	-	-	-	-	-	-
Other reliability, safety and environment	-	10	20	-	-	-	-	-	-	-	-
Total reliability, safety and environment	-	71	140	157	222	295	358	423	488	555	620
Expenditure on network assets	-	2,710	4,705	6,774	8,701	11,950	15,272	19,033	18,545	20,392	21,965
Expenditure on non-network assets	-	86	156	205	142	520	332	332	564	500	641
Expenditure on assets	-	2,796	4,861	6,978	8,842	12,470	15,604	19,365	19,109	20,893	22,606
Commentary on options and considerations made in the assessment of forecast expenditure											
<i>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</i>											

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11a(ii): Consumer Connection

Consumer types defined by EDB*

Subdivision

Substation

High Voltage Connection

Residential & Commercial (Low Voltage)

Public lighting

*include additional rows if needed

Consumer connection expenditure

less Capital contributions funding consumer connection

Consumer connection less capital contributions

11a(iii): System Growth

Subtransmission

Zone substations

Distribution and LV lines

Distribution and LV cables

Distribution substations and transformers

Distribution switchgear

Other network assets

System growth expenditure

less Capital contributions funding system growth

System growth less capital contributions

11a(iv): Asset Replacement and Renewal

Subtransmission

Zone substations

Distribution and LV lines

Distribution and LV cables

Distribution substations and transformers

Distribution switchgear

Other network assets

Asset replacement and renewal expenditure

less Capital contributions funding asset replacement and renewal

Asset replacement and renewal less capital contributions

Current Year CY

CY+1

CY+2

CY+3

CY+4

CY+5

\$000 (in constant prices)

9,18912,33412,35012,38612,42512,401

6,4946,5766,5846,6036,6246,611

- - - - -

1,7321,7131,7151,7201,7261,722

- - - - -

17,41520,62220,64920,70920,77520,735

14,84514,79915,65816,04916,45516,784

2,5705,8234,9914,6604,3213,951

Current Year CY

CY+1

CY+2

CY+3

CY+4

CY+5

\$000 (in constant prices)

694670- - -

6,66011,9459,5645,2176,27719,690

2,51230,51024,64219,4867,8301,405

4,9595,7103486,4477,12422,358

93- - -

- - -

29- -

14,94648,83534,55331,15121,23143,453

- - -

14,94648,83534,55331,15121,23143,453

Current Year CY

CY+1

CY+2

CY+3

CY+4

CY+5

\$000 (in constant prices)

3,56313,439-9,0348,908-

1,0032425,9745925,867530

12,5767,2778,0357,7236,7486,584

5,7433,8276,0464,3564,4536,654

19,41511,9258,1756,1986,7568,272

3,8088,13110,91810,53810,8977,163

2,6023,6836,3125,8075,6206,032

48,71048,52645,45944,24849,24835,235

- - -

48,71048,52645,45944,24849,24835,235

Company Name	Wellington Electricity Lines
AMP Planning Period	1 April 2026 - 31 March 2036

[illegible][illegible]

41 * Direct billing expenditure by suppliers that direct bill the majority of their consumers

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[illegible]

FDBs may provide explanatory comment on the options they have considered (including scenarios used) in a

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 10.

Company Name **Wellington Electricity Lines**
 AMP Planning Period **1 April 2026 - 31 March 2036**

SCHEDULE 12a: REPORT ON ASSET CONDITION

This schedule requires a breakdown of asset condition by asset class as at the start of the forecast year. The data accuracy assessment relates to the percentage values disclosed in the asset condition columns. Also required is a forecast of the percentage of units to be replaced in the next 5 years. All information should be consistent with the information provided in the AMP and the expenditure on assets forecast in Schedule 11a. All units relating to cable and line assets, that are expressed in km, refer to circuit lengths.

sch ref

Asset condition at start of planning period (percentage of units by grade)												
Voltage	Asset category	Asset class	Units	H1	H2	H3	H4	H5	Grade unknown	Data accuracy (1-4)	% of asset forecast to be replaced in next 5 years	
All	Overhead Line	Concrete poles / steel structure	No.	0.15%	0.21%	27.42%	32.05%	39.56%	0.62%	3	1.42%	
All	Overhead Line	Wood poles	No.	0.34%	2.37%	59.10%	23.76%	12.89%	1.54%	3	17.00%	
All	Overhead Line	Other pole types	No.	-	-	0.84%	1.68%	96.64%	0.84%	3	-	
HV	Subtransmission Line	Subtransmission OH up to 66kV conductor	km	-	-	62.46%	29.82%	7.72%	-	2	-	
HV	Subtransmission Line	Subtransmission OH 110kV+ conductor	km	-	-	-	-	-	- N/A			
HV	Subtransmission Cable	Subtransmission UG up to 66kV (XLPE)	km	-	7.20%	15.24%	67.72%	9.84%	-	3	7.20%	
HV	Subtransmission Cable	Subtransmission UG up to 66kV (Oil pressurised)	km	-	14.59%	85.41%	-	-	-	3	33.15%	
HV	Subtransmission Cable	Subtransmission UG up to 66kV (Gas pressurised)	km	-	46.94%	53.06%	-	-	-	3	53.69%	
HV	Subtransmission Cable	Subtransmission UG up to 66kV (PILC)	km	-	0.60%	99.40%	-	-	-	3	-	
HV	Subtransmission Cable	Subtransmission UG 110kV+ (XLPE)	km	-	-	-	-	-	- N/A			
HV	Subtransmission Cable	Subtransmission UG 110kV+ (Oil pressurised)	km	-	-	-	-	-	- N/A			
HV	Subtransmission Cable	Subtransmission UG 110kV+ (Gas Pressurised)	km	-	-	-	-	-	- N/A			
HV	Subtransmission Cable	Subtransmission UG 110kV+ (PILC)	km	-	-	-	-	-	- N/A			
HV	Subtransmission Cable	Subtransmission submarine cable	km	-	-	-	-	-	- N/A			
HV	Zone substation Buildings	Zone substations up to 66kV	No.	-	-	100.00%	-	-	-	4	-	
HV	Zone substation Buildings	Zone substations 110kV+	No.	-	-	-	-	-	- N/A			
HV	Zone substation switchgear	22/33kV CB (Indoor)	No.	-	15.38%	-	-	84.62%	-	4	15.38%	
HV	Zone substation switchgear	22/33kV CB (Outdoor)	No.	-	-	-	-	-	- N/A			
HV	Zone substation switchgear	33kV Switch (Ground Mounted)	No.	-	-	-	-	-	- N/A			
HV	Zone substation switchgear	33kV Switch (Pole Mounted)	No.	-	-	100.00%	-	-	-	3	-	
HV	Zone substation switchgear	33kV RMU	No.	-	-	-	-	-	- N/A			
HV	Zone substation switchgear	50/66/110kV CB (Indoor)	No.	-	-	-	-	-	- N/A			
HV	Zone substation switchgear	50/66/110kV CB (Outdoor)	No.	-	-	-	-	-	- N/A			
HV	Zone substation switchgear	3.3/6.6/11/22kV CB (ground mounted)	No.	-	58.86%	27.79%	4.36%	8.99%	-	3	6.27%	
HV	Zone substation switchgear	3.3/6.6/11/22kV CB (pole mounted)	No.	-	-	-	-	-	- N/A			
Asset condition at start of planning period (percentage of units by grade)												

sch /

	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
38												
39	HV	Zone Substation Transformer	Zone Substation Transformers	No.	3.85%	15.38%	76.92%	-	3.85%	-	4	11.54%
40	HV	Distribution Line	Distribution OH Open Wire Conductor	km	1.10%	16.56%	37.58%	34.37%	10.39%	-	3	3.40%
41	HV	Distribution Line	Distribution OH Aerial Cable Conductor	km	-	-	47.98%	6.60%	45.42%	-	3	-
42	HV	Distribution Line	SWER conductor	km	-	-	100.00%	-	-	-	3	-
43	HV	Distribution Cable	Distribution UG XLPE or PVC	km	-	0.56%	0.25%	20.91%	78.28%	-	3	-
44	HV	Distribution Cable	Distribution UG PILC	km	1.71%	5.03%	25.12%	59.86%	8.28%	-	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.	-	-	3.70%	7.41%	88.89%	-	3	-
47	HV	Distribution switchgear	3.3/6.6/11/22kV CB (Indoor)	No.	16.09%	17.77%	36.24%	7.12%	22.78%	-	3	8.08%
48	HV	Distribution switchgear	3.3/6.6/11/22kV Switches and fuses (pole mounted)	No.	9.32%	24.32%	17.43%	19.30%	28.10%	1.53%	3	6.72%
49	HV	Distribution switchgear	3.3/6.6/11/22kV Switch (ground mounted) - except RMU	No.	15.08%	28.53%	49.62%	5.64%	1.13%	-	3	37.45%
50	HV	Distribution switchgear	3.3/6.6/11/22kV RMU	No.	12.80%	34.59%	20.69%	9.61%	22.31%	-	3	3.81%
51	HV	Distribution Transformer	Pole Mounted Transformer	No.	-	0.55%	35.59%	52.24%	11.63%	-	3	8.19%
52	HV	Distribution Transformer	Ground Mounted Transformer	No.	-	0.70%	60.14%	34.24%	4.92%	-	3	7.34%
53	HV	Distribution Transformer	Voltage regulators	No.	-	-	-	-	-	-	N/A	-
54	HV	Distribution Substations	Ground Mounted Substation Housing	No.	3.81%	33.46%	39.38%	18.29%	5.06%	-	3	3.81%
55	LV	LV Line	LV OH Conductor	km	5.23%	30.90%	46.76%	14.28%	2.83%	-	2	1.40%
56	LV	LV Cable	LV UG Cable	km	0.00%	5.50%	49.90%	25.04%	19.56%	-	2	0.90%
57	LV	LV Streetlighting	LV OH/UG Streetlight circuit	km	1.56%	11.29%	53.24%	26.63%	7.28%	-	2	0.50%
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.	24.19%	17.80%	47.77%	2.75%	7.49%	-	3	8.45%
60	All	SCADA and communications	SCADA and communications equipment operating as a single system	Lot	48.03%	24.02%	7.48%	9.45%	11.02%	-	3	39.37%
61	All	Capacitor Banks	Capacitors including controls	No.	-	-	-	-	-	-	N/A	-
62	All	Load Control	Centralised plant	Lot	-	20.00%	60.00%	4.00%	16.00%	-	3	20.00%
63	All	Load Control	Relays	No.	-	-	-	-	-	-	N/A	-
64	All	Civils	Cable Tunnels	km	-	-	100.00%	-	-	-	3	-

Company Name
AMP Planning Period

Wellington Electricity Lines
1 April 2026 - 31 March 2036

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	12b(i): System Growth - Zone Substations	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
9		8 Ira Street	16	Winter	20	N-1 switched	No constraint	4.2	Winter	0.57	N-1 switched	Winter	0.0	0.0	N-1 switched	Security		8 Subtransmission circuit	Undecided	Planning stage	> 3 years	Demand forecast is highly dependent on future customer intentions and consumption patterns. Temporary measure is load control and post contingency offload to neighbouring zone substations.
10		Brown Owl	16	Winter	18	N-1	No constraint	2.9	Winter	1.81	N-1	Winter	0.0	0.9	N-1	Security		9 Subtransmission circuit	Undecided	Planning stage	> 3 years	Demand forecast is highly dependent on future customer intentions and consumption patterns. Temporary measure is load control and post contingency offload to neighbouring zone substations.
11		Evans Bay	12	Winter	24	N-1 switched	No constraint	11.7	Winter	10.94	N-1 switched	Winter	11.4	10.4	N-1 switched	No constraint	10+	Not applicable	Not required	Not applicable	Not applicable	
12		Frederick Street	24	Winter	30	N-1 switched	No constraint	6.3	Winter	4.57	N-1 switched	Winter	0.0	3.9	N-1 switched	No constraint	10+	Not applicable	Not required	Not applicable	Not applicable	
13		Gracefield	10	Winter	18	N-1	No constraint	8.7	Winter	8.55	N-1	Winter	4.9	7.9	N-1	No constraint	10+	Not applicable	Not required	Not applicable	Not applicable	
14		Hataitai	15	Winter	18	N-1 switched	No constraint	3.3	Winter	3.27	N-1 switched	Winter	2.4	3.0	N-1 switched	No constraint	10+	Not applicable	Not required	Not applicable	Not applicable	
15		Johnsonville	20	Winter	16	N-1	Security	0.0	Winter	0.00	N-1	Winter	0.0	0.0	N-1	Security	None	Subtransmission circuit	Network upgrade	Planning stage	> 3 years	Solution is a permanent load transfer to proposed Grenada zone substation from 2028. Temporary measure is load control and post contingency offload to neighbouring zone substations.
16		Karori	14	Winter	19	N-1 switched	No constraint	5.0	Winter	3.51	N-1 switched	Winter	1.6	3.0	N-1 switched	No constraint	10+	Not applicable	Not required	Not applicable	Not applicable	
17		Kenepeurua	11	Winter	18	N-1	No constraint	7.2	Winter	6.68	N-1	Winter	4.1	6.5	N-1	No constraint	10+	Not applicable	Not required	Not applicable	Not applicable	
18		Korokoro	17	Winter	16	N-1	Security	0.0	Winter	0.00	N-1	Winter	0.0	0.0	N-1	Security	None	Subtransmission circuit	Undecided	Planning stage	> 3 years	Demand forecast is highly dependent on future customer intentions and consumption patterns. Temporary measure is load control and post contingency offload to neighbouring zone substations.
19		Maldstone	14	Winter	18	N-1	No constraint	3.8	Winter	2.78	N-1	Winter	1.1	2.3	N-1	No constraint	10+	Not applicable	Not required	Not applicable	Not applicable	
20		Mana	11	Winter	7	N-1	Security	0.0	Winter	0.00	N-1	Winter	0.0	0.0	N-1	Security	None	Distribution back-up circuit capacity	Network upgrade	Planning stage	> 3 years	Solution is upgrade of 11kV bus tie between Mana and Plimmerton. Temporary measure is load control and post contingency offload.
21		Moore Street	18	Summer	30	N-1 switched	No constraint	11.6	Summer	10.24	N-1 switched	Summer	4.7	11.0	N-1 switched	No constraint	10+	Not applicable	Not required	Not applicable	Not applicable	
22		Naemae	15	Winter	18	N-1	No constraint	3.0	Winter	2.19	N-1	Winter	0.0	1.1	N-1	Security		6 Subtransmission circuit	Undecided	Planning stage	> 3 years	Demand forecast is highly dependent on future customer intentions and consumption patterns. Temporary measure is load control and post contingency offload to neighbouring zone substations.
23		Nairn Street	20	Winter	22	N-1	No constraint	2.5	Winter	0.84	N-1	Winter	0.0	0.5	N-1	Security		6 Subtransmission circuit	Undecided	Planning stage	> 3 years	Demand forecast is highly dependent on future customer intentions and consumption patterns. Temporary measure is load control and post contingency offload to neighbouring zone substations.
24		Ngauranga	10	Winter	10	N-1	Security	0.0	Winter	0.00	N-1	Winter	0.0	0.0	N-1	Security	None	Zone substation transformer	Network upgrade	Planning stage	> 3 years	Solution is a power transformer upgrade. Temporary measure is load control and post contingency offload.
25		Palm Grove	22	Winter	20	N-1 switched	Security	0.0	Winter	0.00	N-1 switched	Winter	0.0	0.0	N-1 switched	Security	None	Zone substation transformer	Divert load to alternative substation	Planning stage	> 3 years	Solution is to build new zone substation in Newtown to relieve Palm Grove transformers. Temporary measure is load control and post contingency offload.
26		Plimmerton	6	Winter	7	N-1	No constraint	1.1	Winter	0.57	N-1	Winter	0.0	0.0	N-1	Security		Distribution back-up circuit capacity	Network upgrade	Planning stage	Not applicable	Solution is upgrade of 11kV bus tie between Mana and Plimmerton. Temporary measure is load control and post contingency offload.



Company Name
AMP Planning Period

Wellington Electricity Lines
1 April 2026 - 31 March 2036

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	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
7	12b(i): System Growth - Zone Substations																				
27	Porirua	21	Winter	16	N-1	Security	0.0	Winter	0.00	N-1	Winter	0.0	0.0	N-1	Security	None	Zone substation transformer	Network upgrade	Planning stage	Not applicable	Solution is Zone substation upgrade and constructing new 11 kV feeders from Kenepuru. Temporary measure is load control and post contingency offload.
28	Seaview	14	Winter	14	N-1	Security	0.0	Winter	0.00	N-1	Winter	0.0	0.0	N-1	Security	None	Subtransmission circuit	Undecided	Planning stage	> 3 years	Demand forecast is highly dependent on future customer intentions and consumption patterns. Temporary measure is load control and post contingency offload to neighbouring zone substations.
29	Tawa	14	Winter	16	N-1	No constraint	2.1	Winter	0.88	N-1	Winter	0.0	0.3	N-1	Security	2	Zone substation transformer	Undecided	Planning stage	> 3 years	Temporary measure is load control and post contingency offload to neighbouring zone substations.
30	The Terrace	20	Winter	30	N-1 switched	No constraint	10.2	Winter	9.62	N-1 switched	Winter	7.1	9.0	N-1 switched	No constraint	10+	Not applicable	Not required	Not applicable	Not applicable	
31	Trentham	17	Winter	19	N-1	No constraint	2.3	Winter	0.00	N-1	Winter	0.0	0.0	N-1	Security	1	Subtransmission circuit	Network upgrade	Planning stage	Not applicable	Solution is to replace the Trentham fluid-filled 33kV cable and Upgrade strategic sections of cable and overhead line between Trentham and Maidstone Zone Substation and SCADA-use open points. Temporary measure is load control and post contingency offload.
32	University	17	Winter	20	N-1 switched	No constraint	3.4	Winter	2.75	N-1 switched	Winter	1.4	2.5	N-1 switched	No constraint	10+	Not applicable	Not required	Not applicable	Not applicable	
33	Waikowhai Street	13	Winter	15	N-1 switched	No constraint	2.0	Winter	1.97	N-1 switched	Winter	0.8	1.6	N-1 switched	No constraint	10+	Not applicable	Not required	Not applicable	Not applicable	
34	Wainuiomata	17	Winter	16	N-1	Security	0.0	Winter	0.00	N-1	Winter	0.0	0.0	N-1	Security	None	Zone substation transformer	Network upgrade	Planning stage	Not applicable	Solution is to replace the transformers with higher capacity units
35	Waitangirua	13	Winter	16	N-1	No constraint	2.6	Winter	1.59	N-1	Winter	0.0	0.2	N-1	Security	7	Zone substation transformer	Undecided	Planning stage	> 3 years	Demand forecast is highly dependent on future customer intentions and consumption patterns. Temporary measure is load control and post contingency offload to neighbouring zone substations.
36	Waterloo	15	Winter	18	N-1	No constraint	3.0	Winter	2.72	N-1	Winter	0.9	2.5	N-1	No constraint	10+	Not applicable	Not required	Not applicable	Not applicable	
37	* Extend table as necessary to disclose all capacity and constraint information by each zone substation																				

Company Name **Wellington Electricity Lines**AMP Planning Period **1 April 2026 - 31 March 2036****SCHEDULE 12c: REPORT ON FORECAST NETWORK DEMAND**

This schedule requires a forecast of new connections (by consumer type), peak demand and energy volumes for the disclosure year and a 5 year planning period. The forecasts should be consistent with the supporting information set out in the AMP as well as the assumptions used in developing the expenditure forecasts in Schedule 11a and Schedule 11b and the capacity and utilisation forecasts in Schedule 12b.

sch ref

12c(i): Consumer Connections

Number of ICPs connected during year by consumer type

 Number of connections
 Current Year CY CY+1 CY+2 CY+3 CY+4 CY+5

Consumer types defined by EDB*

Domestic
Small Commercial
Medium Commercial
Large Commercial
Small Industrial
Large Industrial
Unmetered

817	948	892	898	905	911
22	153	353	355	358	360
5	8	12	12	12	12
9	11	13	13	13	13
10	16	21	21	21	21
-	1	1	1	1	1
46	-	-	-	-	-
909	1,137	1,291	1,300	1,309	1,319

Connections total

*include additional rows if needed

Distributed generation

Number of connections made in year

Capacity of distributed generation installed in year (MVA)

Current Year CY CY+1 CY+2 CY+3 CY+4 CY+5

681	780	894	1,025	1,175	1,347
3	4	4	5	6	7

12c(ii): System Demand**Maximum coincident system demand (MW)**

GXP demand

plus Distributed generation output at HV and above

Maximum coincident system demand

less Net transfers to (from) other EDBs at HV and above

Demand on system for supply to consumers' connection points

Current Year CY CY+1 CY+2 CY+3 CY+4 CY+5

471	491	498	501	503	505
60	60	60	60	60	60
531	551	558	561	563	565
-	-	-	-	-	-
531	551	558	561	563	565

Electricity volumes carried (GWh)

Electricity supplied from GXPs

less Electricity exports to GXPs

plus Electricity supplied from distributed generation

less Net electricity supplied to (from) other EDBs

Electricity entering system for supply to ICPs

less Total energy delivered to ICPs

Losses

Load factor

Loss ratio

2,225	2,225	2,253	2,265	2,273	2,282
103	103	103	103	103	103
258	258	258	258	258	258
-	-	-	-	-	-
2,381	2,381	2,409	2,421	2,429	2,437
2,280	2,280	2,307	2,319	2,326	2,334
101	101	102	102	103	103
51%	49%	49%	49%	49%	49%
4.2%	4.2%	4.2%	4.2%	4.2%	4.2%

Company Name

Wellington Electricity Lines

AMP Planning Period

1 April 2026 - 31 March 2036

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)	12.2	12.9	13.4	12.8	11.4	10.9
12	Class C (unplanned interruptions on the network)	30.7	29.6	29.6	29.6	29.6	29.6
13	SAIFI						
14	Class B (planned interruptions on the network)	0.08	0.08	0.09	0.08	0.07	0.07
15	Class C (unplanned interruptions on the network)	0.43	0.46	0.46	0.46	0.46	0.46

Company Name **Wellington Electricity Lines**
 AMP Planning Period **1 April 2026 - 31 March 2036**
 Asset Management Standard Applied **PAS 55**

SCHEDULE 13: REPORT ON ASSET MANAGEMENT MATURITY

This schedule requires information on the EDB's self-assessment of the maturity of its asset management practices.

Question No.	Function	Question	Score	Evidence—Summary	User Guidance	Why	Who	Record/documented Information
3	Asset management policy	To what extent has an asset management policy been documented, authorised and communicated?	3	WELL maintains an Asset Management Policy that is aligned with its organisational vision and directly linked to its broader strategies, objectives, and performance targets. Supporting this framework, WELL has published an overarching Asset Management Strategy, together with asset-specific Fleet Strategies that guide the lifecycle management of individual asset classes.		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 Asset Management Strategy are reflected within this AMP. In developing both the overarching Strategy and the supporting Fleet Strategies, WELL has ensured alignment with relevant organisational policies and has taken into account the expectations and interests of 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 policies, strategies and stakeholder requirements as covered in drafting the asset management policy but at a greater level of detail.	Top management. The organisation's strategic planning team. The management team that has overall responsibility for asset management.	The organisation's asset management strategy document and other related organisational policies and strategies. Other than the organisation's strategic plan, these could include those relating to health and safety, environmental, etc. Results of stakeholder consultation.
11	Asset management strategy	In what way does the organisation's asset management strategy take account of the lifecycle of the assets, asset types and asset systems over which the organisation has stewardship?	2	WELL has published an Asset Management Strategy that provides a framework for the comprehensive management of its asset base. Supporting Asset Fleet Strategies have been developed for the primary asset classes and were reviewed in 2025 to ensure continued relevance and alignment with business objectives. Strategies for secondary asset classes are substantially complete and are in the process of being finalised, with publication and implementation to follow.		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	Building on the Asset Fleet Strategies described above, WELL has implemented comprehensive lifecycle-based asset management plans for each key asset class, ensuring that planning, operation, maintenance, renewal, and disposal activities are aligned with its asset management objectives and overarching strategy.		The asset management strategy need to be translated into practical plan(s) so that all parties know how the objectives will be achieved. The development of plan(s) will need to identify the specific tasks and activities required to optimize costs, risks and performance of the assets and/or asset system(s), when they are to be carried out and the resources required.	The management team with overall responsibility for the asset management system. Operations, maintenance and engineering managers.	The organisation's asset management plan(s).

Company Name **Wellington Electricity Lines**
 AMP Planning Period
 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/document Information
27	Asset management plan(s)	How has the organisation communicated its plan(s) to all relevant parties to a level of detail appropriate to the receiver's role in their delivery?	3	The plan is communicated to relevant employees, stakeholders, and contracted service providers, with all asset strategies issued as controlled documents under WELL's document management framework. Additional work has been undertaken to improve forward visibility of the multi-year work programme to contractors, supporting resourcing certainty and more efficient delivery planning.	The AMMAT score increased from 2 to 3 following the completion of the project to formalise and control asset management strategies within WELL's document framework and provide contractors with improved forward visibility of the multi-year work programme.	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 clearly documents accountabilities for the delivery of planned actions and provides sufficient detail to support effective implementation. Roles and responsibilities for individuals and organisational functions are defined to ensure clarity of ownership and coordination across the business.		The implementation of asset management plan(s) relies on (1) actions being clearly identified, (2) an owner allocated and (3) that owner having sufficient delegated responsibility and authority to carry out the work required. It also requires alignment of actions across the organisation. This question explores how well the plan(s) set out responsibility for delivery of asset plan actions.	The management team with overall responsibility for the asset management system. Operations, maintenance and engineering managers. If appropriate, the performance management team.	The organisation's asset management plan(s). Documentation defining roles and responsibilities of individuals and organisational departments.
31	Asset management plan(s)	What has the organisation done to ensure that appropriate arrangements are made available for the efficient and cost effective implementation of the plan(s)? (Note this is about resources and enabling support)	3	WELL has established a Project Management Office (PMO) to oversee the outsourced delivery of large capital projects. These work packages are structured on an end-to-end design and construction basis, enabling internal resources to remain focused on critical business-as-usual programmes. In parallel, WELL is broadening its contractor base, with increased emphasis on civil capability, to ensure the market has the skills and capacity required to deliver the forward work plan. During 2025 and early 2026, the business has also progressed the alignment of internal processes and governance frameworks to support the efficient and coordinated delivery of the expanded programme.		It is essential that the plan(s) are realistic and can be implemented, which requires appropriate resources to be available and enabling mechanisms in place. This question explores how well this is achieved. The plan(s) not only need to consider the resources directly required and timescales, but also the enabling activities, including for example, training requirements, supply chain capability and procurement timescales.	The management team with overall responsibility for the asset management system. Operations, maintenance and engineering managers. If appropriate, the performance management team. Where appropriate the procurement team and service providers working on the organisation's asset-related activities.	The organisation's asset management plan(s). Documented processes and procedures for the delivery of the asset management plan.
33	Contingency planning	What plan(s) and procedure(s) does the organisation have for identifying and responding to incidents and emergency situations and ensuring continuity of critical asset management activities?	3	WELL maintains a comprehensive suite of Emergency Response Procedures and Contingency Plans designed to mitigate and manage the consequences of High Impact Low Probability (HILP) events. These plans, which are listed and described in Section 12 of this AMP, support coordinated response, service restoration, and business continuity across the organisation. All contingency and continuity documentation, including the Major Event Plan, was reviewed and updated in 2025 to ensure it remains aligned with current risk assessments, regulatory expectations, and operational arrangements.		Widely used AM practice standards require that an organisation has plan(s) to identify and respond to emergency situations. Emergency plan(s) should outline the actions to be taken to respond to specified emergency situations and ensure continuity of critical asset management activities including the communication to, and involvement of, external agencies. This question assesses if, and how well, these plan(s) triggered, implemented and resolved in the event of an incident. The plan(s) should be appropriate to the level of risk as determined by the organisation's risk assessment methodology. It is also a requirement that relevant personnel are competent and trained.	The manager with responsibility for developing emergency plan(s). The organisation's risk assessment team. People with designated duties within the plan(s) and procedure(s) for dealing with incidents and emergency situations.	The organisation's plan(s) and procedure(s) for dealing with emergencies. The organisation's risk assessments and risk registers.

Company Name **Wellington Electricity Lines**
 AMP Planning Period
 Asset Management Standard Applied **PAS 55**

SCHEDULE 13: REPORT ON ASSET MANAGEMENT MATURITY (cont)

Question No.	Function	Question	Score	Evidence—Summary	User Guidance	Why	Who	Record/documented Information
37	Structure, authority and responsibilities	What has the organisation done to appoint member(s) of its management team to be responsible for ensuring that the organisation's assets deliver the requirements of the asset management strategy, objectives and plan(s)?	3	Accountability for asset management is clearly defined within WELL's organisational structure, cascading from the Chief Executive Officer to the General Manager – Asset Management, and through to the relevant functional Line Managers responsible for delivery.		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	Senior management recognises that a step change in investment will be required to deliver the forward work programme and is therefore developing an updated delivery strategy and resourcing plan to support this transition. This includes scaling both internal capability and outsourced delivery capacity, and building new competencies beyond current levels. In parallel, WELL is assessing whether a CPP application would better align revenue allowances with the resourcing required to deliver the programme sustainably, given the constraints of the DPP4 settings.		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 structured through annual AMP disclosures, routine internal and external reporting, and regular weekly and monthly meetings with management teams and service providers to ensure alignment, transparency, and effective programme delivery.		Widely used AM practice standards require an organisation to communicate the importance of meeting its asset management requirements such that personnel fully understand, take ownership of, and are fully engaged in the delivery of the asset management requirements (eg, PAS 55 s 4.4.1 g).	Top management. The management team that has overall responsibility for asset management. People involved in the delivery of the asset management requirements.	Evidence of such activities as road shows, written bulletins, workshops, team talks and management walkabouts would assist an organisation to demonstrate it is meeting this requirement of PAS 55.
45	Outsourcing of asset management activities	Where the organisation has outsourced some of its asset management activities, how has it ensured that appropriate controls are in place to ensure the compliant delivery of its organisational strategic plan, and its asset management policy and strategy?	3	WELL outsources a range of asset management activities, particularly within Service Delivery functions, as outlined in Section 5 of this AMP. These arrangements are governed by comprehensive contracts with clearly defined performance measures to ensure activities are delivered efficiently, safely, and cost-effectively.		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.

Company Name **Wellington Electricity Lines**
 AMP Planning Period
 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
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 maintains formal role descriptions for all positions with asset management responsibilities and ensures these roles are filled by appropriately qualified and experienced personnel to support the effective delivery of its asset management functions.		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	Formal position descriptions are in place for all staff involved in asset management functions, and targeted training and development programmes are undertaken to ensure personnel can meet the requirements set out in the AMP. Competency requirements are also defined for all principal contracting activities, with WELL actively monitoring and verifying that contractor personnel hold and maintain the necessary qualifications and certifications.		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 beginning of each year and are reviewed regularly through the staff performance review process. Competency requirements are defined for all principal contracting activities, and WELL monitors and verifies that contractor personnel hold and maintain the necessary skills and qualifications.		A critical success factor for the effective development and implementation of an asset management system is the competence of persons undertaking these activities. Organisations should have effective means in place for ensuring the competence of employees to carry out their designated asset management function(s). Where an organisation has contracted service providers undertaking elements of its asset management system then the organisation shall assure itself that the outsourced service provider also has suitable arrangements in place to manage the competencies of its employees. The organisation should ensure that the individual and corporate competencies it requires are in place and actively monitor, develop and maintain an appropriate balance of these competencies.	Managers, supervisors, persons responsible for developing training programmes. Staff responsible for procurement and service agreements. HR staff and those responsible for recruitment.	Evidence of a competency assessment framework that aligns with established frameworks such as the asset management Competencies Requirements Framework (Version 2.0); National Occupational Standards for Management and Leadership; UK Standard for Professional Engineering Competence, Engineering Council, 2005.

						Company Name	Wellington Electricity Lines	
						AMP Planning Period		
						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
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, WELL maintains regular contract management meetings between its Safety, Asset Management, and Service Delivery managers and the respective service providers to review performance, risks, and forward work programmes. More detailed asset management matters are communicated between employees and contractors through safety alerts, technical alerts, network instructions, and participation in technical forums, ensuring alignment on standards, emerging issues, and continuous improvement initiatives.		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	Comprehensive asset management documentation and control processes are established across the business and are described in Section 5 of this AMP, including the governance, approval, review, and version control arrangements that support effective implementation.		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	A comprehensive review of asset management information requirements was completed in 2025 to define the data architecture, system integrations, governance frameworks, and analytical capability required to support a more mature asset management system. Delivering the identified enhancements — including improved data quality, expanded condition and performance datasets, strengthened platform integration, and advanced analytics — will require sustained investment beyond what is accommodated within DPP4 allowances and is therefore is likely to be more appropriately supported through a CPP.		Effective asset management requires appropriate information to be available. Widely used AM standards therefore require the organisation to identify the asset management information it requires in order to support its asset management system. Some of the information required may be held by suppliers. The maintenance and development of asset management information systems is a poorly understood specialist activity that is akin to IT management but different from IT management. This group of questions provides some indications as to whether the capability is available and applied. Note: To be effective, an asset information management system requires the mobilisation of technology, people and process(es) that create, secure, make available and destroy the information required to support the asset management system.	The organisation's strategic planning team. The management team that has overall responsibility for asset management. Information management team. Operations, maintenance and engineering managers	Details of the process the organisation has employed to determine what its asset information system should contain in order to support its asset management system. Evidence that this has been effectively implemented.
63	Information management	How does the organisation maintain its asset management information system(s) and ensure that the data held within it (them) is of the requisite quality and accuracy and is consistent?	2	Controls are in place, including defined data quality standards, to manage the integrity and accuracy of information entered into WELL's asset management information systems. Formal quality assurance and audit processes support ongoing validation of critical datasets. Further work is required to strengthen and enforce data quality expectations for externally sourced information, such as smart metering data, to ensure it meets the standards necessary to support robust asset management decision-making.		The response to the questions is progressive. A higher scale cannot be awarded without achieving the requirements of the lower scale. This question explores how the organisation ensures that information management meets widely used AM practice requirements (eg, s 4.4.6 (a), (c) and (d) of PAS 55).	The management team that has overall responsibility for asset management. Users of the organisational information systems.	The asset management information system, together with the policies, procedure(s), improvement initiatives and audits regarding information controls.

Company Name Wellington Electricity Lines AMP Planning Period 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
64	Information management	How has the organisation's ensured its asset management information system is relevant to its needs?	3	Asset management requirements were comprehensively reviewed during the development of the business cases for the implementation of SAP-PM and the GIS upgrade to ensure alignment with WELL's asset management needs. These systems have also been subject to periodic independent review by CHED auditors, Jacobs, PwC, and other external specialists to confirm their adequacy and effectiveness in supporting asset management processes.		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 management approach with CKI's by adopting the Enterprise Risk Management (ERM) – Integrated Framework: Risk Management – Principles and Guidelines standard. This framework provides a structured and robust methodology for identifying, assessing, and managing risk, and is applied consistently across 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 systematically incorporated into standards, procedures, and training programmes through actions arising from governance forums, operational meetings, and other structured communications. These actions are recorded and monitored through the 1FICs tracking tool, with progress and close-out status reported through to the Board level to ensure appropriate oversight and accountability.		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 maintains in-house capability to manage legal, regulatory, and statutory obligations, as well as broader asset management requirements, with dedicated staff responsible for ensuring compliance, supporting regulatory engagement, and integrating these requirements into business planning and operational processes.		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

Company Name **Wellington Electricity Lines**
 AMP Planning Period
 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
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 engaged where appropriate to support the design phase, with clearly defined scopes of work governed by Short Form Agreements. Procurement activities are managed in accordance with approved materials standards to ensure consistency and compliance. Construction and commissioning are outsourced to service providers under formal contractual arrangements, with defined performance, quality, and safety controls to ensure effective delivery.		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	An inspection and maintenance programme is in place, with remedial actions prioritised based on the criticality of identified defects. Ongoing training supports consistency in inspection practices and condition assessment, and ensures that outputs are effectively translated into optimised maintenance planning. These programmes are reviewed annually to confirm their continued effectiveness and to incorporate improvements where appropriate.		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 undertakes an annual assessment of all primary assets using Asset Health Indicators (AHI) aligned with the EEA Asset Health Indicator Guide, complemented by internally developed Asset Criticality Indices (ACI) to better quantify network risk. These assessments draw on data generated through the inspection and maintenance programme delivered by the Field Service Provider in accordance with defined standards and frequencies. The combined AHI and ACI analysis informs performance monitoring, supports risk-based prioritisation, and is used to update Fleet Strategies and associated renewal 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 established formal procedures that clearly define roles, responsibilities, and escalation pathways for managing major incidents and emergency situations. In addition, the Asset Failure Investigation Standard sets out the structured process for investigating asset-related failures, including accountabilities, root cause analysis requirements, and feedback mechanisms to ensure lessons learned are incorporated into asset management practices.		Widely used AM standards require that the organisation establishes implements and maintains process(es) for the handling and investigation of failures incidents and non-conformities for assets and sets down a number of expectations. Specifically this question examines the requirement to define clearly responsibilities and authorities for these activities, and communicate these unambiguously to relevant people including external stakeholders if appropriate.	The organisation's safety and environment management team. The team with overall responsibility for the management of the assets. People who have appointed roles within the asset-related investigation procedure, from those who carry out the investigations to senior management who review the recommendations. Operational controllers responsible for managing the asset base under fault conditions and maintaining services to consumers. Contractors and other third parties as appropriate.	Process(es) and procedure(s) for the handling, investigation and mitigation of asset-related failures, incidents and emergency situations and non conformances. Documentation of assigned responsibilities and authority to employees. Job Descriptions, Audit reports. Common communication systems i.e. all Job Descriptions on Internet etc.

					Company Name	Wellington Electricity Lines		
					AMP Planning Period			
					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/document Information
105	Audit	What has the organisation done to establish procedure(s) for the audit of its asset management system (process(es))?	3	CKI's internal audit function, CHED Services (Melbourne), undertakes comprehensive audits of two selected business areas each year, providing independent oversight of key processes and controls. In addition, WELL's asset management activities and processes have been subject to an external review by Jacobs, which resulted in a positive assessment confirming the strength and maturity of the framework in place.		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 investigations are conducted collaboratively by WELL and its service providers, with resulting corrective actions formally recorded, reviewed, and discussed at weekly operational meetings. The 1FICs software platform is used to log incidents, assign and monitor actions, and track progress through to completion and formal close-out, ensuring transparency and accountability across the organisation.		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 set out asset-specific approaches to achieving WELL's asset management objectives. These strategies assess performance and condition across the full asset lifecycle, together with maintenance and replacement costs and associated asset risks. They are maintained as controlled documents and reviewed annually, with the update process supporting continual improvement in the management of asset performance, condition, cost efficiency, and risk.		Widely used AM standards have requirements to establish, implement and maintain process(es)/procedure(s) for identifying, assessing, prioritising and implementing actions to achieve continual improvement. Specifically there is a requirement to demonstrate continual improvement in optimisation of cost risk and performance/condition of assets across the life cycle. This question explores an organisation's capabilities in this area—looking for systematic improvement mechanisms rather than reviews and audit (which are separately examined).	The top management of the organisation. The manager/team responsible for managing the organisation's asset management system, including its continual improvement. Managers responsible for policy development and implementation.	Records showing systematic exploration of improvement. Evidence of new techniques being explored and implemented. Changes in procedure(s) and process(es) reflecting improved use of optimisation tools/techniques and available information. Evidence of working parties and research.
115	Continual Improvement	How does the organisation seek and acquire knowledge about new asset management related technology and practices, and evaluate their potential benefit to the organisation?	3	As part of a wider international group, WELL places significant importance on capturing and applying learnings from its sister companies and from across the New Zealand electricity industry. Regular forums and video conferences are held to share developments in asset management practice, technology, and delivery models, ensuring that international experience and industry best practice inform WELL's ongoing continuous improvement initiatives.		One important aspect of continual improvement is where an organisation looks beyond its existing boundaries and knowledge base to look at what 'new things are on the market'. These new things can include equipment, process(es), tools, etc. An organisation which does this (eg, by the PAS 55 s 4.6 standards) will be able to demonstrate that it continually seeks to expand its knowledge of all things affecting its asset management approach and capabilities. The organisation will be able to demonstrate that it identifies any such opportunities to improve, evaluates them for suitability to its own organisation and implements them as appropriate. This question explores an organisation's approach to this activity.	The top management of the organisation. The manager/team responsible for managing the organisation's asset management system, including its continual improvement. People who monitor the various items that require monitoring for 'change'. People that implement changes to the organisation's policy, strategy, etc. People within an organisation with responsibility for investigating, evaluating, recommending and implementing new tools and techniques, etc.	Research and development projects and records, benchmarking and participation knowledge exchange professional forums. Evidence of correspondence relating to knowledge acquisition. Examples of change implementation and evaluation of new tools, and techniques linked to asset management strategy and objectives.

Schedule 14a: Mandatory Explanatory Notes on Forecast Information

(In this Schedule, clause references are to the Electricity Distribution Information Disclosure Determination 2012 – as amended 27 November 2024)

This Schedule requires 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 the 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 the 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 2026.

The difference between 1 April 2026 (CY+1) through to 1 April 2035 (CY+10) reflects inflation. Inflation is consistent with the Reserve Bank's February 2026 Monetary Policy Statement⁸³.

Disclosure Year Beginning 1 April			
2026	2027	2028	2029 to 2035
2.2%	2.2%	2.2%	2.2%

Commentary on the 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 the 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 2026.

The difference between 1 April 2026 (CY+1) through to 1 April 2035 (CY+10) reflects inflation. Inflation is consistent with the Reserve Bank's February 2026 Monetary Policy Statement⁸⁴.

Disclosure Year Beginning 1 April			
2026	2027	2028	2029 to 2035
2.2%	2.2%	2.2%	2.2%

⁸³ Reserve Bank of New Zealand, Monetary Policy Statement, February 2026, https://www.rbnz.govt.nz/-/media/project/sites/rbnz/files/publications/monetary-policy-statements/2026/feb-180226/mps_report_feb2026.pdf

⁸⁴ Supra n83

Appendix D EDB Information Disclosure Determination 2012 Compliance Register

Clauses as prescribed by Attachment A of the Information Disclosure Determination 2012	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	5.2, 5.3
3.3 A purpose statement which- 3.3.1 makes clear the purpose and status of the AMP in the EDB's asset management practices. The purpose statement must also include a statement of the objectives of the asset management and planning processes 3.3.2 states the corporate mission or vision as it relates to asset management 3.3.3 identifies the documented plans produced as outputs of the annual business planning process adopted by the EDB 3.3.4 states how the different documented plans relate to one another, with particular reference to any plans specifically dealing with asset management 3.5.3 includes a description of the interaction between the objectives of the AMP and other corporate goals, business planning processes, and plans	2.1 3.1 5.5 5.4 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 3.6.2 what these interests are 3.6.3 how these interests are accommodated in asset management practices 3.6.4 how conflicting interests are managed	3.6.1 3.6.1 3.6.1 3.6.2

Clauses as prescribed by Attachment A of the Information Disclosure Determination 2012	AMP section
3.7 A description of the accountabilities and responsibilities for asset management on at least 3 levels, including- 3.7.1 governance—a description of the extent of director approval required for key asset management decisions and the extent to which asset management outcomes are regularly reported to directors 3.7.2 executive—an indication of how the in-house asset management and planning organisation is structured 3.7.3 field operations—an overview of how field operations are managed, including a description of the extent to which field work is undertaken in-house and the areas where outsourced contractors are used	3.2.2 3.2.4.1 3.2.3 3.2.5 3.2.3, 3.2.5, 4.4.6, 5.1.1, 5.4.1, 6.1.4
3.8 All significant assumptions: 3.8.1 quantified where possible 3.8.2 clearly identified in a manner that makes their significance understandable to interested persons, including 3.8.3 a description of changes proposed where the information is not based on the EDB's existing business 3.8.4 the sources of uncertainty and the potential effect of the uncertainty on the prospective information 3.8.5 the price inflator assumptions used to prepare the financial information disclosed in nominal New Zealand dollars in the Report on Forecast Capital Expenditure set out in Schedule 11a and the Report on Forecast Operational Expenditure set out in Schedule 11b.	Appendix A Appendix A Appendix A Appendix A 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	4.1, 4.2, Appendix A
3.10 An overview of asset management strategy and delivery	5.2, 5.4
3.11 An overview of systems and information management data 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;	5.6, Appendix C 5.2.2 10

Clauses as prescribed by Attachment A of the Information Disclosure Determination 2012	AMP section
(c) the systems and controls to ensure the quality and accuracy of asset management information;	10.3
(d) the extent to which these systems, processes and controls are integrated;	10.1
(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
3.12 A statement covering any limitations in the availability or completeness of asset management data and disclose any initiatives intended to improve the quality of this data	10.3
3.13 A description of the processes used within the EDB for-	
3.13.1 managing routine asset inspections and network maintenance .	8.4, 8.5 10.1.1.10
3.13.2 planning and implementing network development projects	9.5
3.13.3 measuring network performance	6.2.2
3.14 An overview of asset management documentation, controls and review processes	5.5
3.15 An overview of communication and participation processes	3.6
3.16 The AMP must present all financial values in constant price New Zealand dollars except where specified otherwise;	2.3
3.17 The AMP must be structured and presented in a way that the EDB considers will support the purposes of AMP disclosure set out in clause 2.6.2 of the determination.	2.2
<u>Assets Covered</u>	
4. The AMP must provide details of the assets covered, including-	3.3
4.1 a high-level description of the service areas covered by the EDB and the degree to which these are interlinked, including-	3.4
4.1.1 the region(s) covered	3.4
4.1.2 identification of large consumers that have a significant impact on network operations or asset management priorities	3.5.1
4.1.3 description of the load characteristics for different parts of the network	3.4
4.1.4 peak demand and total energy delivered in the previous year, broken down by sub-network , if any.	3.4

Clauses as prescribed by Attachment A of the Information Disclosure Determination 2012	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, 9.5 to 9.10
4.2.3 a description of the distribution system, including the extent to which it is underground;	3.4
4.2.4 a brief description of the network's distribution substation arrangements;	3.4
4.2.5 a description of the low voltage network including the extent to which it is underground;	3.4
4.2.6 an overview of secondary assets such as protection relays, ripple injection systems, SCADA and telecommunications systems; and	8.5.15 8.5.17 8.5.16
4.2.7 a quantification of the contribution each non-network solution makes towards solving a network risk or constraint, and a description of the extent to which those non-network solutions are provided by a related party or third party.	9.5.4
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;	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 to 8.5.18
4.5.2 assets owned by the EDB but installed at bulk electricity supply points owned by others;	8.5.19
4.5.3 EDB owned mobile substations and generators whose function is to increase supply reliability or reduce peak demand; and	8.5.2.4 8.5.18.2
4.5.4 other generation plant owned by the EDB .	8.5.18.2

Clauses as prescribed by Attachment A of the Information Disclosure Determination 2012	AMP section
<u>Service Levels</u>	
5. The AMP must clearly identify or define a set of performance indicators for which annual performance targets have been defined. The annual performance targets must be consistent with business strategies and asset management objectives and be provided for each year of the AMP planning period . The targets should reflect what is practically achievable given the current network configuration, condition and planned expenditure levels. The targets should be disclosed for each year of the AMP planning period .	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 .	6.2
7. Performance indicators for which targets have been defined in clause 5 above should also include-	6.5
7.1 Consumer oriented indicators that preferably differentiate between different consumer types;	
7.2 Indicators of asset performance, asset efficiency and effectiveness, and service efficiency, such as technical and financial performance indicators related to the efficiency of asset utilisation and operation.	6.3, 7.2.1, 7.3.2, 8.2
8. The AMP must describe the basis on which the target level for each performance indicator was determined. Justification for target levels of service includes consumer expectations or demands, legislative, regulatory, and other stakeholders' requirements or considerations. The AMP should demonstrate how stakeholder needs were ascertained and translated into service level targets.	6 7.1, 7.2
9. Targets should be compared to historic values where available to provide context and scale to the reader.	6.2, 7.1, 7.3
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
<u>Network Development Planning</u>	
11. AMPs must provide a detailed description of network development plans, including—	
11.1 A description of the planning criteria and assumptions for network development;	9.5.2.1
11.2 Planning criteria for network developments should be described logically and succinctly. Where probabilistic or scenario-based planning techniques are used, this should be indicated and the methodology briefly described;	9.8 to 9.13 9.14.1 9.14.4
11.3 A description of strategies or processes (if any) used by the EDB that promote cost efficiency including through the use of standardised assets and designs;	8.2.2
11.4 The use of standardised designs may lead to improved cost efficiencies. This section should discuss-	
11.4.1 the categories of assets and designs that are standardised;	9.5.3
11.4.2 the approach used to identify standard designs.	8.2.2 9.5.3
11.5 A description of strategies or processes (if any) used by the EDB that promote the energy efficient operation of the network .	9.5.3.2
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 .	9.5.2.1

Clauses as prescribed by Attachment A of the Information Disclosure Determination 2012	AMP section
11.7 A description of the process and criteria used to prioritise network development projects and how these processes and criteria align with the overall corporate goals and vision.	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;	9.6
11.8.1 explain the load forecasting methodology and indicate all the factors used in preparing the load estimates;	9.7.1
11.8.2 provide separate forecasts to at least the zone substation level covering at least a minimum five year forecast period. Discuss how uncertain but substantial individual projects/developments that affect load are taken into account in the forecasts, making clear the extent to which these uncertain increases in demand are reflected in the forecasts;	9.6, 9.8
11.8.3 identify any network or equipment constraints that may arise due to the anticipated growth in demand during the AMP planning period ; and	8.5, 9.8
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.	9.5.5
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- ;	9.8 to 9.13
11.9.1 the reasons for choosing a selected option for projects where decisions have been made;	9.8 to 9.13
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	9.8 to 9.13
11.9.3 consideration of planned innovations that improve efficiencies within the network , such as improved utilisation, extended asset lives, and deferred investment.	9.5
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-	9.8 to 9.13
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;	9.8 to 9.13
11.10.2 a summary description of the programmes and projects planned for the following four years (where known); and	9.8 to 9.13
11.10.3 an overview of the material projects being considered for the remainder of the AMP planning period .	9.8 to 9.13
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.	9.5.5
11.12 A description of the EDB's policies on non-network solutions , including-	9.5.4
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;	9.5.4
11.12.2 the potential for non-network solutions to address network problems or constraints; and	9.5.4

Clauses as prescribed by Attachment A of the Information Disclosure Determination 2012	AMP section
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.	9.5.5.2
<u>Lifecycle Asset Management Planning (Maintenance and Renewal)</u> 12. The AMP must provide a detailed description of the lifecycle asset management processes, including— 12.1 The key drivers for maintenance planning and assumptions; 12.2 Identification of routine and corrective maintenance and inspection policies and programmes and actions to be taken for each asset category, including associated expenditure projections. This must include- 12.2.1 the approach to inspecting and maintaining each category of assets, including a description of the types of inspections, tests and condition monitoring carried out and the intervals at which this is done; 12.2.2 any systemic problems identified with any particular asset types and the proposed actions to address these problems; and 12.2.3 budgets for maintenance activities broken down by asset category for the AMP planning period .	8.4 8.5 8.5 8.5 8.6
12.3 Identification of asset replacement and renewal policies and programmes and actions to be taken for each asset category, including associated expenditure projections. This must include- 12.3.1 the processes used to decide when and whether an asset is replaced or refurbished, including a description of the factors on which decisions are based, and consideration of future demands on the network and the optimum use of existing network assets; . 12.3.2 a description of innovations made that have deferred asset replacement; 12.3.3 a description of the projects currently underway or planned for the next 12 months; 12.3.4 a summary of the projects planned for the following four years (where known); and 12.3.5 an overview of other work being considered for the remainder of the AMP planning period	8.2, 8.5 8.5 8.5 8.5 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: .	8.2
12.5.1 the approach that the EDB uses to inform its capital expenditure projections for lifecycle asset management; and	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

Clauses as prescribed by Attachment A of the Information Disclosure Determination 2012	AMP section
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	8.2.4
<u>Non-Network Development, Maintenance and Renewal</u>	
13. AMPs must provide a summary description of material non-network development, maintenance and renewal plans, including—	10
13.1 a description of non-network assets ;	10.1 to 10.5
13.2 development, maintenance and renewal policies that cover them;	10.1 to 10.5
13.3 a description of material capital expenditure projects (where known) planned for the next five years;	10.1 to 10.5
13.4 a description of material maintenance and renewal projects (where known) planned for the next five years.	10.6
14. AMPs 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;	7.2, 12.4
14.3 A description of the policies to mitigate or manage the risks of events identified in sub clause 14.2	12.4.2
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;	7
15.2 An evaluation and comparison of actual service level performance against targeted performance;	7.3
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
<u>Capability to Deliver</u>	
16. AMPs must describe the processes used by the EDB to ensure that-	
16.1 The AMP is realistic and the objectives set out in the plan can be achieved;	1.6, 4.4.6
16.2 The organisation structure and the processes for authorisation and business capabilities will support the implementation of the AMP plans.	3.2

Clauses as prescribed by Attachment A of the Information Disclosure Determination 2012	AMP section
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	6.5.1.1
17.4.4 commonly encountered delays and potential timeframes for different connections.	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.	9.5.1.1 9.5.5.2
<i>New connections likely to have a significant impact on network operations or asset management priorities</i>	
17.5 A description of the following:	
17.5.1 how the EDB assesses the impact that new demand, generation, or storage capacity will have on the EDB's network , including:	9.5.4
(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;	9.5.5
<i>Innovation practices</i>	
17.6 a description of the following:	
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;	11.1
17.6.2 the EDB's desired outcomes of any innovation practices , and how they may improve outcomes for consumers ;	11.2.2.1 to 11.2.2.4
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;	11.2
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	11.2.3 11.2.2.6
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.	11.2.2.5
17.7 For the purpose of disclosing the information required under clauses 17.6.1- 17.6.5 above, an EDB is not required to include commercially sensitive or confidential information.	

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

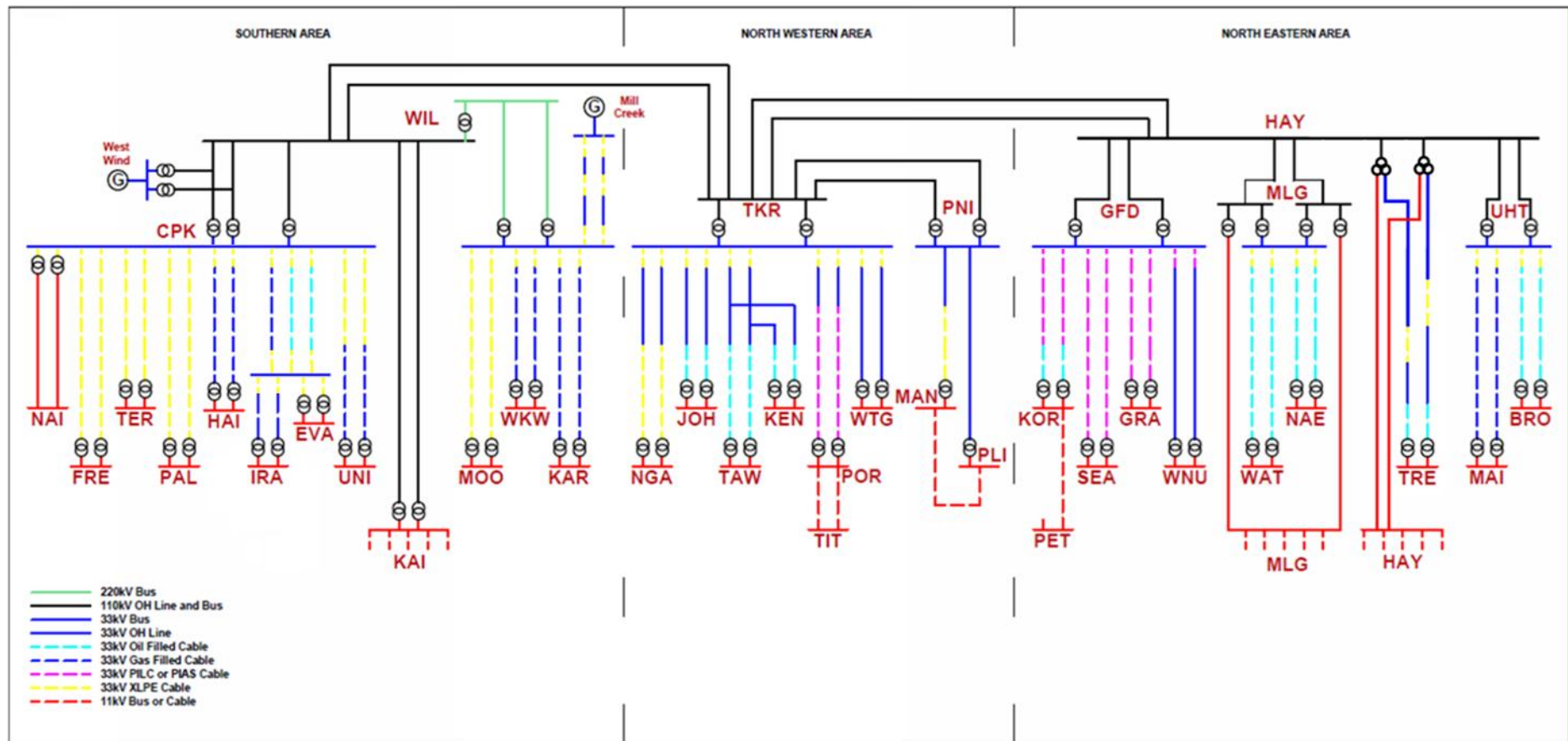
EDO	Expulsion Drop-out Fuse
EEA	Electricity Engineers Association
EECA	Energy Efficiency and Conservation Authority
EEP	Emergency Evacuation Plan
EIPC	Electricity Industry Participation Code
EMS	Energy Management System
ENA	Electricity Network Association
ERP	Emergency Response Plan
ESG	Environmental, 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 2.6.1, 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
Chairman



Charles Tsai
Director

25 March 2026

25 March 2026



*safer
together*